# Southern Ute Indian Tribe

## *Air Quality Program*

# Title V Operating Permit

**Southern Ute Indian Tribe**
**Environmental Programs Division**
**Air Quality Program**
**71 Mike Frost Way**
**Ignacio, Colorado 81137**

**AIR POLLUTION CONTROL**
**TITLE V PERMIT TO OPERATE**

In accordance with the provisions of Title V of the Clean Air Act (42 U.S.C. 7661-7661f) and Part 1, Article II of the Southern Ute Indian Tribe/State of Colorado Environmental Commission's Reservation Air Code (RAC) and applicable rules and regulations,

**Harvest Four Corners, LLC**
**Ignacio Gas Plant**

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the conditions listed in this permit.

This source is authorized to operate at the following location:

**Southern Ute Indian Reservation**
**SE ¼ of Section 35 SW ¼ of Section 36, T34N R9W**
**La Plata County, Colorado**

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. All terms and conditions of the permit are enforceable by the Tribe and citizens under the Clean Air Act.

Danny J Powers

Daniel Powers, Air Quality Program Manager
Environmental Programs Division
Southern Ute Indian Tribe

**AIR POLLUTION CONTROL**
**TITLE V PERMIT TO OPERATE**
**Harvest Four Corners, LLC**
**Ignacio Gas Plant**

SUIT Account Identification Code: 2-036
Permit Number: V-SUIT-0027-2017.03
[Replaces Permit No.: V-SUIT-0027-2017.02]

Issue Date: November 15, 2021
Effective Date: November 15, 2021
Expiration Date: June 5, 2022

The SUIT account identification code and permit number cited above should be referenced in future correspondence regarding this facility.

**Permit Issuance History**

| DATE | TYPE OF ACTION | DESCRIPTION OF ACTION | PERMIT NUMBER |
|---|---|---|---|
| November 19, 2003 | Initial Permit Issued | | # V-SU-0027-00.00 |
| January 28, 2013 | 1st Renewal Permit Issued | | # V-SU-000027-2008.00 |
| June 5, 2017 | Initial Part 70 Permit issued | | # V-SUIT-0027-2017.00 |
| December 7, 2018 | Permit Revision | Administrative Revision<br>• Change of Ownership from Williams Four Corners, LLC to Harvest Four Corners, LLC.<br>• Updated Air Quality Program Manager<br>• Updated Responsible Official Title | #V-SUIT-0027-2017.01 |
| November 23, 2020 | Permit Revision | Administrative Revision<br>• Corrected emission unit IDs<br>• Corrected Compliance Assurance Monitoring plan | #V-SUIT-0027-2017.02 |
| November 15, 2021 | Permit Revision | Significant Revision<br>• Incorporation of emission units B001 and B002<br>• Reclassification from major source to area source | #V-SUIT-0027-2017.03 |

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# Abbreviations and Acronyms

| | |
|---|---|
| 4SLB | Four-Stroke Lean-Burn |
| 4SRB | Four-Stroke Rich-Burn |
| AFS | Air Facility System database |
| AQP | Southern Ute Indian Tribe's Air Quality Program |
| bbl | Barrels |
| BACT | Best Available Control Technology |
| CAA | Clean Air Act [42 U.S.C. Section 7401 et seq.] |
| CAM | Compliance Assurance Monitoring |
| CEMS | Continuous Emission Monitoring System |
| CFR | Code of Federal Regulations |
| CMS | Continuous Monitoring System (includes COMS, CEMS and diluent monitoring) |
| COMS | Continuous Opacity Monitoring System |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| dscf | Dry standard cubic foot |
| dscm | Dry standard cubic meter |
| EPA | United States Environmental Protection Agency |
| gal | Gallon |
| GPM | Gallons per minute |
| $H_2S$ | Hydrogen sulfide |
| HAP | Hazardous Air Pollutant |
| hr | Hour |
| ID | Identification Number |
| kg | Kilogram |
| lbs | Pounds |
| MACT | Maximum Achievable Control Technology |
| Mg | Megagram |
| MMBtu | Million British Thermal Units |
| MMSCFD | Million standard cubic feet per day |
| mo | Month |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NMHC | Non-methane hydrocarbons |
| $NO_x$ | Nitrogen Oxides |
| NSPS | New Source Performance Standard |
| NSR | New Source Review |
| pH | Negative logarithm of effective hydrogen ion concentration (acidity) |
| PM | Particulate Matter |
| $PM_{10}$ | Particulate matter less than 10 microns in diameter |
| ppbvd | Parts per billion by volume, dry |
| ppm | Parts per million |
| ppmvd | Parts per million by volume, dry |
| PSD | Prevention of Significant Deterioration |
| PTE | Potential to Emit |
| psi | Pounds per square inch |
| psia | Pounds per square inch absolute |
| RAC | Southern Ute Indian Tribe/State of Colorado Environmental Commission's Reservation Air Code |
| RICE | Reciprocating Internal Combustion Engine |
| RMP | Risk Management Plan |
| scf | Standard cubic feet |
| scfm | Standard cubic feet per minute |
| SI | Spark Ignition |
| $SO_2$ | Sulfur Dioxide |
| SUIT | Southern Ute Indian Tribe |
| tpy | Ton(s) Per Year |

| | |
|---|---|
| Tribe | Southern Ute Indian Tribe |
| US EPA | United States Environmental Protection Agency |
| VOC | Volatile Organic Compounds |

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# Section I – Source Information and Emission Unit Identification

## 1. Source Information

| | |
|---|---|
| **Owner Name:** | Harvest Four Corners, LLC |
| **Facility Name:** | Ignacio Gas Plant |
| **Facility Location:** | SE ¼ of Section 35 SW ¼ of Section 36, T34N R9W |
| Latitude: | 37.145278 °N |
| Longitude: | 107.784444 °W |
| **State:** | Colorado |
| **County:** | La Plata |
| **Responsible Official:** | EH & S Manager |
| **SIC Code:** | 1321 |
| **ICIS Identification Number:** | SU000000008067U0038 |
| **EPA Facility Registry ID:** | 110009557470 |

**Other Clean Air Act Permits:** EPA issued the first PSD permit to the facility in 1984. PSD Permit #PSD-SU-0027-01.00 was issued on December 22, 2010 to incorporate the requirements of the 1984 PSD permit and two Consent Decrees. This Part 70 permit replaces the facility's EPA-issued Part 71 permit (V-SU-000027-2008.00). There are no other CAA permits issued to this facility.

**Process Description:**

The Ignacio Gas Plant provides compression, dehydration, sweetening, and natural gas liquids recovery for the San Juan Gathering Systems, an approximately 5,300 mile pipeline system gathering gas from the San Juan Basin. The San Juan Basin spans the southwest corner of Colorado and the northwest corner of New Mexico.

The Ignacio Gas Plant has the ability to condition approximately 500 to 650 million standard cubic feet (MMscfd) of field gas per day into saleable natural gas liquids and residue gas. The primary plant operations include inlet compression, dehydration, carbon dioxide removal, natural gas liquids removal, fractionation, and storage.

This facility consists of one turbo-expander cryogenic plant nominally rated at 450 MMscfd and one NGL fractionation plant. Present total gas throughput averages close to 500 MMscfd. Of this, approximately 380 MMscfd is Trunk S gas that is processed in the cryogenic plant. About 90 MMscfd is from Trunk C that is dehydrated and then normally bypasses all other plant processes, including amine treating and the cryogenic plant.

There are two primary incoming pipelines to the plant. The 30" Trunk S from the San Juan Basin area of primarily New Mexico brings hydrocarbon liquid-rich gas for processing. During July 2011, the WMB and WPZ Boards approved a Four Corners Area Consolidation Project where the S-87 lateral was constructed from Dogie Station to Trunk S and now transfers historic Lybrook Plant volumes to the

Ignacio Gas Plant. A filter separator and slug catcher are used to recover free liquids from the inlet stream. This protects the compressor turbines from foreign material and free liquids. Trunk C is a 16" line that brings in gas with a lower content of recoverable hydrocarbon liquids that contains about 6% carbon dioxide and must be treated or blended with the cryogenic process reside stream for the entire outlet stream to meet interstate pipeline quality specifications. This can be processed in the amine treater and/or cryogenic plant if necessary to achieve interstate pipeline gas quality specifications.

Primary plant operations include inlet compression turbines, the east glycol dehydration unit, the amine plant, the west glycol dehydration unit, the molecular sieve dehydrator, the turbo-expander plant (cryogenic removal of natural gas liquids), the fractionation plant, and recompression. Each of these plant operations is described in detail below.

**Inlet Compression**

Inlet compression at the facility is accomplished through an arrangement of compressors driven by stationary natural gas turbines. The turbines are 1-Solar Titan 130 Natural Gas-Fired Turbine (Trunk S), 1 – Solar Mars 100 Natural Gas-Fired Turbine (Trunk S) and 1 – Solar Taurus 70 Natural Gas-Fired Turbine (Trunk C) equipped with a heat recovery steam generator.

**Dehydration**

Dehydration of Trunk C field gas is accomplished at the East Dehydrator. The East Dehydrator is equipped with a natural gas-fired reboiler rated at 0.75 MMBTU/hr. The East dehydration unit regenerator vent goes to the Callidus Thermal Oxidizer (ThOx). Emission Limits and Operating Requirements dictated by PSD-SU-00027-01.00 issued December 22, 2010 are applicable.

Initial dehydration of Trunk S field gas is accomplished at the West Dehydrator which removes excess moisture to decrease the burden on the molecular sieve dehydrator. The West Dehydrator is equipped with a steam-heated glycol reboiler. The West Dehydration unit regenerator vent's hydrocarbon slip is controlled by the Flare. Emission limits and operating requirements dictated by PSD-SU-00027-01.00 issued December 22, 2010 may be applicable.

The molecular sieve dehydrator consists of four beds. Three beds are typically active while the fourth undergoes regeneration. Regeneration is accomplished by a natural gas-fired regeneration gas heater which is designated at 18.5 MMBtu/hr. the standby regeneration gas heater, which is also natural gas fired, is design-rated at 13.02 MMBtu/hr.

**Carbon Dioxide Removal**

Carbon dioxide removal occurs within the Amine Treatment System. Because the amine reboiler utilizes heat from plant steam, it is not a source of combustion emissions. However, hydrocarbons are released from the process during amine regeneration. These hydrocarbons, entrained in the carbon dioxide vent stream, are controlled by the Thermal Oxidizer. Emission Limits and Operating Requirements dictated by Prevention of Significant Deterioration (PSD) Permit No. PSD-SU-00027-01.00 issued December 22, 2010 are applicable.

**Natural Gas Liquids Removal, Fractionation and Storage**

At the Turbo-Expander Unit, the demethanizer separates methane from the natural gas liquids. The natural gas liquids are then sequentially separated into Ethane, Propane, Butane and Natural Gasoline at the

fractionation plant. Variation in fractionation operations can occur based on market conditions. The demethanizer, deethanizer, depropanizer, and debutanizer reboilers utilize plant steam. Storage facilities are located within the facility and include:

| Product | No. of Vessels | Vessel Size (gallons) | Pressure Rating (psig) |
|---|---|---|---|
| Y-Grade Bullets | 5 | 25,200 | 700 |
| Propane Bullets | 10 | 42,000 | 250 |
| Butane Spheres | 2 | 260,232 | 85 |
| Natural Gasoline Spheres | 2 | 214,900 | 30 |
| Condensate Bullets | 2 | 41,581 | 85 |
| LNG Bullet | 1 | 38,500 | 185 |
| LNG Bullet | 1 | 55,000 | 90 |
| Propane Bullet | 1 | 90,000 | 240 |
| Condensate Bullet | 1 | 90,000 | 240 |

**Loading of Natural Gas Liquids**

Natural gas liquids are transported off-site via pipelines and tanker trucks. Y-grade (demethanized mix of natural gas liquids composition of which depends on a number of plant operating variables), is transported off-site via a natural gas liquids pipeline. The loading of the remaining natural gas liquids occurs through loading racks - two (2)-propane loading racks, one (l)-butane loading rack, two (2)-natural gasoline loading racks and one (1) LNG loading rack. These liquids can also be sent to the pipeline when excess at the plant is available.

**Re-Compression**

The methane stream leaving the Turbo-Expander Plant (TXP) is recompressed by two (2) Solar Titan 130 natural gas-fired turbine driven compressors equipped with Heat Recovery Steam Generators (HRSG).

**Utilities**

The following combustion sources at the Ignacio Plant are equipped with waste heat recovery units:

- Trunk C - Solar Taurus 70
- Recompression - Two (2)-Solar Titan 130s
- Thermal Oxidizer

These waste heat recovery units provide the Ignacio Plant with high pressure steam (600 psig) to drive a steam turbine generator set to produce plant electricity, as well as low pressure steam (60 psig). Supplemental low pressure steam is produced by the Vogt CL.VV-22.5 boilers. These units generally operate only when the re-compressors are not in operation. The plant includes a two-cell cooling tower

The following combustion sources located at the La Plata B Compressor Station provide steam for the Ignacio Gas Plant:

- Two (2) Deltak Delta 3S6-347 Boilers

**Emission Control Equipment**
VOCs may be released from various process units, storage tanks and leaking components. Such releases occur throughout the plant, and may be controlled or uncontrolled (fugitive). Controlled releases are collected and routed through a header to the smokeless flare or the flash gas system.
Releases from the following sources are controlled through the flare system:

- Inlet separator (C Trunk)
- Inlet Gas Cooler
- West Dehydration Unit
- Fuel Gas Line and Filter
- Various Process Scrubbers and Blow Down Vents
- Booster Compressor CG-8104 Suction Line (TXP)
- Deethanizer Reflux Condenser, Overhead Off Gas, Reflux Accumulator, Reboiler and Feed Pre-Heater
- Depropanizer and Depropanizer Reflux Accumulator
- Debutanizer, Debutanizer Reflux Pumps and Accumulator
- Ethane/Propane Product Accumulator
- Vent from Y-Grade Storage
- Propane Storage and Loading
- Butane Storage and Loading
- Natural Gasoline Loading and Storage
- Condensate Storage
- Closed Drain System
- Chromatography Vent
- Emergency Releases

The Flash Gas System takes various streams for re-compression by two electric driven reciprocating compressors prior to being sent to the facility inlet for re-processing. The flash gas system controls emissions from the following sources:

- West glycol dehydrator flash tank
- Amine Treatment flash tank
- Liquefied Natural Gas (LNG) flashing

The Ignacio Gas Plant operates a Callidus Technologies Thermal Oxidizer (TO), installed in 1999 and equipped with a forced draft combustion air blower and vent stack. The TO controls emissions from the East Dehydration Unit and the Amine Treatment System. Thermal Oxidizer Emission Limits and Operating Requirements dictated by Prevention of Significant Deterioration (PSD) Permit No. PSD-SU-00027-01.00 issued December 22, 2010 are applicable.

The uncontrolled releases are minimized through the implementation of a Leak Detection and Repair (LDAR) program.

