DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit AQ0270CPT04 **Final – October 13, 2009**
Rescinds Permit 9873-AC006

The Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Construction Permit AQ0270CPT04 to the Permittee listed below.

Permittee:	**BP Exploration (Alaska) Inc.** P.O. Box 196612 Anchorage, Alaska 99519
Owner(s):	See next page
Operator	Same as Permittee
Stationary Source:	**Central Gas Facility (CGF)**
Location:	Latitude: 70° 19' 15" N; Longitude: 148° 31' 00" W
Physical Address:	Section 11, Township 11N, Range 14E, Umiat Meridian
Project Name:	H_2S Limit Increase Project
Permit Contact:	Jim Pfeiffer (907) 564-4549

The Central Compressor Plant (CCP) and CGF are considered as one stationary source for air permitting purposes. The project is classified under 18 AAC 50.306 as a Prevention of Significant Deterioration (PSD) significant modification for Sulfur Dioxide (SO_2). This permit revises the SO_2 Best Available Control Technology (BACT) limits in the form of fuel gas hydrogen sulfide (H_2S) limits. This permit also establishes H_2S limits to comply with the ambient air quality standards and increments. This permit satisfies the obligation of the Permittee to obtain a construction permit under AS 46.14.120(a) and 18 AAC 50.306.

This permit authorizes the Permittee to modify the CGF under the terms and conditions of this permit, and as described in the original permit application and subsequent application supplements listed in Section 7 except as specified in this permit.

The Permittee shall **not operate** under this permit until after the Department issues a revised operating permit that includes the provision of this construction permit.

John F. Kuterbach
Manager, Air Permits Program

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Owner(s):

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

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

ExxonMobil Corporation
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

Abbreviations/Acronyms

AAAQS ....Alaska Ambient Air Quality Standards
AAC ....Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AS..................................Alaska Statutes
ASTM............................American Society of Testing and Materials
BACT ....Best Available Control Technology
BPXA ....BP Exploration (Alaska), Inc.
CCP ....Central Compressor Plant
CGF ....Central Gas Facility
C.F.R. ....Code of Federal Regulations
EPA ....Environmental Protection Agency
LHE ....Lean Head End
MR&R...........................Monitoring, Recordkeeping, and Reporting
NA ....Not Applicable
NSPS ....New Source Performance Standards
ORL...............................Owner Requested Limit
O/C ....Operating/Construction
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RM.................................Reference Method
TAR...............................Technical Analysis Report

Units and Measures

bhp.................................brake horsepower or boiler horsepower
gr./dscf...........................grains per dry standard cubic foot (1 pound = 7,000 grains)
dscf ....dry standard cubic foot
gph.................................gallons per hour
g/hp-hr ....grams per horsepower-hour
g/kW-hr ....grams per kilowatt-hour
hp...................................horsepower
kW ....kilowatts (electric)
lb....................................pounds
MMBtu ....million British thermal units
MMBtu/hr......................million British thermal units per hour
MMscf ....million standard cubic feet
MW................................Megawatts (electric)
ppm................................parts per million
ppmv..............................parts per million by volume
ppmvd............................parts per million by volume dry
scf ....standard cubic feet (dry gas at 68 °F and absolute pressure of 760 mmHg)
scfm ....standard cubic feet per minute (dry gas at 68 °F and absolute pressure of 760 mmHg)
TPY ....tons per year
wt%................................weight percent

Pollutants

CO ....Carbon Monoxide
NO_X ....Oxides of Nitrogen
NO_2................................Nitrogen Dioxide
PM-10............................Particulate Matter with an aerodynamic diameter less than 10 microns
S.....................................Sulfur
SO_2 ....Sulfur Dioxide
H_2S ....Hydrogen Sulfide

Table of Contents

Section 1. Emission Unit Inventory

1. **Installation Authorization.** The Permittee is authorized to install the emission units listed in Table 1 subject to terms and conditions of this permit. Except as noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement emission unit, including any applicable minor or construction permit requirements.

Table 1 – Emission Unit Inventory

Unit No.	Tag Number	Unit Description	Rating/ Size	Construction / Date[1]
		Gas Fired Turbines		
1	NGI-19-1883	GE Frame 6 Injection Compressor	53,665 hp ISO	4/1998
2	NGI-19-1884	GE Frame 6 Injection Compressor	53,665 hp ISO	4/1998
3	NGI-19-1885	GE Frame 6 Injection Compressor	53,665 hp ISO	4/1998
4	NGI-19-1886	GE Frame 6 Injection Compressor	53,665 hp ISO	4/1998
5	NGI-19-1801	Cooper-Rolls/RB211-24C Booster Compressor	33,300 hp ISO	1986
6	NGI-19-1802	Cooper-Rolls/RB211-24C Booster Compressor	33,300 hp ISO	1986
7	NGI-19-1805	Cooper-Rolls/RB211-24C Miscible Injectant Compressor	33,300 hp ISO	1986
8	NGI-19-1855	Cooper-Rolls/RB211-24C Miscible Injectant Compressor	33,300 hp ISO	1986
9	NGI-19-1806	GE MS5382C (Frame 5) Refrigerant Compressor	38,000 hp ISO	7/1998
10	NGI-19-1856	GE MS5382C (Frame 5) Refrigerant Compressor	38,000 hp ISO	8/1998
11	NGI-19-1857	GE MS5382C (Frame 5) Booster Compressor	38,000 hp ISO	9/1999
		Gas Fired Heaters		
12	NGI-19-1401	Chiyoda-John Zink Hot Oil Heater	216[2] MMBtu/hr	1986
13	NGI-19-1402	Chiyoda-John Zink Hot Oil Heater	216[2] MMBtu/hr	1986
14	NGI-19-1403	Chiyoda-John Zink Hot Oil Heater	216[2] MMBtu/hr	1986
		Liquid Fired Equipment		
15	NGI-19-2890	GM (EMD)/20-645F4B Emergency Electric Generator	2,865 kW/4,000 hp	1992
16	NGI-19-2802	GM (EMD)/20-645F4B Emergency Electric Generator	2,865 kW/4,000 hp	1986 (est.)
17	NGI-19-2819	GM (EMD)/20-645F4B Emergency Electric Generator	2,865 kW/4,000 hp	1986 (est.)
18	NGI-19-1529	Caterpillar/3406P Emergency Fire Water Pump	330 hp	1986 (est.)
		Flares		
19	19-1408	IHI-John Zink Emergency Flare (HP-Primary Pit)	3.0 MMscf/day combined total (pilot/purge/assist)	1986 (est.)
20	19-1409	IHI-John Zink Emergency Flare (LP-Primary Pit)		1986 (est.)
21	19-1410	IHI-John Zink Emergency Flare (HP-Emergency Pit)		1986 (est.)
22	19-1411	IHI-John Zink Emergency Flare (LP-Emergency Pit)		1986 (est.)
23	19-1412	IHI-John Zink Emergency Flare (NGL Burn Pit)		1986 (est.)
		Fixed Roof Storage Tanks (> 10,000 Gallon Capacity)		
24	19-1902	Arctic (No. 1) Diesel	2,175 bbls	1986
25	19-1905	Methanol	934 bbls	1986
		Natural Gas Processing Plant		
26	Modules and Skids	NGL Plant	N/A	1993

1 – Date construction commenced (if known) or the startup date of the unit. If a unit has been modified as defined by AS 46.990, then the most recent modification date has been provided.
2 - Heat Input, Low Heat Value

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. The quantity for which fees will be assessed is the lesser of

   2.1 the CGF portion of the stationary source's assessable potential to emit of 13,426 TPY; or

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

      a. an enforceable test method described in 18 AAC 50.220;

      b. material balance calculations;

      c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

      d. other methods and calculations approved by the Department**.**

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

   3.1 No later than March 31 of each year, the Permittee may submit an estimate of the CGF portion of the stationary sources's assessable emissions to ADEC, 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 31 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

Industrial Process and Fuel-Burning Equipment

4. **Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from Units 1 through 23 in Table 1 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

5. **Particulate Matter.** The Permittee shall not cause or allow particulate matter emitted from Units 1 through 23 listed in Table 1 to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

6. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from Units 1 through 23 listed in Table 1 to exceed 500 parts per million (ppm) averaged over three hours.

Section 4. Best Available Control Technology Limits

NO_X BACT[1] for Turbines carried over from past permit actions

7. **Turbine Lean Head End (LHE) Liners (Units 9 through 11)**. The Permittee shall operate Units 9 through 11 with LHE liner combustion technology or alternative technology capable of achieving continuous compliance with the limits specified in Condition 8.2. Monitoring shall consist of an annual certification that the Permittee complies with this condition.

8. **Turbines (Units 1 through 4 and 9 through 11).**

   8.1 For Units 1 through 4 limit the NO_X emissions as follows:

      a. 125 ppm by volume (ppmv) corrected to 15 percent Oxygen, and

      b. 282 lb/hour per unit.

   8.2 For Units 9 through 11, limit the NO_X emissions as follows:

      a. 85 ppmv corrected to 15 percent Oxygen, and

      b. 130 lb/hour per unit, expressed as NO_2.

   8.3 Monitoring, recordkeeping and reporting for Units 1 through 4 and 9 through 11:

      a. The Permittee shall conduct a NO_X emission source test on any one of Units 1 through 4 and one NO_X emission source test on any one of Units 9 through 11 no less than once every five years to demonstrate compliance with the limits in Conditions 8.1a, 8.1b, 8.2a and 8.2b. Perform and submit results of source test as described in General Source Testing Requirements in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

      b. For Units 1 through 4 and 9 through 11 use the results of the source tests performed in Condition 8.3a, to demonstrate compliance with the NO_X emission limits in Conditions 8.1a, 8.1b, 8.2a and 8.2b.

      c. Submit copies of the results obtained in Condition 8.3a with the Operating Report described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 submitted during the reporting period in which the source test results are submitted.

NO_X BACT[2] for Emergency Generator carried over from past permit actions

9. **Emergency Generator (Unit 15).**

   9.1 Limit

      a. NO_X emissions to no more than 146.4 lb/hr; and

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[1] These BACT limits were established in Permit 9873-AC006 for the miscible inject project in 1998 and carried over to Permit 270TVP01.

[2] These BACT limits were established in Permit 9273-AA016 for the gas expansion project in 1993 and carried over to Permit 270TVP01.

b. non-emergency[3] operation to no more than 200 hours per consecutive 12 month period.

9.2 To show compliance with the limit in Condition 9.1a, the Permittee shall keep records available for inspection which demonstrate the engine is maintained in good operating condition and in accordance with BPXA's established guidelines and operating procedures.

9.3 To show compliance with the limit in Condition 9.1b, monitor and record as described in Conditions 15.1, 15.2 and 15.3 of this permit.

10. Report Excess Emissions and Permit Deviation as descibed in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, should the emissions exceed the limits in Conditions 8.1 or 8.2.

Carbon Monoxide (CO) BACT[4] for Turbines carried over from past permit actions

11. **Turbines (Units 1 through 4 and 9 through 11).**

11.1 Limit the CO emissions

a. for Units 1 through 4, to no more than 10 ppmv, dry (ppmvd); and

b. for Units 9 through 11 to no more than 20 ppmvd.

11.2 To show compliance with the CO emission limits in Conditions 11.1a, and 11.1b, the Permittee shall keep records, available for inspection, which demonstrate each turbine is maintained in good operating condition and in accordance with BPXA established guidelines and operating procedures.

CO BACT[5] for Emergency Generator carried over from past permit actions

12. **Emergency Generator (Unit 15).**

12.1 Limit the CO emissions from Unit 15 to no more than 2.8 lb/hr.

12.2 Monitor, record and report as described in Condition 9.2.

SO_2 BACT[6] (revises previous BACT limits)

13. **Turbine Units 1 through 4 and Units 9 through 11.** Limit the H_2S content of the fuel gas burned in Units 1 through 14 to no more than 300 ppmv at any time.

13.1 Determine compliance monthly with the fuel gas H_2S content as follows:

a. Determine the fuel gas H_2S content of the fuel using ASTM D 4810-88, ASTM D 4913-89, Gas Producer's Association (GPA) method 2377-86, or an alternative analytical method approved by the Administrator.

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[3] This limit originated in Permit 9273-AA016 but did not specify whether it was for non-emergency operations. In O/C Permit 270TVP01 the limit was for non-emergency operations absent the definition. In this permit, non-emergency means maintenance operations.

[4] See footnote 1

[5] See footnote 2

[6] Fuel gas H_2S BACT limit of 30 ppmv was established for turbine Units 1through 4 and 9 through 11 in Permit 9873-AC006 for the Miscible Injection Project in 1998. The limit is revised to 300 ppmv in this permit action.

b. The fuel gas H_2S analysis required under this condition may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

13.2 Keep records of the analysis conducted as required in Condition 13.1a.

13.3 Report the monthly fuel gas H_2S concentration, for each month of the reporting period, in each Operating Report described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

13.4 Report Excess Emissions and Permit Deviations as described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, should the fuel gas H_2S concentration exceed the limit in Condition 13.

Particulate Matter (PM) BACT[7] carried over from past permit actions

14. **Turbines (Units 1 through 4) and Emergency Generator (Unit 15).**

14.1 Limit the PM emissions

a. for Units 1 through 4, to no more than 14 lb/MMscf; and

b. for Unit 15, to no more than 1.0 g/hp-hr.

14.2 For Unit 15, to show compliance with the limit in Condition 14.1b, monitor, record and report as required by Condition 9.2.

[7] See footnote 2

Section 5. Ambient Air Quality Protection Requirements

Engine Hours of Operation Limit

15. The Permittee shall limit the hours of non-emergency[3] operation for Units 16 through 18 to no more than 200 hours per consecutive 12-month period per unit.

    15.1 Monitor and record the monthly hours of non-emergency operation and the consecutive 12-month summation for each of the units subject to the hour limits.

    15.2 Report the monthly and consecutive 12-month total of non-emergency hours that each of the units operated each month of the reporting period with the operating report described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50.

    15.3 Report under Excess Emissions and Permit Deviation descibed in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, if the consecutive 12-month total hours of non-emergency operation exceed the limit.

16. The Permittee shall limit the fuel gas H_2S content to no more than 105 ppmv at any time, in each of the fuel gas fired Units 1 through 14 and 19 through 23 listed in Table 1.

    16.1 Monitor, record and report as required in Conditions 13.1, 13.2 and 13.3.

    16.2 Report Excess Emissions and Permit Deviations as descibed in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 should the fuel gas H_2S concentration exceed the limit listed in Condition 16.

17. The Permittee shall not burn liquid fuel with a sulfur concentration that exceeds 0.11 percent by weight in Emission Units 15 through 18.

    17.1 For liquid fuel from a North Slope topping plant, the Permittee shall obtain from the topping plant, the results of a monthly fuel sulfur analysis;

        a. Include in the Operating Report described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, a list of the sulfur content measured for each month covered by the operating report;

    17.2 For liquid fuel obtained from a third-party supplier that requires a sulfur content less than the limit in Condition 17, the Permittee shall keep receipts from the supplier that specify fuel grade and amount for each shipment of fuel.

        a. Include in the Operating Report described in Operating the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 a list of the fuel grades received at the CGF during the reporting period.

    17.3 Report Excess Emissions and Permit Deviations as descibed in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, if the liquid fuel sulfur content exceeds the limit in Condition 17.

18. The Permittee shall contruct and maintain vertical uncapped exhaust stacks for the three emergency generators (Units 15 through 17 in Table 1), except when the liquid fuel sulfur content at CGF is less than or equal to 0.019 percent, by weight. When the fuel sulfur content is less than or equal to 0.019 percent, the stacks may be capped or have a horizontal discharge. The uncapped stack requirement does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

    18.1 Include in the Operating Report described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50, the stack configuration (orientation and capped or uncapped) for the emergency generators (Units 15 through 17 in Table 1) for each applicable month of the reporting period.

    18.2 Notify the Department under Excess Emissions and Permit Deviations as described in the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50 if any of the emergency generators, (Units 15 through 17 in Table 1) are operated with horizontal or capped exhaust stacks and the liquid fuel sulfur concentration exceeds 0.019 percent by weight.

Section 6. Standard Permit Conditions

19. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    19.1 an enforcement action; or

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

20. 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.

21. 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.

22. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

    22.1 included and specifically identified in the permit; or

    22.2 determined in writing in the permit to be inapplicable.

23. 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.

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

Section 7. Permit Documentation

May 22, 2009	e-mail from Jeff Alger (AECOM) with attached cost analysis for Sulfa Treat as applicable to CCP and CGF.
May 6, 2009	e-mail from Jim Pfeiffer (BPXA) to Zeena Siddeek (the Department) agreeing to provide detailed cost estimates for Sulfa Treat technology.
May 5, 2009	e-mail from Zeena Siddeek (the Department) to Jim Pfeiffer (BPXA) requesting that submit a detailed BACT cost analysis for Sulfa Treat technology that was originally found infeasible but for which BPXA provided partial cost estimates.
January 26, 2009	e-mail from Zeena Siddeek (the Department) to BPXA notifying that ERG (the contractor) has all the necessary information for the BACT review.
January 26, 2009	e-mail from Bryan Lange (ERG) to Zeena Siddeek (the Department) informing that ERG has the necessary information to continue the BACT review.
January 23, 2009	Jim Pfeiffer (BPXA) to Zeena Siddeek with attached Response for missing information.
January 20, 2009	e-mail from Zeena Siddeek (the Department) to Jim Pfeiffer (BPXA) clarifying the items in the contractor request for additional information for BACT review.
January 15, 2009	e-mail from Jim Pfeiffer (BPXA) to Sally Ryan and Zeena Siddeek (the Department) with attached Draft Reply from BPXA for additional information.
December 26, 2008	Letter from Rachel Buckbee (BPXA) to Sally Ryan (the Department) asking for more time until January 15, 2009 to submit the additional information.
December 23, 2008	e-mail from Sally Ryan (the Department) to Jim Pfeiffer (PBXA) with letter attached requesting additional information for BACT review by December 26, 2008.
September 19, 2008	Permit application from BPXA to Revise and Rescind Fuel Sulfur Limits for Air Quality Operating/Construction Permit AQ0270TVP01 Prudhoe Bay Unit Central Gas Facility.
August 4, 2003	Operating/Construction Permit 270TVP01 Statement of Basis.
May 11, 1993	Technical Analysis Report for Permit 9273-AA016.
July 15, 1998	Technical Analysis Report for Construction Permit 9873-AC006

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR PERMITS PROGRAM

TECHNICAL ANALYSIS REPORT

Air Quality Control Minor Permit AQ0166CPT04
BP Exploration (Alaska) Inc.
Central Compressor Plant (CCP)
H_2S LIMIT INCREASE PROJECT

AND

Air Quality Control Construction Permit AQ0270CPT04
BP Exploration (Alaska) Inc.
Central Gas Facility (CGF)
H_2S LIMIT INCREASE PROJECT

Prepared by Zeena Siddeek
Supervisor: Sally A. Ryan
Final – October 13, 2009

TABLE OF CONTENTS

ABBREVIATIONS/ACRONYMS

AAAQS...................Alaska Ambient Air Quality Standard
AAC........................Alaska Administrative Code
ADEC......................Alaska Department of Environmental Conservation
AS ....Alaska Statutes
BACT......................Best Available Control Technology
BPXA......................BP Exploration (Alaska) Inc.
CCP.........................Central Compressor Plant
CGF.........................Central Gas Facility
CFR. ....Code of Federal Regulations
EPA.........................Environmental Protection Agency
GHX........................Gas Handling Expansion
MIX.........................Miscible Injection Expansion
NA...........................Not Applicable
O/C..........................Operating/Construction
ORL.........................Owner Requested Limit
PSD ....Prevention of Significant Deterioration
PTE ....Potential to Emit
SIC ....Standard Industrial Classification
TAR.........................Technical Analysis Report

Units and Measures

gr./dscf ....grains per dry standard cubic foot (1 pound = 7,000 grains)
dscf..........................dry standard cubic foot
gph...........................gallons per hour
kW...........................kiloWatts[1]
lbs............................pounds
mmBtu.....................million British Thermal Units
ppm ....parts per million
ppmv ....parts per million by volume
tpy ....tons per year
wt% ....weight percent

Pollutants

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

[1] kW refers to rated generator electrical output rather than engine output

1.0 Introduction

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) bases for issuing to BP Exploration (Alaska) Inc. (BPXA) Air Quality Control Construction Permit AQ0166CPT04 for the Central Compressor Plant (CCP), and Construction Permit AQ0270CPT04 for the Central Gas Facility (CGF).

The application is dated September 19, 2008, and the Department received it on October 2, 2008. BPXA submitted additional information on January 23, and May 22, 2009 for Best Available Control Technology (BACT) analysis.

In the Construction Permit AQ0270CPT04 for CGF, the Department is increasing the sulfur dioxide (SO_2) BACT limits (in the form of fuel gas H_2S limits) from 30 parts per million by volume (ppmv) to 300 ppmv for certain equipment that had a 30 ppmv BACT limit. The Department is also establishing ambient air protection limits for liquid fuel sulfur content and fuel gas H_2S content in Construction Permits AQ0166CPT04 and AQ0270CPT04 for CCP and CGF, along with stack restrictions on select emission units at CGF, to protect the SO_2 ambient air quality standards and increments.

Additionally, the Department is re-establishing the Title I permit conditions in Construction Permits AQ0166CPT04 and AQ0270CPT04, for the past permit actions and rescinding the past Title 1 permits for CCP and CGF.

1.1 Stationary Source Description

The CCP and CGF are considered as one stationary source for air permitting purposes. The aggregated CCP/CGF stationary source is classified as a Prevention of Significant Deterioration (PSD) major source for having the potential to emit greater than 250 tons per year (tpy) of one or more regulated pollutants.

The CCP receives part of the raw gas separated from crude oil in the BPXA flow stations and gathering centers. The raw gas flows through the two CCP inlet separators and then to the CGF, where separation takes place to produce a lean residue gas. This lean residue gas then flows back to the CCP where 17 compressors driven by 15 turbines compress the gas for injection into the gas cap of the Prudhoe Bay reservoir[2]. The CGF consists of 11 compressors, 3 oil heaters, 3 emergency generators, a firewater pump and 5 flares.

The fuel gas burned in the gas-fired emission units at CCP and CGF, originates at the Prudhoe Bay field. Because of fuel gas souring over time in the Prudhoe Bay gas reservoir, the H_2S in the fuel gas burned at the CGF has increased to near the permitted level of 30 ppmv listed in O/C Permit 270TVP01.

1.2 Permit History for CCP

The CCP was originally permitted prior to implementation of the PSD permitting program in 1977. Subsequent modifications to the CCP were permitted, prior to the Department obtaining the authority for the PSD permit program, by the Environmental Protection Agency (EPA). EPA issued four field-wide PSD permits (referenced in order as PSD I, PSD II, PSD III, and PSD IV) between May 1979 and September 1981 for new equipment operated at that time by Atlantic

[2] As described in Facility Identification in Statement of Basis, (page 2), of O/C Permit No. 166TVP01.

Richfield Company (ARCO) and Sohio Petroleum Company at the Prudhoe Bay Unit (PBU)[3]. EPA permitted modifications to CCP under the PSD I permit on May 17, 1979, the PSD II permit on June 13, 1980 and the PSD North Slope Swap Project on February 5, 1981. Each of the four EPA PSD permits for Prudhoe Bay was amended by EPA and reissued with clarifications and revised emission limits on August 29, 1997. The only EPA PSD BACT limits that apply at CCP are identified in the August 29, 1997 amendment to the PSD II permit. These limits, which apply to one CCP turbine only (unit tag no. NGT-18-1813), affect emissions of NO_X, CO and PM. No EPA PSD limits apply at CCP for SO_2 emissions.

On September 17, 1990, the Department issued a PSD permit for the Gas Handling Expansion (GHX I) Project (Permit No. 8936-AA006). [4]

A brief description of CCP permits in which the Department or EPA established limits is presented below, in order of issue date.

PSD-X80-09 revised August 29, 1997- This EPA permit was issued on September 29, 1981and was amended August 29, 1997. This permit contains BACT limits for Unit 13 of: NO_X: 150 ppmv @ 15% O_2, CO: 50 lb/MMscf, Particulate Matter (PM): 0.014 lb/MMBtu, and opacity: 10 percent (as surrogate for PM). As revised through 1997, the permit only contains the PM limit and the opacity limits.

Permit 8936-AA006 (GHX I Project) issued September 17, 1990 - This permit allowed the installation and operation of three new gas-fired turbines (only two turbines, Units 14 and 15) were installed), one new process heater (Unit 16), and thirteen upgraded turbines (Units 1 through 13) at the Central Compressor Plant. In this permit, the Department established NO_X and CO BACT limits for these units, as shown in Exhibit A). This permit action did not trigger PSD for SO_2. However, the permit did include a fuel gas H_2S limit of 30 ppmv, which was later removed by the Department in 2003 (in O/C Permit 166TVP01). The reason to include the 30 ppmv in 1990 was not documented in the TAR, but the Department suspects the limit was to avoid PSD for SO_2. The reason to remove the limit in 2003 was not documented in the Statement of Basis for Permit 166TVP01 either.

Permit 9573-AA014 issued January 19, 1996 - This permit was a renewal for Permit to Operate 8936-AA006. The Department carried over the BACT limits from 8936-AC006 to Permit to Operate No. 9573-AA014.

Construction Permit No. 0073-AC006 issued in 2000 and revised in July 2001 – The Department issued this permit to upgrade turbine Unit 2 with Lean Head End (LHE) technology and to install a new emergency generator Unit 23. This project avoided PSD review for NO_X and CO through Owner Requested Limits (ORLs). Because the Department included the provisions of this permit - after 'permit hygiene' - in Operating/Construction (O/C) Permit No. 166TVP01, it appears that Permit 0073-AC006 was replaced by O/C Permit 166TVP01 although not documented anywhere.

Operating/Construction Permit No. 166TVP01 issued August 4, 2003 - This O/C Permit contains the Title 1 provisions of Permits PSD-X80-09, 9573-AA014 and 0073-AC006. In the permit, the Department

[3] The permitted sources at PBU are now operated by BPXA
[4] Permit to Operate No. 8936-AA006 was renewed as Permit to Operate No. 9573-AA014 on January 19, 1996.

(1) revised the CO limit for Unit 16 (originally established in Permit 8936-AA0006) to 0.061 lb/MMBtu to reflect the 1996 version of AP-42 emissions factor for low-NO_X burner technology;
(2) removed the 150 ppmv BACT limit for Unit 2, ostensibly for what is referred to as 'permit hygiene' (the removal of this limit was a mistake as described in section 4.0 of this TAR);
(3) removed the 30 ppmv fuel gas H_2S limit for all units (at BPXA's request - see letter dated November 19, 1997) (according to BPXA, the limit was not necessary because fuel gas souring was not considered a modification at the time before the Department adopted the Federal PSD program); and
(4) included the EPA annual limits of 958 tpy of NO_X and 90 tpy of CO from EPA Permit PSD-X80-09. (This was part of EPA approval to transfer the EPA short-term BACT limits of 150 ppmv NO_X and 50 lb/MMscf CO for Unit 13. These are now Title I limits for Unit 13 in a Department issued permit. As a result of this there are no BACT limits for NO_X and CO for Unit 13 in the EPA permit.)

Permit 166TVP01 expired on September 3, 2008 along with the Title 1 provisions in it. BPXA is operating under the expired operating permit through a permit shield after submitting a timely permit renewal.

1.3 Permit History for CGF

The EPA initially authorized operations at CGF in 1984 under the permitting action known as SWAP IV, as an administrative revision to PSD permits for the Prudhoe Bay Unit (PBU) facilities. Under SWAP IV, the EPA authorized additional heater and turbine capacity at the location where the CGF was later constructed. The CGF was subject to PSD review and permitting by EPA, thereby ensuring that CGF process operations were constructed in accordance with EPA PSD rules.

The Department issued two PSD permits for CGF: for the Gas Handling Expansion (GHX II) project in 1993 and the Miscible Injection Expansion (MIX) project in 1998.

A brief description of CGF permits in which the Department or EPA established limits is presented below, in order of issue date.

PSD-X81-13 revised August 29, 1997- This EPA permit was issued on September 29, 1981and was amended August 29, 1997. This permit contains the following BACT limitsr:

Units 5 through 8 of: NO_X 150 ppmv and 999 tpy, CO: 0.17 lb/MMBtu and 193 tpy, SO_2 6.5 tpy, PM: 16 tpy and opacity: 10 percent (as surrogate for PM);

Units 9 and 10 of: NO_X 150 ppmv and 1,115 tpy, CO: 0.17 lb/MMBtu and 269 tpy, SO_2: 9.0 tpy, PM: 22 and opacity: 10 percent (as surrogate for PM); and

Units 12 through 14 of: NO_X 0.08 lb/MMBtu and 84 tpy, CO: 0.061 lb/MMBtu and 64 tpy, SO_2: 5.4 tpy and PM: 12 tpy.

Permit 9273-AA016 (GHX II Project) revised in December 23, 1996 – This permit was originally issued on May 11, 1993. The permit allowed the installation and operation of turbine Units 1 through 4, one emergency generator Unit 15 and installation of a waste heat recovery system on two existing turbine Units 9 and 10. The Department established NO_X, CO and PM

BACT limits for these units as shown in Exhibit A. Permit 9273-AA016 did not include an SO_2 or fuel gas H_2S limit.

Permit 9873-AC006 (MIX Project) issued July 15, 1998 - This permit allowed the installation of turbine Unit 11 and modifications to Units 1 through 4, 9 and 10. Units 9, 10 and 11 were fitted with Lean Head End (LHE) technology. The Department established NO_X, CO and SO_2 BACT limits for these units. The NO_X and CO BACT limits in this permit, superseded the BACT limits established in Permit 9273-AA016. The Department included the provisions of this permit – after 'permit hygiene' - in O/C Permit 270TVP01. O/C Permit 270TVP01 replaced Permit 9873-AC006 although not explicitly documented anywhere.

Operating/Construction (O/C) Permit 270TVP01 issued August 4, 2003 - This O/C Permit contains the Title 1 provisions of Permits PSD-X81-13, 9273-AA016 and 9873-AC006. Permit 270TVP01 expired on September 3, 2008 along with the Title 1 provisions in it. In the permit, the Department established an ORL of 30 ppmv (annual average) for fuel gas H_2S for turbine Units 5 through 8, and heater Units 12 through 14. The limit was requested by BPXA to reflect the EPA tpy SO_2 BACT limits for these units.

2.0 Application Description

2.1 Application for CCP

BPXA requested a minor permit under 18 AAC 50.508(5) to establish a liquid fuel sulfur content limit of 0.11 percent by weight in all the liquid fuel fired emission units (Units 23 through 25) to protect the 24-hour SO_2 ambient air quality increment near CCP and CGF. BPXA stated that no fuel gas H_2S limit is needed to protect the SO_2 AAAQS. BPXA also stated that no liquid fuel sulfur limits or fuel gas H_2S content limits exist for CCP.

The Departments findings regarding the application are in Section 4.0.

2.2 Application for CGF

The fuel gas H_2S content in the Prudhoe Bay gas reservoir has gradually increased over time. The level is now in the range of the 30 ppmv SO_2 BACT limit established at CGF for Emission Units 1 through 4 and 9 through 11. BPXA's permit application requested that the Department increase the fuel gas H_2S BACT limits in the O/C Permit 270TVP01.

BPXA's permit application requested the Department to make the following changes to the O/C Permit 270TVP01:

- Revise the fuel gas H_2S limit (SO_2 BACT) limit of 30 ppmv (not to exceed) to 300 ppmv (not to exceed) for the turbine Units 1 through 4 and 9 through 11.
- Rescind the fuel gas H_2S ORL of 30 ppmv (annual average) for the turbine Units 5 through 8 and 12 through 14. (Department Note: This annual average limit for Units 5 through 8 and 12 through 14 originated in O/C Permit 270TVP01 at BPXA's request[5], to reflect the SO_2 ton per year limits in the EPA permit PSD-X81-13).
- Establish limits to protect ambient air quality standards and increments for SO_2 as follows:

[5] As described in the Statement of Basis for Permit 270TVP01. The EPA annual limit is in the EPA permit.

- 105 ppmv (annual average) fuel gas H_2S ambient air protection limits for all fuel gas fired Units 1 through 14 and 19 through 23;
- 0.11 percent by weight sulfur content ambient air protection limit for liquid fired Units 15 through 18; and
- vertical, uncapped exhaust stack when any of the emergency generators combust liquid fuel with a sulfur concentration that exceeds 0.019 percent by weight.

- Process the application for CGF under 18 AAC 50.508(6) for a minor permit, to revise terms and conditions of an existing Title 1 permit. BPXA also submitted all the necessary information to process the application under 18 AAC 50.306. BPXA submitted a minor permit application because BPXA asserts that fuel gas souring is not, in itself a change in the method of operation, and therefore, is not a modification.

The Department's review of the application is in Section 2.3 and the findings regarding the application are in Section 4.0.

2.3 Department Review of the Application

The stationary source consisting of CCP and CGF is a PSD major stationary source because the existing PTE exceeds 250 tpy for one or more regulated pollutants.

BPXA has requested that Department increase the BACT limit only for those units at CGF that already have a BACT limit of 30 ppmv. The Department believes BPXA's request is based on EPA's 1987 Ogden Martin[6] guidance memorandum for correcting a BACT limit with which a source is not able to comply. The Department has used this guidance when an initial BACT limit was set too stringent for a source to comply despite the source taking all reasonable measures to attempt to comply. The Department has not found any EPA determination that this approach should be used for the situation where a source complied with a limit for years, but now requires either physical or operational controls to continue to comply with the limit because of fuel gas souring.

The requested change would increase authorized SO_2 emissions by 704[7] tons per year, and the applicant has in the past and is currently complying with the existing BACT limit. Therefore, the Department does not consider this change to be correcting a BACT limit. Consistent with the Department's decision on January 11, 2008 to the Endicott permit and EPA, Region 10's (R10'October 27, 2003[8] letter to ConocoPhillips Alaska Inc., the Department treats this change as a change in the method of operation of the emission units, but has agreed to follow any subsequent federal guidance on this point. Because the change in the method of operation results in a significant increase in actual emissions, the change is a major modification as defined in 18 AAC 50.990(53).

[6] November 1987 memorandum from EPA to Ogden Martin Tulsa municipal Waste Incinerator Facility: Request for Determination on BACT Issues

[7] Using current actual (based on 30 ppmv) to future potential (based on 300 ppmv) for only those units (Units 1 through 4 and 9 through 11) that have a current fuel gas H_2S BACT limit of 30 ppmv (See Table 2 of this TAR and Table 3 of Exhibit C of this TAR).

[8] October 2003, Memorandum from Janice Hastings, Acting Director, Office of Air Quality, EPA Region 10, to Thomas Manson, ConocoPhillips Alaska Inc. regarding SO_2 BACT determination for Kuparuk Seawater Treatment Plant.

EPA, R10's October 27, 2003 letter to ConocoPhillips Alaska Inc states that increasing H_2S concentration in field gas resulting from ConocoPhillips' practice of injecting seawater into the reservoir (to enhance crude oil recovery), is arguably a physical change. However, based on 40 CFR 51.166(b)(2)(iii)(e), BACT does not apply for emission units for which the use of higher sulfur fuel gas could be accommodated without violating any federally enforceable permit condition.

The turbines and heaters at CCP can accommodate the higher sulfur fuel gas without violating any federally enforceable permit conditions. Therefore, the increase in SO_2 emissions at CCP from burning fuel gas with higher H_2S content is not a change in the method of operation. Therefore, BACT is not required for the CCP emission units.

Similarly, turbine Units 5 through 8 and heater Units 12 through 14, at CGF can accommodate the higher fuel H_2S. Although these units have annual SO_2 limits, through EPA imposed BACT limits, they are not limited to burning higher sulfur fuel. With the higher sulfur fuel, they can still comply with the annual limit. Therefore, the increase in SO_2 emissions from burning high H_2S fuel is not a change in the method of operation for these units. Therefore, BACT is not required for these units, as a result of this project.

The 105 ppmv limit established in the permits for CCP and CGF (See Exhibit B of this TAR) are federally enforceable limits established under regulations approved pursuant to 40 CFR Subpart I. Therefore, any future relaxation of this limit for Units 5 through 8 and 12 through 14 at CGF or for units at CCP to accommodate a higher sulfur fuel would not qualify for the alternate fuel exemption.

3.0 Emissions Summary

3.1 SO_2 Emissions at CCP

Sulfur dioxide is the only pollutant affected by Permit AQ0166CPT04. There are no changes to emissions for any other pollutants. The SO_2 emissions before and after the modification are shown in Table 1. BPXA provided the calculations in the application.

The new potential to emit (PTE) shown in, Table 1 is based on fuel oil sulfur content of 0.11 percent by weight and fuel gas H_2S content of 105 ppmv (limit imposed by the Department to protect the ambient air quality standards and increments, in the vicinity of CCP (See Exhibit B, Modeling Memorandum). The 1997 Actual Emissions and current PTE (before Permit AQ0166CPT04) shown in Table 1 are based on fuel gas H_2S content of 30 ppmv and fuel oil sulfur content of 0.5 percent by weight although no limit existed for fuel oil prior to this permit. The current PTE shown in Table 1 is only for informational purposes.

Table 1 – SO_2 Emissions Before and After Modification by Permit No. AQ0166CPT04

ID	Unit Description	Rating	SO_2 (tpy)		
			2007 Actual Emissions[c]	Current PTE	New PTE[d]
1	GE MS5371 PATP Gas Compressor	35,400 hp ISO	7.11	9.1	32.0
2	GE MS5371 PATP w/LHE Gas Compressor	35,800 hp ISO	7.43	9.4	33.2
3	GE MS5371PATP Gas Compressor	35,400 hp ISO	6.86	9.1	32.0
4			6.84	9.1	32.0
5			7.06	9.1	32.0
6			7.11	9.1	32.0
7			6.40	9.1	32.0
8			6.05	9.1	32.0
9			7.16	9.1	32.0
10			6.77	9.1	32.0
11			6.96	9.1	32.0
12			7.15	9.1	32.0
13			7.04	9.1	32.0
14	GE MS5382C Tandem Compressor	38,000 hp ISO	7.17	9.8	34.4
15			7.02	9.8	34.4
16	Broach Glycol Heaters	28.5 MMBtu/hr	0.28	0.72	2.6
17		37.5 MMBtu/hr	0.13	0.95	3.4
18			0.07	0.95	3.4
19	Eclipse Glycol Heaters	10.7 MMBtu/hr	0.24	0.27	0.96
20		12.3 MMBtu/hr	0.00	0.31	1.11
21	BS&B TEG Reboilers	4.1 MMBtu/hr	0.00	0.10	0.37
22			0.00	0.10	0.37
23	Solar T-4001 Emergency Generator	3,550 hp	0.08	2.2	0.48[a]
24	GM Emergency Generator	3,600 hp	0.05	1.29	0.28[a]
25	Cummins Emergency Fire Water Pump	255 hp	0.01	0.13	0.03[b]
26	John Zink HP/IP Emergency Flare	2.0 MMscf/day combined total (pilot/purge/assist)	0.81	1.8	6.5
27	John Zink STV Emergency Flare				
28	Line Emergency Backup Flare				
29	Line Emergency Backup Flare				
	Total Emissions		**106**	**147**	**505**

Table 1 Notes:

[a] Based on existing annual operating limit of 200 hours.

[b] Based on existing annual operating limit of 295 hours.

[c] BPXA's permit application provided only the 2007 emissions. Baseline Actual Emissions for PSD applicability are pollutant emissions representative of a 24 consecutive month average during a ten year period preceding the date on which the application was submitted. However, the Department did not request actual emissions for 2006 because doing so would not change the outcome of the PSD permit applicability assessment.

[d] The new PTE is based on 105 ppmv H_2S in the fuel gas and 0.11 percent sulfur by weight in the liquid fuel.

3.2 SO_2 Emissions at CGF

Sulfur dioxide is the only pollutant affected by Permit AQ0270CPT04. There are no changes to any other pollutants. BPXA provided the calculations for Table 2 in the application. The Department agrees with the calculations. Table 2 shows the SO_2 emissions increases due to the changes in fuel gas H_2S content and fuel oil sulfur content. The new PTE is based on the ambient air protection limits for fuel gas H_2S content of 105 ppmv, fuel oil sulfur content of 0.11 percent by weight and the SO_2 BACT limits for Units 5 through 10 and 12 through 14 in EPA permit PSD-X81-13. The Actual Emissions and current PTE (before Permit AQ0270CPT04) are based on fuel gas H_2S content of 30 ppmv and liquid fuel sulfur content of 0.5 percent by weight (although no liquid fuel sulfur limit existed for CGF before Permit AQ0270CPT04).

