# 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

Danny 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-0027-2017.02
[Replaces Permit No.: V-SUIT-0027-2017.01]

Issue Date: November 23, 2020
Effective Date: November 23, 2020
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 |

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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 450MMscfd 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

The following combustion sources at the La Plata B Compressor Station are equipped with waste heat recovery units:

- Two (2) Solar Taurus T-6502s

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.

**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

<table>
<tr><th>Emission Unit ID</th><th colspan="4">Description</th><th>Control Equipment</th></tr>
<tr><td rowspan="2">12</td><td colspan="4">C.E. Natco MN620740009020 Molecular Sieve Regeneration Heater</td><td rowspan="2">None</td></tr>
<tr><td>Serial No.</td><td>IJ052</td><td>Install Date:</td><td>1/1/1984</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td rowspan="2">12a</td><td colspan="4">Struthers IF – 10 Back-Up Molecular Sieve Regeneration Heater</td><td rowspan="2">None</td></tr>
<tr><td>Serial No.</td><td>NM085347/M050102</td><td>Install Date:</td><td>1/1/1984</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td></td><td colspan="4">Vogt CL. VV – 22.5 Industrial Boiler</td><td rowspan="3">None</td></tr>
<tr><td>13</td><td rowspan="2">Serial No.</td><td>1425</td><td rowspan="2">Install Date:</td><td>1/1/1956</td></tr>
<tr><td>14</td><td>1426</td><td>1/1/1956</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td rowspan="2">15</td><td colspan="4">Sivalls 500 MMscfd TEG Dehydrator Regenerator (West), 3.0 (Steam Heat) MMBtu/hr Glycol Regenerator Reboiler</td><td rowspan="2">Plant Flare (Emission Unit 23)</td></tr>
<tr><td>Serial No.</td><td>26461</td><td>Install Date:</td><td>1992</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td rowspan="2">16</td><td colspan="4">Sivalls 120 MMscfd SB – 18-18H TEG Dehydrator Regenerator (East) 0.75 MMBtu/hr Natural Gas – Fired Glycol Regenerator Reboiler</td><td rowspan="2">Thermal Oxidizer (Emission Unit 22)</td></tr>
<tr><td>Serial No.</td><td>9004-174</td><td>Install Date:</td><td>1/1/1991</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td rowspan="2">17</td><td colspan="4">Amine Unit Regenerator Vent</td><td rowspan="2">Thermal Oxidizer (Emission Unit 22)</td></tr>
<tr><td>Serial No.</td><td></td><td>Install Date:</td><td>1/1/1984</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td rowspan="2">18</td><td colspan="4">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</td><td rowspan="2">2011 Enhanced LDAR</td></tr>
<tr><td rowspan="3">Serial No.</td><td></td><td rowspan="3">Install Date:</td><td>Pre-1971</td></tr>
<tr><td>19</td><td></td><td>1984 PSD</td><td>LDAR Program</td></tr>
<tr><td>20</td><td></td><td>1998 NSPS KKK</td><td>LDAR Program</td></tr>
<tr><td colspan="6"></td></tr>
</table>

| | | | | | |
|---|---|---|---|---|---|
| 21 | Natural Gas Liquids Loadout System (one pipeline and five loading racks) | | | | Plant Flare (Emission Unit 23) |
| | Serial No. | | 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. | | 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. | 1355M | Install Date: | 2/1/2013 | |
| | | | | | |
| | Solar Titan 130 Natural Gas Fired Turbine | | | | |
| 28 | Serial No. | 0710L | Install Date: | 2/1/2013 | None |
| 30 | | 0723L | | 4/4/2014 | None |
| 31 | | 0724L | | 4/4/2014 | None |
| | | | | | |
| 29 | Solar Taurus 70 Natural Gas Fired Turbine (Trunk C) | | | | None |
| | Serial No. | 0764B | Install Date: | 2/1/2013 | |
| | | | | | |
| | Horton 42,000 Gallon Produced Water Storage Tank | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 32 | Serial No. | | Install Date: | 1956 | None |
| 33 | | | | 1956 | None |
| | | | | | |
| | General Electric M3142J A/T Natural Gas Fired Turbine | | | | None |
| *10 | Serial No. | 282514 | Install Date: | 1984 | None |
| *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 |
| N/A | 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 absence of actual emissions data, calculate the annual fee based on the potential to emit (as defined at RAC 1-103(51)) 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 for Engines or Turbine Replacement *[RAC 2-110(8)]*

2.3.1. Replacement of an existing engine 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. Standards of Performance for Stationary Compression Ignition Internal Combustion at 40 CFR Part 60, Subpart IIII;

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

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

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

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

2.3.1.4.8. 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;

2.3.1.4.9. 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

2.3.1.4.10. 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.

## 2.4. Alternative Operating Scenario for Thermal Oxidizer Maintenance/Repair *[RAC 2-110(8)]*

2.4.1. 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:

2.4.1.1. 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.

2.4.1.2. 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.

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

Nothing in this permit shall alter or affect the following:

2.5.1. 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;

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

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

2.5.4. 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.

## Section III – Site Specific Permit Terms

### 1. <u>New Source Performance Standards (NSPS) and 40 CFR Part 60</u>

**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 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 1$^{st}$ of each year and covering the previous twelve-month period from January 1st through the December 31$^{st}$. 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]

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 methane and 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 methane and 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)]

## 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 shall meet all applicable requirements of 40 CFR Part 63 Subparts A and HH as they apply to each affected source as defined at 40 CFR 63.760.

2.1.1. **Affected Sources**

2.1.1.1. The following emission units are affected sources for purposes of 40 CFR Part 63, Subpart HH:

2.1.1.1.1. Emission unit EU-15 (West Dehydrator) – a 500 MMscf/day TEG dehydration unit and associated control device, emission unit EU-23, a continuous pilot smokeless flare.

2.1.1.1.2. Emission Unit EU-16 (East Dehydrator) – a 120 MMscf/day TEG dehydration unit (east dehydrator) and associated control device, emission unit EU-22, a 55 MMBtu/hr thermal oxidizer

2.1.1.1.3. Emission Units 32 and 33 – 42,000 Gallon produced water storage vessels with the potential for flash emissions

2.1.1.1.4. The group of all ancillary equipment, except compressors, located at natural gas processing plants intended to operate in volatile hazardous air pollutant (VHAP) service as determined per the requirements of §63.772(a). Affected sources include but are not limited to portions of the plant within the inlet, fractionation, and storage/loading processes.

