Alaska Department of Environmental Conservation
Air Permits Program

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BP Exploration (Alaska) Inc.
Central Gas Facility

STATEMENT OF BASIS
of the terms and conditions for
Permit No. AQ0270TVP02

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INTRODUCTION

This document sets forth the statement of basis for the terms and conditions of Operating Permit No. AQ0270TVP02.

STATIONARY SOURCE IDENTIFICATION

ADEC has determined the Central Gas Facility (CGF) and the Central Compressor Plant (CCP) to be a single stationary source (the Gas Plant) for purpose of Title I and Title V permitting for the following reasons:

1) Physical proximity - the two facilities are located ¼ of a mile from each other.
2) Common sense notion of a plant - these two facilities constitute the gas handling plant. The raw material (low pressure high molecular weight gas) is delivered to CGF from the hubs for removal of miscible injectant/natural gas liquids and pressurization (to intermediate pressure) for distribution, the vast majority of which is delivered to the Central Compressor Plant for additional pressurization. This final product (high pressure low molecular weight gas) is then distributed to injection wells nearby CCP for ultimate disposal/storage underground.
3) These two facilities were originally permitted as a single stationary source but ADEC disaggregated the two sites for air permitting purposes during the late 1980s.

The stationary source is owned and operated by BP Exploration (Alaska) Inc. (BPXA), and BP Exploration (Alaska) Inc. is the Permittee for the stationary source's operating permit. The SIC code for this stationary source is 1311 - Crude Petroleum and Natural Gas Production. The NAICS code is stationary source is 211111.

In consultation with the applicant, ADEC issued separate Air Quality operating permits to CGF and to CCP.

Section 1 of Operating Permit No. AQ0270TVP02 contains information on CGF as provided in the Title V permit application.

BPXA's Central Gas Facility is an existing gas processing site that consists of four GE Frame 6 natural gas-fired combustion turbines, four Cooper-Rolls natural gas-fired combustion turbines, three GE Frame 5 natural gas-fired combustion turbines, three Chiyoda-John Zink natural gas-fired heaters, three GM diesel-fired emergency generators, one Caterpillar diesel fired emergency firewater pump, five IHI-John Zink natural gas-fired flares, several hydrocarbon storage tanks, and a natural gas processing plant.

The U.S. EPA originally permitted Central Gas Facility (CGF) on January 10, 1984 under the Prudhoe Bay Unit (PBU) federal prevention of significant deterioration permitting action known as SWAP IV as an administrative change to Prevention of Significant Deterioration (PSD) permits for other existing stationary sources at PBU. The purpose of SWAP IV was to authorize additional heater and turbine capacity at the location where the CGF was later constructed by using units already permitted but not constructed at other stationary sources. ADEC reviewed modifications at CGF under PSD review in 1992 and again 1998. Major modifications were completed at the stationary source in 1992 in association with the Gas Handling Expansion

(GHX) II project (Permit No. 9273-AA016), and in 1998, for the Miscible Injectant Expansion (MIX) project (Permit No. 9873-AC006).

CGF is designed to improve the overall field gas off-take by recovering natural gas liquids (NGL) and miscible injectant (MI) from the gas and then (together with the Central Compressor Plant [CCP]) compress and return the remaining residue gas into the gas cap of the Prudhoe Bay reservoir. The NGL and MI products are captured from the feed gas stream using a refrigeration/condensation process. Up to 100,000 barrels per day (bbls/day) of NGL can be produced with approximately 30,000 bbls/day shipped to the Kuparuk oil field for MI injection. The remaining NGL production is blended with crude oil and sent to Alyeska Pipeline Service Company Pump Station 1 as sales oil. Approximately 600 million standard cubic feet per day (MMscfd) of MI product is produced for use in the Prudhoe Bay oil field. When compressed and re-injected into the oil bearing formation, MI lowers the viscosity of the crude oil, allowing it to flow to the well bore more easily. The overall effect is a significant increase in recoverable oil.

The fuel gas used in all fuel gas-fired equipment at CGF is lean natural gas after separation from NGL and MI at the CGF. No alternate fuel gas is used at this stationary source.

Inlet Separation

The purpose of the Inlet Separators is to protect downstream equipment at CGF from entrained liquid hydrocarbon/triethylene glycol (TEG) carryover from the Flow Stations in the Prudhoe Bay Eastern Operating Area (EOA) and Gathering Centers in the Western Operating Area (WOA). Raw gas from the Flow Stations and Gathering Centers (called residue gas at these stationary sources) is piped to both CCP and CGF. The two CCP Inlet Separators remove entrained liquid in the gas going to CCP. A single CGF Inlet Separator removes entrained liquid in the gas going to CGF.

Feed gas leaving the CCP separators is routed to CGF and recombines with gas leaving the CGF separator. The combined gas is then routed to the Low Temperature Separators (LTS) 1, 2 and 3 via the booster compressors. The entrained liquid, a mixture of TEG and hydrocarbons, segregates into two streams in the CGF Inlet Separator. The recovered hydrocarbon is routed to the Stabilizer, and the TEG is collected in a recovery drum and then trucked out for recycle use by the Flow Stations and Gathering Centers.

Booster Compressors

The purpose of booster compressors is to increase the pressure of feed gas entering LTS-l, 2 and 3 from approximately 540 psig to approximately 660 psig. There are two principal benefits to this pressure increase: to deliver a higher pressure to CCP and to raise the pressure for the LTS, thereby offsetting the pressure losses in these units. Higher pressure also makes it easier to condense a gas into a liquid. Each pair of booster compressors, which feed LTS-l and 2, operates on a single shaft driven by a RB-2ll Rolls Royce gas turbine (EU ID(s) 5 and 6). The booster compressor, which feeds LTS-3, operates on a single shaft driven by a GE Frame 5 gas turbine (EU ID 11). LTS-l and 2 can operate with one or more compressors off-line, albeit with lower efficiency.

LTS-1 and 2

The purpose of the LTS system is to separate NGL and MI liquids from lighter non-condensable (mainly methane) components of the hydrocarbon feed gas. Booster discharge gas is cooled to approximately -10°F in a series of exchangers and a reboiler before the gas enters LTS-l and 2.

The -10°F combined stream is further cooled to -40°F as it exchanges heat with propane refrigerant in the chiller before entering the LTS units.

To maximize the amount of liquids condensed from feed gas, the propane refrigeration unit and chillers are operated to maintain LTS feed inlet temperatures as low as possible. That temperature is limited by the horsepower/maximum operating speed of the Refrigeration Compressors, which compress propane vapor. During summer months, reduced cooling of the refrigeration fin-fan condensers limits the capacity of the system.

Within the separators, the exchange of pumped bottoms with incoming feed provides heat for LTS distillation. Distillation is important to control methane in liquids sent to the stabilizers. The mainly methane LTS overhead vapor (now called residue gas), after exchanging heat with the incoming feed, is routed to CCP for further compression and ultimate re-injection into the gas cap with residual gas used for North Slope fuels in-field, at neighboring fields, for Deadhorse, and TAPs. Liquid from the LTS bottom, after exchanging heat with the incoming feed, is routed to the Stabilizer at 380 psig and 60°F for further processing.

LTS-3

LTS-3 performs the same function as LTS-l and 2 but is a later (1994 versus 1987), more thermally efficient design. When all three LTS trains are in service, LTS-3 is fed directly from the Inlet Separator. Booster discharge gas is cooled to approximately -40°F as it exchanges with propane refrigerant in two parallel chillers before entering LTS-3.

Four tandem compressors (powered by four General Electric Frame 6 gas turbines (EU ID(s)1 through 4)) take suction on the mainly methane LTS-3 overhead vapors. From there, compressed gas is returned to the gas cap. LTS bottom liquid, after exchanging with the incoming feed, is normally split equally between feed lines to the two Stabilizers where it is further processed.

Stabilization

The purpose of the Stabilization section is to separate lighter MI (methane/ethane/propane/CO_2) components from heavier NGL (butane and heavier) products. This process also produces a stable NGL product suitable for blending with crude oil that goes to the Trans-Alaska Pipeline System (TAPS).

NGL production is controlled to meet the maximum vapor pressure limit (14.7 psia @ 110°F) for the Crude/NGL blend arriving at Pump Station 1. Overhead vapors from the Stabilizer are partially condensed in fin-fan condensers, and condensate collected in the Overhead Drum is pumped back to the column as reflux to control the top tray temperature. Vapors (the noncondensed portion) from the Overhead Drum are fed to the MI Compressors.

MI Compressors

The purpose of MI compressors is to raise the pressure of vapors from the Stabilizer Overhead Drum for injection into dedicated wells in EOA and WOA for enhanced oil recovery (EOR). The two identical, parallel MI compressor trains each consist of a RB-211 Rolls Royce gas turbine (EU ID(s)7 and 8). The 330 psig supply from the Stabilizer Overhead Drum is increased in two stages: to 1800 psig in the first stage and then to nominal 4000 psig in the second stage MI Compressor. The nominal flow capacity of each MI compressor train is 225 MMscfd, or 450 MMscfd for both. Maximum MI production is between 600 to 650 MMscfd, depending on gas feed rate, ambient temperature, and other process parameters.

Refrigeration

The purpose of the Refrigeration System is to provide a cooling medium for the four LTS feed chillers. Raw gas feed to the LTS on the tube side of the chiller is cooled from minus-10°F to nominal minus-40°F by flashing liquid propane of 99.9% purity. Approximately 2,850 bbls of propane are contained in the closed loop system.

Refrigeration is a closed loop system consisting of two General Electric Frame 5 gas turbines (EU ID(s) 9 and 10) driving parallel three-stage compressors. There are four fin-fan condenser skids that are common to both compressors.

Heaters and Hot Oil System

Therminol (3,600 bbls) is heated and circulated as the Hot Oil medium for process and utility heating needs throughout CGF. Temperature of the hot oil system is controlled at 525°F by firing three 216 MMBtu/hr gas-fired heaters (EU ID(s) 12 through 14).

Emergency Systems and Operations

There are a number of emergency systems employed at CGF. Three diesel-driven emergency generators (EU ID(s)15 through 18) and battery banks with inverters provide emergency electrical power should primary electrical service be lost. The emergency power is typically used to drive process safety and life support systems. A diesel-driven emergency fire water pump provides back-up fire water supply in the event electrical power is lost to the primary electrically-driven fire water pump.