Table 2 – SO_2 Emissions Before and After Modification by Permit No. AQ0270CPT04

ID	Unit Description	Rating	SO_2 (tpy)		
			2007 Actual Emissions[c]	**Current PTE**	**New PTE[d]**
1	GE Frame 6 Injection Compressors	53,665 hp ISO	8.84	11.9	42.7
2			9.09	11.9	42.7
3			8.79	11.9	42.7
4			8.86	11.9	42.7
5	Cooper Rolls/RB211-24C Booster Compressors	33,300 hp ISO	4.88	6.5	6.5[b]
6			4.74	6.5	6.5[b]
7	Cooper Rolls/RB211-24C Miscible Injectant Compressors	33,300 hp ISO	4.64	6.5	6.5[b]
8			4.22	6.5	6.5[b]
9	GE MS5382C (Frame 5) Refrigerant Compressors	38,000 hp ISO	5.88	9.0	9.0[b]
10			6.02	9.0	9.0[b]
11	GE MS5382C (Frame 5) Booster Compressor	38,000 hp ISO	6.97	9.5	34.0
12	Chiyoda-John Zink Hot Oil Heaters	216 MMBtu/hr	2.14	5.4	5.4[b]
13			2.15	5.4	5.4[b]
14			1.73	5.4	5.4[b]
15	GM (RMD)/20-645F4B Emergency Electric Generators	2,865 kW	0.106	1.6	0.314[a]
16			0.091	1.6	0.314[a]
17			0.089	1.6	0.314[a]
18	Caterpillar/3406P Emergency Fire Water Pump	330 hp	0.007	0.03	0.0259[a]
19	IHI-John Zink Emergency Flares	3.0 MMscf/day combined total (pilot/purge/assist)	1.76	2.7	9.7
20					
21					
22					
23					
	Total Emissions		**81**	**125**	**276**

Table 2 Notes:

[a] Based on existing annual operating limit of 200 hours.

[b] Annual BACT limits in EPA Permit No. PSD-X81-13, as amended on 08/29/97.

[c] BPXA's permit application provided only the 2007 emissions. Baseline Actual Emissions for PSD applicability are pollutant emissions representative of a 24 consecutive month average during a ten year period preceding the date on which the application was submitted. However, the Department did not request actual emissions for 2006 because doing so would not change the outcome of the PSD permit applicability assessment.

[d] Except for emission units with an existing EPA BACT limit for SO_2, the new PTE is based on 105 ppmv H_2S in the fuel gas and 0.11 percent sulfur by weight in the liquid fuel.

3.3 PSD Applicability

As shown in Table 3, the SO_2 emissions from the requested modifications for CGF and the resulting increase at the stationary source (CCP and CGF and CGF combined) exceed the PSD major modification threshold of 40 tons per year listed in 40 CFR 52.21(b)(23)(i) for SO_2.

Table 3 – PSD Applicability Analysis for SO_2

	Combined
Past Actual	187
PTE	781
Increase	594
PSD Major Modification Threshold	40
PSD Major Modification	yes

3.4 Assessable Emissions

The assessable emissions for CCP are shown in Table 4. These values (except SO_2) are copied from the operating permit renewal application for CCP at BPXA's request. The Department is not establishing these values in this permit action. The Department is only establishing the SO_2 component of the assessable emissions in Permit AQ0166CPT04 based on the new PTE for CCP.

Table 4 – Assessable Emissions for CCP

UNIT	EMISSIONS IN TONS PER YEAR					
	NO_X	CO	PM-10	SO_2	VOC	Total
Assessable Emissions listed in O/C Permit AQ0166TVP02 (renewal application)	14,237	1,631	208	147	84	16,307
Increase due to Permit AQ0166CPT04	0	0	0	358	0	358
New Assessable Emissions	14,238	1,631	208	505	84	16,665

Similarly, the assessable emissions for CGF are shown in Table 5. These values (except SO_2) are copied from the operating permit renewal application for CGF at BPXA's request. The Department is not establishing these values in this permit action. The Department is only establishing the SO_2 component of the assessable emissions in Permit AQ0270CPT04 based on the new PTE for CGF.

Table 5 – Assessable Emissions for CGF

UNIT	EMISSIONS IN TONS PER YEAR					
	NO_X	CO	PM-10	SO_2	VOC	Total
Assessable Emissions listed in O/C Permit No. AQ0270TVP02 (renewal application)	10,968	1,787	305	125	90	13,275
Increase due to Permit AQ0270CPT04	0	0	0	151	0	151
Assessable Emissions	10,968	1,778	305	276	90	13,426

4.0 Department Findings

The Department finds that:

In regards to *both* CCP and CGF

1. The combined CCP and CGF stationary source is located in the North Slope Borough. The project is consistent with the Alaska Coastal Management Program (ACMP) through AS 46.40.040(b)(1). The Department did not notify the local district and resource agencies of the permit action to request additional ACMP review because the North Slope Borough Coastal District plan does not have an enforceable policy in effect at this time. The Department informed the Coastal District Coordinator of the proposed project and provided opportunity to comment on the preliminary permit during the public comment period. In addition, the resource agencies had the opportunity to comment on the preliminary permit during the public notice period.
2. BPXA used a fuel gas H_2S content of 105 ppmv in their modeling analysis to keep the SO_2 impacts from CCP and CGF below the SO_2 significant impact levels at all offsite source locations. This restriction of the CCP/CGF significant impact area is a major component of BPXA's ambient air demonstration. As such, a fuel gas H_2S limit of 105 ppmv (instantaneous) is included in the CCP and CGF permits for purposes of protecting the SO_2 AAAQS and increments

In regards to *just* CCP

3. BPXA does not need an application under 18 AAC 50.508(5) for SO_2 because the project is PSD for SO_2. BPXA needs a fuel oil sulfur limit of 0.11 percent to protect the SO_2 ambient air quality standard and increments.
4. There are no liquid fuel sulfur limits for CCP prior to Permit AQ0166CPT04, except to comply with the state emissions standard of 500 ppmv for sulfur compound emissions under 18 AAC 50.055(c).
5. BPXA stated in the application, that there is no existing restriction for fuel gas content. After reviewing the past Title 1 permit actions for CCP, the Department found that the CCP contained a fuel gas H_2S limit of 30 ppmv that originated in 1990 in Permit 8936-AA006 for the GHX I project. The project was PSD for NO_X and CO. ARCO (owner at the time) avoided PSD review for SO_2 by assuming that the fuel gas H_2S content was less than 25 ppmv that amounted to 28 tpy for the GHX I project. Permit No. 8936-AA006 imposed a 30 ppmv limit for H_2S, but the permit TAR did not explain the underlying basis for the limit. The Department believes that 30 ppmv limit was imposed by the Department to limit the increase in sulfur emissions to the PSD threshold of 40 tpy. The H_2S limit was carried over to permit to operate 9573-AA014 in 1995. However, the Department removed the limit in O/C Permit 166TVP01 at BPXA's request (November 19, 1997 letter from BPXA to the Department) after finding that the limit was unnecessary to avoid PSD based on the rules and policies in place at the time.
6. CCP and CGF is one stationary source for permitting purposes. The SO_2 increase associated with the changes requested at CGF alone is greater than the 40 tpy PSD major modification threshold. Therefore, the Department reviewed the application

under 18 AAC 50.306 for the stationary source consisting of CCP and CGF, combined. However, BACT does not apply to CCP units because these units are capable of accommodating the higher sulfur fuel and the change is not considered a change in the method of operation of the CCP units under 40 CFR 51.166(b)(2)(iii)(e).

7. O/C Permit 166TVP01 (issued in August 2003), contains the provisions of Permit 0073-AC006 (issued in July 2000) after 'permit hygiene'. Therefore, O/C Permit 166TVP01 ought to have replaced Permit 0073-AC006. Because the Title 1 provisions are embedded in the operating permit that expired in December 2008, there is a need to collect all the Title 1 provisions of the past actions. In this Construction Permit AQ0166CPT04, the Department is explicitly rescinding Permit 0073-AC006. There is no need to explicitly rescind O/C Permit 166TVP01 because the permit has already expired but BPXA is operating only under a permit shield.

8. EPA (permit PSD-X80-09 as amended on August 29, 1997) established tpy (long term) and lb/MMBtu (short-term) BACT limits for Unit 13. EPA agreed to drop the NO_X and CO limits because the Department established NO_X and CO BACT limits for Unit 13. However, per Statement of Basis for Permit 166TVP01, EPA required the Department to include the annual NO_X and CO limits for Unit 13, in the Department's permit[9]. As a result, there are no NO_X and CO limits for Unit 13 in the EPA Permit.

9. The Department included the EPA PM BACT limit for Unit 13 in the O/C Permit 166TVP01 at BPXA's request. There is no requirement for the Department to carry over the EPA PM BACT limit for Unit 13 into Permit AQ0166CPT04 and BPXA has not requested the inclusion.

10. The Department established NO_X and CO BACT limits for the turbines (Units 1 through 15) in Permit 8936-AA006 for the GHX I project in 1990. The Department removed the BACT limits for Unit 2 in O/C Permit 166TVP01 by mistake, because of the more stringent ORLs later established to avoid PSD review for the MIX project (Permit 0073-AC006) in July 2000. Since BACT limits never go away unless replaced by another BACT limit, Unit 2 must contain the original BACT limits of 150 ppmv for NO_X and 50 lb/MMBtu for CO that were established in Permit 8936-AA006.

11. The basis for the historical 200 hour annual limit for the emergency generators (Units 23 and 24), and the 295 hour limit for the firewater pump (Unit 25), are unclear. The limit appeared in Permit 9273-AA016 but the TAR for the permit did not include an explanation for the limit. The limit may have been to protect ambient standards and increments. For the current permit action, BPXA relied on these limits to demonstrate compliance with the ambient air quality standards and increments. Because there is no clear basis for the historical limit, this permit includes the limit in the section for Ambient Air Quality Protection to provide the basis.

[9] This information was obtained from the Statement of Basis in Permit 270TVP01. The Department did not have a copy of the permit application for Permit 270TVP01 in hand to verify EPA's request to include the annual limits for Unit 13 in the Department issued permit.

12. The provisions in Construction Permit AQ0166CPT04, do not contravene conditions in O/C Permit No. 166TVP01. Therefore, BPXA can operate under the provisions of Construction Permit AQ0166CPT04 when the permit is issued. Such operation does not qualify for the permit shield provided by AS 46.14.290 until the construction permit is incorporated into the applicable Title V operating permit.

In regards to *just* CGF

13. BPXA submitted a permit application under 18 AAC 50.508(6) requesting to increase the fuel gas H_2S BACT limit to 300 ppmv (from 30 ppmv) for turbine Units 1 through 4 and 9 through 11. The permit application also contained the necessary information to process the application under 18 AAC 50.306 and 40 C.F.R. 52.21. The Department is processing the application under 18 AAC 50.306.

14. Fuel gas H_2S content of 300 ppmv BACT limit is higher than the 105 ppmv limit required for ambient protection. Under the definition of BACT in 40 CFR 52.21(b)(12), the BACT limit must be at least as stringent as the applicable standards under 40 CFR parts 60 and 61 and no other threshold is specified in the BACT definition.

15. The previous (prior to Permit AQ0270CPT04) fuel gas H_2S **BACT limit of 30 ppmv** (not to exceed) for Units 1 through 4 and 9 through 11, in Condition 13 of O/C Permit 270TVP01 originated in Permit No. 9873-AA006 in 1998 for the MIX project. That project was a PSD major modification for NO_X, CO and SO_2.

16. The 30 ppmv (annual average) limit for Units 5 through 8 and 12 through 14 found in Table 2, Table 3 and Condition 13 of O/C Permit 270TVP01 is **not a BACT limit** and was not a federally enforceable limit established under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166. The limit is an ORL that was established as an operating permit condition in O/C Permit No. 270TVP01 to reflect the EPA ton per year BACT limit for SO_2. On BPXA's request, the Department is rescinding the 30 ppmv ORL for Units 5 through 8 and 12 through 14.

17. BPXA has requested to revise the fuel gas H_2S (surrogate for SO_2) BACT limit to 300 ppmv (from 30 ppmv) to only those units that have an existing (prior to Permit AQ0270CPT04) BACT limit of 30 ppmv. The requested revision is a PSD modification for the stationary source. As a result of this modification, BACT applies to Units 1 through 4 and 9 through 11. BACT does not apply to Units 5 through 8 and 12 through 14 because these units are capable of accommodating the higher sulfur fuel and the change is not considered a change in the method of operation under 40 CFR 51.166(b)(2)(iii)(e).

18. There are no liquid fuel sulfur limits (prior to Permit AQ0270CPT04) for CGF. The only sulfur compound emissions limit is to comply with the SO_2 emissions standards of 500 ppmv in 18 AAC 50.055(c). SO_2 actual emissions (as shown in Table 2) are based on 0.5 percent fuel oil sulfur content and actual operating hours of the units.

19. O/C Permit 270TVP01 contains Title 1 provisions carried forward from Construction Permit 9873-AC006. Permit 270TVP01 has expired, and these Title 1 provisions have also expired. The Department did not intend for Title 1 provisions to expire, and this result is an artifact of the combined nature of permit 270TVP01 and the

change in permitting rules adopted in 2004. Therefore, the Department has included the past Title 1 requirements in this Construction Permit AQ0270CPT04 and explicitly rescinded Permit 9873-AC006. There is no need to explicitly rescind O/C Permit 270TVP01 because the permit has already expired and BPXA is operating only under a permit shield.

20. The Department included the EPA BACT limits from PSD-X81-13 (amended on August 29, 1997) in the O/C Permit 270TVP01 as an applicable requirement. There is no requirement for the Department to include the EPA limits in Permit AQ0270CPT04. Units 5 through 10 and 12 through 14 have annual SO_2 BACT limits in the EPA PSD-X81-13 permit. PTE calculations for SO_2 for this permit action included the annual limits in the EPA permit.

21. The basis for the historical 200 hour annual limit for the emergency generator Units 16 through 18 is unclear. The limit appeared in Permit 9273-AA016 but the TAR did not include an explanation for the limit. The limit may have been to protect ambient standards and increments. For generator Unit 15 (installed under Permit 9273-AA016 in 1993), the 200 hour limit is a BACT limit. For the current permit action, BPXA relied on these limits to demonstrate compliance with the ambient air quality standards and increments. The limit was included in the section for Ambient Air Quality Protection to clarify the basis for these conditions.

22. Increasing fuel gas H_2S would contravene the Title V permit condition for fuel gas H_2S of 30 ppmv. The construction permit revises the applicable requirement basis for this condition, but cannot change the condition for purposes of title V. This change at CGF does not qualify for the operational flexibility provisions of 40 CFR 71.6(a)(13), because it is a modification under Title 1 of the Clean Air Act. Therefore, the change requires a Title V permit revision before BPXA can operate under the provisions of Permit AQ0270CPT04.

5.0 Permit Requirements for a Permit classified under 18 AAC 50.306

These permits for CCP and CGF fulfill the requirements of 18 AAC 50.306 for PSD Permits. This TAR includes general requirements for PSD permits in Section 5.1.

5.1 General Requirements for PSD Permits

State regulations in 18 AAC 50.306 describe the elements that the Department must include in PSD permits. As described in 18 AAC 50.306(b), the owner or operator must comply with the requirements under 40 CFR 52.21 as adopted by reference in 18 AAC 50.040. As required under 40 CFR 52.21, this TAR includes:

1. A control technology review as required under 40 CFR 52.21(j), as adopted by 18 AAC 50.040(h)(8). The control technology review for this project is presented in Section 5.2 and details of the analysis are in Exhibit C of this TAR, and permit requirements incorporating the results of the control technology review are included in the permit.

2. A source impact analysis as required under 40 CFR 52.21(k), as adopted by 18 AAC 50.040(h)(9) to demonstrate that the project will not cause an air pollution violation.

A summary of the source impact analysis for this project is presented in Section 5.4 and the details are presented in Exhibit B, of this TAR. The permit requirements incorporating the results of the source impact analysis are included in Section 6 of Permits AQ0166CPT04 and AQ0270CPT04 for CCP and CGF, respectively.

3. An air quality analysis (preconstruction monitoring) as required under 40 CFR 52.21(m) as adopted by 18 AAC 50.040(h)(11). The air quality analysis for this project is presented in Exhibit B. There are no resultant permit conditions associated with this requirement.

4. A source description, as required under 40 CFR 52.21(n), as adopted by 18 AAC 50.040(h)(12). A description of this source and a list of emission units covered under CCP and CGF are presented in Sections 1.1, 3.1 and 3.2 of this TAR, and authorizations for construction of these units is included in Section 1 (Emission Unit Inventory) of the permit.

5. An analysis on the project's impact on visibility, soils, and vegetation as required under 40 CFR 52.21(o), as adopted by 18 AAC 50.040(h)(13). The impact analysis review for this project is presented in Exhibit B. There are no resultant permit conditions associated with this requirement.

6. The requirements for state emissions standards as required under 40 CFR 52.21(r)(3), as adopted by 18 AAC 50.040(h)(15) are in Section 3 of Permits AQ0166CPT04 and AQ0270CPT04.

In addition, 18 AAC 50.306(d) describe the elements that the Department must include in PSD permits. Therefore, this includes:

1. Terms and conditions necessary to ensure that the Permittee constructs and operates the proposed modification with appropriate monitoring equipment, testing requirements, recordkeeping, and reporting requirements. These include monitoring fuel gas H_2S limits and fuel oil sulfur content, operating hours of the emergency generators and the exhaust stack orientation at CGF. All other conditions are Title 1 requirements for past actions.

   Monitoring for fuel gas H_2S and fuel oil sulfur are the same as for compliance with state emissions standards for sulfur compound emissions and New Source Performance Standards Subpart GG that are already in place in the operating permits. Monthly monitoring for fuel gas is sufficient for compliance because fuel gas H_2S content variation is a very slow process. For fuel gas H_2S monitoring, the permits require testing using the standard test methods and reporting monthly. For fuel oil sulfur reporting, the permits require submitting monthly fuel sulfur analysis from either of the North Slope topping plants. i.e. the Prudhoe Bay or Kuparuk topping plants or submitting a list of the fuel grades received from a third-party supplier and the amount of fuel received for each shipment. Reporting stack orientation for the emergency generators at CGF is included in construction Permit AQ0270CPT04. Monitoring for the diesel generators are already in place in the operating permits. All other monitoring, recordkeeping and reporting requirements are for past actions and are copied from the operating permits for CCP and CGF. These provisions are included throughout each of the permits.

Note that the references to Permit 166TVP01 in Construction Permit AQ0166CPT04 and the references to Permit No. 270TVP01 in Construction Permit AQ0270CPT04, refer to the language in the respective operating permits and the language still applies even though these permits expired (on September 3, 2008). The Department's objective is to ensure that the requirements cross-referenced by conditions in other permits go on even if the other permit is rescinded, expired, or renewed.

2. Terms and conditions necessary to ensure the Permittee pay fees pursuant to 18 AAC 50.400-420. These requirements are included in Section 2.

5.2 Best Available Control Technology (BACT) under 40 CFR 52.21(j)

As described in 40 CFR 52.21(j) a major modification must apply BACT for each pollutant where the modification results in a significant net emissions increase at the source. As shown in Table 3, there is a significant emissions increase for SO_2, due to the requested increase in fuel gas H_2S content from 30 ppmv to 300 ppmv for Units 1 through 4 and 9 through 11 at CGF. BACT applies to each of these emission units at which a net increase will occur as a result of a physical or change in the method of operation of an emission unit. Therefore, each of these units is subject to BACT for SO_2.

BPXA evaluated the cost effectiveness of SO_2 control technologies that are feasible for emissions units that burn fuel gas and the financial impact to BPXA. The Department contracted Eastern Research Group (ERG) Inc., of 1600 Perimeter Park, Morrisville, NC 27560-8421 to review BPXA's BACT analysis. ERG reviewed and revised BPXA's cost estimates based on what ERG believed was appropriate. ERG's report is included as Exhibit C of this TAR after the Department made corrections and necessary contextual changes.

A summary of the Technically Feasible Control Technologies and the associated costs in order of control efficiency, are shown in Table 6 below. In the original application, BPXA claimed that H_2S Scavenging (Sulfa-Treat®) was technically infeasible because the fuel gas volume at CGF is too large for direct treatment. BPXA narrowed down only Liquid Redox (LO-CAT®) and the Adsorption Process (Amine) as technically feasible. ERG did not agree with BPXA's analysis. After requesting for additional information, on May 22, 2009, BPXA submitted the cost analysis to demonstrate that Sulfa-Treat® was cost ineffective.

BPXA's BACT analysis (October 2008), was based on treating 136 MMscf/d, of fuel gas burned in the turbines and heaters at CGF only. When the Department contracted ERG to review BPXA's BACT analysis, it was thought that BACT applied to all the units that burned high sulfur fuel gas. Therefore, the Department revised BPXA's cost estimates to include all of the units that burn fuel gas at the stationary source that included the units at CCP and CGF. However, after careful examination of the alternate fuels exemptions allowed under 40 CFR 51.166(b)(2)(iii)(e), the Department has concluded that BACT applies only to Units 1 through 4 and 9 through 11 at CGF. The Department did not re-visit BACT cost analysis because there is no benefit to doing so. The cost estimates based on treating a larger volume of fuel gas (to include fuel gas burned in all the equipment at CCP and CGF) is more conservative than the cost estimates based on the fuel gas burned only in Units 1 through 4 and 9 through 11 at CGF. Moreover, any change to the cost estimate will not alter the final BACT conclusions.

ERG based the BACT analysis (see Table 3 of Exhibit C), based on treating 295 MMscf/d (including the 5 MMscf/day from the flares), of fuel gas burned at CCP and CGF with H_2S

content of 300 ppmv. The projected SO_2 emissions, using fuel gas with 300 ppmv H_2S is 2,647 tpy. The combined CCP and CGF PTE based on the ambient air protection limit 105 ppmv for ambient protection, is 781 tpy (see Table 3). The cost effectiveness based on the 300 ppmv is more conservative than using the 105 ppmv.

Table 6 - Technically Feasible Control Technology

Control Technology	Annualized Costs (Revised)	Control Efficiency (%)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
Liquid Redox (LO-CAT®)	$ 38,201,145	99.7%	$ 15,526	$ 14,476
H_2S Scavenging (Sulfa-Treat®)	$ 33,461,456	98.7%	$ 13,420	$ 12,806
Adsorption Process (Amine)	$ 46,369,135	96.7%	$ 21,729	$ 18,113

Under 40 CFR 52.21(b)(12) the permitting agency is allowed to take into account the energy, environmental, or economic impacts and other costs on a case by case basis. The Department finds that even using a conservative baseline fuel gas H_2S content of 300 ppmv, the cost effectiveness of the control technologies listed in Table 6 are significantly higher than what the Department has previously determined as BACT for SO_2. Therefore, the Department agrees with BPXA that BACT for souring of the fuel gas is good combustion practices with no controls, based on the available fuel gas quality.

The Department has included fuel gas H_2S content limit of 300 ppmv as SO_2 BACT for turbine Units 1 through 4 and 9 through 11 at CGF.

5.3 State Emission Standards

As described in 40 CFR 52.21(r)(3), the source must comply with applicable Federal and State standards. No new Federal requirements are triggered by this modification. The only new requirement under the state implementation plan is for fuel burning equipment to comply with sulfur compound emissions standard of 500 ppmv under 18 AAC 50.055(c). Calculations have shown that as long as the fuel gas H_2S content is below 4,000 ppmv, the sulfur compound emissions will be less than 500 ppmv. Therefore, no additional monitoring requirements are necessary for compliance.

BPXA is not installing new emission units under these permits. Ongoing monitoring requirements are already in place in each of the operating permits for compliance with the state emissions standards. Therefore, there is no need to repeat the ongoing monitoring requirements in Construction Permit AQ0270CPT04 and AQ0166CPT04.

5.4 Ambient Air Quality Standards

BPXA submitted an ambient demonstration for SO_2 in order to satisfy the requirements of 40 CFR 52.21(k) and 18 AAC 50.040(h)(9). A memorandum describing the Department's review of the ambient demonstrations is in Exhibit B of this TAR.

5.4.1 Limit Necessary for CCP

BPXA's application requested a fuel oil sulfur content limit of 0.11 percent by weight for the oil fired equipment. The Department's review of BPXA's modeling analysis found that in order to satisfy BPXA's request to maintain air quality impacts to below significant impact levels in the vicinity of offsite sources, the following limits are necessary.

1. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
2. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
3. Limit the annual operations for the emergency generators to 200 hours.
4. Limit the annual operations for the firewater pump to 295 hours.

5.4.2 Limit Necessary for CGF

BPXA's application requested a fuel gas H_2S limit of 105 ppm (annual average) for all the gas equipment and fuel oil sulfur content limit of 0.11 percent by weight. The Department's review of BPXA's modeling analysis found that in order to, the following limits are necessary

1. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
2. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
3. Limit the annual operations for the emergency generators and firewater pump to 200 hours.
4. Construct and maintain vertical, uncapped exhaust stacks for the three emergency generators (Tag No. NGI-19-2802, NGI-19-2819, NGI-19-2890), except when the liquid fuel sulfur content at CGF is less than or equal to 0.019 percent, by weight. When the fuel sulfur content is less than or equal to 0.019 percent, the stacks may be capped or have a horizontal discharge. The uncapped stack requirement does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

5.5 Requirement for all Air Quality Control Permits

The permit contains the requirements as necessary to ensure that the Permittee will construct and operate the stationary source in accordance with 18 AAC 50, as described in 18 AAC 50.345(c)(1) and (2) and (d) – (h). These requirements are listed in Section 7 of Construction permit AQ0166CPT04 and Section 6 of Construction Permit AQ0270CPT04 under "Standard Permit Conditions."

6.0 Permit Administration

BPXA is currently operating CCP and CGF under O/C Permits 166TVP01 and 270TVP01, respectively (expired but operating under a permit shield after applying for operating permit renewals).

For reasons described in Item 12 of the Department Findings Section 4.0, BPXA can operate CCP under the provisions of Construction Permit AQ0166CPT04 upon issuance. For reasons described in Item 22 of the Department Findings Section 4.0, BPXA must obtain a permit revision to the operating permit before operating CGF under the provisions of Construction Permit AQ0270CPT04.

The Department notes that permit renewals for the operating permits for CCP and CGF are underway at the same time as these Title 1 permits are processed. The Department will incorporate the provisions of AQ0166CPT04 and AQ0270CPT04 into the respective operating permits.

Exhibit A: Limits from Past Permit Actions and New Limits

Limits for Emissions Units at the Central Compressor Plant

Unit		8936-AA006 (PSD for NO_X and CO)	0073-AA006 Rev 1 (Avoided PSD)	166TVP01 ('Permit hygiene')	AQ0166CPT04 (PSD for SO_2)
1	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 50 lb/MMscf see "all fuel gas units" below		 see "all fuel gas units"	 Est. 300 ppmvd BACT limit
2	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 50 lb/MMscf see "all fuel gas units" below	Est. PSD avoidance limit of 134 lb/hr, and 90 ppmvd at 15% O_2. No change to BACT limits. Est. 177 tpy PSD avoidance limit	Remove BACT limit of 150 ppmv @ 15% O_2 Remove BACT limit of 50 lb/MMscf see "all fuel gas units"	Re-establish BACT limit of 150 ppmv, 15% O_2 Re-establish BACT limit of 50 lb/MMscf Est. 300 ppmvd BACT limit
3 thru 12	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 50 lb/hr see "all fuel gas units" below			 Est. 300 ppmvd BACT limit
13	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 50 lb/MMscf see "all fuel gas units" below		Add 958 tpy (transfer from EPA Permit PSD-80-09) Add 90 tpy (transfer from EPA Permit PSD-80-09) see "all fuel gas units"	 Est. 300 ppmvd BACT limit
14 and 15	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 50 lb/MMscf see "all fuel gas units" below			 Est. 300 ppmvd BACT limit
16	NO_X CO PM SO_2	Est. BACT limit of 0.08 lb/MMBtu Est .BACT limit of 0.018 lb/MMBtu see "all fuel gas units" below		No change to BACT limit Revise BACT limit to 0.061 lb/MMBtu see "all fuel gas units"	 Est. 300 ppmvd BACT limit
All fuel gas units	SO_2	Est. 30 ppmv fuel gas H_2S limits (limit for all fuel gas units, presumably to avoid PSD for SO_2)		Remove 30 ppmv limit	

Limits for Emissions Units at the Central Gas Facility

Unit		9273-AA016 (PSD for NO_X, CO and PM)	9873-AC006 (PSD for NO_X, CO and SO_2)	166TVP01 (Permit hygiene)	AQ0166CPT04 (PSD for SO_2)
1 thru 4	NO_X CO PM SO_2	Est. BACT limit of 132 ppmv at 15% O_2 Est. BACT limit of 100 lb/MMscf Est. 14 lb/MMscf	Est. BACT limit of 125 ppmv at 15% O_2 and 282 lb/hr Est. BACT limit of 10 ppmv at full load No change to PM BACT limit Est. BACT limit of 30 ppmv fuel gas H_2S		Est. 300 ppmvd BACT limit
5 thru 8	NO_X CO PM SO_2			Est. ORL of 30 ppmv fuel gas H_2S	Est. 300 ppmvd BACT limit
9 and 10	NO_X CO PM SO_2	Est. BACT limit of 150 ppmv at 15% O_2 Est. BACT limit of 109 lb/MMscf No PM BACT limit established	Est. BACT limit of 85 ppmv at 15% O_2 and 130 lb/hr Est. BACT limit of 20 ppmv at full load Est. BACT limit of 30 ppmv fuel gas H_2S		Est. 300 ppmvd BACT limit
11	NO_X CO PM SO_2		Est. BACT limit of 85 ppmv at 15% O_2 and 130 lb/hr Est. BACT limit of 20 ppmv at full load Est. BACT limit of 30 ppmv fuel gas H_2S		Est. 300 ppmvd BACT limit
12 thru 14	NO_X CO PM SO_2			Est. ORL of 30 ppmv fuel gas H_2S	Est. 300 ppmvd BACT limit
15	NO_X CO PM SO_2	Est. BACT limit of 146.4 lb/hr Est. BACT limit of 2.8 lb/hr Est. BACT limi 1.0 g/hp-hr Est. BACT limit of 200 hour/year		Est. ORL of 30 ppmv fuel gas H_2S	Est. 300 ppmvd BACT limit
All fuel gas units	SO_2				Est. 300 ppmvd BACT limit for Units 1 through 4 and 9 through 11.

Exhibit B: Modeling Memorandum

MEMORANDUM

State of Alaska
Department of Environmental Conservation
Division of Air Quality

TO: File

THRU:

FROM: Alan E. Schuler, P.E.
Environmental Engineer
Air Permits Program

DATE: September xx, 2009

FILE NO: AQ0270CPT04 – Modeling
AQ0166CPT04 – Modeling

PHONE: 465-5100
FAX: 465-5129

SUBJECT: Review of BPXA's Ambient SO_2 Assessment for CGF/CCP -- **REVISED**

This memorandum summarizes the Department's *revised* findings regarding the ambient sulfur dioxide (SO_2) assessment submitted by BP Exploration (Alaska), Inc. (BPXA) for the Central Gas Facility (CGF) and the Central Compressor Plant (CCP).[1] BPXA submitted this analysis in support of their September 2008 Prevention of Significant Deterioration (PSD) permit application for CGF, and their September 2008 minor permit application for CCP.[2] BPXA's ambient air analysis adequately demonstrates that operating the CGF and the CCP emission units within the constraints described in this memorandum will not cause or contribute to a violation of the SO_2 Alaska Ambient Air Quality Standards (AAAQS) provided in 18 AAC 50.010, or the SO_2 maximum allowable increases (increments) listed in 18 AAC 50.020.

The Department also finds that BPXA's PSD applications 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).

BACKGROUND

CGF and CCP are existing, adjacent facilities located within the Prudhoe Bay Unit (PBU) of Alaska's North Slope. They are considered as a single stationary source, but operate under a different set of Title I and Title V air quality control permits.

Due to their close proximity and classification as a single stationary source, BPXA modeled both facilities together. This memorandum likewise treats the analysis as a combined assessment, even though the analysis was submitted in support of two different permit applications.

[1] This revision supersedes the February 23, 2009 version of the Department's memorandum regarding BPXA's ambient SO_2 assessment for CGF and CCP. The Department revised the memorandum to address issues raised by BPXA during the public comment period for the assoicated permit actions.
[2] The Department subsequently determined that BPXA's permit application for CCP was subject to PSD review.

Area Classification

The North Slope is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, CGF/CCP 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 kilometers (km) to the south of CGF/CCP.

Source/Project Description

CGF and CCP are classified as a PSD-major stationary source. BPXA is presently operating CGF under Operating Permit AQ0270TVP01, and CCP under Operating Permit AQ0166TVP01.

BPXA submitted the permit applications to accommodate an expected increase in the hydrogen sulfide (H_2S) content of their fuel gas. The H_2S content at CGF is currently restricted to 30 parts per million by volume (ppmv) due to a Best Available Control Technology (BACT) limit imposed during a previous PSD review. BPXA would like to increase the BACT limit to 300 ppmv. Both limits are on a not-to-exceed (i.e., instantaneous) basis.

There are no existing H_2S restrictions to protect the SO_2 AAAQS/ increments. However, BPXA is requesting an *annual average* H_2S limit of 105 ppmv, and various other limits at both CGF and CCP, in order to protect the SO_2 AAAQS/increments. All of BPXA's proposed ambient air related limits are listed below:

BPXA's Proposed Ambient Air Limits for **CCP**
- Liquid fuel sulfur limit of 0.11 percent, by weight

BPXA's Proposed Ambient Air Limits for **CGF**
- Liquid fuel sulfur limit of 0.11 percent, by weight
- Fuel gas H_2S limit of 105 ppmv (annual average)
- Vertical, uncapped stacks for the three GM (EMD) emergency generators (Emission Units 15 – 17), whenever the sulfur content of the liquid fuel burned by these units exceeds 0.019 percent, by weight

The numerical value of BPXA's proposed H_2S limit for ambient air protection is less than the proposed BACT limit. BPXA provided a detailed clarification regarding the basis for these differences in a December 17, 2008 electronic mail (e-mail) message.[3] The Department's findings regarding the proposed ambient air limits are provided in this memorandum.

Ambient Demonstration Requirements

An increase in the fuel gas H_2S level will lead to an increase in the SO_2 emissions. The SO_2 emissions associated with BPXA's requested revisions are sufficient to classify the project as a PSD-major modification. 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),

[3] E-Mail from Rachael Buckbee (BPXA) to Alan Schuler (ADEC) and Fathima Siddeek (ADEC); *FW: CGF H_2S Limit*; December 17, 2008.

- 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).

The nearest Class I area to CGF, Denali National Park, is 750 km away. This is too distant to warrant a Class I impact analysis under 40 CFR 52.21(p).

BPXA's request to limit the fuel sulfur content at CCP is classified as an owner requested limit under 18 AAC 50.508(5). This classification incurs no unique obligations in regards to ambient demonstrations.

Modeling Protocol

BPXA submitted a general modeling protocol in October 2001 for assessing the SO_2 impacts associated with fuel gas souring within PBU.[4] The Department approved the protocol, with comment, on April 18, 2002.

BPXA's consultant, ENSR Corporation (which is now known as AECOM Environment), verbally discussed the adequacy of the 2001 protocol with me on April 8, 2008.[5] ENSR summarized this conversation in an April 16, 2008 e-mail.[6] I provided additional comments on April 24, 2008.[7] BPXA described all changes from the protocol in Section 1.1 of their modeling report (Attachment VI of their application). The Department's findings regarding the resulting analysis are described in the applicable portions of this memorandum.

Project Submittal

BPXA submitted the application on September 22, 2008. ENSR prepared the actual permit applications, and conducted the ambient assessment, on behalf of BPXA.

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 to 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 both data needs is discussed below.

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[4] The protocol was prepared by BPXA's consultant at that time, SECOR International Incorporated.
[5] ENSR was represented by Thomas Damiana and Anthony Galligan.
[6] E-Mail from Thomas Damiana (ENSR) to Alan Schuler (ADEC); *CCP/CGF SO_2 Modeling Procedures for PSD Review*; April 16, 2008.
[7] E-Mail from Alan Schuler (ADEC) to Thomas Damiana (ENSR); *RE: CCP/CGF SO_2 Modeling Procedures for PSD Review*; April 24, 2008.

Pre-Construction Monitoring

BPXA noted that the project impacts exceed the SO_2 pre-construction monitoring threshold. Therefore, pre-construction SO_2 data is needed for this application.

The pre-construction monitoring data must be collected at a location and manner that is consistent with the U.S. Environmental Protection Agency's (EPA's) *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which is adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of maximum impact, the data must be current, and the data must meet the PSD quality assurance requirements.

BPXA operates a long-term ambient nitrogen dioxide (NO_2), SO_2, ozone (O_3) and particulate matter (PM-10) monitoring station at CCP. The location adequately meets the pre-construction siting requirements for the CGF/CCP stationary source. BPXA used the latest SO_2 data available at the time of application (the 2007 data set) to meet the pre-construction monitoring requirement.

BPXA submitted the 2007 CCP data for Department review on May 2, 2008. The data was reviewed on behalf of the Department by Enviroplan Consulting (Enviroplan), who found that the SO_2 data adequately meets the PSD quality assurance requirements.[8]

BPXA did not reiterate the maximum SO_2 concentrations in their PSD application. The Department is therefore providing these values below in Table 1. The values are reported in both a volumetric basis (parts per million – ppm), which is the format used in BPXA's monitoring data report, and on a mass basis (micrograms per cubic meter – $\mu g/m^3$) which is the format used in modeling. The ambient standard (in both formats) is also provided. The maximum concentrations are well below the AAAQS.

Table 1: Maximum SO_2 Concentrations Measured at CCP During Calendar Year 2007

Air Pollutant	Avg. Period	Volumetric Basis (ppm)		Mass Basis ($\mu g/m^3$)		% of AAAQS
		Max Conc	AAAQS	Max Conc	AAAQS	
SO_2	3-hr	0.011	**0.5**	29	**1300**	2%
	24-hr	0.009	**0.14**	24	**365**	6%
	Annual	0.001	**0.031**	3	**80**	3%

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

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[8] *Meteorological and Pollutant Data Review – BPXA 2007 Prudhoe Bay Unit Data*; Enviroplan Consulting; January 5, 2009.

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 the maximum concentrations measured at their A Pad monitoring station during calendar year 2007 as the background concentrations. This is an appropriate data set for this application. The maximum values are provided in the "Results and Discussion" section of this memorandum.[9] The A Pad data was reviewed with the CCP data (by Enviroplan) and was also found to meet the PSD quality assurance requirements.

SOURCE IMPACT ANALYSIS

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

Approach

BPXA made two sets of preliminary runs with just the CGF/CCP emission units in order to reduce the number of receptors needed for the subsequent cumulative (aka "full field") impact assessment. This approach is warranted (especially when modeling large emission inventories – as is the case here) in order to produce acceptable computer run times.

One set of runs was used to cull out "far-field" receptors with insignificant *project* impacts. For purposes of this analysis, BPXA considered receptors located between 2 and 8 km of CGF/CCP as far-field. BPXA defined the project impacts as the proposed change in *gas-fired* SO_2 emissions – i.e., the SO_2 emissions associated with a fuel gas H_2S content of 105 ppm minus the SO_2 emissions associated with the most recent two-year average fuel gas H_2S concentration (which is 25 ppm). BPXA did <u>not</u> include the *liquid-fired* units in the project impact analysis since their SO_2 emissions are decreasing. Excluding the liquid-fired units makes the project impact analysis conservative.

In the second set of preliminary runs, BPXA modeled the "near-field" receptor grid (receptors located within 2 km of CGF/CCP) to find the 30 worst-case near-field receptors. BPXA modeled the potential SO_2 emissions at CGF/CCP, rather than just the project emissions. BPXA selected 30 receptors, rather than 10 (as proposed in the 2001 modeling protocol), in response to the Department's April 24, 2008 comments questioning the adequacy of only 10 near-field receptors. The use of 30 worst-case receptors, compiled from all three SO_2 averaging periods and all five meteorological data years (see Meteorological Data discussion), makes the subsequent AAAQS/increment analysis adequately robust.

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[9] BPXA reported the maximum concentrations measured at A Pad in Table 1-20 (of Attachment VI) of their application. BPXA reported the values in both ppm and µg/m^3. The Department found that the reported 3-hour and annual average ppm values contain typographical errors. However, the reported µg/m^3 values are correct.

