Navajo Nation Environmental Protection Agency
Navajo Nation Operating Permit Program

Elk Operating Services, LLC
Aneth Unit

Permit No: NN OP 17-012

2017

THE NAVAJO NATION

RUSSELL BEGAYE PRESIDENT
JONATHAN NEZ VICE PRESIDENT

Navajo Nation Environmental Protection Agency –Air Quality Control/Operating Permit Program
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TITLE V PERMIT TO OPERATE

PERMIT #:	FACILITY NAME:	LOCATION:	COUNTY:	STATE:
NN OP 17-012	ELK OPERATING SERVICES, LLC - ANETH UNIT	MONTEZUMA CREEK	SAN JUAN	UT
ISSUE DATE:	EXPIRATION DATE:	AFS PLANT ID:	PERMITTING AUTHORITY:	
04/25/2017	04/25/2022	04-017-NAV01	NNEPA	

ACTION/STATUS: ADMINISTRATIVE AMENDMENT

Scott Hornafius
Elk Operating Services, LLC
1700 Lincoln Street, Suite 2950
Denver, Colorado 80203

RE: Administrative Amendment to Title V Operating Permit for the change in ownership for the Aneth Unit from Resolute Natural Resources Company, LLC to Elk Operating Services, LLC

Mr. Hornafius:

We are issuing an Administrative Amendment to the Title V Operating Permit for Resolute Natural Resources Company, LLC – Aneth Unit for a change in ownership to Elk Operating Services, LLC. NNEPA has made the change to the permit under an administrative amendment pursuant to 40 CFR 40 CFR § 71.7 (d) & NNOPR § 405 (C).

We have enclosed the amendment to the Title V operating permit with a clear understanding that the changes made in the permit will not affect the permit terms and conditions that became effective April 25, 2017 and expire on April 25, 2022. A copy of the administrative permit amendment is also being provided to US EPA Region IX pursuant to 40 CFR § 71.7(d)(3)(ii). If you have any questions regarding this matter, please contact Tennille Denetdeel at (928) 729-4248 or tbbegay@navajo-nsn.gov.

MAR 2 6 2018

Date

Dr. Donald Benn, Executive Director
Navajo Nation Environmental Protection Agency

THE NAVAJO NATION

RUSSELL BEGAYE PRESIDENT
JONATHAN NEZ VICE PRESIDENT

Navajo Nation Environmental Protection Agency – Office of the Executive Director
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TITLE V PERMIT TO OPERATE

PERMIT #:	FACILITY NAME:	LOCATION:	COUNTY:	STATE:
NN OP 17-012	RESOLUTE NATURAL RESOURCES COMPANY, LLC – ANETH UNIT	MONTEZUMA CREEK	SAN JUAN	UT

ISSUE DATE:	EXPIRATION DATE:	AFS PLANT ID:	PERMITTING AUTHORITY:
04/25/2017	04/25/2022	04-017-NAV01	NNEPA

ACTION/STATUS: PART 71 OPERATING PERMIT

Patrick E. Flynn, Vice President
Resolute Natural Resources Company, LLC
1700 Lincoln Street, Suite 2800
Denver Colorado 80203

APR 25 2017

Re: Issuance of Title V Operating Permit to Resolute Natural Resources Company, LLC – Aneth Unit

Mr. Flynn:

This permit is being issued and administered by the Navajo Nation EPA ("NNEPA") pursuant to the Delegation Agreement between the United States Environmental Protection Agency ("USEPA" or "EPA") Region IX and NNEPA, dated October 15, 2004. In accordance with the provisions of Title V of the Clean Air Act, 40 CFR Part 71, Navajo Nation Operating Permit Regulations ("NNOPR"), and all other applicable rules and regulations, the permittee, Resolute Natural Resources Company, LLC – Aneth Unit, is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the permit conditions listed in this permit.

Terms and conditions not otherwise defined in this permit have the same meaning as assigned to them in the referenced regulations. With the exception of Condition IV(A), which is enforceable by NNEPA only, all terms and conditions of this permit are enforceable by NNEPA and by EPA, as well as by citizens under either or both the Navajo Nation Clean Air Act and the Federal Clean Air Act as applicable. If all proposed control measures and/or equipment are not installed and/or properly operated and maintained, the permittee will be considered in violation of the permit.

This permit is valid for a period of five (5) years and shall expire at midnight on the date five (5) years after the date of issuance unless a timely and complete renewal application has been submitted at least six (6) months but not more than eighteen (18) months prior to the date of expiration. The permit number cited above should be referenced in future correspondence regarding this facility.

Dr. Donald Benn, Executive Director
Navajo Nation Environmental Protection Agency

Elk Operating Services, LLC - Aneth Unit

CONTENTS

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TITLE V PERMIT TO OPERATE

PERMIT #:	FACILITY NAME:	LOCATION:	COUNTY:	STATE:
NN OP 17-012	ELK OPERATING SERVICES, LLC – ANETH UNIT	MONTEZUMA CREEK	SAN JUAN	UT
ISSUE DATE:	**EXPIRATION DATE:**	**AFS PLANT ID:**	**PERMITTING AUTHORITY:**	
04/25/2017	04/25/2022	04-017-NAV01	NNEPA	

ACTION/STATUS: PART 71 OPERATING PERMIT RENEWAL ISSUANCE

TABLE OF CONTENTS

Abbreviations and Acronyms

Administrator	Administrator of the US EPA
acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
Btu	British Thermal Units
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CAM	Continuous Assurance Monitoring
CFR	Code of Federal Regulations
CO	Carbon monoxide
CO_2	Carbon dioxide
gal	gallon
H_2S	Hydrogen sulfide
HAP	Hazardous Air Pollutant
hr	hour
Id. No.	Identification Number
Kg	kilogram
lb	pound
lb-mole	pound mole
m/s	meter per second
MACT	Maximum Achievable Control Technology
MVAC	Motor Vehicle Air Conditioner
Mg	megagram
MMBtu	million British Thermal Units
MMscf	million standard cubic feet
NESHAP	National Emission Standards for Hazardous Air Pollutants
NNEPA	Navajo Nation Environmental Protection Agency
NNOPR	Navajo Nation Operating Permit Regulations
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate Matter
PM_{10}	Particulate matter less than 10 microns in diameter
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
psia	pounds per square inch absolute
QIP	Quality Improvement Plan
RMP	Risk Management Plan
SNAP	Significant New Alternatives Program
SO_2	Sulfur Dioxide
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit

I. Source Identification

- Company Name: Elk Operating Services, LLC
- Mailing Address: 1700 Lincoln Street, Suite 2950
  Denver, Colorado 80203
- Plant Name: Aneth Unit
- Plant Location: Near Montezuma Creek , San Juan County, Utah on the Navajo Reservation at the following locations:

  Header 21-14 – SWNE Section 14, T40S, R24E
  Header 21-15 – NENE Section 15, T40S, R24E
  Header 21-16 – SENW Section 16, T40S, R24E
  Header 21-22 – SWNE Section 22, T40S, R24E
  Tank Battery 21 – SENW Section 21, T40S, R24E
  CO_2 Recycle Facility – SENE Section 22, T40S, R24E
- County: San Juan, Utah
- EPA Region: Region 9
- Reservation: Navajo Nation
- Tribe: Navajo
- Company Contact: Jeff Roedell Phone: (970) 564-5200 ext 2325
  Sherri Robbins Phone: (303) 861-6255 ext 1150
- Responsible Official: Scott Hornafius Phone: (303) 861-6255 ext 1130
- EPA Contact: Lisa Beckham Phone: (415) 972-3811
- Tribal Contact: Tennille Begay Phone: (928) 729-4248
- SIC Code: 1311
- AFS Plant Identification Number: 04-017-NAV01
- Description of Process: The Aneth Unit is an oil and natural gas production facility. This permit covers four (4) oil well Headers (21-14, 21-15, 21-16, and 21-21), Tank Battery 21, and a CO_2 Recycle Facility.

- **Significant Emission Units:**

Unit ID	Unit Description	Maximum Capacity	Commenced Construction Date	Control Method
21-14 21-15 21-16 21-22	Four (4) headers.	Varies	After 1964	Flare 21-14-F-1 Flare 21-15-F-1 Flare 21-16-F-1 Flare 21-22-F-1
21-ST-1 21-ST-2 21-ST-3 21-ST-4	Four (4) oil production tanks at Tank Battery 21	3,000 bbl (126,000 gal) Each	1991	Vapor Recovery Unit (VRU) 21-ST-VRU; Flare 21-F-1
21-F-1	Emergency/upset flare at Tank Battery 21	54 MMscfd	After 1964	N/A
INJ-DEHY-1	One (1) triethylene glycol dehydrator at CO_2 recycle facility.	100 MMscfd	2011	Thermal Oxidizer INJ-TO-1; Flare INJ-F-1 as a back-up control
INJ-F-1	Emergency/upset non-assisted flare at CO_2 Recycle Facility; Emissions are vented to this flare when the compressors or thermal oxidizer (INJ-TO-1) are down.	5 MMscfd	1999	N/A
INJ-HMO-1	One (1) natural gas-fired heat medium oil (HMO) burner at CO_2 recycle facility.	6 MMBtu/hr	2011	N/A
Fugitive Emissions				
21-Fugitives	Fugitive VOC and HAP emissions at Tank Battery 21 area.	N/A	1991 and after	N/A
INJ-Fugitive	Fugitive VOC and HAP emissions at CO_2 Recycle Facility.	N/A	1991 and after	N/A
Road Fugitives	Fugitive emissions from unpaved roads.	N/A	1991	N/A

- **Insignificant Emission Units with Applicable Requirements:**

One (1) natural gas fired spark ignition emergency generator (GEN-100), installed in 2011, with a maximum power output of 425 hp, and located at the CO_2 Recycle Facility.

II. Requirements for Specific Units

II.A. Facility-wide Emission Limitations and Requirements [40 CFR § 71.6(b) and CAA § 304(f)]

The total emissions from the four (4) production tanks at Tank Battery 21 (21-ST-1, 21-ST-2, 21-ST-3, and 21-ST-4), the glycol dehydrator (INJ-DEHY-1) at the CO_2 Recycle Facility, and the flares (21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, 21-22-F-1, and INJ-F-1) shall not exceed the emission limits specified below:

1. 240.0 tons/yr of VOC based on a 12-month rolling sum.

2. 60.0 tons/yr of NOx based on a 12-month rolling sum.

3. 153.1 tons/yr of SO_2 based on a 12-month rolling sum.

4. 180.0 tons/yr of CO based on a 12-month rolling sum.

5. 9.0 tons/yr for any single HAP based on a 12-month rolling sum.

6. 24.0 tons/yr for total HAPs based on a 12-month rolling sum.

7. The thresholds listed in Table 1 to 40 CFR § 68.130 for any regulated substance listed in 40 CFR § 68.130.

Note: In order to be consistent with past single source determinations made in the previous Part 71 permit (NN-OP 00-02, issued on July 30, 2007), the permittee requested that this Part 71 permit renewal cover the Headers 21-14, 21-15, 21-16 and 21-22, Tank Battery 21, and the CO_2 Recycle Facility and the emissions from these units are aggregated as one single source for Part 71 permitting and New Source Review purposes. However, under the current "major source" definition in 40 CFR § 71.2, Tank Battery 21 and the CO_2 Recycle Facility are located more than 1⁄4 mile away from each other and would be considered two (2) separate sources.

II.B. Control Requirements [40 CFR § 71.6(b) and CAA § 304(f)]

1. <u>Vapor Recovery Units (VRUs) and Oil Storage Tanks:</u>

    a. The permittee shall operate each of the production oil storage tanks at Tank Battery 21 with a VRU. Each VRU shall be connected to the production oil storage tanks through a closed-vent system. The gases collected by the VRUs shall be added to the sales or recycle gas stream or incinerated in a flare. The gases stored in the production oil storage tanks and recovered in each VRU shall not be vented to the atmosphere except during periods of malfunction, maintenance, or repair of the VRU.

b. The VRUs shall be in operation while the storage tanks are receiving fluids, except during periods of malfunction, maintenance, or repair. Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions. The permittee shall keep records of the time and duration of any periods of malfunction, maintenance or repair, and the specific maintenance or repair activity.

c. The permittee shall keep records of periods when the VRU is not operating and the tanks vapors cannot be sold, recycled or incinerated. The permittee shall monitor the gases sent to the flares and calculate emissions according to the flare requirements in Condition II.C of this permit.

d. The cover and all openings on the cover (e.g., access hatches, sampling ports, and gauge wells) of each production oil storage tank shall be designed to form a continuous barrier over the entire surface area of the liquid in the storage tank. Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the storage tank on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) Add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) Inspect or sample the material in the unit;

(iii) Inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) Vent liquids, gases, or fumes from the unit through a closed-vent system to the VRU system.

e. A copy of the owner/operator instruction manual for the VRUs shall be kept at the nearest manned facility and accessible to personnel at the source.

2. <u>Flares</u>

a. The permittee shall use flares INJ-F-1, 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, and 21-22-F-1 to reduce VOC and HAP emissions from the CO_2 Recycle Facility, Tank Battery 21, and Headers 21-14, 21-15, 21-16 and 21-

22.

b. Each flare shall be operated at all times when emissions may be vented to them.

3. Triethylene Glycol Dehydrator (INJ-DEHY-1)

a. The permittee shall control the VOC and HAP emissions from the dehydrator (INJ-DEHY-1) by a thermal oxidizer (INJ-TO-1).

b. The thermal oxidizer (INJ-TO-1) shall be operated at all times when the dehydrator (INJ-DEHY-1) is in operation.

c. The permittee shall operate and maintain the dehydrator (INJ-DEHY-1) and the thermal oxidizer (INJ-TO-1) in a manner consistent with safety and good air pollution control practices for minimizing emissions.

II.C. Monitoring and Testing Requirements [40 CFR §§ 71.6(a)(3)(i) and 71.6(a)(3)(i)(A), and NNOPR § 302(E)]

1. Vapor Recovery Units (VRU) and Oil Storage Tanks

a. The total amount of oil or hydrocarbon fluid transferred to each production oil storage tank shall be recorded monthly. The total amount of gas recovered by the VRUs shall be measured and recorded daily.

b. The VRUs, storage tanks, and closed-vent systems shall be monitored as follows: for valves, flanges, tank hatch gaskets, joints, seams, and other connections that are permanently and semi-permanently sealed, the permittee shall:

(i) use a portable hydrocarbon detection instrument monthly to demonstrate that the closed-vent system has no leaks; leaks shall be defined as instrument reading greater than 500 parts per million by volume above background;

(ii) conduct annual visual inspections for visible, audible, or olfactory indication of leaks;

(iii) conduct monthly visual inspections or use a portable hydrocarbon detection instrument 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); and

(iv) in the event that a leak or defect is detected, the owner or operator shall repair the leak or defect or replace components as soon as practicable, but not later than 15 days after the leak or defect is detected.

c. By the 30th day of each month, the permittee shall calculate HAP and VOC emissions for the previous month from the storage tanks, including emissions due to working, breathing, and flash losses from the storage tanks. The permittee shall keep records of the following information:

(i) The calculation method or model used, such as the latest version of EPA TANKS model or E & P Tank model, to determine HAP and VOC emissions;

(ii) A record of input and output parameters used in the calculation method or model (inputs to the calculation method or model shall be representative of actual operating conditions);

(iii) The calculations used to determine emissions estimates;

(iv) Any liquid and/or gas analysis completed and a description of gas sampling procedures and test method(s) used to conduct the gas analysis; and

(v) Any assumptions used to determine emissions estimates. The permittee shall not use a calculation method if the site-specific factors for the storage tanks are beyond the specific constraints for the calculation method.

d. The permittee shall calculate the 12-month rolling sum for VOC and each HAP emitted by summing the monthly emissions for each production oil storage tank, and adding the sum to the total emissions for the previous 11 months. The calculations for each month must be completed by the 30th day of the following month. The permittee shall maintain all records of actual operating data and calculations.

2. <u>Flares</u>

a. The permittee shall operate and monitor each flare to assure that each flare is operated and maintained in conformance with its design.

b. The permittee shall continuously measure and record the total volume of gas vented to and combusted in flares 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, 21-22-F-1, and INJ-F-1. On a monthly basis, the permittee shall determine the total volume of gas combusted in each flare during all times, including normal operation, malfunctions, emergencies, and upsets. The permittee shall calculate and record the total emissions from each flare. The volume of gas shall be recorded in MMscf on a monthly basis.

c. Flares 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, and 21-22-F-1 shall be equipped and operated at all times with automatic continuous spark igniters. The permittee shall inspect the flares monthly to assure the continuous spark igniters for the flares are operating properly. The permittee shall take corrective action as soon as practicable but not later than 15 days if the continuous spark igniters for the flares malfunction or are inoperable. No gas shall be sent to any flare that has an inoperable continuous spark igniter.

d. The permittee shall equip and operate a continuous heat sensing monitoring device on flare INJ-F-1 that indicates continuous ignition of the pilot flame. The heat sensing monitoring device shall be operated at all times. Flare INJ-F-1 shall be equipped with an alarm that informs source operators of any period when a pilot flame is not present in the flare and no gas shall be sent to the flare until a pilot flame is restored.

e. The permittee shall operate flare INJ-F-1 with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. EPA Test Method 22 in Appendix A of 40 CFR Part 60 shall be used to determine the compliance of flares with the visible emission provisions. The observation period is 2 hours and shall be used according to Method 22. The permittee shall perform monthly visible emissions tests during a flaring event at flare INJ-F-1 using Method 22.

f. On an annual basis, the permittee shall determine the Btu, sulfur, HAP, and VOC content of the gas vented to each flare through a gas analysis using the appropriate ASTM or EPA test methods. The Btu content shall be based on the higher heating value of the gas.

g. By the 30th day of each month, the permittee shall calculate monthly emissions from each flare using the monthly fuel consumption, the most recent higher heating value of the fuel, sulfur, HAP, and VOC content from the most recent monthly gas analysis, EPA-approved emission factors (e.g., AP-42) for NOx and CO, and the destruction efficiency of each flare. Monthly emissions shall be calculated using the following equations:

(i) For NO_x and CO emissions:

$$E_x = EF \text{ x } Q \text{ x } H \text{ x } (1\ ton/2000\ lb)$$

Where:
E_x = Emissions rate for the pollutant in tons/month
EF = Emission factor for the pollutant in lb/MMBtu
Q = Fuel use in MMscf/month

H = Btu content of the fuel based on the higher heating value in MMBtu/MMscf.