[40 CFR 63.760(b)(1)]

### 2.1.2. **General Standards**

2.1.2.1. Table 2 of 40 CFR Part 63, Subpart HH specifies the General Provisions of 40 CFR Part 63, Subpart A that apply to this subpart.

2.1.2.2. All reports required under 40 CFR Part 63, Subpart A shall be sent to the Tribe and EPA at the following addresses:

Submittals to the Tribe must be sent to:
airquality@southernute-nsn.gov

And, submittals to EPA must be sent to:

Director, Air and Toxics Technical Enforcement Program
Office of Enforcement, Compliance and Environmental Justice
1595 Wynkoop Street, Denver, CO 80202-1129
Mail Code 8ENF—AT

[40 CFR 63.764(b)]

2.1.2.3. At all times the owner or operator 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. 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 63.764(j)]

### 2.1.3. **Dehydration Unit Control Equipment Requirements**

The permittee shall comply with the control requirements for existing small dehydration units at a major source of HAPs, as follows:

2.1.3.1. The permittee shall limit BTEX emissions from each process vent, as defined in §63.761, to the limit determined in Equation 1 of §63.765(b)(1)(iii). The limits determined using Equation 1 must be met as follows:

2.1.3.1.1. Emission unit EU-15 shall be controlled with a flare (Emission Unit EU-23) that meets the design and operation requirements for flares as specified in §63.11(b)

2.1.3.1.2. Emission unit EU-16 shall be controlled with an enclosed combustion device (Emission Unit EU-22) designed and operated to meet the levels specified in §63.771(f)(1)(i).

[40 CFR 63.764(c)(1)(i), and 40 CFR 63.771(f)(1)]

2.1.3.2. The process vents on Emission Units EU-15 and EU-16 shall be connected to a control device or combination of control devices through a closed-vent system designed and configured as follows:

2.1.3.2.1. The closed vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the following requirements:

2.1.3.2.1.1. The closed vent system shall be designed and operated with no detectable emissions.

2.1.3.2.1.2. If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, the owner or operator shall meet the requirements specified below:

2.1.3.2.1.2.1. At the inlet to the bypass device that could divert the stream away from the control device to the atmosphere, properly install, calibrate, maintain, and operate a flow indicator that is capable of taking periodic readings and sounding an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere; or

2.1.3.2.1.2.2. Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a lock-and-key type configuration.

2.1.3.2.1.3. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements for bypass devices

2.1.3.3. Each control device used to comply with this subpart shall be operating at all times. The permittee may vent more than one unit to a control device used to comply with this subpart.

[40 CFR 63.765(b)(1)(iii), 40 CFR 63.771(c) and 40 CFR 63.771(f)(2)]

2.1.4. **Test Methods, Compliance Procedures, and Compliance Demonstrations**

2.1.4.1. Each piece of ancillary equipment and compressors are presumed to be in VHAP service or in wet gas service unless the owner or operator demonstrates that the piece of equipment is not in VHAP service or in wet gas service.

2.1.4.1.1. For a piece of ancillary equipment and compressors to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10.0 percent by weight. For the purposes of determining the percent VHAP content of the process fluid that is contained in or contacts a piece of ancillary equipment or compressor, you shall use the method in either paragraph 63.772(a)(1)(i) or paragraph (a)(1)(ii) of this section.

2.1.4.1.1.1. Method 18 of 40 CFR part 60, appendix A, or

2.1.4.1.1.2. ASTM D6420-99 (2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference - see §63.14), provided that the provisions of paragraphs 63.772(a)(1)(ii)(A) through (D) of this section are followed:

2.1.4.1.1.2.1. The target compound(s) are those listed in section 1.1 of ASTM D6420-99 (2004);

2.1.4.1.1.2.2. The target concentration is between 150 parts per billion by volume and 100 parts per million by volume;

2.1.4.1.1.2.3. For target compound(s) not listed in Table 1.1 of ASTM D6420-99 (2004), but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in section 10.5.3 of ASTM D6420-99 (2004), is conducted, met, documented, and submitted with the data report, even if there is no moisture condenser used or the compound is not considered water soluble; and

2.1.4.1.1.2.4. For target compound(s) not listed in Table 1.1 of ASTM D6420-99 (2004), and not amenable to detection by mass spectrometry, ASTM D6420-99 (2004) may not be used.

2.1.4.1.2. For a piece of ancillary equipment and compressors to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction of natural gas liquids.

[40 CFR 63.772(a)]

2.1.4.2. The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

2.1.4.2.1. The determination of actual flowrate of natural gas to a glycol dehydration unit shall be made using the procedures of either paragraph 63.772(b)(2)(i) or (ii) of this section.

2.1.4.2.1.1. The owner or operator shall install and operate a monitoring instrument that directly measures natural gas flowrate to the glycol dehydration unit with an accuracy of plus or minus 2 percent or better. The owner or operator shall convert annual natural gas flowrate to a daily average by dividing the annual flowrate by the number of days per year the glycol dehydration unit processed natural gas.

2.1.4.2.1.2. The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

2.1.4.2.2. The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either 63.772(b)(2)(i) or (ii) of this section. Emissions shall be determined with federally enforceable controls in place.

2.1.4.2.2.1. The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI-GLYCalcTM, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalcTM Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1); or

2.1.4.2.2.2. The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in §63.772(a)(1)(i) or (ii), or an alternative method according to §63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

[40 CFR 63.772(b)]

2.1.4.3. <u>Test Procedures for Small Dehydrators equipped with a Flare Control Device</u>

2.1.4.3.1. The compliance determination for Emission Unit EU-23, a flare control device as defined in §63.761, shall be conducted using Method 22 of 40 CFR part 60, Appendix A, to determine visible emissions. Emission Unit EU-23 is exempt from the requirements to conduct performance tests and design analyses under §63.772(e).

[40 CFR 63.772(e)(1)(i) and 40 CFR 63.772(e)(2)]

2.1.4.4. <u>Test Procedures for Small Dehydrators equipped with an Enclosed Combustion Device</u>

2.1.4.4.1. To determine compliance with the BTEX emission limit for Emission Unit EU-22, a thermal oxidizer, the permittee shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420-99 (Reapproved 2004), as specified in §63.772(a)(1)(ii) (incorporated by reference as specified in §63.14); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

2.1.4.4.1.1. The sampling site shall be located at the outlet of the combustion device.

2.1.4.4.1.2. The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

2.1.4.4.1.3. The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

2.1.4.4.2. The mass rate of BTEX (Eo) shall be computed using the equations and procedures specified below:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

$E_o$ = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour

$C_{oj}$ = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume

$M_{oj}$ = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole

$Q_o$ = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute

$K_2$ = Constant, $2.494 \times 10^{-6}$ (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C

n = Number of components in sample

2.1.4.4.2.1. When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420-99 (Reapproved 2004) (incorporated by reference as specified in §63.14), shall be summed using the *mass rate of BTEX* equation above.