BPXA included both the 30 worst-case near-field receptors and the significant far-field receptors in the full field AAAQS/increment analysis. They also modeled the following two scenarios:

- A fuel gas H_2S content of 105 ppm for the gas-fired CGF/CCP emission units, and a liquid fuel sulfur content of 0.11 percent (by weight) for the diesel-fired CGF/CCP emission units. However, in order to demonstrate compliance with the air quality standards and increments, BPXA noted that the horizontal exhaust stacks on the three CGF emergency generators (Tag Nos. NGI-19-2802, NGI-19-2819, and NGI-19-2890) must be turned vertical (with no rain caps).

- The same 105 ppm H_2S content, but with a liquid fuel sulfur content of 0.019 percent (by weight) and no stack modifications for the three CGF emergency generators.

<u>Intermittent Well Servicing Equipment</u>
BPXA included intermittent well servicing equipment in the full field analysis, as requested by the Department in the April 4, 2002 protocol approval. BPXA assumed well servicing activities are occurring at the West Gas Injection (WGI) pad, which is located 0.5 km north of CCP. This is the nearest pad to CCP/CGF on which well servicing activities might occur. BPXA used the Alpine Frac Unit source characterization to represent the well servicing activities. This is consistent with the Department's April 2002 recommendation.

<u>Increment Analysis</u>
The SO_2 baseline date for the Northern Alaska Intrastate Air Quality Control Region is June 1, 1979. Therefore, there are both baseline and increment consuming emission units within the PBU, including CGF and CCP.

BPXA's approach for modeling the SO_2 increment consumption is described in Section 1.2 of Attachment VI of their application. In summary, BPXA assumed the SO_2 emissions from all *gas-fired* CGF/CCP emission units are *entirely* increment consuming since the baseline H_2S level is unknown (i.e., they did not take any credit for the baseline SO_2 emissions). They likewise did <u>not</u> take credit for the increment *expanding* CGF/CCP emissions associated with the decrease in liquid fuel sulfur content. Both of these assumptions result in a larger SO_2 modeled increment impact than what will really occur. BPXA did <u>not</u> include offsite intermittent well servicing equipment in the increment analysis per the Department's *Intermittently Used Oilfield Support Equipment* policy (Policy and Procedure No. 04.02.105). BPXA's approach for modeling the SO_2 increment is reasonable and conservative.

Model Selection
There are a number of air dispersion models available to applicants and regulators. The U.S. Environmental Protection Agency (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 analysis. AERMOD is an appropriate model for this application.

The AERMOD Modeling System consists of three components: AERMAP (which is used to process terrain data), AERMET (which is used to process the meteorological data), and AERMOD (which is used to estimate the ambient concentrations).

BPXA only needed to use the AERMET and AERMOD components in the CGF/CCP analysis. BPXA did not need to use the AERMAP component since there are no significant terrain features near CGF/CCP or the greater PBU area. BPXA used the current version of each applicable component (version 07026 for AERMOD and version 06341 for AERMET).

BPXA recompiled the AERMOD source code using Intel's FORTRAN compiler. Prior to recompiling the code, BPXA corrected a FORMAT statement error regarding the placement of the page header form-feeds. BPXA made no other changes to the source code. According to the application, they also conducted test runs to confirm that the recompiled version provided the same results as EPA's compiled version.

Section 3.1.2 of the Guideline allows users to make minor changes to the source code, as long as the changes do not affect the resulting concentrations. Recompiling the source code and correcting print-out errors fall within this category of acceptable changes. To confirm that BPXA did not inadvertently introduce an error to the program, the Department made limited test runs using both BPXA's version and EPA's version. The Department confirmed that BPXA's version provides the same results as EPA's version.

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 three years (1998, 1999 and 2006) of PBU A Pad surface data for this analysis. BPXA substituted missing solar radiation and temperature difference (SRDT) data with cloud cover data measured by the NWS at Deadhorse. They also used concurrent NWS upper air data from Barrow.

<u>Discussion re Land-Sea Breeze Affects</u>

BPXA noted that CGF/CCP is located 1 kilometer (km) inland, while the A Pad meteorological station is 12 km inland. They therefore addressed whether the A Pad data adequately represents the potential land-sea breezes that may exist at CGF/CCP, since the public has raised this type of question in other North Slope projects.

BPXA provided a number of arguments based on boundary layer theory and a 2007 study conducted by the U.S. Mineral Management Services (MMS) to support their position that the A Pad data is adequately representative of the CGF/CCP meteorological conditions. They also analyzed the meteorological conditions associated with the highest 24-hour SO_2 increment impact. They did not assess the meteorological conditions associated with the other SO_2 averaging periods, or the maximum AAAQS impacts, since the modeled impacts were much less than the applicable standard (i.e., there could be notable error in the analysis without jeopardizing the compliance demonstration).

BPXA found that the twenty highest 24-hour SO_2 increment impacts occur during mid to late winter. Land-sea breezes do not occur during this time due to little or no solar radiation and continuous snow/ice cover between the land and sea. BPXA further noted that the highest mid-winter impacts occur during periods of sustained high winds blowing parallel to the coast (i.e., opposite to land-sea breezes). The highest late-winter impacts occur during periods of strong surface inversions and low variable winds. Both events create conditions that would lead to worst-case impacts for the CGF/CCP emission units.

BPXA's argument regarding the mid-winter wind events is compelling. Gerry Guay of the Department's Monitoring and Quality Assurance Group also confirmed that North Slope winters tend to be windier than summers, after reviewing a 1920-1970 climatological data set from Barrow and a 1947-1970 climatological data set from Barter Island.[10]

The Department further notes that the maximum impacts from CGF/CCP occur at pad edge and are either associated with downwash conditions, or strong inversions (which are accommodated with low wind speeds). Land-sea breezes do not occur during inversions, so periods with inversions are not in question. Downwash occurs when there is sufficient wind speed to entrain the exhaust plume into the building wake. The cause for these higher wind speeds (i.e., whether it be sea-land induced or weather front induced) is irrelevant. The question is: are the wind speeds and directions that lead to the highest impacts adequately characterized? If this answer is unclear, then the next question becomes: would the correction of the alleged error in wind speed/direction change the conclusion of the compliance demonstration.

The Department agrees with BPXA's argument that most of the modeled scenarios have an adequately wide margin for error. The 24-hour increment analysis of the 0.019% fuel sulfur scenario is the one exception. In this case, the maximum impact is 95-percent of the Class II increment. The maximum impacts for all other scenarios are *no more than* 61-percent of the applicable standard. Most of the maximum impacts are no more than a third of the applicable standard. Therefore, the land-sea breeze question focuses on whether the winds at CGF/CCP would be sufficiently different from the winds at A Pad to lead to a modeled violation of the 24-hour increment. The potential for that kind of variation, or an unrepresented condition, is unlikely.

The Department therefore considers the A Pad surface data as site-specific for purposes of characterizing the meteorological conditions at CGF/CCP. The use of three years of data exceeds EPA's minimum data requirements and allows for the potential year-to-year variations in meteorology to be assessed.

[10] E-Mail from Gerry Guay (ADEC) to Alan Schuler (ADEC); *RE: Meteorological Data Question re North Slope Land-Sea Breezes*; December 23, 2008.

Quality Assurance Review Findings

The Department previously reviewed the 1998, 1999 and 2006 A Pad meteorological data to determine whether they meet the PSD criteria for acceptability. The Department's findings regarding the 1998 and 1999 meteorological data were transmitted to BPXA in a July 19, 2007 letter.[11] The findings regarding the 2006 meteorological data were transmitted to BPXA on February 14, 2008.[12] The findings for all three data years are summarized below:

1998-1999 A Pad Meteorological Data

- Out of a 1998-2000 and 2002 data set reviewed by the Department, 1999 is the only year that completely complies with the PSD quality assurance requirements.
- With one exception, all of the 1998 meteorological data meet the PSD criteria for acceptability. The wind speed data for the 4th quarter is the one exception due to inadequate data capture (85.5 percent instead of the required 90 percent).
- BPXA may nevertheless use the 1998 data in conjunction with the 1999 data since the data capture is still fairly good and the 1999 data satisfies the minimum meteorological data requirements.[13]

2006 A Pad Meteorological Data

- With one exception, all of the 2006 A Pad meteorological data meet the PSD criteria for acceptability. The delta-temperature parameter was the one exception due to inadequate data capture (76.1 percent instead of the required 90 percent).

While not stated in the findings for the 2006 data, the Department allowed BPXA to use the 2006 A Pad meteorological data since:

1) the 1999 data already satisfies the minimum data requirements;
2) most aspects of the 2006 data set also meet the PSD requirements; and
3) the Deadhorse NWS cloud-cover data is an acceptable surrogate for missing delta-temperature data.

AERMET Surface Parameters

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 used the same values as previously approved and used for A Pad. However, the use of these values warrants discussion due to EPA's January 2008 revision to the *AERMOD Implementation Guide*.

[11] July 19, 2007 letter from Alan Schuler to Jim Pfeifer (BPXA), "A Pad Data Review Findings and Request for Revised WRDx Modeling Protocol."

[12] E-mail from Alan Schuler to Jim Pfeiffer (BPXA) and Alison Cooke (BPXA); *2006 A-Pad/CCP Data Findings*; February 14, 2008.

[13] Section 8.3.1.2b of the Guideline allows the use of partial meteorological data years when combined with a complete year of data.

BPXA originally proposed the A Pad surface characteristics in the modeling protocol for their WRDx Gas Partial Processing PSD Project (as revised on December 28, 2006). The Department then listed the accepted values in the January 31, 2007 protocol approval. In EPA's subsequent revision to the *AERMOD Implementation Guide*, the domain and methodology for weighting the surface parameters changed. BPXA therefore reviewed the previous values to determine whether they needed to be revised for the CGF/CCP analysis. BPXA noted that the land cover around A Pad is fairly homogeneous throughout an area that extends beyond the area used to determine the AERMET surface characteristics. The resulting values would therefore be identical using either method. The Department agrees with BPXA's assessment and is continuing to accept the previously approved surface characteristics for A Pad. The accepted values are repeated below in Table 2.

Table 2: Approved AERMET Surface Parameters for 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.

<u>Design Concentrations</u>

EPA allows applicants to compare the high second-high (h2h) modeled concentration to the short-term air quality standards if at least one year of temporally representative site-specific, or five years of representative NWS data, are used. When these criteria are not met, then applicants must use the high first-high (h1h) concentration. In all cases, applicants must compare the h1h modeled concentration to the annual average standards/increments, the SILs, and the pre-construction monitoring thresholds. The Department allowed BPXA to compare the h2h concentration to the short-term AAAQS/increments since they used site-specific meteorological data.

Emission Unit Inventory

BPXA modeled all of the gas-fired and liquid-fired emission units listed in the current Title V permits for CGF and CCP. The emission unit inventories are provided in Tables 1-1 and 1-2 of Attachment VI of BPXA's application.

Emission Rates and Stack Parameters

The assumed emission rates and stack parameters have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully.

<u>Operational Restrictions</u>

BPXA assumed most of the CGF/CCP emission units are constantly operating. The only exceptions regard the liquid-fired units, all of which have an existing annual operating limit. BPXA used these existing limits when modeling the annual average SO_2 impacts. The liquid-fired units, and their annual operating limits, are listed below in Table 3.

Table 3: Emission Units with Annual Operating Limits

Source/Emission Unit			Limit (hr/yr)
Model ID	Tag No.	Description	
CGF			
1110	NGI-19-2802	GM 20-645F4B Emergency Generator	200
1111	NGI-19-2819	GM 20-645F4B Emergency Generator	200
1121	NGI-19-2890	GM 20-645F4B Emergency Generator	200
1122	NGI-18-1529	Caterpillar/3406P Emergency Fire Water Pump	200
CCP			
816	EDTG-18-2897	Solar T-4001 Emergency Generator	200
817	EDG-18-2897-01	GM Emergency Generator	200
818	EDG-18-1522	Cummins Emergency Fire Water Pump	295

The historical purpose for the annual operating limits is not well documented. However, in reviewing the current analysis, it is apparent that the annual restrictions are needed to at least protect the annual average SO_2 AAAQS and increment. The Department suspects the annual limits are likewise needed to protect the annual average nitrogen dioxide (NO_2) AAAQS/increment and the annual average particulate matter (PM-10) AAAQS/increment. This is especially probable in regards to NO_2 since the NO_2 AAAQS/increment tend to be more restrictive than the SO_2 AAAQS/increment when modeling combustion units. The potential need for restricting the annual operations to protect the PM-10 AAAQS/increment is not as clear. However, if an annual restriction is needed to protect the annual SO_2 AAAQS/increment, then an annual restriction is *likely* needed to protect the annual PM-10 AAAQS/increment as well. The Department presumes that is the case here. The Department is therefore clarifying through this memorandum that the annual operating limits listed in Table 3 are being imposed to protect the annual average NO_2, SO_2 and PM-10 AAAQS/increments.[14]

<u>SO_2 Emissions</u>

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. While BPXA's requested H_2S and fuel sulfur limits have already been presented, BPXA's assumptions warrant additional discussion.

BPXA assumed the maximum liquid fuel sulfur content at CCP and CGF is 0.11 percent, by weight. This is a notable reduction from the current 0.75 percent threshold associated with the 500 ppm SO_2 emission limit listed in 18 AAC 50.055(c). The Department is therefore imposing BPXA's 0.11 percent fuel sulfur assumption as a permit limit at both CCP and CGF, in order to protect the SO_2 AAAQS/increments.

While BPXA assumed the *maximum* liquid fuel sulfur content is 0.11 percent, they also ran an alternative scenario where the fuel sulfur content *at CGF* is less than 0.019 percent (while the fuel sulfur content at CCP remains at 0.11 percent). In this case, BPXA used a lower fuel sulfur

[14] The Department's presumption does not preclude BPXA from submitting additional information (e.g., a revised air quality modeling analysis) under 18 AAC 50.508(6) to demonstrate that annual limits are not necessary to protect the annual AAAQS/increments.

content to offset the increased impacts from an alternative stack design. This scenario is further discussed in the Horizontal/Capped Stack section of this memorandum.

BPXA requested an *annual average* H_2S limit for CGF. They did not request any H_2S limits for CCP. The requested limit for CGF is 105 ppm. BPXA also stated that an instantaneous limit is *not* needed to protect the short-term AAAQS/increments since the H_2S content would need to increase to 250 ppm during the short-term period in order for the SO_2 increment to be consumed.

BPXA provided a brief supporting argument for an annual average limit in Section 1.11.3 of Attachment VI. They also provided additional clarification regarding their assertions, in response to Department questions.[15, 16] BPXA concluded, "Since the fuel gas H_2S levels at CGF and CCP vary less than 30 percent on a short-term basis and less than 10 percent on an annual basis, it is possible to conclude that compliance can be assured by monitoring fuel gas levels only once per year, at least as long as the measured concentration is considerably less than 250 ppmv."

The Department notes that BPXA derived the 250 ppm H_2S value from a post-run analysis of their *near-field* impacts. However, they did not evaluate the potential far-field effects.

BPXA limited their cumulative impact assessment to the project's significant impact area (SIA). BPXA assumed an instantaneous H_2S content of 105 ppm when establishing the SIA. Therefore, BPXA's argument regarding the 250 ppm upper bound is incomplete.

The Department conducted a cursory sensitivity test by rerunning the 24-hour SIA analysis for a randomly selected meteorological data year (2006). The Department found that at 250 ppm, the SIA would extend to Gathering Center 3 (GC3) and the Central Power Station (CPS). Since this area was not included in BPXA's cumulative impact assessment, it is unknown whether BPXA could still demonstrate compliance with the AAAQS/increments within this new area.

BPXA used 105 ppm, rather than 250 ppm, as the instantaneous H_2S content in their ambient analysis. The Department is therefore imposing 105 ppm as an *instantaneous* limit. The monitoring frequency can be the same as that imposed under the Best Available Control Technology (BACT) analysis.

The Department acknowledges that a higher instantaneous H_2S limit (somewhere between 105 ppm and 250 ppm) *may be* viable. However, BPXA would need to provide that demonstration in order for the Department to impose a higher fuel gas H_2S limit.

<u>Horizontal/Capped Stacks</u>
The presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. Most of the emission units at CGF and CCP have vertical, uncapped releases. However, there are several units with horizontal releases (including the three CGF

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[15] E-mail from Thomas Damiana (AECOM) to Alan Schuler (ADEC); *BPXA CCP/CGF H_2S Increase Application – Gas-fired source impact conclusions explanation*; January 28, 2009.
[16] E-mail from Sims Duggins (AECOM) to Alan Schuler (ADEC); *RE: BPXA CCP/CGF H_2S Increase Application – Gas-fired source impact conclusions explanation*; January 29, 2009.

emergency generators). There are also offsite emission units with either horizontal or capped releases.

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 flowrate). 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.[17] BPXA used this non-default option to characterize all capped/horizontal stacks.

BPXA requested that the Department impose a permit condition to require vertical stack orientations for the three CGF emergency generators whenever the sulfur content of the liquid fuel burned by these units exceeds 0.019 percent, by weight. The Department reviewed the files and agrees that a vertical stack orientation is required to protect the SO_2 AAAQS/increment whenever these units burn fuel with a sulfur content ranging between 0.019 percent and the fuel sulfur cap (0.11 percent). The Department is therefore including this condition in the CGF permit.

Stack Dimensions

BPXA stated that they made an extensive effort to verify and update the physical stack parameters for CGF and CCP. The Department compared computerized images of the modeled stack/building configurations to photographs of the CGF and CCP facilities. The modeled stack heights appear valid. The stack diameters and orientations likewise appear valid. [18]

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 pad edge as the ambient air boundary. This is an appropriate ambient air boundary for North Slope sources.

Receptor Grid

BPXA used a 500 meter grid spacing in the far-field (i.e., 2 km – 8 km) significant impact analysis. BPXA also placed additional receptors near around Gathering Center 1 (GC-1), and the

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

[18] The Department found an "error" in Table 1-10 of Attachment 6 in regards to the stack diameter listed for the CGF Emergency Fire Water Pump (unit NGI-19-1529). The stated 31.5 meter diameter is actually the artificially large diameter used to characterize horizontal stacks in a non-downwash scenario. However, according to the modeling files that BPXA provided, the actual diameter for this unit is 0.15 meters. Therefore, this is just a reporting error, not a modeling error.

Gathering Center 3 (GC-3) and Central Power Station (CPS) pads. This not only made the SIA analysis more robust, it also highlighted the approximate location of these sources.

BPXA stated that *only* the 24-hour averaging period had significant impacts within the far-field grid. The Department found a single exception: the 3-hour averaging period has a single receptor with significant impacts during the 2006 meteorological data year. However, this receptor also had significant 24-hour impacts, so the effect of this oversight is moot.

For the preliminary near-field analysis, BPXA used the following receptor grid density:

- 25-meter spacing along the ambient air boundary;
- 25-meter resolution from the boundary outward to 100 meters in each cardinal direction;
- 100-meter resolution from the 25-meter grid outward to 1 kilometer (km) in each direction; and
- 250-meter resolution from the 1km grid outward to 2 km in each direction.

In the full-field (cumulative impact) analysis, BPXA limited the receptor grid to the 30 worst-case near-field receptors and the far-field receptors that had significant project impacts.

BPXA's receptor grids are acceptable. The maximum cumulative impacts (for the given H_2S and fuel-sulfur assumptions) occur in the CGF/CCP near-field.

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.

BPXA included building downwash for the CGF and CCP emission units, along with those offsite sources located near the CGF/CCP SIA (i.e., GC-1, GC-2, GC-3 and CPS). BPXA stated that they reviewed and revised, when warranted, the previously assumed CGF/CCP building parameters. The Department compared the assumed building layout to photographs of these facilities. Since the layout compares well, the Department accepts BPXA's revised CGF/CCP building parameters.

BPXA stated they used the same building parameters for the off-site sources as developed for the November/December 2007 minor permit applications for GC1, GC-2, GC-3 and CPS. These applications are currently on hold and therefore, have not yet been reviewed by the Department. However, the Department confirmed that downwash was included for these sources and therefore, considers the assumed parameters adequate for an offsite inventory.

Off-Site Impacts

In a cumulative impact analysis, the applicant must include impacts from large sources located within 50 km of the applicant's SIA. These impacts from "off-site" sources are typically assessed through modeling. However, the off-site impacts in an AAAQS analysis can also be accounted for with ambient monitoring data, if representative data is available.

BPXA included the permitted stationary sources located within Prudhoe Bay, Milne Point, the Kuparuk River Unit, and Deadhorse in the modeled off-site inventory. They also included the Endicott (including the recently permitted "Liberty" project emission units), Badami and Northstar stationary sources.

The Department found a minor modeling error in regards to the Seawater Injection Plant East (SIPE) emission inventory. BPXA used a "907" and "908" nomenclature for the two main seawater injection turbines (tag number NGT-31-15101 and NGT-31-15102). However, they used a 907**C** and 908**C** (emphases added) nomenclature in the "source group" designations. The effect of this inconsistency is that AERMOD estimated the impacts from these units, but did *not* include those impacts when calculating the total impacts. The Department considers this error to be inconsequential since SIPE is relatively distant and not located within either of the predominate wind directions of CGF/CCP. The Department nevertheless confirmed this consideration by correcting the error and rerunning the worst-case averaging period (24-hour) and meteorological data year (1999). The maximum impact did not change.

Results and Discussion

The maximum SO_2 AAAQS impacts are shown in Tables 4 and 5. Table 4 provides the results for the 0.11 percent liquid fuel sulfur scenario. Table 5 provides the results for the 0.019 percent liquid fuel sulfur alternative. The background concentrations, total impacts and ambient standards are also shown in both tables. In all cases, the maximum impacts are no more than a third of the AAAQS.

Table 4: Maximum AAAQS Impacts When Liquid Fuel Sulfur = 0.11 percent

Air Pollutant	Avg. Period	Maximum Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
SO_2	3-hr	149.0	41.9	**191**	1,300
	24-hr	53.5	34.0	**88**	365
	Annual	7.1	2.6	**10**	80

Table 5: Maximum AAAQS Impacts With Alternative 0.019 percent Fuel Sulfur Limit at CGF

Air Pollutant	Avg. Period	Maximum Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
SO_2	3-hr	314.3	41.9	**356**	1,300
	24-hr	87.0	34.0	**121**	365
	Annual	7.1	2.6	**10**	80

The maximum SO_2 increment impacts are shown in Tables 6 and 7, along with the Class II increments. All of the maximum impacts are less than the applicable Class II increments.

Table 6: Maximum Increment Impacts When Liquid Fuel Sulfur = 0.11 percent

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
SO_2	3-hr	**143**	512
	24-hr	**52**	91
	Annual	**7**	20

Table 7: Maximum Increment Impacts With Alternative 0.019 percent Fuel Sulfur Limit at CGF

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
SO_2	3-hr	**314**	512
	24-hr	**87**	91
	Annual	**7**	20

It is important to note that since ambient concentrations vary with distance and direction from each emission unit, the maximum values shown represent the highest annual and high second high short term values value that may occur within the area. Except for maximum short term concentrations which are allowed to exceed the respective standards once per year, the concentrations at other locations within the modeling domain should be less than the values reported above.

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 2 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 addressed this requirement in two manners. First, they referenced a 1989 – 1994 North Slope vegetation study conducted by the Boyce Thompson Institute for Plant Research that found no adverse impacts due to air contaminants. Second, they compared the modeled impacts to the secondary 3-hour SO_2 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 Tables 4 and 5, the maximum 3-hour SO_2 impact is well below the AAAQS. Therefore, the project should not adversely affect the nearby vascular plants.

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 $\mu g/m^3$.[19] While it is not known whether North Slope lichens have this same sensitivity, these values provide a surrogate measure of the potential sensitivity threshold.

The maximum annual average SO_2 impact from either scenario (10 $\mu g/m^3$) 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.

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

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. BPXA does not expect significant changes in these categories. The Department accepts BPXA's assessment.

CONCLUSION

The Department reviewed BPXA's modeling analysis for the requested H_2S increase and concluded the following:

1. BPXA provided the source impact analysis required under 40 CFR 52.21(k) ***Source Impact Analysis***. The analysis adequately demonstrates that the SO_2 emissions associated with operating the CGF/CCP stationary source, within the constraints described in this memorandum, will not cause or contribute to a violation of the AAAQS provided in 18 AAC 50.010 or the maximum allowable increases (increments) provided in 18 AAC 50.020.
2. BPXA appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
3. BPXA provided the pre-application air quality analysis required under 40 CFR 52.21(m)(1) ***Preapplication Analysis***.
4. BPXA provided the additional visibility, soils, vegetation and secondary impact analysis required under 40 CFR 52.21(o) ***Additional Impact Analysis***.

The Department developed conditions in the CGF and CCP air quality control permits to ensure BPXA complies with the SO_2 ambient air quality standards and increments. These conditions are summarized below.

In the CGF Permit

5. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
6. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
7. Comply with the unit specific annual operating limits shown in Table 3.[20]
8. Construct and maintain vertical, uncapped exhaust stacks for the three emergency generators (Tag No. NGI-19-2802, NGI-19-2819, NGI-19-2890), except when the liquid fuel sulfur content at CGF is less than or equal to 0.019 percent, by weight. When the fuel sulfur content is less than or equal to 0.019 percent, the stacks may be capped or have a horizontal discharge. The uncapped condition does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

[20] The annual operating limits in Table 3 are being imposed to protect the annual average air quality standards and increments for the following pollutants: NOx, SO_2 and PM-10.

In the CCP Permit

1. For all diesel-fired emission units, limit the maximum fuel sulfur content to 0.11 percent, by weight.
2. For all gas-fired emission units, limit the maximum H_2S content to 105 ppm (on an instantaneous basis).
3. Comply with the unit specific annual operating limits shown in Table 3.[17]

Exhibit C: BACT Review

AIR QUALITY TITLE I PSD PERMITS
BACT FINDINGS REPORT (FINAL REPORT)

BP Exploration Alaska Inc. (BPXA)
Prudhoe Bay Central Compressor Plant (CCP) and Central Gas Facility (CGF)
900 E. Benson Boulevard
P.O. Box 196612
Anchorage, AK 99519-6612

Prepared for:

Alaska Department of Environmental Conservation
Division of Air Quality
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Under Contract 18-3001-12 and NTP 18-3001-12-9B

June 16, 2009

TABLE OF CONTENTS

LIST OF TABLES

Tables **Page No.**

1.0 Executive Summary

BP Exploration Alaska Inc. (BPXA) submitted the Prudhoe Bay Unit Prevention of Significant Deterioration (PSD) Construction Permit No. AQ0270CPT04 application on September 13, 2008 to the Alaska Department of Environmental Conservation (ADEC).

North Slope fuel gas souring has increased hydrogen sulfide (H_2S) concentrations in the fuel gas. The higher H_2S concentrations in the fuel gas result in higher sulfur dioxide (SO_2) emissions from the exhaust of Central Compressor Plant (CCP) and Central Gas Facility (CGF) combustion equipment. The CCP and CGF currently consists of the following fuel gas combustion equipment: twenty six (26) fuel gas fired turbines and eight (8) fuel gas fired heaters and two (2) reboilers and nine (9) flares. The CCP and CGF combustion equipment burns 295 million standard cubic feet of fuel gas per day (MMscf/d).

Under the US EPA permit PSD-X81-13, as amended August 29, 1997, SO_2 emissions from six (6) turbines and three (3) heaters at CGF are restricted. Under the ADEC permit 9873-AC006, issued July 15, 1998, the H_2S in the fuel gas at CGF is restricted for seven (7) turbines. These current limits are based on fuel gas conditions that existed in 1997. BPXA is unable to maintain continuous compliance with these current limits due to fuel gas souring unless emissions controls are added to the process.

BPXA is unable to determine to what level fuel gas H_2S levels will climb during the next 10 years, but estimates that H_2S fuel gas levels could increase to as high as 300 ppmv and elected to use this value as a conservative estimate for the BACT analysis. The resulting emission increase from the Fuel Gas Souring Project (Project) will exceed the significant emissions increase thresholds in 40 CFR 52.21(b)(2)(i) for SO_2, therefore the Project is classified as a PSD major modification for SO_2 and requires a Best Available Control Technology (BACT) assessment for SO_2. The Project does not increase emissions of volatile organic compounds (VOC), nitrogen (NO_x), carbon monoxide (CO), or for particulate matter (PM/PM_{10}).

BPXA performed a BACT analysis, which was reviewed for its technical accuracy, and adherence to accepted engineering cost estimation practices by Eastern Research Group, Inc. (ERG) under contract with the Alaska Department of Environmental Conservation. The purpose of this document is to report on ERG's assessment of BPXA's BACT analysis.

Table 1 provides a list of the control technologies that were determined to be technically feasible for the CCP and CGF combustion equipment. The shaded row indicates the control level for SO_2 proposed by the source as BACT.

Table 1. Technically Feasible Control Technology Summary

Control Technology	Annualized Costs (Revised)	Control Efficiency (%)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
LO-CAT®	**$ 38,201,145**	**99.7%**	**$ 15,526**	**$ 14,476**
Sulfa Treat®	**$ 33,461,456**	**98.7%**	**$ 13,420**	**$ 12,805**
Adsorption Process (Amine)	**$ 46,369,135**	**96.7%**	**$ 21,729**	**$ 18,113**
Limit Sulfur in Fuel	**-**	**-**	**-**	**-**

ERG agreed with BPXA's list of technically feasible control technologies. However, cost analyses were revised to adjust for the following items. Appendix A contains a comparison of the BPXA's cost analysis and the revisions made by ERG.

- Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.
- Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries will include all appropriate controls.
- Reduced Amine painting costs from 6 percent of the base equipment costs to 4 percent.

2.0 Background

Alaska Department of Environmental Conservation contracted with Eastern Research Group, Inc. (ERG) to assess the BACT analyses submitted by BPXA and their adherence to accepted engineering standards. This report documents ERG's findings in the review of the BPXA BACT analyses.

2.1 Best Available Control Technology

ERG has reviewed the BACT analyses for SO_2 conducted by BPXA. The review included the identification of available technologies; the technical feasibility, control effectiveness, and energy, environmental and economic impacts of the controls.

The review has been conducted in accordance with state and federal rules and the conventional "Top-Down" Best Available Control Technology process. The steps for conducting a top-down BACT analysis are listed below:

Step 1 Identify all potentially available control options:

In Step 1, the applicant identifies all 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/or operational limitations. To assist in identifying available controls, the applicant and the Department review the available controls listed on EPA's RACT/BACT/LAER Clearinghouse (RBLC) bulletin board where permitting agencies nationwide have listed the BACT control technologies imposed.

Step 2 Eliminate technically infeasible control options:

In Step 2, the applicant evaluates the technical feasibility of the various control options in relation to the specific emission unit under consideration. If the applicant can clearly document and demonstrate, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option, it is eliminated from further consideration in this step.

Step 3 Rank remaining control technologies by control effectiveness:

In Step 3, the remaining control options are listed in order of control effectiveness for the pollutant under review, with the most effective option at the top. In this step, the applicant also presents detailed information about the control efficiency, the expected emission rate and/or the expected emission reduction.

Step 4 Evaluate the most effective controls and document the results as necessary:

In Step 4, the energy, environmental, and economic impacts are considered to decide the final level of control. The applicant is responsible for presenting 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:

In Step 5, the most effective control option not eliminated in step 4 is proposed as BACT for the pollutant and emission unit under review. The final BACT requirements determined for each emission unit are listed in this step.

The BACT analysis included in this findings report are based on the following information:

(a) The BACT analysis information submitted by BPXA on September 13, 2008 and additional information received on January 26, 2009 and May 20, 2009;

(b) Information from vendors, suppliers, and subcontractors; and

(c) The EPA RACT/BACT/LAER (RBLC) Clearinghouse.

The BACT Determinations for SO_2 follow in Section 3.0.

3.0 BACT Determination for SO_2

North Slope fuel gas souring has increased H_2S concentrations in the fuel gas. The higher H_2S concentrations in the fuel gas result in higher SO_2 emissions from the exhaust of CCP and CGF combustion equipment. Therefore, it is classified as a PSD major modification under 40 CFR 52.21. Fuel gas fired equipment at the CCP and CGF consists of the combustion equipment listed in the table below. Table 2 presents the projected potential SO_2 emissions and the maximum daily gas usage for the gas fired CCP and CGF equipment. These are important data relevant to the BACT analysis pertaining to cost effectiveness and the amount of SO_2 controlled based on the control efficiency of the technically feasible control technologies identified later in this document.

Table 2. BPXA CCP and CGF Combustion Equipment

Tag No.	Emission Unit Description	Projected SO_2 (tpy)	Maximum Daily Gas Usage (MMscf/d)
NGI-19-1883	GE Frame 6 Injection Compressor	117.9	13.59
NGI-19-1884	GE Frame 6 Injection Compressor	117.9	13.59
NGI-19-1885	GE Frame 6 Injection Compressor	117.9	13.59

NGI-19-1886	GE Frame 6 Injection Compressor	117.9	13.59
NGI-19-1801	Cooper-Rolls/RB211-24C Booster	63.7[a]	7.04
NGI-19-1802	Cooper-Rolls/RB211-24C Booster	63.7[a]	7.04
NGI-19-1805	Cooper-Rolls/RB211-24C Miscible Injectant	63.7[a]	7.04
NGI-19-1855	Cooper-Rolls/RB211-24C Miscible Injectant	63.7[a]	7.04
NGI-19-1806	GE MS5382C Refrigerant Compressor	95.5[a]	11.76
NGI-19-1856	GE MS5382C Refrigerant Compressor	95.5[a]	11.76
NGI-19-1857	GE MS5382C Booster Compressor	95.5	11.76
19-1408	IHI-John Zink Emergency Flare (HP Primary Pit)	27.7	3
19-1409	IHI-John Zink Emergency Flare (LP Primary Pit)		
19-1410	IHI-John Zink Emergency Flare (HP Emergency Pit)		
19-1411	IHI-John Zink Emergency Flare (LP Emergency Pit)		
19-1412	IHI-John Zink Emergency Flare (NGL Primary Pit)		
NGI-19-1401	Chiyoda-John Zink Hot Oil Heater	55.3[a]	5.98
NGI-19-1402	Chiyoda-John Zink Hot Oil Heater	55.3[a]	5.98
NGI-19-1403	Chiyoda-John Zink Hot Oil Heater	55.3[a]	5.98
NGT-18-1801	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1802	GE MS5371PATP w/LHE Gas Compressor	94.8	10.27
NGT-18-1803	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1804	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1805	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1806	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1807	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1808	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1809	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1810	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1811	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1812	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1813	GE MS5371PATP Gas Compressor	91.4	9.90
NGT-18-1876	GE MS5382C Tandem Compressor	98.2	10.63
NGT-18-1878	GE MS5382C Tandem Compressor	98.2	10.63
NGH-18-1410	Broach Glycol Heater	7.3	0.79
NGH-18-1491	Broach Glycol Heater	9.6	1.04
NGH-18-1492	Broach Glycol Heater	9.6	1.04

NGH-21-1501	Eclipse Glycol Heater	3.1	0.34
NGH-21-1502	Eclipse Glycol Heater	2.7	0.30
NGH-21-1503	BS&B TEG Reboiler	1.0	0.11
NGH-21-1504	BS&B TEG Reboiler	1.0	0.11
18-1403	John Zink HP/IP Emergency Flare	18.6	2.0
18-1494	John Zink STV Emergency Flare		
18-1496	Line Emergency Backup Flare		
18-1497	Line Emergency Backup Flare		
Total		**2,647**	**295**

[a]The projected potential SO_2 emission rate for these emission units is based on the assumption that the current EPA SO_2 ton-per-year limits will be increased as a result of a future application by the Permittee to revise the limit to the value shown here (i.e., to be based on 300 ppmv H_2S in the fuel gas instead of 30 ppmv H_2S).

There are two available SO_2 control approaches: 1) Prevent SO_2 emissions by reducing the H_2S concentrations through fuel gas treatment (H_2S Removal) or 2) Control SO_2 emissions in the flue gas exhaust, such as a desulfurization scrubber add-on control.

The following presents ERG's review of BPXA's BACT analysis for the available SO_2 control options using the step-by-step top-down approach described previously.

3.1 Identify All Control Technologies (Step 1)

<u>H_2S Removal Controls</u>

The following seven (7) control technologies for removal of H_2S emissions from North Slope fuel gas were identified:

1. Oil Reservoir Treatment Control (Biocide Injection)

H_2S levels in fuel gas are rising as reservoirs are souring across the North Slope as a result of waterflood operations used in enhanced oil recovery. Souring occurs when sulfate reducing bacteria which reduce the sulfate to H_2S, is injected with the water. Application of biocides into an oil field can reduce the activity of sulfate reducing bacteria and lower the H_2S content of the fuel gas.

Biocides introduced into the oilfield can retard the growth and proliferation of the sulfate reducing bacteria that are causing the H_2S levels in the gas to increase. To be effective, biocide treatments are often introduced as high dose slugs over extended intervals of time. The ultimate effectiveness of biocide injection on fuel gas on the North Slope is unknown.

2. H_2S Scavenging (SulfaTreat® and Sulfa-Rite®)

The scavenging process can be accomplished with either solid or liquid scavengers, which have nonregenerable reaction systems. The most common systems are marketed under SulfaTreat® and Sulfa-Rite® and both use an iron oxide scavenger. Gas Technology Products LLC (a Merichem Company) offers the Sulfur-Rite® technology for license. This technology is a representative H_2S scavenger system. The Sulfur-Rite® process is selective to H_2S and mercaptans, and is effective if the removal of other gas components, such as CO_2, is not required. In Sulfa-Rite® fuel gas is routed through a vessel containing a solid scavenger. Instead of merely absorbing H_2S, the Sulfur-Rite® process chemically changes H_2S into iron pyrite (FeS_4), which is a safe and stable compound. Sulfur-Rite® is designed to sweeten gas streams containing low levels of H_2S to less than 10 ppmv.

The most common liquid scavenger is an aminealdehyde condensate that is offered as a water-based solution. The scavenger liquid is typically injected directly into the gas stream using a static mixer or long length of pipe. The efficiency of the system is dependent on the degree of mixing and is, therefore, sensitive to flow fluctuations. Optimum performance of the scavenger requires that the fuel gas be 60 to 80 percent saturated before entering the vessel.

3. Liquid Redox (LO-CAT®)

The liquid redox process employs an aqueous based solution typically containing metal ions, usually iron, which are capable of transferring electrons in reduction-oxidation (redox) reactions. A commercial application offered by Gas Technology Products is called the LO-CAT® process. The LO-CAT® process converts H_2S to elemental sulfur using a patented, dual chelated iron catalyst, which has been shown to be environmentally safe.

This liquid redox technology uses a countercurrent liquid-gas absorption tower. The sour gas travels up the absorption tower and comes into contact with the patented LO-CAT® liquid solution flowing downward. Saturated sweet gas exits the top of the contactor. 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. A slip stream of this LO-CAT® solution is then filtered to remove the sulfur and is then returned to service in the countercurrent liquid-gas absorption tower. The solid elemental sulfur is filtered out as a cake of approximately 30 percent by weight solid (70 percent liquid) and sent to a landfill for disposal. Access to high purity fresh water is necessary to operate the LO-CAT® system to continually replenish to the LO-CAT® liquid.

The LO-CAT® processes have achieved H_2S removal efficiencies of greater than 99.9 percent in many different applications and industries. These applications range in size from a few standard cubic feet per minute (scfm) to several hundred MMscf/day and from a few pounds of sulfur produced to greater than 20 long tons of sulfur produced each day. The sour gas entering these LO-CAT® systems contain anywhere from 100 ppmv to 100 percent H_2S.

4. Thiopaq/Shell-Paques Technologies

Thiopaq/Shell-Paques 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. Thiopaq is a bio-catalyzed scrubber process which operates at ambient temperatures and pressures and does not require expensive catalysts and chemicals. The Thiopaq scrubber can be regarded as a caustic scrubber in which the spent caustic solution is continuously regenerated in the bioreactor. The H_2S removal efficiency can be as high as 99 percent.

The amount of water in the fuel gas, or the dew point, is very critical for the process and safety parameter. A sub dew point gas in an arctic environment can freeze lines, causing safety hazards and production downtime. Thiopaq technology uses water in the treatment system, so in addition to producing water for the Thiopaq technology, the fuel gas stream must be reconditioned to meet the -50°F dew point requirement.

The Shell-Paques process is very similar to the Thiopaq process except it can accommodate low, midlevel, and high pressure fuel inlet gas streams (2 to 1,300 psig). The major difference between the two technologies allowing the application of the Shell-Paques process to higher fuel inlet pressures is the use of 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 is transferred to a flash vessel to remove dissolved hydrocarbon gases that become 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. Regenerated solvent from the bioreactor is pumped back to the scrubber for reuse. The biological sulfur slurry produced may be disposed of in a landfill, used for agricultural purposes, or purified to a high quality (>99 percent pure) sulfur cake. Applications range in size from approximately 200 lbs to 40 tons of sulfur produced per day.