An emergency air-assist flare system safely disposes of hydrocarbon gases vented from process equipment during process upsets (unavoidable emergencies or malfunctions), process equipment startups or shutdowns, or de-pressurization for non-routine repair purposes. The flares are operated and maintained consistent with good engineering practice.

Enclosed modules, which house process equipment operated at CGF, are equipped with fire suppression systems. In the event of a fire, Halon 1301 fire suppressant is automatically released to inhibit the chemical reaction of combustion and extinguish the flames.

EMISSION UNIT INVENTORY AND DESCRIPTION

Under 18 AAC 50.326(a), the Department requires operating permit applications to include identification of all emissions-related information, as described under 40 C.F.R. 71.5(c)(3).

The emission units at the Central Gas Facility that have specific monitoring, recordkeeping, and reporting requirements are listed in Table A of Operating Permit No. AQ0270TVP02.

There have been no revisions to the emission units since the issuance of Permit No. AQ0270TVP01. Table A of Operating Permit No. AQ0270TVP02 contains information on the emission units regulated by this permit as provided in the application. The table is provided for informational and identification purposes only. Specifically, the emission unit rating/size provided in the table is not intended to create an enforceable limit.

EMISSIONS

A summary of the potential to emit (PTE)[1] and assessable PTE as calculated by the Department for the Central Gas Facility is shown in the table below.

Table H - Emissions Summary, in Tons Per Year (TPY)

Pollutant	NO_X	CO	PM-10	SO_2	VOC	CO_2e	HAPs	Total
PTE	10,968	1,787	305	276	90	2,684,802	59	13,426
Assessable PTE	10,968	1,787	305	276	90	0	59	13,426

The assessable PTE listed under Condition 64.1 is the sum of the emissions of each individual regulated air pollutant other than CO_2e and HAPs for which the stationary source has the potential to emit quantities greater than 10 TPY. HAP emissions are almost all VOCs, therefore, to avoid double counting HAP emissions are not included in the "Total" column. The emissions listed in Table H are estimates that are for informational use. The listing of the emissions does not create an enforceable limit to the stationary source.

Potential criteria pollutant emissions were based on emission calculations included in Construction Permit No. AQ0270CPT04, issued October 13, 2009. Turbine (EU ID(s) 1 through 11) PTE values for NO_X, CO and PM_{10} are set by BACT and Owner Requested Limits stated in Preconstruction and Construction Permit listed in Section 3 of this permit.

For Greenhouse Gas (GHG) emissions calculations were submitted by the Permittee on August 22, 2011. PTE for carbon dioxide equivalent (CO_2e) was estimated based on emission factors found in 40 C.F.R. 98, Subpart C, Tables C-1 and C-2.

HAP emissions were estimated in the permit renewal application. AP-42 emission factors were used to estimate HAP emissions for the turbines (EU ID(s) 1 through 11) and internal combustion engines (EU ID(s) 16 through 18), and a combination of AP-42 and field data from GRI-HAPCalc® Version 3.0 were used to estimate HAP emissions for the heaters (EU ID(s) 12 through 14). Flare (EU ID(s) 19 through 23) HAP emissions were estimated using emission factors provided by the Ventura County Air Pollution Control District (VCAPCD). Total aggregate HAP emissions are estimated at 58.7 TPY with a maximum single HAP (formaldehyde) emission rate of 14.8 TPY. Based on these findings, CGF is major for HAPs since the calculated HAP emissions are greater than the triggers of 10/25 TPY.

[1] *Potential to Emit* or *PTE* means the maximum capacity of a stationary source to emit a pollutant under its physical or operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is Federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source, as defined in AS 46.14.990(23).

BASIS FOR REQUIRING AN OPERATING PERMIT

In accordance with AQ 46.14.130(b), an owner or operator of a Title V source[2] must obtain a Title V permit consistent with 40 C.F.R. Part 71, as adopted by reference in 18 AAC 50.040.

Except for sources exempted or deferred by AS 46.14.120(e) or (f), AS 46.14.130(b) lists three categories of sources that require an operating permit:

(1) A major source;

(2) A stationary source subject to federal new source performance standards or national emission standards;

(3) Another stationary source designated by the federal administrator by regulation.

This stationary source requires an operating permit because it is classified under 18 AAC 50.326(a) and 40 C.F.R. 71.3(a) and EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases* as:

- A major stationary source of air pollutants, as defined in Section 302 of the Act, that directly emits or has the potential to emit 100 TPY or more of any air pollutant;
- A major stationary source of hazardous air pollutants, as defined in Section 112 of the Act, that emits or has the potential to emit 10 TPY of any hazardous air pollutant, or 25 TPY or more of any combination of hazardous air pollutants, and
- An existing source, that emits or has a PTE equal to or greater than 100,000 TPY of CO_2e **and** 100 TPY GHGs on a mass basis.

AIR QUALITY PERMITS

Previous Air Quality Permit to Operate

The most recent permit issued for CGF is permit-to-operate number 9273-AA016, as amended through December 23, 1996. This permit-to-operate included all State construction authorizations issued through December 23, 1996, and was issued before January 18, 1997 (the effective date of the separated Title I/Title V permitting programs). In addition, EPA Prevention of Significant Deterioration (PSD) permit number PSD-X81-13, as amended through August 29, 1997, contains specific BACT requirements for CGF. All stationary source-specific requirements established in these permits applicable to CGF are included in the new operating permit.

Title I (Construction and Minor) Permits

The Department issued Construction Permit No. 9873-AC006 to this stationary source on July 15, 1998 authorizing a PSD significant modification to CGF. The stationary source-specific requirements established in this construction permit were included in the operating permit AQ0270TVP01.

[2] "Title V source" means a stationary source classified as needing a permit under AS 14.130(b) *[ref. 18 AAC 50.990(111)]*.

Construction Permit No. AQ0270CPT04 was issued to the stationary source on October 13, 2009. In Construction Permit AQ0270CPT04 for CGF, the Department increased 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 also established 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 respectively, along with stack restrictions on select emission units at CGF, to protect the SO_2 ambient air quality standards and increments. An increase in allowable SO_2 emissions due to these permit actions by ADEC raised the SO_2 BACT limit originally established by EPA in one of the four EPA permits issued (PSD IV).

Title V Operating Permit Application, Revisions and Renewal History

The owner or operator submitted an initial application on December 5, 1997. The owner or operator amended this application on six separate occasions, the last being March 24, 2003.

The Department issued Operating Permit AQ0270TVP01 effective on August 4, 2003.

The permit was reopened February 11, 2004 to correct material mistakes. The permit was reopened because it was determined that using either standard or infrared video cameras did not meet the flare as an NSPS control device requirements of 40 C.F.R. 60.18(f)(2). However, per correspondence from EPA Region X to BPXA dated September 1, 2005, EPA has determined that these monitoring techniques have been accepted as being equivalent to using a thermocouple to comply with 40 C.F.R. 60 Subpart A. In addition, the permit was also reopened to include the applicable requirements of 40 C.F.R. 63 Subpart HH. However, per correspondence dated October 7, 2003 from EPA Region X to BPXA and follow-up correspondence from BPXA to EPA Region X dated August 20, 2004, the BPXA CGF is not subject to Subpart HH per 40 C.F.R. 63.760(d).

The Permittee requested a minor operating permit modification on June 7, 2006. The Department did not process that application.

The Permittee requested an administrative operating permit amendment application to update the Title I provisions of AQ0270CPT04 as currently applicable requirements for CGF. ADEC amended the operating permit on October 20, 2009.

The owner or operator submitted a permit renewal application on March 3, 2008.

The Department received additional information on May 30, 2008. This information consisted of a spreadsheet of the PTE calculations for all regulated pollutants and documentation of VOC emissions from hydrocarbon storage tanks using TANKS v4.09d.

The Department received additional information on NESHAP Subpart ZZZZ on March 15, 2011. The applicant submitted additional information on November 12, 2012 including updated applicability determinations and GHG emissions information. Finally, the applicant submitted further additional information on NESHAPS Subpart DDDDD on July 11, 2013.

COMPLIANCE HISTORY

CGF has operated at its current location since 1986. Review of the permit files for CGF, which includes the past inspection reports, indicates a activities generally operating in compliance with the operating permit. However, in the annual compliance certification for 2007, the stationary source certified that the CGF was not in compliance with the requirements that limit the actual SO_2 emissions from the turbines, EU ID(s) 1 through 11. The Permittee applied for and, in 2009, obtained Construction Permit No. AQ0270CPT04 which revised sulfur emission limits, and the stationary source is currently in compliance with fuel sulfur requirements. CGF also has intermittent excess flare visible emissions. There are presently no remedial measures proposed to rectify this issue.

APPLICABLE REQUIREMENTS FROM PRE-CONSTRUCTION PERMITS

Incorporated by reference at 18 AAC 50.326(j), 40 C.F.R. Part 71.2 defines “applicable requirement” to include the terms and conditions of any pre-construction permit issued under rules approved in Alaska’s State Implementation Plan (SIP).

Alaska’s SIP includes the following types of pre-construction permits:

- Permit-to-operate issued before January 18, 1997 (these permits cover both construction and operations);
- Construction Permits issued after January 17, 1997; and
- Minor permits issued after October 1, 2004.

Pre-construction permit terms and conditions include both source-specific conditions and conditions derived from applicable regulatory requirements such as standard conditions, generally applicable conditions and conditions that quote or paraphrase requirements in regulation.

These requirements include, but are not limited to, each source-specific requirement established in these permits issued under 18 AAC 50 that are still in effect at the time of this operating permit issuance. Table I below lists the requirements carried over from Operating Permit No. AQ0270TVP01 into Operating Permit No. AQ0270TVP02 to ensure compliance with the applicable requirements.