## 2. Source Emission Points

### Table 1 - Emission Units

| Emission Unit ID | Description | | | | Control Equipment |
|---|---|---|---|---|---|
| 12 | C.E. Natco MN620740009020 Molecular Sieve Regeneration Heater | | | | None |
| | Serial No. | IJ052 | Install Date: | 1/1/1984 | |
| | | | | | |
| 12a | Struthers IF – 10 Back-Up Molecular Sieve Regeneration Heater | | | | None |
| | Serial No. | NM085347/M050102 | Install Date: | 1/1/1984 | |
| | | | | | |
| 13 | Vogt CL. VV – 22.5 Industrial Boiler | | | | None |
| | Serial No. | 1425 | Install Date: | 1/1/1956 | |
| 14 | | 1426 | | 1/1/1956 | |
| | | | | | |
| 15 | Sivalls 500 MMscfd TEG Dehydrator Regenerator (West), 3.0 (Steam Heat) MMBtu/hr Glycol Regenerator Reboiler | | | | Plant Flare (Emission Unit 23) |
| | Serial No. | 26461 | Install Date: | 1992 | |
| | | | | | |
| 16 | Sivalls 120 MMscfd SB – 18-18H TEG Dehydrator Regenerator (East) 0.75 MMBtu/hr Natural Gas – Fired Glycol Regenerator Reboiler | | | | Thermal Oxidizer (Emission Unit 22) |
| | Serial No. | 9004-174 | Install Date: | 1/1/1991 | |
| | | | | | |
| 17 | Amine Unit Regenerator Vent | | | | Thermal Oxidizer (Emission Unit 22) |
| | Serial No. | N/A | Install Date: | 1/1/1984 | |
| | | | | | |
| 18 | Piping Component Fugitives: pumps, pressure relief devices, open ended valve lines, compressors, and flanges or other connectors that are in VOC or wet gas service | | | | 2011 Enhanced LDAR |
| | Serial No. | N/A | Install Date: | Pre-1971 | |
| 19 | | N/A | | 1984 PSD | LDAR Program |
| 20 | | N/A | | 1998 NSPS KKK | LDAR Program |
| | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 21 | Natural Gas Liquids Loadout System (one pipeline and five loading racks) | | | | Plant Flare (Emission Unit 23) |
| | Serial No. | N/A | Install Date: | Pre-1972 | |
| | | | | | |
| 22 | Callidus Technologies 203313-00 Thermal Oxidizer | | | | None |
| | Serial No. | 203313-000 | Install Date: | 1/1/1999 | |
| | | | | | |
| 23 | Zecco Plant Flare | | | | None |
| | Serial No. | 17790 | Install Date: | 2009 | |
| | | | | | |
| 24 | Fluor Company Cooling Tower | | | | None |
| | Serial No. | N/A | Install Date: | 1/1/1956 | |
| | | | | | |
| 25 | Waukesha H866D Diesel Fired Water Pump Engine, 384 Nameplate Rated Horsepower | | | | None |
| | Serial No. | 909602 | Install Date: | 1/1/1978 | |
| | | | | | |
| 26 | Caterpillar 4W-3798 Diesel Fired Water Pump Engine, 305 Nameplate Rated Horsepower | | | | None |
| | Serial No. | 6TB04260 | Install Date: | 1/1/1985 | |
| | | | | | |
| 27 | Solar Mars 100 Natural Gas Fired Turbine (Trunk S) | | | | None |
| | Serial No. | OHK19-M3865 | Install Date: | 2/1/2013 | |
| | | | | | |
| 28 | Solar Titan 130 Natural Gas Fired Turbine | | | | |
| | Serial No. | OHB19-L6137 | Install Date: | 2/1/2013 | None |
| 30 | | OHC18-L4936 | | 4/4/2014 | None |
| 31 | | OHB18-L4717 | | 4/4/2014 | None |
| | | | | | |
| 29 | Solar Taurus 70 Natural Gas Fired Turbine (Trunk C) | | | | None |
| | Serial No. | OHH21-B0605 | Install Date: | 9/29/2021 | |
| | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 32 | Horton 42,000 Gallon Produced Water Storage Tank | | | | None |
| | Serial No. | N/A | Install Date: | 1956 | |
| 33 | | N/A | | 1956 | None |
| | | | | | |
| B001 | Deltak Delta 3S6-347 Natural Gas Fired Waste Heat Recovery Boiler, 29 MMBtu/hr | | | | None |
| | Serial No. | G92001A | Install Date: | 1992 | |
| B002 | | G92001B | | 1992 | None |
| | | | | | |
| *10 | General Electric M3142J A/T Natural Gas Fired Turbine | | | | None |
| | Serial No. | 282514 | Install Date: | 1984 | |
| *11 | | 282515 | | 1984 | None |
| | | | | | |

* According to the previous permit holder, these units have been permanently removed from the facility. However, these units remain listed in the Part 70 permit as they are still listed in the PSD permit for this facility. As of October 2018, this facility is operated by Harvest Four Corners, LLC.

## Table 2 - Insignificant Emission Units

| Emission Unit ID | Amount | Description | Size | Units |
|---|---|---|---|---|
| N/A | 2 | Lube oil storage tank | 2,060 | gal |
| N/A | 1 | Diesel tank (river water pump building & fire water pump generators) | 290 | gal |
| N/A | 1 | Diesel tank (river water pump building & fire water pump generators) | 322 | gal |
| N/A | 1 | Spent lube oil storage tank | 33,694 | gal |
| N/A | 1 | Lube oil storage tank | 11,653 | gal |
| N/A | 1 | Diesel storage tank | 517 | gal |
| TK1 | 1 | Diesel storage tank | 1,028 | gal |
| N/A | 1 | Gasoline storage tank | 582 | gal |
| N/A | 1 | Petroleum solvent storage tank | 509 | gal |
| N/A | 1 | Lube oil storage tank | 6,300 | gal |
| N/A | 1 | Spent lube oil storage tank | 2,000 | gal |
| N/A | 1 | Turbine 32 oil storage tank | 8,820 | gal |
| N/A | 2 | Natural gasoline sphere – 30 psig | 214,924 | gal |
| N/A | 2 | Natural gas liquid rundown pressurized tank – 85 psig | 41,581 | gal |
| N/A | 1 | Recovery oil tank (T9103) | 504 | gal |
| N/A | 1 | Recovery oil tank (T9104) | 500 | gal |
| N/A | 1 | Ambitrol storage tank | 748 | gal |
| N/A | 2 | Butane sphere – 85 psig | 260,232 | gal |
| N/A | 5 | Y-Grade bullet – 700 psig | 22,321 | gal |
| N/A | 10 | Propane bullet – 250 psig | 40,805 | gal |

| | | | | |
|---|---|---|---|---|
| N/A | 1 | Sulfuric acid storage tank | 4,200 | gal |
| N/A | 1 | Sulfuric acid storage tank | 294 | gal |
| N/A | 1 | TEG storage tank | 2,910 | gal |
| N/A | 1 | Raw water storage tank (West tank) | 215,904 | gal |
| N/A | 1 | Raw water storage tank (East tank) | 200,000 | gal |
| N/A | 1 | Optisphere HP55441 tank | 400 | gal |
| N/A | 1 | Ambitrol storage tank | 2,300 | gal |
| N/A | 1 | DI water storage tank | 215,977 | gal |
| N/A | 2 | Raw water storage tank | 21,000 | gal |
| N/A | 1 | Salt water storage tank | 4,300 | gal |
| N/A | 1 | Depositrol PY5206 tank | 400 | gal |
| N/A | 1 | Biomate MBC2881 tank | 55 | gal |
| N/A | 1 | Cooling tower blend tank | 2,970 | gal |
| N/A | 1 | Klaraid IC1172 tank | 400 | gal |
| N/A | 1 | Cortol OS2001 tank | 400 | gal |
| N/A | 1 | Steammate NA0120 tank | 400 | gal |
| N/A | 3 | Gas spec (amine) storage tank – 1 fresh, 1 mixed, and 1 regenerated | 16,800 | gal |
| N/A | 1 | Gas Spec (amine) storage tank | 4,200 | gal |
| N/A | 1 | Gas spec (amine) storage tank | 20,000 | gal |
| N/A | 1 | Methanol storage tank | 24,240 | gal |
| N/A | 1 | Turbine 32 oil storage tank | 300 | gal |
| N/A | 1 | Gengard GN7110 tank | 550 | gal |
| N/A | 1 | Bleach tank | 330 | gal |
| N/A | 1 | Waste oil tank | 630 | gal |
| N/A | 1 | TEG storage tank | 719 | gal |
| N/A | 1 | Turbine 32 oil storage tank (steam turbine) | 850 | gal |
| N/A | 1 | Klaraid IC1172 tank | 500 | gal |
| N/A | 1 | Polyfloc AE1115 tank (inside clear water building) | 120 | gal |
| N/A | 1 | Diesel storage tank | 564 | gal |
| N/A | 1 | LNG pressurized bullet – 185 psig | 38,513 | gal |
| N/A | 1 | LNG pressurized bullet – 90 psig | 55,000 | gal |
| N/A | 1 | Waste water frac tank | 16,800 | gal |
| N/A | 1 | Slop oil tank | 4,200 | gal |
| N/A | 1 | Odorant storage tank | 796 | gal |
| N/A | 1 | Propane bullet – 240 psig | 90,000 | gal |
| N/A | 1 | Condensate bullet – 240 psig | 90,000 | gal |
| N/A | 1 | Sodium Hydroxide tank | 35 | gal |
| N/A | 1 | Lube oil storage tank | 6,300 | gal |
| N/A | 2 | Lube oil storage tank | 2,000 | gal |
| N/A | 1 | Lube oil/water storage tank | 1,000 | gal |
| N/A | 1 | Sodium Hydroxide tank | 300 | gal |

# Section II – General Requirements

## 1. Title V Administrative Requirements

### 1.1. Annual Fee Payment *[RAC 2-110(1)(h) and RAC 2-118]*

1.1.1. An annual operating permit emission fee shall be paid to the Tribe by the permittee.

[RAC 2-118(2)]

1.1.2. The permittee shall pay the annual permit fee each year no later than April 1st for the preceding calendar year.

[RAC 2-118(2)]

1.1.3. Fee payments shall be remitted in the form of a money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the Southern Ute Indian Tribe and sent or delivered by the United States Postal Service c/o Environmental Programs Division Part 70 Program, P.O. Box 737 MS #84, Ignacio, Colorado 81137; or by common carrier (such as UPS or FedEx) c/o Environmental Programs Division Part 70 Program, 398 Ouray Drive, Ignacio, Colorado 81137.

[RAC 2-118(4)(a)]

1.1.4. The permittee shall send an updated fee calculation worksheet submitted annually by the same deadline as required for fee payment to the address listed in the **Submissions** section of this permit.

[RAC 2-118]

1.1.5. Basis for calculating annual fee:

1.1.5.1. Subtotal annual fees shall be calculated by multiplying the applicable emission fee set pursuant to RAC § 2-119(1) times the total tons of actual emissions for each fee pollutant. In lieu of actual emissions, annual fees may be calculated based on the potential to emit for each fee pollutant. Emissions of any regulated air pollutant that already are included in the fee calculation under a category of regulated pollutant, such as a federally listed hazardous air pollutant that is already accounted for as a VOC or as PM10, shall be counted only once in determining the source's actual emissions.

[RAC 2-119(2)(a)]

1.1.5.1.1. "Actual emissions" means the actual rate of emissions in tpy of any fee pollutant (for fee calculation) emitted from a Title V source over the preceding calendar year or any other period determined by the Tribe to be more representative of normal operation and consistent with the fee schedule adopted by the Tribe and approved by the Administrator. Actual

emissions shall be calculated using each emissions units actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year or other period used for this calculation.

[RAC 1-103(2)]

1.1.5.1.2. Actual emissions shall be computed using compliance methods required by the permit.

[RAC 2-118(1)(b)]

1.1.5.1.3. If actual emissions cannot be determined using the compliance methods in the permit, the permittee shall use other federally recognized procedures.

[RAC 2-118(1)(b)]

1.1.5.2. The total annual fee submitted shall be the greater of the applicable minimum fee or the sum of subtotal annual fees for all fee pollutants emitted from the source.

[RAC 2-119(2)(b)]

*[Explanatory note: The applicable emission fee amount and applicable minimum fee (if necessary) are revised each calendar year to account for inflation, and they are available from AQP prior to the start of each calendar year.]*

1.1.5.3. The permittee shall exclude the following emissions from the calculation of fees:

1.1.5.3.1. The amount of actual emissions of any one fee pollutant that the source emits in excess of 4,000 tons per year

1.1.5.3.2. Any emissions that come from insignificant activities not required in a permit application pursuant to RAC § 2-106(4).

[RAC 1-103(2)(c)]

1.1.6. Annual fee calculation worksheets shall be certified as to truth, accuracy, and completeness by a responsible official.

[RAC 2-105 and RAC 2-118(2)(c)]

1.1.7. Failure of the permittee to pay fees by the due date shall subject the permittee to assessment of penalties and interest in accordance with RAC § 2-118(6).

[RAC 2-118(6)]

1.1.8. When notified by the Tribe of underpayment of fees, the permittee shall remit full payment within 30 days of receipt of an invoice from the Tribe.

[RAC 2-119(3)(b)]

1.1.9. A permittee who thinks a Tribe assessed fee is in error and who wishes to challenge such fee shall provide a written explanation of the alleged error to the Tribe along with full payment of the assessed fee.

[RAC 2-119(3)(c)]

**1.2. Compliance Requirements**

1.2.1. Compliance with the Permit

1.2.1.1. The permittee must comply with all conditions of this part 70 permit. Any permit noncompliance with federally enforceable or Commission-only permit conditions constitutes a violation of the RAC and Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application.

[RAC 2-110(3)(a)]

1.2.1.2. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

[RAC 2-110(3)(b)]

1.2.1.3. All terms and conditions of this permit which are required under the Clean Air Act or under any of its applicable requirements, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Clean Air Act, except terms and conditions the permit specifically designates as not being federally enforceable under the Clean Air Act that are not required under the Clean Air Act or under any of its applicable requirements. Terms and conditions so designated are not subject to the requirements of RAC §§ 2-108, 2-111, 2-112, other than those contained in this paragraph.

[RAC 2-110(3)(f)]

1.2.1.4. This permit, or the filing or approval of a compliance plan, does not relieve any person from civil or criminal liability for failure to comply with the provisions of the RAC and the Clean Air Act, applicable regulations thereunder, and any other applicable law or regulation.

[RAC 2-110(3)(g)]

1.2.1.5. For the purpose of submitting compliance certifications in accordance with the Compliance Certifications condition below of this permit, or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[Section 113(a) and 113(e)(1) of the Act, 40 CFR §§ 51.212, 52.12, 52.33, 60.11(g), and 61.12]

1.2.2. Compliance Certifications

1.2.2.1. The permittee shall submit to the Tribe and the Administrator an annual certification of compliance which shall certify the source's compliance status with all permit terms and conditions and all applicable requirements relevant to the source, including those related to emission limitations, standards, or work practices. The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with RAC § 2-110(9)(a). The certification of compliance shall be submitted annually by April 1st and shall cover the preceding calendar year in which the certification of compliance is due, except that the first annual certification of compliance will cover the period from the issuance date of this permit through December 31st of the same year.

[RAC 2-110(9)(c)]

1.2.3. Compliance Schedule

1.2.3.1. For applicable requirements with which the source is in compliance, the source will continue to comply with such requirements.

[RAC 2-106(4)(l)(ii)]

1.2.3.2. For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis.

[RAC 2-106(4)(l)(iii)]

**1.3. Duty to Provide and Supplement Information** *[RAC 2-110(7)(e), 2-106(5), and 2-124]*

1.3.1. The permittee shall furnish to the Tribe, within the period specified by the Tribe, any information that the Tribe request in writing to determine whether cause exists for reopening and revising, revoking, and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Tribe copies of records that are required to be kept by the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of RAC 2-124.

[RAC 2-110(7)(e) and RAC 2-124]

1.3.2. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application or in a supplemental submittal, shall promptly submit such supplementary facts or corrected information. In addition, a permittee shall provide additional information as necessary to address any requirements that become applicable after the date a complete application is filed, but prior to release of a draft permit.

[RAC 2-106(5)]

**1.4. Submissions** *[RAC 2-105]*

1.4.1. Any application, form, report, compliance certification, or other document submitted by the permittee under this permit shall contain a certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

*[Explanatory Note: The Tribe has developed a reporting form "CTAC" for certifying truth, accuracy and completeness of part 70 submissions. The form may be found on the AQP's website (http://www.southernute-nsn.gov/environmental-programs/air-quality).]*

1.4.2. Except where otherwise noted, any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted:

by email at: airquality@southernute-nsn.gov

or by United States Postal Service:
Part 70 Program
Environmental Programs Division
Air Quality Program
P.O. Box 737 MS #84
Ignacio, Colorado 81137

or by Common Carrier:
Part 70 Program
Environmental Programs Division
Air Quality Program
398 Ouray Drive
Ignacio, CO 81137

**1.5. Severability Clause** *[RAC 1-106 and RAC 2-110(1)(f)]*

The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any provision is held invalid, the remaining permit conditions shall remain valid and in force.

**1.6. Permit Actions** *[RAC 2-110(3)]*

1.6.1. This permit may be modified, reopened and revised, revoked and reissued, or terminated for cause.

[RAC 2-110(3)(c)]

1.6.2. The filing by the permittee of a request for a permit revision, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance shall not stay any permit condition.

[RAC 2-110(3)(d)]

**1.7. Administrative Permit Revision** *[RAC 2-111(2)]*

1.7.1. The permittee may submit an application for an administrative permit revision as defined in RAC § 1-103.

[RAC 2-111(2)(a)]

1.7.2. The permittee may implement an administrative permit revision immediately upon submittal of the request for the administrative revision.