5. Adsorption Process (Amine Treatment)

The Adsorption Process is a common process for sweetening sour natural gas that involves the use of an amine solution to remove the H_2S. The process is commonly referred to as the ‘amine process’ and is widely used across the U.S. in gas sweetening operations at oil and gas field production and processing plants. The sour gas is run through a packed or trayed tower, which contains the liquid amine solution. The amine system will saturate the fuel gas in the treatment process while removing the H_2S from the fuel gas. The solution has an affinity for sulfur and absorbs it. There are two principle amine solutions used, monoethanoliamine (MEA) and diethanolamine (DEA). Other amines are also available and may be blended to enhance their performance in specialized applications. Either of these compounds, in liquid form, will absorb sulfur compounds from natural gas as the gas passes through.

The effluent gas is virtually free of sulfur compounds and thus is no longer sour, but sweet. The rich amine is heated in a reboiler and routed to a still column where the amine is re-generated and an acid gas containing H_2S is generated. The acid gases must be routed to either a H_2S scavenging system, LO-CAT®, or Thiopaq process for sulfur recovery.

6. Oxidation Process (Xergy ACT)

The Xergy ACT (Advanced Catalytic Technology) is a dry gas phase direct oxidation technology to convert H_2S to elemental sulfur and water. The above dew point process, which is appropriate for the fuel gas stream at CGF, operates like a catalytic reactor in a traditional large scale sulfur recovery plant (Claus process).

The sour gas (untreated fuel gas) is heated to reaction temperature, after which air is added just before the mixture enters the fixed bed catalytic reactor. In the reactor, the oxidation of H_2S takes place. In the above dew point process, the elemental sulfur is not absorbed into the catalyst, but stays in the vapor phase and is recovered in the condenser. This process can be applied at pressures ranging from 5 psig to over 1,000 psig. The Xergy ACT process produces Claus quality (bright yellow) molten sulfur.

7. 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 deaerating the seawater, the fuel gas is stripped of H_2S. The scrubbing tower saturates the fuel gas with corrosive seawater, which can produce extensive corrosion problems in the piping and heater burners. The fuel gas must be treated in a drying system to remove all the water prior to combustion.

SO_2 Controls

The following techniques to control SO_2 emissions in the exhaust of CCP and CGF combustion equipment were identified:

8. Limit Sulfur in Fuel

The SO_2 emissions are proportional to the sulfur content of the fuel. Therefore, limiting the sulfur content of the fuel can limit the SO_2 emissions effectively. (Note: BPXA's BACT analysis did not include this option, but included an option for Good Combustion Practices (GCP). GCP is appropriate for VOC, CO, or NO_X control, but not relevant for SO_2 control as SO_2 emissions are a function of the sulfur content of the fuel, and not a function of a poor combustion environment. In addition, fuel sulfur limits have formed the basis of ADEC's previous BACT determinations for SO_2 from fuel gas-fired equipment; therefore, ERG has added this control option to the BACT analysis and has dropped GCP from further consideration).

9. Flue Gas Desulfurization (FGD)

Flue gas desulfurization add-on control technology is commonly known as FGD and is the technology used for removing SO_2 from the exhaust flue gases. Absorption is a process used for scrubbing flue gases to remove SO_2. Devices that are based on absorption principles include packed towers, plate (or tray) columns, venturi scrubbers, and spray chambers.

In most cases the sorbent is an alkaline slurry, commonly limestone, slacked lime, or a mixture of slacked lime and alkaline fly ash, though many other sorbent processes exist. Pollutant removal may be enhanced by manipulating the chemistry of the absorbing solution so that it reacts with the pollutants, e.g., caustic solution for acid-gas absorption vs. pure water as a solvent. Caustic solution (sodium hydroxide, NaOH) is the most common scrubbing liquid used for acid-gas control (e.g., HCl, SO_2, or both), though sodium carbonate (Na_2CO_3) and calcium hydroxide (slacked lime, $Ca[OH]_2$) are also used.

When the acid gases are absorbed into the scrubbing solution, they react with alkaline compounds to produce neutral salts. Typical pollutant acid gas concentrations range from 250 to 10,000 ppmv. Most absorbers have removal efficiencies in excess of 90 percent.

3.2 Eliminate Technically Infeasible Control Options (Step 2)

The following control options have been determined to be technically infeasible:

1. Biocide technology cannot guarantee a required H_2S concentration level or a BACT compliance timeline. Therefore, the technology is deemed infeasible for this Project.

2. Thiopaq is a low pressure system (near atmospheric pressure) not suitable for the high pressure gas at CCP or CGF. Although the Shell-Paques biotechnology process accommodates high pressure gas inlet streams, it was also eliminated from further consideration based on information provided by the licensed vendor (NATCO). NATCO stated that the ratio of CO_2 to H_2S and CO_2 partial pressure are both too high for the Shell-Paques system.

3. The oxidation process is considered technically infeasible for the Project because it is not commercially available on this scale. The standard Xergy system uses a single reactor and has a maximum design gas treatment rate of 18 MMscf/d. The CCP and CGF Project requires 290 MMscf/d of gas treatment to fuel the

combustion equipment. The licensed vendor (Xergy) has no experience with treating this high volume of gas.

4. Seawater scrubbing is considered technically infeasible for the Project because the turbine manufacturers' tight restrictions on the amount of trace metals that may be contained in the fuel. In addition, seawater scrubbing produces a fuel gas that is saturated with corrosive seawater and contaminants, therefore requiring the following: additional fuel gas dehydration, new metallurgy throughout the gas lines, and replacement of existing turbine blades with those designed to withstand a marine environment. A review of technical literature shows no instances of seawater scrubbing being used to treat fuel gas being supplied to combustion turbines. Seawater scrubbing cannot reasonably be installed and operated with existing combustion turbines. It should be noted that Kuparuk Seawater Treatment Plant (KSTP) has two seawater de-aerator towers currently in service to de-aerate the water. A side effect of this process is a reduction in fuel gas H_2S at KSTP for a portion of the fuel gas burned at that source. The de-aerators produce extensive corrosion problems in the downstream piping and heater burners. Upgrades in the metallurgy have not solved KSTP's corrosion problems.

5. FGD technology is typically used in conjunction with high sulfur fuels such as coal and oil. North Slope fuel gas is more similar to natural gas than coal or oil. A search of the RBLC database (see Section 3.5) did not identify any add-on controls as a requirement for natural gas-fired equipment. The combustion of fuel gas containing 300 ppmv of H_2S will result in SO_2 concentrations at or below 10 ppmv. Typical applications of FGD technology are for exhaust streams with 100 ppmv to 2,000 ppmv SO_2. Therefore, this technology is not considered technically feasible for this project.

6. GCP, such as operator training and maintenance activities can be effective at reducing CO, VOC, and NO_X. The technology is not relevant for reducing SO_2 emissions. Therefore, GCP is deemed technically infeasible for this project.

3.3 Rank the Remaining Control Technologies by Control Effectiveness (Step 3)

The remaining technically feasible control technologies are listed in table below.

Table 3. Technically Feasible SO_2 Control Options

Control Technology	Control Efficiency
Liquid Redox (LO-CAT®)	99.7%
H_2S Scavenging (Sulfa-[illegible]®)	98.7%
Adsorption Process (Amine)	96.7%
Limit Sulfur in Fuel	-

3.4 Evaluate the Most Effective Controls and Document Results (Step 4)

The most effective control applicable to the Prudhoe Bay CCP and CGF combustion equipment is control with LO-CAT®. This type of control can reduce the SO_2 emissions 99.7 percent. At a flowrate of 295 MMscf/d of fuel gas, a LO-CAT® system can reduce SO_2 emissions by 2,639 tons per year.

Fuel gas levels of 300 ppmv H_2S are considered the baseline conditions for the fuel gas. BPXA performed an economic impact analysis for the technically feasible control technologies. The results are summarized in the table below:

Table 4. SO_2 Cost Effectiveness Summary for the Combustion Equipment

Control Technology	Annualized Costs (Revised)	Total SO_2 Removed (tpy)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
Liquid Redox (LO-CAT®)	$38,201,145	2,639	$15,526	$14,476
H_2S Scavenging (Sulfa-Treat®) [1]	$33,461,456	2,613	$13,445	$12,806
Adsorption Process (Amine)	$46,369,135	2,560	$21,729	$18,113
Limit Sulfur in Fuel	-	-	-	-

1 - This cost value reflects only the scavenger material costs estimated by BPXA. No revisions were made to the estimates.

The BPXA's original application submitted in October 2008, indicated that the large quantity of scavenger material required by a Sulfa-Treat® system made it technologically in feasible. In response to ADEC's request on December 23, 2008 for additional information, on January 15, 2009 and May 20, 2009, BPXA provided more details indicating that the control technology was feasible, but not cost effective.

The control costs for the scavenging process Sulfa-Treat® do not include costs to control 295 MMscf/d. The analysis excluded the nine (9) emergency flares, or 8 MMscf/d of the total CFG-CCP fuel gas flowrate. Collectively this equipment accounted for a small portion of the total CFG-CCP fuel gas usage. Therefore, the $33 million annualized cost (shown in Table 4 above) represents the vast majority of systems costs; the 8 MMscf/d that was excluded accounts for less than 3 percent of the total CFG-CCP fuel gas flowrate. This exclusion will not dramatically affect the cost effectiveness.

The detailed cost estimates for the LO-CAT® and amine system were developed by BPXA based on treating 70 MMscf/d of fuel gas. Costs to treat 295 MMscf/d of fuel gas were projected using the "six-tenths rule". The six-tenths rule is a standard practice for projecting costs from a detailed estimate to similar equipment operating at a higher production rate. ADEC has accepted the six-tenths rule in previous BACT determinations including ConocoPhillips Permit No. 489CP10 issued September 17, 2004.

In reviewing BPXA's detailed cost analysis for the Sulfur-Treat®, LO-CAT® and amine system, ERG made revisions to some of the values and assumptions. Appendix A contains a line-by-line comparison of the BPXA cost analysis values and ERG's revisions. Table 4 above presents the following: the revised annualized cost, the applicants cost effectiveness, and the revised cost effectiveness. The revisions to the applicants cost are as follows:

- BPXA included a contingency factor of 30 percent of the base equipment costs. ERG does not agree with this level of uncertainty. The US EPA Cost Control Manual estimates contingency to be between 5 to 15 percent of total base equipment costs (EPA/452/B-02-001). Because of the scope and size of the CCP and CGF Project, ERG has estimated contingency using 15 percent of the base equipment costs.

- Equipment costs included three components: 1) Basic Equipment and Auxiliaries, 2) Instruments and Controls, and 3) Module Materials. Costs associated with the arctic grade module to house the basic treatment equipment are justified. However, details provided by BPXA and their consultant, WorleyParsons, did not adequately justify instruments and control costs. ERG believes the basic equipment and auxiliaries include all appropriate controls. ERG recalculated the cost of equipment excluding instruments and controls.

- BPXA included painting costs of 4 and 6 percent of the base equipment costs for the LO-CAT® and amine system, respectively. The Cost Control Manual estimates painting costs between 1 to 4 percent of total base equipment costs. It should be noted that retrofit installations will require additional ductwork and piping to tie in the control devices. Painting of the additional piping and ductwork is required. ERG has estimated the amine system painting costs using 4 percent of the base equipment costs.

The collateral impact clause of the BACT definition allows permitting authorities to temper the stringency of BACT in cases where the energy, environmental, or economic impacts that are associated with the use of a control option at a specific stationary source are viewed by the review agency as sufficiently adverse as to render the use of that technology inappropriate for a given stationary source. These impacts are discussed below for each technically feasible control option.

3.4.1 Liquid Redox (LO-CAT®)

The second most effective control applicable to the CCP and CGF combustion equipment is control with LO-CAT ®. The revised total capital cost to install a LO-CAT ® system capable of treating 295 MMscf/d of fuel gas per day is $200 million.

While technically not part of the control system, costs for both the LO-CAT® and amine system include a tri-ethylene glycol (TEG) contactor to remove water from the treated gas and a reboiler to reclaim the TEG, and a compressor to capture hydrocarbon vapors from the dehydration system for routing vapors back to the process gas system. The amount of water in the fuel gas, or the dew point, is a very important factor and safety parameter. A sub dew point gas in an arctic environment can freeze lines, causing safety hazards and production downtime. Gas is dehydrated to a -50°F dew point at the production facilities prior to being sent to the CCP and CGF. The LO-CAT® and dehydration system require approximately 530 kWe of power.

The LO-CAT® system would have several environmental impacts:

- The LO-CAT® system generates a sulfur waste product that would require disposal in the nearby landfill or injection down a waste well.
- LO-CAT® also uses a small amount of caustic solution to control pH in the oxidizer vessel.
- Some CO_2 would be absorbed into the chelate solution and ultimately converted to bicarbonate, which is eliminated with the sulfur cake. The reduced CO_2 results in a fuel gas with a higher heating value, which would create higher localized flame temperatures in the combustion system (due to lack of CO_2 diluent). NO_X emissions increase exponentially with flame temperature. Therefore, any significant change in the heating value could potentially result in an increase of NO_X emissions.

3.4.2 H_2S Scavenging (Sulfa-Treat®)

BPXA provided a detailed Sulfa-Treat ® cost analysis for controlling SO_2 emissions. The Sulfa-Treat ® system will require Sulfa-Treat ® skids, gas dehydration, high pressure water washing system, vacuum collection system, a water treatment system, and a water injection system. The revised total capital cost to install a system capable of treating 287 MMscf/d of fuel per day is $70 million (Table A-5, Appendix A).

The collateral environmental impacts of a Sulfa-Treat® system should also be noted; Each Sulfa-Treat® reaction vessels must be cleaned out, the spent scavenger loaded into trucks, and hauled to the North Slope Borough landfill at least once every month. For a combined operation of CCP and CGF, the process will generate approximately 400 tons of waste per month. This volume of solid waste would present significant challenges to the North Slope Borough.

3.4.3 Adsorption Process (Amine)

The revised total capital cost to install an Amine system capable of treating 295 MMscf/d of fuel gas per day is $246 million.

As discussed above the Amine system will include a gas dehydration unit with vapor recovery compressor. The Amine system and dehydration system require approximately 450 kWe of power.

The Amine system would have several environmental impacts:

- The Amine process generates a sulfur waste product that would require disposal in the nearby landfill or injection down a waste well.

Approximately 40 percent of the CO_2 would be absorbed into the amine solution. The reduced CO_2 results in a fuel gas with a higher heating value. A significant change in the heating value could potentially result in an increase of NO_X emissions.

3.4.4 Limit Sulfur in Fuel Gas

BPXA proposed GCP with no controls as BACT, based on the available fuel gas quality. As discussed above, GCP can be effective at reducing emissions of CO, VOC, and NO_X, but would not be effective in reducing SO_2 emissions. The most straightforward method of limiting SO_2 emissions is to burn fuels that contain less sulfur (H_2S).
Therefore, ERG recommends that a short term H_2S limit in fuel gas be included in the BPXA Prudhoe Bay - Fuel Gas Souring Permit.

3.5 Select BACT (Step 5)

BPXA contends that the control cost for each system, LO-CAT ®, Sulfa-Treat®, and amine treatment, exceeds previous ADEC BACT determinations. At $12,806/ton of SO_2 removed, Sulfa-Treat® is the most affordable, technically feasible control system. It should be noted that this removal cost reflects only a portion of the systems total cost. LO-CAT ® and amine treatment system are more expensive at $14,475 and $18,113 per ton of SO_2 removed, respectively.

<u>Additional Cost Discussions</u>

The BPXA's original application submitted in October 2008 did not include a discussion for bypassing the pollution control device with a portion of the combustion gas; a control approach, which would reduce the size of the equipment and therefore, the capital costs. In response to ADEC's request on December 23, 2008 for additional information, on January 15, 2009, BPXA indicated this practice is not allowed under BACT.

In the introduction section of the New Source Review DRAFT Manual (October 1990) it is stated that BACT is "an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to the standard….".

BPXA indicated that by ConocoPhillips Alaska Inc. proposed this control approach in their 2004 H_2S/SO_2 BACT analysis for the Kuparuk Seawater Treatment Plant. ConocoPhillips proposed to by-pass a portion of the fuel gas to be treated to minimize costs. EPA Region 10 rejected the BACT on the basis that the gas was not being treated to the maximum potential of the technology. ERG agrees that the ConocoPhillips precedent applies to this CCP and CGF Project.

There are two additional factors that would further increase the cost per ton of SO_2 removed:

- The LO-CAT® and amine system cost do not include collection and disposal of the sulfur by-product.
- The LO-CAT® and amine solutions absorb CO_2, increasing the higher heating value of the fuel gas, reducing overall fuel gas usage, reducing the volume of fuel gas to be treated.

The Department will determine BACT based on the analysis discussed above.
Today, the Prudhoe Bay gas reservoir is H_2S level is at 30 ppmv. BPXA is unable to determine to what level fuel gas H2S will climb during the next 10 years, but estimates that fuel gas H_2S levels will increase to 300 ppmv and elected to use this value as a conservative estimate for the BACT analysis. If in the future fuel gas levels exceed 300 ppmv, then the BACT decision would also need to be revisited. ERG suggests that a short term H_2S limit in fuel gas be included in the BPXA Prudhoe Bay - Fuel Gas Souring Permit. Such a limit is consistent with other PSD permits in the RBLC database and the recently issued PSD permit for the BPXA Liberty Project (Permit No. AQ0181CPT06).

The RBLC database shows seventy two (72) SO_2 BACT determinations for natural gas-fired turbines and engines, with a rating between 40,000 and 400,000 hp, have been permitted under PSD since January 2003. Forty five (45) required fuel restriction such as allowing only pipeline quality natural gas to be combusted. None of the RBLC turbines and engines required an add-on control device as BACT.

The information available in the RBLC did not include removal costs. This could be because all chosen control options were no cost options, either a production limit or Good Control Practices. The results of the RBLC search for controlling SO_2 emissions from turbines can be found in Appendix B. For comparison, the four (4) most recent SO_2 BACT determinations from the RBLC search results are listed in the table below:

Table 5. RBLC Search Results for SO_2 BACT Determination

Source Details	Short Term Limits	Annual Emissions (tpy)
- BPXA Proposed BACT -		
Prudhoe Bay Unit Central Gas Facility		-
53,665 hp GE Frame 6 Injection Compressors (4) [1, 2]	300 ppmv H_2S [3]	-
33,300 hp Cooper-Rolls RB211 Booster Compressors (2) and Miscible Injectant Compressors (2) [2]		-

38,000 hp GE MS5382 Refrigerant Compressors (2) and Booster Compressor [1, 2]		-
85,000 hp (216 MMBtu/hr) Zink Heaters (3) [2]		-
- RBLC Database -		
American Municipal Power Generating Station; Source ID: OH-0310; Permit issued: 02/07/08;		
58,937 hp Boiler, Uncontrolled.	0.09 lb SO_2/hr	0.39
Thyssenkrupp Steel and Stainless USA, LLC; Source ID: AL-0230; Permit issued: 08/17/07;		
66,402 hp Reheat Furnace, Uncontrolled.	0.0006 lb SO_2/MMBtu	0.44
77,050 hp Reheat Furnace, Uncontrolled.	0.0006 lb SO_2/MMBtu	0.52
Ineos USA LLC - Chocolate Bayou Facility; Source ID: TX-0497; Permit issued: 08/29/06;		
46,935 hp Cogen. Trains 2 & 3; Low Sulfur Fuel.	12.66 lb SO_2/hr (=0.05 gr S/scf hourly)	10.06
Kern River Gas Transmission Company - Goodsprings Station Source ID: NV-0046; Permit issued: 05/16/06;		
15,422 hp Simple Cycle Turbine; Low Sulfur Fuel	0.33 lb/hr	1.45

1 – These units have SO_2 BACT limits of 30 ppmv under the ADEC permit 9873-AC006.
2 – ADEC has imposed an H_2S limit of 105 ppmv (not to exceed) for ambient protection.
3 – ERG has proposed a fuel sulfur limit as BACT.

4.0 Summary of Findings by Task

4.1 Completeness Review

The Department received the original application on September 22, 2008. On December 23, 2008, the Department requested that BPXA supply additional information regarding the BACT review. Additional information was received on January 23, 2009 and May 20, 2009.

BPXA has evaluated all known, commercially available lower-polluting processes, control technologies, and combinations of techniques for SO_2 control applicable to the eleven (11) fuel gas fired turbines and three (3) fuel gas fired heaters. BPXA provided data from which emission estimates and cost were extracted.

Specific H_2S removal processes evaluated by BPXA included the 1) Oil Reservoir Treatment Control (Biocide Injection); 2) H_2S Scavenging (SulfaTreat® and Sulfa-Rite®); 3) Liquid Redox (LO-CAT®); 4) Thiopaq/Shell-Paques Technologies; 5) Adsorption Process (Amine Treatment); 6) Oxidation Process (Xergy ACT); 7) H_2S Seawater Scrubbing; and 8) GCP. Flue gas desulfurization was also evaluated for emission control effectiveness and feasibility. Percent removals provided by BPXA and were consistent with technical literature.

ERG concurred with BPXA's list of control technologies considered and has added evaluation of a fuel sulfur limit as the baseline.

4.2 Technical Accuracy

The design features for each identified control technologies were appropriately considered by BPXA. The specifics of the plant, such as its remote location were considered in feasibility positions.

BPXA eliminated from consideration technically infeasible control options based on reasonable grounds. Findings were supported by BPXA with information from pollution control vendors and suppliers. ERG concurs with all technology elimination conclusions.

4.3 Cost Estimates and Cost Recovery

BPXA obtained cost estimates for each control technology from WorleyParsons and vendors. Installation costs such as insulation, piping, foundations, equipment setting, instrumentation, and electrical service connections were primarily consistent with the EPA Cost Control Manual (EPA/452/B-02-001).

To calculate the capital recovery costs BPXA assumed a 10-year expected useful life of each feasible control device and a seven (7) percent discount rate.

ERG made several other revisions to the cost analyses which have been listed in the Executive Summary and Section 3 of this document. The more significant revisions are reduction in contingency costs and the removal of extraneous instrument and control costs.

4.4 Errors and/or Uncertainties

The costs for the H_2S scavenging process (Sulfa-Treat®) reflected control for only 287 MMscf of the total 295 MMscf/d CFG-CCP fuel gas flowrate. To more accurately estimate control cost necessary to achieve the 98.7 percent control efficiency the price of the entire system should be quantified. However, the estimated cost effectiveness of the system ($12,806/ton) appears to make this technology cost-prohibitive.

A copy of the WorleyParsons cost estimate support package was provided in the BPXA application - Appendix C. Although each specific costs contained in Attachment V cannot be located in Appendix C, they are within an order of magnitude. These discrepancies appear to be attributed to the fact that the stated scope of the WorleyParsons package is a conventional LO-CAT® system to treat 141 MMscf/d of fuel gas, while system costs presented in Attachment V are scaled to treat 295 MMscf/d.

5.0 Findings Summary

ERG finds that:

1. The BPXA, CCP and CGF is an existing stationary source is classified as a Prevention Significant Deterioration (PSD) major source under the Departments Air Quality Control Regulations as listed in 18 AAC 50.300(c)(1).

2. The CCP and CFG Fuel Gas Souring Project is subject to major source review for SO_2 for having emissions increases greater than the PSD significance thresholds listed in 18 AAC 50.30(h)(3)(B)(ii) and (iii).

3. BPXA proposes SO_2 BACT for the twenty six (26) fuel gas fired turbines and eight (8) fuel gas fired heaters and two (2) reboilers to be GCP.

4. ERG recommends that a short term H_2S limit in the fuel gas be included in the BPXA Prudhoe Bay - Fuel Gas Souring Permit as BACT. Such a limit is consistent with other PSD permits in the RBLC database.

5. Several cost assumptions and factors were inappropriate, these include:

    - Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

    - Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries will include all appropriate controls.

    - Reduced Amine painting costs from 6 percent of the base equipment costs to 4 percent.

Additional information from BPXA may provide a more defensible justification for including these costs. As shown above, even with these cost reductions, ERG agrees with BPXA's position that Sulfa-Treat®, LO-CAT ®, and amine treatment are not cost-effective.

APPENDIX A

BACT COST ANALYSIS

Appendix A - Table A-1. Prudhoe Bay - Initial Capital Costs for

LO-CAT on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

DIRECT COSTS 1) Purchased Equipment		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
a) Basic Equipment and Auxiliaries (A)	Equipment Vendors & WorleyParsons	-	8,681,137		8,681,137		
b) Instruments and Controls	WorleyParsons	-	1,964,840		-		(1)
c) Module Materials	WorleyParsons	-	10,438,519		10,438,519		
d) Freight (Anchorage, N. Slope, Sealift)	0.10 * (a+b+c) + WorleyParsons	-	6,590,700	31%	6,590,700		
e) Taxes	0.03 * (a+b+c)	-	632,535		573,590		(2)
Total Equipment Cost (B)	B = (a + b + c + d + e)	-	28,307,731	67,063,214	26,283,946	62,268,710	(2)
2) Anchorage Construction Costs			-				(2)
a) Foundations and Supports	0.002 (a+b+c)	0.002	51,780		38,239		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.242	5,139,965		4,626,957		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.055	1,171,180		1,051,581		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.069	1,458,742		1,319,256		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.142	3,023,192		2,714,991		(2)
f) Piping	Equipment Factor * (a+b+c)	0.254	5,399,625		4,856,393		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.031	655,132		592,709		(2)
h) Painting	Equipment Factor * (a+b+c)	0.026	547,785	4%	497,111		(2)
Total Anchorage Construction Costs (C)	C = (a + b + c + d + e + f + g + h)	-	17,457,401	41,357,939	15,697,238	37,187,975	(2)
3) North Slope Construction Costs							
a) Foundations and Supports	Equipment Factor * (a+b+c)	0.007	141,680		133,838		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.022	463,760		420,632		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.075	1,595,000		1,433,974		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.009	197,606		172,077		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.040	851,898		764,786		(2)
f) Piping	Equipment Factor * (a+b+c)	0.090	1,908,280		1,720,769		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.009	189,851		172,077		(2)
h) Painting	Equipment Factor * (a+b+c)	0.009	196,460		172,077		(2)
Total North Slope Construction Costs (D)	D = (a + b + c + d + e + f + g + h)	-	5,544,535	13,135,434	4,990,230	11,822,243	(2)
Total Direct Costs (TDC)	B + C + D	-	51,309,667	121,556,588	46,971,413	111,278,928	(2)
INDIRECT COSTS							
4) Engineering and Procurement	WorleyParsons	-	11,410,300		11,410,300		
5) Unit Operator Costs (UOC)	0.13 * TDC	-	6,670,257		6,106,284		(2)
6) Start-up	Included in UOC	-	-				
7) Performance Test	0.015 * B	-	426,671		394,259		(2)
8) License Fee	Vendor Data or 0.015 * B	-	131,000		131,000		
Total Indirect Costs (IDC)			18,636,173	44,150,542	18,041,843	42,742,528	(2)
Total Direct Costs + Indirect Costs (TDC + IDC)			69,945,840	165,707,130	65,013,256	154,021,456	(2)
9) Contingency	30 percent of (TDC + IDC)	-	20,983,752	49,712,139	9,751,988	46,206,437	(3)
Total Capital Costs (TCC) [TDC + IDC + Contingency]		-	90,929,591	215,419,268	74,765,245	200,227,893	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

Appendix A - Table A-2. Prudhoe Bay - Annualized Costs for
LO-CAT on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

Direct Costs		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
1) Operating Labor (E):	1 hr per 12 hr shift (730 hrs/yr @ $138/hr)	-	100,740	238,661	100,623	238,384	(2)
2) Supervisory Labor	[0.15 * (E)]	-	15,111	35,799	15,093	35,758	(2)
3) Maintenance Labor:	1.1 hr per 12 hr shift (803 hrs/yr @ $138/hr)	-	110,814	262,527	110,686	262,223	(2)
4) Parts and Materials	[100 percent of maintenance labor]	-	110,814	262,527	110,686	262,223	(2)
5) Utilities							
a) Electricity	(0.10/kW-hr, 265 kWe, 530 kWe, 8,760 hr/yr)	-	232,140	549,958	232,140	549,958	
b) Additional fuel	Not estimated	-	-	-	-	-	
6) Chemicals	WorleyParsons	-	711,251	1,685,009	710,860	1,684,082	
Total Direct Costs							(2)
Indirect Costs							
7) Overhead	[included in No. 1) and No. 3)]	-	-	-	-	-	
8) Property Tax	(0.01 * TCC)	-	909,296	2,154,193	747,652	2,002,279	(2)
9) Insurance	(0.01 * TCC)	-	909,296	2,154,193	747,652	2,002,279	(2)
10) G&A Charges	(0.02 * TCC)	-	1,818,592	4,308,385	1,495,305	4,004,558	(2)
11) Capital Recovery (CRF * TCC)							
	Capital Recovery Factor (CRF)(7 percent ROR, 10-year life = 0.1424)	-	12,946,328	30,670,857	10,644,889	28,507,947	(2)
Total Indirect Costs		-	16,583,512	39,287,628	13,635,499	36,517,063	(2)
TOTAL ANNUALIZED COSTS		-	17,294,763	40,972,637	14,346,358	38,201,145	(2)
Tons/year of SO2 Removed		-	610	2,639	610	2,639	
Emission reduction		-					
COST EFFECTIVENES		-	28,370	15,526	23,530	14,476	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

Appendix A - Table A-3. Prudhoe Bay - Initial Capital Costs for
Amine System on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

DIRECT COSTS 1) Purchased Equipment		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
a) Basic Equipment and Auxiliaries (A)	Equipment Vendors & WorleyParsons	-	17,394,100		17,394,100		
b) Instruments and Controls	WorleyParsons	-	2,296,230		-		(1)
c) Module Materials	WorleyParsons	-	10,440,265		10,440,265		
d) Freight (Anchorage, N. Slope, Sealift)	0.10 * (a+b+c) + WorleyParsons	-	7,706,483		7,706,483		
e) Taxes	0.03 * (a+b+c)	-	903,918		835,031		(2)
Total Equipment Cost (B)	B = (a + b + c + d + e)	-	38,740,996	91,780,430	36,375,879	86,177,284	(2)
2) Anchorage Construction Costs							(2)
a) Foundations and Supports	0.002 (a+b+c)	0.002	51,780		55,669		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.171	5,139,937		4,759,676		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.039	1,171,180		1,085,540		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.087	2,607,120		2,421,590		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.164	4,936,438		4,564,836		(2)
f) Piping	Equipment Factor * (a+b+c)	0.319	9,603,510		8,879,162		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.044	1,322,555		1,224,712		(2)
h) Painting	Equipment Factor * (a+b+c)	0.042	1,265,460	6%	1,113,375		(4)
Total Anchorage Construction Costs (C)	C = (a + b + c + d + e + f + g + h)	-	26,098,008	61,828,209	24,104,560	57,105,576	(2)
3) North Slope Construction Costs							
a) Foundations and Supports	Equipment Factor * (a+b+c)	0.005	141,680		139,172		(2)
b) Erection and Handling	Equipment Factor * (a+b+c)	0.015	463,760		417,515		(2)
c) Mechanical	Equipment Factor * (a+b+c)	0.053	1,595,000		1,475,221		(2)
d) Instrumentation	Equipment Factor * (a+b+c)	0.012	355,904		334,012		(2)
e) Electrical	Equipment Factor * (a+b+c)	0.047	1,408,663		1,308,215		(2)
f) Piping	Equipment Factor * (a+b+c)	0.104	3,131,700		2,894,774		(2)
g) Insulation	Equipment Factor * (a+b+c)	0.009	282,040		250,509		(2)
h) Painting	Equipment Factor * (a+b+c)	0.013	405,240		-		(4)
Total North Slope Construction Costs (D)	D = (a + b + c + d + e + f + g + h)	-	7,783,987	18,440,870	6,819,419	16,155,734	(2)
Total Direct Costs (TDC)	B + C + D	-	72,622,991	172,049,508	67,299,858	159,438,594	(2)
INDIRECT COSTS							
4) Engineering and Procurement	WorleyParsons	-	13,798,368		13,798,368		
5) Unit Operator Costs (UOC)	0.13 * TDC	-	9,440,989		8,748,982		(2)
6) Start-up	Included in UOC	-	-				
7) Performance Test	0.015 * B	-	581,115		545,638		(2)
8) License Fee	Vendor Data or 0.015 * B	-	Included with (A)				
Total Indirect Costs (IDC)			23,820,472	56,432,549	23,092,988	54,709,082	(2)
Total Direct Costs + Indirect Costs (TDC + IDC)			96,443,463	228,482,057	90,392,846	214,147,676	(2)
9) Contingency	30 percent of (TDC + IDC)	-	28,933,039	68,544,617	13,558,927	32,122,151	(3)
Total Capital Costs (TCC) [TDC + IDC + Contingency]			125,376,502	297,026,674	103,951,773	246,269,827	(2)

FOOTNOTES:
(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.
(2) = These calculations dependant on purchased equipment costs, which have been revised.
(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.
(4) = Reduced Amine painting costs from 6 percent of the base equipment costs to 4 percent.

Appendix A - Table A-4. Prudhoe Bay - Annualized Costs for
Amine System Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

Direct Costs		Technology Factor	Applicant (70 MMscfd)	Applicant (295 MMscfd)	Revised (70 MMscfd)	Revised (295 MMscfd)	
1) Operating Labor (E):	1 hr per 12 hr shift (730 hrs/yr @ $138/hr)	-	100,740	238,661	100,623	238,661	(2)
2) Supervisory Labor	[0.15 * (E)]	-	15,111	35,799	15,093	35,799	(2)
3) Maintenance Labor:	1.1 hr per 12 hr shift (803 hrs/yr @ $138/hr)	-	110,814	262,527	110,686	262,527	(2)
4) Parts and Materials	[100 percent of maintenance labor]	-	110,814	262,527	110,686	262,527	(2)
5) Utilities		-					
a) Electricity	(0.10/kW-hr, 265 kWe, 530 kWe, 8,760 hr/yr)	-	197,100	466,945	197,100	466,945	
b) Additional fuel	Not estimated	-	-	-	-	-	
6) Chemicals	WorleyParsons	-	80,000	189,526	80,000	189,526	
Total Direct Costs			614,579	1,455,985	614,188	1,455,058	(2)
Indirect Costs							
7) Overhead	[included in No. 1) and No. 3)]	-	-	-	-	-	
8) Property Tax	(0.01 * TCC)	-	1,253,765	2,970,267	1,039,518	2,462,698	(2)
9) Insurance	(0.01 * TCC)	-	1,253,765	2,970,267	1,039,518	2,462,698	(2)
10) G&A Charges	(0.02 * TCC)	-	2,507,530	5,940,533	2,079,035	4,925,397	(2)
11) Capital Recovery (CRF * TCC)							
	Capital Recovery Factor (CRF)(7 percent ROR, 10-year life = 0.1424)	-	17,850,793	42,289,916	14,800,394	35,063,283	(2)
Total Indirect Costs		-	22,865,853	54,170,983	18,958,465	44,914,076	(2)
TOTAL ANNUALIZED COSTS		-	23,480,432	55,626,969	19,572,653	46,369,135	(2)
Tons/year of SO2 Removed		-	591	2,560	591	2,560	
Emission reduction		-					
COST EFFECTIVENES		-	39,710	21,729	33,101	18,113	(2)

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

Appendix A - Table A-5. Prudhoe Bay - Initial Capital Costs for
Sulfa Treat ® System on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

DIRECT COSTS		Technology Factor	Applicant (136 MMscfd)	Applicant (287 MMscfd)	Revised (287 MMscfd)	
1) Purchase Equipment						
a) Basic Equipment and Auxiliaries (A)	Equipment Vendors & WorleyParsons	-	7,144,100	12,660,750	12,660,750	
b) Instruments and Controls	0.1 * A	-	714,410	1,266,075	-	(1)
c) Module Materials	WorleyParsons	-	6,865975	10,997,398	10,997,398	
d) Freight (Anchorage, N. Slope, Sealift)	0.10 * (a+b+c) + WorleyParsons	-	4,257,049	6,276,622	6,276,622	
e) Taxes	0.03 * (a+b+c)	-	441,735	747,727	709,744	(2)
Total Equipment Cost (B)	B = (a + b + c + d + e)	-	19,423,269	31,948,572	30,644,514	
2) Anchorage Construction Costs						
a) Erection and Handling	Equipment Factor * (a+b+c)	-	2,121,600	2,883,200	2,883,200	
b) Instrumentation	Equipment Factor * (a+b+c)	-	542,952	962,217	962,217	
c) Electrical	Equipment Factor * (a+b+c)	-	1,157,344	2,051,042	2,051,042	
d) Piping	Equipment Factor * (a+b+c)	-	1,878,327	3,328,755	3,328,755	
e) Insulation	Equipment Factor * (a+b+c)	-	271,476	481,109	481,109	
f) Painting	Equipment Factor * (a+b+c)	-	257,188	455,787	455,787	
g) Labor adjustment			771,563	1,367,361	1,367,361	
Total Anchorage Construction Costs (C)	C = (a + b + c + d + e + f + g)	-	7,000,450	11,529,481	11,529,481	
3) North Slope Construction Costs						
a) Foundations and Supports	Equipment Factor * (a+b+c)	-	43,320	60,648	60,648	
b) Erection and Handling	Equipment Factor * (a+b+c)	-	530,400	720,800	720,800	
c) Instrumentation	Equipment Factor * (a+b+c)	-	28,576	50,643	50,643	
d) Electrical	Equipment Factor * (a+b+c)	-	128,594	227,894	227,894	
e) Piping	Equipment Factor * (a+b+c)	-	681,118	1,207,076	1,207,076	
f) Insulation	Equipment Factor * (a+b+c)	-	14,288	25,322	25,322	
g) Painting	Equipment Factor * (a+b+c)	-	28,576	50,643	50,643	
h) Labor adjustment			35,721	63,304	63,304	
Total North Slope Construction Costs (D)	D = (a + b + c + d + e + f + g + h)	-	1,490,593	2,406,330	2,406,330	
Total Direct Costs (TDC)	B + C + D	-	27,914,312	45,884,383	45,884,383	
INDIRECT COSTS						
4) Engineering and Procurement	WorleyParsons	-	5,303,719	8,718,032	8,718,032	
5) Unit Operator Costs (UOC)	0.13 * TDC	-	3,628,861	5,964,970	5,964,970	
6) Start-up	Included in UOC	-	-			
7) Performance Test	0.015 * B	-	291,349	479,229	479,229	
8) License Fee	Vendor Data or 0.015 * B	-	-			
Total Indirect Costs (IDC)			9,223,929	15,162,230	15,162,230	
Total Direct Costs + Indirect Costs (TDC + IDC)			37,138,240	61,046,613	61,046,613	
9) Contingency	30 percent of (TDC + IDC)	-	11,141,472	18,313,984	9,156,992	(3)
Total Capital Costs (TCC) [TDC + IDC + Contingency]			48,279,712	79,360,597	70,203,605	

FOOTNOTES:

(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.

(2) = These calculations dependant on purchased equipment costs, which have been revised.

(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

Appendix A - Table A-6. Prudhoe Bay - Annualized Costs for
Sulfa Treat ® System on the Fuel Gas Fired Turbines, Heaters, Reboilers and Flares

Direct Costs		Technology Factor	Applicant (136 MMscfd)	Applicant (287 MMscfd)	Revised (295 MMscfd)	
1) Operating Labor (E):	1 hr per 12 hr shift (730 hrs/yr @ $109/hr)	-	79,570	79,570	79,570	
2) Supervisory Labor	[0.15 * (E)]	-	11,936	11,936	11,936	
3) Maintenance Labor:	1.1 hr per 12 hr shift (803 hrs/yr @ $109/hr)	-	87,527	87,527	87,527	
4) Parts and Materials	[100 percent of maintenance labor]	-	175,054	175,054	175,054	
5) Sulfa Treat XLP (Media)	WorleyParsons	-	5,678,815	12,417,526	12,417,526	
6) Sulfa Treat Changeout Cost	WorleyParsons		3,606,618	6,924,706	6,924,706	
7) Sulfa Treat Disposal Cost	WorleyParsons		500,000	960,000	960,000	
Total Direct Costs			10,139,520	20,656,319	20,656,319	
Indirect Costs						
7) Overhead	[included in No. 1) and No. 3)]	-	-	-	-	
8) Property Tax	(0.01 * TCC)	-	482,797	793,606	702,036	(2)
9) Insurance	(0.01 * TCC)	-	482,797	793,606	702,036	(2)
10) G&A Charges	(0.02 * TCC)	-	965,594	1,587,212	1,404,072	(2)
11) Capital Recovery (CRF * TCC)						
	Capital Recovery Factor (CRF)(7 percent ROR, 10-year life = 0.1424)	-	6,875,031	11,300,949	9,996,993	(2)
Total Indirect Costs		-	8,806,219	14,475,373	12,805,138	(2)
TOTAL ANNUALIZED COSTS		-	18,945,739	35,131,691	33,461,456	(2)
Tons/year of SO_2 Removed		-	1,164	2,613	2,613	
Emission reduction		-				
COST EFFECTIVENES		-	16,276	13,445	12,806	(2)

FOOTNOTES:
(1) = Removed instrument and control costs from base equipment costs. Basic equipment and auxiliaries include all appropriate controls.
(2) = These calculations dependant on purchased equipment costs, which have been revised.
(3) = Reduced contingency factor from 30 percent of the base equipment costs to 15 percent.