(ii) For SO_2 Emissions:

$$E_{SO_2} = Q \times Y_{H_2S} \times \frac{1}{C} \times M_{SO_2} \times MW_{SO_2} \text{ x } \mathit{(1\ ton/2000\ lbs)} \text{ x } \mathit{10^6\ scf/MMscf}$$

Where:
E_{SO_2} = SO_2 emissions rate in tons/month
Q = Fuel use in MMscf/month
Y_{H_2S} = Mole fraction of H_2S in inlet gas
C = Molar volume of ideal gas, 379 scf/lb-mole at 60 degrees Fahrenheit and 1 atmosphere
M_{SO_2} = Molar conversion ratio from H_2S to SO_2, lb-mole SO_2/lb-mole H_2S (based on stoichiometry and assuming complete conversion of H_2S to SO_2, M_{SO_2} = 1)
MW_{SO_2} = Molecular weight of SO_2, lb SO_2/lb-mole SO_2 = 64

(iii) For HAP and VOC Emissions:

$$E_x = Q \times Y_x \times \frac{1}{C} \times MW_x \times \left(1 - \frac{DRE}{100}\right) \text{ x } \mathit{(1\ ton/2000\ lbs)} \text{ x } \mathit{10^6\ scf/MMscf}$$

Where:
E_x = Emissions rate for the pollutant in tons/month
Q = Fuel use in MMscf/month
Y_x = Mole fraction of the pollutant in the inlet stream
C = Molar volume of ideal gas, 379 scf/lb-mole at 60 degrees Fahrenheit and 1 atmosphere
MW_x = Molecular weight of pollutant
DRE = Destruction and removal efficiency of the flare = 98%

h. The permittee shall calculate the 12-month rolling sum for VOC, NOx, CO, SO_2, and each HAP by summing the monthly emissions for flares 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, 21-22-F-1, and INJ-F-1, and adding the sum to the total emissions for the previous 11 months. The calculations for each month must be completed by the 30th day of the following month. The permittee shall maintain all records of actual operating data and calculations.

i. The permittee shall perform the following test requirements for flare INJ-F-1 annually to demonstrate that the flare is operating as designed. The permittee has the choice of adhering to the requirements of Condition

II.C.2.i.(i), or the heat content specifications in Condition II.C.2.i.(ii) and the maximum tip velocity specifications in Condition II.C.2.i.(iii) as follows:

(i) The flare shall have a diameter of 3 inches or greater, is nonassisted, have a hydrogen content of 8.0 percent (by volume) or greater, and is designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity Vmax, as determined by the following equation:

$$V_{max} = (X_{H_2} - K_1) \times K_2$$

Where:
V_{max}= Maximum permitted velocity, m/sec
K_1 = Constant, 6.0 volume-percent hydrogen
K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen
X_{H_2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77.

The actual exit velocity of a flare shall be determined by dividing the volumetric flow rate of gas being combusted (in units of emission standard temperature and pressure), as determined by Test Method 2, 2A, 2C, or 2D in appendix A to 40 CFR Part 60, as appropriate, by the unobstructed (free) cross-sectional area of the flare tip

(ii) The flare shall be used only with the net heating value of the gas being combusted at 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted at 7.45 MJ/scm (200 Btu/scf) or greater if the flare is non-assisted. The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

where:
H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of off-gas is based on combustion at 25 degrees Celsius and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 degrees Celsius.

K = Constant 1.740×10^{-7} (1/ppm)(gmole/scm)(MJ/kcal) where the standard temperature for (gmole/scm) is 20 degrees Celsius.

C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994).

H_i = Net heat of combustion of sample component i, kcal/g-mole at 25 degrees Celsius and 760 mmHg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 if published values are not available or cannot be calculated.

n = Number of sample components

(iii) For a non-assisted flare, the permittee shall operate the flare as follows:

(A) It shall be designed for and operated with an exit velocity less than 18.3 m/sec (60 ft/sec), except as provided in subparagraphs (2) and (3) specified as follows. The actual exit velocity of a flare shall be determined by dividing the volumetric flow rate of gas being combusted (in units of emission standard temperature and pressure), as determined by Test Method 2, 2A, 2C, or 2D in appendix A to 40 CFR Part 60, as appropriate, by the unobstructed (free) cross-sectional area of the flare tip.

(B) A flare designed for and operated with an exit velocity, equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec), is allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf). The exit velocity of a flare shall be determined by dividing the volumetric flow rate of gas being combusted (in units of emission standard temperature and pressure), as determined by Test Method 2, 2A, 2C, or 2D in appendix A to 40 CFR Part 60, as appropriate, by the unobstructed (free) cross-sectional area of the flare tip.

(C) A flare designed for and operated with an exit velocity that is less than the velocity Vmax, as determined by the method specified as follows, but less than 122 m/sec (400 ft/sec) is allowed. The exit velocity of the flare shall be determined by dividing the volumetric flow rate of gas being combusted (in units of emission standard temperature and pressure), as determined by Test Method 2, 2A, 2C, or 2D in appendix A to 40 CFR Part 60, as appropriate, by the unobstructed (free) cross-sectional area of the flare tip. The maximum permitted velocity, Vmax, for flares complying with this paragraph shall be determined by the following equation:

$$Log_{10}(V_{max}) = \frac{H_T + 28.8}{31.7}$$

Where:

V_{max} = Maximum permitted velocity, m/sec
28.8 = Constant
31.7 = Constant
H_T = The net heating value as determined earlier in this permit

3. Triethylene Glycol Dehydrator (INJ-DEHY-1)

a. The permittee shall operate and monitor the triethylene glycol dehydrator (INJ-DEHY-1) and the associated thermal oxidizer (INJ-TO-1) to ensure it is operated and maintained in conformance with its design.

b. The permittee shall continuously measure and record the total volume of gas vented to the triethylene glycol dehydrator (INJ-DEHY-1). On a monthly basis, the permittee shall determine the total volume of gas combusted in the thermal oxidizer during all times, including normal operation, malfunctions, emergencies, and upsets. The permittee shall calculate and record the total emissions from the triethylene glycol dehydrator after control. The volume of gas shall be recorded in MMscf on a monthly basis.

c. On a monthly basis, the permittee shall record the total hours when the emissions from the triethylene glycol dehydrator (INJ-DEHY-1) are vented to the back-up control flare (Flare INJ-F-1), instead of the thermal oxidizer.

d. On an annual basis, the permittee shall determine the Btu, sulfur, HAP, and VOC content of the gas vented to the triethylene glycol dehydrator through a gas analysis using the appropriate ASTM or EPA test methods. The Btu content shall be based on the higher heating value of the gas.

e. By the 30th day of each month, the permittee shall calculate NOx, CO, SO_2, VOC, and HAP emissions for the previous month from the triethylene glycol dehydrator (INJ-DEHY-1). The permittee shall keep records of the following information:

(i) The calculation method or model used, such as the latest version of GRI-GLYCalc to determine SO_2, VOC, and HAP emissions; EPA-approved emission factors (e.g., AP-42) to determine the NOx and

CO from the thermal oxidizer; the destruction efficiency of the thermal oxidizer; and the most recent sulfur, VOC, and HAP contents from the most recent monthly gas analysis;

(ii) A record of input and output parameters used in the calculation method or model (inputs to the calculation method or model shall be representative of actual operating conditions);

(iii) The calculations used to determine emissions estimates;

(iv) Any gas analysis completed and a description of gas sampling procedures and test method(s) used to conduct the gas analysis; and

(v) Any assumptions used to determine emissions estimates. The permittee shall not use a calculation method if the site-specific factors for the storage tanks are beyond the specific constraints for the calculation method.

e. The permittee shall calculate the 12-month rolling sum for NOx, CO, SO_2, VOC, and each HAP by summing the monthly emissions for the triethylene glycol dehydrator (INJ-DEHY-1), and adding the sum to the total emissions for the previous 11 months. The calculations for each month must be completed by the 30th day of the following month. The permittee shall maintain all records of actual operating data and calculations.

4. Facility-wide

a. The permittee shall sum the rolling 12-month emission calculations for NOx, CO, SO_2, VOC, and each HAP determined in Conditions II.C.1.d, II.C.2.h, and II.C.3.e to demonstrate compliance with the emission limits specified in Condition II.A.

b. The calculations for each month must be completed by the 30th day of the following month. The permittee shall maintain all records of actual operating data and calculations.

II.D. Recordkeeping Requirements [40 CFR § 71.6(a)(3)(ii) and NNOPR § 302(F)]

The permittee shall retain the following records at the stationary source for a period of five (5) years from the date of monitoring, sampling, measurement, or reporting. All applicable records shall be maintained at the nearest manned facility and shall be readily accessible.

1. Monthly emissions calculations for all pollutant-emitting units.

2. Each 12-month rolling sum for HAPs, VOCs, SO_2, CO and NOx.

3. Monthly records of the total amount of oil or hydrocarbon fluid transferred and stored in each production oil storage tank.

4. Monthly records of hydrocarbon fluid and natural gas throughput for the source.

5. Daily records of the total amount of gas recovered in each VRU.

6. A written log of the following information for each monthly and annual inspection for the VRUs, storage tanks and closed vent systems:

   a. The date and time of the observation, and the name of the observer;

   b. The method (i.e., visual or detection instrument);

   c. The components inspected;

   d. Whether any leaks or defects were detected or observed;

   e. A description of any corrective actions taken, repairs made and components replaced; and

   f. The date(s) of corrective actions, repairs and replacement of components.

7. Times and durations of each pressure release.

8. All records of any times and durations when the VRUs and flares were not in operation.

9. For the VRUs, any records of the times and duration of any periods of malfunction, maintenance or repair, and the specific maintenance or repair activity.

10. Records of periods when flash gas from the oil production storage tanks was re-directed from the VRUs to any flares.

11. All records of gas analyses and testing.

12. The monthly total volume of gas vented to each flare.

13. Records of flare design for flares INJ-F-1, 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, and 21-22-F-1.

14. A written log of the monthly inspections of flares 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, and 21-22-F-1 containing the following information for each inspection:

    a. The date and time of the inspection, and the name of the observer;

b. A description of any corrective actions taken and repairs made; and

c. The date(s) of corrective actions and repairs.

15. For flare INJ-F-1, all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made, and all periodic records and other recorded periods when the pilot flame is absent.

16. For the triethylene glycol dehydrator (INJ-DEHY-1), monthly records of the total volume of gas treated by the triethylene glycol dehydrator (INJ-DEHY-1) and the total volume of gas combusted in the thermal oxidizer (INJ-TO-1).

17. Records of all regulated substances listed in 40 CFR § 68.130 in each process at the source.

18. Records that demonstrate that the source does not have a threshold quantity of any regulated substance listed in 40 CFR § 68.130 in any process at the source.

II.E. NSPS General Provisions [40 CFR Part 60, Subpart A]

The following requirements apply to the affected facilities that has equipment leaks in accordance with 40 CFR Part 60, Subparts A and KKK (Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011), and to the emergency generator (GEN-100) in accordance with 40 CFR Part 60, Subparts A and JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines):

1. All requests, reports, applications, submittals, and other communications to the NNEPA pursuant to 40 CFR Part 60 shall be submitted in duplicate to the EPA Region 9 office at the following address [40 CFR § 60.4(a)]:

   Manager, Air & Tri-Section ENF-2-1
   US EPA Region 9
   Enforcement Division
   75 Hawthorne Street
   San Francisco, CA 94105-3901

2. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative [40 CFR § 60.7(b)].

3. The availability to the public of information provided to, or otherwise obtained by, the EPA Administrator under this permit shall be governed by 40 CFR § 2. (Information submitted voluntarily to the Administrator for the purposes of

compliance with 40 CFR §§ 60.5 and 60.6 is governed by 40 CFR §§ 2.201 through § 2.213 and not by 40 CFR § 2.301.) [40 CFR § 60.9].

4. The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided [40 CFR § 60.11(c)].

5. At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected facilities, including associated air pollution control equipment, 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 is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source [40 CFR § 60.11(d)].

6. For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in 40 CFR Part 60, nothing in 40 CFR Part 60 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 [40 CFR § 60.11(g)].

7. The permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere [40 CFR § 60.12].

8. With respect to compliance with all New source Performance Standards (NSPS) of 40 CFR Part 60, the permittee shall comply with the "General notification and reporting requirements" found in 40 CFR § 60.19 [40 CFR § 60.19].

9. The permittee shall provide written notification to NNEPA and US EPA or, if acceptable to NNEPA, US EPA and the permittee, electronic notification to NNEPA and US EPA of any reconstruction of an affected facility, or any physical or operational change to an affected facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under this permit or in 40 CFR § 60.14(e) [40 CFR § 60.7(a)].

II.F. NSPS for Equipment Leaks, 40 CFR Part 60, Subpart KKK Requirements

The permittee shall comply with the following requirements for the affected facilities, listed in Attachment A to this permit, in accordance with 40 CFR Part 60, Subpart KKK (Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas

Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011):

1. The permittee shall comply with the requirements of NSPS, Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006) for the following affected facilities: [40 CFR § 60.632(a)]

    a. For each affected pumps in light liquid service, the permittee shall comply the requirements specified in 40 CFR § 60.482-2 (see Attachment B).

    b. For each affected compressor, the permittee shall comply the requirements specified in 40 CFR § 60.482-3 (see Attachment B).

    c. For each affected open ended valves or lines, the permittee shall comply the requirements specified in 40 CFR § 60.482-6 (see Attachment B).

    d. For each affected valves in gas vapor service and light liquid service, the permittee shall comply the requirements specified in 40 CFR § 60.482-7 (see Attachment B).

    e. For each affected pumps and valves in heavy liquid services, and each pressure relief device in light liquid service, the permittee shall comply the requirements specified in 40 CFR § 60.482-8 (see Attachment B).

    f. The permittee shall comply with the delay of repair requirements specified in 40 CFR § 60.482-9 (see Attachment B).

    g. For each affected closed vent system and control device, the permittee shall comply the requirements specified in 40 CFR § 60.482-10 (see Attachment B).

    h. The permittee shall demonstrate compliance with the requirements in Condition II.F.1.a through g by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR § 60.485 (see Attachment B). [40 CFR §§ 60.632(a) and 60.482-1(b)]

2. For each affected pressure relief device in gas or vapor service, the permittee shall comply with the following requirements: [40 CFR § 60.633(b)]

    a. Monitor each pressure relief device in gas/vapor service quarterly and within 5 days after each pressure release to detect leaks by the methods specified in 40 CFR § 60.485(b) (see Attachment B).

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

c. 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 40 § 60.482-9 for Delay of Repair (see Attachment B).

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

e. Any pressure relief device that is located in a nonfractionating plant that is monitored only by nonplant personnel may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days.

f. No pressure relief device described in Condition II.F.2.e shall be allowed to operate for more than 30 days after a pressure release without monitoring.

3. Flares used to comply with this subpart shall comply with the requirements of 40 CFR § 60.18. [40 CFR § 60.632(g)]

4. The permittee shall comply with the test method and procedure list in 40 CFR § 60.485 (see Attachment B). [40 CFR § 60.632(d)].

5. The permittee shall comply with the following record keeping requirements:

a. For the affected facilities specified in Condition II.F.2, the permittee shall comply with the applicable recordkeeping requirements specified in 40 CFR § 60.486 of NSPS, Subpart VV (see Attachment B). [40 CFR §§ 60.632(e) and 60.635(a)]

b. For each affected pressure relief device, the permittee shall comply with the following recordkeeping requirements: [40 CFR § 60.635(b)]

(i) When each leak is detected as specified in Condition II.F.2.b, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(ii) When each leak is detected as specified in Condition II.F.2.b, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(A) The instrument and operator identification numbers and the equipment identification number.

(B) The date the leak was detected and the dates of each attempt to repair the leak.

(C) Repair methods applied in each attempt to repair the leak.

(D) "Above 10,000 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 10,000 ppm or greater.

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

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

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

(H) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(I) The date of successful repair of the leak.

(J) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR § 60.482-4(a). The designation of equipment subject to the provisions of 40 CFR § 60.482-4(a) shall be signed by permittee.