Table I - Comparison of Operating Permit AQ0270TVP01 Conditions to Operating Permit No. AQ0270TVP02 Conditions[3]

Permit No. AQ0270TVP01 Condition No.	Description of Requirement	Permit No. AQ0270TVP02 Condition No.	How Condition was Revised
3a and 3c	Visible emissions … "more than three minutes in any one hour"	None	EPA approved changes to the SIP limits, effective 9/17/07
3d	Visible emissions not to exceed more than 20% averaged over any six consecutive minutes	None	Condition carried forward from Federal Prudhoe Bay Unit PSD Permit No. PSD-X81-13 more stringent
3e, 6, 7, 8, 9, 10, 11, 12, 13 and 14		1.1 through 20	Limits from Construction Permit No. 9873-AC006, Permit to Operate No. 9273-AA016, Federal Prudhoe Bay Unit PSD Permit No. PSD-X81-13, as revised according to AQ0270CPT04
15, 18, 20, 22, 36 and 37.3d	40 C.F.R. 60 Subparts A and KKK Requirements for flares used as control devices	22, 27, 28, 31, 41, and 42.3.d	Requirements for EU 23 removed; EPA has determined that EU ID 23 is not a control device for EU ID 26
23	40 C.F.R. 60 Subpart Kb Requirements for Tanks 19-1902 and 19-1905	None	Tanks previously only subject to recordkeeping requirements are no longer subject, effective 10/15/03
39.1a	First Method 9 observation within six months after the effective date of the permit	None	Requirement removed; initial Method 9 observations were conducted within six months of initial permit term
43	Report exhaust stack diameter of EU ID(s)15 through 18	None	Requirement removed; completed during initial permit term
53	Compliance plan for flare exit velocity determination	None	Removed; Waiver from EPA Region X (8/22/05)
54	Compliance plan for flare pilot monitoring	None	Removed; IR/UV monitoring techniques accepted as equivalent monitoring (ref. EPA Region X letter, 9/1/05)
55	Compliance plan for 40 C.F.R. 63 Subpart HH	None	Removed; Stationary source not subject (ref. BPXA letter, 8/20/04, and EPA Region X letter, 10/7/03)

[3] This table does not include all standard and general conditions.

NON-APPLICABLE REQUIREMENTS

Each permit is required to contain a discussion of all applicable requirements as set forth in 40 C.F.R. 71.6(a) adopted in 18 AAC 50.040(j). This section discusses selected conditions that are not included in the permit for specific reasons.

- **Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution (40 C.F.R. 60 Subpart OOOO):** There have been no affected sources constructed, reconstructed or modified at the CGF after August 23,2011, which is the applicable date of this rule per 40 CFR 60.5365.
- **National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities (40 C.F.R. 63 Subpart HH)**: The stationary source is not a crude oil processing and production facility that exclusively processes, stores, or transfer crude oil produced from the Prudhoe Pool.
- **Compliance Assurance Monitoring (40 C.F.R. 64):** The stationary source does not use a control device to achieve compliance with any emission limitation or standard and is therefore not subject to Compliance Assurance Monitoring as it does not satisfy the criteria of 40 C.F.R. 64.2(a)(2).

STATEMENT OF BASIS FOR THE PERMIT CONDITIONS

The State and Federal regulations for each condition are cited in Operating Permit No. AQ0270TVP02. This Statement of Basis provides the legal and factual basis for each term and condition as set forth in 40 C.F.R. 71.6(a)(1)(i).

Conditions 1 - 5: Visible Emissions Standard and MR&R

Legal Basis: These conditions ensure compliance with the applicable requirements in 18 AAC 50.055(a).

- 18 AAC 50.055(a) applies to the operation of fuel-burning equipment and industrial processes. EU ID(s) 1 through 23 are fuel burning equipment or industrial processes.

U.S. EPA incorporated these standards as revised in 2002 into the SIP effective September 13, 2007.

EU ID(s) 5 through 10 are subject to BACT opacity limits contained in the revised EPA PSD IV Permit No. PSD-X81-13 (1997) for the Prudhoe Bay Unit, contained in Condition 1.1.

Factual Basis: Condition 1 prohibits the Permittee from causing or allowing visible emissions in excess of the applicable standard in 18 AAC 50.055(a)(1).

MR&R requirements are listed in Conditions 2 through 5 of the permit.

Except as modified in Condition 1, these conditions have been adopted into regulation as Standard Conditions.

The Permittee must establish by actual visual observations that can be supplemented by other means, such as a defined Stationary Source Operation and Maintenance Program that the stationary source is in continuous compliance with the State's emission standards for visible emissions and particulate matter.

These conditions detail a stepwise process for monitoring compliance with the State's visible emissions for liquid and gas fired emission units. Equipment types covered by these conditions are internal combustion engines, turbines, heaters, boilers, and flares. Initial monitoring frequency schedules are established along with subsequent reductions or increases in frequency depending on the results of the self-monitoring program.

Reasonable action thresholds are established in these conditions that require the Permittee to progressively address potential visible emission problems from emission units either through maintenance programs and/or more rigorous tests that will quantify whether a specific emission standard has been exceeded.

Condition 5 was developed to provide a standardized version of flare monitoring that is not dependent upon the type or design of upstream equipment. It has been claimed that gas-fired flares normally burn without emitting visible emissions, but actual field data demonstrating this assumption is not available. However, gas-fired flares have been shown to smoke when a control device, i.e. a knockout drum, flare scrubber, gas or steam assist, or vapor recovery system malfunctions. Thus, the condition sets out a protocol to collect actual field data to determine compliance with the 20 percent opacity standard for flares.

Gas-Fired Fuel Burning Equipment:

Monitoring – The monitoring of gas-fired emission units for visible emission compliance with the 20% standard is waived, i.e. no source testing will be required. The Department has found that natural gas-fired equipment inherently has low visible emissions. However, the Department can request a source test for visible emissions from any smoking equipment.

Reporting – The Permittee must state in each operating report whether only gaseous fuels were used in the equipment during the period covered by the report.

Liquid Fuel-Fired Burning Equipment:

For the emergency liquid fuel-fired engines, EU ID(s) 15 through 18, as long as none of these emission units exceed 400 hours of operation per consecutive 12-month period, no monitoring is required. The Permittee shall monitor the hours of operation of these emission units. If any of these emission units exceed 400 hours of operation, that emission unit is subject to the visible emissions MR&R requirements described in Conditions 2 through 4.

Monitoring – The Permittee is required to conduct visible emissions observations according to Condition 2, if threshold values for annual hours of operation on liquid fuels are exceeded. Corrective actions such as maintenance procedures and either more frequent or less frequent testing may be required depending on the results of the observations.

Recordkeeping - The Permittee is required to record the visible emission observations.

Reporting - The Permittee is required to report incidents when emissions in excess of the opacity threshold values have been observed. The Permittee is required to include copies of the results of all visible emission observations with the operating report.

Flares:

Monitoring for flares (EU ID(s) 19 through 23) requires Method-9 observations of six scheduled flaring events lasting approximately one hour during the permit term. The Permittee must report the results of these observations to the Department.

Conditions 6 through 8, Particulate Matter (PM) Standard

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.055(b). This requirement applies to operation of all industrial processes and fuel burning equipment in Alaska.

- EU ID(s) 1 through 23 are fuel-burning equipment.

These PM standards also apply because they are contained in the Federally approved SIP effective September 13, 2007.

Factual Basis: Condition 6 prohibits emissions in excess of the state PM (also called grain loading) standard applicable to fuel-burning equipment and industrial processes. The Permittee shall not cause or allow fuel-burning equipment nor industrial processes to violate this standard.

MR&R requirements are listed in Condition 7 of the permit.

The Permittee must establish by actual visual observations which can be supplemented by other means, such as a defined Operation and Maintenance Program that the emission unit is in continuous compliance with the State's emission standards for particulate matter.

Gas-Fired Fuel Burning Equipment:

Monitoring – The monitoring of gas-fired emission units for particulate matter is waived, i.e. no source testing will be required. The Department has found that natural gas-fired equipment inherently has negligible PM emissions. However, the Department can request a source test for PM emissions from any smoking equipment.

Reporting – The Permittee must state in each operating report whether only gaseous fuels were used in the equipment during the period covered by the report.

Liquid Fuel-Fired Burning Equipment:

For the emergency liquid fuel-fired engines, EU ID(s) 15 through 18, as long as none of these emission units exceeds 400 hours of operation per consecutive 12-month period, no monitoring is required. The Permittee shall monitor the hours of operation of these emission units. If any of these emission units exceed 400 hours of operation, that emission unit is subject to the particulate matter MR&R requirements described in Conditions 7 and 8.

Monitoring – The Permittee is required to conduct PM source testing if threshold values for opacity are exceeded.

Recordkeeping - The Permittee is required to record the results of PM source tests.

Reporting - The Permittee is required to report: 1) incidents when emissions in excess of the opacity threshold values have been observed, 2) and results of PM source tests. The Permittee is required to include copies of the results of all visible emission observations with the operating report.

Flares:

Monitoring of gas-fired flares for particulate matter is waived, i.e. no source testing will be required, because of the difficulty and questionable results these tests produce when applied to flares. The Department has recognized this fact by incorporating the waiver in the State Implementation Plan adopted in November 1984, which has not been Federally approved. No recordkeeping or reporting is required.

Condition 9, Sulfur Compound Emissions

Legal Basis: This condition requires the Permittee to comply with the sulfur compound emission standard for all fuel-burning equipment and industrial processes in the State of Alaska.

- EU ID(s) 1 through 23 are fuel-burning equipment and industrial processes.

These sulfur compound standards also apply because they are contained in the Federally approved SIP effective September 13, 2007.

Factual Basis: The condition requires the Permittee to comply with the sulfur compound emission standard applicable to fuel-burning equipment. The Permittee may not cause or allow the affected equipment to violate this standard.

Sulfur dioxide comes from the sulfur in the fuel (e.g. coal, natural gas, fuel oils).

Liquid Fuels:

For oil fired fuel burning equipment, the MR&R conditions are Standard Permit Conditions XI and XII adopted into regulation pursuant to AS 46.14.010(e). The Department has previously determined that the standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard conditions as modified meets the requirements of 40 C.F.R. 71.6(a)(3).

Gaseous Fuels:

Fuel gas sulfur is measured as hydrogen sulfide (H_2S) concentration in ppm by volume (ppmv). Calculations[4] show that fuel gas containing no more than 4000 ppm H_2S will comply with this emission standard at stoichiometric or excess air combustion conditions. This is true for all fuel gases.

The Permittee will be required to sample the natural gas for hydrogen sulfide and sulfur content. This condition cross-references gas H_2S sampling and reporting of Condition 16, and also requires period fuel sulfur testing with a provision that reduces gas sulfur sampling frequency if the gas contains 20 grain of total sulfur /100 standard cubic feet.