APPENDIX B

RBLC SEARCH RESULTS

RBLC ID		Company	Facility	Permit Date	(Last Update)	Process	Capacity	SO_2 Emission Limit	Control Technology	Basis
	AZ-0047	Dome Valley Energy Partners	Wellton Mohawk Generating Station	12/01/04	01/31/06	GE7FA Combined Cycle Combustion Turbine	170 MW	0.0023 lb/MMBtu 4.7 lb/hr	Not Listed	BACT-PSD
	AZ-0047	Dome Valley Energy Partners	Wellton Mohawk Generating Station	12/01/04	01/31/06	Siemens Westinghouse Combined Cycle Turbine	180 MW	0.0023 lb/MMBtu 5.3 lb/hr	Not Listed	BACT-PSD
	AZ-0049	Allegheny Energy Supply, LLC	La Paz Generating Facility	09/04/03	07/24/07	2 Siemens Westinghouse Combustion Turbines	1080 MW	0.0021 lb/MMBtu 4.6 lb/hr	Not Listed	BACT-PSD
	AZ-0049	Allegheny Energy Supply, LLC	La Paz Generating Facility	09/04/03	07/24/07	2 GE Combustion Turbines	1040 MW	0.0021 lb/MMBtu 5.1 lb/hr	Not Listed	BACT-PSD
*	CA-1152	Calpine Western Regional Office	Pastoria Energy Facility	12/23/04	12/04/07	3 GE 7FA Combustion Turbines	168 MW ea	3.5 lb/hr (3 hr avg)	Pipeline Quality Natural Gas	BACT-PSD
	FL-0244	Florida Power and Light	Martin Plant	04/16/03	12/22/03	4 Combined Cycle Natural Gas Fired Turbines	170 MW	0.02 gr S/scf	Low Sulfur Fuel	BACT-PSD
	FL-0245	Florida Power and Light	Manatee Plant - Unit 3	04/15/03	08/30/06	4 Combined Cycle Natural Gas Fired Turbines	170 MW	0.02 gr S/scf	Low Suflur Fuel	BACT-PSD
	FL-0256	Progress Energy	Hines Power Block 3	09/08/03	08/30/06	Combined Cycle Turbnine	1830 MMBt/hr	None	Low Sulfur Fuel	BACT-PSD
	FL-0261	City of Tallahassee	Arvah B. Hopkins Generating Station	10/26/04	03/17/05	2 GE LM6000PC Combustion Turbines	445 MMBtu/hr 50 MW	1.13 lb/hr	Low Sulfur Fuel	BACT-PSD
	FL-0263	Florida Power and Light	Turkey Point Power Plant	02/08/05	01/12/06	4 Gas Fired Combustion Turbines	170 MW ea	0.02 gr S/scf	Low Suflur Fuel	BACT-PSD
	FL-0265	Progress Energy	Hines Power Block 4	06/08/04	01/12/06	Combined Cycle Turbine	530 MW	0.02 gr S/scf	Low Suflur Fuel	BACT-PSD
	FL-0279	Tampa Electric Company	Polk Energy Station	04/28/06	10/02/07	Simple Cycle Gas Turbine Units 4 and 5	1834 MMBtu/hr 80 MW	0.02 gr S/scf 0.7 lb/hr 18.6 tpy	Natural Gas Firing	BACT-PSD
*	LA-0192	Cresent City Power LLC	Cresent City Power	06/06/05	01/15/08	2 Gas Turbines	2006 MMBtu/hr 187 MW	101.1 lb/hr 0.18 gr S/scf 44.2 tpy	Low Sulfur Fuel	BACT-PSD
	MD-0032	Mirant Mid-Atlantic, LLC	Dickerson	11/05/04	04/12/05	Unit 5 GE Frame 7F Combustion Turbine	196 MW	12 lb/hr (3 hr avg)	Low Sulfur Fuel	BACT-PSD
	MD-0032	Mirant Mid-Atlantic, LLC	Dickerson	11/05/04	04/12/05	Unit 4 GE Farme 7F Combustion Turbine	196 MW	11 lb/hr (3 hr avg)	Low Sulfur Fuel	BACT-PSD
	MI-0361	South Shore Power LLC		01/30/03	01/23/04	2 Combined Cycle Combustion Turbines	172 MW ea	0.002 gr S/scf	Pipeline Quality Natural Gas	BACT-PSD
	MI-0362	Midland Cogeneration Venture Limited Partnership		04/21/03	01/23/04	11 Combined Cycle Turbines	984 MMBtu/hr	0.002 gr S/scf	Low Sulfur Fuel	BACT-PSD

	MI-0363	Bluewater Energy Center, LLC		01/07/0	01/23/0	3 Combined Cycle Combustion Turbines	180 MW ea	177 tpy	Pipeline Quality Natural Gas Good Combustion Techniques	BACT-PSD
	MI-0365	Mirant Wyandotte, LLC		01/28/0	08/30/0	2 Combined Cycle Combustion Turbines	2200 MMBtu/h	0.008 gr S/scf 53.4 tpy	Use of Sweet Natural Gas	BACT-PSD
	MN-0053	Minnesota Municipal Power Agency	Fairbault Energy Park	07/15/0	09/21/0	Mitsubishi 501F Combined Cycle Turbine	1876 MMBtu/h 280 MW	0.8 gr S/scf 132 tpy	Low Sulfur Fuel	BACT-PSD
	MN-0054		Mankato Energy Center	12/04/0	08/24/0	2 Combined Cycle Combustion Turbines	1916 MMBtu/h	0.008 gr S/scf	Low Suflur Fuel	BACT-PSD
	MS-0057	South Mississippi Electrick Power Association	Silver Creek Generating Station	05/29/0	10/17/0	3 Simple Cycle Turbines	1109.3 MMBtu/hr	6.1 lb/hr 20.1 tpy	Not Listed	BACT-PSD
	MS-0073	Reliant Energy, LLC	Choctaw County	11/23/0	01/25/0	3 Combustion Turbines (AA-001 to AA-003)	230 MW ea	1.38 lb/hr ea 6.04 tpy ea	Not Listed	BACT-PSD
	MS-0079	Warren Power, LLC	Peaking Plant	01/30/0	09/28/0	4 Gas Fired Simple Cycle Combustion Turbines	959.8 MMBtu/hr	2.9 lb/hr ea 2.9 tpy ea	Clean Fuel; Natural Gas Firing	BACT-PSD
	NC-0101	Forsyth Energy Projects LLC	Forsyth Energy Plant	09/29/0	08/30/0	3 Combined Cycle Combustion Turbines	1844.3 MMBtu/hr	0.006 lb/MMBtu(3 hr avg)	Low Sulfur Fuels	BACT-PSD
	NE-0022	Grand Island Utilities	C.W. Burdick Generating Station	06/22/0	07/08/0	Gas Fired Combustion Turbine	1 MMscf/hr	5.4 lb/hr 2.5 lb/MMBtu	Low Sulfur Fuel	Other
	NV-0033	El Dorado Energy, LLC		08/19/0	09/15/0	Combined Cycle Turbine and Cogeneration	475 MW	1.03 lb/hr per CTG	Not Listed	Other
	NV-0037	Sempra Energy Resources	Copper Mountain Power	05/14/0	12/20/0	2 GE Combustion Turbines	172 MW ea	5.1 lb/hr	Pipeline Quality Natural Gas	BACT-PSD
	NV-0038	Ivanpah Energy Center, LP		12/29/0	12/21/0	2 Westinghouse Model 501FD Combined Cycle Turbines	500 MW	1.55 lb/hr 6.75 tpy	Pipeline Quality Natural Gas	BACT-PSD
*	NV-0046	Kern River Gas Transmission Company	Goodsprings Compressor Station	05/16/0	12/03/0	3 Combustion Turbines - Simple Cycle Model MARS 100-T15000S	97.81 MMBtu/hr 11.5 MW	0.0034 lb/MMBtu 0.33 lb/hr	Low Sulfur Fuel	BACT-PSD
	OH-0252	Duke Energy Hanging Rock, LLC	Hanging Rock Energy Facility	12/28/0	07/05/0	4 GE 7FA Combined Cycle Combustion Turbines	172 MW ea	14.4 lb/hr with duct burners 11.0 lb/hr w/o duct burners 0.02 gr S/scf	Low Sulfur Fuel	BACT-PSD
	OH-0254	Duke Energy North America	Washington County LLC	08/14/0	07/05/0	2 GE 7FA Combined Cycle Turbines	170 MW ea	14.5 lb/hr with duct burners 11.2 lb/hr w/o duct burners 0.02 gr S/scf	Low Sulfur Fuel	BACT-PSD
	OH-0291	First Energy	West Lorain Plant	11/17/0	08/31/0	5 Simple Cycle Combustion Turbines	85 MW	0.6 lb/hr each 39.9 tpy total	Low Sulfur Fuel	BACT-PSD

	OH-0304	Rolling Hills Generating LLC	Rolling Hills Plant	01/17/06	05/08/07	5 Siemens Westinghouse W501F Simple Cycle Gas Fired Turbines	209 MW	5.9 lb/hr 11.8 tpy	Natural Gas Firing	BACT-PSD
	OK-0090	Duke Energy	Stephens LLC	03/21/03	10/10/03	2 Combined Cycle Combustion Turbines	1701 MMBtu/hr	0.006 lb/MMBtu	Pipeline Quality Natural Gas	BACT-PSD
	OK-0096	Redbud Energy LP	Redbud Power Plant	06/03/03	04/23/04	Combustion Turbine	1832 MMBtu/hr	0.003 lb/MMBtu	Low Suflur Fuel	BACT-PSD
	OR-0043	Umatilla Generating Company LP	Umatilla Generating Company, LP	05/11/04	07/01/04	2 GE Frame 7FB Combined Cycle Gas Turbines	2007 MMBtu/hr	8000 ppmw	Low Sulfur Fuel <0.8% by weight	N/A, NSPS
	TX-0374	BP Amoco Chemical Company	Chocolate Bayou Plant	03/24/03	01/04/05	2 Cogeneration Trains 2 and 3, GT-2 and 3	70 MW	0.05 gr S/scf hourly 0.005 gr S/scf annual 12.66 lb/hr ea 10.06 tpy	Low Sulfur Fuels Good Combustion Practices	Other
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	Natural and Process Gas Fired Turbine w/o duct burners	95.5 MW	2.15 lb/hr 12.4 tpy	Not Listed	BACT-PSD
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	Natural and Process Gas Fired Turbine w/ duct burners	95.5 MW	11.15 lb/hr 12.4 tpy	Not Listed	BACT-PSD
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	Gas Fired Combustion Turbine	164 MW	26.14 lb/hr 12.24 tpy	Not Listed	BACT-PSD
	TX-0456	Exxon Mobil Corporation	Baytown Olefins Plant	06/13/03	08/02/07	3 Gas Fired Turbines	39 MW ea	7.3 lb/hr 6.39 tpy	Not Listed	BACT-PSD
	TX-0457	City Public Service	Leon Creek Plant	06/26/03	08/14/07	4 GE LM6000 Combustion Turbine	Not Listed	1.3 lb/hr 5.5 tpy	Good Combustion of Natural Gas	BACT-PSD
	TX-0458	Duke Energy LP	Jack County Power Plant	07/22/03	08/14/07	Natural Gas Fired Combustion Turbine	Not Listed	14.5 lb/hr 58.7 tpy	Low Sulfur Fuel	BACT-PSD
	TX-0467	Ennis-Tractebel LLP	Ennis Tractebel Power	03/24/03	10/01/07	2 Westinghouse Model 501G Combustion Turbines	230 MW	4.8 lb/hr 6.6 tpy	Use of Pipeline Quality Natural Gas	BACT-PSD
	TX-0468	Union Carbide Corporation	Texas City Operations	01/23/03	10/01/07	Gas Fired Combustion Turbine	12000 lb/hr	3.8 lb/hr 15 tpy	Not Listed	BACT-PSD
	TX-0469	Texas Petrochemicals LP	Houston Facility	10/08/03	10/01/07	2 GE 7EA Combined Cycle Turbine	664 MMBtu/hr	37.06 lb/hr 28.2 tpy	Sweet Natural Gas Good Combustion Practices	BACT-PSD
	TX-0487	Rohm and Hass Texas Inc.	Lone Star Plant	03/24/05	10/15/07		Not Listed	0.03 lb/hr0.12 tpy	Not Listed	RACT
*	TX-0497	Ineos USA LLC	Chocolate Bayou Facility	08/29/06	10/02/07	Cogeneration Train 2 and 3	35 MW	12.66 lb/hr 0.05 gr S/scf hourly 10.06 tpy	Low Sulfur Fuels	BACT-PSD

*	TX-0509	Ponderosa Pine Energy Partners	Cogeneration Facility	03/15/0[illegible]	11/08/0[illegible]	Simple Cycle Gas Turbine	375 MMBtu/hr 250 MW	87.22 lb/hr 92.5 tpy	Natural Gas Firing	BACT-PSD
	VA-0265	Dynegy	Chickahominy Power	01/10/0[illegible]	08/31/0[illegible]	4 501F Simple Cycle Combustion Turbines	1862 MMBtu/hr	1.1 lb/hr ea	Low Sulfur Fuels Good Combustion Practices	BACT-PSD
	VA-0269	Cinergy Capital and Trading	Martinsville Plant	01/08/0[illegible]	06/23/0[illegible]	4 Simple Cycle Combustion Turbines	82 MW ea	4 lb/hr 9.8 tpy	Low Sulfur Fuels Good Combustion Practices	Other
	VA-0279	Cinergy Capital and Trading	Martinsville Plant	01/08/0[illegible]	06/28/0[illegible]	4 Simple Cycle Combustion Turbines	82 MW ea	4 lb/hr 9.8 tpy 0.15 gr S/scf hourly 0.08 gr S/scf annual	Low Sulfur Fuels	BACT-PSD
	VA-0280	Old Dominion Electric Cooperative	Marsh Plant	02/14/0[illegible]	06/28/0[illegible]	GE Model PG7241S Simple Cycle Combustion Turbine	1624 MMBtu/hr	0.2 gr S/scf hourly 0.02 gr S/scf annual	Low Suflur Fuel	BACT-PSD
	VA-0281	Dynegy	Chickahominy Power	01/10/0[illegible]	08/31/0[illegible]	4 501F Simple Cycle Combustion Turbines	182.6 MW	1.1 lb/hr ea 0.002 gr S/scf 56 tpy	Low Sulfur Fuel	BACT-PSD
	VA-0282	Old Dominion Electric Cooperative	Louisa Plant	03/11/0[illegible]	06/21/0[illegible]	GE Model PG7241S Simple Cycle Combustion Turbine	1624 MMBtu/hr	0.2 gr S/scf hourly 0.02 gr S/scf annual	Low Suflur Fuel	BACT-PSD
	VA-0287	James City Energy Park, LLC	James City Energy Park	12/01/0[illegible]	03/29/0[illegible]	Combined Cycle Natural Gas Turbine	1973 MMBtu/hr	11.4 lb/hr	Low Suflur Fuel	BACT-PSD
	VA-0289	Duke Energy Wythe, LLC		02/05/0[illegible]	03/25/0[illegible]	Combined Cycle Turbine	170 MW	1.74 lb/hr w/o duct burner 2.08 lb/hr w/ duct burner 0.003 gr S/scf	Low Sulfur Fuels Good Combustion Practices	BACT-PSD
	WA-0291	Wallula Generation, LLC	Wallula Plant	01/03/0[illegible]	08/31/0[illegible]	4 Combined Cycle Natural Gas Fired Turbines	1300 MW	0.35 ppmdv @ 15%O2 (1 hr avg) 4.5 lb/hr (24 hr avg)	Natural Gas Firing	Other
	WA-0315	Sumas Energy 2	Generation Facility	04/17/0[illegible]	08/31/0[illegible]	2 Combined Cycle Combustion Turbines	660 MW	1 ppmvd (1 hr avg) 189 lb/day each 0.002 gr S/scf (7 day avg) 0.011 gr S/scf annual	Low Sulfur Fuel	BACT-PSD
*	WA-0328	BP West Coast Products, LLC	Cherry Point Cogeneration Project	01/11/0[illegible]	08/14/0[illegible]	3 GE 7FA Combustion Turbines	174 MW ea	None	Limit Fuel Use to Natural Gas	BACT-PSD
	WI-0240	Wisconsin Electric Power	Concord	01/26/0[illegible]	11/29/0[illegible]	Combustion Turbine	100 MW	0.0068 lb/MMBtu	Natural Gas Firing	BACT-PSD
*	AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/0[illegible]	04/03/0[illegible]	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	169 MMBtu/hr	0.0006 lb/MMBtu	Not Listed	BACT-PSD

	OH-0310	AMERICAN MUNICIPAL POWER	AMERICAN MUNICIPAL POWER GENERATING STATION	02/07/08	05/13/08	AUXILIARY BOILER	150 MMBtu/hr	0.09 lb/hr	Not Listed	BACT-PSD
	AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/07	04/03/08	NATURAL GAS -FIRED ANNEALING FURNACE (LA43) (MULTIPLE EMISSION POINTS)	196.4 MMBtu/hr	0.0006 lb/MMBtu	Not Listed	BACT-PSD
*	TX-0499	SANDY CREEK ENERGY ASSOCIATES	SANDY CREEK ENERGY STATION	07/24/06	11/08/07	AUXILLARY BOILER	175 MMBtu/hr	0.11 lb/hr	Not Listed	BACT-PSD
	WI-0228	WISCONSIN PUBLIC SERVICE	WPS - WESTON PLANT	10/19/04	08/31/06	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	229.8 MMBtu/hr	0.0006 lb/MMBtu	Natural Gas	BACT-PSD
	MI-0368	MICHIGAN PAPERBOARD COMPANY	MICHIGAN PAPERBOARD COMPANY	09/08/04	10/25/04	BOILER	185 MMBtu/hr	280 lb/hr	Not Listed	BACT-PSD
	OH-0241	MILLER BREWING COMPANY	MILLER BREWING COMPANY - TRENTON	05/27/04	07/11/05	BOILER (2), NATURAL GAS	238 MMBtu/hr	1.6 lb/MMBtu	Not Listed	BACT-PSD
	WV-0023	LONGVIEW POWER, LLC	MAIDSVILLE	03/02/04	12/06/05	AUXILIARY BOILER	225 MMBtu/hr	0.004 lb/hr	Low Sulfur Natural Gas Fuel	BACT-PSD
	VA-0270	VIRGINIA COMMONWEALTH UNIVERSITY	VCU EAST PLANT	03/31/03	07/15/03	BOILER NATUAL GAS	150 MMBtu/hr	0.1 lb/hr	Good Combustion Practices. Low sulfur fuel	BACT-PSD
	VA-0278	Virginia Commonwealth University	VCU EAST PLANT	03/31/03	06/21/04	BOILER, NATURAL GAS, (3)	150.6 MMBtu/hr	0.1 lb/hr	Low Sulfur Fuel	BACT-PSD

Response to Comments on Preliminary Construction Permits AQ0166CPT04 and AQ0270CPT04 BPXA Central Compressor Plant and Central Gas Facility Revise Fuel Gas H_2S BACT Limits and Establish ORLs

Prepared by Zeena Siddeek October 13, 2009

This document provides the Alaska Department of Environmental Conservation's (Department's) reply to all public comments on the preliminary decision to issue Construction Permits AQ0166CPT04 and AQ0270CPT04 to BP Exploration (Alaska) Inc. (BPXA) for the Central Compressor Plant (CCP) and Central Gas Facility (CGF), respectively. The Department provided opportunity for public comment n these permits starting July 5, 2009 and ending August 19, 2009.

The Department received comments from:

(1) Karen Wuestenfeld of BPXA; and
(2) Marilyn Crockett of Alaska Oil and Gas Association (AOGA).

This document contains a verbatim copy of all comments, unless indicated otherwise. The Department's responses are shown in *Times New Roman italic font*.

Commentator: Karen Wuestenfeld (BPXA)

General Comments Regarding PSD Applicability of Permit Action and Inclusion of Construction Permit Hygiene Action by the Department

1) ADEC included statements in the TAR indicating that fuel gas souring is a modification of a stationary source. ADEC's term contractor (ERG) also included similar statements in their report in Exhibit C of the TAR. One of ADEC's statements is found on page 12 of the TAR as Department Finding no. 2, where ADEC indicates that a decision has been made by the Department that fuel gas souring is a modification despite the fact that EPA has not conclusively ruled on the subject and that discussions are ongoing with EPA (as acknowledged by ADEC on page 8 of the TAR). The underlying basis for ADEC's decision appears to be that EPA has not yet made a determination; therefore, it must be a modification. What EPA has determined, and BPXA agrees, is that if fuel gas souring (i.e., an alternative fuel use) results in the inability of a source to comply with an existing PSD permit condition (i.e., BACT), then an updated BACT analysis is required. [See our comment 59) for more discussion on EPA's findings on this subject.] We assert that until additional findings are published by EPA, the permitting actions taken in conjunction with fuel gas souring should be founded solely upon the requirement to revise an existing PSD limit, and not upon an assumption of what EPA might determine.

   <u>Therefore, we do not agree with the approach that ADEC and its term contractor have used to defend implementation of a new BACT limit for emission units not currently subject to an existing limit when preparing these permits and associated TAR.</u>

Response: *The commentator did not provide a copy of the EPA determination they reference. The Department believes the approach put forth by the commentator is EPA's* *guidance for correcting a BACT limit with which a source is not able to comply. The Department has used this guidance when an initial BACT limit was set too stringent for a source to comply despite the source taking all reasonable measures to attempt to comply. The Department has not found any EPA determination that this approach should be used for the situation where a source complied with a limit for years, but now requires either physical or operational controls to continue to comply with the limit because of fuel gas souring.*

The requested change would increase authorized SO_2 emissions by 704[1] *tons per year. The applicant has in the past and is currently complying with the existing BACT limit. Therefore, Department does not consider this change to be correcting a BACT limit. Consistent with the Department's decision on January 11, 2008 for the Endicott permit and EPA, R10's October 27, 2003 letter to ConocoPhillips Alaska Inc.*[2] *the Department is treating this change as a change in the method of operation of the emission units, but has agreed to follow any subsequent federal guidance on this point. Because the change in the method of operation results in a significant increase in actual emissions, the change is a major modification as defined in 18 AAC 50.990(53)*[3]*. The commentator has requested a change to the permit in their comment #4f consistent with treating this action as a major modification..*

The commentator is correct that, BACT only applies to emission units at which a net emissions increase would occur as a result of a physical change or change in the method of operation ***in the unit.*** *40 CFR 51.166(b)(2)(iii)(e) exempts the use of higher sulfur fuel gas if could be accommodated without violating certain federally enforceable permit conditions. Therefore, there is no change in the method of operation of those emission units that can accommodate the use of higher sulfur fuel without violating existing permit conditions, and these emission units do not need to apply BACT for this change. . Based on this, BACT does not apply to units at CCP for the current net emissions increase.*

Similarly, turbine units 5 through 8 and heater units 9 through 11 at CGF can accommodate the higher sulfur fuel gas without violating any federally enforceable permit conditions. Although these units are subject to federally enforceable annual sulfur dioxide BACT limits, they are can still comply with the limit while burning higher sulfur fuel authorized in this permit. Therefore, BACT is not required for these units for this project.

[1] *Using current actual (based on 30 ppmv) to future potential(based on 300 ppmv) for only those units (Units 1 through 4 and 9 through 11) that have a current fuel gas H_2S BACT limit of 30 ppmv for which BPXA is requesting an increase (See Table 3 of the TAR).*

[2] *October 2003, Memorandum from Janice Hastings, Acting Director, Office of Air Quality, EPA Region 10, to Thomas Manson, ConocoPhillips Alaska Inc. regarding SO_2 BACT determination for Kuparuk Seawater Treatment Plant.*

[3] *EPA, R10's October 27, 2003 letter to ConocoPhillips Alaska Inc does not definitely conclude that increasing H2S concentration is a physical change. The Department agrees that the preliminary TAR did not correctly describe the Department's basis for treating the current action as a PSD major-modification.*

The limit of 105 ppmv established in this permit action for CCP and CGF is a federally enforceable limit established under regulations approved pursuant to 40 CFR Subpart I. Any future relaxation of this limit for Units 5 through 8 and 12 through 14 at CGF or for units at CCP to accommodate a higher sulfur fuel would not qualify for the exemption in 40 CFR51.166(b)(2)(iii)(e). The Department has revised the TAR to better describe the basis for treating BPXA's request as a PSD-major modification consistent with the response above.

Please also note that the final TAR has been re-organized with Item nos 1, 2 and 3 of the Department Findings section brought to a new Subsection 2.3 Department Review of the application.

2) Please delete all discussions and limits established in these permits based on past permit actions pertaining to previous construction permits and modification of those permits. While ADEC has spent considerable time and effort in documenting limits established in past permitting actions, these are unrelated to our permit applications and the associated requested limits. In doing so, ADEC seems to overlook the painstaking permit hygiene process that was completed in conjunction with the Title V permit applications submitted to ADEC in 1997.

The agreed purpose of that hygiene work was to carefully research limits found in historical air quality permits to operate, to determine the basis for any limit found in those permits, and to only carry forward into the Title V operating permits those limits that were founded upon a BACT determination, owner requested limit, air quality protection, applicable NSPS limits, or any other enforceable limit. In addition, the agreed intent was to document the corrections to past limits as determined during the hygiene review. One result of the hygiene project was submittal of construction permit applications to ADEC in conjunction with the Title V operating permit application submittals. [Another result of the hygiene project was reissuance of the EPA PSD permits with clarified limits. See the basis to our comment 43).] In response to these applications, ADEC elected to create a single operating/construction permit for each source where both types of applications were submitted.

In retrospect, we believe ADEC should have issued separate operating and construction permits for sources operated by BPXA (as was done for ConocoPhillips Alaska at Kuparuk, for example). Because this was not done for Prudhoe Bay sources, the CCP and CGF Title V permits cite the old permits to operate as the basis for certain limits and the limits inadvertently could be assumed to expire. The operating/construction permits issued for CCP and CGF on August 4, 2003, were intended to replace the permits to operate in the form of new construction permits with corrected limits. For example, the changes made to the CCP permits to operate are documented on pages 5 through 13, 17 and 18 of the Statement of Basis for the CCP Title V permit (no. AQ0166TVP01).

The TAR contains factual and material errors regarding the administrative history of these permits, resulting in a permit which is more cumbersome and confusing than necessary. One fundamental error is the assumption that a 30 ppmv H_2S limit found in the CCP GHX-

1 PSD permit was founded upon a PSD avoidance limit requested by the applicant. See our comment 3) for more discussion regarding this specific subject.

It is disconcerting that the permit and TAR contain statements pertaining to past permitting actions that are inaccurate, and that we were not informed of ADEC's intent to conduct a sweeping review of past permitting actions. Again, this approach seems to overlook historic work to create Title V permits that accurately reflect all limits that were established on a valid basis. We agree that a new construction permit should be issued so that the provisions of operating/construction permits issued for CCP and CGF do not expire. However, we believe that these permits should be created as part of the Title V permit renewal process to correct the approach used by ADEC in order to meet EPA deadlines during preparation of the original Title V permits.

Therefore, we request that ADEC remove all historical information and unrelated permit limits that do not apply directly to the fuel gas H_2S and liquid fuel sulfur permitting action we applied for in September 2008. Further, if ADEC decides to consolidate all applicable ADEC PSD, air quality protection, and PSD avoidance permit limits into a single individual construction permit for each of CCP and CGF, we urge ADEC to use the limits as stated in the Title V permits for CCP and CGF to develop the construction permit. We believe the Title V permits accurately reflect all enforceable limits. Please inform us of ADEC's intent to take such action; we will comment on the draft permits that are issued by ADEC as a result of the permit consolidation effort for CCP and CGF.

Response: *The commentator agrees that a new construction permit should be issued so that the provisions of the existing Construction/Operating (O/C) permit do not expire, but recommends that this be done as part of the Title V renewal process rather than in this construction permit. The Department disagrees for several reasons. The permittee did not include any mention of this new element of Title V renewal in their Title V permit application, nor did they submit a Title I action in conjunction with their Title V renewal. The permit requested by the applicant changes some of those very conditions which would be carried forward. Finally, as a matter of effective use of permit staff, it makes sense for staff to do all construction permit actions on a given source at the same time. If the Title V renewal application had indicated the applicant's preferred method of addressing this issue, the Department could have accommodated it with separate actions, but at this late juncture, accommodating the applicant would delay issuance of this permit. Therefore, the Department will continue to process this permit to include valid construction permit conditions from the current O/C permit.*

The Department did not change any of these conditions except to correct a mistake in the CCP permit. Despite the 'painstaking permit hygiene process,' the CCP O/C permit failed to include the NO_X BACT limit of 150 ppmv for Unit 2. In accordance with AS 46.14.280(a)(2), the Department may modify the permit after 30 days notice if the department finds that the permit contains a material mistake. The Department notified the permittee through the public notice on July 5, 2009, that it intended to correct this material mistake, and will modify the permit through this permit action. The Department has met the obligation under AS 46.14.280 to provide 30 day written notice to the permittee.

The commentator incorrectly alleges that the TAR assumes "that a 30 ppmv H_2S limit found in the CCP GHX-1 PSD permit was founded upon a PSD avoidance limit requested by the applicant." The TAR correctly notes that the applicant at the time "avoided PSD review for SO_2 by assuming that the fuel gas H_2S content was less than 20 ppm." Since 30 ppmv equates to 40 TPY, the only possible reason to impose that limit would have been to ensure the original project was appropriately classified with respect to PSD. The TAR improperly characterized this conclusion as "PSD avoidance." Years later, the permittee convinced the Department that the limit was no longer necessary because the Department did not consider fuel souring to be a modification under its state permitting language. Given the rules in effect at the time this was not a mistake, and TAR will be correct to reflect that fact.

The department disagrees with the commentator regarding certain aspects of the so-called "permit hygiene." However, because the Department does not dispute that the 30 ppmv permit condition was removed and does not base limits in this permit in any way on that decision, discussion of "permit hygiene" is irrelevant to the permit at hand. Also, the question of whether separate permits should have been issued in the past is irrelevant to the current permit and is not addressed.

Comments on Permit AQ0166CPT04 (CCP)

3) ADEC's assumption that ARCO included a fuel gas H_2S content owner-requested limit (ORL) in the GHX-1 permit application to avoid SO_2 PSD is without historic bases and is based on inference by ADEC. ADEC originally made BPXA aware of this assumption in a May 5, 2009 email from Zeena Siddeek to Jim Pfeiffer (BPXA) and Sims Duggins (AECOM). In that email, ADEC stated an assumption that ARCO (the owner at the time the GHX-1 permit application was submitted in 1989) avoided PSD review for SO_2 and that was the reason a limit was included in the GHX-1 PSD permit (no. 8936-AA006). However, ADEC has acknowledged (in Finding no. 8 beginning on page 12 of the TAR as well as in the May 2009 email) that the TAR for the GHX-1 PSD permit does not provide an underlying basis for a 30 ppm fuel gas H_2S limit that was included in the permit.

The 25 ppmv H_2S concentration used in the application was a few ppmv above the actual fuel gas H_2S content at the time the application was submitted. It is important to recognize that the fuel gas H_2S concentration "creep" had not yet been identified as such at the time of the GHX-1 permit application. Clearly, the fuel gas souring at Prudhoe Bay has historically been a very slow process given that the H_2S content has increased only by about 10 ppmv in the past 30+ years since the CCP first went into operation.

It has been established by administrative record that the Department's practice at the time was to <u>not</u> consider reservoir souring a modification. Therefore, the notion of PSD avoidance to account for increasing H_2S concentration is contrary to the approach that was taken at that time, which was to account only for the change in SO_2 emissions resulting from increased fuel consumption by the source due to new or modified emission units. The GHX-1 application used a fuel gas H_2S concentration of 25 ppmv to estimate emissions and did not assume there would be any change in the fuel gas H_2S level as a result of the GHX-1 project. We have reviewed the GHX-1 PSD permit application and can find no evidence of a SO_2 ORL in the application. Thus to assume that there must have been an ORL absent a permit, TAR, or application record of it, especially in light of the clear Department policy history to not require PSD handling of H_2S concentration increases at the time, is not a logical conclusion.

Therefore, we request that ADEC remove all statements of assumed fact in the draft CCP permit and TAR indicating that an ORL had been requested by ARCO as part of the GHX-1 PSD permit application as a PSD avoidance limit and that an ORL was the basis for the 30 ppmv H_2S limit found in the GHX-1 PSD permit, and remove all statements, whether directly stated or implied, that relaxation of a 30 ppmv H_2S PSD avoidance ORL is the basis for ADEC's determination that a BACT analysis must be done in conjunction with the CCP permit application. See also basis #3 to our comment 21).

Response: *The comment itself appears inconsistent. On one hand, the commentator admits that H_2S creep had not been identified at the time of that application. On the other hand, the commentator asserts that the Department had a practice to exclude H_2S creep. It should also be noted that the magnitude of the eventual increase in emissions (over 700 tons per year in the current action) had not been seen at that time. As discussed earlier, the TAR does not assert that there was an owner-requested limit and does not base any limit in this permit on the original 30 ppmv limit. The Department revised the TAR to remove any suggestion that the limit was an ORL but documented that the limit was imposed by the Department.*

The fuel gas H_2S limit in Permit 8936-AA006 is not the reason that BACT applied to the emission units at CCP in the preliminary permit. The department proposed BACT for the units at CCP because these units would experience a significant net emissions increase as a result of the major modification to the combined CCP/CGF stationary source. Under 40 CFR 52.21(j)(3), BACT applies to each emission unit at which a net emissions increase would occur as a result of a physical change or change in the method of operation.

As explained in the response to comment 1), after careful examination of the exemption allowed in 40 CFR 51.166(b)(2()iii)(e)(1) for alternative fuels, there is no change in the method of operation of units at CCP. Therefore, BACT does not apply to the CCP units.

4) **Permit Cover Page –** Make several corrections to the permit cover page as follows:

a. Change the second line of the cover page heading as shown:

"Air Quality Control ~~*Minor*~~ *Construction* Permit"

b. Change the permit no. from AQ0166CPT04 to AQ0166CPT01. Make this change globally throughout the permit and the TAR.

Basis: We suggest that the construction permit numbering begin at "01" to eliminate the possibility for confusion in the future as to whether or not permits "01", "02", and "03" exist.

c. Per our comment 2), delete the line that indicates that permit AQ0166CPT04 rescinds permit 0073-AC006.

d. Expand the list of owners to match our construction permit application and the CCP Title V permit renewal application, and enter BPXA as the operator of CCP as a separate line item, as follows:

Owner*(s)*~~*/Operator*~~: ***BP Exploration (Alaska) Inc.***
900 East Benson Blvd (zip 99508)
P.O. Box 196612
Anchorage AK, 99519-6612

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

ExxonMobil Corporation
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

Operator: *Same as Permittee*

e. Revise the location as follows to correct the latitude and longitude information:

Location: Latitude: 70° 19' 13" *N*; Longitude: 148° 29' 53" *W*

f. Because ADEC has elected to make this a PSD construction permit instead of a minor permit, we believe the last sentence of the paragraph that immediately follows the source identification information should be changed as follows:

"The permit satisfies the obligation of the Permittee to obtain a construction permit under ~~*18 AAC 50*~~ *AS 46.14.120(a)*."

Response:

a. The Department corrected the error in comment 4(a).

b. The Department declined the request in 4(b) to change the permit number from AQ0166CPT04 to AQ0166CPT01. Permit numbering is generated by the Department's administrative support group. The numbers are assigned sequentially to all the construction permits issued in the past. The Department issued three construction permits including the Construction/Operating Permit 166TVP01 for CCP before this construction permit. Although the past permits *used the old numbering system, they are recorded as CPT01, CPT02 and CPT03 in the Department's database. Therefore, this construction permit is CPT04 in the sequence. The Department is using this numbering system for all stationary sources in the state. It is not practical for the Department to use a different numbering system just for CGF and CCP.*

c. Permit 166TVP01 did not explicitly rescind Construction Permit 0073-AC006. Therefore, the Department is including this provision in the current permit to make it clear that the old construction permit has no legal effect.

d. The permit cover page of the final permit is revised to include the list of owner's as requested in Comment 4(d) and as described in the permit application.

e. The location description is revised as requested in Comment 4(e).

f. The Department agrees with the commentator that the permit is for a major modification as required by 18 AAC 50.302 and 18 AAC 50.306. The permit therefore, should cite both AS 46.14.120(a) and 18 AAC 50 to prevent any confusion.

5) **Abbreviations/Acronyms**:

a. Add "O/C Operating/Construction"

b. Revise the description for "gr/dscf" as follows:

"grains per dry standard cubic ~~*feet*~~ *foot* (1 pound = 7,000 grains)

Response: *The Department made the requested revisions in Comments 5(a) and 5(b).*

6) **Condition 1 – Installation Authorization –** Replace this condition in its entirety, as follows:

"~~***Installation Authorization.***~~ ~~*The Permittee is authorized to install the emission units listed in Table 1. Except as noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement emission unit, including any applicable minor or construction permit requirements.*~~ *The current Central Compressor Plant emission unit inventory is listed in Table 1.*"

Basis: This paragraph is not relevant to the purpose of this permit, which is to establish BACT and ORL limits on existing equipment. It appears that ADEC has included this language with the intent of revising and rescinding current construction permits in place for CCP. Per our comment 2), the construction permit "hygiene" that the

Department has attempted to perform is not appropriate as part of this permitting action.

Response: *The Department disagrees with revising as requested. This permit also includes the past Title 1 conditions that include authorizations to install existing emission units. The reason to include the past Title I conditions have been addressed in response to Comment 2).*

7) **Table 1 – Emission Unit Inventory –** Update Table 1 to include important clarifying information regarding the heater ratings, make corrections to the ratings shown in the table for units 20 and 25, and update the footnotes to use the descriptive terms as defined in the current Alaska rules (i.e., "emission unit" instead of "source") as outlined in our application to renew operating permit no. AQ0166TVP01, as follows:

Unit No	Tag No.	Unit Description	Rating/Size	Construction/ Date[1]
Group I - Gas-Fired Combustion Turbines				
<…>				
Group II - Gas-Fired Heaters				
16	NGH-18-1410	Broach Glycol Heater	28.5 MMBtu/hr *(heat input, LHV)*	1990
17	NGH-18-1491	Broach Glycol Heater	37.5 MMBtu/hr *(heat input, LHV)*	4/74
18	NGH-18-1492	Broach Glycol Heater	37.5 MMBtu/hr *(heat input, LHV)*	4/74
19	NGH-21-1501	Eclipse Glycol Heater	10.7 MMBtu/hr *(heat input, LHV)*	Pre-1977
20	NGH-21-1502	Eclipse Glycol Heater	~~10.7~~ *12.345* MMBtu/hr *(heat input, LHV)*	Pre-1977
21	NGH-21-1503[2]	BS&B TEG Reboiler	4.1 MMBtu/hr *(heat input, LHV)*	Pre-1977
22	NGH-21-1504[2]	BS&B TEG Reboiler	4.1 MMBtu/hr *(heat input, LHV)*	Pre-1977
Group III – Liquid Fuel-Fired Equipment				
23	EDTG-18-2897	Solar T-4001 Emergency Generator	3,550 hp ISO	2000[3]
24	EDG-18-2897-01	GM Emergency Generator	3,600 hp	11/84
25	EDG-18-1522	Cummins Emergency Fire Water Pump	~~310~~ *255* hp	Pre-1977

1-Date construction commenced (if known) or the startup date of the unit. If a unit has been modified as defined by AS 46.14.990, then the most recent modification date is provided.
2-These ~~sources~~*emission units* are decommissioned, but retained for future use.
3-The turbine in this ~~source~~*emission unit* was replaced in March 2000 with a new unit subject to NSPS Subpart GG. However, the engine replacement does not change the status of this ~~source~~*emission unit* as it pertains to PSD increment consumption. The original installation date that applies to PSD increment consumption is April 1974.