6. The permittee shall comply with the following reporting requirements:

a. The permittee shall comply with the applicable recordkeeping requirements specified in 40 CFR § 60.487 of NSPS, Subpart VV (see Attachment B). [40 CFR § 60.636(a)]

b. The permittee shall include the following information in all semiannual reports in addition to the information required in 40 CFR § 60.487(c)(2) (i) through (vi) of NSPS, Subpart VV (see Attachment B): [40 CFR § 60.636(c)]

(i) Number of pressure relief devices for which leaks were detected; and

(ii) Number of pressure relief devices for which leaks were not repaired.

II.G. NSPS for Stationary Spark Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart JJJJ Requirements

The following requirements apply to the emergency generator (GEN-100) in accordance with 40 CFR Part 60, Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines):

1. Emissions from the emergency generator (GEN-100) shall not exceed the following [40 CFR § 60.4233(e)]:

    a. 2.0 g/HP-hr for NO_X emissions.

    b. 4.0 g/HP-hr for CO emissions.

    c. 1.0 g/HP-hr for VOC emissions.

2. If the emergency generator (GEM-100) does not meet the standards applicable to non-emergency engines, the permittee shall install and operate a non-resettable hour meter. [40 CFR § 60.4237(b)]

3. If the emergency generator (GEM-100) is a non-certified engine, the permittee shall keep a maintenance plan and records of conducted maintenance and shall, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the permittee shall conduct an initial performance test within 1 year of engine startup to demonstrate compliance. [40 CFR § 60.4243(a)(2)(ii)]

4. The operation hours for the emergency generator (GEN-100) shall be limited to the following: [40 CFR § 60.4243(d)]

    a. No use time limit for emergency situations.

    b. A maximum of 100 hours per calendar year for maintenance/testing and emergency demand response, as specified below, and for non-emergency situations:

        (i) Maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) For periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

c. A maximum of 50 hours per calendar year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

5. The permittee shall comply with the applicable test methods and procedures specified in 40 CFR § 60.4244. [40 CFR § 60.4244]

6. The permittee shall comply with the applicable recordkeeping and reporting requirements specified in 40 CFR § 60.4245. [40 CFR § 60.4245]

II.H. NESHAP General Provisions [40 CFR Part 63, Subpart A]

1. Prohibited Activities and Circumvention [40 CFR § 63.4]

a. The permittee shall not operate any affected source in violation of the requirements of 40 CFR Part 63. Affected sources subject to and in compliance with either an extension of compliance or an exemption from compliance are not in violation of the requirements of 40 CFR Part 63. An extension of compliance can be granted by the Administrator under this part.

b. The permittee shall not fail to keep records, notify, report, or revise reports as required by 40 CFR Part 63.

c. The permittee shall not build, erect, install, or use any article, machine, equipment, or process to conceal an emission that would otherwise constitute noncompliance with a relevant standard. Such concealment includes, but is not limited to:

(i) The use of diluents to achieve compliance with a relevant standard based on the concentration of a pollutant in the effluent discharged to the atmosphere; or

(ii) The use of gaseous diluents to achieve compliance with a relevant standard for visible emissions.

2. The permittee shall follow the preconstruction review and notification requirements specified in 40 CFR § 63.5. [40 CFR § 63.5]

3. Monitoring shall be conducted as set forth in 40 CFR § 63.8 and the relevant standard, with the exception of requirements set forth in 40 CFR § 63.8(e), (f)(4), and (f)(6). [40 CFR § 63.8]

4. The permittee shall maintain files of all information (including all reports and notifications) required by 40 CFR Part 63 in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, on microfiche, or on other forms of electronic storage. [40 CFR § 63.10(b)(1)]

II.I. NESHAP for Oil and Natural Gas Production Facilities, 40 CFR Part 63, Subpart HH Requirements

The permittee shall comply with the following 40 CFR Part 63, Subpart HH (National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities) requirements for the triethylene glycol dehydrator (INJ-DEHY-1) at the CO_2 Recycle Facility:

1. The permittee shall operate the triethylene glycol dehydrator (INJ-DEHY-1) such that the actual glycol circulation rate does not exceed the optimum glycol circulation rate determined in accordance with 40 CFR § 63.764(d)(2)(i) or an alternate circulation rate calculated using GRI-GLYCalcTM, Version 3.0 or higher. [40 CFR § 63.764(d)(2)(ii)]

2. If operating conditions change and a modification to the optimum glycol circulation rate is required, the permittee shall prepare a new determination in accordance with 40 CFR § 63.764(d)(2)(i) or (ii) and submit the information specified below: [40 CFR §§ 63.764(d)(2)(iii), and 63.775(c)(7)(ii) through (v)]

   a. Calculation of the optimum glycol circulation rate determined in accordance with 40 CFR § 63.764(d)(2)(i).

   b. If applicable, documentation of the alternate glycol circulation rate calculated using GRI-GLYCalcTM, Version 3.0 or higher and documentation stating why the dehydrator unit must operate using the alternate glycol circulation rate.

c. The name of the manufacturer and the model number of the glycol circulation pump(s) in operation.

d. Statement by a responsible official, with that official's name, title, and signature, certifying that the facility will always operate the glycol dehydration unit using the optimum circulation rate determined in accordance with 40 CFR § 63.764(d)(2)(i) or 40 CFR § 63.764(d)(2)(ii), as applicable.

3. At all times the permittee shall 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)]

4. The permittee 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. [40 CFR § 63.774(b)(1)]

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

b. 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.

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

d. Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

5. The permittee shall maintain the records specified in 40 CFR § 63.10(b)(2). [40 CFR § 63.774(b)(2)]

6. The permittee must keep a record of the calculation used to determine the optimum glycol circulation rate in accordance with 40 CFR § 63.764(d)(2)(i) or 40 CFR § 63.764(d)(2)(ii), as applicable. [40 CFR § 63.774(f)]

7. The permittee 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 permittee shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR § 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)]

II.J. NESHAP for Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63, Subpart ZZZZ Requirements

The following requirements apply to the emergency generator (GEN-100) in accordance with 40 CFR Part 63, Subpart ZZZZ (National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines):

1. For the emergency generator (GEN-100), compliance with the requirements of NSPS for Stationary Spark Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart JJJJ, specified in Condition II.G, fulfills the requirements of this NESHAP [40 CFR § 63.6590(c)].

II.K. Permit Shield [40 CFR § 71.6(f)(1)(i) and NNOPR § 302(J)]

A permit shield is granted for the following federal emission standards:

1. Oil storage tanks 21-ST-1, 21-ST-2, 21-ST-3, and 21-ST-4 are not subject to 40 CFR Part 60, Subpart K (New Source Performance Standards (NSPS) for Volatile Liquid Storage Vessels Constructed or Modified after June 11, 1973 and Prior to May 19, 1978).

2. Oil storage tanks 21-ST-1, 21-ST-2, 21-ST-3, and 21-ST-4 are not subject to 40 CFR Part 60, Subpart Ka (New Source Performance Standards (NSPS) for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984).

3. Oil storage tanks 21-ST-1, 21-ST-2, 21-ST-3, and 21-ST-4 are not subject to 40 CFR Part 60, Subpart Kb (New Source Performance Standards (NSPS) for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984).

4. The equipment leaks from this source is not subject to 40 CFR Part 61, Subpart V (National Emission Standard for Equipment Leaks (Fugitive Emission Sources)).

5. This source is not subject to the requirements of 40 CFR Part 68, Subpart M (Chemical Accident Prevention Regulation). This permit shield shall no longer

apply if the permittee does not operate in accordance with Condition II.A.7 of this permit.

II.L. Operational Flexibility [40 CFR § 71.6(a)(13)(i)][NNOPR § 404(A)][The NNOPR provision is enforceable by NNEPA only.]

1. The permittee is allowed to make a limited class of changes under Section 502(b)(10) of the Clean Air Act within the permittee that contravene the specific terms of this permit without applying for a permit revision, provided the changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions) and are not Title I modifications. This class of changes does not include:

    a. Changes that would violate any applicable requirement; or

    b. Changes that would contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements. [40 CFR § 71.2] [NNOPR § 102(54)]

2. The permittee is required to send written notice to NNEPA and US EPA Region IX at least 7 days in advance of any change made under this provision. The notice must describe the change, when the change will occur, any change in emissions, and identify any permit terms or conditions made inapplicable as a result of the change. The permittee shall attach each notice to its copy of this permit.

3. Any permit shield provided in this permit does not apply to changes made under this subsection.

III. Facility-Wide or Generic Permit Requirements

Conditions in this section of the permit apply to all emissions units located at the facility.

III.A. Testing Requirements [40 CFR § 71.6(a)(3)]

In addition to the unit-specific testing requirements derived from the applicable requirements for each individual unit contained in Section II of this permit, the permittee shall comply with the following generally applicable testing requirements as necessary to ensure that the required tests are sufficient for compliance purposes:

1. Submit to NNEPA and US EPA Region IX a source test plan 30 days prior to any required testing. The source test plan shall include and address the following elements:

    1.0 Purpose of the Test
    2.0 Source Description and Mode of Operation during Test
    3.0 Scope of Work Planned for Test
    4.0 Schedule/Dates
    5.0 Process Data to be Collected During Test
    6.0 Sampling and Analysis Procedures
    6.1 Sampling Locations
    6.2 Test Methods
    6.3 Analysis Procedures and Laboratory Identification
    7.0 Quality Assurance Plan
    7.1 Calibration Procedures and Frequency
    7.2 Sample Recovery and Field Documentation
    7.3 Chain of Custody Procedures
    7.4 QA/QC Project Flow Chart
    8.0 Data Processing and Reporting
    8.1 Description of Data Handling and QC Procedures
    8.2 Report Content

2. Unless otherwise specified by an applicable requirement or permit condition in Section II, all source tests shall be performed at maximum operating rates (90% to 110%) of device design capacity.

3. Only regular operating staff may adjust the processes or emission control device parameters during a compliance source test. The permittee must keep a record of adjustments made to any operating parameters within two (2) hours of the start of a test, along with the reason for these adjustments, and this record must be submitted to NNEPA and US EPA Region IX along with the test results. NNEPA and US EPA Region IX reserve the right to determine whether any operating adjustments made during a source test that are a result of consultation during the tests with source testing personnel, equipment vendors, or consultants should render the source test invalid.

4. During each test run and for two (2) hours prior to the test and two (2) hours after the completion of the test, the permittee shall record the following information:

   a. Fuel characteristics and/or amount of product processed (if applicable).

   b. Visible emissions.

   c. All parametric data which is required to be monitored in Condition II for the emission unit being tested.

   d. Other source-specific data identified in Condition II, such as minimum test length (e.g., one hour, 8 hours, 24 hours, etc.), minimum sample volume, other operating conditions to be monitored, correction of O_2, etc.

5. Each source test shall consist of at least three (3) valid test runs and the emissions results shall be reported as the arithmetic average of all valid test runs and in the terms of the emission limit. There must be at least 3 valid test runs, unless otherwise specified.

6. Source test reports shall be submitted to NNEPA and US EPA Region IX within 60 days of completing any required source test.

III.B. Recordkeeping Requirements [40 CFR §§ 40 CFR 60.7(f), 71.6(a)(3)(ii)][40 CFR § 60.7(f)][NNOPR § 302(F)][The NNOPR provision is enforceable by NNEPA only.]

In addition to the unit-specific recordkeeping requirements derived from applicable requirements for each individual unit and contained in Condition II, the permittee shall comply with the following generally applicable recordkeeping requirements:

1. The permittee shall keep records of required monitoring information that include the following:

   a. The date, place, and time of sampling or measurements;

   b. The date(s) analyses were performed;

   c. The company or entity that performed the analyses;

   d. The analytical techniques or methods used;

   e. The results of such analyses; and

   f. The operating conditions as existing at the time of sampling or measurement.

2. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

3. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports and records.

III.C. Reporting Requirements [40 CFR § 71.6(a)(3)(iii)][NNOPR § 302(G)][The NNOPR provision is enforceable by NNEPA only.]

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

1. The permittee shall submit to NNEPA and US EPA Region IX reports of any monitoring required under 40 CFR §§ 71.6(a)(3)(i)(A), (B), or (C) each six-month reporting period from January 1 to June 30 and from July 1 to December 31. All reports shall be submitted to NNEPA and US EPA Region IX and shall be postmarked by the 30th day following the end of the reporting period. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Section IV.E.

    a. A monitoring report under this section must include the following:

        (i) The company name and address.

        (ii) The beginning and ending dates of the reporting period.

        (iii) The emissions unit or activity being monitored.

        (iv) The emissions limitation or standard, including operational requirements and limitations (such as parameter ranges), specified in the permit for which compliance is being monitored.

        (v) All instances of deviations from permit requirements, including those attributable to upset conditions as defined in the permit and including excursions or exceedances as defined under 40 CFR § 64, and the date on which each deviation occurred.

(vi) If the permit requires continuous monitoring of an emissions limit or parameter range, the report must include the total operating time of the emissions unit during the reporting period, the total duration of excess emissions or parameter exceedances during the reporting period, and the total downtime of the continuous monitoring system during the reporting period.

(vii) If the permit requires periodic monitoring, visual observations, work practice checks, or similar monitoring, the report shall include the total time when such monitoring was not performed during the reporting period and, at the permittee's discretion, either the total duration of deviations indicated by such monitoring or the actual records of deviations.

(viii) All other monitoring results, data, or analyses required to be reported by the applicable requirement.

(ix) The name, title, and signature of the responsible official who is certifying to the truth, accuracy, and completeness of the report.

b. Any report required by an applicable requirement in Condition II that provides the same information described in Condition III.C.1.a.i through ix above shall satisfy the requirement under Condition III.C.1.

c. "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 record keeping established in accordance with 40 CFR §§ 71.6(a)(3)(i) and (a)(3)(ii). For a situation lasting more than 24 hours, each 24-hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

(i) A situation when emissions exceed an emission limitation or standard.

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

(iii) 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.

(iv) A situation in which an exceedance or an excursion, as defined in the compliance assurance plan at 40 CFR Part 64, occurs.

2. The permittee shall promptly report to NNEPA and US EPA Region IX deviations from permit requirements or start-up, shut-down, or malfunction plan requirements, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. 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. Where the underlying applicable requirement does not define prompt or provide a timeframe for reporting deviations, reports of deviations shall be submitted based on the following schedule:

   a. For emissions of a HAP 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 within 24 hours of the occurrence.

   b. For emissions of any regulated pollutant excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours.

   c. For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report required in Condition III.C.1 of this permit.

3. If any of the conditions in Condition III.C.2.a or b of this permit are met, the source must notify NNEPA and US EPA Region IX by telephone, facsimile or electronic mail sent to airquality@navajo-nsn.gov and AEO_R9@epa.gov, based on the timetable listed. A written notice, certified consistent with Condition III.C.4, must be submitted within 10 working days of the occurrence. All deviations reported under this paragraph must also be identified in the 6-month report required under Condition III.C.1.

4. Any application form, report, or compliance certification required to be submitted by this permit shall contain certification by a responsible official of truth, accuracy, and completeness. All certifications shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

III.D. Stratospheric Ozone and Climate Protection

1. The permittee shall comply with the standards for the labeling of products using ozone-depleting substances pursuant to 40 CFR Part 82, Subpart E:

   a. All containers in which a Class I or Class II substance is stored or transported, all products containing a Class I substance, and all products directly manufactured with a Class I substance must bear the required warning statement if they are being introduced into interstate commerce pursuant to 40 CFR § 82.106.

b. The placement of the required warning statement must comply with 40 CFR § 82.108.

c. The form of the label bearing the required warning statement must comply with 40 CFR § 82.110.

d. No person may modify, remove, or interfere with the required warning statement except as described in 40 CFR § 82.112.

2. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs), MCAV-like appliances and/or small appliances:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with required practices under 40 CFR § 82.156.

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

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

d. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR § 82.152) must comply with recordkeeping requirements pursuant to 40 CFR § 82.166.

e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements under 40 CFR § 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR § 82.166(k).

3. If the permittee manufactures, transforms, destroys, imports, or exports a Class I or Class II controlled substance, the permittee is subject to all requirements in 40 CFR Part 82, Subpart A.

4. If the permittee performs a service on a motor (fleet) vehicle that involves ozone-depleting refrigerant (or a regulated substitute substance) in the MVAC, the permittee is subject to all requirements in 40 CFR Part 82, Subpart B.

The term “motor vehicle,” as used in Subpart B, does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC,” as used in Subpart B, does not include the air-tight sealed refrigeration systems used for refrigerated cargo or the systems used on passenger buses using HCFC-22 refrigerant.

5. The permittee shall be allowed to switch from any ozone-depleting substance to any acceptable substitute that is listed pursuant to 40 CFR Part 82, Subpart G.

III.E. Asbestos from Demolition and Renovation [40 CFR Part 61, Subpart M]

The permittee shall comply with the requirements of 40 CFR §§ 61.140 through 61.157 for all demolition and renovation projects.

IV. Title V Administrative Requirements

IV.A. Fee Payment [NNOPR Subpart VI][The NNOPR provision is enforceable by NNEPA only]

1. The permittee shall pay an annual permit fee in accordance with the procedures outlined below. [NNOPR §§ 603(A) and (B)]

   a. The permittee shall pay the annual permit fee by April 1 of each year.

   b. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the Navajo Nation Environmental Protection Agency.

   c. The permittee shall send the fee payment and a completed fee filing form to:

      Navajo Nation Air Quality Control Program
      Operating Permit Program
      P.O. Box 529
      Fort Defiance, AZ 86504

2. The permittee shall submit a fee calculation worksheet form with the annual permit fee by April 1 of each year. Calculations of actual or estimated emissions and calculation of the fees owed shall be computed on the fee calculation worksheets provided by the US EPA. Fee payment of the full amount must accompany each fee calculation worksheet. [NNOPR § 603(A)].