Equations to calculate the exhaust gas SO_2 concentrations resulting from the combustion of fuel gas were not included in this permit. Fuel gas with an H_2S concentration of even 10 percent of 4000 ppm is currently not available on the North Slope and is not projected to be available during the life of this permit. The Permittee is required to record the fuel gas H_2S concentration of the fuel gas. The Permittee is required to report as State excess emissions whenever the fuel combusted causes sulfur compound emissions to exceed the standards in this condition. The Permittee is required to include copies of the records mentioned in the previous paragraph with the stationary source operating report.

Conditions 1.1 and 10 through 20, Pre-Construction and Construction Permit Requirements

Legal Basis: The Permittee is required to comply with all effective stationary source-specific requirements that were carried forward from previous EPA PSD permits, SIP approved permits to operate issued before January 18, 1997, SIP approved construction permit(s), SIP approved minor permits, operating permits issued between January 18, 1997 and September 30, 2004, or owner requested limits established under 18 AAC 50.225. These requirements include Best Available Control Technology limits, limits to ensure compliance with the attainment or maintenance of ambient air quality standards or maximum allowable ambient concentrations, and owner requested limits. State pre-construction requirements apply because they were originally developed through case-by-case action under a Federally approved SIP or approved Operating Permit program. EPA approved the latest SIP effective September 13, 2007.

These conditions apply because these are BACT, operating permit, and construction permit limits that were carried forward from previous PSD permits for the GHX II project (Permit

[4] See ADEC Air Permits Web Site at http://www.dec.state.ak.us/air/ap/docs/sulfgas.pdf, under "*Stoichiometric Mass Balance Calculations of Exhaust Gas SO2 Concentration*."

No. 9273-AA016), followed by the MIX project (Permit No. 9873-AC006), and construction permit No AQ0270CPT04.

Factual Basis: These conditions contain BACT-derived limits from a previous PSD permit and revised through subsequent construction permits. The Permittee shall not cause or allow the equipment to violate these standards.

Between 1979 and 1981, EPA Region 10 issued four PSD permits for Prudhoe Bay stationary sources. On August 29, 1997 EPA issued revisions to the four PSD permits. The primary revisions include identification of specific equipment and tag numbers, apportionment of either field-wide or stationary source-wide ton per year limits to unit specific limits, and updating emission limits based solely on AP-42 factors to values in the edition of AP-42 that were current in 1997.

As part of the EPA process, the previous owner and operator demonstrated to Region 10 that on a ton per year basis an overall decrease in allowable emissions would occur under the permit revision.

The EPA revisions established ton per year emission limitations for turbines that were incorporated into the initial Title V Operating Permit.

EPA imposed ton per year emission limits for EU ID(s) 5 through 8 (turbines) on NO_X, CO, PM, and SO_2 and for EU IDs 9 and 10 on NO_X, CO, and PM. For NO_X and CO, EPA also established short-term BACT emission limits in other terms (i.e. ppmv, lb/MMscf, or lb/MMBtu). The Permittee also requested short-term ppmv H_2S limit for EU ID(s) 5 through 8 based on the value (30 ppmv) used to calculate the ton per year BACT limit.

The short-term EPA NO_X BACT limits for EU ID(s) 9 through 10 were superseded by a more stringent BACT limit established by ADEC in the 1998 MIX PSD permit. Also, the Department superseded the Federal short-term ppmv H_2S limit through a BACT decision made in AQ0270CPT04.

For EU ID(s) 5 through 10, the Permittee is required to calculate and report emission levels for pollutants with applicable limits. Monitoring for compliance with the short-term turbine BACT emission limit for NO_X is identical to that for Subpart GG turbine NO_X emission testing except more frequent testing is triggered by test results exceeding a percentage of the BACT limits. Monitoring for compliance with the short-term CO emission rate limit is a maintenance protocol. Additionally, the Permittee is required to conduct a CO emission source test once every five years to demonstrate compliance with the short-term limits.

For EU ID(s) 12 through 14 (heaters), EPA imposed ton per year emission limits for NO_X, CO, PM, and SO_2. EPA also established short-term BACT NO_X and CO emission limits of 0.08 and 0.061 lb/MMBtu, respectively. The Permittee originally requested short-term ppmv H_2S limit for EU ID(s) 12 through 14 based on the value (30 ppmv) used to calculate the ton per year BACT limit. This limit was superseded by new an updated ppmv H_2S BACT limits issued in Permit No. AQ0270CPT04, issued after the applicant's original operating permit renewal application.

EU ID(s) 1 through 4 also have a short-term PM BACT limit established by ADEC in the GHX II permit (Permit No. 9273-AA016). The other short-term NO_X and CO BACT limits established in the GHX II permit for EU ID(s) 1through 4 and 9 through 11 were superseded by new BACT limits set by the CGF MIX permit (Permit No. 9873-AC006) and are not included in this renewal permit action.

EU ID(s) 1 through 4, and 9 through 11 also have NO_X, CO and SO_2 short-term emission rates (ppmvd, lb/hr and ppmv H_2S) BACT limits that were established by ADEC Permit No. 9873-AC006 as a result of the CGF MIX permit decision. Monitoring for compliance with the short-term NO_X and CO emission rate limits is periodic source testing for NO_X and CO, with a maintenance protocol called out for CO. As mentioned above, the Department's AQ0270CPT04 decision replaced the ppmv H_2S limit established in Permit 9873-AC006.

For EU ID 15 ADEC established short-term NO_X, CO, and PM BACT emission limits during review of the GHX II project. Condition 13 lists these limits and the monitoring for compliance with the short-term emission rate limit using a maintenance protocol for NO_X, CO, and PM. Additionally, the Permittee is required to conduct an emission source test for NO_X and CO no less than once every five years to demonstrate compliance with the short-term limits.

Condition 14 carries forward owner requested limits for emergency diesel equipment at CGF. In Permit No. 9273-AA016, the Department imposed an hour limit on EU IDs 15-18. For monitoring, record keeping and reporting, this permit requires use of dedicated hour meters and reporting the operating hours each month. From those records, the Permittee would then calculate the 12-month rolling operations for each unit.

Conditions 15 and 20 carry forward fuel consumption monitoring, record keeping and reporting provisions established in Permit No. 9273-AA016. Although there does not appear to be a fuel consumption limit and the hour limit is only on EU IDs 15-18, these records are part of the monitoring, record keeping and reporting basis to determine annual BACT emission limit compliance under Conditions 11 and 12.

Construction Permit No. AQ0270CPT04 requires fuel gas H_2S not to exceed 300 ppmv for EU ID 1-4 and 9 through 11as part of its BACT decision, and requires fuel gas H_2S not to exceed 105 ppmv for EU ID 1 through 14 and 19 through 23, as set out in Conditions 16 and 17 of this permit respectively. Monitoring, record keeping and reporting fuel gas properties are set out in Condition 16 and cross referenced in Condition 17. The Permittee is required to sample fuel gas no less than once a month.

Construction permit No. AQ0270CPT04 also restricts liquid fuel sulfur content to protect ambient air quality. Those limits are reiterated in Conditions 18 and 19 of this operating permit. Monitoring, record keeping and reporting fuel sulfur content cross references Condition 9.8. In addition, the conditional provision in Condition 19 set out stack configurations for EU ID 15 through 17. That condition provides for the monitoring, record keeping and reporting of their stack configurations.

Condition 21, Insignificant Emission Units

Legal Basis: The Permittee is required to meet state emission standards set out in 18 AAC 50.055 for all industrial processes fuel-burning equipment, and incinerators regardless of size.

Factual Basis: The condition re-iterates the emission standards and requires compliance for insignificant emission units. The Permittee may not cause or allow their equipment to violate these standards. Insignificant emission units are not listed in the permit unless specific monitoring, recordkeeping and reporting are necessary to ensure compliance.

Conditions 22 – 31, NSPS Subpart A Requirements

Legal Basis: The Permittee must comply with those New Source Performance Standard (NSPS) provisions incorporated by reference the NSPS effective July 1, 2007, for specific industrial activities, as listed in 18 AAC 50.040[5].

Most affected facilities (with the exception of some storage tanks) subject to an NSPS are also subject to Subpart A. At this stationary source, EU ID(s)1 through 11 are subject to NSPS Subpart GG, EU ID(s)12 through 14 are subject to NSPS Subpart Db and EU ID 26 is subject to NSPS Subpart KKK and therefore subject to Subpart A. EU ID 19-22 serve as control devices for EU ID 26. As such, these flare systems are also subject to NSPS Subpart A provisions.

Conditions 22.1 through 22.3 - The Permittee has already complied with the notification requirements in 40 C.F.R. 60.7 (a)(1) - (4) for EU ID(s) 1 through 14 and 26. However, the Permittee will be still subject to these requirements in the event of a new NSPS affected facility or in the event of a modification or reconstruction of an existing facility into an affected facility. For example, a combustion turbine regulated as an affected facility under NSPS Subpart GG, is an existing facility under NSPS Subpart KKKK. As such, any of the existing turbines could be subject to the notification requirements if modified or reconstructed.

Conditions 22.4 through 22.6 - The requirements to notify the EPA and the Department of the date of a continuous monitoring system performance demonstration, no less than 30 days before demonstration commences (40 C.F.R. 60.7(a)(5) – (7)) are applicable to EU ID(s) 12 through 14.

Condition 22.7- The requirements to notify the EPA and the Department of any proposed replacement of components of an existing facility (40 C.F.R. 60.15) apply in the event that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

Condition 23 - Start-up, shutdown, or malfunction record maintenance requirements in 40 C.F.R. 60.7(b) are applicable to all NSPS affected facilities subject to Subpart A.

Conditions 24 and 25 - NSPS excess emission reporting requirements and summary report form in 40 C.F.R. 60.7(c) & (d) are applicable to EU ID(s)1 through 14. The Department has included in Attachment A of the statement of basis a copy of the Federal EEMSP summary report form for use by the Permittee.

Recordkeeping requirements in 40 C.F.R. 60.7(f) are applicable to all NSPS affected facilities. (Satisfied by Condition 83)

[5] EPA has not delegated to the Department the authority to administer the NSPS program as of the issue date of this permit

Condition 26 - The Permittee has already complied with the initial performance test requirements in 40 C.F.R. 60.8 for EU ID(s) 1 through 11. However, the Permittee is still subject to these requirements in the event of a new NSPS affected facility, in the event of a modification or reconstruction of an existing facility into an affected facility or at such other times as may be required by EPA.