Response: *The Department made the requested changes to the ratings of Units 20 and 25 in order to be consistent with the changes that are going to be implemented in the operating permit renewal. The Department also specified the heat input for the heaters and reboilers to be consistent with the operating permit and made the other administrative changes requested in the comment.*

8) **Condition 2 – Assessable Emissions –** Change the third sentence of this condition as follows:

"The Permittee shall pay to the Department … The Department will assess fees per ton of each air ~~contaminant~~*pollutant* that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year…."

Basis: The Alaska rules no longer use the term "air contaminant". This language is from Standard Permit Condition (SPC) I (as referenced by 18 AAC 50.346(b)(1)). We request that the language in the permit match the language of SPC I as revised August 25, 2004.

Response: *The Department made the requested changes.*

9) **Condition 2.1 –** Change the CCP portion of the assessable PTE from 16,446 to 16,665.

Basis: The assessable PTE of 16,665 tpy for CCP is derived from the emissions information for all criteria pollutants provided in our February 2008 application to renew CCP operating permit no. AQ0166TVP01, and replacing the value shown in the renewal application for SO_2 (1,433 tpy) with a value of 505 tpy as the new SO_2 PTE presented in our September 2008 application for the CCP minor permit. The value shown in the operating permit renewal application was based on a fuel gas H_2S content of 300 ppmv, whereas the updated PTE is based on the more stringent ORL of 105 ppmv found in the CCP minor permit application.

Response: *BPXA made changes to the assessable emissions in the operating permit renewal application. The new emissions are based on the new AP-42 (April, 2000) emission factors for the gas turbines. Except for the SO_2 emissions, the Department copied the assessable emissions from the operating permit renewal application as requested. The SO_2 emissions in the operating permit renewal is based on 300 ppmv BACT limit whereas the SO_2 emissions herein is based on 105 ppmv.*

10) **Condition 3.1 –** revise this condition as follows:

"No later than March 31 of each year, the Permittee may submit an estimate of the *CCP portion of the* stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., *Suite 303,* Juneau, AK 99801-1795**;** …"

Basis: We request that this condition remain consistent with the language used in the draft permit for condition 2 to clarify that fees associated with these conditions are from the CCP, which is only a portion of the aggregated CCP and CGF stationary source. Further, we suggest that the address presented in the condition include the appropriate suite number for mail delivery.

Response: *The Department made the requested revision.*

11) **Condition 3.2 –** revise this condition as follows:

"If no estimate is ~~*received*~~ *submitted* on or before March 31 of each year,…"

Basis: This change to SPC I has been approved and endorsed by ADEC's operating permit section to remove the ambiguity in the Assessable Emissions Estimates conditions. The specific ambiguity is that condition 3.1 (of the CCP public notice draft permit) requires *submission* of a stationary source's assessable emissions no later than March 31st of each year. However Condition 3.2 states what is to occur if no estimate is *received* on or before March 31 of each year. This approved change to permit language that deviates from that found in SPC I is documented in the Department's operating permits section Title V permitting update no. 2009-011, dated April 13, 2009, which is included as Attachment I to these comments.

Response: *The Department agrees that the most recent Title V permit standard permit condition for permit fees contains the language requested in the comment. Therefore, the Department revised the final permit as requested.*

12) Delete **conditions 7 and 8** in their entirety per our comment 2).

Response: *In response to Comment 2, the Department described the reason to bring in the past Title 1 conditions into one permit. The Department is declining BPXA's request to delete Condition 7 and 8. The reason to retain the past Title 1 conditions was addressed in response to Comment 2).*

13) Revise **the header** that immediately precedes **condition 9** as follows:

"SO_2 BACT[3] ~~*(revises old PSD Avoidance Limit from Permit 8936-AA006)*~~"

Basis: A PSD avoidance limit was not included in permit 8936-AA006. See our comment 3).

Response*: The Department agrees to revise the heading as requested. The revision is based on the Department's response to Comment 3).*

14) **Condition 9 –** revise this condition as follows:

"**Turbines (Units 1 through 15) and Heaters (Units 16 through 22).** Limit the H_2S content of the fuel gas burned in Units 1 through 22 to no more than 300 ppmv *at any time*."

Basis: The additional phrase clarifies the applicable period of the limit (i.e., clearly indicating that it is not an annual limit).

Response: *The Department has determined that BACT does not apply to the CCP units. Therefore, Condition 9 of permit AQ0166CPT04 was deleted. The findings are addressed in response to Comments 2), 3) and 59).*

15) **Conditions 9.3 and 9.4**- revise these conditions as follows:

"9.3 Report the monthly fuel gas H_2S concentration, for each month of the reporting period, in each Operating Report described in *the current applicable CCP Operating* Permit *(AQ0166TVPxx)*~~*166TVP01*~~.

9.4 Report ~~*under*~~ Excess Emissions and Permit Deviation*s as* described in *the current applicable CCP Operating* Permit *(AQ0166TVPxx)*~~*166TVP01*~~, should the fuel gas H_2S concentration exceed the limit in Condition 9."

Basis: It does not make sense to refer to an expired operating permit in a construction permit that never expires. We propose that this condition generically refer to the CCP operating permit as shown above. It would also be appropriate to add a footnote to these conditions stating that "xx" represents the active version of the operating permit. This is particularly important given that the Operating Report and EE/PD reporting requirements of more recent versions of the operating permit may evolve over time and not be the same as those stated in permit 166TVP01 (e.g., the required frequency of the operating report or deadline for submittal of EE/PD reports). When/if this happens, BPXA would be obligated to report the same information based on different requirements.

Response: *The Department made the changes requested except to reference a generic Operating Permit AQ0166TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

16) Delete **conditions 10 and 11** in their entirety per our comment 2).

Response: *The Department declines BPXA's request to delete Conditions 10 and 11. The request to decline the request is addressed in the Department's response to BPXA's Comment 2. Condition 11 is the monitoring requirements for the CO limit carried over from Permit 166TVP01.*

17) **Condition 12 –** revise conditions 12 through 12.3 as shown below.

a. correct grammar (condition 12);

b. add a provision to allow for use of liquid fuel from a third party supplier (shown as new condition 12.2);

c. remove the reference to an expired operating permit (former condition 12.2, now shown as condition 12.1a and condition 12.3) with a basis as described in our comment 15);

d. make the language at the conclusion of condition 12.3 consistent with that used in other conditions of the draft permit (e.g., conditions 9.4 and 13.2); and

e. revise the draft language of condition 12.3 ("when the liquid fuel sulfur content exceeds"), which implies an assumption that an excess emission/permit deviation report will be triggered.

"12. The Permittee shall not burn liquid fuel with sulfur content that ~~exceed~~ *exceeds* 0.11 percent by weight in Emission Units 23 through 25.

12.1 For liquid fuel from a North Slope topping plant, the Permittee shall obtain from the topping plant, the results of a monthly fuel sulfur analysis;

~~12.2~~*a.* ~~Report~~*Include* in the Operating Report described in *the current Operating* Permit *(AQ0166TVPxx)*~~166TVP01~~, a list of the sulfur content measured for each month covered by the operating report;

12.2 For liquid fuel obtained from a third-party supplier that requires a sulfur content less than the limit in Condition 12, the Permittee shall keep receipts from the supplier that specify fuel grade and amount for each shipment of fuel.

a. Include in the Operating Report described in the current applicable CCP Operating Permit (AQ0166TVPxx) a list of the fuel grades received at the CCP during the reporting period.

12.3 Report ~~under~~ Excess Emissions and Permit Deviations *as* described in *the current CCP Operating* Permit *(AQ0166TVPxx)*~~166TVP01~~, ~~when~~ *if* the liquid fuel sulfur content exceeds ~~0.11 percent by weight~~ *the limit in Condition 12*."

Response: *The Department made all the changes requested in 'a' through 'e' except the request to reference a generic Operating Permit AQ0166TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

18) Revise **conditions 13 and 13.2** as follows:

"13. The Permittee shall limit the H_2S content of the fuel gas to no more than 105 ppmv *at any time* in each of the fuel gas fired Units 1 through 22 and 26 through 29 listed in Table 1.~~; and~~

13.1 Monitor and record as required in Conditions 9.1, 9.2, and 9.3.

13.2 Report ~~under~~ Excess Emissions and Permit Deviation*s as* described in *the current applicable CCP Operating* Permit *(AQ0166TVPxx)*~~166TVP01~~, should the fuel gas H_2S concentration exceed the limit in Condition 13."

Basis: See the basis to our comments 14) and 15).

Response: *The Department made the changes requested in 'a' through 'e' except to use a generic Operating Permit No. AQ0166TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

19) Delete **condition 14**.

Basis: The operating limits stated in condition 14 of the public notice draft permit are carried forward to the CCP Title V operating permit from permit no. 9573-AA014, which was prepared prior to the divided operating permit and construction permit programs took effect on January 18, 1997. These limits were used in the air quality modeling because they are applicable and enforceable limits from previous permitting actions carried forward to the operating permit. Use of these previously established limits in the modeling does not trigger a need to include them again in this permit.

Response: *The Department is denying BPXA's request for two reasons. First, there is a need to include the Title 1 conditions for past actions in one place. Second, the decision on this permit action must document that BPXA relied on the limits in the modeling analysis to demonstrate compliance with the air quality standards and increments.*

20) **Section 7 (conditions 15 through 20) –** We propose that the heading for this section be renamed as follows:

"*~~Terms to Make Permit Enforceable~~ Standard Permit Conditions*"

Basis: The conditions found in this section of the permit are "standard permit conditions" outlined in the Alaska air quality regulations under 18 AAC 50.345. These are not always included in minor permits and 18 AAC 50.345 indicates that the Department "*may* include [these] conditions…in each minor permit and construction permit…" (emphasis added), so we do not believe they "make [the] permit enforceable" as stated in the draft permit section header. Therefore, we propose this change to describe what these conditions represent without implying that they are anything more than standard permit conditions that the Department has elected to include in the construction permit. (Note: 18 AAC 50.345 indicates that the standard permit conditions listed in this section of the regulations will be included in operating permits.)

Response: *Because our regulations in 18 AAC 50.345 list these conditions as standard conditions, the Department has changed the section title as requested.*

21) **Section 8 –** Revise the permit documentation provided in this section of the draft permit as follows:

"May 22, 2009	e-mail from Jeff Alger (AECOM) with attached ~~Cost~~ *cost* analysis for Sulfa Treat as applicable to CCP and CGF.

May 6, 2009	e-mail from Jim Pfeiffer (BPXA) to Zeena Siddeek (the Department) agreeing to provide detailed cost estimates for Sulfa Treat technology. ~~*Jim disagreed with the Department's finding that a fuel gas H_2S limit existed for CCP to avoid PSD review. Per Jim the Department's old practice did not consider fuel gas souring a modification for PSD applicability.*~~
May 5, 2009	e-mail from Zeena Siddeek (the Department) to Jim Pfeiffer (BPXA) informing BPXA that CCP must also undergo BACT review for the proposed modification. ~~*The Department found that CCP had a fuel gas H_2S limit that was incorrectly removed from the operating permit in 2003.*~~ In this e-mail the Department also requested BP to submit a detailed BACT cost analysis for Sulfa Treat technology that was originally found infeasible but for which BPXA provided partial cost estimates.
September ~~*20*~~ *19*, 2008	Minor permit application for an Owner Requested Limit.
August 4, 2003	Operating / Construction Permit 166TVP01 Statement of Basis.
~~*May 24, 2000*~~	~~*Technical Analysis Report for Construction Permit 0073-AC006.*~~
~~*September 17, 1990*~~	~~*Technical Analysis Report for Permit to Operate 8936-AA006."*~~

Basis: 1) Change the cited permit application date to match the date on the cover letter of the application (September 19, 2008).

2) Per our comment 2), inclusion of the references to the TARs for previous permits is not relevant to this permit action. Therefore, they should be removed from the permit.

3) There is no administrative record to support the finding in ADEC's May 5, 2009 email regarding a "possible" owner-requested fuel gas H_2S limit made by ARCO to avoid PSD for the GHX I gas expansion project.

Although it is true that the May 5, 2009 email mentions the assumption made by the Department regarding the historical fuel gas H_2S ORL to avoid PSD, this assumption does not appear to play the fundamental role in the Department's decision that a BACT review was required to process the CCP permit application. According to the Department's finding no. 2 in draft TAR Section 3.3 on page 16, fuel gas souring "is caused by a physical change to the source and therefore is a modification to the stationary source.[4]" This appears to be the basis upon which the Department required

[4] *The thought process that fuel gas souring is a modification requiring PSD permitting is further described by ADEC's contractor, ERG, who prepared the "BACT Finding Report" on behalf of ADEC. See, for example, the Executive Summary found on page 1 of the ERG report included as Exhibit C of the TAR.*

that BACT for SO_2 emissions be completed for all fuel gas fired turbines and heaters at CCP and CGF. While BPXA has clearly communicated our disagreement with this finding (BPXA letter to ADEC Commissioner Hartig, dated February 28, 2008), we also have agreed to disagree and to proceed by providing information requested by ADEC to allow the BACT analysis to be completed for these emission units in order to minimize any further delay in receipt of the requested permit.

Response: *The Department changed the cited permit application date to September 19, 2008 (from September 20, 2009) and deleted the reference to the fuel gas H_2S limit in the May 5, and 6, 2009 e-mails. The reference to the past H_2S limit in the e-mail description appears to give the wrong impression that CCP was required to undergo BACT review because of the old limit. The Department also declines to delete the TAR's for the past permits (in the list). These TAR's contain the basis for some of the conditions in the permit.*

Comments on Permit AQ0270CPT04 (CGF)

22) **Permit Cover Page –** Make several corrections to the permit cover page as follows:

a. Change the permit no. from AQ0270CPT04 to AQ0270CPT01. Make this change globally throughout the permit and the TAR.

Basis: We suggest that the construction permit numbering begin at "01" to eliminate the possibility for confusion in the future as to whether or not permits "01", "02", and "03" exist.

b. Per our comment 2), delete the line that indicates that permit AQ0270CPT04 rescinds permit 9873-AC006.

c. Expand the list of owners to match our construction permit application and the CGF Title V permit renewal application, and enter BPXA as the operator of CGF as a separate line item, as follows:

Owner*(s)~~/Operator~~*:	***BP Exploration (Alaska) Inc.*** *900 East Benson Blvd (zip 99508)* *P.O. Box 196612* *Anchorage AK, 99519-6612*	***ConocoPhillips Alaska, Inc.*** *700 G Street (zip 99501)* *P.O. Box 100360* *Anchorage, AK 99510-0360*
	ExxonMobil Corporation *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*

Operator: *Same as Permittee*

d. Revise the location as follows to correct the latitude and longitude information:

Location: Latitude: 70° 19' 15" *N*; Longitude: 148° 31' 00" *W*

Response: *The Department disagrees with changing the permit number to AQ0270CPT01 because this permit is the fourth construction permit issued to CGF. The Department issued three construction permits (including O/C Permit 270TVP01) to CGF prior to this permit. The numbering in the Department's database corresponds to the number in the sequence of construction permits issued to CGF. The Department also disagrees with deleting the line that indicates Permit 9873-AC006 is rescinded. This permit has brought all the past Title 1 permit conditions into one place and explicitly deleted the past construction permits. It must be noted that the O/C permit 270TVP01 made changes to the previous permits. Although, it is implied that the past Title 1 permits were replaced by the O/C permit, it is not very obvious when it is not explicitly stated. Therefore, the Department chose to state in the cover page that Permit 9873-AC006 is rescinded.*

23) **Abbreviations/Acronyms:**

a. Add "O/C Operating/Construction"

b. Revise the description for "gr/dscf" as follows:

"grains per dry standard cubic ~~*feet*~~ *foot* (1 pound = 7,000 grains)

Response: *The Department made the requested changes.*

24) **New Condition –** add a new condition somewhere in the CGF construction permit that specifically rescinds the owner-requested 30 ppmv annual average H_2S limit found in condition operating/construction permit AQ0270TVP01. Our proposed language is as follows:

"*The owner-requested limit of 30 ppmv fuel gas H2S for emission units 5 through 6 and 12 through 14 found in Table 2, Table 3, and condition 13 of Operating/Construction Permit no. AQ0270TVP012 is rescinded.*"

Response: *BPXA's request is not a condition, but a clarification that belongs in the TAR. The Department has explicitly documented in Section 4.0 (Department Findings) of the TAR that the 30 ppmv fuel gas H_2S limit for Units 5 through 8 and 12 through 14 is an ORL to reflect the EPA annual BACT limit. It is unnecessary and out of place to duplicate this clarification in the permit.*

25) **Condition 1 – Installation Authorization –** Replace this condition in its entirety, as follows:

"~~***Installation Authorization.*** *The Permittee is authorized to install the emission units listed in Table 1 subject to the terms and conditions of this permit. Except as noted elsewhere in this permit, the information in Table 1 is for identification purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement emission unit, including any*~~

~~applicable minor or construction permit requirements.~~ *The current Central Gas Facility emission unit inventory is listed in Table 1.*"

Basis: This paragraph is not relevant to the purpose of this permit, which is to establish BACT and ORL limits on existing equipment. It appears that ADEC has included this language with the intent of revising and rescinding current construction permits in place for CGF. Per our comment 2), the construction permit "hygiene" that the Department has attempted to perform is not appropriate as part of this permitting action.

Response: *The Department cannot revise as requested because this permit also brought in the past Title 1 conditions that authorized the installation of the existing emission units. The reason to bring in the Title 1 conditions is addressed in response to Comment 2).*

26) **Table 1 – Emission Unit Inventory –** Update Table 1, as follows:

a. Remove the superscripted "a" at the end of the Table 1 title. This does not appear to refer to any footnotes.

b. Change the description for units 15, 16, and 17 from "GM (RMD)…" to "GM (EMD)…"

c. Change the description for unit 25 from "Methonol" to "Methanol".

Response: *The Department made the requested changes to the permit.*

27) **Condition 2.1 –** Change the CGF portion of the assessable PTE from 13,416 to 13,426.

Basis: The assessable PTE of 13,426 tpy for CGF is derived from the emissions information for all criteria pollutants provided in our February 2008 application to renew CGF operating permit no. AQ0270TVP01, and replacing the value shown in the renewal application for SO_2 (1,231 tpy) with a value of 276 tpy as the new SO_2 PTE presented in our September 2008 application for the CGF minor permit. The value shown in the operating permit renewal application was based on a fuel gas H_2S content of 300 ppmv and neglected to account for the limit on SO_2 PTE established by historical EPA PSD permits, whereas the updated PTE is based on the more stringent ORL of 105 ppmv found in the CGF minor permit application and a correction to account for the EPA PSD ton-per-year SO_2 emission limits.

Response: *BPXA's application for operating permit renewal shows that the CO assessable emissions were revised to 1, 787tpy (from 1,779 tpy) and VOC emissions was revised to 90 tpy (from 88 tpy), a total change of 10 tpy. The new assessable emissions are based on the new AP-42 (April, 2000) emission factors for the gas turbines. Except for the SO_2 emissions, the Department copied the assessable emissions from the operating permit renewal application. The SO_2 emissions in the operating permit renewal is based on 300 ppmv BACT limit whereas the SO_2 emissions herein is 276 tpy and is based on 105 ppmv.*

The Department documented in the TAR that these values are not established in this Title 1 permit, but copied from the Title V renewal application on BPXA's request.

28) **Condition 3.1 –** revise this condition as follows:

"No later than March 31 of each year, the Permittee may submit an estimate of the *CGF portion of the* stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., *Suite 303,* Juneau, AK 99801-1795**;** …"

Basis: We request that this condition remain consistent with the language used in the draft permit for condition 2 to clarify that fees associated with these conditions are from the CGF, which is only a portion of the aggregated CCP and CGF stationary source. Further, we suggest that the address presented in the condition include the appropriate suite number for mail delivery.

Response: *The Department made the requested changes to the permit.*

29) **Condition 3.2 –** revise this condition as follows:

"If no estimate is ~~*received*~~ *submitted* on or before March 31 of each year,…"

Basis: See the basis for our comment 11).

Response: *The Department made the requested change. See also response to Comment 11).*

30) Delete **conditions 7 through 12** in their entirety per our comment 2).

Response: *The Department declines to make the requested change because the Department intends to keep the past Title 1 conditions in this permit. The reason to keep the past Title 1 conditions is addressed in response to Comment 2).*

31) **Condition 13 –** revise this condition as follows:

"**Turbines (Units 1 through 11) and Heaters (Units 12 through 14).** Limit the H_2S content of the fuel gas burned in Units 1 through 14 to no more than 300 ppmv *at any time*."

Basis: The additional phrase clarifies the applicable period of the limit (i.e., clearly indicating that it is not an annual limit).

Response: *The Department made the requested change and also revised Condition 13 so that BACT applies only to Units 1 through 4 and 9 through 11.*

32) **Conditions 13.3 and 13.4**- revise these conditions as follows:

"13.3 Report the monthly fuel gas H_2S concentration, for each month of the reporting period, in each Operating Report described in *the current applicable CGF Operating* Permit *(AQ0270TVPxx)*~~270TVP01~~.

13.4 Report ~~under~~ Excess Emissions and Permit Deviation*s as* described in *the current applicable CGF Operating* Permit *(AQ0270TVPxx)*~~270TVP01~~, should the fuel gas H_2S concentration exceed the limit in Condition 13."

Basis: It does not make sense to refer to an expired operating permit in a construction permit that never expires. We propose that this condition generically refer to the CGF operating permit as shown above. It would also be appropriate to add a footnote to these conditions stating that "xx" represents the active version of the operating permit. This is particularly important given that the Operating Report and EE/PD reporting requirements of more recent versions of the operating permit may evolve over time and not be the same as those stated in permit 270TVP01 (e.g., the required frequency of the operating report or deadline for submittal of EE/PD reports). When/if this happens, BPXA would be obligated to report the same information based on different requirements.

Response: *The Department made the requested changes except to reference AQ0270TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

33) Delete **conditions 14 and 15** in their entirety per our comment 2).

Response: *The Department declines to revise as requested. The reason to bring in the past Title 1 conditions into this permit is addressed in the Department's response to Comment 2).*

34) Revise conditions 16, 16.1, 16.2, and 16.3 as follows:

"16. The Permittee shall limit the fuel gas H_2S content to no more than 105 ppmv *at any time* in each of the fuel gas fired Units 1 through 14 and 19 through 23 listed in Table 1.

16.1 Monitor ~~and record~~*, record and report* as required in Conditions 13.1 ~~and 13.2~~*, 13.2, and 13.3*.

~~*16.2 Report the monthly fuel gas H2S concentration, for each month of the reporting period, with each Operating Report described in Permit 270TVP01.*~~

~~*16.3*~~*16.2* Report ~~under~~ Excess Emissions and Permit Deviation*s as* described in *the current applicable CGF Operating* Permit *(AQ0270TVPxx)*~~270TVP01~~, should the fuel gas H_2S concentration exceed the limit in Condition 16."

Basis: See the basis to our comments 14) and 15). In addition, we propose that the layout of this condition match that of condition 13 in the draft CCP construction permit AQ0166CPT04 (i.e., condition 16.1 should refer to the monitoring, recordkeeping, and reporting outlined in a previous condition of the permit and draft condition 16.2 should be deleted).

Response: *The Department made the requested changes except to reference AQ0270TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

35) **Condition 17 –** revise conditions 17 through 17.3 as shown below.

a. Make condition 17 more concise;

b. add a provision to allow for use of liquid fuel from a third party supplier (shown as new condition 17.2);

c. remove the reference to an expired operating permit (former condition 17.2, now shown as condition 17.1a and condition 17.3) with a basis as described in our comment 15);

d. make the language at the conclusion of condition 17.3 consistent with that used in other conditions of the draft permit (e.g., conditions 13.4); and

"17. The Permittee shall not ~~use~~*burn* liquid fuel with sulfur concentration that exceeds 0.11 percent by weight in ~~*the liquid fuel fired emission units (Units 15 through 18)*~~*Emission Units 15 through 18*.

17.1 For liquid fuel from a North Slope topping plant, the Permittee shall obtain from the topping plant, the results of a monthly fuel sulfur analysis;

~~*17.2*~~*a.* Include in the Operating Report described in *the current CGF Operating* Permit *(AQ0270TVPxx)*~~*270TVP01*~~, a list of the sulfur content measured for each month covered by the operating report;

17.2 For liquid fuel obtained from a third-party supplier that requires a sulfur content less than the limit in Condition 17, the Permittee shall keep receipts from the supplier that specify fuel grade and amount for each shipment of fuel.

a. Include in the Operating Report described in the current applicable CGF Operating Permit (AQ0270TVPxx) a list of the fuel grades received at the CGF during the reporting period.

17.3 Report ~~*under*~~ Excess Emissions and Permit Deviation*s* *as* described in *the current CGF Operating* Permit *(AQ0270TVPxx)*~~*270TVP01*~~, if the liquid fuel sulfur content exceeds ~~*0.11 percent by weight*~~ *the limit in Condition 17*."

Response: *The Department made the requested changes except to reference AQ0270TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

36) Revise **condition 18** as follows:

"The Permittee ~~*contruct*~~*shall construct* and maintain vertical uncapped exhaust stacks for the three emergency generators (Units 15 through 17 in Table 1), …The uncapped ~~*condition*~~*stack requirement* does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume."

Response: *The Department made the requested changes.*

37) Revise conditions 18.1 and 18.2 as follows:

"18.1 ~~*If the most recent result of the liquid fuel sulfur analysis conducted as required by Condition 14.1 indicates a liquid fuel sulfur content of greater than 0.019 percent by weight, report*~~ *Include* in the Operating Report described in *the current applicable CGF Operating* Permit *(AQ0270TVPxx)*~~*270TVP01*~~, ~~*whether*~~ the *stack configuration (orientation and capped or uncapped) for the* emergency generators (Units 15 through 17 in Table 1) ~~*were operated with vertically oriented, uncapped exhaust stacks*~~ for each applicable month of the reporting period.

18.2 Notify the Department under Excess Emissions and Permit Deviation*s* as ~~*desecibed*~~ *described* in *the current CGF Operating* Permit *(AQ0270TVPxx)*~~*270TVP01*~~ if any of the emergency generators, (Units 15 through 17 in Table 1) are operated with horizontal or capped exhaust stacks and the liquid fuel sulfur concentration exceeds 0.019 percent by weight."

Basis: BPXA requests that the contents of the operating reports be as consistent as possible. Condition 18.1, as presented in the draft permit, requires reporting information in the operating report only if certain conditions are met. Our proposed revision requires BPXA to report the stack configuration information with each operating report regardless of the liquid fuel sulfur content. In addition, as written in the draft permit, condition 18.1 does not include a requirement to report the information in association with any third-party fuel deliveries. Again, the reporting requirements of this condition as we have proposed would not be contingent upon any fuel sulfur data.

Response: *The Department made the requested changes except to reference AQ0270TVPxx. Instead the department will refer to "the applicable operating permit issued for the source under AS 46.14.130(b) and 18 AAC 50."*

38) **Section 6 (conditions 19 through 24) –** We propose that the heading for this section be renamed as follows:

"~~*Terms to Make Permit Enforceable*~~ *Standard Permit Conditions*"

Basis: See the basis to our comment 20).

Response: *Because our regulations in 18 AAC 50.345 list these conditions as standard conditions for minor permit, the Department has changed the section title as requested.*

39) **Section 7 –** Revise the permit documentation provided in this section of the draft permit as follows:

"May 22, 2009	e-mail from Jeff Alger (AECOM) with attached ~~Cost~~ *cost* analysis for Sulfa Treat as applicable to CCP and CGF.
May 6, 2009	e-mail from Jim Pfeiffer (BPXA) to Zeena Siddeek (the Department) agreeing to provide detailed cost estimates for Sulfa Treat technology. ~~*Jim disagreed with the Department's finding that a fuel gas H_2S limit existed for CCP to avoid PSD review. Per Jim the Department's old practice did not consider fuel gas souring a modification for PSD applicability.*~~
May 5, 2009	e-mail from Zeena Siddeek (the Department) to Jim Pfeiffer (BPXA) ~~*informing BPXA that CCP must also undergo BACT review for the proposed modification. The Department found that CCP had a fuel gas H_2S limit that was incorrectly removed from the operating permit in 2003. In this e-mail the Department also requested BP to*~~ *requesting that BPXA* submit a detailed BACT cost analysis for Sulfa Treat technology that was originally found infeasible but for which BPXA provided partial cost estimates.
<…>	
~~*October 2*~~*September 19*, 2008	Permit application from BPXA to Revise and Rescind Fuel Sulfur Limits for Air Quality Operating/Construction Permit AQ0270TVP01 Prudhoe Bay Unit Central Gas Facility.
August 4, 2003	Operating / Construction Permit 270TVP01 Statement of Basis.
~~*May 11, 1993*~~	~~*Technical Analysis Report for Permit 9273-AA016.*~~
~~*July 15, 1998*~~	~~*Technical Analysis Report for Construction Permit 9873-AC006*~~"

Basis: 1) Change the cited permit application date to match the date on the cover letter of the application (September 19, 2008).

2) Per our comment 2), inclusion of the references to the TARs for previous permits is not relevant to this permit action. Therefore, they should be removed from the permit.

3) We request that ADEC not include in the CGF permit documentation any statements about the Department's assumptions regarding the CCP permit limits. Our proposed language reduces the documentation pertaining to the May 5 and 6, 2009 emails to only that which had any bearing on the CGF permit application and BACT analysis.

Response: *The Department changed the cited permit application date to September 19, 2008 (from September 20, 2009) and deleted the reference to the fuel gas H_2S limit in the May 5, and 6, 2009 e-mails that pertain to CCP permit. The Department disagrees with deleting the list of TAR's for the past permits. The Department reviewed these past TAR's that formed the basis of this construction permit.*

Comments on Technical Analysis Report for Permits AQ0166CPT04 and AQ0270CPT04

40) **TAR Abbreviations/ Acronyms**:

a. Change the BPXA company name to BP Exploration (Alaska) Inc.

b. Revise the description for "gr/dscf" as follows:

"grains per dry standard cubic ~~feet~~ *foot* (1 pound = 7,000 grains)

Response: *The Department made the requested changes.*

41) **TAR Section 1.0, Introduction –** Revise this section of the TAR as follows:

a. The first paragraph refers to a permit number of AQ0166CPT01 for the CCP construction permit. We believe this is the appropriate number, but is inconsistent with the permit and the rest of the TAR. This inconsistency will be corrected if ADEC makes the permit number changes we have requested in our comments 4)b and 22)a. However, if there is a purpose for ADEC's decision to begin the construction permit numbering with "04" instead of "01", then the number stated in this paragraph for the CCP construction permit should be changed to match the rest of the permit and TAR.

b. The last sentence of the third paragraph and in various other discussions presented in the TAR, the Department has stated that the ORLs for liquid fuel sulfur content and fuel gas H_2S content are "to protect the ambient air quality standards and increments for SO_2 near CCP and CGF". However, as shown in our applications, the predicted air quality impacts near CCP and CGF are well below the allowable standards and increments in the vicinity of the CCP/CGF complex when complying with the fuel sulfur/H_2S ORLs and vertical/uncapped stacks are used by the CGF emergency generators. We agree that these ORLs are established to protect ambient air quality, but a more accurate description would be to state that they are established to minimize impacts downwind of the CCP/CGF complex so that there are no "significant impacts" as defined in 18 AAC 50.215(d) in the vicinity of any offsite sources. A more relevant ORL that is necessary to protect the air quality standards and increments for SO_2 near CCP and CGF is the requirement to operate the emergency generators at CGF with vertical, uncapped stacks unless the liquid fuel sulfur content is less than 0.019 wt.%. Based on this comment, we propose the following changes to the last sentence of the third paragraph of the TAR introduction:

"The Department is also establishing Owner Requested Limits (ORLs) for liquid fuel sulfur content and fuel gas H_2S content *in both construction permits* to *minimize the effect of emissions from CCP and CGF to levels that are below the significant impact level for SO_2 as defined in 18 AAC 50.215(d) in the vicinity of Gathering Centers 1 and 3 and the Central Power Station. In addition, operational restrictions for the emergency generators at CGF have been established by the Department to require operation of these units with vertical, uncapped stacks unless the liquid fuel sulfur content is below a more restrictive level than the primary ORL. These restrictions and the secondary ORL are necessary to* protect the ambient air quality standards and increments for SO_2 near CCP and CGF~~*, in both construction permits*~~."

c. Delete the final paragraph of this section per our comment 2). We urge the Department to make their proposed permit consolidation and hygiene a separate permitting action and limit these permits to addressing that which we requested in our permit applications.

Response: *The Department used the permit numbering ending with CPT04. The reason for using the chosen numbering is explained in response Comments 4) and 22).*

The Department agrees that the last sentence of the third paragraph is partially inaccurate, but found the suggested language to be cumbersome and partially inaccurate as well. However, the requested level of detail is best suited for the ambient air sections of the TAR, rather than the Introduction. The Department therefore moved the "in both construction permits" phrase – as suggested by BPXA; added a phrase regarding new stack requirements on select CGF units; and deleted the phrase "near CCP and CGF." This simpler sentence points to the ambient air basis for the described conditions, but leaves the details for subsequent sections of the TAR.

The Department did not delete the last paragraph. The reasons to retain the past Title 1 conditions are addressed in the Department's response to Comment 2).

42) **TAR Section 1.1, Stationary Source Description –** delete the first comma in the second sentence of the last paragraph so that the sentence reads as "Because of fuel gas souring over time <delete comma> in the Prudhoe Bay gas reservoir,…"

Response: *The Department made the requested change.*

43) **TAR Section 1.2, Permit History for CCP –** limit this section to briefly present historical PSD permits issued for the CCP and to state that none of them included a BACT limit for SO_2. The remaining discussion in this section might be appropriate (with certain

corrections which we are not commenting on at this time) as supporting documentation to a separate permit consolidation and hygiene action. If necessary, we will comment more in depth on the CCP permit history when a draft construction permit and TAR are prepared by the Department for permit consolidation and hygiene. In the meantime, our proposed revision to this section of the TAR is to greatly simplify the history and focus only on that which addresses the existence of any applicable SO_2 limits that apply at CCP as follows:

"*The CCP was originally permitted prior to implementation of the PSD permitting program in 1977. Subsequent modifications to the CCP were permitted,* ~~P~~*p*rior to the Department obtaining the authority for the PSD permit program, *by* the Environmental Protection Agency (EPA)*. EPA* issued four field-wide PSD permits (referenced in order as PSD I, PSD II, PSD III, and PSD IV) between May 1979 and September 1981 for new equipment operated *at that time* by *Atlantic Richfield Company (*ARCO*)* and ~~*BPXA*~~*Sohio Petroleum Company at the Prudhoe Bay Unit (PBU). <add a footnote here stating – "The permitted sources at PBU are now operated by BPXA.">* EPA ~~*originally*~~ permitted *modifications to* CCP under the PSD I permit on May 17, 1979,~~*for nitrogen oxides (NOx) and carbon monoxide (CO). Subsequent PSD permits were issued for CCP in June 1980 (PSD II), December 1980 (PSD III, North Slope Swap Project), by EPA*~~ *the PSD II permit on June 13, 1980 and the PSD North Slope Swap Project on February 5, 1981. Each of the four EPA PSD permits for Prudhoe Bay was amended by EPA and reissued with clarifications and revised emission limits on August 29, 1997. The only EPA PSD BACT limits that apply at CCP are identified in the August 29, 1997 amendment to the PSD II permit. These limits, which apply to one CCP turbine only (unit tag no. NGT-18-1813), affect emissions of NOx, CO and PM. No EPA PSD limits apply at CCP for SO_2 emissions.* ~~*and*~~

On September *17,* 1990, ~~*by*~~ the Department *issued a PSD permit* for the Gas Handling Expansion (GHX I) Project (Permit No. 8936-AA006).[3] <Replace the footnote included in the draft TAR at this point in the document with a new footnote that states, "*Permit to Operate No. 8936-AA006 was renewed as Permit to Operate No. 9573-AA014 on January 19, 1996."> This permitting action did not trigger PSD for SO_2. However, this permit did include a fuel gas H_2S limit of 30 ppmv, which was later removed by the Department. The Department determined during the construction permit hygiene project associated with issuance of the original CCP Title V permit that this restriction is not necessary for protection of the ambient air quality SO_2 standards and increments and confirmed that BACT was not triggered for SO_2 by the GHX I project.*"

~~*A brief description of CCP permits*~~…<delete the entirety of Section 1.2 beginning at this point>.

Basis: The permit history for CCP is complex, in part due to incomplete and inconsistent historical documents and the fact that permitting of the CCP occurred in multiple stages, including original permits that were issued prior to the PSD program going into effect in 1977. The primary purpose of the EPA and ADEC construction permit hygiene work completed in conjunction with the Title V permit applications for Prudhoe Bay sources was to create corrected and less confusing construction permits.

This eliminated the need to recreate the permit history at any future time or to reassess the validity of the historical permits. The result was issuance by EPA of the August 29, 1997 amended PSD permits. Unfortunately, ADEC did not issue separate construction permits for the PBU sources, but chose instead to incorporate the ADEC construction (also air quality permits to operate) permit hygiene for PBU sources into their respective Title V operating permits. As a result, the CCP operating/construction permit cites ADEC air quality control permits to operate as the basis for certain limits. However, technically, the operating/construction permit issued for CCP on August 4, 2003, was intended to replace the permits to operate as a new construction permit with corrected limits. The changes made to the permits to operate, including the ADEC PSD permit for the GHX I project, are documented on pages 5 through 13, 17 and 18 of the Statement of Basis for the CCP Title V permit (no. AQ0166TVP01). (Note: In conjunction with similar actions taken to conduct permit hygiene of the EPA PSD permits and ADEC air quality permits to operate for Title V sources at Kuparuk, the Department did issue separate construction permits along with the original issued Title V permits for the Kuparuk sources. In this case, the Kuparuk Title V permits cite the hygiene construction permit that was issued concurrently as the basis for applicable Title I limits for the Kuparuk sources.)

Response: *The purpose of Section 1.2 is to give a brief history of the origin of CCP and CGF and a brief description of the origin of the limits established in each of the Department issued permits. BPXA has provided important information about the origin of the source. The Department has incorporated the information into the final TAR. The Department however, does not agree to include the basis for the 30 ppmv fuel gas H_2S limit in the same section. The Department also does not agree to delete the description of the permits and the limits that originated in those permit. The Department retained the description of the past permits issued for CCP. The description of the past fuel gas H_2S limit of 30 ppmv at CCP is described under the permit in which it originated. This information does not tie into the permit history and is best suited to be in description of the Gas Expansion Project (GHX-I).*

The Department has addressed the reasons to bring in the past Title I conditions in the Department's response to Comment 2).

44) **TAR Section 1.3, Permit History for CGF –** limit this section to focus primarily on historical permits issued for the CGF that established fuel gas H_2S limits and SO_2 emissions limits. The remaining discussion in this section might be appropriate (with certain corrections which we are not commenting on at this time) as supporting documentation to a separate permit consolidation and hygiene action. If necessary, we will comment more in depth on the CGF permit history when a draft construction permit and TAR are prepared by the Department for permit consolidation and hygiene. In the meantime, our proposed revision to this section of the TAR is to greatly simplify the history and focus only on that which addresses the existence of any applicable SO_2 BACT limits that apply at CGF, as shown below. We have also revised the first sentence of the next to last paragraph of this section. As drafted, the language regarding the upgrades related to the MIX project is unclear and could be interpreted to mean that LHE liners were

also installed in units 1 through 4, when in fact the liners were installed in units 9 through 11 only. Our proposed revisions to this section are as follows:

"The EPA initially authorized operations at CGF in 1984 under the *permitting action known as* SWAP IV, as an administrative revision to PSD permits for the Prudhoe Bay Unit (PBU) facilities. Under ~~*the*~~ SWAP IV, the EPA authorized additional heater and turbine capacity at the location where the CGF was later constructed. The CGF was subject to PSD review and permitting by EPA, thereby ensuring that CGF process operations were constructed in accordance with EPA PSD rules.

The Department issued two PSD permits for CGF: for the Gas Handling Expansion (GHX II) project in 1993 and the Miscible Injection Expansion (MIX) project in 1998.

A brief description of CGF permits in which the Department or EPA established *SO_2 and/or fuel gas H_2S* limits ~~*are*~~ *is* presented below, in order of issue date.

PSD-X81-13 revised ~~*through*~~ August 29, 1997- This EPA permit was issued on September 29, 1981 and was amended ~~*through*~~ August 29, 1997. This permit contains~~*ed*~~ the following *SO_2* BACT limits ~~*for*~~:

Units 5 through 8*: 6.5 tpy* ~~*of: NO_X 150 ppmv and 999 tpy, CO: 0.17 lb/MMBtu and 193 tpy, SO_2 6.5 tpy, PM: 16 tpy and opacity: 10 percent (as surrogate for PM)*~~;

Units 9 and 10*: 9.0 tpy* ~~*of: NO_X 150 ppmv and 1,115 tpy, CO: 0.17 lb/MMBtu and 269 tpy, SO_2: 9.0 tpy, PM: 22 and opacity: 10 percent (as surrogate for PM)*~~; and

Units <insert space>12 through 14*: 5.4 tpy* ~~*of: NO_X 0.08 lb/MMBtu and 84 tpy, CO: 0.061 lb/MMBtu and 64 tpy, SO_2: 5.4 tpy and PM: 12 tpy*~~.