[40 CFR 63.772(e)(3)(v)]

2.1.4.5. <u>Enclosed Combustion Device Performance Testing Schedule</u>

2.1.4.5.1. The permittee shall conduct performance test for Emission Unit E-22, an existing combustion control device at a major source of HAPs, according to the schedule specified below:

2.1.4.5.1.1. An initial performance shall be conducted no later than October 15, 2015.

2.1.4.5.1.2. The first periodic performance tests shall be conducted no later than 60 months after the initial performance test. Subsequent periodic performance tests shall be conducted ate intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit.

2.1.4.5.1.3. A combustion control device demonstrating during the initial performance test that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C is not required to conduct periodic performance tests.

[40 CFR 63.772(e)(3)(vi)]

2.1.4.6. <u>Compliance Demonstration Requirements for Small Dehydrators equipped with an Enclosed Combustion Device:</u>

2.1.4.6.1. The permittee shall demonstrate compliance with the control device performance requirements for Emission Unit EU-22, by following the requirements specified below:

2.1.4.6.1.1. The permittee shall establish a site specific maximum or minimum monitoring parameter value (as appropriate) according to the requirements of §63.773(d)(5)(i).

2.1.4.6.1.2. The permittee shall calculate the daily average of the applicable monitored parameter in accordance with §63.773(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

2.1.4.6.1.3. Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under §63.772(h) or under the performance test conducted under §63.772(e), as applicable.

2.1.4.6.1.4. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

2.1.4.6.1.5. Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

2.1.4.6.1.6. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

[40 CFR 63.772(f)]

2.1.4.7. <u>Requirements for ancillary equipment and compressors</u>

2.1.4.7.1. Each piece of ancillary equipment and compressors are presumed to be in VHAP service or in wet gas service unless the owner or operator demonstrates that the piece of equipment is not in VHAP service or in wet gas service.

2.1.4.7.2. For a piece of ancillary equipment and compressors to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10.0 percent by weight. For the purposes of determining the percent VHAP content of the process fluid that is contained in or contacts a piece of ancillary equipment or compressor, you shall use one of the methods listed in the following two paragraphs:

2.1.4.7.2.1. Method 18 of 40 CFR part 60, appendix A, or

2.1.4.7.2.2. ASTM D6420-99 (2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference—see §63.14), provided that the provisions of the following paragraphs are followed:

2.1.4.7.2.2.1. The target compound(s) are those listed in section 1.1 of ASTM D6420-99 (2004);

2.1.4.7.2.2.2. The target concentration is between 150 parts per billion by volume and 100 parts per million by volume;

2.1.4.7.2.2.3. For target compound(s) not listed in Table 1.1 of ASTM D6420-99 (2004), but potentially detected by mass spectrometry, the additional system continuing calibration check after each run, as detailed in section 10.5.3 of ASTM D6420-99 (2004), is conducted, met, documented, and submitted with the data report, even if there is no moisture condenser used or the compound is not considered water soluble; and

2.1.4.7.2.2.4. For target compound(s) not listed in Table 1.1 of ASTM D6420-99 (2004), and not amenable to detection by mass spectrometry, ASTM D6420-99 (2004) may not be used.

2.1.4.7.3. For a piece of ancillary equipment and compressors to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction of natural gas liquids.

[40 CFR 63.772(a)]

2.1.5. **Monitoring Requirements**

2.1.5.1. The owner or operator shall comply with the monitoring requirements specified in this section.

2.1.5.1.1. Each closed-vent system shall be inspected according to the procedures and schedule specified in paragraphs 63.773(c)(2)(i) and (ii).

2.1.5.1.1.1. For each closed-vent system joints, seams, or other connections that are permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), the owner or operator shall:

2.1.5.1.1.1.1. Conduct an initial inspection according to the procedures specified in §63.772(c) to demonstrate that the closed-vent system operates with no detectable emissions. Inspection results shall be submitted with the Notification of Compliance Status Report as specified in §63.775(d)(1) or (2).

2.1.5.1.1.1.2. Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. The owner or operator shall monitor a component or connection using the procedures in §63.772(c) to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. Inspection results shall be submitted in the Periodic Report as specified in §63.775(e)(2)(iii).

2.1.5.1.2. In the event that a leak or defect is detected, the owner or operator shall repair the leak or defect as soon as practicable.

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

2.1.5.1.2.2. Repair shall be completed no later than 15 calendar days after the leak is detected.

2.1.5.1.3. Delay of repair of a closed-vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in §63.761, or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next shutdown.

2.1.5.1.4. Any parts of the closed-vent system that are designated as difficult to inspect are exempt from the inspection requirements of this section if:

2.1.5.1.4.1. The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

2.1.5.1.4.2. The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years.

[40 CFR 63.773(c)]

2.1.5.1.5. For each control device, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements §63.771(f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

2.1.5.1.5.1. Each continuous parameter monitoring system shall measure data values at least once every hour and record each measured data value.

2.1.5.1.5.2. A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph 63.773(d) and in §63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in the approved site-specific monitoring plan. Using the process described in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs 63.773(d)(1)(ii)(A) through (E) in your site-specific monitoring plan.

2.1.5.1.5.2.1. The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

2.1.5.1.5.2.2. Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements;

2.1.5.1.5.2.3. Equipment performance checks, system accuracy audits, or other audit procedures;

2.1.5.1.5.2.4. Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (3); and

2.1.5.1.5.2.5. Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

2.1.5.1.5.3. The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

2.1.5.1.5.4. The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

2.1.5.1.6. The owner or operator shall install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph 63.773(d)(3)(i).

2.1.5.1.6.1. A continuous monitoring system that measures the following operating parameters:

2.1.5.1.6.1.1. For a thermal vapor incinerator that demonstrates during the performance test conducted under §63.772(e) that the combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

2.1.5.1.6.1.2. For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

2.1.5.1.7. Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

2.1.5.1.8. For each operating parameter monitor installed in accordance with the requirements of paragraph 63.773(d)(3)(i), the owner or operator shall comply with the following paragraph for all control devices.