Condition 27 - Good air pollution control practices in 40 C.F.R. 60.11 are applicable to all NSPS affected facilities subject to Subpart A (EU ID(s) 1 through 14, 19 through 22 and 26).

Condition 28 - States that any credible evidence may be used to demonstrate compliance or establishing violations of relevant NSPS standards for EU ID(s) 1 through 14, 19 through 22 and 26.

Condition 29 - Concealment of emissions prohibitions in 40 C.F. R. 60.12 are applicable to EU ID(s) 1 through 14, 19 through 22 and 26.

Condition 30 - Monitoring requirements in 40 C. F. R. 60.13 are applicable to EU ID(s) 12 through 14 because a CMS is used to determine compliance with Subpart Db emission standards.

Condition 31 – General control device requirements in 40 C.F.R. 60.18 apply to the flares, EU ID(s) 19 through 22, because they are used as control devices for EU ID 26, which is subject to Subpart KKK. EU ID 23, the NGL liquid burn pit, is not subject to 40 C.F.R. 60.18 because it is not a flare control device. (EPA Region X letter, 10/19/05, re: liquid burn pit). The Department added monitoring, record keeping and reporting to this condition for flared gas heat content and flow rate to ensure that each flare complies with the control equipment provisions.

Factual Basis: Subpart A contains the general requirements applicable to all affected facilities (emission units) subject to NSPS. In general, the intent of NSPS is to provide technology-based emission control standards for new, modified and reconstructed affected facilities.

Condition 32, NSPS Subpart Db Requirements

Legal Basis: Since the Permittee identified affected facilities at this stationary source, this condition requires the Permittee to comply with NSPS Subpart Db. The NSPS Subpart Db applies to steam generating units for which construction, modification, or reconstruction commenced after June 19, 1984 and have a heat input capacity of greater than 29 MW (100 MMBtu/hr). EU ID(s) 12 through 14 were constructed in 1986 and each have a heat input capacity of 216 MMBtu/hr; and are therefore subject to Subpart Db.

EU ID(s) 12 through 14 are subject to the sections of Subpart Db that apply to gas-fired heaters with a heat input capacity less than 250 MMBtu/hr, an annual capacity factor of greater than 10 percent, and a low heat release rate as defined by 40 C.F.R. 60.41b. In addition, the paragraphs of 40 C.F.R. 60.13 pertaining to calibration, maintenance, and operation of a continuous emissions monitoring system apply to the CEMS installed to monitor NO_X emissions from EU ID(s) 12 through 14.

As each heater is configured to burn only natural gas, the particulate matter and sulfur dioxide provisions of this subpart do not apply.

Factual Basis: The condition incorporates the Subpart Db emission standard for nitrogen oxides and the monitoring, recordkeeping, and reporting required to ensure compliance with the standard. The stationary source must install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides discharged to the atmosphere.

Conditions 33 - 34, NSPS Subpart GG Requirements

Legal Basis: These conditions prohibit the Permittee from exceeding emission standards set out in Subpart GG. NSPS Subpart GG applies to stationary gas turbines with a heat input at peak load (maximum load at 60 percent relative humidity, 59 ºF, and 14.7 psi) equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), but less than or equal to 107.2 gagajoules per hour based on the lower heating value of the fuel fired and constructed, modified, or reconstructed on or after October 3, 1982.

Factual Basis: These conditions incorporate NSPS Subpart GG NO_X emission and sulfur compound limits. The Permittee may not allow equipment to violate these standards.

NO_X Standard: For a turbine subject to 40 C.F.R. 60.332, the NO_X standard is determined by the following equation:

$$STD_{NOX} = 0.015(14.4/Y) + F$$

where,

STD_{NOx}	=	allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis)
Y	=	manufacturer's maximum rated heat input (kJ/W-hr), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the affected stationary source. The value of Y shall not exceed 14.4 kJ/W-hr
F	=	NO_X emissions allowance for fuel bound nitrogen, percent by volume, **assumed to be zero for distillate fuel**.

Based on the manufacturer's heat rating at manufacturer's rated peak load, and assuming fuel bound nitrogen of zero, the NO_X standard is 213 ppmv for EU ID(s) 5 through 8 and 176 ppmv for EU ID(s) 9 through 11.

The fuel gas nitrogen monitoring requirement of 40 C.F.R. 60.334(b) has been waived for these affected facilities per correspondence from EPA dated August 19, 1996. Therefore, fuel gas nitrogen monitoring is not required by this permit condition for NSPS Subpart GG.

SO_2 Standard: The Permittee is required to comply with one of the following sulfur requirements for EU ID(s) 1 through 11 (turbines):

(1) do not cause or allow SO_2 emission in excess of 0.015 percent by volume, at 15 percent O_2 and on a dry basis (150 ppmv), or

(2) do not cause or allow the sulfur content for the fuel burned in EU ID(s) 1 through 11 to exceed 0.8 percent by weight .

The Permittee has elected to comply with the fuel sulfur content limit.

Exemptions:

EU ID(s) 1 through four have a manufacturer’s rated base load that exceeds 107.2 gigajoules per hour and are not electric utility stationary gas turbines, and are therefore not subject to Subpart GG NOx standards in 40 C.F.R. 60.334(a)(2) .

Condition 33, NOX Monitoring, Recordkeeping, and Reporting

Legal Basis: Periodic monitoring is included in Condition 33.1 for all turbines that normally operate for greater than 400 hours in a 12 month period. This additional monitoring is necessary to demonstrate whether the turbine emissions comply with the NSPS NO_x standard and is required under 40 C.F.R. 71.6(a)(3) as this subpart does not contain MR&R sufficient for an operating permit.

Factual Basis: The Department does not have enough information to make categorical determinations that certain types of turbines, or turbines with emission test results below a certain percentage of the Subpart GG NO_x emission limit will inherently comply with the Subpart GG limit at all times and will never need additional testing. After a sufficient body of NO_x data is gathered under monitoring conditions for compliance with 40 C.F.R. 60, Subpart GG, the Department may find that it has enough information to make such categorical determinations. In that event, the Department would revise the NOx monitoring conditions. The Department may determine that to assure compliance it is necessary to retain or increase the current monitoring frequency.

This condition does not include the initial NSPS performance test requirements as the Subpart A conditions cover these requirements. If an turbine classified under this subpart as an affected facility is still subject to the initial performance test requirement of 40 C.F.R. 60.8, the requirement is covered under the Subpart A related conditions of this permit.

The intent of this condition is to routinely demonstrate that turbines or groups of turbines comply with the emission standard on no less than a 5-year cycle. If the most recent performance test on a turbine showed NOx emissions at less than or equal to 90 percent of the limit shown in Condition 33, then periodic monitoring is required at the first applicable of three criteria: either within 5 years of the last performance test; or within a year of the issue date of the permit; or within a year of exceeding 400 hours of operation within a 12-month period. For clarification, the Department added a 6 month cut-off date for triggering source testing within 1 year after permit issue date in accordance with Condition 33.1.a(i). The condition identifies a six month evaluation period immediately prior to the permit effective date when Condition 33.1.a(ii) would require source testing within 1 year of the effective date. This ensures that a unit would not appear to be out of compliance with Condition 33.1.a(i) if it were to trigger Condition 33.1.a(ii).

If the most recent performance test showed operations at greater than 90 percent of the emissions listed in Condition 33, then periodic monitoring source testing is required every year until two consecutive tests show emissions at less than or equal to 90 percent of the limit.

The condition does not state how load must be measured. For some turbines it may be possible to directly measure load as either mechanical or electrical output. For others, it may be necessary to calculate load indirectly based on measurements of other parameters. The Department is not attempting to dictate what method is most appropriate through the permit condition, but should evaluate the adequacy of methods of calculating load based on the load monitoring proposed by the Permittee.

Subpart GG defines "emergency gas turbine[6]" and exempts turbines meeting that definition from the GG emission standards. Some turbines may be operated as standby equipment but not meet the definition of emergency turbine, so the Department has added a Method 20, or Method 7E and either Method 3 or 3A, monitoring threshold of 400 hours per 12-month period. For turbines expected to operate less than 400 hours the Department has also added recordkeeping for hours of operation. The Department does not intend to require the Permittee to operate a turbine solely for the purpose of testing.

The condition requires testing at a range of loads, consistent with the performance test requirements in Subpart GG, that is, test at 30, 50, 75, and 100 percent load. If testing at these four loads is not reasonable, the condition allows the Permittee to propose to the Department what test loads will be reasonable and adequate, and the Department will have the responsibility to make a finding on that proposal. If EPA has already approved alternative test loads for the initial performance test the Department would allow those test loads if the information that went into that decision were still representative of the turbine operation.

In Condition 33, the Department considers "fuel type" to mean, for liquid fuels a type of fuel as described in an ASTM or similar fuel specification.

Load measurements or load calculations from load surrogate measurements are for one-hour periods. The intent is to match the averaging period for the test method. Method 20 identifies a number of traverse points that vary with the size of the stack. From these points the tester is to choose at least 8 points for NOx measurements. The time at each point is to be at least one minute plus the average response time of the instrument. The recorded value is the average steady state response. Presumably, the steady state response would exclude some or all of the response time of the instrument. Three runs are to be done at each test load.

The three runs would represent 24 minutes of measurement time or more. A one-hour average load is therefore a reasonable approximation of a load period corresponding to the test method.

[6] Emergency Gas Turbine means any stationary gas turbine that operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation, as defined in 40 C.F.R. 60.331(e).

Condition 34, SO_2 Monitoring, Recordkeeping, and Reporting

Legal Basis: This condition requires the Permittee to comply with NSPS Subpart GG SO_2 or fuel quality monitoring, recordkeeping, and reporting.

Factual Basis: Monitoring, recordkeeping, and reporting requirements for this condition are described in NSPS Subpart GG and have been referenced here. No additional monitoring outside of the Subpart GG requirements is necessary to ensure compliance with the NSPS SO_2 standard.

Monitoring: Condition 34.1 incorporates NSPS Subpart GG fuel sulfur monitoring requirements and cites the previously approved alternative fuel monitoring schedule granted by EPA in accordance with 40 C.F.R. 60.334(h)(4). EPA approved the alternative monitoring plan and schedule in correspondence to BPXA dated July 13, 1993, August 20, 1993, October 18, 1993, August 19, 1996, and October 2, 1997, in accordance with 40 C.F.R. 60.334(i)(3).