~~***Permit 9273-AA016 (GHX II Project) revised in December 23, 1996 –*** *This permit was originally issued on May 11, 1993. The permit allowed the installation and operation of turbine Units 1 through 4, one emergency generator Unit 15 and installation of a waste heat recovery system on two existing turbine Units 9 and 10. The Department established NO_X, CO and PM BACT limits for these units as shown in Exhibit A.*~~

Permit 9873-AC006 (MIX Project) issued July 15, 1998 - This permit allowed the installation of turbine Unit 11, ~~*upgrade*~~ *and a modification to* Units 1 through 4, 9 and 10*. Units 9, 10 and 11 were fitted* with Lean Head End (LHE) technology. The Department established NO_X, CO and SO_2 BACT limits for these units. ~~*as shown in Exhibit A. The NO_X and CO BACT limits in this permit, superseded the BACT limits established in Permit 9273-AA016. Because the*~~ *The* Department included the provisions of this permit – after permit hygiene - in O/C Permit 270TVP01. ~~*, it appears that*~~ Permit 9873-AC006 was replaced by O/C Permit 270TVP01 ~~*although not documented anywhere*~~.

Operating/Construction (O/C) Permit 270TVP01 issued August 4, 2003 - This O/C Permit contains the Title 1 provisions of Permits PSD-X81-13, 9273-AA016 <insert a footnote here that states, "Permit no. 9273-AA016 did not include an SO_2 or fuel gas H_2S limit. It is listed here only to make the discussion complete.> and 9873-AC006. Permit 270TVP01 expired on September 3, 2008 along with the Title 1 provisions in it. In the permit, the Department established an ORL of 30 ppmv (annual average) for fuel gas H_2S for turbine Units 5 through 8~~, and 9 through 12~~ and heater Units 12 through 14. The limit was requested by BPXA to reflect the EPA tpy SO_2 BACT limits for these units."

Response: *The Department added the details to the early history of the source as requested. The Department did not delete the details of Permit 9273-AA016. The Department also retained the discussions pertaining to other pollutant limits other than SO_2 and H_2S BACT limits because this permit includes all the past Title 1 conditions. The reason to retain the past Title 1 Conditions is addressed in the Department's response to Comment 2).*

45) **TAR Section 2.1, Application for CCP –**

a. Revise the first paragraph of this section as follows:

"BPXA requested a minor permit under 18 AAC 50.508(5) to establish a liquid fuel sulfur content limit of 0.11 percent by weight in all the liquid fuel fired emission units (Units 23 through 25)~~. The liquid fuel sulfur content 0.11 percent by weight is necessary~~ to protect the *24-hour* SO_2 ambient air quality~~ standards and~~ increment~~s~~ near CCP and CGF. BPXA stated that no fuel gas H_2S limit is needed for ambient protection. BPXA also stated that *no* ~~because no previous (to Construction Permit AQ0166CPT04)~~ liquid fuel sulfur limits or fuel gas H_2S content limits exist~~ed~~ for CCP~~, there are no SO_2 emissions increase at CCP~~."

Basis: Our permit application for CCP states that the 0.11 percent by weight liquid fuel sulfur limit is necessary to demonstrate compliance with the allowable SO_2 24-hour air quality increment. However, this was true only when the application used 250 ppmv or higher as the fuel gas H_2S content. Later versions of the modeling were conducted with fuel gas H_2S set at 105 ppmv in order to reduce predicted impacts in the vicinity of offsite sources to below the significant impact levels stated in 18 AAC 50.215(d). We propose to combine the first two sentences of the paragraph above to clarify that the need for the limit to protect the 24-hour SO_2 increment was a statement found in the application, but is not necessarily the outcome of the permit findings. The findings should reflect the fact that the liquid fuel sulfur limit of 0.11 wt% is to keep impacts below the significant impact level at offsite sources. See our comment 41)b.

Also, the last sentence of this paragraph is incorrect. Our CCP application does not state that there will be no SO_2 emissions increase at CCP. The application states that there will be no change in actual emissions from fuel gas emissions as a result of implementing the owner requested limit on the sulfur content of the liquid fuel and that actual emissions of SO_2 will increase gradually as the gas reservoir continues to gradually sour (see page II-2 of the application). We propose to revise the last sentence to instead indicate that BPXA included a statement in the application indicating that there are no existing fuel gas H_2S or liquid fuel sulfur limits that apply at CCP. This is a correct observation that should be included in this section of the TAR.

b. Revise the second paragraph of this section to refer to Section 4.0, not 4.3. As drafted, Section 4.3 contains “State Emissions Standards”, not the Department’ findings. See also our comment 58).

c. Delete “Exhibit B”.

Response: *The Department revised the first paragraph as requested since it describes BPXA’s intentions rather than the Department’s findings. The Department also reworded the “needed for* ***ambient*** *protection” phrase (emphasis added) to clarify that the sentence regards protection of the ambient air quality* ***standards*** *(rather than standards* ***and*** *increments).*

The Department inadvertently duplicated the numbering of Subsection 3.1 and 3.2 in the preliminary permit. The subsection numbers are listed as 3.1 (SO_2 Emissions at CCP), 3.2 (SO_2 Emissions at CGF), 3.1 (PSD Applicability), 3.2 (Assessable Emissions) and 3.3 (Department Findings). The numbering in the final permit is corrected to 3.1, 3.2, 3.3, 3.4 to follow the numbering sequence. However, the ‘Department Findings’ section is numbered 4.0 in the final permit. Consequently, the reference to the ‘Department Finding’ section in Section 2.1 is renumbered as Section 4.

The Department has explained in response to Comment 2 the reason to have the Title 1 conditions in one place and the reason why the Department took the opportunity to do it in this permit action. The past Title 1 limits summarized in Exhibit B is an important part of the new construction permit contents. Therefore, the department declines to delete Exhibit B.

46) **TAR Section 2.2, Application for CGF**

a. Revise the first paragraph of this section to provide clarification and to use a more accurate term to describe the rate of increase in the fuel gas H_2S content, as follows:

“The fuel gas H_2S content in the Prudhoe Bay gas reservoir has ~~*steadily*~~ *gradually* increased over time. The ~~*increase*~~ *level* is now in the range of the 30 ppmv SO_2 BACT limit *established at CGF for emission units 1 through 4 and 9 through 11*….”

b. Revise the second bullet of this section as follows:

“Rescind the fuel gas H_2S ORL of 30 ppmv (annual average) for the turbine Units 5 through 8 *and 12 through 14*. (Department Note: This annual average limit for Units 5 through 8 *and 12 through 14* originated in O/C Permit 270TVP01 at BPXA’s request[4], to reflect the ~~*6.5*~~ ton per year limit*s* in the EPA permit PSD-X81-13.)”

c. Correct the third bullet of this section by changing S_{O2} to SO_2.

d. Pertaining to the third bullet of this section, our permit application for CGF states that the 0.11 percent by weight liquid fuel sulfur limit is necessary to demonstrate compliance with the allowable SO_2 24-hour air quality increment. However, this was true only when the application used 250 ppmv or higher as the fuel gas H_2S content. Later versions of the modeling were conducted with fuel gas H_2S set at 105 ppmv in order to reduce predicted impacts in the vicinity of offsite sources to below the significant impact levels stated in 18 AAC 50.215(d). The findings should reflect the fact that the liquid fuel sulfur limit of 0.11 wt% is to keep impacts below the significant impact level at offsite sources. See our comment 41)b.

e. BPXA does not disagree with the assertion that fuel gas souring is not a modification. Correct the fourth bullet of this section at the first line of page 8, as follows:

"…permit application because BPXA ~~*disagreed*~~ *asserts* that fuel gas souring is not, in itself a change…"

f. Revise the last paragraph of this section to refer to Section 4.0, not 4.3. As drafted, Section 4.3 contains "State Emissions Standards", not the Department' findings. See also our comment 58).

Response: *The Department made all of the requested changes, except the request in item'd'. The bullet referenced in item'd' contains three sub-bullets, which would have needed to be further split apart to provide the level of detail requested by the commentator. The commentator didn't provide suggested language for this breakdown, nor did the commentator explain why additional detail is even needed – especially since it doesn't change any conclusions or permit conditions. While BPXA may have initially selected the 0.11 fuel sulfur value based on their significant impact analysis, the resulting restriction of the significant impact area was a major component of BPXA's SO_2 air quality standard/increment demonstration. Since the third bullet regards the overall goal of the requested limits – i.e., ambient air protection – the Department left the wording as is.*

47) **TAR Section 3.1, SO_2 Emissions at CCP –** revise the first paragraph of this section, as follows:

"Sulfur dioxide is the only pollutant affected by Permit AQ0166CPT04…. BPXA provided the calculations in the application.~~*, but stated that the calculations are only for illustration because there is no actual emissions increase at CCP. As discussed previously in Section 2.1 of this TAR, BPXA believed that there was*~~ *There are* no existing fuel gas H_2S limits or fuel oil sulfur limits *at CCP* ~~*and no fuel gas H_2S limit needed for ambient protection. The only limit needed was for fuel oil sulfur content*~~."

Basis: 1) Our CCP application does not state that there will be no SO_2 emissions increase at CCP. The application states that there will be no change in actual emissions from fuel gas emissions as a result of implementing the owner requested limit on the sulfur content of the liquid fuel and that actual emissions of SO_2 will increase gradually as the gas reservoir continues to gradually sour (see page II-2 of the application).

2) Further, we reiterate our comment 3) regarding any fuel gas H_2S limits at CCP.

3) Finally, we do not believe the last phrase regarding the need for a fuel gas H_2S limit at CCP or a liquid fuel sulfur limit at CCP is relevant to this section of the TAR. This paragraph should state facts pertaining to actual and potential SO_2 emissions at CCP, not whether or not BPXA believes there should be a limit.

Response: *The Department misquoted the application statement 'there will be no SO_2 emissions increase at CCP.' The permit application states that there will be no change in actual emissions. The Department agrees with BPXA to keep the contents of Section 3.1 to only the facts pertaining to actual and potential SO_2 emissions. The Department made the requested changes to the discussion in Section 3.1.*

48) **TAR Table 1, SO_2 Emissions Before and After Modification by Permit No. AQ0166CPT04 –** Revise this table as follows in order to make correction to typographical errors and omissions in this draft TAR table (Note: rows that do not require edits are not shown in the table below):

ID	Unit Description	Rating	SO_2 (tpy)		
			Actual Emissions[c]	**Current PTE**	**New PTE**[d]
1	GE MS5371 PATP Gas Compressor	*35,400 hp ISO*	7.11	9.1	32.0
2	GE MS5371 PATP w/LHE Gas Compressor	*35,800 hp ISO*	7.43	~~9.1~~ *9.4*	~~32.0~~ *33.2*
3	GE MS5371PATP Gas Compressor	35,400 hp *ISO*	6.86	9.1	32.0
4			6.84	9.1	32.0
5			7.06	9.1	32.0
6			7.11	9.1	32.0
7			6.40	9.1	32.0
8			6.05	9.1	32.0
9			7.16	9.1	32.0
10			6.77	9.1	32.0
11			6.96	9.1	32.0
12			7.15	9.1	32.0
13			7.04	9.1	32.0
14	GE MS5382C Tandem Compressor	38,000 hp *ISO*	7.17	9.8	34.4
15			7.02	9.8	34.4
<…>					
19	Eclipse Glycol Heaters	10.7 MMBtu/hr	~~0.34~~ *0.24*	0.27	0.96
<…>					
25	Cummins Emergency Fire Water Pump	255 hp	~~0.00~~ *0.01*	0.13	0.03[b]

Response: *The Department made the requested changes to the ratings to be consistent with the operating permit. The Department also agrees with changes to the emissions and revised the final TAR accordingly.*

49) Revise **footnote c of Table 1 of the TAR** as follows:

"[c] BPXA's permit application ~~referred to this as~~ *provided only the* 2007 Actual Emissions. ~~*Since a*~~*A*ctual emissions are pollutant emissions representative of *a* 24 consecutive month average during a ten year period preceding the date on which the application was submitted*. However*, the Department *did not request actual emissions for 2006 because doing so would not change the outcome of the PSD permit applicability assessment.*~~*assumes that this is pollutant emissions for the two year period period ending in 2007. The Department intends to verify this during the public comment period.*~~"

Basis: We acknowledge that the permit application should have included 2 years of actual emissions to establish a baseline. However, we would like to point out that the reason we included the actual emissions in the application was not to establish a baseline for PSD applicability at CCP, but rather to provide the current actual emissions as required for ORL applications under 18 AAC 50.508(5) [via 18 AAC 50.225(a)(3)]. We have historically only provided one year of actual emissions in order to meet the requirements of 18 AAC 50.225(a)(3), but realize now that perhaps the actual emissions required for ORL applications should be 2 years of actual emissions. However, as stated in our proposed revision to this footnote, making a correction by averaging the 2006 actual emissions with the 2007 actual emissions will have a relatively small effect on the baseline actual emissions number used to determine if PSD is triggered under the traditional actual-to-potential (or actual-to-projected actual) test for PSD applicability.

Response: *The Department agrees that some of the information in Table 1 of the draft permit were incorrect. The Department made the corrections needed. The Department also changed the heading of 'Actual Emissions' to '2007 Actual Emissions' to avoid it being interpreted as the baseline actual emissions. BPXA did not provide two years emissions data in the original application that they should have. Therefore, the Department could not establish the baseline Actual Emissions and to make Table 1 complete. However, the Department agrees that making corrections by averaging the 2006 emissions with the 2007 emissions will have a relatively small effect on the baseline actual emissions. The actual-to-projected actual emissions test would not change the PSD applicability determinations. The TAR was revised to clarify that the emissions are not truly "Baseline Actual Emissions" as defined in 40 CFR 52.21(b)(21).*

50) Add **new footnote "d" to Table 1 of the TAR** to indicate that *the new PTE is based on 105 ppmv H_2S in the fuel gas and 0.11 percent sulfur by weight in the liquid fuel*.

Response: *The Department added a footnote to Table 1 as requested.*

51) **TAR Section 3.1, SO_2 Emissions at CCP –** revise the paragraph that immediately follows the notes to **Table 1**, as follows:

"From Table 1, it is seen that there is an increase in SO_2 emissions of 399 tons based on Baseline Actual Emissions to future PTE *at a fuel gas H_2S limit of 105 ppmv and a limit* *of 0.11 wt.% sulfur in the liquid fuel~~, and 358 tons based on current PTE to future PTE as a result of the increase in fuel gas H_2S content to 105 ppmv (from 30 ppmv)~~.*"

Basis: A "PTE-to-PTE" test is not relevant to a PSD permit applicability analysis. We suggest that the language that refers to this test be deleted. Including this statement in the TAR implies that a "PTE-to-PTE" test can be used to determine PSD applicability. Also, we request that the paragraph spell out the fuel limits used as the basis for estimating the new PTE.

Response: *The Department made the requested change to the first sentence but also replaced the term 'Baseline Actual Emissions to future PTE' with 'actual-to-future actual.' It is incorrect to refer to the 2007 emissions data as Baseline Actual Emissions because it contains only one year of emissions data. The Department also agrees to delete the discussion pertaining to PTE to future PTE because it has no bearing to the PSD applicability determination.*

52) **TAR Section 3.2, SO_2 Emissions at CGF –** revise the last sentence of the first paragraph of this section as follows:

"The Actual Emissions and current PTE … 0.5 percent by weight (although no liquid fuel sulfur *limit* existed for CGF before Permit AQ0270CPT04)."

Response: *The Department made the requested change.*

53) **TAR Table 2 – SO_2 Emissions Before and After Modification by Permit No. AQ0270CPT04** - Revise this table as follows in order to make correction to typographical errors and omissions in this draft TAR table (Note: rows that do not require edits are not shown in the table below):

ID	Unit Description	Rating	SO_2 (tpy)		
			2007 Actual Emissions	**Current PTE**	**New PTE**
1	GE Frame 6 Injection Compressor	53,665 hp *ISO*	8.84	11.9	42.7
2			9.09	11.9	42.7
3			8.79	11.9	42.7
4			8.86	11.9	42.7
5	Cooper Rolls/RB211-24C Booster Compressor	33,300 hp *ISO*	~~4.86~~ *4.88*	6.5	6.5[3]
6			4.74	6.5	6.5[3]
7	Cooper Rolls/RB211-24C ~~Booster~~*Miscible Injectant* Compressor	33,300 hp *ISO*	4.64	6.5	6.5[3]
8			4.22	6.5	6.5[3]
9	GE MS5382C (Frame 5) Refrigerant Compressors	38,000 hp *ISO*	5.88	9.0	9.0[3]
10			6.02	9.0	9.0[3]
11	GE MS5382C (Frame 5) Booster Compressor	38,000 hp *ISO*	6.97	~~9.0~~ *9.5*	34.0[2]

Response: *The Department corrected the contents in Table 2 as requested.*

54) Revise the footnotes to Table 2 of the TAR, as follows:

a. Table 2 references a footnote 2 for units 11 and 19 through 23, but there is no footnote 2. Delete the footnote 2 references.

b. There is no footnote 1. We request that a new footnote 1 be added to indicate that *except for emission units with an existing EPA BACT SO_2 limit, the new PTE is based on 105 ppmv H_2S in the fuel gas and 0.11 percent sulfur by weight in the liquid fuel*.

Response: *The Department changed the numbering of the footnotes to look similar to Table 1. The numbering of the footnotes were revised so that they correspond correctly to reference in Table 2. The Department also changed the heading of 'Actual Emissions' to '2007Actual Emissions' to avoid it being interpreted as the baseline actual emissions.*

55) **TAR Section 3.2, SO_2 Emissions at CGF –** revise the paragraph that immediately follows the notes to **Table 2**, as follows:

"From Table 2, it is seen that there is an increase in SO_2 emissions of 195 tons based on baseline actual emissions to future PTE *at a fuel gas H_2S limit of 105 ppm, a limit of 0.11 wt.% sulfur in the liquid fuel, and the EPA SO_2 BACT ton per limits that apply to emission units 5 though 10 and 12 though 14*~~, and 151 tons based on current PTE to future PTE as a result of the increase in fuel gas H_2S content to 105 ppmv (from 30 ppmv)~~."

Basis: See the basis to our comment 51). In addition, we request that this paragraph clearly indicate that the new PTE for emission units subject to the EPA SO_2 BACT is unchanged from the current PTE for those same units since the EPA BACT limit establishes the PTE for these units regardless of the fuel gas H_2S content.

Response: *The Department made the requested change to the first sentence but also replaced the term 'baseline actual emissions to future PTE' with 'actual-to-future actual.' It is incorrect to refer to the 2007 emissions data as Baseline Actual Emissions because it contains only one year of emissions data. The Department also agrees to delete the discussion pertaining to PTE to future PTE because it has no bearing to the PSD applicability determination.*

56) TAR Page 11, second **occurrence** of Section 3.1, PSD Applicability- Change the number of this Section to 3.3.

Response: *The Department made the requested change.*

57) TAR Page 11, second occurrence of Section 3.2, Assessable Emissions - Change the number of this Section to 3.4.

Response: *The Department made the requested change.*

58) **TAR Page 11, Section 3.3, Department Findings** - Change the number of this Section to 4.0. All subsequent section numbers should be incrementally increased by one. For example, draft Section 4.0 of the TAR will become Section 5.0, etc.

Response: *The Department made the requested change.*

59) **TAR Page 12, Finding 2** –revise this finding to state that the reservoir souring is due to a reservoir aging process that is a likely result of reservoir management techniques planned as part of field development. Further, revise the statement that implies that action is appropriate based on EPA not having conclusively ruled whether or not fuel gas souring at CCP/CGF is a modification, and remove the statement indicating that EPA did rule in an October 2003 memorandum that a fuel gas increase at Kuparuk is a modification to the Kuparuk Seawater Treatment Plant. Our proposed language for this finding is as follows:

> "Fuel gas souring and associated H_2S increase in the Prudhoe Bay reservoir is caused by ~~*BPXA'a activities in the field and is not due to*~~ *a reservoir* ~~*natural*~~ aging process *that is a likely result of reservoir management techniques planned as part of field development*. Although EPA has not yet conclusively ruled on ~~*it*~~ *whether or not fuel gas souring at Prudhoe Bay is a modification subject to the review requirements of the PSD permitting process,* ~~*EPA has not indicated otherwise. According to EPA's 2003 letter to ConocoPhillips Alaska Inc. for the Kuparuk Seawater Treatment Plant[2] field gas souring and consequently the fuel gas H2S increase is caused by a physical change to the source and therefore is a modification to the stationary source*~~ *the Department has decided in the interim to treat fuel gas souring as a modification for the CCP and CGF permit applications. Although BPXA does not agree with this decision, BPXA has provided the necessary information necessary to process the applications based on the Department's decision.*"

Basis: ADEC states that EPA's October 27, 2003 letter to ConocoPhillips Alaska for the Kuparuk Seawater Treatment Plant field gas souring indicates a determination by EPA that field gas souring is a modification. Our understanding is that this letter states that fuel gas souring could potentially be considered a modification, but EPA elects not to address it in the letter further than that. Instead, EPA cites 40 CFR 51.166(b)(2)(iii)(e) in stating that use of an alternate raw material or fuel is not considered a modification so long as the change can be accomplished without relaxation of an existing PSD (i.e., BACT) limit. They presented this as part of their finding that ADEC's regulations that existed at the time "[did] not explicitly provide any exemptions from [the definition of a modification] for certain physical or operational changes" and that, as such, the fuel exemption would not be applicable in Alaska "even if the source was capable of accommodating the increased sulfur in the fuel with existing permit limits". This approach to their findings indicates that if a source could accommodate an increase in fuel sulfur content, the increase would fall under the exemption provided in 40 CFR 51.166(b)(2)(iii)(e). Otherwise, if the increase in fuel sulfur required a relaxation of an existing BACT limit, then the exemption would not apply and the increase would be considered a change in the method of operation. This was the case for ConocoPhillips at Kuparuk. As such,

> EPA's letter concludes with a requirement to "[update] the BACT analysis… to complete the application for the increased annual SO_2 emissions limitations in [the Kuparuk PSD permit]." By this statement, EPA specifically refers to the fact that their determination is based on the presence of an existing BACT limit at Kuparuk that was to be relaxed in order to remain in compliance, thereby requiring a revised permit application that includes an updated BACT analysis.

Response: *The commentator incorrectly limits 40 CFR 51.166(b)(2)(iii)(e) to allowing change as long as it does not relax an existing PSD(i.e. BACT) limit. That federal regulation actually refers to **any** limit established under 40 CFR 52.21, or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166. These references incorporate more than just PSD BACT limits. In particular, 40 CFR Subpart I goes beyond PSD and includes any state preconstruction permit approved as part of the State Implementation Plan. The commentator is correct that in the particular case of EPA's October 27, 2003 letter the limit at issue was a BACT limit.*

EPA, R10's October 27, 2003 letter to ConocoPhillips Alaska Inc.[5] *states that increasing H_2S concentration in field gas resulting from ConocoPhillips' practice of injecting seawater into the reservoir (to enhance crude oil recovery), is arguably a physical change. So, it was incorrect for the Department to state conclusively that H_2S increase is caused by a physical change to the source and therefore, a modification to the stationary source. The Department revised Finding 2 with some changes to the proposed language including keeping the citation of the EPA R10 letter to ConocoPhillips as a footnote. The Department also added a statement that until EPA determines that fuel gas souring is not a change in the method of operation, the Department will continue to assume that it is a change in the method of operation.*

*The commentator is correct that, for the emission units at CCP, the use of higher sulfur fuel gas could be accommodated without violating any federally enforceable permit condition. Therefore, for this permit, the increase in sulfur emissions at the source is not considered a change in the method of operation of those emission units. BACT is not required for those emission units. However, the limit of 105ppmv established in this permit **is** a federally enforceable limit established under regulations approved pursuant to 40 CFR subpart I. So any future relaxation of this limit to accommodate a higher sulfur fuel would not qualify for the exemption for these units.*

The Department also re-organized the TAR so that Items 1, 2 and 3 of the Findings are in a Subsection 2.3 with the heading 'Department Review of the Application.'

60) **TAR Page 12, Finding 6 –** revise this paragraph as follows:

"There ~~is~~*are* no liquid fuel sulfur limits for CCP…"

Response: *The Department made the requested change.*

[5] *See footnote **Error! Bookmark not defined.***

61) **TAR Page 12, Finding 7 –** revise this paragraph as follows:

"BPXA did not request ~~for~~ a fuel gas H_2S limit for CCP. However, the Department finds that BPXA used a fuel gas H_2S content of 105 ppmv ~~*(instantaneous)*~~ in their modeling analysis *with the intent* to *maintain the impact of CCP and CGF SO_2 emissions in the vicinity of all offsite sources below the SO_2 significant impact levels.* ~~*show compliance with the short term ambient air quality standard and increments for SO_2 in the vicinity CCP and CGF*~~. As such, a fuel gas H_2S limit of 105 ppmv *(instantaneous)* is included in the permit. *To change this limit, approved ambient air quality modeling must be submitted by the Permittee to demonstrate that SO_2 impacts due to emissions originating from the CCP/CGF complex do not significantly contribute to a predicted exceedance of the ambient SO_2 air quality standards or increments in the vicinity of any offsite sources.*"

Basis: Our use of 105 ppmv H_2S in the air quality modeling was not done to demonstrate compliance with the standards and increments in the vicinity of CCP and CGF. Our application clearly shows that a value of 105 ppmv is <u>not necessary</u> to protect ambient air in the vicinity of the CCP/CGF complex. In fact, we demonstrated in the application that the fuel gas H_2S content could increase to about 250 ppmv before the standards and increments would be threatened. We stress the fact that use of a certain fuel sulfur level (fuel gas and/or liquid fuel) in the air quality modeling does not <u>by itself</u> trigger the requirement to include that value in the permit as a limit. A limit should only be added to the permit if modeling demonstrates a need for the limit to protect ambient air quality standards and/or increments. However, we agree that until a demonstration is made that air quality in the vicinity of offsite sources will still be in compliance with the standards and increments with CCP/CGF complex SO_2 emissions based on a fuel gas H_2S content of 250 ppmv (which we did not demonstrate in the modeling completed for this application), a limit of 105 ppmv is reasonable.

Also, we remind ADEC that air quality modeling is <u>not</u> represented by an instantaneous emission rate. The modeling is based on an average emission rate for the averaging period assessed by the model. The shortest averaging period for SO_2 air quality impact modeling is 3 hours and the modeling is based on a 3-hr, 24-hr, or annual average SO_2 emission rate (i.e., fuel gas H_2S content). We agree that compliance monitoring can be based on an instantaneous fuel sample, but want to be sure that incorrect information is not provided in the TAR about the modeled emission rates.

Response: *The Department used a variation of the commentator's suggested wording regarding BPXA's modeling analysis, but moved the finding to the CCP/CGF section. The Department also added a new sentence clarifying that BPXA's restriction of the CCP/CGF significant impact area was a major component of their ambient air demonstration. The Department then clarified that the resulting purpose for imposing the 105 ppmv H_2S limit is to protect the SO_2 Alaska ambient air quality standards (AAAQS) and increments. The Department did <u>not</u> include the additional sentence regarding future submittals.*

*While the commentator is attempting to make a distinction between near-field and far-field impacts, the bottom-line is still the same. BPXA used the 105 ppmv value in their ambient AAAQS/increment demonstration. This value is therefore needed to protect the SO_2 AAAQS/increments since BPXA did not show that they could comply with the SO_2 AAAQS/increments at **all** areas of concern when using a higher H_2S content.*

The commentator's apparent intent regarding the future submittal sentence is to limit the scope of a future ambient demonstration associated with a request to increase the H_2S limit under 18 AAC 50.508(6). The commentator likely thought a limited analysis would be acceptable since BPXA already provided an argument for a higher H_2S limit (250 ppmv) at near-field receptors. However, there is no guarantee that BPXA would not want to exceed the 250 ppmv value in a future submittal (especially since the BACT limit is 300 ppmv), or that the current near-field analysis would even be representative of a future permit application. Therefore, the Department rejected the additional sentence since the details regarding a future demonstration can best be resolved at the time of the future submittal.

62) Delete **TAR Page 12, Item 8**, per our comment 3).

Basis: The 30 ppmv fuel gas H_2S limit found in Permit 8936-AA006 for the GHX-1 project was a material error by ADEC in that it was not based on BACT, not based on an ORL, and not necessary to protect ambient air (as has been clearly demonstrated again in our most recent application which shows that the fuel gas H_2S content can increase to about 250 ppmv before the SO_2 standards and increments would be threatened). According to the Department, the TAR for the GHX-1 PSD permit does not provide an underlying basis for establishing a 30 ppmv fuel gas H_2S limit in the permit. Furthermore, the emission estimates in the application were based on a fuel gas H_2S content of 25 ppmv (not 20 ppmv as stated by the Department in Finding 8), which was slightly above the actual fuel gas H_2S level at the time of the application (1989) and ARCO did not request a limit on the fuel gas H_2S level to avoid PSD.

Response: *The Department disagrees with deleting Item 8 of the findings in the preliminary TAR. The discussion is for information purposes and is relevant for the permit history. As stated in the Department's response to Comment 3), the limit was imposed by the Department, likely to match the PSD significance threshold, and it was not a BACT, or ambient protection limit. The Department did not use the limit to required BACT for the CCP units in the preliminary permit. After careful examination of the federal regulations, the Department deleted the BACT for CCP units. The issue has been addressed in the Department's response to Comment 3).*

However, the last sentence of Item 8 was deleted because it was incorrect to state that the Department 'made a mistake in stripping the limit' in O/C Permit 166TVP01. The Department also corrected that the fuel gas content at the time was 25 ppmv and not 20 ppmv.

63) **TAR Page 13, Finding 9 –** this finding by ADEC is based on the assumption that fuel gas souring is considered a change in the method of operation of a source. See our comments 1) and 59). We reiterate here that a decision has not yet been made by EPA on this issue.

Response: *The Department agrees with BPXA that EPA has not yet ruled that fuel gas souring is a change in the method of operation. Conversely, EPA has not ruled that fuel gas souring is not a change in the method of operation. To be consistent with any future EPA decision regarding the appropriate mechanism for allowing an emissions increase that would otherwise violate a federal BACT decision, the Department has processed this permit using the most rigorous mechanism—a PSD major modification based on a change in the method of operation. This process has not established any limits or other source obligation that would not have been established in a minor permit. The Department acknowledges that if EPA decides in the future that fuel gas souring should not be considered a change in the method of operation, then the Department will follow that decision regardless of what is written in this TAR. Therefore, none of the permittee's interests will be adversely affected by this decision and no change to Finding 9 was made.*

64) Per our comment 2), delete **Findings 10 through 14 on pages 13 and 14 of the TAR**.

Response: *The reason to bring in the past Title 1 conditions to one place is explained in response to Comment 2). Therefore, the Department has retained Findings 23, 25 and 27 of this TAR.*

65) **TAR Page 14, Finding 17 –** revise this paragraph as follows:

"BPXA has requested an ORL of 105 ppmv (annual average) in all the fuel gas burning emission units at CGF~~, to protect SO_2 ambient air quality standards and increments~~. Because BPXA used *a* fuel gas H_2S content of 105 ppmv ~~(instantaneous)~~ in their modeling analysis *with the intent* to *maintain the impact of CCP and CGF SO_2 emissions in the vicinity of all offsite sources below the SO_2 significant impact levels,* ~~demonstrate compliance with the 24-hour increment standards for SO_2~~ a 105 ppmv (instantaneous) is required in the permit. *To change this limit, approved ambient air quality modeling must be submitted by the Permittee to demonstrate that SO_2 impacts due to emissions originating from the CCP/CGF complex do not significantly contribute to a predicted exceedance of the ambient SO_2 air quality standards or increments in the vicinity of any offsite sources.*"

Basis: See the basis to our comment 61). In addition, note that the limit necessary to make the compliance demonstration for the 24-hour SO_2 increment standard is the secondary ORL limit of 0.019 wt.% sulfur in the liquid fuel that has been requested to apply if the emergency generators at CGF are operated with a horizontal or capped stack. The fuel gas H_2S content was not a critical factor in this demonstration.

Response: *The Department deleted this finding since it is identical to a previously stated finding (see the response to Comment 61).*

66) **TAR Page 14, Finding 21** – this finding by ADEC is based on the assumption that fuel gas souring is considered a change in the method of operation of a source. See our comments 1) and 59). We reiterate here that a decision has not yet been made by EPA on this issue.

Response: *See the response to comment number 63. In addition, the Department has determined that only Units 1 through 4 and 9 through 11 are subject to BACT. All other fuel gas burning units are exempt from BACT for reasons addressed in response to Comment 2) and 3). The Department has revised the finding (Finding 17 in the final TAR) accordingly.*

67) Per our comment 2), delete **Findings 23, 25, and 27 on page 15 of the TAR.**

Response: *The Department has explained the reason behind the need to bring in the past Title 1 conditions to one permit in response to Comment 2). Therefore, the Department has retained the findings (Findings 19, 20 and 21 in the final TAR).*

68) **TAR Page 16, first item 1, item 2, and item 4** - the section references in these paragraphs are incorrect. Appropriate references are shown in the table below.

Item No.	Incorrect reference	Corrected reference based on the draft TAR	Corrected reference based on our comments to revise the section numbers in the TAR
1	Section 4.3	Section 4.2	*Section 5.2*
2	Section 5.5	Section 4.4	*Section 5.4*
4	Sections 4.1 and 4.2	Sections 3.1 and 3.2	*Sections 3.1 and 3.2*

Response: *The Department made the requested changes to the TAR.*

69) TAR Pages 16 and 17, second item 1 (beginning near the bottom of page 16) – revise the three paragraphs of this discussion as follows:

"Terms and conditions necessary to ensure that the Permittee … These include monitoring fuel gas H_2S limits and fuel ~~*oils*~~ *oil* sulfur content~~*, operating hours of the emergency generators*~~ and the exhaust stack orientation at CGF. ~~*All other conditions are Title 1 requirements for past actions.*~~

Monitoring for fuel gas H_2S and fuel oil sulfur are the same … For fuel oil sulfur ~~*monitoring*~~*reporting*, the permits require submitting monthly fuel sulfur analysis from either of the North Slope topping plants. i.e. the Prudhoe Bay or Kuparuk topping plants or *submitting a list of the fuel grades received from a third-party supplier and the amount of fuel received for each shipment*. Reporting ~~*Monitoring for*~~ stack orientation for the emergency generators at CGF is a ~~*new*~~ requirement included in construction permit no. AQ0270CPT04. ~~*Monitoring for the diesel generators are already in place in the operating permits. All other monitoring, recordkeeping and reporting requirements are*~~

~~*for past actions and are copied from the operating permits for CCP and CGF. These provisions are included throughout each of the permit.*~~

Note that the references to Permit *AQ0*166TVP~~*01*~~*xx* in Construction Permit AQ0166CPT04 and the references to Permit No. *AQ0*270TVP~~*01*~~*xx* in Construction Permit No. AQ0270CPT04, refer to the language in the respective *operating* permits and *is intended to apply to the version of the operating permit that is active at any given time.*~~the language still applies even though these permits expired (on September 3, 2008).~~ The Department's objective is to ensure that the requirements cross-referenced by conditions in ~~*other*~~ *construction* permits go on *and are always consistent with the reporting requirements of the currently effective operating permit* even ~~*if the other*~~ *when an operating* permit is rescinded, expired, or renewed."

Basis: 1) There is no need to include operating time limits for the liquid fuel fired emission units in the new CCP and CGF construction permits. These limits already apply and were used in the air quality modeling demonstration for this application because they are applicable limits that establish the PTE of these emission units.

2) Per our comment 2), we request that these permits and the TAR not include any permit hygiene or consolidation actions with respect to past permitting not associated with a fuel gas H_2S or SO_2 emission limit.

3) We request that the TAR reflect the requested additional provisions to be added to the permit with regard to fuel sulfur deliveries from third-party suppliers. See our comments 17) and 35).

4) We propose that ADEC consider making the references to reporting requirements in operating permits a generic reference to the most recent operating permit. Using this approach, if there is a change to the reporting requirements associated with operating reports or excess emissions/ permit deviation reporting over time, BPXA will not be required to follow two different reporting requirements (one as required by the "01" operating permit versus the revised requirements in the most recent permit). See also our comment 15).

Response: *The Department disagrees with deleting the emergency generator limits. Per the modeling memorandum in Exhibit B of the TAR, the limit must be included in the permit because BPXA relied on the limit in the modeling analysis. Hence the basis for the limits must be described in the TAR.*

Per response to Comment 2), the Department declines the request to delete the past Title 1 conditions in this permit and the relevant discussion in this section.

The Department has added the description to the reporting requirement for fuel oil sulfur content from fuel delivered by third party suppliers.

70) **TAR Section 4.2, Best Available Control Technology (BACT) –** As indicated in our comment 1) and per basis #3 to comment 21), we have agreed to disagree with ADEC's

decision to treat fuel gas souring at CCP and CGF as a change in the method of operation, thereby requiring BACT for all fuel gas fired CCP and CGF turbines and heaters, regardless of whether or not an existing BACT limit is in place for a given emission unit. We have done so in order to minimize further delay in receipt of these permits. However, this entire section is written from ADEC's perspective on the matter of BACT applicability. In order to prevent the loss of BPXA's perspective on the subject of what emission units should be subject to a BACT analysis, we request that ADEC include a footnote attached to the heading of this section with the following statement for the benefit of future readers of this document:

> **"***The Department has decided to treat fuel gas souring as a modification for the CCP and CGF permit applications and has developed the BACT analysis for these applications accordingly. However, BPXA does not agree with this decision and, as of the date of this permit, EPA has not ruled on whether or not it considers fuel gas souring at Prudhoe Bay to be a modification. BPXA believes that a BACT determination is required only for those emission units with existing BACT limits that must be relaxed as a result of the fuel gas souring. However, BPXA has cooperated with the Department by providing the necessary information to process the applications based on the Department's decision.*"

Response: *The Department has revised Section 4.2 of the preliminary TAR (Section 5.2 in the final TAR) to state that BACT applies to only those units with existing permit limits i.e. Units 1 through 4 and 9 through 11 CGF. However, the Department's reasoning is not synonymous with BPXA's reasoning. The Department's findings are addressed in response to Comments 2), 3), and 59). Therefore, the Department will not add the statement as requested.*

71) **TAR Section 4.2, Best Available Control Technology (BACT) –** revise the first paragraph of this section as follows:

> **"**As described in 40 CFR 52.21(j) a ~~*major*~~ modification *is major and* must apply BACT for each pollutant ~~*there is*~~ *where the modification results in* a significant net emissions increase at the source. As shown in Table 3, there is a significant emissions increase for SO_2, due to the increase in fuel gas H_2S content. BACT applies to each emission unit at which a net increase will occur as a result of ~~*the*~~ *a* physical or change in the method of operation ~~*in the*~~ *of an emission* unit. Therefore, each of these units is subject to BACT for SO_2."

Response: *The Department has revised as requested and also clarified the findings regarding the Units to which BACT applies.*

72) **TAR Section 4.2, Best Available Control Technology (BACT), Page 18 –** revise the first line at the top of page 18 to change "*missions*" to "*emissions*".

Response: *The Department made the requested change.*

73) TAR Section 4.2, Best Available Control Technology (BACT), Page 18, first full paragraph – revise this paragraph as follows:

"ERG revised BPXA's BACT analysis (see Table 3 of Exhibit C), based on treating *295* MMscf/d, of fuel gas burned at CCP and CGF with H_2S content of 300 ppmv. The projected SO_2 emissions, using fuel gas with 300 ppmv H_2S is ~~2,611~~ *2,647* tpy. The *combined CCP and CGF* PTE based on the ORL of 105 ppmv for ambient protection, is ~~594~~*781* tpy (see Table 3)…."

Basis: For the basis to our first edit, see comment 91)f regarding the ERG report in Exhibit C of the TAR. For the basis to our second and third edits, refer to the "combined new PTE" stated in Table 3 of the TAR.

Response: *The project SO_2 emissions reported in Section 4.2 of the draft TAR originated in Table 3 of the term contractor's report (Exhibit C or the TAR). The Department agrees that the SO_2 emissions for the flares were mistakenly calculated based on 105 ppmv, whereas it should have been based on 300 ppmv fuel gas H_2S content as for emission from all other units. The Department made the requested change. The Department also revised the costs for control technologies in the appendices of the report.*

74) **TAR Page 18, Table 6 –** Correct the control efficiency of Sulfa Treat to 99.5% and that of the Adsorption Process to 96.7%. These values are based on the control efficiencies used by ERG in Appendix A of their BACT Review document included as Exhibit C to the TAR. See also our comments 87) and 97)c.