2.1.5.1.8.1. The owner or operator shall establish a minimum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §63.771(f)(1). Each minimum operating parameter value shall be established as follows:

2.1.5.1.8.1.1. If the owner or operator conducts performance tests in accordance with the requirements of §63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in §63.771(f)(1), then the minimum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by control device manufacturer recommendations.

2.1.5.1.9. An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs 63.773(d)(6)(i) through (vi) being met. When multiple operating parameters are monitored for the same control device and during the same operating day and more than one of these operating parameters meets an excursion criterion specified in paragraphs 63.773(d)(6)(i) through (vi), then a single excursion is determined to have occurred for the control device for that operating day.

2.1.5.1.9.1. An excursion occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established for the operating parameter in accordance with the requirements of paragraph 63.773(d)(5)(i).

2.1.5.1.9.2. An excursion occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

2.1.5.1.9.3. If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, an excursion occurs when:

2.1.5.1.9.3.1. For each bypass line subject to §63.771(c)(3)(i)(A) the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

2.1.5.1.9.3.2. For each bypass line subject to §63.771(c)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

2.1.5.1.10. For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

[40 CFR 63.764(c)(1)(ii) and 63.773(d)]

2.1.6. **Recordkeeping Requirements**

2.1.6.1. Table 2 of this subpart specifies the recordkeeping provisions of 40 CFR part 63, subpart A that apply.

2.1.6.2. The owner or operator of an affected facility shall maintain the records specified in this section.

2.1.6.2.1. The owner or operator of an affected source shall maintain files of all information (including all reports and notifications) required by this subpart. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or period.

2.1.6.2.1.1. All applicable records shall be maintained in such a manner that they can be readily accessed.

2.1.6.2.1.2. The most recent 12 months of records shall be retained on site or shall be accessible from a central location by computer or other means that provides access within 2 hours after a request.

2.1.6.2.1.3. The remaining 4 years of records may be retained offsite.

2.1.6.2.1.4. Records may be maintained in hard copy or computer-readable form.

[40 CFR 63.774(b)(1)]

2.1.6.2.2. The owner or operator shall maintain relevant records for such source of:

2.1.6.2.2.1. The occurrence and duration of each startup or shutdown when the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards;

2.1.6.2.2.2. The occurrence and duration of each malfunction of operation (i.e., process equipment) or the required air pollution control and monitoring equipment;

2.1.6.2.2.3. All required maintenance performed on the air pollution control and monitoring equipment;

2.1.6.2.2.3.1. Actions taken during periods of startup or shutdown when the source exceeded applicable emission limitations in a relevant standard and when the actions taken are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan (see §63.6(e)(3)); or

2.1.6.2.2.3.2. Actions taken during periods of malfunction (including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation) when the actions taken are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan (see §63.6(e)(3));

2.1.6.2.2.4. All information necessary, including actions taken, to demonstrate conformance with the affected source's startup, shutdown, and malfunction plan (see §63.6(e)(3)) when all actions taken during periods of startup or shutdown (and the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), and malfunction (including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. (The information needed to demonstrate conformance with the startup, shutdown, and malfunction plan may be recorded using a "checklist," or some other effective form of recordkeeping, in order to minimize the recordkeeping burden for conforming events);

2.1.6.2.2.5. Each period during which a CMS is malfunctioning or inoperative (including out-of-control periods);

2.1.6.2.2.6. All required measurements needed to demonstrate compliance with a relevant standard (including, but not limited to, 15-minute averages of CMS data, raw performance testing measurements, and raw performance evaluation measurements, that support data that the source is required to report);

2.1.6.2.2.6.1. This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (b)(2)(vii) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

2.1.6.2.2.6.2. This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (b)(2)(vii) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

2.1.6.2.2.6.3. The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph 63.10(b)(2)(vii) if the administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

2.1.6.2.2.7. All results of performance tests, CMS performance evaluations, and opacity and visible emission observations;

2.1.6.2.2.8. All measurements as may be necessary to determine the conditions of performance tests and performance evaluations;

2.1.6.2.2.9. All CMS calibration checks;

2.1.6.2.2.10. All adjustments and maintenance performed on CMS;

2.1.6.2.2.11. Any information demonstrating whether a source is meeting the requirements for a waiver of recordkeeping or reporting requirements under this part, if the source has been granted a waiver under paragraph §63.10(f);

2.1.6.2.2.12. All emission levels relative to the criterion for obtaining permission to use an alternative to the relative accuracy test, if the source has been granted such permission under §63.8(f)(6); and

2.1.6.2.2.13. All documentation supporting initial notifications and notifications of compliance status under §63.9.

[40 CFR 63.10(b)(2) and 63.774(b)(2)]

2.1.6.2.3. Notwithstanding the requirements of §63.10(c), monitoring data recorded during periods identified in paragraphs 63.774(b)(3)(i) through (iv) shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

2.1.6.2.3.1. Monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments;

2.1.6.2.3.2. Periods of non-operation resulting in cessation of the emissions to which the monitoring applies; and

2.1.6.2.3.3. Excursions due to invalid data as defined in §63.773(d)(6)(iv).

2.1.6.2.4. In addition to complying with the requirements specified above, the owner or operator of an affected source required to install a CMS by a relevant standard shall maintain records for such source of:

2.1.6.2.4.1. All required CMS measurements (including monitoring data recorded during unavoidable CMS breakdowns and out-of-control periods);

2.1.6.2.4.2. The date and time identifying each period during which the CMS was inoperative except for zero (low-level) and high-level checks;

2.1.6.2.4.3. The date and time identifying each period during which the CMS was out of control, as defined in §63.8(c)(7);

2.1.6.2.4.4. The specific identification (i.e., the date and time of commencement and completion) of each period of excess emissions and parameter monitoring exceedances, as defined in the relevant standard(s), that occurs during startups, shutdowns, and malfunctions of the affected source;

2.1.6.2.4.5. The specific identification (i.e., the date and time of commencement and completion) of each time period of excess emissions and parameter monitoring exceedances, as defined in the relevant standard(s), that occurs during periods other than startups, shutdowns, and malfunctions of the affected source;

2.1.6.2.4.6. The nature and cause of any malfunction (if known);

2.1.6.2.4.7. The corrective action taken or preventive measures adopted;

2.1.6.2.4.8. The nature of the repairs or adjustments to the CMS that was inoperative or out of control;

2.1.6.2.4.9. The total process operating time during the reporting period; and

2.1.6.2.4.10. All procedures that are part of a quality control program developed and implemented for CMS under §63.8(d).