[RAC 2-111(2)(c)]

*[Note to permittee: If the provisions allowing for an administrative permit revision do not apply, please contact the Air Quality Program for a determination of similarity prior to submitting your request for an administrative permit revision.]*

**1.8. Minor Permit Revisions** *[RAC 2-111(3)]*

1.8.1. The permittee may submit an application for a minor permit revision as defined in RAC § 1-103.

1.8.2. An application requesting the use of minor permit revision procedures shall meet the requirements of RAC § 2-106(4) and shall include the following:

1.8.2.1. A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

1.8.2.2. If changes are requested to the permit language, the permittee's suggested draft permit changes;

1.8.2.3. Certification by a responsible official, consistent with RAC § 2-105, that the proposed revision meets the criteria for use of minor permit revision procedures and a request that such procedures be used; and

1.8.2.4. Completed forms for the Tribe to use to notify the Administrator and affected programs as required under RAC § 2-108

1.8.2.5. If the requested permit revision would affect existing compliance plans or schedules, related progress reports, or certification of compliance requirements, and an outline of such effects.

[RAC 2-111(3)(a)]

1.8.3. The permittee shall not submit multiple minor permit revision applications that may conceal a larger revision that would not constitute a minor permit revision.

[RAC 2-111(3)(b)]

1.8.4. The permittee may make the change proposed in its minor permit revision application immediately after it files such application, provided, however, for sources that have previously utilized this provision during the term of the permit and, on two or more occasions have failed to file a complete application, may thereafter make the change only after the application is deemed complete. After the permittee makes the change and until the Tribe takes any of the actions specified in the following subsection, the permittee must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this period, the permittee need not comply with the existing permit terms and conditions it seeks to modify. If the permittee fails to comply with its proposed permit terms and conditions during this period, however, the existing permit terms and conditions it seeks to modify may be enforced against it.

[RAC 2-111(3)(e)]

1.8.5. The permit shield under RAC § 2-110(10) does not extend to minor permit revisions.

[RAC 2-110(10)(d)]

**1.9. Significant Permit Revisions** *[RAC 2-111(4)]*

1.9.1. The permittee must request the use of significant permit revision procedures as defined in RAC § 1-103.

1.9.2. Significant permit revisions shall meet all requirements of the RAC for permit issuance and renewal, including those for applications, review by the Administrator and affected programs, and public participation.

[RAC 2-111(4), 2-109, and 2-106(3)]

**1.10. Permit Reopenings, Revocations and Reissuances, and Terminations** *[RAC 2-112]*

1.10.1. The permit may be reopened and revised for any of the reasons listed in the paragraphs below. Alternatively, the permit may be revoked and reissued for the reasons listed in the paragraphs below:

1.10.1.1. Additional requirements under the Clean Air Act become applicable to a major source with a remaining permit term of 3 or more years, provided that the Tribe shall revise such permits to incorporate such additional requirements no later than 18 months after promulgation of such requirements, and no such reopening is required if the effective date of the requirement is later than the permit expiration date unless the original permit or any of its terms or conditions have been extended past the permit expiration date pursuant to RAC § 2-104(2)(b)(iii);

1.10.1.2. Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

1.10.1.3. The Tribe or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the terms or conditions of the permit; or

1.10.1.4. The Tribe or the Administrator determines that the permit must be revised or revoked and reissued to assure compliance with applicable requirements.

1.10.2. The permit may be terminated for any of the reasons in (a) through (g) below:

1.10.2.1. The permittee fails to meet the requirements of an approved compliance plan;

1.10.2.2. The permittee has been in significant or repetitious noncompliance with the operating permit terms or conditions;

1.10.2.3. The permittee has exhibited a history of willful disregard for environmental laws of any tribal or state authority, or of the United States;

1.10.2.4. The permittee has knowingly misrepresented a material fact in any application, record, report, plan, or other document filed or required to be maintained under the permit;

1.10.2.5. The permittee falsifies, tampers with, or renders inaccurate any monitoring device or method required to be maintained under the permit;

1.10.2.6. The permittee fails to pay fees required under RAC§§ 2-118 and 2-119; or

1.10.2.7. The Administrator has found that cause exists to terminate the permit.

### 1.11. Property Rights *[RAC 2-110(3)(e)]*

This permit does not convey any property rights of any sort, or any exclusive privilege.

### 1.12. Inspection and Entry *[RAC 2-110(9)(b)]*

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized representatives of the Tribe or other authorized representative to perform the following:

1.12.1. Enter upon the permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

1.12.2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

1.12.3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

1.12.4. As authorized by the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

**1.13. Emergency Situations** *[RAC 2-117]*

1.13.1. The permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency as defined in RAC § 1-103. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

1.13.1.1. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

1.13.1.2. The permitted facility was at the time being properly operated;

1.13.1.3. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

1.13.1.4. The permittee reported the emergency to the Tribe in compliance with RAC § 2-110(7).

[RAC 2-117(1)]

1.13.2. In any enforcement preceding the permittee attempting to establish the occurrence of an emergency has the burden of proof.

[RAC 2-117(2)]

1.13.3. This emergency situation provision is in addition to any emergency or upset provision contained in any applicable requirement.

[RAC 2-117(3)]

## 1.14. Permit Transfers *[RAC 2-113]*

1.14.1. This permit shall not be transferable, by operation of law or otherwise, from one location to another or from one source to another, except that a permit may be transferred from one location to another in the case of a portable source that has notified the Tribe in advance of the transfer, pursuant to the RAC. A permit for a source may be transferred from one person to another if the Tribe finds that the transferee is capable of operating the source in compliance with the permit. This transfer must be accomplished through an administrative permit revision in accordance with the Administrative Permit Revisions section of this permit.

## 1.15. Off-Permit Changes *[RAC 2-116(2)]*

1.15.1. The permittee is allowed to make, without a permit revision, certain changes that are not addressed or prohibited by this permit provided that the following requirements are met:

1.15.1.1. Each such change meets all applicable requirements and shall not violate any existing permit term or condition;

1.15.1.2. Such changes are not subject to any requirements under title IV of the Clean Air Act and are not modifications under title I of the Clean Air Act;

1.15.1.3. Such changes are not subject to permit revision procedures under RAC § 2-111; and

1.15.1.4. The permittee provides contemporaneous written notice to the Tribe and the Administrator of each such change, except for changes that qualify as insignificant activities. Such notice shall state when the change occurred and shall describe the change, any resulting emissions change, pollutants emitted, and any applicable requirement that would apply as a result of the change.

[RAC 2-116(2)(a)]

1.15.2. The permit shield does not apply to changes made under this provision.

[RAC 2-110(10)(d)]

1.15.3. The permittee shall keep a record describing changes made at the source that result in emissions of any regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

[RAC 2-116(2)(b)]

1.15.4. A copy of each off-permit change notification shall be made available to the Tribe upon request.

[RAC 2-110(6)]

### 1.16. Permit Expiration and Renewal

*[RAC §§ 2-104(3), 2-106(2)(b), 2-107(7)(a), 2-107(7)(b), 2-110(1)(a), and 2-106(3)]*

1.16.1. This permit shall expire five years from the effective date of this permit.

[RAC 2-110(1)(a)]

1.16.2. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least 6 months but not more than 18 months prior to the date of expiration of this permit.

[RAC 2-107(7)(b)]

1.16.3. If the permittee submits a timely and complete permit application for renewal, consistent with RAC § 2-106 but the Tribe has failed to issue or disapprove a renewal permit before the end of the permit term, then the permit shall not expire and all its terms and conditions shall remain in effect until the renewal permit has been issued or disapproved.

[RAC 2-104(2)(b)]

1.16.4. The ability to operate under this permit shall cease if (1) the Tribe takes final action to issue the permittee a renewal permit or deny the permittee a permit or (2) the permittee fails to submit by the deadline specified in writing by the Tribe any additional information identified as being needed to process the application.

[RAC 2-104(3)]

1.16.5. Renewal of this permit is subject to the same procedures, including those for public participation and affected program and EPA review, as those that apply to initial permit issuance.

[RAC 2-107(7)(a)]

1.16.6. The application for renewal shall include the current permit number, description of permit revisions and off permit changes that occurred during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form.

[RAC 2-106(4)(e)(ix)]

## 2. Facility-Wide Requirements

Conditions in this section of the permit apply to all emissions units located at the facility, including any units not specifically listed in Table 1 or Table 2 of the Source Emission Points section of this permit.

[RAC 2-110(1)(d)]

### 2.1. General Recordkeeping Requirements *[RAC 2-110(6)]*

The permittee shall comply with the following generally applicable recordkeeping requirements:

2.1.1. If the permittee determines that his or her stationary source that emits (or has the potential to emit, without federally recognized controls) one or more hazardous air pollutants is not subject to a relevant standard or other requirement established under 40 CFR part 63, the permittee shall keep a record of the applicability determination, for a period of five years after the determination, or until the source changes its operations to become an affected source, whichever comes first. Each of these records shall be made available to the Tribe upon request. The record of the applicability determination shall include an analysis (or other information) that demonstrates why the permittee believes the source is unaffected (e.g., because the source is an area source).

[40 CFR 63.10(b)(3)]

2.1.2. Records shall be kept of off permit changes made, as required by the Off Permit Changes section of this permit.

**2.2. General Reporting Requirements**

2.2.1. The permittee shall submit to the Tribe all reports of any required monitoring under this permit semiannually, by April 1 and October 1 of each year. The report due on April 1 shall cover the July 1 - December 31 reporting period of the previous calendar year. The report due on October 1 shall cover the January 1 - June 30 reporting period of the current calendar year. All instances of deviations from permit requirements shall be clearly identified in such reports. All required reports shall be certified by a responsible official consistent with the Submissions section of this permit.

[RAC 2-110(7)(a)]

2.2.2. "Deviation" means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or recordkeeping established in accordance with RAC 2-110(5) and (6). For a situation lasting more than 24 hours which constitutes a deviation, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

2.2.2.1. A situation where emissions exceed an emission limitation or standard;

2.2.2.2. A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met; or

2.2.2.3. A situation in which observations or data collected demonstrate noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit.

2.2.2.4. A situation in which an exceedance or an excursion, as defined in 40 CFR Part 64 occurs.

[RAC 1-103(21)]

2.2.3. The permittee shall promptly report to the Tribe deviations from permit requirements, (including emergencies), including the date, time, duration, and the probable cause of such deviations, the quantity and pollutant type of excess emissions resulting from the deviation, and any preventative, mitigation, or corrective actions or measures taken. Prompt deviation reports shall be submitted to the following email address: airquality@southernute-nsn.gov

2.2.4. "Prompt" is defined as follows:

2.2.4.1. Where the underlying applicable requirement contains a definition of "prompt" or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern.

2.2.4.2. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

2.2.4.2.1. For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made by email, telephone, verbal, or facsimile communication by the close of business the next working day, upon discovery of the occurrence, and in writing within 10 working days from the occurrence;

2.2.4.2.2. For emissions of any regulated air pollutant, excluding those listed in RAC § 2-110(7)(b)(i), that continue for more than 2 hours in excess of permit requirements, the report must be made by email, telephone, verbal, or facsimile communication by the close of business the next working day, upon discovery of the occurrence, and in writing within 10 working days from the occurrence;

2.2.4.2.3. For all other deviations from permit requirements, the report shall be contained in the report submitted with the semi-annual monitoring report.

[RAC 2-110(7)(b)]

**2.3. Alternative Operating Scenarios** *[RAC 2-110(8)]*

2.3.1. Replacement of an existing engine or turbine identified in this permit shall be allowed as an off-permit change pursuant to the Off Permit Changes provisions of this permit provided all of the following conditions are met:

2.3.1.1. The engine or turbine replacement is not subject to any requirements under Title IV of the Clean Air Act and is not a modification under Title I of the Clean Air Act;

2.3.1.2. The replacement engine or turbine is of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced.

2.3.1.3. The replacement engine or turbine meets all applicable requirements identified in this permit that apply to the existing engine being replaced.

2.3.1.4. All applicable requirements that apply to the replacement engine or turbine are already included in the permit. Replacement of an existing engine or turbine identified in this permit with a new, modified, or reconstructed engine must utilize a Minor Permit Revision as specified in RAC 2-111(3) or a Significant Permit Revision as specified in RAC 2-111(4) to incorporate any new applicable requirements. The applicable requirements include, but may not be limited to:

2.3.1.4.1. Standards of Performance for Stationary Compression Ignition Internal Combustion at 40 CFR Part 60, Subpart IIII

2.3.1.4.2. Standards of Performance for Stationary Spark Ignition Internal Combustion Engines at 40 CFR Part 60, Subpart JJJJ;

2.3.1.4.3. National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines at 40 CFR Part 63, Subpart ZZZZ;

2.3.1.4.4. Standards of Performance for Stationary Gas Turbines at 40 CFR Part 60, Subpart GG;

2.3.1.4.5. Standards of Performance for Stationary Combustion Turbines at 40 CFR Part 60, Subpart KKKK;

2.3.1.4.6. National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines at 40 CFR Part 63, Subpart YYYY;

2.3.1.4.7. Requirements established in a permit or permits issued pursuant to the Federal Minor New Source Review Program in Indian Country at 40 CFR Part 49;

2.3.1.4.8. Requirements established in a permit or permits issued pursuant to the Prevention of Significant Deterioration of Air Quality Program at 40 CFR Part 52; or

2.3.1.4.9. Requirements established in any promulgated Federal Implementation Plan that may apply to engines located on the Southern Ute Indian Reservation.

2.3.2. The permittee shall provide contemporaneous written notice to the Tribe and the Administrator of any replacement of an existing engine or turbine identified in this permit. Such notice shall state when the replacement occurred and shall describe the replacement and any applicable requirement that would apply as a result of the replacement.

2.3.3. The permittee shall keep a record of the engine or turbine replacement.

2.3.4. The use of a backup thermal oxidizer (Unit 22a) with equivalent capacity and emission destruction efficiency and configured to operate in the same manner as the primary thermal oxidizer (Unit 22) shall be an allowed alternative operating scenario under this permit provided that the following conditions are met:

2.3.4.1. Any emission limits, requirements, testing or other provisions that apply to the primary thermal oxidizer shall also apply to the backup thermal oxidizer except that an annual performance test shall only be conducted on the backup thermal oxidizer Unit 22a if the unit operates for more than 500 hours in any calendar year.

2.3.4.2. At no time shall the backup thermal oxidizer operate at the same time the primary thermal oxidizer is operating except periods of transition between the primary and backup thermal oxidizers. Transition events shall be documented, last no more than 30 minutes in duration, and will be reported as excess emission events in accordance with the PSD Permit deviation reporting requirements outlined in this permit.

**2.4. Permit Shield** *[RAC 2-110(10)(c)]*

Nothing in this permit shall alter or affect the following:

2.4.1. The provisions of Section 303 of the Clean Air Act, 42 U.S.C. § 7603 concerning emergency powers, including the respective authorities of the Administrator under those sections;

2.4.2. The liability of a permittee for any violation of applicable requirements prior to or at the time of permit issuance;

2.4.3. The applicable requirements of the acid rain program consistent with section 408(a) of the Act; or

2.4.4. The ability of the Administrator respectively to obtain information from a source pursuant to Section 114 of the Clean Air Act, 42 U.S.C. § 7414.

**2.5. Stratospheric Ozone and Climate Protection** *[40 CFR Part 82]*

The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F:

2.5.1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR §82.156.

2.5.2. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR §82.158.

2.5.3. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR §82.161.

# Section III – Site Specific Permit Terms

## 1. New Source Performance Standards (NSPS) and 40 CFR Part 60

### 1.1. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels *[40 CFR 60.110b-60.116b and RAC 3-102]*

The permittee shall meet all applicable requirements of 40 CFR Part 60 Subparts A and Kb as they apply to each affected source as defined at 40 CFR 60.110b.

#### 1.1.1. Affected Sources

1.1.1.1. The following emission units are subject to 40 CFR Part 60, Subpart Kb:

33,694 gallon spent lube oil storage tank
Two (2) – 21,000 gallon spent lube oil/water storage tanks
Two (2) – 42,000 gallon produced water tanks

[40 CFR 60.110b]

#### 1.1.2. Recordkeeping Requirements

1.1.2.1. The permittee shall keep readily accessible records showing the dimension of the storage vessel, an analysis showing the capacity of the storage vessel, and an analysis showing the vapor pressure of the storage vessel contents.