Response: *The Department made the requested changes.*

75) Revise the last sentence of the final paragraph of **TAR Section 4.3, Page 19** to change "Permit~~s~~" to "*Permit*".

Response: *The Department made the requested change.*

76) **TAR Sections 4.4.1 and 4.4.2, Limit Necessary for CCP** and **Limit Necessary for CGF** – revise the last sentence of the opening paragraph of each of these sections, as follows:

"The Department's review of BPXA's modeling analysis found that in order to ~~*protect the ambient air quality standards and increments*~~ *satisfy BPXA's request to maintain air quality impacts to below significant impact levels in the vicinity of offsite sources*, the following limits are necessary"

Basis: See our comments 41)b, 61), and 65).

Response: *The Department did not make the requested changes. BPXA's purpose for restricting the significant impact area was to demonstrate compliance with the AAAQS/increments. Therefore, the sentences correctly describe the Department's basis for imposing the listed limits.*

77) **TAR Sections 4.4.1 and 4.4.2, Limit Necessary for CCP** and **Limit Necessary for CGF** – delete items (limits) 3 and 4 from Section 4.4.1 of the draft TAR and delete item (limit) 3 from Section 4.4.2.

Basis: The limits on annual operations of the emergency generators and firewater pumps at CCP and CGF are not required to protect ambient air quality as long as they are operated with vertical, uncapped stacks. The results of the annual ambient air quality impacts in the vicinity of the CCP and CGF are well below the allowable SO_2 ambient air quality standards and increments as shown on page VI-31 and VI-32 of the permit applications document. As such, the results do not support ADEC's finding that the operating time limits already in place for these emission units are necessary to protect ambient air quality.

Response: *Department disagrees with the requested changes. The commentator correctly noted that the annual SO_2 AAAQS and increment are* <u>*not*</u> *threatened. Therefore, it is likely that the emergency generators and firewater pumps could be operated for a longer period than the listed limits, without violating the annual average AAAQS/increments. However, simple proration of the modeled impacts by the assumed operating hours shows that unrestricted operation could lead to modeled violations of the SO_2 AAAQS/increment. It is also likely that a tighter restriction would be needed to protect the annual average NO_2 AAAQS/increment. Therefore, until BPXA adequately demonstrates that these units can continuously operate without violating the annual average AAAQS/increments, the Department will impose the assumed operating levels as ambient air condition.*

78) **TAR Section 4.4.2, Limit Necessary for CGF –** add an introductory paragraph prior to item (limit) 4 of this section and revise the text of item 4, as follows:

"*The Department's review of BPXA's modeling analysis found that in order to protect the ambient air quality standards and increments, the following limit is necessary*

4. Construct and maintain vertical, uncapped exhaust stacks for the three emergency generators (Tag No. NGI-19-2802, NGI-19-2819, NGI-19-2890), …The uncapped ~~*condition*~~ *stack requirement* does not preclude the use of flapper valve rain covers…."

Response: *The Department did* <u>*not*</u> *add the requested sentence, but did change "condition" to "stack requirement." The requested sentence is unnecessary since the Department is imposing* <u>*all*</u> *of the ambient air conditions to protect the AAAQS and increments.*

79) **TAR Section 5.0, Requirement for all Air Quality Control Permits –**

a. Revise the heading of this section of the TAR as follows:

"**5.0 Requirement for ~~*all*~~ Air Quality Control *PSD (Construction)* Permits**"

b. Delete paragraphs 1, 3, and 4 of this section and replace them with the following paragraph to be included as the new first paragraph of this section of the TAR:

"*All air quality PSD permits must contain the information outlined in 18 AAC 50.306(d).*" Follow this statement with appropriate language in this new paragraph to document that the CCP and CGF construction permits include the required monitoring, recordkeeping, reporting and fee payment requirements outlined in 18 AAC 50.306(d).

Basis: Paragraphs 1, 3, and 4 of this section of the draft TAR describe permit terms and conditions that are required for operating permits and, in the case of the first paragraph, the language refers to the recordkeeping requirements under 18 AAC 50.544, which applies to minor permits under 18 AAC 50.502(c), not to PSD permits. The required elements of a PSD (construction) permit are stated under 18 AAC 50.306(d).

Regarding the necessity of including the standard conditions under 18 AAC 50.345, see the basis to our comment 0. See also comment 80) below.

***Response**: In this section, the Department inadvertently described the contents that must be included in a minor permit. The specific requirements for a construction permit were already described in the previous Sections 4.1 through 4.4 of the preliminary TAR (Section 5.1 through 5.4 of the final TAR). Except for Paragraph 2 that describe the standard permit conditions, the rest of the contents don't apply to the construction permit. Therefore, the Department is retaining the section heading as is and retaining only paragraph 2 of this section and deleting paragraphs 1, 3 and 4. The section is re-numbered as Section 5.5 in the final TAR.*

80) **TAR Section 5.0, Requirement for all Air Quality Control Permits** – revise the second paragraph of this section as follows:

"The permit ~~*must also*~~ contains ~~*additional*~~ *standard permit conditions* ~~*requirements as necessary to ensure that the Permittee will construct and operate the stationary source in accordance with 18 AAC 50,*~~ as described in 18 AAC 50.345(c)(1) and (2) and (d) – (h). These requirements are listed in Section 7 of Construction permit No. AQ0166CPT04 and Section 6 of Construction Permit No. AQ0270CPT04 under "~~*Terms to Make Permit Enforceable*~~ *Standard Permit Conditions*." *All other required standard permit conditions that apply to operation of the CCP and CGF source are included in the respective operating permits.*"

Basis: This paragraph written as proposed above documents the Department's decision to include the standard permit conditions found in 18 AAC 50.345(c)(1), (2), and (d) through (h) and that other standard conditions (i.e., 18 AAC 50.345(i) through (o)) are stated in the applicable operating permits. This eliminates the need to reference the information requests required under 18 AAC 50.345(i) and the certification requirement under 18 AAC 50.345(j) in any other paragraph of this section. See also the basis to our comment 0.

Response*: The Department has made the changes with some revisions*

81) TAR **Section 6.0, Permit Administration** – revise the second paragraph and the first sentence of the third paragraph of this section as follows:

> **"**For reasons described in Item 15 of the Department Findings Section ~~3.3~~*4.0*, BPXA can operate CCP under the provisions of Construction Permit~~s~~ AQ0166CPT~~04~~*01* upon issuance. Similarly, for reasons described in Item 26 of the Department Findings Section ~~3.3~~*4.0*, BPXA can operate ~~CCP~~*CGF* under the provisions of Construction Permit~~s~~ ~~AQ0166CPT04~~*AQ0270CPT01* upon issuance.
>
> The Department notes that permit renewals for the operating permits for CCP and CGF are underway at the same time as these Title 1 permit*s* are processed."

Response*: Except to renumber the permits to end with CPT01, the Department made the editorial changes requested in the comment. The reason to number the permits to end with CPT04 is discussed in response to Comment 4).*

82) Delete **TAR Exhibit A** in its entirety. This exhibit is no longer relevant to the TAR if ADEC removes all discussions pertaining to past permit actions as requested by our comment 2).

Response*: The Department has explained in response to Comment 2), the reason to bring in all the past Title 1 conditions into this permit as a vehicle for Title 1 conditions. Exhibit A in the TAR lists the Title 1 limits and the permits in which they originated and whether they were superseded by other permit limit. This information is important and is the historical basis for the limits that will be useful in the future.*

Comments on Exhibit B to the Technical Analysis Report (Modeling Memorandum)

83) **TAR, Exhibit B, Page 3, last paragraph** - Revise this paragraph as follows:

> "40 CFR 52.21(m)(1) requires PSD applicants to submit … Hence, these data are referred *to* as "pre-construction monitoring" data."

Response*: The Department made the requested change.*

84) **TAR, Exhibit B, Page 5, last sentence of the next to last paragraph** – revise as follows:

> "Excluding the liquid-fired *unit* credits makes the project impact analysis conservative."

Response*: The Department used a variation of the requested change to clarify the sentence.*

85) **TAR, Exhibit B, Page 11, first paragraph** – revise as follows:

> "The historical purpose for the annual operating limits is not well documented….However, if an annual restriction is needed to protect the annual SO_2 AAAQS/increment, ~~than~~ *then* an annual restriction is *likely* needed to protect the annual

PM-10 AAAQS/increment as well. The Department presumes that is the case here. …protect the annual average NO_2, SO_2 and PM-10 AAAQS/increments. *The Department's assumptions stated here do not preclude BPXA from providing additional information to the Department (e.g., approved air quality modeling) to demonstrate that these limits are not necessary to protect the annual average air quality standards and increments.*"

Basis: BPXA requests that the modeling memorandum include here an allowance to clearly provide BPXA the opportunity to demonstrate through approved means that the annual operating limits are not necessary for ambient air quality protection.

Response*: The Department corrected the typographical error, and inserted a variation of BPXA's requested sentence as a footnote. While applicants always have the option of providing a revised ambient analysis to support a request to remove an ambient air condition under 18 AAC 50.508(6), there's no harm in including this type of statement in the modeling review.*

Comments on Exhibit C to the Technical Analysis Report (BACT Review)

86) **TAR Exhibit C, Section 1.0, 4th paragraph** – Revise the first sentence of this paragraph as follows:

"BPXA ~~*expects*~~ *is unable to determine to what level fuel gas H_2S levels will climb* ~~*that*~~ during the next 10 years, *but estimates that* H_2S fuel gas levels ~~*will*~~ *could* increase to *as high as* 300 ppmv *and elected to use this value as a conservative baseline estimate for the BACT analysis*."

Basis: BPXA <u>does not expect</u> the fuel gas H_2S content to increase to 300 ppmv within the next 10 years. As stated on page V-3 of our application, "Although it is <u>unlikely that levels as high as 300 ppmv will occur during the next 10 years</u>, use of this value as a baseline to assess the BACT cost effectiveness is very conservative because the amount of pollutant controlled increases with higher baseline H_2S concentrations." (emphasis added)

Response*: Exhibit C of the TAR contains the BACT review report from the term contractor, Eastern Research Group Inc. (ERG). The Department agrees that BPXA is unable to determine to what level the fuel gas H_2S will climb but estimates that H_2S content will increase to 300 ppmv. Therefore, it is incorrect to state that BPXA expects the fuel gas H_2S content to increase to 300 ppmv. The Department made the requested changes to the ERG's report.*

87) **TAR Exhibit C, Page 2, Table 1 –** According to the control level used by ERG in Appendix A to the BACT Review document, the control efficiency of Sulfa-Treat is 99.5%, not 99.8% (2597 tons SO_2 removed based on a total potential SO_2 emission rate of 2611 tons is 99.5% removal). Revise Table 1 to reflect this correction. See also our comment 97)c.

Response*: The Department revised the control technology efficiency for Sulfa Treat to be 98.7% to be consistent with the value in BPXA's submittals. The value is addressed in the Department's response to Comment 97).*

88) **TAR Exhibit C, Page 2, bullets 1 and 2 –** Delete these two bullets. BPXA does not agree with ERG's conclusion to 1) reduce the contingency factor from 30 percent to 15 percent; and 2) remove the cost of instrument and controls from the estimate. We request that ERG recalculate the BACT cost effectiveness without these two adjustments to BPXA's BACT analysis and revise the BACT Review document accordingly.

Basis: 1) The 30 percent contingency factor has been included by a design estimating group based on past experience with projects on the North Slope of Alaska. The current BACT analyses are based on a conceptual layout that has identified necessary equipment. A more detailed design can result in cost changes that can be expensive when implementing the design for North Slope operation. In addition, severe weather can create considerable delays.

2) While the control equipment may include costs for stand alone controls, modules must be interconnected with the main control module. These costs are not included in the vendor quotes.

Response*: The Department believes that ERG took into account the remote location and the adverse conditions of the North Slope when doing the cost calculations. ERG believed the basic equipment and auxiliaries include all appropriate controls. ERG revised the contingency from 30 percent to 15 percent of the instrument and controls because they thought 30 percent was excessive. Therefore, the Department did not make the requested changes to the cost estimates in the ERG report. Moreover, the requested change will not alter the BACT outcome.*

89) **TAR Exhibit C, Section 2.0 –** BPXA requests that Section 2.0 paragraphs 1 through 3 and Table 2 be deleted from the BACT Review document.

Basis: These paragraphs provide some historical perspective for the project, make an assessment of whether there will be a significant emission increase resulting from the "project", and continues to propagate the thought that the "project" is a major modification due to fuel gas souring. None of this information is relevant to conducting a BACT review and some statements made in these paragraphs, particularly with respect to how the project triggers PSD, are points of debate between ADEC and BPXA.

The background provided in Section 2.0 should simply begin with the statement found in the 4th paragraph of the draft section, where ERG is identified as the contractor selected by ADEC to conduct the BACT review. The fact that a BACT review must be done in the first place is sufficient basis for stating that the project has triggered PSD. Additional analysis as to the PSD applicability of the project is not important to this document.

Response*: The Department agrees with BPXA's comment that Section 2 of the ERG's report duplicates the historical perspective for the project which has already been covered in the main TAR document. The Department also agrees that the information is not relevant to conducting the BACT review. Therefore, the Department retained only the 4th paragraph of that section to state that ERG was contracted to review BPXA's BACT analysis. The Department also deleted Table 2 and renumbered the ensuing Tables accordingly.*

90) **TAR Exhibit C, Section 3.0, 1st paragraph –** Revise this paragraph as shown:

"North Slope fuel gas souring has increased H_2S concentrations in the fuel gas. The higher H_2S concentrations in the fuel gas result in higher SO_2 emissions from the exhaust of CCP and CGF combustion equipment. ~~*The potential to emit of SO2 resulting from the Project is 2,349 tons per year; which is greater than 40 tons per year of SO2 and exceeds the thresholds in 40 CFR 52.21(b)(2)(i). Therefore it is classified as a PSD major modification under 40 CFR 52.21.*~~ Fuel gas fired equipment at the CCP and CGF consists of the combustion equipment listed in the table below. *Table 3* [to be renumbered to Table 2] *presents the projected potential SO_2 emissions and the maximum daily gas usage for the gas fired CCP and CGF equipment. These are important data relevant to the BACT analysis pertaining to cost effectiveness and the amount of SO_2 controlled based on the control efficiency of the technically feasible control technologies identified later in this document.* "

Basis: 1) We have requested that the value of 2,349 tons per year be deleted from this paragraph, but we also remind ADEC and ERG that a determination of the PSD major modification status of a project is based on a baseline consisting of the current actual emissions. ERG has used in this paragraph and in Table 3 the current SO_2 PTE for CCP and CGF as the baseline. This is not appropriate. But regardless, as stated in earlier comments, we do not believe it is within the scope of a BACT Review document to make assertions as to the PSD applicability of a project. Such determinations were already made prior to this document being prepared, which is the reason a BACT analysis was completed and a review was requested. We request that the disputed reason for triggering PSD not be stated as fact in the BACT review document.

2) Because the PSD applicability of the project is not in question and need not be re-evaluated in the BACT Review document, we propose that the introductory paragraph to Table 3 (to be renumbered as Table 2) also introduce the purpose for listing the potential emissions and fuel gas usage as important to the BACT cost effectiveness review. See also the comment below where we request revisions to Table 3 (2).

Response*: The Department agrees to delete the 2,349 tpy value in ERG's report because the numbers have changed after Table 3 was revised to account for the revisions to the flare emissions that is addressed in Comment 91). The Department also agrees that it is incorrect to base the PSD applicability determination on the current PTE to future PTE. The Department has already covered the basis for the PSD modification in the main document and the contents in the paragraph pertaining to the discussion with PSD applicability are unnecessary and misleading. Therefore, the Department made the requested changes to the paragraph.*

91) **TAR Exhibit C, Table 3 –** Revise this table to address the following corrections. Also presented below is a markup of this table accounting for the necessary revisions.

a. Renumber Table 3 to be Table 2 due to the deletion of Table 2 of draft Exhibit C per our comment 89).

b. The maximum daily fuel gas usage values for the Cooper-Rolls RB211-24C turbines and the GE MS5382C turbines are switched.

c. Delete the column labeled "Current PTE SO_2 (tpy)". This information is not relevant to the BACT Review document and is incorrectly used as the baseline to determine PSD applicability. See basis #1 of comment 90). This edit also results in the removal of footnotes 1 and 2 of the draft table.

d. Change the label of the second column from "*Source* Description" to "*Emission Unit* Description" and correct the descriptions of several units as shown below.

e. Add a footnote that points to the potential SO_2 emissions for the six CGF turbines and three CGF heaters that are subject to an EPA SO_2 BACT ton-per-year emission limit. ERG has estimated the potential emissions of these units based on the assumption that EPA will eventually amend the SO_2 BACT limits for these turbines although technically, as of the date of the BACT Review document, the potential emissions from these six turbines and three heaters remains unchanged irrespective of the fuel gas H_2S level because the EPA BACT limits the allowable emissions, therefore, defining the PTE. However, we concur that for this analysis, the assumption can be made that the EPA BACT limit will likewise be adjusted and that the "projected potential" emissions are appropriate to be stated in Table 3. This is a conservative approach. Our proposed footnote is provided below.

f. Correct the projected potential SO_2 emissions for the CCP and CGF flares to be based on 300 ppmv H_2S in the fuel gas. The values presented in the draft table for the flares are based on 105 ppmv H_2S in the fuel. The effect of this correction is significant in that it changes the total projected potential SO_2 emissions from 2,611 tons per year to 2,647 tons per year.

g. Correct the projected potential SO_2 emissions and the maximum daily gas usage for Eclipse glycol heater NGH-21-1502 to coincide with the correct rating of this heater. (Note: the rating of heater NGH-21-1502 is 12.3 MMBtu/hr while the rating of heater NGH-21-1501 is 10.7 MMBtu/hr, as documented in Table II-1 of our permit application. As such, their potential emissions and maximum gas usage values are not the same.)

Table ~~3~~*2*. BPXA CCP and CGF Combustion Equipment

Tag No.	~~Source~~ ***Emission Unit*** **Description**	~~**Current PTE SO2 (tpy)**~~	**Projected *Potential* SO_2 (tpy)**	**Maximum Daily Gas Usage (MMscf/d)**
NGI-19-1883	GE Frame 6 Injection Compressor	~~11.9[1]~~	117.9	13.59
NGI-19-1884	GE Frame 6 Injection Compressor	~~11.9[1]~~	117.9	13.59
NGI-19-1885	GE Frame 6 Injection Compressor	~~11.9[1]~~	117.9	13.59
NGI-19-1886	GE Frame 6 Injection Compressor	~~11.9[1]~~	117.9	13.59
NGI-19-1801	Cooper-Rolls/RB211-24C Booster Compressor	~~6.5[2]~~	63.7*[1]*	~~11.76~~ *7.04*
NGI-19-1802	Cooper-Rolls/RB211-24C Booster Compressor	~~6.5[2]~~	63.7*[1]*	~~11.76~~ *7.04*
NGI-19-1805	Cooper-Rolls/RB211-24C Miscible Injectant	~~6.5[2]~~	63.7*[1]*	~~11.76~~ *7.04*
NGI-19-1855	Cooper-Rolls/RB211-24C Miscible Injectant	~~6.5[2]~~	63.7*[1]*	7.04
NGI-19-1806	GE MS5382C Refrigerant Compressor	~~9.0[1, 2]~~	95.5*[1]*	~~7.04~~ *11.76*
NGI-19-1856	GE MS5382C Refrigerant Compressor	~~9.0[1, 2]~~	95.5*[1]*	~~7.04~~ *11.76*
NGI-19-1857	GE MS5382C Booster Compressor	~~9.0[1]~~	95.5	~~7.04~~ *11.76*
19-1408	IHI-John Zink Emergency Flare (HP Primary Pit)	~~2.7~~	~~9.7~~ *27.7*	3
19-1409	IHI-John Zink Emergency Flare (LP Primary Pit)			
19-1410	IHI-John Zink Emergency Flare (HP Emergency Pit)			
19-1411	IHI-John Zink Emergency Flare (LP Emergency Pit)			
19-1412	IHI-John Zink Emergency Flare (NGL Primary Pit)			
NGI-19-1401	Chiyoda-John Zink Hot Oil Heater	~~5.4[2]~~	55.3*[1]*	5.98
NGI-19-1402	Chiyoda-John Zink Hot Oil Heater	~~5.4[2]~~	55.3*[1]*	5.98
NGI-19-1403	Chiyoda-John Zink Hot Oil Heater	~~5.4[2]~~	55.3*[1]*	5.98
NGT-18-1801	GE MS5371PATP Gas Compressor	9.1	91.4	9.90
NGT-18-1802	GE MS5371PATP w/LHE Gas Compressor	9.5	94.8	10.27
NGT-18-1803	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1804	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1805	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1806	GE MS5371PATP Gas Compressors	9.1	91.4	9.90

Tag No.	~~Source~~ *Emission Unit* Description	~~Current PTE SO2 (tpy)~~	Projected *Potential* SO_2 (tpy)	Maximum Daily Gas Usage (MMscf/d)
NGT-18-1807	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1808	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1809	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1810	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1811	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1812	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1813	GE MS5371PATP Gas Compressors	9.1	91.4	9.90
NGT-18-1876	GE MS5382C Tandem Compressors	9.8	98.2	10.63
NGT-18-1878	GE MS5382C Tandem Compressors	9.8	98.2	10.63
NGH-18-1410	Broach Glycol Heater~~s~~	~~0.7~~	7.3	0.79
NGH-18-1491	Broach Glycol Heater~~s~~	~~1.0~~	9.6	1.04
NGH-18-1492	Broach Glycol Heater~~s~~	~~1.0~~	9.6	1.04
NGH-21-1501	Eclipse Glycol Heater~~s~~	~~0.3~~	2.7	0.30
NGH-21-1502	Eclipse Glycol Heater~~s~~	~~0.3~~	~~2.7~~*3.1*	~~0.30~~ *0.34*
NGH-21-1503	BS&B TEG Reboiler~~s~~	~~0.1~~	1.0	0.11
NGH-21-1504	BS&B TEG Reboiler~~s~~	~~0.1~~	1.0	0.11
18-1403	John Zink HP/IP Emergency Flare	~~1.8~~	~~6.5~~ *18.6*	2.0
18-1494	John Zink STV Emergency Flare			
18-1496	Line Emergency Backup Flare			
18-1497	Line Emergency Backup Flare			
Total		~~262~~	**2,6~~11~~*47***	**295**

~~1 – Limited under the ADEC permit 9873-AC006.~~
~~2 – Limited under the US EPA permit PSD-X81-13.~~
1 – The projected potential SO_2 emission rate for these emission units is based on the assumption that the current EPA SO_2 ton-per-year limits for these units will be increased as a result of a future application by the Permittee to revise the limit to the value shown here (i.e., to be based on 300 ppmv H_2S in the fuel gas instead of 30 ppmv H_2S). Otherwise the PTE for these units would be reduced by a factor of 10.

Response:

a. *The Department renumbered Table 3 to Table 2 because Table 2 of ERG's report was deleted (see response to Comment 89).*

b. *ERG has inadvertently switched around the fuel gas usage values for the Cooper-Rolls RB211-24C (Units 5 through 8) turbines and the GE MS5382C (Units 9* *through 11) turbines. The Department corrected the fuel gas use values as requested.*

c. *Since PSD applicability determination is based on the Baseline Actual to Projected Actual Emissions test, the information in the Current PTE column is irrelevant and gives an erroneous basis for PSD applicability determination. Therefore, the Department deleted the column containing the current SO_2 PTE in Table 3 of ERG's report in Exhibit C of the TAR.*

d. *The Department changed the label of the second column from Source Description to Emission Unit Description.*

e. *The Department agrees that the EPA SO_2 BACT limits for Units 5 through 10 and 12 through 14 are applicable at this time. However, for the BACT cost estimates ERG has used the 300 ppmv fuel gas H_2S content as in the permit application. The latter approach is also the more conservative method of determining the costs. The Department added the footnote to Table 3 of the ERG report with some edits.*

f. *The Department corrected the projected potential SO_2 emissions for the flares based on fuel gas H_2S content of 300 ppmv. The ERG report based it on 105 ppmv which is incorrect.*

g. *The Department corrected the projected potential SO_2 emissions and the maximum daily gas usage for the Eclipse Glycol Heater based on the correct rating of 12.3 MMBtu/hr.*

92) **TAR,** global **edits –** The BACT Review completed by ERG should be revised to account for the changes made to the table above that correct the total projected potential SO_2 emissions.

***Response**: The Department revised the BACT review report to reflect the changes made in Table 3.*

93) **TAR Exhibit C, Page 8, 1st paragraph of item 2 –** Revise the next to last sentence of this paragraph as follows:

"Instead of merely absorbing H_2S, the Sulfur-Rite® process chemically changes H_2S into iron pyrite (FeS_4), which is a safe and stable compound~~, iron pyrite (FeS4)~~."

***Response**: The Department made the requested change.*

94) **TAR Exhibit C, Section 3.2, Item 3 on pages 11 and 12 –** We propose that ADEC add a note to the end of the technical feasibility discussion for Xergy as follows to document that ACT is not offered at this time.

> "…The licensed vendor (Xergy) has no experience with treating this high volume of gas. *(Note: recent conversations with a former Xergy project manager have revealed that Xergy is no longer a commercial entity and that Xergy ACT is not offered at this time.*"

Response*: ERG has not indicated that they had any conversations with Xergy to reveal that Xergy is no longer a commercial entity and to state that Xergy is not offered at this time. Therefore, the Department disagrees with including such a statement in the ERG report.*

95) **TAR Exhibit C, Section 3.2, Page 12, Item 4 –** Revise the last sentence of this paragraph as follows:

> "Seawater scrubbing is considered technically infeasible for the Project because… Seawater scrubbing cannot reasonably be installed and operated with existing combustion turbines. It should be noted that Kuparuk Seawater Treatment Plant (KSTP) has two seawater de-aerator towers currently in service to ~~treat fuel gas to reduce H_2S~~ *de-aerate the water. A side effect of this process is a reduction in fuel gas H_2S at KSTP for a portion of the fuel gas burned at that source*."

Basis: The KSTP does not use seawater for the purpose of treating fuel gas. Instead, the fuel gas is being use to treat (de-aerate) the water. Any reduction in the H_2S levels is simply a side effect of the process used at that location.

Response*: The Department edited ERG's report as requested.*

96) **TAR Exhibit C, Page 12, Table 4 –**

a. Renumber Table 4 to be Table 3. This is due to Table 2 being deleted per our comment 89).

b. Change the control efficiency of Sulfa-Rite to *99.5%* from *98.7%*. See our comment 87). See also our comment 97)c.

Response*: The Department re-numbered Table 4 as Table 3 for reasons discussed in response to Comment 89. The control efficiency for Sulfa Treat is not very well documented in BPXA's cost estimates submitted on January 15, 2009. It is unclear whether the control efficiency for Sulfa Treat is 99.5% or 98.7%. Based on BPXA's cost estimates for treating 136 MMscf fuel gas, it is 98.7% whereas for 287 MMscf it is a different value that the Department has not been able to decipher from BPXA's January 15, 2009 submission. It appears that ERG back calculated from BPXA's annualized cost estimates rather than verify the cost control independently. The value of the control efficiency whether 99.5% or 98.7%, Sulfa Treat ranks 2nd in order of control efficiencies and makes very little change to the overall cost. Either of the values will not alter the final outcome of BACT. Therefore, the*

Department used a control efficiency of 98.7% in order to be consistent with BPXA's estimates and revised ERG's report accordingly.

97) **TAR** Exhibit **C, Section 3.4 –**

a. In this section, Sulfa-Treat is declared as the most effective control method at 99.8 percent. However, we calculate a control efficiency of 99.5% (see our comment 87), which is less than the efficiency for LO-CAT® of 99.7% as documented by our permit application and used by ERG in their BACT Review. If 99.5% is the correct control efficiency, then this section should be revised to present LO-CAT® as the most effective control and Sulfa-Treat as the second most effective.

b. If 99.8 percent is correct, then the amount of SO_2 emissions control stated throughout the TAR for Sulfa-Treat should be changed from 2,597 tons per year to the appropriate value based on control of 2,647 tons of SO_2, not 2,611 tons per our comment 91)f.

c. If 99.8 percent is the correct control effectiveness for Sulfa-Treat, then that should be consistently reflected in TAR Table 6, TAR Exhibit C Table 1, and TAR Exhibit C Table 4. This would negate our comments 74), 87), 96)b, and 103).

Response*:*

a. The Department agrees that ERG made a mistake in Section 3.4 by declaring Sulfa Treat as the most effective control technology but ranked Sulfa Treat below LO-CAT in Table 5. Since LO-CAT is 99.7% efficient and Sulfa Treat is 98.7% efficient, the ranking in Table 5 is correct. So the Department revised the description in Section 3.4 in order to be consistent with Table 5.

b. The Department agrees that ERG has inadvertently switched around the fuel gas usage values for the Cooper-Rolls RB211-24C (Units 5 through 8) turbines and the GE MS5382C (Units 9 through 11) turbines. The Department corrected the fuel gas use values.

c. The Department has used 98.7% control efficiency for Sulfa Treat. Therefore, the order of the control technologies in Table 5 remains the same. However, the annualized cost for the technology is revised to correspond to 98.7%.

98) **TAR** Exhibit **C, Table 5 –**

a. Renumber Table 5 to be Table 4. This is due to our comment 89) to delete Table 2 of Exhibit C.

b. Revise Table 5 to match the values presented in Appendix A of Exhibit C as follows. Note that our requested revisions include reformatting the table to make the reference to footnote 1 more visible:

***~~Table 5~~Table 4*. SO_2 Cost Effectiveness Summary for the Combustion Equipment**

Control Technology	Annualized Costs (Revised)	Total SO_2 Removed (tpy)	Cost $/ton removed	
			Applicant Estimate	Revised Estimate
H_2S Scavenging (Sulfa-Rite®) [1] ~~Liquid Redox (LO-CAT®)~~	$33,461,456	2,597	$13,528	$12,885
Liquid Redox (LO-CAT®) ~~H_2S Scavenging (Sulfa-Rite®) [1]~~	$38,201,145	2,603	$15,742	$14,678
Adsorption Process (Amine)	$46,369,135	~~2,603~~*2,524*	$22,036	$18,369
Limit Sulfur in Fuel	-	-	-	-

99) **TAR** Exhibit **C, Page 14, 1st and 2nd bullets –** Delete these bullets. For the reasons discussed in comment 88), BPXA does not agree with the ERG conclusion that the contingency be reduced from 30 percent to 15 percent and the cost of instrument and controls removed from the estimate.

***Response**: The Department re-numbered Table 5 as Table 4 for reasons covered in response to Comment 89). In bullet 2, of Section 3.4, ERG stated that details provided by BPXA's vendor, Worley Parsons, did not adequately justify instruments and control costs. ERG believed the basic equipment and auxiliaries include all appropriate controls and ERG revised the contingency from 30 percent to 15 percent of the instrument and controls. Therefore, the Department did not make the requested changes to the cost estimates in the ERG report. Furthermore, the requested revisions would not have altered the outcome of the BACT determination.*

100) **TAR Exhibit C, Page 14 –** BPXA recommends that sections 3.4.1 and 3.4.2 be switched. The reordering is justified because Liquid Redox (LO-CAT®) is the most effective control. See also our comment 97)a.

***Response**: The Department switched the sections 3.4.1 and 3.4.2 in order to be consistent with the order of efficiencies for the control technologies. Because LO-CAT is the most efficient control technology, it must precede Sulfa Treat.*

101) **TAR** Exhibit **C, Section 3.4.3, Page 15 –** Change the section title from "*H_2S Scavenging (Sulfa-Rite)*" to "*Adsorption Process (Amine)*".

***Response**: The Department agrees that Section 3.4.3 pertains to the Adsorption Process (Amine) and not H_2S Scavenging and corrected the mistake.*

102) **TAR Exhibit C, Page 17, 1st paragraph after the two bullets –** Revise the second sentence of this paragraph to match the edits requested and justified in our comment 86).

Response*: As described in response to Comment 86, the Department agrees that BPXA is unable to determine to what level the fuel gas H_2S will climb but estimates that H_2S content will increase to 300 ppmv. Therefore, it is incorrect to state that BPXA expects the fuel gas H_2S content to increase to 300 ppmv. The Department made the requested changes to the paragraph.*

103) **TAR Exhibit C,** Page **19, Section 4.4 –** In the Errors and/or Uncertainties section, ERG lists a control efficiency for Sulfa-Treat as *99.8* percent. The control efficiency should be *99.5* percent. See also our comments 87) and 97)c.

Response*: As described in response to Comment 96), the Department used a control efficiency of 98.7% for Sulfa Treat and revised Section 4.4 accordingly.*

104) **TAR Exhibit C, Page** 20**, Item 5, bullets 1 and 2 –** Delete these bullets. For the reasons discussed in comment 88), BPXA does not agree with the ERG conclusion that the contingency be reduced from 30 percent to 15 percent and the cost of instrument and controls removed from the estimate.

Response*: For reasons provided in response to Comments 88) and 99) the Department did not revise as requested. Furthermore, the requested revisions will not alter the BACT conclusion.*

105) **TAR Exhibit C, Appendix A, Table A-4 –** The cost effectiveness in the last column is in error. The table lists *$8,369*. This value should be *$18,369*.

Response*: The Department agrees that the cost effectiveness for Sulfa Treat was off by an order of 10,000. This was a typographical error. Also, the cost effectiveness was revised to 18,113 to account for 2,647 MMscf (from 2,611 MMscf/d in the preliminary permit). This change was due to the amount of gas projected to be burned in the flares that was based on 105 ppmv in the draft TAR whereas it ought to have been based on 300 ppmv as for all other units.*

Comment from Alaska Oil and Gas Association (AOGA)

The Alaska Oil and Gas Association (AOGA) is a private, nonprofit trade association whose member companies account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in Alaska.

On July 6, 2009 the Department proposed two Construction Permits for the referenced Gas Plants, based on request from BP Exploration (Alaska) Inc. (BPXA) to increase
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On July 6, 2009 the Department proposed two Construction Permits for the referenced Gas Plants, based on a request from BP Exploration (Alaska) Inc. (BPXA) to increase allowable fuel gas H2S content. Our understanding is that the increase is necessary to alleviate ongoing oil production curtailments necessary to stay within current limits. The two proposed permits authorize the requested increase. However, the Department of Environmental Conservation ("ADEC") on its own accord with no request or reasoning, also proposes to modify several very important provisions within the permits that will have a material impact on each of the permitted facilities that are unrelated to BPXA's original request. These permit provisions include the deletion of footnotes that prescribe elements of the Best Available Control Technology (BACT) limits for combustion turbines, provisions that reverse multiple previous permit hygiene actions; and permit provisions that inaccurately infer the basis of permit decisions made nearly 20 years ago.

It is unusual for AOGA to submit comments on an individual member company's permit. However, ADEC's actions are unprecedented and have the potential to impact numerous other member companies. AOGA has participated in numerous meetings between member companies, ADEC and the Environmental Protection Agency on H2S permitting issues associated with reservoir souring and supports modification of member company permits to address this concern. Because many AOGA member companies have ADEC-issued permits with similar conditions, AOGA submits the following comments regarding the proposed BPXA permits. As you know, AOGA submitted comments expressing this same concern on the similar proposed revisions to Union Oil of Company of California (UOCC) Steelhead Platform, Minor Permit No. AQ0009MSS01 it submitted on June 19, 2009.

AOGA recognizes the statutory authority of ADEC to reopen and revise a permit to address a material mistake. However, using that authority in conjunction with a time critical, compliance and production-dependant permit action to reopen many previous decisions made by the Department causes significant procedural concerns for AOGA members. Because similar limits are applied to numerous comparable sources and permit hygiene has occurred in so many permits, the impact of such revisions is not necessarily limited to the permit under review at the particular time.

When ADEC believes it necessary to reopen provisions in a New Source Review permit, AOGA encourages the Department to work collaboratively with the permittee prior to preparing the draft permits. Since the majority of the oil and gas operators in Alaska are AOGA members, the Association is uniquely positioned to work cooperatively with ADEC to address industry-wide issues such as BACT for turbines and changes to previous permit hygiene philosophy. A collaborative approach to these issues is a better use of the limited resources of all interested parties.

Specifically, the Department should withdraw all conditions and portions of both the permit and the Technical Analysis Report that are unrelated to the changes requested by BPXA in their application from the Gas Plants permits. The Department should not take an opportunistic approach to construction or operating permit actions to change significant conditions from previous permit actions that they believe may not be consistent with current philosophy. In the rare instance where a material error has occurred in a permit, the Department should notify the permittee and work jointly to find a satisfactory resolution. However, that is not the case here and instead the Department has chosen to modify long established permit terms and conditions that were applied to the industry as a whole in a single permit for a single operator.

AOGA members value their relationship with ADEC and the opportunity to collaborate on complex issues. We look forward to working with you on this issue.

Response: *It is not clear to the Department what AOGA referred to as footnotes that prescribed the element of the BACT limits for the turbines. The Department suspects that AOGA is referring to the fuel gas H_2S limit that was established 20 years ago for CCP but stripped off in the O/C permit in 2003. The Department believes that the limit was established to avoid PSD review for SO_2 for the gas expansion project. The Department informed BPXA in May, 2009, that based on the limit, the emissions increase at CCP was above the PSD modification threshold and must undergo PSD review for SO_2. But the Department later realized that these old permits were issued under the Department's SIP approved program when the Department had the flexibility to consider fuel gas souring as a natural phenomenon. Any emissions increase associated with fuel gas souring was not considered for PSD applicability determinations. The Department is now operating under the Federal delegated program (since October 2004) and is obligated to follow the interpretation of the EPA for fuel gas souring. The Department is using the EPA's 2003 letter to ConocoPhillips Alaska Inc[6] as a guide. Please see response to Comments 2) and 59). Therefore, the issue of the historical limit is now moot. The Department wants to emphasize that the reason for the CCP units to undergo BACT is not because of a limit 20 years ago but because of the reasons described below:*

BPXA's application requested the Department to revise the BACT limits for certain units at CGF. In order to relax the limit from 30 ppmv to 300 ppmv for those units that had a previous BACT limit, the Department imposed a stationary source wide limit of 105 ppmv (for CCP and CGF) to comply with ambient standards and increments in the vicinity of CGF and CCP. That made the project a major modification based on the actual-to-future actual test. However, after careful examination of the exclusion allowed for alternative fuels under 40 CFR 51.166(b)(2)(iii)(e) that can be accommodated, the Department has concluded that BACT is not required for the CCP units.

The Department brought in the past Title 1 conditions because there are no Title 1 permits for CCP and CGF. In 2003 when the operating and construction permits were combined, Alaska's operating permit program would have required these conditions to be carried forward into all future Title V permits. When the program was replaced with a federal-style program in 2004 at industry's request, this was no longer the case. Therefore, the Department took the opportunity in this permit action to include the past Title 1 conditions, so that all the Title 1 conditions are in one place and serve as a base for the Title 1 conditions for past permit actions. Bringing Title 1 conditions to these permits was the most efficient way to do it. The Department could split the two permits as requested in BPXA's comment 2) but it

[6] *See footnote 5*

would take even more time to accomplish that. Therefore, the Department decided to leave the permit as it is.

When bringing in the old Title 1 conditions, the Department found a material mistake in O/C Permit 166TVP01. A 150 ppmv NO_X BACT limit for Unit 2 at CCP established in Permit 9836-AA006 was with an ORL of 90 ppmv in Permit 0073-AA006 in 2000. While the ORL is more stringent than the BACT limit, a BACT limit cannot go away, it can only be replaced with another BACT limit. Therefore, it was a material mistake that the Department corrected in this construction permit. The Department agrees with AOGA that proper procedures must be followed to correct material mistakes. The Department has met the obligation under AS 46.14.280, by way of the 30 day public notice.

Additional changes made by the Department to Permit AQ0270CPT04

The Department made an error in the preliminary permit to state that the Permittee may operate CGF under permit (AQ0270CPT04) upon issuance. The Department based it on the exemption in 40 CFR 71.6(a)(13)(i) that allows the permittee to make Section 502(b)(10) changes without a permit revision for changes that are not a rate of emissions or total emissions. The Department realizes that exemption is only for changes that are not Title 1 modifications. Lacking EPA guidance to what is meant by Title 1 modifications; the department considers Title 1 modifications to be PSD major modifications, and modification under NSPS or under CAA Section 112. Therefore, the change to the H_2S BACT limit being a PSD modification, BPXA cannot operate without a Title V revision.