3. The fee calculation worksheet shall be certified as to truth, accuracy, and completeness by a responsible official consistent with 40 CFR § 71.5(d).

4. Basis for calculating the annual fee:

   The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of all fee pollutants emitted from the source by the applicable emissions fee (in dollars/ton) in effect at the time of calculation. 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. [NNOPR § 602(A) and (B)(1)]

   a. "Actual emissions" means the amount of emissions calculated using the actual rate of emissions in TPY of any fee pollutant emitted from a Part 71 source over the preceding calendar year and each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year. Actual emissions shall not include emissions of any one fee pollutant in excess of 4,000 TPY, or any emissions that come from insignificant activities. [NNOPR §§ 602(B)(1), 102(5)]

b. Actual emissions shall be computed using methods required by the permit for determining compliance, such as monitoring or source testing data.

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

d. The term "fee pollutant" is defined in NNOPR § 102(24).

e. The term "regulated air pollutant" is defined in NNOPR § 102(50), except that for purposes of this permit the term does not include any pollutant that is regulated solely pursuant to 4 N.N.C. § 1121 nor does it include any hazardous air pollutant designated by the Director of NNEPA pursuant to 4 N.N.C. § 1126(B).

f. The permittee should note that the applicable fee is revised each year to account for inflation and is available from NNEPA starting on March 1 of each year.

g. The total annual fee due shall be the greater of the applicable minimum fee and the sum of subtotal annual fees for all fee pollutants emitted from the source. [NNOPR § 602(B)(2)]

5. The permittee shall retain, in accordance with the provisions of 40 CFR § 71.6(a)(3)(ii), all fee calculation worksheets and other emissions-related data used to determine fee payment for five years following submittal of fee payment. Emission-related data include emissions-related forms provided by NNEPA and used by the permittee for fee calculation purposes, emissions-related spreadsheets, records of emissions monitoring data, and related support information.

6. Failure of the permittee to pay fees in a timely manner shall subject the permittee to the assessment of penalties and interest in accordance with NNOPR § 603(C).

7. When notified by NNEPA of underpayment of fees, the permittee shall remit full payment within 30 days of receipt of notification.

8. A permittee who thinks an NNEPA assessed fee is in error and wishes to challenge such fee shall provide a written explanation of the alleged error to NNEPA along with full payment of the NNEPA assessed fee. NNEPA shall, within 90 days of receipt of the correspondence, review the data to determine whether the assessed fee was in error. If an error was made, the overpayment shall be credited to the account of the permittee.

IV.B. Blanket Compliance Statement [CAA §§ 113(a) and (e)(1), 40 CFR §§ 51.212, 52.12, 52.33, 60.11(g), 71.6(a)(6)]

1. The permittee must comply with all conditions of this Part 71 permit. Any permit noncompliance, including, but not limited to, violation of any applicable requirement; any permit term or condition; any fee or filing requirement; any duty to allow or carry out inspection, entry, or monitoring activities; or any regulation or order issued by the permitting authority pursuant to Part 71 constitutes a violation of the federal CAA and is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. 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. [40 CFR §§ 71.6(a)(6)]

2. Determinations of deviations, continuous or intermittent compliance status, or violations of this permit are not limited to the applicable testing or monitoring methods required by the underlying regulations or this permit. Other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered in such determinations. [CAA §§ 113(a) and (e)(1), 40 CFR §§ 51.212, 52.12, 52.33, 60.11(g)]

IV.C. Compliance Certifications [40 CFR § 71.6(c)(5)][NNOPR § 302(I)][The NNOPR provision is enforceable by NNEPA only.]

1. The permittee shall submit to NNEPA and US EPA Region IX a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices, postmarked by January 30 and covering the previous calendar year. The compliance certification shall be certified as to truth, accuracy, and completeness by the permit-designated responsible official consistent with Section IV.E. of this permit and 40 CFR § 71.5(d) [40 CFR § 71.6(c)(5)]

2. The permittee shall submit to NNEPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices, postmarked by July 30 of each year and covering the previous six months. The compliance certification shall be certified as to truth, accuracy, and completeness by the permit-designated responsible official consistent with Section IV.E. of this permit. This condition is enforceable by NNEPA only. [NNOPR § 302(I)].

3. The certification shall include the following:

    a. Identification of each permit term or condition that is the basis of the certification.

    b. Identification of the method(s) or other means used for determining the compliance status of each term and condition during the certification period.

c. The compliance status of each term and condition of the permit for the period covered by the certification based on the method or means designated above. The certification shall identify each deviation and take it into account in the compliance certification.

d. A statement whether compliance with each permit term was continuous or intermittent.

e. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with CAA § 113(c)(2), which prohibits knowingly making a false certification or omitting material information.

IV.D. Duty to Provide and Supplement Information [40 CFR §§ 71.6(a)(6)(v), 71.5(b)][NNOPR § 301(E)][The NNOPR provision is enforceable by NNEPA only.]

The permittee shall furnish to NNEPA, within a reasonable time, any information that NNEPA may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to NNEPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. (Confidential information may be provided to US EPA IX only, pursuant to 40 CFR § 71.6(a)(6)(v), at the permittee's discretion.) Information claimed to be confidential should be accompanied by a claim of confidentiality according to the provisions of 40 CFR Part 2, Subpart B. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit to NNEPA such supplementary facts or corrected information. The permittee shall also provide additional information to NNEPA as necessary to address any requirements that become applicable to the facility after this permit is issued.

IV.E. Submissions [40 CFR §§ 71.5(d), 71.6][NNOPR § 103][The NNOPR provision is enforceable by NNEPA only.]

Any document required to be submitted with this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. All documents required to be submitted, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, applications for renewals, and permit modifications, shall be submitted to NNEPA and US EPA Region IX, as applicable, at the respective addresses below:

Navajo Nation Air Quality Control Program
Operating Permit Program
P.O. Box 529
Fort Defiance, AZ 86504

For Permit Renewal and Modification Applications:

Permits Office Chief, Air-3
US EPA Region 9
Air Division
75 Hawthorne Street
San Francisco, CA 94105-3901

For All Other Submissions:

Manager, Air & Tri-Section ENF-2-1
US EPA Region 9
Enforcement Division
75 Hawthorne Street
San Francisco, CA 94105-3901

IV.F. Severability Clause [40 CFR § 71.6(a)(5)][NNOPR § 302(A)(5)][The NNOPR provision is enforceable by NNEPA only.]

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

IV.G. Permit Actions [40 CFR § 71.6(a)(6)(iii)][NNOPR § 406][The NNOPR provision is enforceable by NNEPA only.]

This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

IV.H. Administrative Permit Amendments [40 CFR § 71.7(d)][NNOPR § 405(C)][The NNOPR provision is enforceable by NNEPA only.]

The permittee may request the use of administrative permit amendment procedures for a permit revision that:

1. Corrects typographical errors.

2. Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source.

3. Requires more frequent monitoring or reporting by the permittee.

4. Allows for a change in ownership or operational control of a source where NNEPA determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to NNEPA.

5. Incorporates into the permit the requirements from preconstruction review permits authorized under a US EPA-approved program, provided that such a program meets procedural requirements substantially equivalent to the requirements of 40 CFR §§ 71.7, 71.8 and 71.10 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in 40 CFR § 71.6.

6. Incorporates any other type of change which NNEPA has determined to be similar to those listed above in Condition IV.H.1 through 5.

IV.I. Minor Permit Modifications [40 CFR § 71.7(e)(1)][NNOPR § 405(D)][The NNOPR provision is enforceable by NNEPA only.]

1. The permittee may request the use of minor permit modification procedures only for those modifications that:

    a. Do not violate any applicable requirement.

    b. Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit.

    c. Do not require or change a case-by-case determination of an emissions limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis.

    d. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

        i. A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of CAA Title I; and

        ii. An alternative emissions limit approved pursuant to regulations promulgated under CAA § 112(i)(5).

    e. Are not modifications under any provision of CAA Title I.

f. Are not required to be processed as a significant modification.

2. Notwithstanding the list of changes eligible for minor permit modification procedures in Condition IV.I.1, minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by US EPA.

3. An application requesting the use of minor permit modification procedures shall meet the requirements of 40 CFR § 71.5(c) and shall include the following:

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

   b. The source's suggested draft permit;

   c. Certification by a responsible official, consistent with 40 CFR § 71.5(d), that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

   d. Completed forms for NNEPA to use to notify affected States and the Administrator as required under 40 CFR §§ 71.8 and 71.10(d).

4. The permittee may make the change proposed in its minor permit modification application immediately after it files such application. After the permittee makes the change allowed by the preceding sentence, and until NNEPA takes any of the actions authorized by 40 CFR §§ 71.7(e)(1)(iv)(A) through (C), the permittee must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time 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 time period, however, the existing permit terms and conditions it seeks to modify may be enforced against it.

5. The permit shield under 40 CFR § 71.6(f) may not extend to minor permit modifications.

IV.J. Significant Permit Modifications [40 CFR §§ 71.5(a)(2), 71.7(e)(3)][NNOPR §§ 301(C), 405(E)][The NNOPR provisions are enforceable by NNEPA only.]

1. The permittee must request the use of significant permit modification procedures for those modifications that:

a. Do not qualify as minor permit modifications or as administrative amendments.

b. Are significant changes in existing monitoring permit terms or conditions.

c. Are relaxations of reporting or recordkeeping permit terms or conditions.

2. Nothing herein shall be construed to preclude the permittee from making changes consistent with Part 71 that would render existing permit compliance terms and conditions irrelevant.

3. The permittee must meet all requirements of Part 71 for applications for significant permit modifications. Specifically, for the application to be determined complete, the permittee must supply all information that is required by 40 CFR § 71.5(c) for permit issuance and renewal, but only that information that is related to the proposed change.

IV.K. Reopening for Cause [40 CFR § 71.7(f)][NNOPR § 406][The NNOPR provision is enforceable by NNEPA only.]

1. NNEPA or US EPA shall reopen and revise the permit prior to expiration under any of the following circumstances:

a. Additional requirements under the CAA become applicable to a major Part 71 source with a remaining permit term of 3 or more years.

b. NNEPA or US EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

c. NNEPA or US EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

2. Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists, and shall be made as expeditiously as practicable.

3. Reopening for cause by NNEPA or EPA shall not be initiated before notice of such intent is provided to the permittee by NNEPA or EPA at least 30 days in advance of the date that the permit is to be reopened, except that NNEPA or EPA may provide a shorter time period in the case of an emergency.

4. Reopening for cause by US EPA shall follow the procedures set forth in 40 CFR § 71.7(g).

IV.L. Property Rights [40 CFR § 71.6(a)(6)(iv)][NNOPR § 302(B)(5)][The NNOPR provision is enforceable by NNEPA only.]

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

IV.M. Inspection and Entry [40 CFR § 71.6(c)(2)][NNOPR § 302(I)(2)][The NNOPR provision is enforceable by NNEPA only.]

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized representatives from NNEPA and US EPA to perform the following:

1. Enter upon the permittee's premises where a Part 71 source is located or emissions-related activity is conducted or where records must be kept under the conditions of the permit;

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

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

4. As authorized by the federal CAA, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

IV.N. Emergency Provisions [40 CFR § 71.6(g)][NNOPR § 305][The NNOPR provision is enforceable by NNEPA only.]

1. In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

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

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

    c. 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

d. The permittee submitted notice of the emergency to NNEPA and US EPA within 2 working days of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements of Condition III.C.2 of this permit.

In any enforcement proceeding, the permittee has the burden of proof to establish the occurrence of an emergency.

2. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the permittee, including acts of God, which situation requires immediate corrective action to restore normal operation and that causes the source to exceed a technology-based emissions limitation under this permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

IV.O. Transfer of Ownership or Operation [40 CFR § 71.7(d)(1)(iv)][NNOPR § 405(C)][The NNOPR provision is enforceable by NNEPA only.]

A change in ownership or operational control of this facility may be treated as an administrative permit amendment if NNEPA determines no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to NNEPA.

IV.P. Off-Permit Changes [40 CFR § 71.6(a)(12)][NNOPR § 404(B)][The NNOPR provision is enforceable by NNEPA only.]

The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met:

1. Each change is not addressed or prohibited by this permit;

2. Each change must comply with all applicable requirements and must not violate any existing permit term or condition;

3. Changes under this provision may not include changes or activities subject to any requirement under CAA Title IV or that are modifications under any provision of CAA Title I;

4. The permittee must provide contemporaneous written notice to NNEPA and US EPA Region IX of each change, except for changes that qualify as insignificant activities under 40 CFR § 71.5(c)(11). The written notice must describe each

change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change; and

5. The permittee must keep a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit and the emissions resulting from those changes.

IV.Q. Permit Expiration and Renewal [40 CFR §§ 71.5(a)(1)(iii), 71.6(a)(11), 71.7(b), 71.7(c)(1)(i) and (ii)][NNOPR §§ 301(B)(2) and 401(F)][The NNOPR provision is enforceable by NNEPA only.]

1. This permit shall expire upon the earlier occurrence of the following events:

   a. For sources other than those identified in Condition IV.Q.1.a, five years elapse from the date of issuance; or

   b. The source is issued a Part 70 permit by a US EPA-approved permitting authority.

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

3. If the permittee submits a timely and complete permit application for renewal consistent with 40 CFR § 71.5(a)(2), but NNEPA has failed to issue or deny the renewal permit, the permit shall not expire until the renewal permit has been issued or denied.

4. The permittee's failure to have a current Part 71 permit is not a violation of Part 71 until NNEPA takes final action on the permit renewal application. This protection shall cease to apply if, subsequent to a completeness determination under 40 CFR § 71.7(a)(4), the permittee fails to submit any additional information identified as being needed to process the application by the deadline specified in writing by NNEPA.

5. Renewal of this permit is subject to the same procedural requirements that apply to initial permit issuance, including those for public participation, affected State review, and tribal review.

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.

Navajo Nation Environmental Protection Agency –Air Quality Control/Operating Permit Program
Post Office Box 529, Fort Defiance, AZ 86504 • Bldg. #2837 Route 112
Telephone (928) 729-4096, Fax (928) 729-4313, Email airquality@navajo-nsn.gov
www.navajonationepa.org/airquality.html

Detailed Information

Permitting Authority: NNEPA

County: San Juan **State:** Utah **AFS Plant ID:** 04-017-NAV01

Facility: Elk Operating Services, LLC – Aneth Unit

Document Type: STATEMENT OF BASIS

PART 71 FEDERAL OPERATING PERMIT
STATEMENT OF BASIS
Elk Operating Services, LLC – Aneth Unit

Permit No. NN OP 17-012

1. Facility Information

a. Permittee

Elk Operating Services, LLC – Aneth Unit
Near Montezuma Creek, San Juan County, Utah on the Navajo Reservation at the following locations:
CO_2 Recycle Facility – SENE Section 22, T40S, R24E
Tank Battery 21 – SENW Section 21, T40S, R24E
Header 21-14 – SWNE Section 14, T40S, R24E
Header 21-15 – NENE Section 15, T40S, R24E
Header 21-16 – SENW Section 16, T40S, R24E
Header 21-22 – SWNE Section 22, T40S, R24E

Mailing Address:
1700 Lincoln Street, Suite 2950
Denver, Colorado 80203

b. Contact Information

Responsible Official: Scott Hornafius, President
1700 Lincoln Street, Suite 2950
Denver, Colorado 80203
(303) 861-6522 ext 1130

Facility Contact: Jeff Roedell, Vice President, Four Corners Business Unit
23429 County Road G, P.O. Drawer G

Cortez, Colorado 81321
(970) 564-5200 ext 2325
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c. Description_of_Operations,_Products

The Aneth Unit is an oil field operation located near the community of Montezuma Creek in Utah on the reservation of the Navajo Nation. This site mainly produces crude oil. Some natural gas is extracted from the oil well and captured for sale. In addition, this site also utilizes the CO_2 Enhanced Oil Recovery (EOR) technology that injects the CO_2 captured and recycled to the wells to enhance the oil production process. The Aneth field was discovered in 1956 and developed by Texaco, Superior, Phillips and Shell. Resolute Natural Resources Company acquired the Aneth site in 2004 and sold it to Elk Operating Services, LLC in 2017. Elk Operating Services, LLC is the current owner and operator of this site.

Aneth Unit consists of Tank Batteries 20, 21, 26 and 29, a CO_2 Recycle Facility, and several wells and headers. According to the revised "major source" definition in 40 CFR § 71.2, promulgated on June 3, 2016, for onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1⁄4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Therefore, Tank Batteries 20, 21, 26 and 29, and the CO_2 Recycle Facility are located more than 1⁄4 mile of each other and should be considered separate sources. However, the past Part 71 permit (NN-OP 00-02, issued on July 30, 2007) has determined that Headers 21-14, 21-15, 21-16 and 21-22, Tank Battery 21, the CO_2 Recycle Facility were considered one single source for Part 71 permitting and New Source Review (NSR) purposes. This determination was made prior to the revised major source definition in 40 CFR § 71.2, promulgated on June 3, 2016. In order to be consistent with the past permit determinations, the permittee requested that NNEPA continue to apply the same single source determination to this Part 71 renewal permit although Tank Battery 21 and the CO_2 Recycle Facility are located about 1 mile apart from each other.