2.1.6.2.4.11. In order to satisfy the requirements of 63.774(c)(10) through (c)(12) and to avoid duplicative recordkeeping efforts, the owner or operator may use the affected source's startup, shutdown, and malfunction plan or records kept to satisfy the recordkeeping requirements of the startup, shutdown, and malfunction plan specified in §63.6(e), provided that such plan and records adequately address the requirements of 63.774(c)(10) through (c)(12).

[40 CFR 63.10(c), 63.774(b)(3), and 63.764(c)(1)(iii)]

2.1.6.2.5. The owner or operator shall keep the following records up-to-date and readily accessible:

2.1.6.2.5.1. Continuous records of the equipment operating parameters specified to be monitored under §63.773(d) or specified by the Administrator in accordance with §63.773(d)(3)(iii).

2.1.6.2.5.2. Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in §63.773(d)(4) of this subpart.

2.1.6.2.5.3. Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

2.1.6.2.6. Records identifying all parts of the cover or closed-vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

2.1.6.2.7. Records identifying all parts of the cover or closed-vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

2.1.6.2.8. For each inspection conducted in accordance with §63.773(c), during which a leak or defect is detected, the following information:

2.1.6.2.8.1. The instrument identification numbers, operator name or initials, and identification of the equipment.

2.1.6.2.8.2. The date the leak or defect was detected and the date of the first attempt to repair the leak or defect.

2.1.6.2.8.3. Maximum instrument reading measured by the method specified in §63.772(c) after the leak or defect is successfully repaired or determined to be nonrepairable.

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

2.1.6.2.8.5. The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

2.1.6.2.8.6. The expected date of successful repair of the leak or defect if a leak or defect is not repaired within 15 calendar days.

2.1.6.2.8.7. Dates of shutdowns that occur while the equipment is unrepaired.

2.1.6.2.8.8. The date of successful repair of the leak or defect.

2.1.6.2.9. For each inspection conducted in accordance with §63.773(c) during which no leaks or defects are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks or defects were detected.

2.1.6.2.10. Records identifying ancillary equipment and compressors that are subject to and controlled under the provisions of 40 CFR part 60, subpart KKK; 40 CFR part 61, subpart V; or 40 CFR part 63, subpart H.

[40 CFR 63.774(b)]

2.1.6.2.11. The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with §63.764(j), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.774(g)]

2.1.7. **Reporting Requirements**

2.1.7.1. The owner or operator shall submit the information listed in this section.

2.1.7.1.1. The initial notifications required for existing affected sources under §63.9(b)(2) shall be submitted as provided in the following paragraphs.

2.1.7.1.1.1. Except as otherwise provided in the following paragraph, the initial notifications shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000, and plan to be area sources by June 17, 2002, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

2.1.7.1.1.2. An affected source identified under §63.760(f)(7) or (9) shall submit an initial notification required for existing affected sources under §63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by October 15, 2013, whichever is later. An affected source identified under §63.760(f)(7) or (9) that plans to be an area source by October 15, 2015, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

2.1.7.1.2. The date of the performance evaluation as specified in §63.8(e)(2), required only if the owner or operator is required by the Administrator to conduct a performance evaluation for a continuous monitoring system. A separate notification of the performance evaluation is not required if it is included in the initial notification submitted in accordance with paragraph 63.775(b)(1).

2.1.7.1.3. The planned date of a performance test at least 60 days before the test in accordance with §63.7(b). Unless requested by the Administrator, a site-specific test plan is not required by this subpart. If requested by the Administrator, the owner or operator must also submit the site-specific test plan required by §63.7(c) with the notification of the performance test. A separate notification of the performance test is not required if it is included in the initial notification submitted in accordance with paragraph 63.775(b)(1) of this section.

2.1.7.1.4. A Notification of Compliance Status report as described in paragraph 63.775(d);

2.1.7.1.5. Periodic Reports as described in paragraph 63.775(e); and

2.1.7.1.6. If there was a malfunction during the reporting period, the Periodic Report specified in 63.775(e) shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.764(j), including actions taken to correct a malfunction.

[40 CFR 63.775(b)]

2.1.7.2. Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status Report as required under §63.9(h) within 180 days after the compliance date specified in §63.760(f). In addition to the information required under §63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs 63.775(d)(1) through (12). This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph has been submitted at any time prior to 180 days after the applicable compliance dates specified in §63.760(f), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs 63.775(d)(1) through (12) at different times, and/or different submittals, subsequent submittals may refer to previous submittals instead of duplicating and resubmitting the previously submitted information.

2.1.7.2.1. For the closed-vent system and thermal oxidizer, the owner or operators shall submit the following information:

2.1.7.2.1.1. Performance test results including the information specified in the following two paragraphs of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in §63.772(e)(3) and that the test conditions are representative of current operating conditions.

2.1.7.2.1.1.1. The percent reduction of HAP or TOC, or the outlet concentration of HAP or TOC (parts per million by volume on a dry basis), determined as specified in §63.772(e)(3) of this subpart; and

2.1.7.2.1.1.2. The value of the monitored parameters specified in §63.773(d) of this subpart, or a site-specific parameter approved by the permitting agency, averaged over the full period of the performance test.

2.1.7.2.1.2. The results of the closed-vent system initial inspections performed according to the requirements in §63.773(c)(2)(i) and (ii).

2.1.7.2.2. For the closed-vent system and flare, the owner or operator shall submit the performance test results including the information in the following three paragraphs.

2.1.7.2.2.1. All visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by §63.772(e)(2) of this subpart.

2.1.7.2.2.2. A statement of whether a flame was present at the pilot light over the full period of the compliance determination.

2.1.7.2.2.3. The results of the closed-vent system initial inspections performed according to the requirements in §63.773(c)(2)(i) and (ii).

2.1.7.2.3. The owner or operator shall submit the following information for ancillary equipment and compressors which operate in VHAP service equal to or greater than 300 hours per calendar year:

2.1.7.2.3.1. A statement in writing notifying the Administrator that the requirements of §61.247 are being implemented and containing the following information for each source:

2.1.7.2.3.1.1. Equipment identification number and process unit identification.

2.1.7.2.3.1.2. Type of equipment (for example, a pump or pipeline valve).

2.1.7.2.3.1.3. Percent by weight VHAP in the fluid at the equipment.

2.1.7.2.3.1.4. Process fluid state at the equipment (gas/vapor or liquid).

2.1.7.2.3.1.5. Method of compliance with the standard (for example, “monthly leak detection and repair” or “equipped with dual mechanical seals”).