Recordkeeping: The Permittee is required to maintain records of all sulfur monitoring data required by NSPS Subpart GG for five years as set out in 18 AAC 50.350(h)(5). This requirement is stated in Condition 83.

Reporting: NSPS Subpart GG SO_2 standard reporting requirements are incorporated in the permit in Condition 34.4. According to the Alternate Monitoring Schedule (approved on July 13, 1993 and subsequently clarified in EPA letter dated October 18, 1993), the Permittee is required to submit results of H_2S monitoring to EPA at least annually.

Associated with the reporting requirements stated in these conditions is the excess emissions and monitoring systems performance reports required to be submitted to EPA per condition 24.

In Condition 34.4 the Department requests that a summary report of the results from the monitoring requirements in Condition 34.1 be included in the Operating Report required under Condition 88.

Conditions 35 - 43, NSPS Subpart KKK Requirements

Legal Basis: NSPS Subpart KKK applies to the stationary source because it is engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to gas products, or both, and is located onshore. These conditions incorporate Subpart KKK standards and the requirements necessary to ensure that those standards are met. Subpart KKK frequently references the equipment requirements contained in Subpart VV.

Factual Basis: Conditions 35 through 43 contain processing equipment standards and monitoring requirements designed to minimize VOC leaks and detect any that occur at an early stage and institute repairs. These requirements are drawn from Subpart VV where standards had already been developed for:

- pumps in light liquid service;
- compressors;
- pressure relief devices in gas/vapor service;
- open-ended valves or lines;

- valves in gas/vapor service and in light liquid service;
- pumps and valves in heavy liquid service, pressure relief devices in light liquid service or heavy liquid service, and flanges and other connectors; and
- closed vent systems and control devices.

For recordkeeping the stationary source must keep a log for five years that details leaks detected and repairs accomplished. This log is available for agency inspection. Condition 43 requires the stationary source to submit semi-annual reports to both EPA and ADEC documenting leaks and repairs.

Conditions 45 through 48, NESHAP Subpart ZZZZ

Legal Basis: These conditions require the Permittee to comply with applicable regulations in accordance with 40 CFR 63, Subpart ZZZZ for EU ID(s) 15 through 18.

Factual Basis:

- CGF is accessible by the FAHS.
- All are existing engines located at a major source of HAPs.
- Per 40 C.F.R. 63.6590(b)(3)(iii), and §63.6600(c), Subpart ZZZZ does not apply to existing emergency stationary RICE with a site rating greater than 500 hp located at a major source of HAP emissions. In addition, 40 C.F.R. 63.6640(e) and §63.6665 state that Table 8 of Subpart ZZZZ (i.e., 40 C.F.R. 63 Subpart A) does not apply to such engines. Therefore EU ID(s) 15 through 17 at CGF are not subject to the requirements of Subpart ZZZZ or the requirements of Subpart A, except for 40 C.F.R. 63.6640(f)(2). EU ID 18, however, is smaller than 500 hp, and therefore subject to this subpart.
- The reporting requirements that apply to a CMS do not apply to an hourly meter because the requirements of 40 C.F.R. 63.8(c)(7) do not apply to an hourly meter.
- Limits that apply to operation "per year" are calendar year limits (per Melanie King at EPA) and not rolling 12-month limits.
- Reporting requirements for engines subject to operational limitations do not apply to engines subject only to the work/management practices as these are different from operational limitations (per Melanie King at EPA).

Conditions 49 through 55, NESHAP Subpart DDDDD

Legal Basis: These conditions require the Permittee to comply with applicable regulations in accordance with 40 CFR 63, Subpart DDDDD for EU ID(s) 12 through 14.

Factual Basis: EU ID(s) 12 through 14 at CGF are subject to the requirements of Subpart DDDDD because:

- All are existing natural gas-fired process heaters (i.e., constructed prior to June 4, 2010) located at a major source of HAPs.
- The units are classified under 40 CFR 63.7499(l) – units designed to burn gas fuels.
- The gaseous fuel fired by these heaters meets the definition of natural gas under the rule at 40 CFR 63.7575.

Conditions 49 through 55 are the requirements for affected process heaters at a major source of HAPS. These conditions bring forth the national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. These conditions also replicate the requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

Condition 56, Asbestos NESHAP

Legal Basis: The condition requires the Permittee to comply with asbestos demolition or renovation requirements in 40 C.F.R. 61, Subpart M. This condition ensures compliance with the applicable requirement in 18 AAC 50.040(b)(1) and (b)(2)(F). The asbestos demolition and renovation requirements apply if the Permittee engages in asbestos demolition or renovation.

Factual Basis: Because these regulations include adequate monitoring and reporting requirements and because the Permittee is not currently engaged in such activity, simply citing the regulatory requirements is sufficient to ensure compliance with these Federal regulations.

Condition 57, Protection of Stratospheric Ozone, 40 C.F.R. 82

Legal Basis: Condition 57.1 ensures compliance with the applicable requirement in 18 AAC 50.040(d) and applies if the Permittee engages in the recycling or disposal of certain refrigerants. The condition requires the Permittee to comply with the standards for recycling and emission reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F that will apply if the Permittee uses certain refrigerants.

Conditions 57.2 and 57.3 prohibitions also apply to all stationary sources that use halon for extinguishing fires and inert gas to reduce explosion risk. The condition prohibits the Permittee from causing or allowing violations of these prohibitions. The Prudhoe Bay Unit **Central Gas Facility** uses halon and is therefore subject to the Federal regulations contained in 40 C.F.R. 82.

Factual Basis: Because these regulations include adequate monitoring and reporting requirements and because the Permittee is not currently engaged in such activity, simply citing the regulatory requirements is sufficient to ensure compliance with this Federal regulation. This condition also incorporates applicable 40 C.F.R. 82 requirements. The Permittee may not cause or allow violations of these prohibitions.

Condition 58, NESHAPs Applicability Determinations

Legal Basis: This condition requires the Permittee to determine rule applicability of NESHAPS, and requires record keeping for those determinations if required by the source classification.

Factual Basis: The Permittee has conducted an analysis of the stationary source and determined that it is a major HAPs stationary source based on emissions. This condition requires the Permittee to notify the Department and Administrator if the stationary source becomes an affected facility and to keep and make available to the Department copies of the major stationary source determination.

Condition 59, Risk Management Plan (RMP) Requirements, 40 C.F.R. 68

Legal Basis: The Central Gas Facility operates a dry gas refrigeration system that utilizes propane, which is a regulated substance under section 112(r) of the Clean Air Act. The quantity of propane contained in the process exceeds the threshold quantity for that substance. Therefore, the Central Gas Facility dry gas refrigeration process is subject to the Risk Management Plan (RMP) provisions of 40 C.F.R. 68. The process qualifies for a Program 1 RMP because the process has not had an accidental release with offsite consequences in the five years prior to the submission date of the RMP, there are no public receptors within the specified distance to a toxic or flammable endpoint associated with a worst-case release scenario.

Factual Basis: This condition incorporates applicable 40 C.F .R. 68 requirements. The Permittee must comply with the RMP provisions of 40 C.F .R. §68.190 during the permit term.

"Naturally occurring hydrocarbon mixtures" (crude oil, condensate, natural gas and produced water), prior to entry into a petroleum refining process unit (NAICS code 32411) or a natural gas processing plant (NAICS code 211112) are exempt from the threshold determination of 40 C.F .R. 68 for regulated flammable substances. (See Final Rule exempting from threshold determination regulated flammable substances in naturally occurring hydrocarbon mixtures prior to initial processing, 63 FR 640 [January 6, 1998]). The only regulated flammable substance at the stationary source that is not subject to the "naturally occurring hydrocarbon mixtures" exemption and stored in a quantity greater than the threshold quantities of this rule is propane. There are no regulated toxic substances stored at the stationary source in excess of threshold quantities.

Prudhoe Bay has its own professionally-trained fire Department which responds and serves as the local Fire Department for the Central Gas Facility. There is no other jurisdiction providing emergency response to the stationary source, with the exception of mutual aid provided by the fire Departments of other nearby North-Slope Alaska oil fields.

The latest version of the stationary source's Program I RMP was submitted by BPXA to the EPA on September 9, 2010. The next RMP update must be submitted no later than September 9, 2015, or earlier as may be required by 40 C.F.R. §68.l90.

Conditions 60 - 62, Standard Terms and Conditions

Legal Basis: These are standard conditions required under 18 AAC 50.345(a) and (e)-(g) for all operating permits. This provision is incorporated in the Federally approved Alaska operating permit program of November 30, 2001, as updated effective November 9, 2008.

Factual Basis: These are standard conditions that apply to all permits.

Condition 63, Administration Fees

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.400-405 as derived from AS 46.14.130. This condition requires the Permittee, owner, or operator to pay administration fees as set out in regulation. Paying administration fees is required as part of obtaining and holding a permit with the Department or as a fee for a Department action. As CGF is part of a greater Title V Stationary source consisting of both CGF and the Central Compressor Plant, the permit language is changed slightly from that of the standard permit condition.

Factual Basis: The owner or operator of a stationary source who is required to apply for a permit under AS 46.14.130 shall pay to the Department all assessed permit administration fees. The regulations in 18 AAC 50.400-405 specify the amount, payment period, and the frequency of fees applicable to a permit action.

Conditions 64 - 65, Emission Fees

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.410-420. The regulations require all permits to include due dates for the payment of fees and any method the Permittee may use to re-compute assessable emissions.

Factual Basis: These emission fee conditions are Standard Permit Condition I under 18 AAC 50.346(b) adopted pursuant to AS 46.14.010(e). Except for the modification noted in the last paragraph of this “Factual Basis”, the Department determined that these standard conditions adequately meet the requirements of AS 46.14.250. As CGF is part of a greater Title V Stationary source consisting of both CGF and the Central Compressor Plant (CCP), and the Department is issuing a separate permit to CGF and to CCP, therefore, the Department changed the permit language slightly from that of the standard permit condition so that referenced fees under each permit represent permitted emissions from each of CGF and from CCP. No other emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard conditions as edited meet the requirements of AS 46.14.250.

These standard conditions require the Permittee to pay fees in accordance with the Department's billing regulations. The billing regulations set the due dates for payment of fees based on the billing date.

The default assessable emissions are generally potential emissions of each air pollutant in excess of 10 tons per year authorized by the permit (AS 46.14.250(h)(1)(A)).