[40 CFR 60.116b and RAC 2-110(5)]

### 1.2. Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants *[40 CFR 60.630 – 60.636 and RAC 3-102]*

The permittee shall meet all applicable requirements of 40 CFR Part 60 Subpart A and KKK as they apply to each affected source as defined at 40 CFR 60.630.

#### 1.2.1. Affected Sources

1.2.1.1. 40 CFR Part 60, Subpart KKK applies to the following emission units:

1.2.1.1.1 Each compressor in VOC or wet gas service
1.2.1.1.2 The group of all equipment except compressors within a process unit

[40 CFR 60.630]

### 1.2.2. Standards

1.2.2.1. The permittee shall comply with the requirements of §§60.482-1 (a), (b), and (d) and 60.482-2through 60.482-10, except as provided in §60.633, as soon as practicable, but no later than 180 days after initial startup.

1.2.2.2. The permittee may apply to the EPA Region 8 for permission to use an alternative means of emission limitations that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of §60.634 of this subpart.

1.2.2.3. The permittee shall comply with the provisions of §60.485 of this subpart, except as provided in §60.633(f).

1.2.2.4. The permittee shall comply with the provisions of §60.486 and 60.487, except as provided in §§§60.633, 60.635, and 60.636.

1.2.2.5. The permittee shall use the following provision instead of §60.485(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless the permittee demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in wet gas service, it must be determined that the VOC content can be reasonably expected to never exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTEM E169-63, 77, or 93, E168-67, 77, or 92, or E260-73, 91, or 96 (incorporated by reference as specified in §60.17) shall be used.

[40 CFR 60.632]

### 1.2.3. Exceptions

1.2.3.1. Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VV.

1.2.3.2. Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485(b) except as provided in §60.632(c), §60.633(b)(4), and §60.482-4 (a) through (c) of subpart VV.

1.2.3.3. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

1.2.3.3.1. When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9.

1.2.3.3.2. A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

1.2.3.4. Sampling connection systems are exempt from the requirements of §60.482-5.

1.2.3.5. Reciprocating compressors in wet gas service are exempt from the compressor control requirements of §60.482-3.

1.2.3.6. Flares used to comply with this subpart shall comply with the requirements of §60.18.

1.2.3.7. An owner or operator may use the following provisions instead of §60.485(e):

1.2.3.7.1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.17).

1.2.3.7.2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.17).

[40 CFR 60.633]

### 1.2.4. Recordkeeping Requirements

1.2.4.1. The owner or operator of more than one affected facility subject to this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

1.2.4.2. When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.843-2, the following requirements apply:

1.2.4.2.1. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

1.2.4.2.2. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7(c) and no leak has been detected during those 2 months.

1.2.4.2.3. The identification on equipment except on a valve, may be removed after it has been repaired.

1.2.4.3. When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, 60.483-2, and for pressure relief devices subject to §60.633(b)(1), 60.633(b)(2) the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

1.2.4.3.1. The instrument and operator identification numbers and the equipment identification number.

1.2.4.3.2. The date the leak was detected and the dates of each attempt to repair the leak.

1.2.4.3.3. Repair methods applied in each attempt to repair the leak.

1.2.4.3.4. "Above 10,000 ppm" if the maximum instrument reading measured by the methods specified in §60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

1.2.4.3.5. "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

1.2.4.3.6. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

1.2.4.3.7. The expected date of successful repair of the leak if a leak is not repaired within 15 days.

1.2.4.3.8. Dates of process unit shutdowns that occur while the equipment is unrepaired.

1.2.4.3.9. The date of successful repair of the leak.

1.2.4.3.10. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4(a). The designation of equipment subject to the provisions of §60.482-4(a) shall be signed by the owner or operator.

1.2.4.4. The following information pertaining to the design requirements for closed vent systems and control devices described in §60.4782-10 shall be recorded and kept in a readily accessible location:

1.2.4.4.1. Detailed schematics, design specifications, and piping instrument diagrams.

1.2.4.4.2. The dates and descriptions of any changes in the design specifications.

1.2.4.4.3. A description of the parameter or parameters monitored, as required in §60.482-10(e), to ensure that control devices are operated and maintained in

conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

1.2.4.4.4. Periods when the closed vent systems and control devices required in §§60.482-2, 60.482-3, 60.482-4, and 60.482-5 are not operated as designed, including periods when a flare pilot light does not have a flame.

1.2.4.4.5. Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482-2, 60.482-3, 60.482-4, and 60.482-5.

1.2.4.5. The following information pertaining to all equipment subject the requirements in §§60.482-1 to 60.482-10 shall be recorded in a log that is kept in a readily accessible location:

1.2.4.5.1. A list of identification numbers for equipment subject to the requirements of this subpart.

1.2.4.5.2. A list of identification numbers for equipment that are designated for not detectable emissions under the provisions of §§60.482-2€, 60.482-3(i), and 60.482-7(f).

1.2.4.5.2.1. The designation of equipment as subject to the requirements of §§60.482-2(e), 60.482-3(i), or 60.482-7(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

1.2.4.5.3. A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4.

1.2.4.5.4. The dates of each compliance test as required in §§60.482-2(e), 60.482-3(i), 60.482-4, and 60.482-7(f).

1.2.4.5.4.1. The background level measured during each compliance test.

1.2.4.5.4.2. The maximum instrument reading measured at the equipment during each compliance test.

1.2.4.5.5. A list of identification numbers for equipment in vacuum service.

1.2.4.5.6. A list if identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that is in VOC service less than 300 hr/yr.

1.2.4.6. The following information pertaining to all valves subject to the requirements of §60.482-7(g) and (h) and to all pumps subject to the requirements of §60.482-2(g) shall be recorded in a log that is kept in a readily accessible location:

1.2.4.6.1. A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

1.2.4.6.2. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

1.2.4.7. The following information shall be recorded for valves complying with §60.483-2:

1.2.4.7.1. A schedule of monitoring.

1.2.4.7.2. The percent of valves found leaking during each monitoring period.

1.2.4.8. The following information shall be recorded in a log that is kept in a readily accessible location:

1.2.4.8.1. Design criterion required in §§60.482-2(d)(5) and 60.482-3(e)(2) and explanation of the design criterion; and

1.2.4.8.2. Any changes to this criterion and the reasons for the changes.

1.2.4.9. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480(d):

1.2.4.9.1. An analysis demonstrating the design capacity of the affected facility,

1.2.4.9.2. A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

1.2.4.9.3. An analysis demonstrating that equipment is not in VOC service.

1.2.4.10. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

1.2.4.11. The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

[40 CFR 60.486 and 60.635]

1.2.4.12. An owner or operator shall comply with the following requirement in addition to the requirement of §60.486(j): Information and data used to demonstrate that a reciprocating compressor is in wet gas service to apply for the exemption on §60.633(f) shall be recorded in a log that is kept in a readily accessible location.

[40 CFR 60.635]

### 1.2.5. Reporting Requirements

1.2.5.1. Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial startup date.

1.2.5.2. All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486:

1.2.5.2.1. Process unit identification

1.2.5.2.2. For each month during the semiannual reporting period,

1.2.5.2.2.1. Number of valves for which leaks were detected as described in §60.482-7(b) or §60.483-2,

1.2.5.2.2.2. Number of valves for which leaks were not repaired as required in §60.482-7(d)(1),

1.2.5.2.2.3. Number of pumps for which leaks were detected as described in §60.482-2(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

1.2.5.2.2.4. Number of pumps for which leaks were not repaired as required in §60.482-2(c)(1) and (d)(6).

1.2.5.2.2.5. Number of compressors for which leaks were detected as described in §60.482-3(f),

1.2.5.2.2.6. Number of compressors for which leaks were not repaired as required in §60.482-3(g)(1),

1.2.5.2.2.7. Number of pressure relief devices for which leaks were detected as required in §60.633(b)(2),

1.2.5.2.2.8. Number of pressure relief devices for which leaks were not repaired as required in §60.633(b)(3), and

1.2.5.2.2.9. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

1.2.5.2.3. Dates of process unit shutdowns which occurred within the semiannual reporting period.

1.2.5.2.4. Revisions to the initial semiannual report to the Administrator if changes have occurred since the initial report or subsequent revisions to the initial report.

1.2.5.3. An owner or operator electing to comply with the provisions of §§60.483-1 or 60.483-2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

1.2.5.4. An owner of operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

1.2.5.5. The requirements of paragraphs 60.487(a) through 60.487(c) of this section remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs 60.487(a) through 60.487(c) of this section, provided that they comply with the requirements established by the State.

[40 CFR 60.487 and 60.636]

## 1.3. Subpart LLL – Standards of Performance for $SO_2$ Emissions from Onshore Natural Gas Processing Plants *[40 CFR 60.640 – 60.648 and RAC 3-102]*

The permittee shall meet all applicable requirements of 40 CFR Part 60 Subpart A and LLL as they apply to each affected source as defined at 40 CFR 60.640.

### 1.3.1. Recordkeeping and Reporting Requirements

1.3.1.1. To certify that the facility is exempt from the control requirements of these standards, the permittee shall keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of hydrogen sulfide expressed as sulfur.

[40 CFR 60.640(b) and 60.647(c)]

## 1.4. Subpart KKKK – Standards of Performance for Stationary Combustion Turbines *[40 CFR 60.4300 – 60.4420 and RAC 3-102]*

The permittee shall meet all applicable requirements of 40 CFR Part 60 Subpart A and KKKK as they apply to each affected source as defined at 40 CFR 60.4305.

### 1.4.1. Affected Sources

The following are affected sources under this subpart:

- Unit 27 – Solar Mars 100 natural gas-fired turbine
- Unit 28 – Solar Titan 130 natural gas-fired turbine
- Unit 29 – Solar Taurus 70 natural gas-fired turbine
- Unit 30 – Solar Titan 130 natural gas-fired turbine
- Unit 31 – Solar Titan 130 natural gas-fired turbine

[40 CFR 60.4305]

### 1.4.2. Emission Standards

1.4.2.1. Units 27, 28, 29, 30, and 31 shall limit NOx emissions to 25 ppm at 15% $O_2$ or 150 ng/J of useful output (1.2 lb/MWh).

[40 CFR 60.4320 and Table 1]

1.4.2.2. If the permittee has two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOx.

[40 CFR 60.4320(b)]

1.4.2.3. The permittee must not cause to be discharged into the atmosphere from the subject stationary turbines any gases which contain SO2 in excess of 110 nanograms per Joule (ng/J)(0.90 pounds per megawatt-hour (lb/MWh)) gross output.

1.4.2.4. The permittee must not burn in the subject stationary turbines any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. If the turbine(s) simultaneously fires multiple fuels, each fuel must meet this requirement.

[40 CFR 60.4330(a)]

### 1.4.3. General Requirements

1.4.3.1. The permittee must operate and maintain the subject stationary turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

1.4.3.2. When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

1.4.3.2.1. Determine compliance with the applicable NOx emission limits by measuring the emissions combined with the emissions from other unit(s) utilizing the common heat recovery unit; or

1.4.3.2.2. Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

[40 CFR 60.4333]

### 1.4.4. Monitoring Requirements

1.4.4.1. If not using water or steam injection to control NOx emissions, the permittee must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine, the permittee may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance tests exceed 75 percent of the NOx emission limit for the turbine, the permittee must resume annual performance tests.

[40 CFR 60.4340]

1.4.4.2. The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbines if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. The permittee must use one of the following sources of information to make the required demonstration:

1.4.4.2.1. The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw), the total sulfur content for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet, has the potential sulfur emissions of less than 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input; or

1.4.4.2.2. Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.

[40 CFR 60.4365]

### 1.4.5. Testing Requirements

1.4.5.1. The permittee must conduct an initial performance test, as required by §60.8 for measuring NOx from Units 27, 28, 29, 30, and 31 within 60 days after achieving the maximum production rate at which the turbines will we operated, but not later than 180 days after initial startup of the turbines, except as specified by §60.8(a)(1), (a)(2), (a)(3), and (a)(4). Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). The permittee must use the methodology referenced in either §60.4400(1)(i) or 60.4400(1)(ii) to conduct the performance tests.

[40 CFR 60.4400(a), and 60.8]

### 1.4.6. Reporting Requirements

1.4.6.1. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine fuel sulfur content under this subpart, the permittee must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

1.4.6.2. For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report or the results of each performance test before the close of business on the 60$^{th}$ day following completion of the performance test.

[40 CFR 60.4375]

1.4.6.3. If the permittee chooses to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined in §60.4385.

[40 CFR 60.4385]

1.4.6.4. All reports required under §60.7(c) must be postmarked by the 30$^{th}$ day following the end of each 6-month period.

[40 CFR 60.4395]

## 1.5. Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution *[40 CFR 60.5360 – 60.5430 and RAC 3-102]*

The permittee shall meet all applicable requirements of 40 CFR Part 60 Subpart A and OOOO as they apply to each affected source as defined at 40 CFR 60.5365.

### 1.5.1. Standards for Reciprocating Compressors

For each affected reciprocating compressor, the permittee must comply with the following standards:

1.5.1.1. The permittee must replace the reciprocating compressor rod packing on each affected emission unit using one of the following options:

1.5.1.1.1. Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of the reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

1.5.1.1.2. Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

[40 CFR 60.5385]

*[Explanatory note – The permittee has represented that the compliance option for reciprocating compressors at this facility will be rod packing replacement and not an emissions collection system. Therefore, the requirements for an emissions collection system are not incorporated into this permit]*

### 1.5.2. Standards for Affected Process Units

For each affected process unit, the permittee must comply with the following standards:

1.5.2.1. The permittee must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in 60.5401.

1.5.2.2. The permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

1.5.2.3. The permittee must comply with the provisions of §60.485a of this part except as provided in 60.5400(f).

1.5.2.4. The permittee must comply with the provisions of §§60.486a and 60.487a of this part except as provided in 60.5401, 60.5421, and 60.5422.

1.5.2.5. The permittee must use the following provision instead of §60.485a(d)(1): each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described is ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

[40 CFR 60.5400]

### 1.5.3. Exceptions

The permittee may comply with the following exceptions to the provisions of §60.5400(a) and (b).

1.5.3.1. Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified on §60.485a(b) except as provided in §60.5400(c) and in 60.5401(b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

1.5.3.1.1. If an instrument reading of 500 ppm or greater is measured, a leak is detected.

1.5.3.1.1.1. When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

1.5.3.1.1.2. A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

1.5.3.2. Sampling connection systems are exempt from the requirements of §60.482-5a.

1.5.3.3. An owner or operator may use the following provisions instead of §60.485a(e):

1.5.3.3.1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

1.5.3.3.2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

1.5.3.4. An owner or operator may use the following provisions instead of §60.485a(b)(2): a calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored multiplied by 100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with the instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[40 CFR 60.5401]

### 1.5.4. Initial Compliance

1.5.4.1. The initial compliance period for the affected reciprocating compressors begins upon initial startup and ends no later than one year after the initial startup date. During the initial compliance period, for each affected emission unit, the permittee shall:

1.5.4.1.1. Continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

1.5.4.1.2. Submit an initial annual report no later than 90 days after the end of the initial compliance period as required in 60.5420(b) of this section and maintain records as specified in 60.5420(c)(3) of this section.

[40 CFR 60.5410(c)]

1.5.4.2. For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of 60.5400.

[40 CFR 60.5410(f)]

### 1.5.5. Continuous Compliance

1.5.5.1. For each affected reciprocating compressor, the permittee must demonstrate continuous compliance as follows:

1.5.5.1.1. Continuously monitor the number of hours of operation for each reciprocating compressor or track the number of months since the date of the most recent reciprocating compressor rod packing replacement.

1.5.5.1.2. Replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

1.5.5.1.3. Submit annual reports as required in 60.5420(b) and maintain records as required in 60.5420(c)(3).

[40 CFR 60.5415(c)]

1.5.5.2. For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of 60.5400.

[40 CFR 60.5415(f)]

**1.5.6. Notifications, Reporting, and Recordkeeping**

1.5.6.1. The permittee is not required to submit the notifications required in §60.7(a)(1), (3), and (4) for affected reciprocating compressors.

[40 CFR 60.5420(a)(1)]

1.5.6.2. After the initial compliance period, the permittee must submit annual reports on April 1st of each year and covering the previous twelve-month period from January 1st through the December 31st. The annual reports shall contain the following:

1.5.6.2.1. The company name and address of the affected facility.

1.5.6.2.2. An identification of each affected facility being included in the annual report.

1.5.6.2.3. Beginning and ending dates of the reporting period.

1.5.6.2.4. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

[40 CFR 60.5420(b)]

1.5.6.2.5. For each affected reciprocating compressor, the information as follows:

1.5.6.2.5.1. The cumulative number of hours of operation or the number of months since initial startup or since the previous reciprocating compressor rod packing replacement.