2.1.7.2.3.2. The number of each equipment (e.g., valves, pumps, etc.) excluding equipment in vacuum service, and

2.1.7.2.3.3. Any change in the information submitted in this paragraph shall be provided to the Administrator as a part of subsequent Periodic Reports described in 63.775(e)(2)(iv).

2.1.7.2.4. The owner or operator shall submit one complete test report for each test method used for a particular source.

2.1.7.2.4.1. For additional tests performed using the same test method, the results specified in 63.775(d)(1)(ii) shall be submitted, but a complete test report is not required.

2.1.7.2.4.2. A complete test report shall include a sampling site description, description of sampling and analysis procedures and any modifications to standard procedures, quality assurance procedures, record of operating conditions during the test, record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, documentation of calculations, and any other information required by the test method.

2.1.7.2.5. For the thermal oxidizer, the owner or operator shall submit the following information for each operating parameter required to be monitored in accordance with the requirements of §63.773(d):

2.1.7.2.5.1. The minimum operating parameter value or maximum operating parameter value, as appropriate for the control device, established by the owner or operator to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements.

2.1.7.2.5.2. An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in §63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of §63.771(f)(1).

2.1.7.2.5.3. A definition of the source's operating day for purposes of determining daily average values of monitored parameters. The definition shall specify the times at which an operating day begins and ends.

2.1.7.2.6. Results of any continuous monitoring system performance evaluations shall be included in the Notification of Compliance Status Report.

2.1.7.2.7. After a title V permit has been issued to the owner or operator of an affected source, the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this subpart. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this subpart, the owner or operator of such source shall submit the notification of compliance status to the Southern Ute Indian Tribe Air Quality Program following completion of the relevant compliance demonstration activity specified in this subpart.

2.1.7.2.8. The owner or operator shall submit the analysis performed under §63.760(a)(1).

2.1.7.2.9. The owner or operator shall submit a statement as to whether the source has complied with the requirements of this subpart.

2.1.7.2.10. The owner or operator shall submit the analysis prepared under §63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve the BTEX limit in §63.765(b)(1)(iii), through process modifications or a combination of process modifications and one or more control devices.

[40 CFR 63.775(d) and 63.764(c)(iii)]

2.1.7.3. The owner or operator shall prepare periodic reports in accordance with the following subparagraphs and submit them to the Tribe.

2.1.7.3.1. Periodic reports shall be submitted semiannually beginning 60 calendar days after the end of the applicable reporting period. The first report shall be submitted no later than 240 days after the date the Notification of Compliance Status Report is due and shall cover the 6-month period beginning on the date the Notification of Compliance Status Report is due.

2.1.7.3.2. The owner or operator shall include the information specified in the following subparagraphs, as applicable.

2.1.7.3.2.1. The following information contained in §63.10(e)(3). For the purposes of this section, excursions (as defined in §63.773(d)(6)) shall be considered excess emissions.

2.1.7.3.2.1.1. Excess emissions and parameter monitoring exceedances are defined in relevant standards. The owner or operator of an affected source required to install a CMS by a relevant standard shall submit an excess emissions and continuous monitoring system performance report and/or a summary report to the Administrator semiannually, except when:

2.1.7.3.2.1.1.1. More frequent reporting is specifically required by a relevant standard;

2.1.7.3.2.1.1.2. The Administrator determines on a case-by-case basis that more frequent reporting is necessary to accurately assess the compliance status of the source; or

2.1.7.3.2.1.1.3. The affected source is complying with the Performance Track Provisions of §63.16, which allows less frequent reporting.

2.1.7.3.2.1.2. Notwithstanding the frequency of reporting requirements specified in paragraph 63.10(e)(3)(i), an owner or operator who is required by a relevant standard to submit excess emissions and continuous monitoring system performance (and summary) reports on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

2.1.7.3.2.1.2.1. For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected source's excess emissions and continuous monitoring system performance reports continually demonstrate that the source is in compliance with the relevant standard;

2.1.7.3.2.1.2.2. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the relevant standard; and

2.1.7.3.2.1.2.3. The Administrator does not object to a reduced frequency of reporting for the affected source, as provided in paragraph 63.10(e)(3)(iii) of this section.

2.1.7.3.2.1.3. The frequency of reporting of excess emissions and continuous monitoring system performance (and summary) reports required to comply with a relevant standard may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the 5-year recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

2.1.7.3.2.1.4. As soon as CMS data indicate that the source is not in compliance with any emission limitation or operating parameter specified in the relevant standard, the frequency of reporting shall revert to the frequency specified in the relevant standard, and the owner or operator shall submit an excess emissions and continuous monitoring system performance (and summary) report for the noncomplying emission points at the next appropriate reporting period following the noncomplying event. After demonstrating ongoing compliance with the relevant standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard, as provided for in paragraphs 63.10(e)(ii) and (iii).

2.1.7.3.2.1.5. Content and submittal dates for excess emissions and monitoring system performance reports. All excess emissions and monitoring system performance reports and all summary reports, if required, shall be delivered or postmarked by the 30th day following the end of each calendar half or quarter, as appropriate. Written reports of excess emissions or exceedances of process or control system parameters shall include all the information required in paragraphs §63.10(c)(5) through (c)(13) of this section, in §§63.8(c)(7) and 63.8(c)(8), and in the relevant standard, and they shall contain the name, title, and signature of the responsible official who is certifying the accuracy of the report. When no excess emissions or exceedances of a parameter have occurred, or a CMS has not been inoperative, out of control, repaired, or adjusted, such information shall be stated in the report.