The conditions allow the Permittee to calculate actual annual assessable emissions based on previous actual annual emissions. According to AS 46.14.250(h)(1)(B), assessable emissions are based on each air pollutant. Therefore, fees based on actual emissions shall be paid on any pollutant emitted whether or not the permit contains any limitation of that pollutant.

This standard condition specifies that, unless otherwise approved by the Department, calculations of assessable emission based on actual emissions use the most recent previous calendar year's emissions. Since each current year's assessable emission are based on the previous year, the Department will not give refunds or make additional billings at the end of the current year if the estimated emissions and current year actual emissions do not match.

The Department modified the standard condition to correct Condition 65.2 such that it referenced “submitted” (i.e., postmarked) rather than “received” in accordance with the timeframe of Condition 65.1.

Condition 66, Good Air Pollution Control Practice

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.346(b)(5) and applies to all emission units, **except** those subject to Federal emission standards, those subject to continuous emission or parametric monitoring, and for insignificant emission units.

Factual Basis: The condition requires the Permittee to comply with good air pollution control practices for all units.

The Department adopted this condition under 18 AAC 50.346(b) as Standard Permit Condition VI pursuant to AS 46.14.010(e).

The Department previously determined that this standard condition adequately meets the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard condition as modified meets the requirements of 40 C.F.R. 71.6(a)(3).

Maintaining and operating equipment in good working order is fundamental to preventing unnecessary or excess emissions. Standard conditions for monitoring compliance with emission standards are based on the assumption that good maintenance is performed. Without appropriate maintenance, equipment can deteriorate more quickly than with appropriate maintenance. If appropriate maintenance is not applied to the equipment, the Department may have to apply more frequent periodic monitoring requirements (unless the monitoring is already continuous) to ensure that the monitoring results are representative of actual emissions.

The Permittee is required to keep maintenance records to show that proper maintenance procedures were followed, and to make the records available to the Department. The Department may use these records as a trigger for requesting source testing if the records show that maintenance has been deferred.

Condition 67, Dilution

Legal Basis: This condition prohibits the Permittee from using dilution as an emission control strategy as set out in 18 AAC 50.045(a). This state regulation applies to the Permittee because the Permittee is subject to emission standards in 18 AAC 50.

Factual Basis: The condition prohibits the Permittee from diluting emissions as a means of compliance with any standard in 18 AAC 50.

Condition 68, Reasonable Precautions to Prevent Fugitive Dust

Legal Basis: This condition requires the Permittee to use reasonable precautions when handling, storing or transporting bulk materials or engaging in an industrial activity in accordance with the applicable requirement in 18 AAC 50.045(d). Bulk material handling requirements apply to the Permittee because the Permittee will engage in bulk material handling, transporting, or storing; or will engage in industrial activity at the stationary source.

Factual Basis: The condition requires the Permittee to comply with 18 AAC 50.045(d), and take reasonable action to prevent particulate matter (PM) from being emitted into the ambient air.

Condition 69, Stack Injection

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.055(g). It prohibits the Permittee from releasing materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack (i.e. disposing of material by injecting it into a stack). Stack injection requirements apply to the stationary source because the stationary source contains a stack or unit constructed or modified after November 1, 1982.

Factual Basis: No specific monitoring for this condition is practical. Compliance is ensured by inspections, because the unit or stack would need to be modified to accommodate stack injection.

Condition 70, Air Pollution Prohibited

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.110. The condition prohibits the Permittee from causing any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property. Air Pollution Prohibited requirements apply to the stationary source because the stationary source will have emissions.

Factual Basis: While the other permit conditions and emissions limitation should ensure compliance with this condition, unforeseen emission impacts can cause violations of this standard. These violations would go undetected except for complaints from affected persons. Therefore, to monitor compliance, the Permittee must monitor and respond to complaints.

The Department adopted this standard condition into 18 AAC 50.346(a) pursuant to AS 46.14.010(e). The Department determined that this condition adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No emission unit or stationary source operational or compliance factors indicate that unit-specific or stationary-source specific conditions would better meet these requirements. Therefore, the Department concluded that the standard condition meets the requirements of 40 C.F.R. 71.6(a)(3).

The Permittee is required to report any complaints and injurious emissions. The Permittee must keep records of the date, time, and nature of all complaints received and summary of the investigation and corrective actions undertaken for these complaints, and to submit copies of these records upon request of the Department.

Condition 71, Technology-Based Emission Standard

Legal Basis: The Permittee is required to take reasonable steps to minimize emissions if certain activity causes an exceedance of any technology-based emission standard in this permit. This condition ensures compliance with the applicable requirement in 18 AAC 50.235. Technology Based Emission Standard requirements apply to the stationary source because the stationary source contains equipment subject to a technology-based emission standard, such as BACT, MACT, LAER, NSPS or other "technologically feasible" determinations.

Factual Basis: The conditions of this permit list applicable technology-based emission standards and require excess emission reporting for each standard in accordance with Condition 87. Excess emission reporting under Condition 88 requires information on the steps taken to minimize emissions. Monitoring of compliance for this condition consists of the report required under Condition 87.

Condition 72, Open Burning

Legal Basis: The condition requires the Permittee to comply with the regulatory requirements when conducting open burning at the stationary source. This condition ensures compliance with the applicable requirement in 18 AAC 50.065. The open burning state regulation in 18 AAC 50.065 applies to the Permittee if the Permittee conducts open burning at the stationary source.

Factual Basis: No specific monitoring is required for this condition. Condition 72.1 requires the Permittee to keep "sufficient records" to demonstrate compliance with the standards for conducting open burning, but does not specify what these records should contain.

More extensive monitoring and recordkeeping is not warranted because the Permittee does not conduct open burning as a routine part of their business. Also, most of the requirements are prohibitions, which are not easily monitored. Compliance is demonstrated through annual certification required under Condition 89.

Condition 73, Requested Source Tests

Legal Basis: The Permittee is required to conduct source tests as requested by the Department. The Department adopted this condition under 18 AAC 50.345(k) as part of its operating permit program approved by EPA November 30, 2001.

Factual Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.220(a) and applies because this is a standard condition to be included in all operating permits. Monitoring consists of conducting the requested source test.

Conditions 74 - 76, Operating Conditions, Reference Test Methods, Excess Air Requirements

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.220(b) and apply because the Permittee is required to conduct source tests by this permit. The Permittee is required to conduct source tests as set out in Conditions 74 through 76.

Factual Basis: These conditions supplement the specific monitoring requirements stated elsewhere in this permit. Compliance monitoring with Conditions 74 through 76 consist of the test reports required by Condition 81.

Condition 77, Test Exemption

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.345(a) and applies when the emission unit exhaust is observed for visible emissions.

Factual Basis: As provided in 18 AAC 50.345(a), amended November 9, 2008, the requirements for test plans, notifications and reports do not apply to visible emissions observations by smoke readers, except in connection with required particulate matter testing.

Conditions 78 - 81, Test Deadline Extension, Test Plans, Notifications and Reports

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.345(l)-(o) and apply because the Permittee is required to conduct source tests by this permit.

Factual Basis: Standard conditions 18 AAC 50.345(l) - (o) are incorporated through these conditions. These standard conditions supplement specific monitoring requirements stated elsewhere in this permit. The source test itself monitors compliance with these conditions.

Condition 82, Particulate Matter (PM) Calculations

Legal Basis: This condition requires the Permittee to reduce particulate matter data in accordance with 18 AAC 50.220(f). It applies when the Permittee tests for compliance with the PM standards in 18 AAC 50.050 or 50.055.

Factual Basis: The condition incorporates a regulatory requirement for PM source tests.

Condition 83, Recordkeeping Requirements

Legal Basis: Applies because the Permittee is required by the permit to keep records.

Factual Basis: The condition restates the regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit. The records being kept provide an evidence of compliance with this requirement.

Condition 84, Certification

Legal Basis: This condition requires the Permittee to comply with the certification requirement in 18 AAC 50.205 and applies to all Permittees under EPA's approved operating permit program effective November 30, 2001 as updated effective November 9, 2008.

Factual Basis: This standard condition is required in all operating permits under 18 AAC 50.345(j). This condition requires the Permittee to certify any permit application, report, affirmation, or compliance certification submitted to the Department. To ease the certification burden on the Permittee, the condition allows the excess emission reports to be certified with the stationary source report, even though it must still be submitted more frequently than the operating report. This condition supplements the reporting requirements of this permit.

Condition 85, Submittals

Legal Basis: This condition requires the Permittee to comply with standardized reporting requirement in 18 AAC 50.326(j) and applies because the Permittee is required to send reports to the Department.

Factual Basis: This condition lists the Department's appropriate address for reports and written notices. The Permittee is required to submit an original and one copy of reports, compliance certifications, and other submittals required by this permit. Receipt of the submittal at the correct Department office is sufficient monitoring for this condition. This condition supplements the standard reporting and notification requirements of this permit.

Condition 86, Information Requests

Legal Basis: This condition requires the Permittee to submit requested information to the Department. This is a standard condition from 18 AAC 50.345(i) of the state approved operating permit program effective November 30, 2001 as updated effective November 9, 2008.

Factual Basis: This condition requires the Permittee to submit information requested by the Department. Monitoring consists of receipt of the requested information.

Condition 87, Excess Emission and Permit Deviation Reports

Legal Basis: This condition requires the Permittee to comply with the applicable requirement in 18 AAC 50.235(a)(2) and 18 AAC 50.240. Also, the Permittee is required to notify the Department when emissions or operations deviate from the requirements of the permit.

Factual Basis: This condition satisfies two state regulations related to excess emissions - the technology-based emission standard regulation and the excess emission regulation. Although there are some differences between the regulations, the condition satisfies the requirements of each regulation.

The Department adopted this condition as Standard Permit Condition III under 18 AAC 50.346(c) pursuant to AS 46.14.010(e). The Department has determined that the standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. Therefore, the Department concludes that the standard condition meets the requirements of 40 C.F.R. 71.6(a)(3).

Section 13, Notification Form

The notification form contained in Standard Permit Condition IV meets the requirements of Chapter 50, Air Quality Control.

Condition 88, Operating Reports

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.346(b)(6) and applies to all permits.

Factual Basis: The condition restates the requirements for reports listed in regulation. The condition supplements the specific reporting requirements elsewhere in the permit. The reports themselves provide monitoring for compliance with this condition.