1.5.6.2.5.2. Records of deviations from the requirements of this section that occurred during the reporting period.

[40 CFR 60.5420(b)(4)]

1.5.6.2.6. For each affected process unit subject to VOC requirements, the permittee shall submit semiannual reports to the Administrator on April and October 1st of each year. The initial semiannual report shall contain the following information:

1.5.6.2.6.1. Process unit identification

1.5.6.2.6.2. Number of valves subject to the requirements of §60.482-7a, excluding those valves designated for no detectable emissions under the provisions of §60.487a(f)

1.5.6.2.6.3. Number of pumps subject to the requirements of §60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2a(e) and those pumps complying with §60.482-2a(f)

1.5.6.2.6.4. Number of connectors subject to the requirements of §60.482-11a

1.5.6.2.6.5. Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c)

[40 CFR 60.487a(b),60.5422(b), and RAC 2-110(7)]

1.5.6.2.7. All semiannual reports to the Administrator shall include the following information for each month, summarized from the information in §60.486a:

1.5.6.2.7.1. Number of valves for which leaks were detected as described in §60.482-7a(b) or §60.483-2a

1.5.6.2.7.2. Number of valves for which leaks were not repaired as required in §60.482-7a(d)(1)

1.5.6.2.7.3. Number of pumps for which leaks were detected as described in §60.482-2a(b), (d)(4(ii)(A) or (B), or (d)(5)(iii)

1.5.6.2.7.4. Number of pumps for which leaks were not repaired as required in §60.482-2a(c)(1) and (d)(6)

1.5.6.2.7.5. Number of connectors for which leaks were detected as described in §60.482-11a(b)

1.5.6.2.7.6. Number of connectors for which leaks were not repaired as required in §60.482-11a(d)

1.5.6.2.7.7. Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2)

1.5.6.2.7.8. Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3)

[40 CFR 60.5422(c) and 60.487a(c)]

1.5.6.3. The permittee must maintain the following records and the records specified in 40 CFR §60.7(f) onsite or at the nearest local field office for at least 5 years.

1.5.6.3.1. The cumulative number of hours of operation or number of months since initial startup or the previous replacement of the reciprocating compressor rod packing.

1.5.6.3.2. The date and time of each reciprocating compressor rod packing replacement.

1.5.6.3.3. Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385.

[40 CFR 60.5420(c)(3)]

1.5.6.3.4. The permittee may comply with the recordkeeping requirements for the affected facilities in one recordkeeping system if the system identifies each record by each facility.

[40 CFR 60.486a(a)(2)]

1.5.6.3.5. The permittee shall record the following information for each monitoring event required by §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a:

1.5.6.3.5.1. Monitoring instrument identification

1.5.6.3.5.2. Operator identification

1.5.6.3.5.3. Equipment identification

1.5.6.3.5.4. Date of monitoring

1.5.6.3.5.5. Instrument reading

[40 CFR 60.486a(a)(3)]

1.5.6.3.6. When each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, 60.483-2a, and 60.5401(b)(2) (for pressure relief devices) the following requirements apply:

1.5.6.3.6.1. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment

1.5.6.3.6.2. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7a(c) and no leak has been detected during those 2 months.

1.5.6.3.6.3. The identification on a connector may be removed after it has been monitored as specified in §60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

1.5.6.3.6.4. The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

[40 CFR 60.486a(b) and 60.5421(b)(1)]

1.5.6.3.7. When each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, 60.483-2a, and 60.5401(b)(2) (for pressure relief devices), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

1.5.6.3.7.1. The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

1.5.6.3.7.2. The date the leak was detected and the dates of each attempt to repair the leak.

1.5.6.3.7.3. Repair methods applied in each attempt to repair the leak.

1.5.6.3.7.4. Maximum instrument reading measured by Method 21 of appendix A-7 of 40 CFR part 60 at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

1.5.6.3.7.5. “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater (for pressure relief devices only).

1.5.6.3.7.6. “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

1.5.6.3.7.7. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

1.5.6.3.7.8. The expected date of successful repair of the leak if a leak is not repaired within 15 days.

1.5.6.3.7.9. Dates of process unit shutdowns that occur while the equipment is unrepaired.

1.5.6.3.7.10. The date of successful repair of the leak

1.5.6.3.7.11. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

[40 CFR 60.486a(c) and 60.5421(b)(2)]

1.5.6.3.8. The following information pertaining to all equipment subject to the requirements in §§60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

1.5.6.3.8.1. A list of identification numbers for equipment subject to the requirements of this subpart.

1.5.6.3.8.2. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

1.5.6.3.8.2.1. The designation of equipment as subject to the requirements of §60.482-2a(e), §60.482-3a(i), or §60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

1.5.6.3.8.3. A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4a.

1.5.6.3.8.4. The dates of each compliance test as required in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

1.5.6.3.8.4.1. The background level measured during each compliance test.

1.5.6.3.8.4.2. The maximum instrument reading measured at the equipment during each compliance test.

1.5.6.3.8.5. A list of identification numbers for equipment in vacuum service.

1.5.6.3.8.6. A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

1.5.6.3.8.7. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

1.5.6.3.8.8. Records of the information specified in paragraphs 60.486a(e)(8)(i) through (vi) for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).

1.5.6.3.8.8.1. Date of calibration and initials of operator performing the calibration.

1.5.6.3.8.8.2. Calibration gas cylinder identification, certification date, and certified concentration.

1.5.6.3.8.8.3. Instrument scale(s) used.

1.5.6.3.8.8.4. A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.

1.5.6.3.8.8.5. Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

1.5.6.3.8.8.6. If an owner or operator makes their own calibration gas, a description of the procedure used.

1.5.6.3.8.9. The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).

1.5.6.3.8.10. Records of each release from a pressure relief device subject to §60.482-4a.

[40 CFR 60.486a(e)]

1.5.6.3.9. The following information pertaining to all valves subject to the requirements of §60.482-7a(g) and (h), all pumps subject to the requirements of §60.482-2a(g), and all connectors subject to the requirements of §60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

1.5.6.3.9.1. A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

1.5.6.3.9.2. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

[40 CFR 60.486a(f)]

1.5.6.3.10. The following information shall be recorded for valves complying with §60.483-2a:

1.5.6.3.10.1. A schedule of monitoring.

1.5.6.3.10.2. The percent of valves found leaking during each monitoring period.

[40 CFR 60.486a(g)]

1.5.6.3.11. The following information shall be recorded in a log that is kept in a readily accessible location:

1.5.6.3.11.1. Design criterion required in §§60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

1.5.6.3.11.2. Any changes to this criterion and the reasons for the changes.

[40 CFR 60.486a(h)]

1.5.6.3.12. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

1.5.6.3.12.1. An analysis demonstrating the design capacity of the affected facility,

1.5.6.3.12.2. A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

1.5.6.3.12.3. An analysis demonstrating that equipment is not in VOC service.

[40 CFR 60.486a(i)]

1.5.6.3.13. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

[40 CFR 60.486a(j)]

1.5.6.3.14. The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

[40 CFR 60.486a(k)]

## 1.6. Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities

*[40 CFR 60.5360a – 60.5499a]*

The permittee shall meet all applicable requirements of 40 CFR Part 60 Subpart A and OOOOa as they apply to each affected source as defined at 60.5365a.

### 1.6.1. Standards for Affected Process Units

For each affected process unit, the permittee must comply with the following standards:

1.6.1.1. The permittee must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in 60.5401a.

1.6.1.2. The permittee may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402a of this subpart.

1.6.1.3. The permittee must comply with the provisions of §60.485a of this part except as provided in 60.5400a(f).

1.6.1.4. The permittee must comply with the provisions of §§60.486a and 60.487a of this part except as provided in 60.5401a, 60.5421a, and 60.5422a.

1.6.1.5. The permittee must use the following provision instead of §60.485a(d)(1): each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of

equipment, procedures that conform to the methods described is ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

[40 CFR 60.5400a]

### 1.6.2. Exceptions

The permittee may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

1.6.2.1. Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified on §60.485a(b) except as provided in §60.5400a(c) and in 60.5401a(b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

1.6.2.1.1. If an instrument reading of 500 ppm or greater is measured, a leak is detected.

1.6.2.1.1.1. When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

1.6.2.1.1.2. A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

1.6.2.2. Sampling connection systems are exempt from the requirements of §60.482-5a.

1.6.2.3. An owner or operator may use the following provisions instead of §60.485a(e):

1.6.2.3.1. Equipment is in heavy liquid service if the weight percent evaporated is 10 percent at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

1.6.2.3.2. Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

1.6.2.4. An owner or operator may use the following provisions instead of §60.485a(b)(2): a calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more

than 10 percent from the initial calibration value, then all equipment monitored multiplied by 100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with the instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[40 CFR 60.5401a]

### 1.6.3. Initial Compliance

1.6.3.1. For affected facilities at onshore natural gas processing plants, initial compliance with the VOC standards is demonstrated if you are in compliance with the requirements of 60.5400a.

[40 CFR 60.5410a(f)]

### 1.6.4. Continuous Compliance

1.6.4.1. For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of 60.5400a.

[40 CFR 60.5415a(f)]

### 1.6.5. Notifications

1.6.5.1. The permittee must submit the notifications required in §60.7(a)(1), (3), and (4) for affected facilities that are the group of all equipment within a process unit.

[40 CFR 60.5420a(a)(1)]

### 1.6.6. Reporting

1.6.6.1. The permittee must submit **semi-annual** reports to the Tribe and EPA prior to April 1st and October 1st of each year covering the previous six -month period. All semi-annual reports shall contain the following information:

1.6.6.1.1. The company name, facility name, and address of the affected facility.

1.6.6.1.2. An identification of each affected facility being included in the annual report.

1.6.6.1.3. Beginning and ending dates of the reporting period.

1.6.6.1.4. A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

1.6.6.1.5. You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/)*.) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

1.6.6.1.6. You must submit the certification signed by the qualified professional engineer according to §60.5411a(d) for each closed vent system routing to a control device or process.

[40 CFR 60.5420a(b) and RAC 2-110(7)]

1.6.6.2. Initial Semi-annual Report: for the initial report, the reports shall contain the following information for each affected process unit subject to the GHG and VOC requirements:

1.6.6.2.1.1. Process unit identification

1.6.6.2.1.2. Number of valves subject to the requirements of §60.482-7a, excluding those valves designated for no detectable emissions under the provisions of §60.487a(f)

1.6.6.2.1.3. Number of pumps subject to the requirements of §60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482-2a(e) and those pumps complying with §60.482-2a(f)

1.6.6.2.1.4. Number of connectors subject to the requirements of §60.482-11a

1.6.6.2.1.5. The number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c)

[60.5422a(b) and 40 CFR 60.487a(b)]

1.6.6.3. Semi-annual Reports: for each subsequent semiannual report, the report shall include the following information for each month, summarized from the information in §60.486a:

1.6.6.3.1.1. Number of valves for which leaks were detected as described in §60.482-7a(b) or §60.483-2a

1.6.6.3.1.2. Number of valves for which leaks were not repaired as required in §60.482-7a(d)(1)

1.6.6.3.1.3. Number of pumps for which leaks were detected as described in §60.482-2a(b), (d)(4(ii)(A) or (B), or (d)(5)(iii)

1.6.6.3.1.4. Number of pumps for which leaks were not repaired as required in §60.482-2a(c)(1) and (d)(6)

1.6.6.3.1.5. Number of connectors for which leaks were detected as described in §60.482-11a(b)

1.6.6.3.1.6. Number of connectors for which leaks were not repaired as required in §60.482-11a(d)

1.6.6.3.1.7. Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2)

1.6.6.3.1.8. Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3)

[40 CFR 60.5422a(c) and 60.487a(c)]

### 1.6.7. Recordkeeping

1.6.7.1. The permittee may comply with the recordkeeping requirements for the affected facilities in one recordkeeping system if the system identifies each record by each facility.

[40 CFR 60.5421a(a) and 60.486a(a)(2)]

1.6.7.2. The permittee shall record the following information for each monitoring event required by §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a:

1.6.7.2.1. Monitoring instrument identification

1.6.7.2.2. Operator identification

1.6.7.2.3. Equipment identification

1.6.7.2.4. Date of monitoring

1.6.7.2.5. Instrument reading

[40 CFR 60.5421a(a) and 60.486a(a)(3)]

1.6.7.3. When each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, 60.483-2a, and 60.5401(b)(2) (for pressure relief devices) the following requirements apply:

1.6.7.3.1. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment

1.6.7.3.1.1. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482-7a(c) and no leak has been detected during those 2 months.

1.6.7.3.1.2. The identification on a connector may be removed after it has been monitored as specified in §60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

1.6.7.3.1.3. The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

[40 CFR 60.486a(b) and 60.5421a(b)(1)]

1.6.7.3.2. When each leak is detected as specified in §§60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, 60.483-2a, and 60.5401(b)(2) (for pressure relief devices), the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

1.6.7.3.2.1. The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

1.6.7.3.2.2. The date the leak was detected and the dates of each attempt to repair the leak.

1.6.7.3.2.3. Repair methods applied in each attempt to repair the leak.

1.6.7.3.2.4. Maximum instrument reading measured by Method 21 of appendix A-7 of 40 CFR part 60 at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating indications of liquids dripping.

1.6.7.3.2.5. "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater (for pressure relief devices only).

1.6.7.3.2.6. "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

1.6.7.3.2.7. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

1.6.7.3.2.8. The expected date of successful repair of the leak if a leak is not repaired within 15 days.

1.6.7.3.2.9. Dates of process unit shutdowns that occur while the equipment is unrepaired.

1.6.7.3.2.10. The date of successful repair of the leak

1.6.7.3.2.11. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

[40 CFR 60.486a(c) and 60.5421(b)(2)]

1.6.7.3.3. The following information pertaining to all equipment subject to the requirements in §§60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

1.6.7.3.3.1. A list of identification numbers for equipment subject to the requirements of this subpart.

1.6.7.3.3.2. A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

1.6.7.3.3.2.1. The designation of equipment as subject to the requirements of §60.482-2a(e), §60.482-3a(i), or §60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

1.6.7.3.3.3. A list of equipment identification numbers for pressure relief devices required to comply with §60.482-4a.

1.6.7.3.3.4. The dates of each compliance test as required in §§60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

1.6.7.3.3.4.1. The background level measured during each compliance test.

1.6.7.3.3.4.2. The maximum instrument reading measured at the equipment during each compliance test.

1.6.7.3.3.5. A list of identification numbers for equipment in vacuum service.

1.6.7.3.3.6. A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

1.6.7.3.3.7. The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

1.6.7.3.3.8. Records of the information specified in paragraphs 60.486a(e)(8)(i) through (vi) for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and §60.485a(b).

1.6.7.3.3.8.1. Date of calibration and initials of operator performing the calibration.

1.6.7.3.3.8.2. Calibration gas cylinder identification, certification date, and certified concentration.

1.6.7.3.3.8.3. Instrument scale(s) used.

1.6.7.3.3.8.4. A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.

1.6.7.3.3.8.5. Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

1.6.7.3.3.8.6. If an owner or operator makes their own calibration gas, a description of the procedure used.

1.6.7.3.3.9. The connector monitoring schedule for each process unit as specified in §60.482-11a(b)(3)(v).

1.6.7.3.3.10. Records of each release from a pressure relief device subject to §60.482-4a.

[40 CFR 60.486a(e)]

1.6.7.3.4. The following information pertaining to all valves subject to the requirements of §60.482-7a(g) and (h), all pumps subject to the requirements of §60.482-2a(g), and all connectors subject to the requirements of §60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

1.6.7.3.4.1. A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

1.6.7.3.4.2. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

[40 CFR 60.486a(f)]

1.6.7.3.5. The following information shall be recorded for valves complying with §60.483-2a:

1.6.7.3.5.1. A schedule of monitoring.

1.6.7.3.5.2. The percent of valves found leaking during each monitoring period.

[40 CFR 60.486a(g)]

1.6.7.3.6. The following information shall be recorded in a log that is kept in a readily accessible location:

1.6.7.3.6.1. Design criterion required in §§60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

1.6.7.3.6.2. Any changes to this criterion and the reasons for the changes.

[40 CFR 60.486a(h)]

1.6.7.3.7. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

1.6.7.3.7.1. An analysis demonstrating the design capacity of the affected facility,

1.6.7.3.7.2. A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

1.6.7.3.7.3. An analysis demonstrating that equipment is not in VOC service.

[40 CFR 60.486a(i)]

1.6.7.3.8. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

[40 CFR 60.486a(j)]

1.6.7.3.9. The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

[40 CFR 60.486a(k)]

## 1.7. Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units *[40 CFR 60.40c – 60.48c, RAC 3-102]*

This facility is subject to the requirements of 40 CFR Part 60, Subpart Dc for steam generating units with a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less but greater than or equal to 2.9 MW (10 MMBtu/h). Notwithstanding conditions in this permit, the permittee shall meet all applicable requirements of 40 CFR Part 60 Subpart A and Dc as they apply to each affected source as defined at 40 CFR 60.40c.