As requested by the permittee, the "source" referred in this Part 71 renewal permit includes the Headers 21-14, 21-15, 21-16 and 21-22, Tank Battery 21, and the CO_2 Recycle Facility. The emissions from these units are aggregated as a single source for Part 71 and NSR review purposes. Tank Batteries 20, 26, and 29 are all located more than 1 mile away from this source and was historically determined as separate sources.

Therefore, Tank Batteries 20, 26, and 29 are not permitted under this Part 71 renewal permit.

The 2015 annual production at this source is 414,729 barrels (bbl) of oil and 22,245 million standard cubic feet (MMscf) of natural gas. The maximum production of this source is expected to be 2,500 bbl per day. All the wells produce CO_2 rich gas.

d. History

Tank Battery 21 was constructed in 1964 and the CO_2 Recycle Facility was constructed in 1999. There were no construction permits issued for these construction activities. The first Part 71 operating permit (Permit #NN-OP 00-02) was issued to this source on July 30, 2007. In 2010, the source requested an increase in facility-wide emission limits to handle the increased volumes of CO_2 and natural gas produced with the crude oil as a result of greater CO_2 breakthrough within the Aneth Field. This change was permitted in the First Minor Permit Revision #NN-OP 00-02, issued on October 25, 2010. In 2011, the source installed one triethylene glycol dehydrator (INJ-DEHY-1) and gas processing equipment at the existing CO_2 Recycle Facility. The operation of the new units installed in 2011 was permitted in Minor Permit Revision #NN-OP 00-02-B, issued on February 27, 2012.

e. Existing Approvals

The source has been operating under Part 71 Operating Permit NN-OP 00-02, issued on July 30, 2007, and the following approvals:

(1) First Minor Permit Revision to #NN-OP 00-02, issued on October 25, 2010.

(2) Minor Permit Revision #NN-OP 00-02-B, issued on February 27, 2012.

f. Proposed Modifications to the Part 71 Permit:

The permittee requested the following changes be made to their Part 71 permit:

(1) Corrections to the emission calculation equations listed in the permit.

The emission calculation equations listed under Condition II.C.2.g of Permit # NN-OP 00-02, issued on July 30, 2007, do not include the unit conversion factors for weight and volume. The equations listed in this Part 71 renewal permit have been revised to include these unit conversion factors. The source has provided the information to show that the actual emissions from this source during the time period of 2007 to 2011, calculated using the corrected equations and conversion factors, are still below the source-wide VOC, NOx, SO_2, and CO emission limits specified in the Part 71 permit.

(2) Include the emission calculation methods for the dehydrator.

The triethylene glycol dehydrator (INJ-DEHY-1) was installed in 2011. The source-wide emission limits for NOx, CO, SO_2, VOC, and HAP emissions should include the emissions from this unit as well. However, Minor Permit Revision #NN-OP 00-02-B, issued on February 27, 2012 does not include the emission calculation method and recordkeeping requirements for the dehydrator to demonstrate compliance with the source-wide emission limits. This Part 71 permit renewal has included the emission calculation method and recordkeeping requirements for the dehydrator in Condition II.C.3 of the permit.

(3) Apply HAP emission limits to the total emissions from both Tank Battery 21 and the CO_2 Recycle facility.

In Operating Permit NN-OP 00-02, issued on July 30, 2007, the HAP emissions from the oil storage tanks at Tank Battery 21 and the HAP emissions from the oil storage tanks at the CO_2 Recycle facility are each limited to less than 9.0 tons per year (tons/yr) for a single HAP and 24.0 tons/yr for total HAPs because Tank Battery 21 and the CO_2 Recycle facility are not located in continuous property and are considered two separated sources under 40 CFR Part 63 purposes, according to the source definition in 40 CFR § 63.2.

In First Minor Permit Revision to #NN-OP 00-02, issued on October 25, 2010, the HAP emission limits for the oil storage tanks at the CO_2 Recycle facility were removed from the permit since these oil storage tanks no longer exist. This source later installed the triethylene glycol dehydrator (INJ-DEHY-1) in 2011. However, there was no HAP emission limits for this unit established in Minor Permit Revision #NN-OP 00-02-B, issued on February 27, 2012.

Since the actual HAP emissions from the entire source (including Tank Battery 21 area, the CO_2 Recycle Facility, and Headers 21-14, 21-15, 21-16, and 21- 22) have never exceeded 9 tons/yr for a single HAP or 24 tons/yr for total HAPs, the permittee has agreed to take voluntary HAP emission limits to limit the emissions from the entire source to less than 9 tons/yr for a single HAP and less than 24 tons/yr for total HAPs in this Part 71 renewal permit.

(4) Changes to the applicable requirements of National Emission Standards for Hazardous Air Pollutants (NESHAP) from Oil and Natural Gas Production Facilities (40 CFR Part 63, Subpart HH).

The permittee has indicated an error in the applicability of NESHAP, Subpart HH in the previously issued permit. According to the Statement of Basis for Minor Permit Revision #NN-OP 00-02-B, issued on February 27, 2012, the CO_2 Recycle Facility is considered a HAP major source under 40 CFR Part 63 and the requirements for major sources were applied to the affected facilities at this CO_2 Recycle Facility. According to the “major source” definition in 40 CFR § 63.761, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. Since there is no storage vessel at the CO_2 Recycle Facility, only the HAP emissions from the triethylene glycol dehydrator are counted into the total emissions for the HAP major source determination for the CO_2 Recycle Facility. However, the potential to emit HAPs of the dehydrator at this source, calculated using the maximum natural gas or hydrocarbon liquid throughput, is less than 10 tons/yr for a single HAP and less than 25 tons/yr. Therefore, the CO_2 Recycle Facility is actually an area source under NESHAP, Subpart HH. Therefore, the requirements for area sources, instead of the requirements for major sources, under this NESHAP will apply to the affected facilities at the CO_2 Recycle Facility in this Part 71 renewal permit.

In addition, the actual emissions from the entire source (including Tank Battery 21 area, the CO_2 Recycle Facility, and Headers 21-14, 21-15, 21-16, and 21- 22) have never exceeded the HAP major source thresholds (10 tons/yr for a single HAP and 25 tons/yr for total HAPs).

The proposed changes above are considered significant permit modifications. The procedure for reviewing this Part 71 renewal permit fulfills the significant permit modification requirements specified in 40 CFR § 71.7(e)(3) and NNOPR § 405(E).

g. Permitted Emission Units and Control Equipment

Unit ID	Unit Description	Maximum Capacity	Commenced Construction Date	Control Method
21-14 21-15 21-16 21-22	Four (4) headers.	Varies	After 1964	Flare 21-14-F-1 Flare 21-15-F-1 Flare 21-16-F-1 Flare 21-22-F-1
21-ST-1 21-ST-2 21-ST-3 21-ST-4	Four (4) oil production tanks at Tank Battery 21	3,000 bbl (126,000 gal) Each	1991	Vapor Recovery Unit (VRU) 21-ST-VRU; Flare 21-F-1
21-F-1	Emergency/upset flare at Tank Battery 21	54 MMscfd	After 1964	N/A
INJ-DEHY-1	One (1) triethylene glycol dehydrator at CO_2 recycle facility.	100 MMscfd	2011	Thermal Oxidizer INJ-TO-1; Flare INJ-F-1 as a back-up control
INJ-F-1	Emergency/upset non-assisted flare at CO_2 Recycle Facility; Emissions are vented to this flare when the compressors or thermal oxidizer (INJ-TO-1) are down.	5 MMscfd	1999	N/A
INJ-HMO-1	One (1) natural gas-fired heat medium oil (HMO) burner at CO_2 recycle facility.	6 MMBtu/hr	2011	N/A
Fugitive Emissions				
21-Fugitives	Fugitive VOC and HAP emissions at Tank Battery 21 area.	N/A	1991 and after	N/A

Unit ID	Unit Description	Maximum Capacity	Commenced Construction Date	Control Method
INJ-Fugitive	Fugitive VOC and HAP emissions at CO_2 Recycle Facility.	N/A	1991 and after	N/A
Road Fugitives	Fugitive emissions from unpaved roads.	N/A	1991	N/A

h. Unpermitted Emission Units and Control Equipment

No unpermitted emission units were found to be operating at this source during this review process.

i. New Emission Units and Control Equipment

According to the information submitted by the source on November 27, 2016, the source has installed a natural gas-fired emergency generator (GEN-100) at the CO_2 recycle facility in 2011. The maximum power output of this unit is 425 hp. This unit is considered an insignificant unit since the potential to emit of this unit is less than 2 tons/yr for each criteria pollutant. Therefore, the installation of this unit does not trigger a minor new source review permit.

j. Insignificant Activities and Emissions

This stationary source also emits air pollutants from insignificant activities and at insignificant emissions levels, defined in 40 CFR § 71.5(c)(11)(ii) as emissions from an emissions unit with the potential to emit non-hazardous regulated air pollutants in an amount less than 2 tons per year or a single HAP in an amount less than 1,000 pounds per year or the de minimis level established under CAA § 112(g), whichever is less. These emissions come from the following insignificant activities and emissions units:

(1) One (1) oil heater treater at Tank Battery 21, installed in 2013, with a maximum heat input capacity of 1 MMBtu/hr.

(2) One (1) oil heater treater at Tank Battery 21, installed in 2015, with a maximum heat input capacity of 0.75 MMBtu/hr.

(3) One (1) natural gas-fired spark ignition emergency generator (GEN-100), installed in 2011, with a maximum power output of 425 hp, and located at the CO_2 recycle facility.

(4) Condensate stabilizer equipment at the CO_2 Recycle Facility, constructed in 2011.

(5) Refrigeration equipment at the CO_2 Recycle Facility, constructed in 2011.

k. Enforcement Issue

There are no enforcement actions pending.

l. <u>Emission Calculations</u>

See Appendix A of this document for detailed calculations (pages 1 through 12).

m. <u>Potential to Emit</u>

Potential to emit (PTE) means the maximum capacity to emit any CAA-regulated air pollutant under the facility's physical and operational design. Any physical or operational limitation on the maximum capacity of this facility to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, may be treated as a part of its design <u>if</u> the limitation is enforceable by US EPA or NNEPA. Actual emissions are typically lower than PTE.

	Potential to Emit (tons/year)							
Process/facility	PM	PM10	PM2.5	SO_2	NOx	VOC	CO	HAPs
Storage Tanks, Flares, and Dehydrator	0.02	0.10	0.10	Less than 153.1	Less than 60.0	Less than 240	Less than 180	Less than 9.0 for a single HAP; Less than 24.0 for total HAPs
Oil Heater INJ-HMO-1	0.05	0.20	0.20	0.02	2.58	0.14	2.16	Negligible
Insignificant Oil Heaters	0.01	0.06	0.06	0.005	0.75	0.04	0.63	Negligible
Insignificant Emergency Generator	-	-	-	-	0.47	0.23	0.94	Negligible
PTE of the Entire Source	0.09	0.35	0.35	153	63.8	240	184	Less than 9.0 for a single HAP; Less than 24.0 for total HAPs
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10 for a single HAP and 25 for total HAPs

(a) This source is not in one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a) and is not subject to any NSPS or NESHAP that was in effect on August 7, 1980. Therefore, fugitive emissions from this source are not counted toward the Title V or PSD major source determinations, except HAP fugitive emissions are counted for Title V major source determinations.

(b) The potential to emit of SO_2, VOC, and CO are equal to or greater than 100 tons per year. Therefore, this source is considered a major source under 40 CFR § 71.2 (defining "major source" for purposes of the Federal Operating Permit Program).

(c) This source is located in an attainment area and is not in one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a). The potential to emit PM and all criteria pollutants from this source are limited to less than 250 tons per year. Therefore, this source is an existing synthetic minor source under the Prevention of Significant Deterioration (PSD) program.

n. <u>Actual Emissions</u>

The following table shows the actual 2015 emissions from this source. The information was submitted by the permittee based on the emission inventory information reported to NNEPA and the GHG information reported to US EPA.

Pollutant	Actual Emissions (tons/year)
PM_{10}	(not reported)
SO_2	27.5
VOC	26.7
NO_x	7.8
CO	30.3
Benzene	0.2
n-Hexane	0.8
Total HAPs	1.1
Greenhouse Gas (GHG)	27,866

2. Tribe Information

a. <u>General</u>

The Navajo Nation has the largest land base of any tribe in the country, covering more than 27,000 square miles in three states: Arizona, Utah, and New Mexico. The Navajo Nation currently is home to more than 260,000 people. Industries on the Navajo Nation include oil and natural gas production, coal mining, electric generation and distribution, and tourism.

b. <u>Local air quality and attainment status</u>

All areas of the Navajo Nation are currently designated as attainment or unclassifiable for all pollutants for which a National Ambient Air Quality Standard (NAAQS) has been established.

3. Prevention of Significant Deterioration (PSD) Applicability

The construction of this source in 1964 pre-dated the PSD program. Therefore, there was no construction permit issued then. This source is not in one of the 28 source categories listed in 40 CFR § 52.21(b)(1)(i)(a) and is not subject to any NSPS or NESHAP that was in effect on August 7, 1980. Therefore, fugitive emissions are not counted toward the total PTE of the source for the PSD major source determination purposes. The PTE of the entire source has been less than 250 tons/yr from initial construction through 1999, so it has been considered a PSD minor source since the construction through 1999.

This source was later modified in 1999 to add a CO_2 Recycle Facility. This modification did not have a PTE greater than the PSD major source thresholds of 250 tons/hr. Therefore, the modification in 1999 did not trigger PSD review. However, the PTE of SO_2, VOC, and CO from the entire source exceeded 250 tons/yr after the 1999 modification.

Since the actual emissions from this source has never exceeded 250 tons/yr, the permittee voluntarily accepted permit conditions, to limit each of the SO_2, VOC, and CO emissions from the entire source to less than 250 tons/yr in the Title V permit NN-OP 00-02, issued on July 30, 2007. Therefore, this source is considered a PSD synthetic minor source after the issuance of the Title V permit in 2007.

The modification in 2011 added a glycol dehydrator and several gas processing equipment to the existing CO_2 Reclycle Facility. The PTE of this modification project is less than 250 tons/yr. Thefore, the modification project in 2011 did not trigger PSD review.

With the voluntary emission limits proposed in this Part 71 renewal permit, the PTE of this source will continue to stay below 250 tons/yr for SO_2, VOC, and CO. Therefore, this existing source is considered a PSD synthetic minor source.

4. Inapplicable Requirements

(a) The four (4) oil storage tanks at Tank Battery 21 are not subject to the New Source Performance Standards (NSPS) for Volatile Liquid Storage Vessels Constructed or Modified after June 11, 1973 and Prior to May 19, 1978 (40 CFR Part 60, Subpart K) because this subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer, pursuant to 40 CFR § 60.110(b).

(b) The four (4) oil storage tanks at Tank Battery 21 are not subject to the NSPS for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984 (40 CFR Part 60, Subpart Ka) because this subpart does not apply to storage vessels with capacities less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer, pursuant to 40 CFR § 60.110a(b).

(c) The four (4) oil storage tanks at Tank Battery 21 are not subject to the NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (40 CFR Part 60, Subpart Kb) because this subpart does not apply to storage vessels with design capacities less than or equal to 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer, pursuant to 40 CFR § 60.110b(d)(4).

(d) The four (4) oil storage tanks at Tank Battery 21 are not subject to the NSPS for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015 (40 CFR Part 60, Subpart OOOO) because these tanks were constructed before August 23, 2011.

(e) The four (4) oil storage tanks at Tank Battery 21 are not subject to the NSPS for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015 (40 CFR Part 60, Subpart OOOOa) because these tanks were constructed before August 23, 2011.

(f) Each of the oil heaters has a maximum heat input capacity hess than 10 MMBtu/hr. Therefore, this heater is not subject to the requirements of the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Dc), pursuant to 40 CFR § 60.40c(a).

(g) The benzene concentration of the exhausts from this source is less than 10 percent by weight. Therefore, the requirements of the National Emission Standard for Equipment Leaks (Fugitive Emission Sources) (40 CFR Part 61, Subpart V) are not applicable.

(h) This source is not subject to the requirements of Chemical Accident Prevention Regulation (40 CFR Part 68, Subpart M) because the operations at Tank Battery 21 and the CO_2 Recycle Facility do not emit regulated substances more than the thresholds listed under Table 1 to 40 CFR § 68.130.

5. Applicable Requirements

(a) Since this source meets the "natural gas processing plant" definition in 40 CFR § 60.631 and it was modified before August 23, 2011 to add serveral gas processing equipment, this source is subject to the requirements of Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011 (NSPS, Subpart KKK).

Affected Facilities under NSPS, Subpart KKK:

According to 40 CFR § 60.630(a), the affected facilities under this NSPS include any compressor in VOC service or in wet gas service (definied in 40 CFR § 60.631), and all equipment, except compressors, within a process unit. According to the definitions in 40 CFR § 60.631, "process unit" means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. The permittee has identified the emission units listed in the table below as the affected units under this NSPS in the supplemental information submitted on September 1, 2016. These emission units are located at the CO_2 Recycle Facility (a natural gas processing plant) and were constructed after January 20, 1984 and before August 23, 2011. The emissin units are also included in the Attachment A to the permit.