2.1.7.3.2.1.6. Summary report. As required under 63.10(e)(3)(vii) and (viii), one summary report shall be submitted for the hazardous air pollutants monitored at each affected source (unless the relevant standard specifies that more than one summary report is required, e.g., one summary report for each hazardous air pollutant monitored). The summary report shall be entitled "Summary Report—Gaseous and Opacity Excess Emission and Continuous Monitoring System Performance" and shall contain the following information:

2.1.7.3.2.1.6.1. The company name and address of the affected source;

2.1.7.3.2.1.6.2. An identification of each hazardous air pollutant monitored at the affected source;

2.1.7.3.2.1.6.3. The beginning and ending dates of the reporting period;

2.1.7.3.2.1.6.4. A brief description of the process units;

2.1.7.3.2.1.6.5. The emission and operating parameter limitations specified in the relevant standard(s);

2.1.7.3.2.1.6.6. The monitoring equipment manufacturer(s) and model number(s);

2.1.7.3.2.1.6.7. The date of the latest CMS certification or audit;

2.1.7.3.2.1.6.8. The total operating time of the affected source during the reporting period;

2.1.7.3.2.1.6.9. An emission data summary (or similar summary if the owner or operator monitors control system parameters), including the total duration of excess emissions during the reporting period (recorded in minutes for opacity and hours for gases), the total duration of excess emissions expressed as a percent of the total source operating time during that reporting period, and a breakdown of the total duration of excess emissions during the reporting period into those that are due to startup/shutdown, control equipment problems, process problems, other known causes, and other unknown causes;

2.1.7.3.2.1.6.10. A CMS performance summary (or similar summary if the owner or operator monitors control system parameters), including the total CMS downtime during the reporting period (recorded in minutes for opacity and hours for gases), the total duration of CMS downtime expressed as a percent of the total source operating time during that reporting period, and a breakdown of the total CMS downtime during the reporting period into periods that are due to monitoring equipment malfunctions, nonmonitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes;

2.1.7.3.2.1.6.11. A description of any changes in CMS, processes, or controls since the last reporting period;

2.1.7.3.2.1.6.12. The name, title, and signature of the responsible official who is certifying the accuracy of the report; and

2.1.7.3.2.1.6.13. The date of the report.

2.1.7.3.2.1.7. If the total duration of excess emissions or process or control system parameter exceedances for the reporting period is less than 1 percent of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report shall be submitted, and the full excess emissions and continuous monitoring system performance report need not be submitted unless required by the Administrator.

2.1.7.3.2.1.8. If the total duration of excess emissions or process or control system parameter exceedances for the reporting period is 1 percent or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, both the summary report and the excess emissions and continuous monitoring system performance report shall be submitted.

[40 CFR 63.10(e)(3) and 63.775(e)(2)(i)]

2.1.7.3.2.2. A description of all excursions as defined in §63.773(d)(6) of this subpart that have occurred during the 6-month reporting period.

2.1.7.3.2.2.1. For each excursion caused when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit), as specified in §63.773(d)(6)(i), the report must include the daily average values of the monitored parameter, the applicable operating parameter limit, and the date and duration of the period that the excursion occurred.

2.1.7.3.2.2.2. For each excursion caused by the lack of monitoring data, as specified in §63.773(d)(6)(iv), the report must include the date and duration of the period when the monitoring data were not collected and the reason why the data were not collected.

2.1.7.3.2.2.3. For each excursion caused when the maximum inlet gas flowrate identified under §63.772(h) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

2.1.7.3.2.2.4. For each excursion caused when visible emissions determined under §63.772(i) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred, repairs affected to the unit, and date the unit was returned to service.

2.1.7.3.2.3. For each inspection conducted in accordance with §63.773(c) during which a leak or defect is detected, the following records must be included in the next Periodic Report:

2.1.7.3.2.3.1. The instrument identification numbers, operator name or initials, and identification of the equipment.

2.1.7.3.2.3.2. The date the leak or defect was detected and the date of the first attempt to repair the leak or defect.

2.1.7.3.2.3.3. Maximum instrument reading measured by the method specified in §63.772(c) after the leak or defect is successfully repaired or determined to be nonrepairable.

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

2.1.7.3.2.3.5. The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.

2.1.7.3.2.3.6. The expected date of successful repair of the leak or defect if a leak or defect is not repaired within 15 calendar days.

2.1.7.3.2.3.7. Dates of shutdowns that occur while the equipment is unrepaired.

2.1.7.3.2.3.8. The date of successful repair of the leak or defect.

2.1.7.3.2.3.9. Records identifying the carbon replacement schedule under §63.771(d)(5) and records of each carbon replacement.

2.1.7.3.2.4. For each owner or operator subject to the provisions specified in §63.769, the owner or operator shall comply with the reporting requirements specified in 40 CFR 61.247, except that the Periodic Reports shall be submitted on the schedule specified in paragraph 63.775(e)(1).

2.1.7.3.2.5. The information in the paragraphs below shall be stated in the Periodic Report, when applicable:

2.1.7.3.2.5.1. No excursions

2.1.7.3.2.5.2. No continuous monitoring system has been inoperative, out of control, repaired, or adjusted

2.1.7.3.2.6. Any change in compliance methods as specified in §63.772(f).

2.1.7.3.2.7. For flares, all hourly records and other recorded periods when the pilot flame is absent.

2.1.7.3.2.8. The results of any periodic test as required in §63.772(e)(3) conducted during the reporting period.

2.1.7.3.2.9. 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.

2.1.7.4. Whenever a process change is made, or a change in any of the information submitted in the Notification of Compliance Status Report, the owner or operator shall submit a report within 180 days after the process change is made or as a part of the next Periodic Report as required under paragraph 63.775(e) of this section, whichever is sooner. The report shall include:

2.1.7.4.1. A brief description of the process change;

2.1.7.4.2. A description of any modification to standard procedures or quality assurance procedures;

2.1.7.4.3. Revisions to any of the information reported in the original Notification of Compliance Status Report under paragraph 63.775(d); and

2.1.7.4.4. Information required by the Notification of Compliance Status Report under paragraph 63.775(d) for changes involving the addition of processes or equipment.

[40 CFR 63.775(e) and 63.764(c)(1)(iii)]

2.1.7.5. *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in §63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

2.1.7.6. All reports required by this subpart not subject to the requirements in paragraph 63.775(g)(1) of this section must be sent to the Tribe and the Administrator at the addresses listed below:

Submittals to the Tribe must be sent to:
airquality@southernute-nsn.gov

And, submittals to Administrator (EPA) must be sent to:

Director, Air and Toxics Technical Enforcement Program
Office of Enforcement, Compliance and Environmental Justice
1595 Wynkoop Street, Denver, CO 80202-1129
Mail Code 8ENF—AT

2.1.7.7. The Tribe or the Administrator may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph 63.775(g)(1) of this section in paper format.