### 1.7.1. Affected Sources

The following emission units are considered affected sources under 40 CFR Part 60, Subpart Dc:

B001 – 29 MMBtu/hr Deltak Delta 3S6-347 Natural Gas-Fired Waste Heat Recovery Boiler with Duct Burner

B002 – 29 MMBtu/hr Deltak Delta 3S6-347 Natural Gas-Fired Waste Heat Recovery Boiler with Duct Burner

[40 CFR 60.40c]

### 1.7.2. Reporting and Recordkeeping Requirements

1.7.2.1. The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

1.7.2.1.1. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

1.7.2.1.2. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

1.7.2.1.3. The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

1.7.2.1.4. Notification if an emerging technology will be used for controlling $SO_2$ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

1.7.2.2. Except as provided under the paragraphs of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

1.7.2.2.1. As an alternative to recording and maintaining records of the amount of each fuel combusted during each operating day, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the $SO_2$ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

1.7.2.2.2. As an alternative to recording and maintaining records of the amount of each fuel combusted during each operating day, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the $SO_2$ standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

1.7.2.3. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

1.7.2.4. The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[40 CFR 60.48c]

## 2. National Emission Standards for Hazardous Air Pollutants (NESHAP) and 40 CFR Part 63

### 2.1. Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities *[40 CFR 63.760 – 63.63.779 and RAC 4-103]*

The permittee is the owner or operator of glycol dehydration units that are exempt from the standards of 40 CFR §63.764(d). The permittee shall retain each determination used to demonstrate that the actual average benzene emissions from each dehydrator are below 0.90 megagram per year.

[40 CFR 63.764(e)(1), 63.772(b), and 63.774(d)(1)]

2.1.1. The permittee must obtain an extended wet gas analysis of the inlet gas stream at least once per calendar year. The gas sample shall be taken at a point prior to where the gas enters the dehydration system contact tower. The analysis shall include the gas temperature and pressure at which the sample was taken. This analysis must be used to determine the actual average benzene emissions annually, as determined in accordance with §63.772(b)(2)(i).

[RAC 2-110(5)(b)]

2.1.2. The permittee must conduct an annual source determination using the gas analysis outlined in the paragraph above. The source determination shall be made using the procedure outlined in §63.760(a)(1).

[40 CFR 63.760(c) and RAC 2-110(5)(b)]

### 2.2. Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants from Reciprocating Internal Combustion Engines *[40 CFR 63.6580 – 63.6675 & RAC 4-103]*

The permittee shall meet all applicable requirements of 40 CFR Part 63 Subparts A and ZZZZ as they apply to each affected source as defined at §63.6585.

#### 2.2.1. Affected Sources

2.2.1.1. 40 CFR Part 63, Subpart ZZZZ applies to the following engines:

Unit 25, Waukesha H866D Diesel-fired emergency water pump engine, 384 HP

Unit 26, Caterpillar 4W-3798 Diesel-fired emergency water pump engine, 305 HP

### 2.2.2. Maintenance and Operation Requirements

2.2.2.1. The permittee must comply with the following maintenance and operating requirements of Table 2d of 40 CFR Part 63, Subpart ZZZZ:

2.2.2.1.1. Except during periods of startup:

2.2.2.1.1.1. Change oil and filter every 500 hours of operation or annually, whichever comes first; or utilize an oil analysis program as described in §63.6625(i) in order to extend the oil change requirement.

2.2.2.1.1.2. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary

2.2.2.1.1.3. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

2.2.2.1.2. During periods of startup:

2.2.2.1.2.1. Minimize the engine's time at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which the non-startup emission limitations apply.

[40 CFR 63.6603, 40 CFR 63.6625(i), and Table 2d. of 40 CFR Part 63, Subpart ZZZZ]

2.2.2.2. The permittee shall comply with the emission limitations, operating limitations, and other requirements in 40 CFR Part 63, Subpart ZZZZ at all times.

[40 CFR 63.6605(a)]

2.2.2.3. At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions to the levels required by 40 CFR Part 63, Subpart ZZZZ. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if the required levels have been achieved. Determination of whether such operations and maintenance procedures are being used will be based on information available to the Administrator, which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[40 CFR 63.6605(b)]

### 2.2.3. Continuous Compliance and Reporting Requirements

2.2.3.1. The permittee must continuously comply with the following maintenance and operating requirements of Table 6 of 40 CFR Part 63, Subpart ZZZZ:

2.2.3.1.1. Operate and maintain the stationary RICE according to the manufacturer's emission related operation and maintenance instructions; or

2.2.3.1.2. Develop and follow your own maintenance plan, which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 CFR 63.6625(e) and Table 6 of 40 CFR Part 63, Subpart ZZZZ]

2.2.3.2. For emission units 25 and 26, the permittee must install a non-resettable hour meter if one is not already installed.

[40 CFR 63.6625(f)]

2.2.3.3. The permittee must report each instance in which an emission or operating limitation was not met. These instance are deviations from the emission and operating limitations and must be reported according to reporting requirements of §63.6650.

[40 CFR 63.6640(b)]

2.2.3.4. The permittee must also report each instance in which the requirements in Table 8 of 40 CFR Part 63, Subpart ZZZZ, were not met.

[40 CFR 63.6640(e)]

2.2.3.5. For emission units 25 and 26, the permittee must follow the operation requirements specified in §63.6640(f) in order to be considered an emergency engine.

[40 CFR 63.6640(f)]

### 2.2.4. Recordkeeping

2.2.4.1. The permittee must keep the following records to comply with the emission and operating limitations:

2.2.4.1.1. A copy of each notification and report that was submitted to comply with 40 CFR Part 63, Subpart ZZZZ, including all documentation supporting any Initial Notification or Notification of Compliance Status that was submitted, according to the requirements of §63.10(b)(2)(xiv);

2.2.4.1.2. Records of the occurrence and duration of each malfunction of operation (i.e. process equipment) or the air pollution control and monitoring equipment;

2.2.4.1.3. Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii);

2.2.4.1.4. Records of all required maintenance performed on the air pollution control equipment; and

2.2.4.1.5. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.6655(a)]

2.2.4.2. The permittee must keep the records required in Table 6 of this subpart to show continuous compliance with each emission limitation, operating limitation, and work or management practice that applies.

[40 CFR 63.6655(d)]

2.2.4.3. The permittee must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that the unit and after-treatment control device (if any) was operated and maintained according to the permittee's maintenance plan.

[40 CFR 63.6655(e)]

2.2.4.4. The permittee must follow the requirements listed below:

2.2.4.4.1. The permittee must keep records of the hours of operation of the engine(s) that is recorded through the non-resettable hour meter.

2.2.4.4.2. The permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spend for non-emergency operation.

2.2.4.4.3. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep the records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

[40 CFR 63.6655(f)]

2.2.4.5. Records must be in a form suitable and readily available for expeditious review.

[40 CFR 63.6660(a) and 40 CFR 63.10(b)(1)]

2.2.4.6. The permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660(b) and 40 CFR 63.10(b)(1)]

2.2.4.7. The permittee must keep each record readily accessible in hard copy or electronic form at the Ignacio Gas Plant site for five (5) years after the date of each

occurrence, measurement, maintenance, corrective action, report, or record. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

[40 CFR 63.10(b)(1), 40 CFR 63.10(f), and 40 CFR 63.6660(c)]

## 2.3. Subpart CCCCCC – National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities *[40 CFR 63.11110 – 63.11132]*

The permittee shall meet all applicable requirements of 40 CFR Part 63 Subparts A and CCCCCC as they apply to each affected source as defined at §63.11111.

### 2.3.1. Affected Sources

2.3.1.1. 40 CFR Part 63, Subpart CCCCCC applies to the following emission units:

TK1 – Gasoline Storage Tank, 582 gal

[40 CFR 63.11111(b)]

### 2.3.2. General Requirements

2.3.2.1. An affected source shall, upon request by the Administrator, demonstrate that their monthly throughput is less than the 10,000-gallon threshold level, as applicable. Records required under this paragraph shall be kept for a period of 5 years.

[40 CFR 63.11111(e)]

2.3.2.2. Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected Gasoline Dispensing Facility (GDF). If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source.

[40 CFR 63.11111(h)]

2.3.2.3. If your affected source's throughput ever exceeds an applicable throughput threshold, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold.

[40 CFR 63.11111(i)]

2.3.2.4. The dispensing of gasoline from a fixed gasoline storage tank at a GDF into a portable gasoline tank for the on-site delivery and subsequent dispensing of the gasoline into the fuel tank of a motor vehicle or other gasoline-fueled engine or equipment used within the area source is only subject to §63.11116 of this subpart.

[40 CFR 63.11111(j)]

### 2.3.3. Management Practices

Each owner or operator of an affected source under this subpart must comply with the requirements of paragraphs §63.1115(a) and (b) of this section.

2.3.3.1. You must, at all times, operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[40 CFR 63.11115(a)]

2.3.3.2. You must keep applicable records and submit reports as specified in §63.11125(d) and §63.11126(b).

[40 CFR 63.11115(b)]

2.3.3.3. You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

[40 CFR 63.11116(a)]

2.3.3.3.1. Minimize gasoline spills;

[40 CFR 63.11116(a)(1)]

2.3.3.3.2. Clean up spills as expeditiously as practicable;

[40 CFR 63.11116(a)(2)]

2.3.3.3.3. Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;

[40 CFR 63.11116(a)(3)]

2.3.3.3.4. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

[40 CFR 63.11116(a)(4)]

2.3.3.4. You are not required to submit notifications or reports as specified in §63.11125, §63.11126, or subpart A of this part, but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput.

[40 CFR 63.11116(b)]

2.3.3.5. Portable gasoline containers that meet the requirements of 40 CFR part 59, subpart F, are considered acceptable for compliance with paragraph §63.11116(a)(3) of this section.

[40 CFR 63.11116(d)]

**2.3.4. Recordkeeping**

2.3.4.1. The Each owner or operator of an affected source under this subpart shall keep records as specified in paragraphs §63.11125(d)(1) and (2) of this section.

[40 CFR 63.11125(d)]

2.3.4.1.1. Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

[40 CFR 63.11125(d)(1)]

2.3.4.1.2. Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.11115(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.11125(d)(2)]

**2.3.5. General Provisions**

2.3.5.1. Table 3 to this subpart shows which parts of the General Provisions apply to you.

[40 CFR 63.11130]

## 3. Reserved – Tribal Minor New Source Review

## 4. Prevention of Significant Deterioration Requirements (PSD Permit #PSD-SU-00027-01.00)

### 4.1. Requirements for the 10,700 bhp Turbines (Unit 10 and Unit 11)

4.1.1. Turbine Compressor Unit 10 and Turbine Compressor Unit 11 shall each be limited to a maximum NOx concentration in the exhaust of 138 parts per million (percent by volume at 15% oxygen and on a dry basis).

4.1.2. Turbine Compressor Unit 10 and Turbine Compressor Unit 11 shall comply with the applicable requirements of 40 CFR 60, Subpart GG.

4.1.3. Stack testing, when required, shall be performed on Turbine Compressor Unit 10 and Turbine Compressor Unit 11 according to Method 20 of 40 CFR 60, Appendix A to demonstrate compliance with the emission limits.

4.1.4. A test protocol outlining a plan for compliance demonstration shall be submitted to EPA for approval 45 days in advance of any scheduled testing.

4.1.5. All performance testing required pursuant to the PSD permit shall be conducted in accordance with the time schedules and procedures contained in 40 CFR 60.8 performance test results shall be submitted to EPA not more than 45 days after the testing date.

4.1.6. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate Turbine Compressor Unit 10 and Turbine Compressor Unit 11 in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being use will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

4.1.7. The permittee shall notify EPA not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA in writing:

4.1.7.1. The identity of the stack or other emission points where excess emissions occurred;

4.1.7.2. The magnitude of excess emissions expressed in terms of the emission limits;

4.1.7.3. Pertinent operating data during the time of the upset;

4.1.7.4. The time and duration of the excess emissions;

4.1.7.5. The identity of the equipment or process causing the upset and the suspected reasons for the upset;

4.1.7.6. Steps and procedures taken during the upset period to minimize excess emissions; and

4.1.7.7. Steps and procedures take or anticipated to be taken to prevent recurrence of the upset conditions.

4.1.8. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

**4.2. Requirements for the Amine Treatment System (Unit 17)**

4.2.1. The amine treatment system is subject to the major modification of a major stationary source provision of the PSD regulation. BACT for the amine treatment system is as follows:

4.2.1.1. A Thermal Oxidizer with natural gas as supplemental fuel shall be operated such that it is capable of destroying VOCs emitted from the amine regenerator still vent by at least 99%; and

4.2.1.2. A Leak Detection and Repair (LDAR) program to control emissions from equipment leaks from various components (valves, seals, etc.) the LDAR program shall, at a minimum, conform to 40 CFR 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (NSPS KKK). The amine treatment system is not specifically subject to these standards, but they are specified as part of the BACT requirements. These components shall be clearly marked, and identified as subject to BACT requirements.

4.2.2. The emission control devices shall be inspected, monitored, maintained, and operated as per the recommendations of the manufacturer to ensure on-going satisfactory performance. The operating and maintenance plan for all control equipment, control practices, and records of such inspection, monitoring, maintenance, and operation shall be maintained at the site, and made available for review upon request.

4.2.3. Visible emissions shall not exceed 20% opacity during normal operation of the amine treatment system. During periods of startup, process modification, or adjustment of control equipment, visible emissions shall not exceed 30% opacity for more than six (6) minutes in any consecutive 60 minutes. Opacity shall be measured by EPA Method 9.

4.2.4. Volatile organic compound (VOC) emissions of air pollutants attributable to equipment leaks at the amine treatment system shall not exceed 0.72 tons per year (tpy). Compliance with the annual limits shall be determined on a rolling 12-month total. By the end of each month, a new twelve moth total shall be calculated based on the previous 12 months' data. The permittee shall calculate monthly emissions and keep a compliance record on site for review.

4.2.5. The amine treatment system shall be limited to the throughputs as listed below. During the first 12 months of operation, compliance with both the monthly and yearly production limitations shall be required. After the first 12 months of operation, compliance with only the yearly limitation shall be required. Compliance with the yearly production limits shall be determined on a rolling 12 month total. Monthly records shall be maintained by the permittee and made available for inspection upon request:

4.2.5.1. Processing (inlet flow) of natural gas shall not exceed 15,208 MMscf per month;

4.2.5.2. Processing (inlet flow) of natural gas shall not exceed 182,500 MMscf per year; and

4.2.5.3. MDEA (a mixture of alkanolamines, as absorbent to remove carbon dioxide from the natural gas) circulation rate shall not exceed 2,500 gallons per minute.

4.2.6. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the amine treatment system in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

4.2.7. The permittee shall notify EPA and the Tribe not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA and the Tribe in writing:

4.2.7.1. The identity of the stack or other emission points where excess emissions occurred;

4.2.7.2. The magnitude of excess emissions expressed in terms of the emission limits;

4.2.7.3. Pertinent operating data during the time of the upset;

4.2.7.4. The time and duration of the excess emissions;

4.2.7.5. The identity of the equipment or process causing the upset and the suspected reasons for the upset;

4.2.7.6. Steps and procedures taken during the upset period to minimize excess emissions; and

4.2.7.7. Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

4.2.8. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

4.2.9. The permittee shall submit to EPA Region 8 and the Tribe the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for the amine treatment system.