Process/Unit	Equipment ID	Description	Service
Condensate Stabilizer	E-204	Exchanger	Light Liquid Service
Condensate Stabilizer	E-205	Stabilizer Reboiler	Light Liquid Service
Condensate Stabilizer	E-206	Cooler	Light Liquid Service
Condensate Stabilizer	V-203	Condensate Stabilizer	VOC/Light Liquid Service
Dehydration	E-304	Condenser	VOC Service
Dehydration	H-301	Regenerator	VOC Service
Dehydration	P-302	Pump	Light Liquid Service
Dehydration	V-102	Separator	Light Liquid Service
Dehydration	V-103	Contactor	Wet Gas
Dehydration	V-104	Scrubber	Wet Gas
Dehydration	V-301	Flash Tank	VOC Service
Dehydration	V-302	Stripping Column	VOC Service
Dehydration	V-303	Still OVHD Separator	VOC/Light Liquid Service
Dehydration	X-701	Thermal Oxidizer	VOC Service
Flare	P-8601A	Pump	Light Liquid Service
Flare	P-8601B	Pump	Light Liquid Service
Flare	V-8701	Flare Knockout	Light Liquid Service
Flare	V-8702	Flare Knockout	Light Liquid Service
HMO	H-601	Heater (INJ-HMO-1)	Heavy Liquid
HMO	P-601A	Pump	Heavy Liquid
HMO	P-601B	Pump	Heavy Liquid
HMO	V-601	Expansion Tank	Heavy Liquid
Refrigeration	B-401	Condenser	VOC Service
Refrigeration	C-401	Compressor	VOC Service
Refrigeration	E-201	Exchanger	VOC Service
Refrigeration	E-202	Exchanger	VOC Service
Refrigeration	E-203	Gas Chiller	VOC Service
Refrigeration	V-201	Inlet Separator	VOC/Light Liquid Service
Refrigeration	V-202	Low Temp Separator	VOC/Light Liquid Service
Refrigeration	V-401	Separator	VOC Service
Refrigeration	V-402	Propane Accumulator	VOC Service

Applicable Requirements under NSPS, Subpart KKK:

Pursuant to 40 CFR § 60.632(a), the permittee shall comply with the requirements of 40 CFR §§ 60.482-1 (a), (b), and (d), and 60.482-2 through 60.482-10, except the exceptions provided in 40 CFR § 60.633. 40 CFR §§ 60.482-1 through 60.482-10 are the requirements for NSPS, Subpart VV for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006.

Pursuant to 40 CFR § 60.633(b), emissions from the pressure relief device in gas or vapor service shall comply with the requirements in 40 CFR § 60.633(b), instead of the requirements in NSPS, Subpart VV.

Pursuant to 40 CFR § 60.633(c), sampling connection systems are exempt from the requirements of 40 CFR §60.482-5 in NSPS, Subpart VV.

The exceptions listed in 40 CFR § 60.633(d), (e), (f) are not applicable because this plant has actual throughput greater than 10 MMscf/day and is not located in Alaskan North Slope. In addition, this source does not have any reciprocating compressors in wet gas service.

Pursuant to 40 CFR § 60.633(g), flares used to comply with this subpart shall comply with the flare requirements in 40 CFR § 60.18.

The applicable operation and monitoring requirements for this source under NSPS, Subpart KKK are summarized in the table below:

Type of Equipment	Operation/ Monitoring Requirements
Pressure relief device in gas or vapor service	40 CFR § 60.633(b)
Pumps in light liquid service	40 CFR § 60.482-2
Compressor	40 CFR § 60.482-3
Open ended valves or lines	40 CFR § 60.482-6
Gas vapor service and light liquid service	40 CFR § 60.482-7
Pumps and valves in heavy liquid services	40 CFR § 60.482-8
Delay of repair	40 CFR § 60.482-9
Closed vent system and control device	40 CFR § 60.482-10
Flares used to comply with this subpart	40 CFR § 60.18

Pursuant to 40 CFR §§ 60.632(a) and 60.482-1(b), the permittee shall demonstrate compliance with the requirements in the table above with records and reports, performance test results, and inspections using the methods and procedures specified in 40 CFR § 60.485 of NSPS, Subpart VV. The specific operation, monitoring, testing, recordkeeping, and reporting requirements under NSPS, Subpart VV are included in Attachment B to the Part 71 renewal permit.

In addition, the permittee shall also comply with the applicable recordkeeping requirements in 40 CFR § 60.635 and the reporting requirements in 40 CFR § 60.636.

(b) The CO_2 Recycle Facility has equipment that processes, upgrades, or stores hydrocarbon liquids. Therefore, it is subject to the requirements of National Emission Standards for Hazardous Air Pollutants (NESHAP) from Oil and Natural Gas Production Facilities (40 CFR Part 63, Subpart HH). This rule was recently amended on August 16, 2012.

Source Definition for NESHAP Purposes:

Under 40 CFR Part 63, Tank Battery 21 and the CO_2 Recycle Facility are considered two (2) separate sources since they are not located within a contiguous area, according to source definition in 40 CFR § 63.2.

Pursuant to the major source definition in 40 CFR § 63.761, for facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. Since there are no storage tanks at the CO_2 Recycle Facility, only the emissions from the triethylene glycol dehydrator (INJ-DEHY-1) are counted toward to total PTE for HAP major source determination under this NESHAP. According to the PTE calculation methods specified in in 40 CFR §§ 63.760(a)(1) and 63.2, the PTE of the triethylene glycol dehydrator (INJ-DEHY-1) is less than 10 tons/yr for a single HAP and less than 25 tons/yr for total HAPs. Therefore, the CO_2 Recycle Facility is considered a HAP area source under NESHAP, Subpart HH.

Affected Units:

Pursuant to 40 CFR § 63.760(b)(2), for HAP area sources, the affected units include each triethylene glycol (TEG) dehydration unit located at a facility that meets the criteria specified in 40 CFR § 63.760(a). Therefore, the only affected unit under this NESHAP is the triethylene glycol dehydrator (INJ-DEHY-1) located at the CO_2 Recycle Facility. This unit is currently controlled by a thermal oxidizer (INJ-TO-1) and uses flare INJ-F-1 as a back-up control.

Applicable Requirements:

Pursuant to 40 CFR § 63.764(d)(2), the permittee shall operate the TEG dehydration unit such that the actual glycol circulation rate does not exceed the optimum glycol circulation rate determined in accordance with 40 CFR § 63.764(d)(2)(i). The permittee shall also comply with the applicable recordkeeping requirements in 40 CFR § 63.774 and the reporting requirements in 40 CFR § 63.775.

The glycol dehydrator (INJ-DEHY-1) at this source has uncontrolled VOC emissions greater than 100 tons/yr and is controlled by a thermal oxidizer (INJ-TO-1). However, this unit is exempt from the requirements of 40 CFR Part 64 (Compliance Assurance Monitoring (CAM)) because it is subject to requirements of NESHAP, Subpart HH, which was promulgate after November 15, 1990, pursuant to 40 CFR § 64.2(b)(1)(i).

Oil storage tank 21-ST-1 has uncontrolled VOC emissions greater than 100 tons/yr and is controlled by a VRU (95%). This unit is subject to the source-wide VOC emission limit of 240 tons per 12 consecutive month period. This Part 71 renewal permit requires the source to demonstrate compliance with the source-wide VOC emission limit by performing monthly VOC emission calculations. Since the compliance emission calculation is performed monthly, it is consistent with the averaging period established for the emission limitation. Therefore, performing monthly emission calculations is considered a "continuous compliance determination method" as defined in 40 CFR 40 CFR § 64.1. Pursuant to 40 CFR § 64.2(b)(1)(vi), Tank 21-ST-1 is exempt from the requirements of 40 CFR Part 64 (CAM).

No other oil storage tanks at this source have uncontrolled VOC emissions greater than 100 tons/yr. Therefore, the requirements of 40 CFR Part 64 (CAM) are not applicable to other oil storage tanks.

(c) The NG fired emergency generator (GEM-100) was constructed after January 1, 2009 and has a maximum power output greater than 25 hp. Therefore, this unit is subject to the requirements of the New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines (40 CFR Part 60, Subpart JJJJ), pursuant to 40 CFR § 60.4230(a)(4)(iv).

Since the maximum power output of this emergency generator is 425 hp, the emissions from this emergency generator shall comply with the following emission limits, pursuant to 40 CFR § 60.4233(e) and Table 1 of this NSPS:

(1) NO_X emissions shall not exceed 2.0 g/HP-hr.

(2) CO emissions shall not exceed 4.0 g/HP-hr.

(3) VOC emissions shall not exceed 1.0 g/HP-hr.

According to the information submitted by the source on November 27, 2016, the emissions from this emergency generator do meet the emission limits specified in this NSPS. Therefore, this source is not required to install a non-resettable hour meter as required in 40 CFR § 60.4237(b). However, the permittee has installed a non-resettable hour meter with this engine.

Pursuant to the compliance requirements in 40 CFR § 60.4243(a)(2)(ii), if the emergency generator (GEM-100) is a non-certified engine, the permittee shall keep a maintenance plan and records of conducted maintenance and shall, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, the permittee shall conduct an initial performance test within 1 year of engine startup to demonstrate compliance. [40 CFR § 60.4243(a)(2)(ii)]

Pursuant to 40 CFR § 60.4243(d), the permittee must operate the emergency stationary ICE according to the requirements specified in 40 CFR § 60.4243(d)(1) through (3). In addition, the permittee must comply with the applicable test methods and procedures specified in 40 CFR § 60.4244; and the applicable recordkeeping and reporting requirements specified in 40 CFR § 60.4245.

(d) The emergency generator (GEN-100) at this source is considered a stationary reciprocating internal combustion engine (RICE) and is subject to the NESHAP for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63, Subpart ZZZZ). This emergency generator is a spark ignition (SI) engine and considered a new RICE since it was constructed after June 12, 2006.

The emergency generator (GEN-100) has a maximum capacity less than 500 hp and is subject to the requirements of NSPS for Stationary SI ICE, 40 CFR Part 60, Subpart JJJJ. Pursuant to 40 CFR § 63.6590(c)(1), compliance with this NESHAP is demonstrated by complying with the requirements specified in the NSPS for Stationary SI ICE, 40 CFR Part 60, Subpart JJJJ.

(e) The permittee is subject to the requirements of the Asbestos NESHAP (40 CFR Part 61, Subpart M). The applicable requirements are specified in the permit document.

(f) The permittee is subject to the requirements of 40 CFR Part 82 (Protection of Stratospheric Ozone). The applicable requirements are specified in the permit document.

Summary of Applicable Federal Requirements

Federal Air Quality Requirement	Current or Future Requirement	Permit Condition Number
NSPS for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants (40 CFR Part 60, Subpart KKK)	Current	II.F
NESHAP for Oil and Natural Gas Production Facilities (40 CFR 63, Subpart HH)	Current	II.I
NSPS for Stationary Spark Ignition Internal Combustion Engines (40 CFR 60, Subpart JJJJ)	Current	II.G
NESHAP for RICE (40 CFR 63, Subpart ZZZZ)	Current	II.J
Asbestos NESHAP (40 CFR Part 61, Subpart M)	Current	III.E
Protection of Stratospheric Ozone (40 CFR Part 82)	Current	III.D

6. Additional Requirement

(a) The permittee requested including Headers 21-14, 21-15, 21-16 and 21-22, Tank Battery 21, and the CO_2 Recycle Facility as one “single source” for Part 71 permitting and New Source Review purposes, in order to be consistent with the single source determinations made in the past permits. In order to remain a PSD minor source and a HAP minor source, the permittee has voluntarily agreed to limit the total emissions from four (4) production tanks at Tank Battery 21 (21-ST-1, 21-ST-2, 21-ST-3, and 21-ST-4), the glycol dehydrator (INJ-DEHY-1) at the CO_2 Recycle Facility, and the flares (21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, 21-22-F-1, and INJ-F-1) to the emission levels specified below based on a 12-month rolling sum:

1. 240.0 tons/yr for VOC.

2. 60.0 tons/yr for NOx.

3. 153.1 tons/yr for SO_2.

4. 180.0 tons/yr for CO.

5. 9.0 tons/yr for any single HAP.

6. 24.0 tons/yr for total HAPs.

(b) In order to ensure this source does not trigger the requirements of 40 CFR Part 68, Subpart M for Chemical Accident Prevention Regulation, the permittee has taken a voluntary condition that limits the emissions of any regulated substance listed in 40 CFR § 68.130 to less than the thresholds listed in Table 1 to 40 CFR § 68.130.

(c) For the VRU associated with the oil storage tanks (21-ST-1, 21-ST-2, 21-ST-3, and 21-ST-4); flares 21-F-1, 21-14-F-1, 21-15-F-1, 21-16-F-1, 21-22-F-1, and INJ-F-1; and the triethylene glycol dehydrator (INJ-DEHY-1), the permittee shall comply with the control device requirements specified in Condition II.B of the permit, and the monitoring and testing requirements specified in Condition II.C of the permit.

7. Endangered Species Act

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. § 1536, and its implementing regulations at 50 CFR Part 402, USEPA is required to ensure that any action authorized, funded, or carried out by USEPA is not likely to jeopardize the continued existence of any Federally-listed endangered species or threatened species or result in the destruction or adverse modification of such species’ designated critical habitat. NNEPA is issuing this federal Part 71 permit pursuant to a delegation from USEPA. However, this permit does not authorize the construction of new emission units or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. Therefore, NNEPA and USEPA have concluded that the issuance of this permit will have no effect on listed species or their critical habitat.

8. Use of All Credible Evidence

Determinations of deviations from, continuous or intermittent compliance with, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source, NNEPA, and US EPA in such determinations.

9. NNEPA Authority

Authority to administer the Part 71 Permit Program was delegated to the Navajo Nation EPA by US EPA Region IX in part on October 13, 2004 and in whole on March 21, 2006.
In delegating to NNEPA the authority to administer the Part 71 operating permit program, US EPA determined that NNEPA had adequate independent authority to administer the program, as required by 40 CFR § 71.10(a). Specifically, US EPA found NNEPA had adequate permit processing requirements and adequate permit enforcement-related investigatory authorities. Delegation Agreement between US EPA Region IX and NNEPA, §§ IV, V, VI.1, IX.2. Moreover, before waiving its collection of fees under 40 CFR § 71.9(c)(2)(ii), US EPA determined that NNEPA could collect sufficient revenue under its own authorities to fund a delegated Part 71 Program. Delegation Agreement at 1 and § II.2.

The Title V Permit therefore refers both to federal and to tribal provisions. When federal and tribal provisions are cited in parallel, the tribal provisions are identical to the federal provisions and compliance with the federal provision will constitute compliance with the tribal counterpart. Parallel tribal citations do not create any new requirements or impact the federal enforceability of the cited Part 71 requirements. All federal terms and conditions of the permit will be enforceable both by NNEPA and US EPA, as well as by citizens, under the federal Clean Air Act.

The provisions of Navajo law referenced in the permit will only be enforceable by NNEPA and will be enforced by NNEPA under the Navajo Nation Operating Permit Regulations and the Navajo Nation Air Pollution Prevention and Control Act, 4 N.N.C. §§ 1101-1162. Proposed Section IV.A (Fee Payment) refers only to the NNOPR as its source of authority because US EPA waived its collection of fees, as discussed above. This provision will be tribally enforceable only.

10. Public Participation

a. Public Notice

As described in 40 C.F.R. § 71.11(a)(5) and NNOPR § 403(A), all draft operating permits shall be publicly noticed and made available for public comment. The public notice requirements for permit actions and the public comment period are described in 40 C.F.R.

§ 71.11(d) and NNOPR § 403.

Public notice of this proposed permit action was provided to Resolute, US EPA Region IX, and the affected state, local and tribal governments via a mailed copy of the notice. A copy of the notice was also be provided to all persons who submitted a written request to be included on the mailing list. Public notice was also published in newspapers of general circulation in the area affected by this source.

b. <u>Response to Comments</u>

See Appendix B for NNEPA response to all significant comments received on the draft Part 71 permit.

APPENDIX A

Appendix A: Emission Calculations
VOC and HAP Emissions from
Four (4) Oil Storage Tanks at Tank Battery 21 When Venting Through VRU

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Each tank is controlled by a Vapor Recovery Unit (VRU) which provides a 95% control on VOC/HAP.
These tanks are also equipped with a redundant VRU.
When VRU is not in operation, emissions are sent to Flare 21-F-1.

Normal VRU Operation Hours 8,664 (hrs/yr) - assume a maximum of 1 day per calendar quarter due to VRU malfunction.

Potential to Emit with VRU (PTE)[1]	VOC	Benzene	Toluene	Ethylbenzene	Xylenes	n-hexane	Total HAPs
Tank 21-ST-1 (lbs/hr)	12.1	0.07	0.04	0.01	0.01	0.29	0.45
Tank 21-ST-2 (lbs/hr)	0.20	0.00	0.00	0.00	0.00	0.01	0.01
Tank 21-ST-3 (lbs/hr)	0.20	0.00	0.00	0.00	0.00	0.01	0.01
Tank 21-ST-4 (lbs/hr)	0.20	0.00	0.00	0.00	0.00	0.01	0.01
Total PTE (lbs/hr)	12.7	0.07	0.05	0.01	0.03	0.30	0.47
Total PTE (tons/yr)	**55.0**	**0.32**	**0.20**	**0.05**	**0.12**	**1.30**	**2.03**

Notes:

[1] The controlled VOC/HAP emission rates (lbs/hr) were provided by the source in the supplemental information received on 08/25/16. These emissions were estimated using E&P Tanks, version 2.0. For Tank 21-ST-1, the emissions include flashing, working, and standing losses and were estimated at the expected maximum production rate of 2,500 bbl/day. For Tanks 21-ST-2, 21-ST-3, and 21-ST-4, the emissions include working and standing losses and were estimated at the expected maximum production rate of 625 bbl/day.