## 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 2c 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 63.6602, 40 CFR 63.6625(i), and Table 2c. 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. For each CEMS or CPMS, the permittee must keep the following records:

2.2.4.2.1. Records described in §63.10(b)(2)(vi) through (xi).

2.2.4.2.2. Previous (i.e. superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

2.2.4.2.3. Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

[40 CFR 63.6655(b)]

2.2.4.3. 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)]

2.2.4.4. 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)]

2.2.4.5. The permittee must follow the requirements listed below:

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

2.2.4.5.2. 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.

2.2.4.5.3. 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)]

2.2.4.6. 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)]

2.2.4.7. 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)]

2.2.4.8. 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 DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters *[40 CFR 63.7480 – 63.7575 & RAC 4-103]*

The permittee shall meet all applicable requirements of 40 CFR Part 63 Subparts A and DDDDD as they apply to each affected source as defined at §63.7485.

### 2.3.1. Affected Sources

2.3.1.1. The following existing process heaters and industrial boilers as defined in 63.7575 are affected sources for purposes of 40 CFR Part 63, Subpart DDDDD:

Unit 12, C.E. Natco molecular sieve regeneration process heater, 18.5 MMBtu/hr maximum design heat input.

Unit 12a, Struthers molecular sieve regeneration process heater, 13.02 MMBtu/hr maximum design heat input.

Unit 13, Vogt low pressure steam production industrial boiler, 18.0 MMBtu/hr maximum design heat input.

Unit 14, Vogt low pressure steam production industrial boiler, 18.0 MMBtu/hr maximum design heat input.

[40 CFR 63.7490(a)(1)]

**2.3.2. General Standards**

2.3.2.1. Each existing process heater must comply with the applicable requirements of this subpart no later than January 31, 2016.

2.3.2.2. The Permittee shall comply with the following work practice standards specified in Table 3 of this subpart:

2.3.2.2.1. The facility must have a one-time assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement.

2.3.2.2.2. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfied the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575:

2.3.2.2.2.1. A visual inspection of the boiler or process heater system

2.3.2.2.2.2. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints

2.3.2.2.2.3. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator

2.3.2.2.2.4. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage

2.3.2.2.2.5. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified

2.3.2.2.2.6. A list of cost-effective energy conservation measures that are within the facility's control

2.3.2.2.2.7. A list of the energy savings potential of the energy conservation measure identified

2.3.2.2.2.8. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments

[40 CFR 63.7500(a) and Table 3]

2.3.2.3. Boilers and process heaters in units designed to burn gas 1 fuels are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

[40 CFR 63.7500(e)]

2.3.2.4. The standards shall apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

[40 CFR 63.7500(f)]

**2.3.3. Initial Compliance Requirements**

2.3.3.1. The permittee must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

[40 CFR 63.7521(h)]

2.3.3.2. The permittee must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

[40 CFR 63.7530(e)]

**2.3.4. Continuous Compliance Requirements**

2.3.4.1. The Permittee must demonstrate continuous compliance with the applicable work practice standards specified in Table 3.

2.3.4.1.1. The permittee must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in the paragraphs below. You must conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited use boilers and process heaters as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

2.3.4.1.1.1. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

2.3.4.1.1.2. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

2.3.4.1.1.3. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

2.3.4.1.1.4. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOX requirement to which the unit is subject;

2.3.4.1.1.5. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

2.3.4.1.1.6. Maintain on-site and submit, if requested by the Administrator, a report containing the information in the following three paragraphs:

2.3.4.1.1.6.1. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

2.3.4.1.1.6.2. A description of any corrective actions taken as a part of the tune-up; and

2.3.4.1.1.6.3. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

[40 CFR 63.7540(a)(10)]

2.3.4.1.2. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

[40 CFR 63.7540(a)(13)]

2.3.4.2. The permittee must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550.

[40 CFR 63.7540(b)]

2.3.4.3. For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

[40 CFR 63.7540(d)]

**2.3.5. Notifications, Reports, and Records**

2.3.5.1. The permittee must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

2.3.5.2. If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575 the notification must include the information specified in the following paragraphs:.

2.3.5.2.1. Company name and address

2.3.5.2.2. Identification of the affected unit

2.3.5.2.3. Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began

2.3.5.2.4. Type of alternative fuel that you intend to use

2.3.5.2.5. Dates when the alternative fuel use is expected to begin and end

[40 CFR 63.7545(f)]

2.3.5.3. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in the following paragraphs, instead of a semi-annual compliance report.

2.3.5.3.1. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

2.3.5.3.2. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

2.3.5.3.3. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

2.3.5.3.4. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

[40 CFR 63.7550(b)]

2.3.5.4. The compliance report must contain the following information:

2.3.5.4.1. If the facility is subject to the requirements of a tune up, the permittee must submit a compliance report with this information:

2.3.5.4.1.1. Company and facility name and address

2.3.5.4.1.2. Process unit information, emissions limitations, and operating parameter limitations

2.3.5.4.1.3. Date of report and beginning and ending dates of the reporting period

2.3.5.4.1.4. Include the date of the most recent tune up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

2.3.5.4.1.5. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness

2.3.5.4.2. If complying with the fuel analysis, you must submit a compliance report with the following information:

2.3.5.4.2.1. The information contained in 63.7550(c)(5)(i) through (iii).

2.3.5.4.2.2. The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

2.3.5.4.2.3. A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

2.3.5.4.2.4. If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

2.3.5.4.2.5. If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

2.3.5.4.2.6. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

2.3.5.4.2.7. For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

[40 CFR 63.7550(c)]

2.3.5.4.2.8. For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the following information:

2.3.5.4.2.8.1. A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

2.3.5.4.2.8.2. Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

2.3.5.4.2.8.3. If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

[40 CFR 63.7550(d)]

2.3.5.5. The permittee must keep a copy of each notification and report that was submitted to comply with this subpart, including all documentation supporting any Initial Notification of Notification of Compliance Status.

[40 CFR 63.7555(a)(1)]

2.3.5.6. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(xiv).

[40 CFR 63.7555(a)(2)]

2.3.5.7. If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

2.3.5.8. Records must be in a form suitable and readily available for expeditions review, according to §63.10(b)(1).

2.3.5.9. As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

2.3.5.10. You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

[40 CFR 63.7560]

# 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. Reserved – Enhanced Monitoring, Recordkeeping, and Reporting**

# 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. |

| | | | |
|---|---|---|---|
| | 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 1,400°F 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 |

| | | | | |
|---|---|---|---|---|
| | | 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.