### 4.3. Requirements for the Turbo-Expansion Unit

4.3.1. The turbo-expansion unit is subject to the provisions of major modification of a major stationary source. A review under PSD regulations has determined that BACT for VOC equipment leaks from the turbo-expansion unit is an LDAR program. The LDAR program shall, at a minimum, conform to NSPS KKK. An overall control efficiency of 50.2% is assessed for this LDAR program.

4.3.2. The turbo-expansion unit is subject to NSPS KKK

4.3.3. The emission control devices shall be inspected, monitored, maintained, and operated as per the recommendations of the manufacturer to ensure on-going satisfactory performance. The operating and maintenance plan for all control equipment, control practices, and records of such inspection, monitoring, maintenance, and operation shall be maintained at the site, and made available for review upon request.

4.3.4. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the turbo-expansion unit in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

4.3.5. Records of startups, shutdowns, and malfunctions shall be maintained, as required under §60.7.

4.3.6. Excess Emissions and Monitoring System Performance Reports shall be submitted as required under §60.7.

4.3.7. Performance tests shall be conducted as required under §60.8.

4.3.8. The permittee shall submit to EPA Region 8 and the Tribe the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for the turbo-expansion unit.

**4.4. Requirements for the West Dehydrator (Unit 15)**

4.4.1. The west dehydrator is subject to the major modification of a major stationary source provision of the PSD regulation. A review under PSD regulations has determined that BACT for VOC emissions is a flare (Unit 23) with emissions not to exceed 6.7 tpy.

4.4.2. The west dehydrator shall be operated in accordance with the manufacturer's recommendations and specifications, except as otherwise provided in the PSD permit.

4.4.3. The hours of operation of the west dehydrator shall be recorded and used with other available information to quantify and report annual emissions.

4.4.4. A model run using the most recent version of GRI-Glycalc and a current extended gas analysis shall be performed annually to determine and report compliance with the allowable emission rate.

4.4.5. During any period when the flare is not operational or when emissions from the west dehydrator are not routed to the flare, the permittee shall record and report such operations

to EPA and the Tribe. The requisite report shall be made on a semi-annual basis and shall describe the periods of the time that the west dehydrator operated and emissions were not controlled by the flare, the reason why the flare was not operating, and the actions taken by the permittee to allow it to resume operation of the flare.

4.4.6. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the west dehydrator in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

4.4.7. The permittee shall notify EPA and the Tribe not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA and the Tribe in writing:

4.4.7.1. The identity of the stack or other emission points where excess emissions occurred;

4.4.7.2. The magnitude of excess emissions expressed in terms of emission limits;

4.4.7.3. Pertinent operating data during the time of the upset;

4.4.7.4. The time and duration of the excess emissions;

4.4.7.5. The identity of the equipment or process causing the upset and the suspected reasons for the upset;

4.4.7.6. Steps and procedures taken during the upset period to minimize excess emissions; and

4.4.7.7. Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

4.4.8. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

4.4.9. The permittee shall submit to EPA Region 8 and the Tribe the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for the west dehydrator.

### 4.5. Requirements for the East Dehydrator (Unit 16)

4.5.1. The east dehydrator is subject to the major modification of a major stationary source provision of the PSD regulation. A review under PSD regulations has determined that BACT for VOC emissions is with a thermal oxidizer (Unit 22) that currently receives and controls the emissions from the amine treatment system. The emission limits for the thermal oxidizer when both the amine treatment system and the east dehydrator is operating shall not exceed the following:

| | |
|---|---|
| VOCs | 1.16 lbs per hour and 5.1 tons per year |
| Oxides of Nitrogen ($NO_x$) | 8.8 lbs per hour and 38.52 tons per year |
| Carbon Monoxide (CO) | 5.35 lbs per hour and 23.45 tons per year |
| Sulfur Oxides ($SO_2$) | 16.0 lbs per hour and 37.1 tons per year |

4.5.2. The fuel flow to the thermal oxidizer shall not exceed 55 MMBtu/hr and the flow shall be monitored by a continuous recording device.

4.5.3. The east dehydrator shall be operated in accordance with the manufacturer's recommendations and specifications, except as otherwise provided in the PSD permit.

4.5.4. Except as provided below, within 60 days of the date that the east dehydrator commences operation, the permittee shall perform a stack test to determine if the emissions from the thermal oxidizer meet the emission limits set forth.

4.5.4.1. The stack test shall be performed using EPA approved methods. The permittee shall submit a testing protocol to the EPA for comment 30 days before the stack test. This protocol also shall serve as notification to the EPA of the pending test in order to allow a representative to be present at the test.

4.5.4.2. If EPA objects to the test protocol or any part of it, the permittee's obligation to conduct the stack test is suspended until the EPA and the permittee agree on the terms of a test protocol. Once agreement is reached, the permittee shall conduct the stack test within 45 days.

4.5.4.3. The amine treatment system and the east dehydrator shall operate at 90% or more of the permitted facility's current operation capacity for the test.

4.5.4.4. The results of the stack test shall be reported to the EPA and the Tribe within 45 days of the date of the test.

4.5.5. A stack test shall be performed annually to determine the effectiveness of the thermal oxidizer in controlling VOC emissions. As part of the stack test, the permittee shall measure the inlet flow and outlet flow of the thermal oxidizer in order to confirm the stated

destruction of the control unit. The stack test also will be used to determine if the thermal oxidizer is controlling emissions at or below the permitted emission rate.

4.5.6. During any period when the thermal oxidizer is not operational and the east dehydrator and the amine treatment system continue to operate, the permittee shall report such operations to the EPA and the Tribe. The requisite report shall be made on a semi-annual basis and shall describe the periods of time that the east dehydrator and the amine treatment system operated and emissions were not controlled by the thermal oxidizer, the reason why the thermal oxidizer was not operating and the actions taken by the permittee to allow it to resume operation of the thermal oxidizer.

4.5.7. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the east dehydrator in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

4.5.8. The permittee shall notify EPA and the Tribe not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA and the Tribe in writing:

4.5.8.1. The identity of the stack or other emission points where excess emissions occurred;

4.5.8.2. The magnitude of excess emissions expressed in terms of emission limits;

4.5.8.3. Pertinent operating data during the time of the upset;

4.5.8.4. The time and duration of the excess emissions;

4.5.8.5. The identity of the equipment or process causing the upset and the suspected reasons for the upset;

4.5.8.6. Steps and procedures taken during the upset period to minimize excess emissions; and

4.5.8.7. Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

4.5.9. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

4.5.10. The permittee shall submit to EPA Region 8 and the Tribe the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for the east dehydrator.

## 5. Reserved – Consent Decree Requirements

## 6. Compliance Assurance Monitoring (CAM) Requirements

### 6.1. 40 CFR Part 64 CAM

6.1.1. The CAM requirements specified at 40 CFR Part 64 apply to the following emission units with respect to the VOC emission limits identified in the PSD Permit Requirements section of this permit.

6.1.1.1. Unit 15 - West Dehydration System (controlled by Flare Unit 23)

6.1.1.2. Unit 16 - East Dehydration System (controlled by Thermal Oxidizer Unit 22)

6.1.1.3. Unit 17 – Amine Sweetening System (controlled by Thermal Oxidizer Unit 22)

[40 CFR 64.2(a)]

6.1.2. The permittee shall follow the CAM plan provided as an appendix to this permit for Unit 15 (West Dehydration System), Unit 16 (East Dehydration System), and Unit 17 (Amine Sweetening System).

6.1.3. Excursions, as defined in the CAM plan, shall be reported in accordance with the Facility-Wide Reporting Requirements section of this permit.

6.1.4. Operation of Approved Monitoring

6.1.4.1. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

[40 CFR 64.7(b)]

6.1.4.2. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and

associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[40 CFR 64.7(c)]

6.1.4.3. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

[40 CFR 64.7(d)(1)]

6.1.4.4. Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(2)]

6.1.4.5. After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Tribe and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

[40 CFR 64.7(e)]

6.1.5. Based on the results of a determination made under §64.7(d)(2), the Tribe or EPA may require the permittee to develop and implement a Quality Improvement Plan (QIP) in accordance with §64.8.

[40 CFR 64.8(a)]

6.1.6. The permittee shall submit monitoring reports in accordance with §64.9(a) for CAM requirements on a semi-annual basis to the Tribe as specified in the Facility-Wide Reporting Requirements section in this permit.

[40 CFR 64.9(a)]

6.1.7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written QIP required pursuant to Condition e. above and any activities undertaken to implement at QIP, and other supporting information required to be maintained under Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions as specified in §64.9(b).

[40 CFR 64.9(b)]

## 7. Enhanced Monitoring, Recordkeeping, and Reporting

7.1. Any documents required to be submitted under this Title V operating permit, including but not limited to, reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to the Tribe:

by email at: airqualty@southernute-nsn.gov

| or by United States Postal Service: | or by Common Carrier: |
| --- | --- |
| Part 70 Program Environmental Programs Division<br>Air Quality Program<br>P.O. Box 737 MS #84<br>Ignacio, Colorado 81137 | Part 70 Program Environmental Programs Division<br>Air Quality Program<br>398 Ouray Drive<br>Ignacio, CO 81137 |

# Section IV – Appendix

## 1. Compliance Assurance Monitoring (CAM) Plan

### CAM Plan for West Glycol Dehydrator Regenerator Vent (Unit 15)

I. Background

a. Emission Unit

Description: West Glycol Dehydrator (regenerator vent controlled by plant flare)
Identification: Unit ID 15
Facility: Ignacio Gas Plant, Durango, Colorado

b. Applicable Regulations & Emission Limits

Regulation: PSD Permit #PSD-SU-0027-01.00
Emission Limits: 6.7 tpy of VOC (Permit Condition II.J.4.a)

c. Control Technology & PTE

Controls: Open-tip Flare (Unit ID 23)
Potential pre-control device emissions: 584.7 tpy of VOC
Potential post-control device emissions: 6.7 tpy of VOC

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

a. An excursion outside the indicator range signaling the improper operation of the flare will trigger an inspection, corrective action, recordkeeping, and reporting. Maintenance personnel will inspect the control device and indicator within 24 hours and make necessary repairs as soon as practicable.

b. Any number of excursions that exceed the Quality Improvement Plan (QIP) threshold shall trigger the requirement for a QIP for the associated indicator.

If the EPA determines that the permittee has not used acceptable procedures in response to excursions of the indicator, the EPA may require the permittee to prepare a QIP. The QIP will include procedures for evaluating the control performance problems and actions to correct the problems identified, implementation of QIP shall not excuse the permittee from compliance with any emission limitation or standard, or any existing monitoring, reporting, or

recordkeeping requirement that may apply under any federal, state, or local law, or any other applicable regulation under the Clean Air Act.

**Monitoring Approach: Harvest Ignacio Plant Flare for West Glycol Dehydrator Regenerator Vent (Unit ID 15)**

| | | Indicator No. 1 | Indicator No. 2 |
|---|---|---|---|
| I. Indicator | | Operate flare with presence of a pilot flame at all times | Operate flare with no visible emissions |
| Measurement Approach | | Continuously measure the temperature of the pilot flame using a thermocouple or equivalent temperature sensing device equipped with a continuous recording device. | Continuously observe flare for visible emissions using a remote viewing system (camera with live video feed in plant control room). If any visible emissions are observed, operator shall immediately use Method 22 of 40 CFR Part 60, Appendix A to confirm visible emission. The observation period shall be two(2) hours. |
| II. Indicator Range | | An excursion is defined as any loss of flare flame. The pilot system is equipped with auto-ignition and automatically re-lights the pilot. Associated recordkeeping and reporting shall be conducted for each excursion event as required. | An excursion is defined as any visible emissions observed using Method 22 that continues for longer than five (5) minutes during the 2 hour observation period. |
| QIP Threshold | | No more than six (6) excursions in any semiannual reporting period. | No more than 12 excursions in any semiannual reporting period. |
| III. Performance Criteria | A. Data Representativeness | The thermocouple will determine the presences or absence of a pilot flame. Requiring the presence of a pilot flame will assure ignition of the flare when waste gas is vented to it. | Observation of the flare in the plant control room via the remote viewing system will continuously monitor the control device for visible emissions. Requiring the flare operation with no visible emissions will assure proper operation of the flare. |
| | B. Verification of Operational Status | With loss of pilot flame, observation of flare flame will be confirmed with the plant camera and remote viewing system. | The observation of visible emissions will indicate that the control device is malfunctioning. |

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| | C.QA/QC Practices/Criteria | The thermocouple, data recorder, malfunction alarm with notification system shall be inspected for proper operation on a quarterly basis. | The camera and video feed for the remote viewing system shall be inspected for proper operation on a quarterly basis. Records of the inspection shall be maintained at the facility. |
| | D. Monitoring Frequency | The presence of a pilot flame shall be monitored continuously. | The flare shall be continuously monitored with the remote viewing system. |
| | E. Data Collection Procedures | Pilot flame status is continuously monitored by the plant control room using alarm notification from the flare pilot system. The thermocouple shall be equipped with a continuous recording device such as a data logger or chart recorder to monitor proper thermocouple operation. Records of all inspection, maintenance, and repair activities shall be maintained on-site. | All visible emission events and Method 22 measurements shall be recorded in a log and maintained at the facility. The log shall include at a minimum, the date/time the event occurred, the duration of the event, the personnel that observed the event, and the corrective action taken. |
| | F. Averaging Time | Averaging is not necessary since the thermocouple will operate continuously. | None. |

**Justification**

I. Background

This facility processes natural gas from the San Juan Basin gas gathering system. The West Glycol dehydrator uses a glycol solution to remove water from the plant inlet gas stream. The glycol functions in a continuous, closed loop system, and is regenerated in a thermal reaction. This thermal reaction also removes any hydrocarbons that have been stripped away from the inlet gas stream. Hydrocarbon emissions from the West Dehydration Unit (Unit ID 15) are routed to the plant flare for the destruction of volatile organic compounds. The monitoring approach outlined here applies to the flare, which has a 98% destruction efficiency.

II. Rationale for Selection of Performance Indicators

The use of a thermocouple to detect the presence of pilot flame has been selected as a performance indicator because a continuous pilot flame is necessary to ensure waste gas combustion. The thermocouple monitors the temperature at the pilot flame of the flare. If the pilot flame goes out, the thermocouple detects the absence of the pilot flame, and any necessary repairs that need to be made. The data logger associated with the thermocouple will provide continuous measurements for compliance assessment and recording the number of excursions.

Operating the flare with no visible emissions has been selected as a performance indicator because visible emissions indicate the flare is not functioning properly. The plant control room will monitor the flare continuously via a remote viewing system. If visible emissions are noted on the viewing monitor, Method 22 measurements will confirm the visible emissions to determine the remote viewing system is functioning properly. If visible emissions are observed, the permittee will inspect the control device and make any necessary repairs.

Regular inspections of the performance indicators will ensure the monitoring of proper control device operation.

III. Rationale for Selection of Indicator Ranges

The use of a thermocouple to detect the presence of a pilot flame was selected because the technique already being employed by the permittee is an effective monitoring method for proper flare operation. The pilot flame is necessary to ensure combustion of the waste gas and achieve the desired 98% destruction efficiency. Once the absence of a pilot flame is detected, an alarm will trigger an inspection and repair. Quarterly inspections of the thermocouple system will be used for quality assurance purposes.

The performance indicator requiring flare operation with no visible emissions was selected because visible emissions indicate the flare is not functioning properly. The regulations at 40 CFR Part 60.18(b) provide the visible emission requirements that formed the basis for using this as a performance indicator. The flare is continuously observed in the plant control room via a camera and remote viewing monitoring. If the plant operator observes any visible emissions on the monitor, they will be confirmed with Method 22 readings. Any visible emissions will trigger an inspection and necessary repairs.

**CAM Plan for East Glycol Dehydrator Regenerator Vent (Unit 16)**

I. Background

a. Emissions Unit
Description: East Glycol Dehydrator (regenerator vent controlled by thermal oxidizer)
Identification: Unit ID 16
Facility: Ignacio Gas Plant, Durango, Colorado

b. Applicable Regulations & Emission Limits
Regulation: PSD Permit # PSD-SU-0027-01.00
Emission limits: 5.1 tpy of VOC when both Unit 16 and Unit 17 are operating (Permit Condition II.J.5.a)

c. Control Technology & PTE
Controls: Thermal Oxidizer (Unit ID 22)
Potential pre-control device emissions: 107.7 tpy of VOC
Potential post-control device emissions: 5.1 tpy of VOC

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

a. An excursion outside the indicator range signaling the improper operation of the thermal oxidizer will trigger an inspection, corrective action, recordkeeping, and reporting. Maintenance personnel will inspect the control device and indicator with 24 hours and make necessary repairs as soon as practicable.

b. Any number of excursions that exceed the Quality Improvement Plan (QIP) threshold shall trigger the requirement for a QIP for the associated indicator.