Methodology

Total PTE (tons/yr) = Total PTE (lbs/hr) x VRU Normal Operation Hour (hrs/yr) x 1 ton/2000 lbs

Appendix A: Emission Calculations
Criteria Pollutant and HAP Emissions from
Flare 21-F-1 for Oil Storage Tanks

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Content (btu/scf)	Max. Flow Rate scf/day
400	1,284,000
(provided by the source in 2012)	(provided by the source in 2012)

1. Potential to Emit (PTE) of NOx, CO, and SO_2

	Pollutant		
	NOx[a]	CO[a]	SO_2[b]
Emission Factor	0.068 (lbs/MMBtu)	0.370 (lbs/MMBtu)	0.001 (mole fraction)
Potential to Emit in tons/yr	**6.37**	**34.7**	**39.5**

[a] NOx and CO emission factors are from AP-42, Chapter 13.5 - Industrial Flares - Tables 13.5-1 and 13.5-2 (AP-42, 04/15).
[b] This is the maximum mole fraction for H_2S estimated by the source. It is assumed that all the sulfur in H_2S converts to SO_2.

Methodology
NOx/CO Emissions (tons/yr) = Emission Factor (lbs/MMBtu) x Max. Flow Rate (scf/day) x 365 (day/yr) x Heat Content (btu/scf)
x (1 MMBtu/1,000,000 btu) x 1 tons/2000 lbs
SO_2 Emissions (tons/yr) = Max. Flow Rate (scf/day) x Emission Factor (mole fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R)
/ Temp (60F+460) x Mole weight of SO_2 (64 lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs

2. PTE of VOC and HAPs

Flare Control Efficiency: 98%

Pollutant	Mole Fraction[a]	Mole Weight (lbs/lbs mole)	PTE (tons/yr)
VOC	0.1	52	64.2
HAPs			
Benzene	0.0025	78.1	2.41
Toluene	0.0025	92.1	2.84
Ethylbenzene	0.0025	106	3.28
Xylenes	0.0025	106	3.28
n-Hexane	0.015	86.1	15.9
Total HAPs			**27.8**

[a] These are the maximum mole fraction for VOC/HAP estimated by the source.

Methodology
VOC/HAP Emissions (tons/yr) = Max. Flow Rate (scf/day) x Mole Fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R)
/ Temp (60F+460) x Mole weight of VOC/HAP (lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs x (1-Control Efficiency)

Appendix A: Emission Calculations
Criteria Pollutant and HAP Emissions from
Flare 21-14-F-1

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Content (btu/scf)	Max. Flow Rate scf/day
400	405,000
(provided by the source)	(provided by the source)

1. Potential to Emit (PTE) of NOx, CO, and SO_2

	Pollutant		
	NOx[a]	CO[a]	SO_2[b]
Emission Factor	0.068 (lbs/MMBtu)	0.370 (lbs/MMBtu)	0.001 (mole fraction)
Potential to Emit in tons/yr	**2.01**	**10.9**	**12.5**

[a] NOx and CO emission factors are from AP-42, Chapter 13.5 - Industrial Flares - Tables 13.5-1 and 13.5-2 (AP-42, 04/15).

[b] This is the maximum mole fraction for H_2S estimated by the source. It is assumed that all the sulfur in H_2S converts to SO_2.

Methodology

NOx/CO Emissions (tons/yr) = Emission Factor (lbs/MMBtu) x Max. Flow Rate (scf/day) x 365 (day/yr) x Heat Content (btu/scf) x (1 MMBtu/1,000,000 btu) x 1 tons/2000 lbs

SO_2 Emissions (tons/yr) = Max. Flow Rate (scf/day) x Emission Factor (mole fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of SO_2 (64 lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs

2. PTE of VOC and HAPs

Flare Control Efficiency: 98%

Pollutant	Mole Fraction[a]	Mole Weight (lbs/lbs mole)	PTE (tons/yr)
VOC	0.1	52	20.3
HAPs			
Benzene	0.0025	78.1	0.76
Toluene	0.0025	92.1	0.90
Ethylbenzene	0.0025	106	1.03
Xylenes	0.0025	106	1.03
n-Hexane	0.015	86.1	5.03
Total HAPs			**8.76**

[a] These are the maximum mole fraction for VOC/HAP estimated by the source.

Methodology

VOC/HAP Emissions (tons/yr) = Max. Flow Rate (scf/day) x Mole Fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of VOC/HAP (lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs x (1-Control Efficiency)

Appendix A: Emission Calculations
Criteria Pollutant and HAP Emissions from
Flare 21-15-F-1

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Content (btu/scf)	Max. Flow Rate scf/day
400	253,000
(provided by the source)	(provided by the source)

1. Potential to Emit (PTE) of NOx, CO, and SO_2

	Pollutant		
	NOx[a]	CO[a]	SO_2[b]
Emission Factor	0.068 (lbs/MMBtu)	0.370 (lbs/MMBtu)	0.001 (mole fraction)
Potential to Emit in tons/yr	**1.26**	**6.83**	**7.78**

[a] NOx and CO emission factors are from AP-42, Chapter 13.5 - Industrial Flares - Tables 13.5-1 and 13.5-2 (AP-42, 04/15).
[b] This is the maximum mole fraction for H_2S estimated by the source. It is assumed that all the sulfur in H_2S converts to SO_2.

Methodology
NOx/CO Emissions (tons/yr) = Emission Factor (lbs/MMBtu) x Max. Flow Rate (scf/day) x 365 (day/yr) x Heat Content (btu/scf) x (1 MMBtu/1,000,000 btu) x 1 tons/2000 lbs
SO_2 Emissions (tons/yr) = Max. Flow Rate (scf/day) x Emission Factor (mole fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of SO_2 (64 lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs

2. PTE of VOC and HAPs

Flare Control Efficiency: 98%

Pollutant	Mole Fraction[a]	Mole Weight (lbs/lbs mole)	PTE (tons/yr)
VOC	0.1	52	12.7
HAPs			
Benzene	0.0025	78.1	0.48
Toluene	0.0025	92.1	0.56
Ethylbenzene	0.0025	106	0.65
Xylenes	0.0025	106	0.65
n-Hexane	0.015	86.1	3.14
Total HAPs			**5.47**

[a] These are the maximum mole fraction for VOC/HAP estimated by the source.

Methodology
VOC/HAP Emissions (tons/yr) = Max. Flow Rate (scf/day) x Mole Fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of VOC/HAP (lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs x (1-Control Efficiency)

Appendix A: Emission Calculations
Criteria Pollutant and HAP Emissions from
Flare 21-16-F-1

Company Name: **Elk Operating Services, LLC - Aneth Unit**
Address: **Near Montezuma Creek, San Juan County, Utah**
Permit No.: **NN-OP-17-012**
Reviewer: **ERG/YC**
Date: **January 18, 2017**

Heat Content (btu/scf)	Max. Flow Rate scf/day
400	85,000
(provided by the source)	(provided by the source)

1. Potential to Emit (PTE) of NOx, CO, and SO_2

	Pollutant		
	NOx[a]	CO[a]	SO_2[b]
Emission Factor	0.068 (lbs/MMBtu)	0.370 (lbs/MMBtu)	0.001 (mole fraction)
Potential to Emit in tons/yr	**0.42**	**2.30**	**2.62**

[a] NOx and CO emission factors are from AP-42, Chapter 13.5 - Industrial Flares - Tables 13.5-1 and 13.5-2 (AP-42, 04/15).
[b] This is the maximum mole fraction for H_2S estimated by the source. It is assumed that all the sulfur in H_2S converts to SO_2.

Methodology
NOx/CO Emissions (tons/yr) = Emission Factor (lbs/MMBtu) x Max. Flow Rate (scf/day) x 365 (day/yr) x Heat Content (btu/scf) x (1 MMBtu/1,000,000 btu) x 1 tons/2000 lbs
SO_2 Emissions (tons/yr) = Max. Flow Rate (scf/day) x Emission Factor (mole fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of SO_2 (64 lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs

2. PTE of VOC and HAPs

Flare Control Efficiency: 98%

Pollutant	Mole Fraction[a]	Mole Weight (lbs/lbs mole)	PTE (tons/yr)
VOC	0.1	52	4.25
HAPs			
Benzene	0.0025	78.1	0.16
Toluene	0.0025	92.1	0.19
Ethylbenzene	0.0025	106	0.22
Xylenes	0.0025	106	0.22
n-Hexane	0.015	86.1	1.06
Total HAPs			**1.84**

[a] These are the maximum mole fraction for VOC/HAP estimated by the source.

Methodology
VOC/HAP Emissions (tons/yr) = Max. Flow Rate (scf/day) x Mole Fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of VOC/HAP (lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs x (1-Control Efficiency)

Appendix A: Emission Calculations
Criteria Pollutant and HAP Emissions from
Flare 21-22-F-1

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Content (btu/scf)	Max. Flow Rate scf/day
400	129,000
(provided by the source)	(provided by the source)

1. Potential to Emit (PTE) of NOx, CO, and SO_2

	Pollutant		
	NOx[a]	CO[a]	SO_2[b]
Emission Factor	0.068 (lbs/MMBtu)	0.370 (lbs/MMBtu)	0.003 (mole fraction)
Potential to Emit in tons/yr	**0.64**	**3.48**	**11.9**

[a] NOx and CO emission factors are from AP-42, Chapter 13.5 - Industrial Flares - Tables 13.5-1 and 13.5-2 (AP-42, 04/15).
[b] This is the maximum mole fraction for H_2S estimated by the source. It is assumed that all the sulfur in H_2S converts to SO_2.

Methodology
NOx/CO Emissions (tons/yr) = Emission Factor (lbs/MMBtu) x Max. Flow Rate (scf/day) x 365 (day/yr) x Heat Content (btu/scf) x (1 MMBtu/1,000,000 btu) x 1 tons/2000 lbs
SO_2 Emissions (tons/yr) = Max. Flow Rate (scf/day) x Emission Factor (mole fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of SO_2 (64 lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs

2. PTE of VOC and HAPs

Flare Control Efficiency: 98%

Pollutant	Mole Fraction[a]	Mole Weight (lbs/lbs mole)	PTE (tons/yr)
VOC	0.1	52	6.45
HAPs			
Benzene	0.0025	78.1	0.24
Toluene	0.0025	92.1	0.29
Ethylbenzene	0.0025	106	0.33
Xylenes	0.0025	106	0.33
n-Hexane	0.015	86.1	1.60
Total HAPs			**2.79**

[a] These are the maximum mole fraction for VOC/HAP estimated by the source.

Methodology
VOC/HAP Emissions (tons/yr) = Max. Flow Rate (scf/day) x Mole Fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of VOC/HAP (lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs x (1-Control Efficiency)

Appendix A: Emission Calculations
Criteria Pollutant and HAP Emissions from
Flare INJ-F-1 at CO_2 Recycle Facility

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Content (btu/scf)	Max. Flow Rate scf/day
400	5,000,000
(provided by the source)	(provided by the source)

1. Potential to Emit (PTE) of NOx, CO, and SO_2

	Pollutant		
	NOx[a]	CO[a]	SO_2[b]
Emission Factor	0.068 (lbs/MMBtu)	0.370 (lbs/MMBtu)	0.001 (mole fraction)
Potential to Emit in tons/yr	**24.8**	**135**	**154**

[a] NOx and CO emission factors are from AP-42, Chapter 13.5 - Industrial Flares - Tables 13.5-1 and 13.5-2 (AP-42, 04/15).
[b] This is the maximum mole fraction for H_2S estimated by the source. It is assumed that all the sulfur in H_2S converts to SO_2.

Methodology
NOx/CO Emissions (tons/yr) = Emission Factor (lbs/MMBtu) x Max. Flow Rate (scf/day) x 365 (day/yr) x Heat Content (btu/scf) x (1 MMBtu/1,000,000 btu) x 1 tons/2000 lbs
SO_2 Emissions (tons/yr) = Max. Flow Rate (scf/day) x Emission Factor (mole fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of SO_2 (64 lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs

2. PTE of VOC and HAPs

Flare Control Efficiency: 98%

Pollutant	Mole Fraction[a]	Mole Weight (lbs/lbs mole)	PTE (tons/yr)
VOC	0.1	52	250
HAPs			
Benzene	0.0025	78.1	9.39
Toluene	0.0025	92.1	11.1
Ethylbenzene	0.0025	106	12.8
Xylenes	0.0025	106	12.8
n-Hexane	0.015	86.1	62.1
Total HAPs			**108**

[a] These are the maximum mole fraction for VOC/HAP estimated by the source.

Methodology
VOC/HAP Emissions (tons/yr) = Max. Flow Rate (scf/day) x Mole Fraction) x 1 atm / Gas Constant (0.73 atm-cf/lb mole-R) / Temp (60F+460) x Mole weight of VOC/HAP (lbs/lbs mole) x 365 day/yr x 1 ton/2000 lbs x (1-Control Efficiency)

Appendix A: Emission Calculations
Emissions from
Triethylene Glyco Dehydrator (INJ-DEHY-1)

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

The dehydrator (INJ-DEHY-1) is controlled by thermal oxidizer (INJ-TO-1) and uses flare INJ-F-1 as a back-up control.

1. SO_2, VOC, and HAP Emissions:

Pollutants	SO_2*	VOC**	Total HAPs**
Potential to Emit in tons/yr	**65.2**	**8.72**	**2.98**

* The $SO_{2\ emissions}$ information was estimated by the source on 08/10/16 assuming all the H_2S coverts to SO_2 and the mole fraction for H_2S is 0.023.
** The VOC/HAP emissions information was provided by the source on 08/10/16 using GRI-GLYCalc VERSION 4.0, assuming 80 MMscf/day and 95% control efficiency. However, both the thermal oxidizer and the flare provide control efficiencies equal or higher than 98%.

2. PM/PM10/PM2.5, NOx, and CO Emissions When Controlled by the Thermal Oxidizer:

Heat Input Capacity for Thermal Oxidizer MMBtu/hr	Potential Throughput MMSCF/yr	Operation Hours (99% of operation) hrs/yr
3.0	25.5	8,672

	PM	PM10*	PM2.5*	**NO_x	CO
Emission Factor in lbs/MMSCF	1.9	7.6	7.6	100	84.0
Potential to Emit in tons/yr	**0.02**	**0.10**	**0.10**	**1.28**	**1.07**

*PM10 emission factor is condensable and filterable PM combined. PM emission factor is for filterable PM only.
Assume PM10 emissions are equal to PM2.5 emissions.
**Uncontrolled emission factor for NO_x.
Emission factors are from AP-42, Chapter 1.4, Tables 1.4-1 and 1.4-2 (07/98).
MMBtu = 1,000,000 Btu
MMSCF = 1,000,000 Standard Cubic Feet of Gas

Methodology
Potential Throughput (MMSCF/yr) = Heat Input Capacity (MMBtu/hr) x Operation Hours (hrs/yr) x 1 MMSCF/1,020 MMBtu
Potential to Emit (tons/yr) = Potential Throughput (MMSCF/yr) x Emission Factor (lbs/MMSCF) x 1 ton/2000 lbs

3. NOx and CO Emissions When Controlled by Flare INJ-F-1:

Operation time when the dehydrator is controlled by the flare: 88 (hrs/yr) - worst case scenario = 1% of operation

Emission Factor in lbs/MMSCF	NOx	CO
Potential to Emit in tons/yr	**0.25**	**1.36**

Methodology
PTE of NOx/CO (tons/yr) = PTE of NOx/CO for Flare INJ-F-1 / 8760 (hrs/yr) x Operation Time (hrs/yr).