The Department used the Standard Permit Condition VII as revised on September 27, 2010. For reporting, MR&R conditions are Standard Permit Condition VII adopted into regulation pursuant to AS 46.14.010(e). The Department has determined that the standard conditions adequately meet the requirements of 40 C.F.R. 71.6(a)(3). No additional emission unit or stationary source operational or compliance factors indicate the unit-specific or stationary-source-specific conditions would better meet the requirements. The Department deleted the text "*The Permittee may, upon consultation with the Compliance Technician regarding software compatibility, provide electronic copies of data reports, emission source test reports, or other records under a cover letter certified in accordance with Departmental submission requirements*." since it duplicates Condition 85. The Department has determined that the condition included in this permit meets the requirements of 40 C.F.R. 71.6(a)(3). By submitting a quarterly operating report on the 45th day after the close of the quarter's end, compliance records come in roughly 3 months earlier for half the period of operation and 15 days later for the other half. Overall this benefits the Department.

For renewal permits, the condition specifies that for the transition periods between an expiring permit and a renewal permit the Permittee shall ensure that there is date-to-date continuity between the expired permit and the renewal permit such that the Permittee reports against the permit terms and conditions of the permit that was in effect during those partial date periods of the transition. No format is specified. The Permittee may provide one report accounting for each permit term or condition and the effective permit at that time. Alternatively, the Permittee may chose to provide two reports – one accounting for reporting elements of permit terms and conditions from the end date of the previous operating report until the date of expiration of the old permit, and a second operating report accounting for reporting elements of terms and conditions in effect from the effective date of the renewal permit until the end of the reporting period.

Condition 89, Annual Compliance Certification

Legal Basis: This condition ensures compliance with the applicable requirement in 18 AAC 50.040(j)(4) and applies to all Permittees.

Factual Basis: This condition specifies the periodic compliance certification requirements, and specifies a due date for the annual compliance certification. Each annual certification provides monitoring records for compliance with this condition.

Condition 89.2 provides clarification of transition periods between an expiring permit and a renewal permit to ensure that the Permittee certifies compliance with the permit terms and conditions of the permit that was in effect during those partial date periods involved in the transition. No format is specified: the Permittee may provide one report certifying compliance with each permit term or condition for each of the effective permits during the certification period, or may choose to provide two reports – one certifying compliance with permit terms and conditions from January 1 until the date of expiration of the old permit, and a second report certifying compliance with terms and conditions in effect from the effective date of the renewal permit until December 31.

The Permittee is required to submit to the Department an original and one copy of an annual compliance certification report. The Permittee may submit one of the required copies electronically at their discretion. This change more adequately meets the requirements of 18 AAC 50 and agency needs, as the Department can more efficiently distribute the electronic copy to staff in other locations. The Department deleted the text "*The Permittee, at their discretion, may submit one copy in electronic format (PDF or other Department compatible image format).*" since it duplicates Condition 85.

Condition 90, NSPS and NESHAP Reports

Legal Basis: The Permittee is required to provide the Department a copy of each report submitted to EPA for units subject to NSPS or NESHAP Federal regulations under 18 AAC 50.326(j)(4). 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

Factual Basis: The condition supplements the specific reporting requirements in 40 C.F.R. 60, 40 C.F.R. 61, and 40 C.F.R. 63. The reports themselves provide monitoring for compliance with this condition.

Condition 91, Emission Inventory Reporting

Legal Basis: This condition requires the Permittee to submit emissions data to the State to satisfy the Federal requirement to submit emission inventory data from point sources as required under 40 CFR 51.321 (6/10/02). It applies to sources defined as point sources in 40 C.F.R. 51.50. The State must report all data elements in Table 2A of Appendix A to Subpart A of 40 C.F.R. 51 to EPA (73 FR 76556).

Factual Basis: The Department has incorporated Standard Permit Conditions XV and XVI as adopted by regulation on September 27, 2010. The Department adopted these conditions under 18 AAC 50.346(b) pursuant to AS 46.14.010(e). The emission inventory data is due to EPA 12 months after the end of the reporting year (40 C.F.R. 51.30(a)(1) and (b)(1), 12/17/08). A due date of March 31 follows shortly after sources report actual emissions for assessable emissions purposes and provides the Department sufficient time to enter the data into EPA's electronic reporting system. It is noted that the Permittee has requested this date be changed to April 30 due to multiple other reporting requirements for this stationary source. This request notwithstanding, the Department has not revised the reporting date, as it is published in the Standard Permit Condition XV and the Department has not been granting extensions as the extension does not meet Department's timing needed to process the reported information.

The air emissions reporting requirements under 40 C.F.R. Part 51 Subpart A apply to States. However, States rely on stationary source information to meet the State's reporting requirements of Part 51 Subpart A. FS#2 is classified as a "Type A" source for inventory purposes.

To ensure that the Department's electronic system reports complete information to the National Emissions Inventory, Title V stationary sources classified as Type A in Table 1 of Appendix A to Subpart A of 40 C.F.R. 51 are required to submit with each annual report all the data elements required for the Type B source triennial reports (see also Table 2A of Appendix A to Subpart A of 40 C.F.R. Part 51). All Type A sources are also classified as Type B sources. However the Department has streamlined the reporting requirements so a Type A source only needs to submit a single type of report every year instead of both an annual report and a separate triennial report every third year. The Department asserts that this more effectively meets the regulatory need. Other than streamlining the non-applicable standard permit condition text to remove obligations that are not applicable, no other text of the standard permit condition has been changed.

The condition requires reporting of all emissions from *point sources* as defined in 40 C.F.R. 51.20(b) which means *large, stationary (non-mobile), identifiable sources of emissions that release pollutants into the atmosphere*. Pursuant to the definition, non-mobile sources (defined as: *mobile source* means a motor vehicle, non-road engine or non-road vehicle) excludes emissions from non-road engines and EU categories comprised of temporary sources that may be part of mobile equipment (defined as: A *nonroad vehicle* is a vehicle that is run by a non-road engine and that is not a motor vehicle or a vehicle used solely for competition) such as drilling rigs and their associated non-road engines, temporary heaters and boilers.

Condition 92, Permit Applications and Submittals

Legal Basis: The Permittee may need to submit permit applications and related correspondence.

Factual Basis: Standard Permit Condition XIV directs the applicant to send copies of all application materials required to be submitted to the Department directly to the EPA, in electronic format if practicable. This condition shifts the burden of compliance from the Department to ensure that copies of application materials are submitted to EPA by transferring that responsibility to the Permittee as allowed under 40 C.F.R. 71.10(d)(1).

Conditions 93 - 95, Permit Changes and Revisions Requirements

Legal Basis: The Permittee is obligated to notify the Department of certain off-permit source changes and operational changes under18 AAC 50.326(j)(4). 40 C.F.R. 71.6(a)(10), (12), and (13) incorporated by reference under 18 AAC 50.040(j) require these provisions within this permit. 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

Factual Basis: These conditions are required in 40 C.F.R. 71.6 for all operating permits to allow changes within a permitted stationary source without requiring a permit revision.

The Permittee did not request trading of emission increases and decreases as described in 40 C.F.R. 71.6(a)(13)(iii).

Condition 96, Permit Renewal

Legal Basis: The Permittee must submit a timely and complete operating permit renewal application if the Permittee intends to continue source operations in accordance with the operating permit program under18 AAC 50.326(j)(3). The obligations for a timely and complete operating permit application are set out in 40 C.F.R. 71.5 incorporated by reference in 18 AAC 50.040(j)(3). 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

Factual Basis: In accordance with AS 46.14.230(a), this operating permit is issued for a fixed term of five years after the date of issuance, unless a shorter term is requested by the permit applicant. The Permittee is required to submit an application for permit renewal by the specific dates applicable to the stationary source as listed in this condition. As stated in 40 C.F.R. 71.5(a)(1)(iii), submission for a permit renewal application is considered timely if it is submitted at least six months but no more than eighteen months prior to expiration of the operating permit. According to 40 C.F.R. 71.5(a)(2), a complete renewal application is one that provides all information required pursuant to 40 C.F.R. 71.5(c) and must remit payment of fees owed under the fee schedule established pursuant to 18 AAC 50.400. 40 C.F.R. 71.7(b) states that if a source submits a timely and complete application for permit issuance (including renewal), the source's failure to have a permit is not a violation until the permitting authority takes final action on the permit application.

Therefore, for as long as an application has been submitted within the timeframe allowed under 40 C.F.R. 71.5(a)(1)(iii), and is complete before the expiration date of the existing permit, then the expiration of the existing permit is extended and the Permittee has the right to operate under that permit until the effective date of the new permit. However, this protection shall cease to apply if, subsequent to the completeness determination, the applicant fails to submit by the deadline specified in writing by the Department any additional information needed to process the application. Monitoring, recordkeeping, and reporting for this condition consists of the application submittal.

Conditions 97 - 101, General Compliance Requirements and Schedule

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.326(j)(3). The Permittee is required to comply with these standard conditions set out in 18 AAC 50.345 included in all operating permits. 40 C.F.R. 70 Appendix A documents that EPA fully approved the Alaska operating permit program effective November 30, 2001.

Factual Basis: These are standard conditions for compliance required for all operating permits.

Conditions 102 - 103, Permit Shield

Legal Basis: These conditions ensure compliance with the applicable requirement in 18 AAC 50.326(j) and apply because the Permittee has requested that the Department shield the source from the non-applicable requirements listed under this condition under the Federally approved State operating program effective November 30, 2001 as updated effective November 9, 2008.

Factual Basis: Table G of Operating Permit No. AQ0270TVP02 shows the permit shield that the Department granted to the Permittee. The following table shows the requests that were denied and the reasons that they were denied. The Department based the determinations on the permit application, past operating permit, likelihood for the source to become subject during the life of the permit, Title I permits and inspection reports.

ATTACHMENT A

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 C.F.R. 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ________________________ to ____________________________

Company:
Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: _____________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [1]: ____________________________

Emission Data Summary [1]	**CMS Performance Summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... ____ % [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ % [2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 C.F.R. 60.7(c) shall be submitted.

<u>Note</u>: *On a separate page, describe any changes since last quarter in CMS, process or controls.*

I <u>certify</u> that the information contained in this report is true, accurate, and complete.

Name: ____

Signature: ____ *Date*: ___________________

Title: ____