If the Tribe determines that the permittee has not used acceptable procedures in response to excursions of the indicator, the Tribe may require the permittee to prepare a QIP. The QIP will include procedures for evaluating the control performance problems and actions to correct the problems identified. Implementation of QIP shall not excuse the permittee from compliance with any emission limitation or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may apply under any federal, state, or local law, or any other applicable regulation under the Clean Air Act.

**Monitoring Approach: Harvest Ignacio Thermal Oxidizer for East Glycol Dehydrator Regenerator Vent (Unit ID 16)**

| | | Indicator No. 1 | Indicator No. 2 | Indicator No. 3 |
|---|---|---|---|---|
| I. Indicator | | Operate thermal oxidizer combustion chamber above acceptable operating temperature while the east glycol dehydrator is operating. | Operate thermal oxidizer in a manner that achieves desired VOC destruction efficiency to meet emission limits. | Ensure no bypass of the thermal oxidizer is occurring. |
| Measurement Approach | | Continuously measure the temperature of the combustion chamber using a thermocouple or equivalent temperature sensing device equipped with a continuous recording device. | Conduct annual stack test to determine the effectiveness of the thermal oxidizer in controlling VOC emissions. | Any bypass valve that would divert waste gas flow from the thermal oxidizer shall be maintained in a closed position. |
| II. Indicator Range | | An excursion is defined as any detection of a temperature in the combustion chamber below 1,400ºF when the dehydrator is operating. Any temperature detected below this temperature will trigger an alarm to the plant control room, an investigation to determine the problem, and to perform corrective action. Associated recordkeeping and reporting shall be conducted for each excursion event as required. | An excursion is defined as any detection of emissions above the permitted emission limit. | An excursion is defined as any occurrence in which the waste gas flow to the thermal oxidizer is diverted through a bypass line and vented to the atmosphere. The diversion of waste gas through a bypass valve to the atmosphere when necessary to maintain a safe work environment due to upset conditions is not considered an excursion for this indicator. |
| QIP Threshold | | No more than six (6) excursions in any semiannual reporting period. | Any excursions in any annual reporting period. | No more than two (2) excursions in any semiannual reporting period. |
| III. Performance Criteria | A. Data Representativeness | The thermocouple will measure the temperature in the combustion chamber downstream of the combustion | The stack test will determine the destruction efficiency achieved by the thermal oxidizer meets the permitted emission limits. | Monitoring to determine the bypass control valves for waste gas are maintained in a closed position will assure all the |

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| | | zone. The minimum accuracy of the thermocouple is ±5ºF. Requiring the temperature of the combustion chamber above this temperature will ensure the system is operating correctly. | | waste gas is routed to the control device. |
| | B. Verification of Operational Status | Not applicable. | Not applicable. | The observation of waste gas bypass valve in open position and diverted waste gas away from the control device will indicate the control device is malfunctioning. |
| | C.QA/QC Practices/Criteria | The thermal oxidizer system has two (2) thermocouples for redundancy. The backup thermocouple will operate if the primary thermocouple detects a temperature outside the temperature range. | Annual stack test will validate the thermal oxidizer is effectively controlling VOC emissions. The inlet flow and outlet flow of the thermal oxidizer will be measure during the stack test to confirm the destruction efficiency. | All bypass valves which have the potential to divert waste gas away from the thermal oxidizer shall be visually inspected to confirm they are in a closed position on a weekly basis. |
| | D. Monitoring Frequency | The combustion chamber temperature shall be monitored continuously. | The performance test will be conducted annually. | All bypass valves shall be visually inspected on a weekly basis. A flow meter that detects waste gas flow in the bypass line or an electronic monitoring system with alarm notification will satisfy the visual inspection requirement. |
| | E. Data Collection Procedures | The thermocouple shall be equipped with a continuous recording device such as a data logger or chart recorder to monitor proper thermocouple operation. Records of all inspection, maintenance, and | Records of all performance tests shall be provided to the Tribe in an annual report. | A log shall be kept at the facility documenting all weekly inspections of bypass valves. Any excursion shall be documented in the log, along with the date/time of excursion, the personnel that performed |

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| | | repair activities shall be maintained on-site. | | the inspection, and the corrective action taken. |
| | F. Averaging Time | Averaging is not necessary since the thermocouple will operate continuously. | None. | None. |

**Justification**

I. Background

This facility processes natural gas from the San Juan Basin gathering system. The East Glycol dehydrator uses a glycol solution to remove water from the plant inlet gas stream. The glycol functions in a continuous, closed-loop system, and is regenerated in a thermal reaction. This thermal reaction also removes any hydrocarbons that have been stripped away from the inlet gas stream. Hydrocarbon emissions from the East Dehydration Unit (Unit ID 16) are routed to thermal oxidizer for the destruction of volatile organic compounds.

The elevated combustion temperatures found in a thermal oxidizer are required to ensure sufficient destruction (98%+) of the VOCs while overcoming the flame-dampening characteristics found in a carbon dioxide ($CO_2$) rich environment.

II. Rationale for Selection of Performance Indicators

The effectiveness of a thermal oxidizer in terms of waste gas destruction efficiency is usually linked to the operating temperature of the combustion chamber. The rate at which VOCs are oxidized is greatly affected by temperature. A higher operating temperature results in more of the waste gas oxidized to water and carbon dioxide. The combustion chamber operating temperature is used as a performance indicator to monitor the proper operation of the thermal oxidizer.

The destruction efficiency of the thermal oxidizer will be monitored by annual performance test. Performance test measuring the concentration of VOCs in the inlet and outlet flow of the waste gas stream will indicate proper operation of the control device.

Monitoring the status of bypass valves was selected as a performance indicator because bypass valves must be kept in a closed position so that all waste gas is being routed to the control device and not to the atmosphere.

Regular inspections of the performance indicators will ensure the monitoring of proper control device operation.

III. Rationale for Selection of Indicator Ranges

Since the waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature. The core of the thermal oxidizer is a nozzle-stabilized flame maintained by combustion of the auxiliary fuel, waste gas compounds, and supplemental air when necessary. Upon passing through the flame, the waste gas is heated from its inlet temperature to its ignition temperature. The ignition temperature is the temperature at which the combustion reaction rate exceeds the rate of heat losses, raising the temperature of the gases to some higher value. Thus, any organic/air mixture will ignite if its temperature is raised to a sufficiently high level. The organic-containing mixture ignites at a temperature between the preheat temperature and the reaction temperature. That is, ignition occurs at some point during the heating of the waste gas stream as it

passes through the nozzle-stabilized flame regardless of its concentration. It is this ignition temperature that is monitored to ensure the sufficient destruction of VOCs.

If the annual performance test indicates the thermal oxidizer is not achieving the destruction efficiency required to meet the permitted emission limits, the permittee shall inspect the control device and make any necessary repairs to correct the problem. By demonstrating compliance with the permitted emission limits, the performance test indicates the control device is operating correctly.

Any detection of waste gas being diverted through a bypass valve away from the thermal oxidizer was selected because it would result in uncontrolled emissions to the atmosphere. All bypass valves should be maintained in a closed position to effectively route all waste gas to the control device.

**CAM Plan for Amine Unit Regenerator Vent (Unit 17)**

I. Background

a. Emission Unit

Description: Amine Unit (regenerator vent controlled by thermal oxidizer)
Identification: Unit ID 17
Facility: Ignacio Gas Plant, Durango, Colorado

b. Applicable Regulations & Emission Limits

Regulation: PSD Permit #PSD-SU-0027-01.00
Emission Limits: 5.1 tpy of VOC when both Unit 16 and Unit 17 are operating (Permit Condition II.J.5.a)

c. Control Technology & PTE

Controls: Thermal Oxidizer (Unit ID 22)
Potential pre-control device emissions: 296.0 tpy of VOC
Potential post-control device emissions: 3.0 tpy of VOC

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

a. An excursion outside the indicator range signaling the improper operation of the thermal oxidizer will trigger an inspection, corrective action, recordkeeping, and reporting. Maintenance personnel will inspect the control device and indicator within 24 hours and make necessary repairs as soon as practicable.

b. Any number of excursions that exceed the Quality Improvement Plan (QIP) threshold shall trigger the requirement for a QIP for the associated indicator.

If the Tribe determines that the permittee has not used acceptable procedures in response to excursions of the indicator, the Tribe may require the permittee to prepare a QIP. The QIP will include procedures for evaluating the control performance problems and actions to correct the problems identified, implementation of QIP shall not excuse the permittee from compliance with any emission limitation or standard, or any existing monitoring, reporting, or recordkeeping requirement that may apply under any federal, state, or local law, or any other applicable regulation under the Clean Air Act.

**Monitoring Approach: Harvest Ignacio Thermal Oxidizer for Amine Unit Regenerator Vent (Unit ID 17)**

| | | Indicator No. 1 | Indicator No. 2 | Indicator No. 3 |
|---|---|---|---|---|
| I. Indicator | | Operate thermal oxidizer combustion chamber above acceptable operating temperature when the amine unit is operating. | Operate thermal oxidizer in a manner that achieves desired VOC destruction efficiency to meet emission limits. | Ensure no bypass of the thermal oxidizer is occurring. |
| Measurement Approach | | Continuously measure the temperature of the combustion chamber using a thermocouple or equivalent temperature sensing device equipped with a continuous recording device. | Conduct annual stack test to determine the effectiveness of the thermal oxidizer in controlling VOC emissions. | Any bypass valve that would divert waste gas flow from the thermal oxidizer shall be maintained in a closed position. |
| II. Indicator Range | | An excursion is defined as any detection of a temperature in the combustion chamber below 1,400ºF when the amine system is operating. Any temperature detected below this temperature will trigger an alarm to the plant control room, an investigation to determine the problem, and to perform corrective action. Associated recordkeeping and reporting shall be conducted for each excursion event as required. | An excursion is defined as any detection of emissions above the permitted emission limit. | An excursion is defined as any occurrence in which the waste gas flow to the thermal oxidizer is diverted through a bypass line and vented to the atmosphere. The diversion of waste gas through a bypass valve to the atmosphere when necessary to maintain a safe work environment due to upset conditions is not considered an excursion for this indicator. |
| QIP Threshold | | No more than six (6) excursions in any semiannual reporting period. | Any excursions in any annual reporting period. | No more than two (2) excursions in any semiannual reporting period. |
| III. Performance Criteria | A. Data Representativeness | The thermocouple will measure the temperature in the combustion chamber downstream of the combustion | The stack test will determine the destruction efficiency achieved by the thermal oxidizer meets the permitted emission limits. | Monitoring to determine the bypass control valves for waste gas are maintained in a closed position will assure all the |

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| | | zone. The minimum accuracy of the thermocouple is ±5ºF. Requiring the temperature of the combustion chamber above this temperature will ensure the system is operating correctly. | | waste gas is routed to the control device. |
| | B. Verification of Operational Status | Not applicable. | Not applicable. | The observation of waste gas bypass valve in open position and diverted waste gas away from the control device will indicate the control device is malfunctioning. |
| | C.QA/QC Practices/Criteria | The thermal oxidizer system has two (2) thermocouples for redundancy. The backup thermocouple will operate if the primary thermocouple detects a temperature outside the temperature range. | Annual stack test will validate the thermal oxidizer is effectively controlling VOC emissions. The inlet flow and outlet flow of the thermal oxidizer will be measure during the stack test to confirm the destruction efficiency. | All bypass valves which have the potential to divert waste gas away from the thermal oxidizer shall be visually inspected to confirm they are in a closed position on a weekly basis. |
| | D. Monitoring Frequency | The combustion chamber temperature shall be monitored continuously. | The performance test will be conducted annually. | All bypass valves shall be visually inspected on a weekly basis. A flow meter that detects waste gas flow in the bypass line or an electronic monitoring system with alarm notification will satisfy the visual inspection requirement. |
| | E. Data Collection Procedures | The thermocouple shall be equipped with a continuous recording device such as a data logger or chart recorder to monitor proper thermocouple operation. Records of all inspection, maintenance, and | Records of all performance tests shall be provided to the Tribe in an annual report. | A log shall be kept at the facility documenting all weekly inspections of bypass valves. Any excursion shall be documented in the log, along with the date/time of excursion, the personnel that performed |

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| | | repair activities shall be maintained on-site. | | the inspection, and the corrective action taken. |
| | F. Averaging Time | Averaging is not necessary since the thermocouple will operate continuously. | None. | None. |

**Justification**

I. Background

This facility processes natural gas from the San Juan Basin gathering system. Amine Treatment Systems are often used at natural gas processing facilities to remove acid gases such as hydrogen sulfide and $CO_2$ from natural gas streams. The two main processes within an amine unit are absorption and regeneration. A natural gas inlet stream containing acid gases is introduced into an absorption column where the inlet stream is counter-currently contacted with an amine solution. The amine solution absorbs the acid gases, and to some extent small quantities of hydrocarbons in the inlet stream. After the absorption process, the rich amine must be regenerated before it can be reused. The rich amine is sent to a regeneration column to strip the absorbed gas from the amine. These regeneration processes result in acid gases and hydrocarbons released to the atmosphere, a thermal oxidizer is used to control these emissions. The elevated combustion temperatures found in a thermal oxidizer are required to ensure sufficient destruction (98%+) of the VOCs while overcoming the flame-dampening characteristics found in a $CO_2$-rich environment.

II. Rationale for Selection of Performance Indicators

The effectiveness of a thermal oxidizer in terms of waste gas destruction efficiency is usually linked to the operating temperature of the combustion chamber. The rate at which VOCs are oxidized is greatly affected by temperature. A higher operating temperature results in more of the waste gas oxidized to water and carbon dioxide. The combustion chamber operating temperature is used as a performance indicator to monitor the proper operation of the thermal oxidizer.

The destruction efficiency of the thermal oxidizer will be monitored by annual performance test. Performance test measuring the concentration of OVCs in the inlet and outlet flow of the waste gas stream will indicate proper operation of the control device.

Monitoring the status of bypass valves was selected as a performance indicator because bypass valves must be kept in a closed position so that all waste gas is being routed to the control device and not to the atmosphere.

Regular inspections of the performance indicators will ensure the monitoring of proper control device operation.

III. Rationale for Selection of Indicator Ranges

Since the waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature. The core of the thermal oxidizer is a nozzle-stabilized flame maintained by combustion of the

auxiliary fuel, waste gas compounds, and supplemental air when necessary. Upon passing through the flame, the waste gas is heated from its inlet temperature to its ignition temperature. The ignition temperature is the temperature at which the combustion reaction rate exceeds the rate of heat losses, raising the temperature of the gases to some higher value. Thus, any organic/air mixture will ignite if its temperature is raised to a sufficiently high level. The organic-containing mixture ignites at a temperature between the preheat temperature and the reaction temperature. That is, ignition occurs at some point during the heating of the waste gas stream as it passes through the nozzle-stabilized flame regardless of its concentration. It is this ignition temperature that is monitored to ensure the sufficient destruction of VOCs.

If the annual performance test indicates the thermal oxidizer is not achieving the destruction efficiency required to meet the permitted emission limits, the permittee shall inspect the control device and make any necessary repairs to correct the problem. By demonstrating compliance with the permitted emission limits, the performance test indicates the control device is operating correctly.

Any detection of waste gas being diverted through a bypass valve away from the thermal oxidizer was selected because it would result in uncontrolled emissions to the atmosphere. All bypass valves should be maintained in a closed position to effectively route all waste gas to the control device.

## 2. Inspection Information

### 2.1. Driving Directions:

From Durango, Colorado, go southeast approximately 7 miles on US Hwy 160 towards Bayfield. Turn right at stop light onto State Hwy 172. Travel south 2.3 miles towards Ignacio. 0.3 miles after highway curves to the east take a right on County Road 307. Go south 4 miles. Ignacio Gas Plant is on the left (east) side of the road.

### 2.2. Global Positioning System (GPS):

Latitude: N 37.145278
Longitude: W 107.784444

### 2.3. Safety Considerations:

In order to enter the facility, fire retardant clothing, hard hats, safety glasses, and steel toed boots are required. Additionally, upon initial visit and annually thereafter, visitors are required to perform site specific safety training and pass a written exam.