4. Total Emissions from Dehydrator INJ-DEHY-1:

Emission Factor in lbs/MMSCF	PM	PM10	PM2.5	SO_2	NOx	VOC	CO	Total HAPs
Potential to Emit in tons/yr	**0.02**	**0.10**	**0.10**	**65.2**	**1.52**	**8.72**	**2.43**	**2.98**

Appendix A: Emission Calculations
Criteria Pollutant Emissions from
Natural Gas-Fired Heat Medium Oil Burner (INJ-HMO-1)

Company Name: Elk Operating Services , LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Input Capacity MMBtu/hr	Potential Throughput MMSCF/yr
6.0	51.5

Pollutant

	PM	PM10*	PM2.5*	SO_2	**NO_x	VOC	CO
Emission Factor in lbs/MMSCF	1.9	7.6	7.6	0.6	100	5.5	84.0
Potential to Emit in tons/yr	**0.05**	**0.20**	**0.20**	**0.02**	**2.58**	**0.14**	**2.16**

*PM10 emission factor is condensable and filterable PM combined. PM emission factor is for filterable PM only. Assume PM10 emissions are equal to PM2.5 emissions.
**Emission factor for NO_x: Uncontrolled = 100, Low NO_x Burner = 50, Low NO_x Burners/Flue gas recirculation = 32
Emission factors are from AP-42, Chapter 1.4, Tables 1.4-1 and 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
(AP-42 Supplement D 07/98)

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMSCF = 1,000,000 Standard Cubic Feet of Gas

Methodology

Potential Throughput (MMSCF/yr) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMSCF/1,020 MMBtu
Potential to Emit (tons/yr) = Potential Throughput (MMSCF/yr) x Emission Factor (lbs/MMSCF) x 1 ton/2000 lbs

Appendix A: Emission Calculations
Criteria Pollutant Emissions from
Two (2) Insignificant Natural Gas-Fired Oil Heaters

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Heat Input Capacity MMBtu/hr		Potential Throughput MMSCF/yr
1.75	(2 units total)	15.0

Pollutant

	PM	PM10*	PM2.5*	SO_2	$**NO_x$	VOC	CO
Emission Factor in lbs/MMSCF	1.9	7.6	7.6	0.6	100	5.5	84.0
Potential to Emit in tons/yr	**0.01**	**0.06**	**0.06**	**4.51E-03**	**0.75**	**0.04**	**0.63**

*PM10 emission factor is condensable and filterable PM combined. PM emission factor is for filterable PM only. Assume PM10 emissions are equal to PM2.5 emissions.
**Emission factor for NO_x: Uncontrolled = 100, Low NO_x Burner = 50, Low NO_x Burners/Flue gas recirculation = 32
Emission factors are from AP-42, Chapter 1.4, Tables 1.4-1 and 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
(AP-42 Supplement D 07/98)

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMSCF = 1,000,000 Standard Cubic Feet of Gas

Methodology

Potential Throughput (MMSCF/yr) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMSCF/1,020 MMBtu
Potential to Emit (tons/yr) = Potential Throughput (MMSCF/yr) x Emission Factor (lbs/MMSCF) x 1 ton/2000 lbs

Appendix A: Emission Calculations
Criteria Pollutant Emissions from
One (1) Insignificant Natural Gas-Fired Emergency Generator (GEN-100)

Company Name: Elk Operatings Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Power Output Horse Power (HP)	Operation Limit hr/yr
425	500

	Pollutant		
	NO_x	VOC	CO
Emission Factor* (in g/hp-hr)	2.00	1.00	4.00
Potential to Emit in tons/yr	**0.47**	**0.23**	**0.94**

*Emission factors are the emission limits for this unit under NSPS, Subpart JJJJ.

Note: As defined in the September 6, 1995 memorandum from John S. Seitz of US EPA on the subject of "Calculating Potential to Emit for Emergency Generators", an emergency generator's sole function is to provide back-up power when power from the local utility is interrupted. The only circumstances under which an emergency generator would operate when utility power is available are during operator training or brief maintenance checks. The generator's potential to emit is based on an operating time of 500 hours per year as set forth in the EPA memo.

Methodology

PTE (tons/yr) = Power Output (HP) x Emission Factor (g/HP-hr) x 1 lb/453.6 g x Operation Limit (hr/yr) x 1 ton/2000 lbs

Appendix A: Emission Calculations
PTE Summary

Company Name: Elk Operating Services, LLC - Aneth Unit
Address: Near Montezuma Creek, San Juan County, Utah
Permit No.: NN-OP-17-012
Reviewer: ERG/YC
Date: January 18, 2017

Limited Potential To Emit after Control

Emission Units	PM	PM10	PM2.5	SO_2	NO_x	VOC	CO	Total HAPs
Tanks at Tank Battery 21 (emissions through VRU)	-	-	-	-	-	55.0	-	2.03
Flare 21-F-1	-	-	-	39.5	6.37	64.2	34.7	27.8
Flare 21-14-F-1	-	-	-	12.5	2.01	20.3	10.9	8.76
Flare 21-15-F-1	-	-	-	7.78	1.26	12.7	6.83	5.47
Flare 21-16-F-1	-	-	-	2.62	0.42	4.25	2.30	1.84
Flare 21-22-F-1	-	-	-	11.9	0.64	6.45	3.48	2.79
Flare INJ-F-1	-	-	-	154	24.8	250	135	108
Dehydratior INJ-DEHY-1	0.02	0.10	0.10	65.2	1.52	8.72	2.43	2.98
Total PTE of Tanks, Flares, and Dehydrator	**0.02**	**0.10**	**0.10**	**293**	**37.0**	**421**	**196**	**160**
Total Emissions from Storage Tanks, Flares, and Dehydrator with Permit Limits on SO_2, NOx, VOC, CO, and HAPs	**0.02**	**0.10**	**0.10**	**153.1**	**60.0**	**240.0**	**180.0**	**24.0**
Oil Heater INJ-HMO-1	0.05	0.20	0.20	0.02	2.58	0.14	2.16	Negligible
Insignificant - Oil Heaters	0.01	0.06	0.06	4.51E-03	0.75	0.04	0.63	Negligible
Insignificant - Emergency Generator	-	-	-	-	0.47	0.23	0.94	Negligible
Fugitive Emissions from CO_2 Recycle Facility*	-	-	-	-	-	15.8	-	1.40
Fugitive Emissions from Tank Battery 21*	-	-	-	-	-	2.30	-	0.70
Fugitive Emission from Road Dust**	3.51	16.3	14.1	-	-	-	-	-
Total PTE * (tons/yr)**	**0.09**	**0.35**	**0.35**	**153**	**63.8**	**240**	**184**	**24.0**

Note: (*) The fugitive leak emission information was calculated by the source and was provided in the supplemental information submitted on 08/10/16.

(**) Fugitive road dust information was from the Statement of Basis for Permit #NN-OP 00-02, issued on 07/30/07.

(***) Since this source is not in one of 28 source categories and is not subject to any NSPS or NESHAP that was in effect on 08/07/1980, fugitive emissions from this source are not counted toward the Title V or PSD major source determinations.

ATTACHMENT A

Attachment A

Affected Units under NSPS, Subpart KKK

Process/Unit	Equipment ID	Description	Service
Condensate Stabilizer	E-204	Exchanger	Light Liquid Service
Condensate Stabilizer	E-205	Stabilizer Reboiler	Light Liquid Service
Condensate Stabilizer	E-206	Cooler	Light Liquid Service
Condensate Stabilizer	V-203	Condensate Stabilizer	VOC/Light Liquid Service
Dehydration	E-304	Condenser	VOC Service
Dehydration	H-301	Regenerator	VOC Service
Dehydration	P-302	Pump	Light Liquid Service
Dehydration	V-102	Separator	Light Liquid Service
Dehydration	V-103	Contactor	Wet Gas
Dehydration	V-104	Scrubber	Wet Gas
Dehydration	V-301	Flash Tank	VOC Service
Dehydration	V-302	Stripping Column	VOC Service
Dehydration	V-303	Still OVHD Separator	VOC/Light Liquid Service
Dehydration	X-701	Thermal Oxidizer	VOC Service
Flare	P-8601A	Pump	Light Liquid Service
Flare	P-8601B	Pump	Light Liquid Service
Flare	V-8701	Flare Knockout	Light Liquid Service
Flare	V-8702	Flare Knockout	Light Liquid Service
HMO	H-601	Heater (INJ-HMO-1)	Heavy Liquid
HMO	P-601A	Pump	Heavy Liquid
HMO	P-601B	Pump	Heavy Liquid
HMO	V-601	Expansion Tank	Heavy Liquid
Refrigeration	B-401	Condenser	VOC Service
Refrigeration	C-401	Compressor	VOC Service
Refrigeration	E-201	Exchanger	VOC Service
Refrigeration	E-202	Exchanger	VOC Service
Refrigeration	E-203	Gas Chiller	VOC Service
Refrigeration	V-201	Inlet Separator	VOC/Light Liquid Service
Refrigeration	V-202	Low Temp Separator	VOC/Light Liquid Service
Refrigeration	V-401	Separator	VOC Service
Refrigeration	V-402	Propane Accumulator	VOC Service

ATTACHMENT B

Attachment B

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006

[Based on the rule version dated as November 16, 2007]

§60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485(b), except as provided in §60.482-1(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482-1(c) and (f) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482-1(f).

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection if the instrument reading for that monitoring event was less than 10,000 ppm and the pump was not repaired since that monitoring event.

(i) Monitor the pump within 5 days as specified in §60.485(b). If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak within 15 days of detection by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is—

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section.

(A) Monitor the pump within 5 days as specified in §60.485(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) of this section is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in §60.486(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482-10, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§60.482-3 Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482-1(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482-10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

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

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482-10, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)-(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§60.482-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482-1(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b) and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§60.482-7 Standards: Valves in gas/vapor service and in light liquid service.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, §60.482-1(c) and (f), and §§60.483-1 and 60.483-2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482-1(c), and §§60.483-1 and 60.483-2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the valves on the process unit are monitored in accordance with §60.483-1 or §60.483-2, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483-2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

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

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into 2 or 3 subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482-9.

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

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either becomes an affected facility through §60.14 or §60.15 or the owner or operator designates less than 3.0 percent of the total number of valves as difficult-to-monitor, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

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

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482-9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§60.482-2(c)(2) and 60.482-7(e).

§60.482-9 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump or valve that remains in service, the pump or valve may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§60.482-10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (f)(1)(ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in §60.485(b); and

(ii) Conduct annual inspections according to the procedures in §60.485(b).

(g) Leaks, as indicated by an instrument reading greater than 500 parts per million by volume above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

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

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

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown 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 process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (j)(2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (k)(3) of this section:

(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) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (l)(5) of this section.

(1) Identification of all parts of the 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) Identification of all parts of the 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.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486(c).

(4) For each inspection conducted in accordance with §60.485(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§60.485 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482-1 through 60.482-10, 60.483, and 60.484 as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(c) The owner or operator shall determine compliance with the no detectable emission standards in §§60.482-2(e), 60.482-3(i), 60.482-4, 60.482-7(f), and 60.482-10(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the

maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d) (1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec)

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units)

= 28.56 ft/sec (English units)

K_2 = 0.7084 m^4/(MJ-sec) (metric units)

= 0.087 ft^4/(Btu-sec) (English units)

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units)

C_i = Concentration of sample component "i," ppm

H_i = Net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole

(5) Method 18 or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 parts per million by volume) and ASTM D2504-67, 77 or 88 (Reapproved 1993) (incorporated by reference—see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference—see §60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with §60.483-1 or §60.483-2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L/V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves

V_L = Number of valves found leaking

V_T = The sum of the total number of valves monitored

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with §60.482-7(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§60.486 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

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

(b) When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following requirements apply:

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

(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.

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

(c) When each leak is detected as specified in §§60.482-2, 60.482-3, 60.482-7, 60.482-8, and 60.483-2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) “Above 10,000” 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.

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

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

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

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482-10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(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.

(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.

(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.

(e) The following information pertaining to all equipment subject to 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) A list of identification numbers for equipment subject to the requirements of this subpart.

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

(ii) 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.

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

(4)(i) 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).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(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 §60.482-1(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.

(f) 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) 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.

(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.

(g) The following information shall be recorded for valves complying with §60.483-2:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

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

(2) Any changes to this criterion and the reasons for the changes.

(i) 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) An analysis demonstrating the design capacity of the affected facility,

(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

(3) An analysis demonstrating that equipment is not in VOC service.

(j) 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.

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

§60.487 Reporting requirements.

(a) 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.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

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

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

(4) Number of compressors subject to the requirements of §60.482-3, excluding those compressors designated for no detectable emissions under the provisions of §60.482-3(i) and those compressors complying with §60.482-3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

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

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

(iii) 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),

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

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

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

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

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) 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.

(e) An owner or 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.

(f) The requirements of paragraphs (a) through (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 (a) through (c) of this section, provided that they comply with the requirements established by the State.

APPENDIX B

Public Notice

PROPOSED RENEWAL OF PART 71 PERMIT

RESOLUTE NATURAL RESOURCES COMPANY, LLC- ANETH UNIT

LOCATED NEAR MONTEZUMA CREEK, SAN JUAN COUNTY, UT

FEBRUARY 17, 2017

The Navajo Nation Environmental Protection Agency ("NNEPA"), Navajo Air Quality Control Program ("NAQCP"), Operating Permit Program ("OPP") is accepting written comments on the renewal of the Part 71 Title V permit for Resolute Natural Resources Company, LLC- Aneth Unit. The Facility is an oil and natural gas production facility located on the Navajo Nation.

Resolute Natural Resources Company acquired the Aneth site in 2004 and is the current owner and operator of this site. The units covered under this Title V permit include Headers 21-14, 21-15, 21-16, 21-22, Tank Battery 21, and the CO2 Recycle Facility. The first Part 71 operating permit was issued to this source on July 30, 2007 and later received two Minor Permit Revision Approvals in 2010 and 2012.

Written comments, written requests for a public hearing, written requests for notification of the final decision regarding these permit actions, or inquiries or requests for additional information regarding these permit actions may be submitted to Tennille Begay at NAQCP/OPP P.O. Box 529, Fort Defiance, AZ 86504. **Written comments and/or written requests must be received by 5:00 pm, March 20th, 2017.** Written comments will be considered prior to final permit decisions.

If NNEPA finds a significant degree of public interest, a public hearing will be held. NNEPA will send notification of the final permit decision to the applicant and to each person who has submitted written comments or a written request for notification of the final decision.

The applications, proposed air permits, and statements of basis are available for review at NNEPA, NAQCP/OPP Route 112, Bldg. # 2837 Fort Defiance, AZ 86504. Viewing hours are from 8:00 am to 4:30 pm, Monday through Friday (except holidays). Copies of the draft permit and the statement of basis can also be obtained from the following chapter houses: Aneth Chapter, Red Mesa Chapter, and Teec Nos Pos Chapter. An Informational Session will be held at Aneth Chapter on March 14, 2017 from 10:00 am-2:00 pm. All draft documents can also be found on the NNEPA/OPP website at http://navajonationepa.org/main/images/Resolute%20Draft%20Permit.pdf.

Inquiries or requests for additional information regarding these permit actions should be directed to Tennille Begay at the above address or by phone at (928) 729-4248.

Persons wishing to be included on the NAQCP permit public notice mailing list should contact Angie Frank in writing at NAQCP/OPP at the above address, by phone at (928) 729-4096, or by email at angiefrank@navajo-nsn.gov. E-files of permit public notices and permits can be requested from NNEPA (NAQCP) by email request at tbbegay@navajo-nsn.gov.

Southern Ute Indian Tribe

March 16, 2017

Tennille Begay
Navajo Nation Environmental Protection Agency
Air Quality Control Program/Operating Permit Program
P.O. Box 529
Fort Defiance, AZ 86504

Re: Proposed Renewal of Part 71 Permit for Resolute Natural Resources Company, LLC – Aneth Unit

Dear Sir or Madam:

The Southern Ute Indian Tribe (Tribe) appreciates the opportunity to provide comments on the Navajo Air Quality Control Program's Part 71 Operating Permit renewal for Resolute Natural Resources Company, LLC's - Aneth Unit. After review of the draft permit, the Tribe is submitting the following comments on the proposed permit:

1. Section f(3) of the Statement of Basis indicates that the Part 71 operating permit renewal will include a significant permit modification to create facility-wide emissions limits for individual HAP and total HAP to establish the source as a synthetic minor HAP source. According to the provisions in §49.153(3) of the rule titled *Part 49 – Indian Country: Air Quality Planning and Management*, any synthetic minor limits established after August 30, 2011 must be established through a synthetic minor source permit. Additionally, continuing to establish synthetic minor emission limits in a Part 71 operating permit is not appropriate in that it allows a source to bypass the more stringent control technology and National Ambient Air Quality Standard reviews that would be required under the Tribal Minor New Source Review permitting program.

Thank you for considering the Tribe's comments.

Sincerely,

Clement J. Frost

Clement J. Frost, Chairman
Southern Ute Indian Tribal Council

THE NAVAJO NATION

RUSSELL BEGAYE PRESIDENT
JONATHAN NEZ VICE PRESIDENT

Navajo Nation Environmental Protection Agency –Air Quality Control/Operating Permit Program
Post Office Box 529, Fort Defiance, AZ 86504 • Bldg. #2837 Route 112
Telephone (928) 729-4096, Fax (928) 729-4313, Email airquality@navajo-nsn.gov
www.navajonationepa.org/airquality.html

Detailed Information

Permitting Authority: NNEPA

County: San Juan **State:** Utah **AFS Plant ID:** 04-017-NAV01

Facility: Resolute Natural Resources Company, LLC – Aneth Unit

Document Type: RESPONSE TO COMMENTS

RESPONSES TO COMMENTS

On the Draft Part 71 Permit Renewal to Operate Resolute Natural Resources Company, LLC – Aneth Unit

Permit No. NN OP 17-012

Resolute Natural Resources Company, LLC – Aneth Unit, located near Montezuma Creek, San Juan County, Utah on the Navajo Reservation, applied for a Part 71 Operating Permit renewal to operate an oil and natural gas production facility. On February 17, 2017, the Navajo Nation Environmental Protection Agency (NNEPA) issued a public notice stating that NNEPA proposed to issue an operating permit renewal for this source and provided information on how the public could review the proposed permit and other documentation. This notice also included the information for a public informational session on March 14, 2017 at the Aneth Chapter House, where an opportunity to submit written comments was also provided. Finally, the notice informed interested parties that comments on the draft Part 71 permit must be received by March 20, 2017.

NNEPA did not receive any written comments at the informational session on March 14, 2017. NNEPA received only one written comment, from the Southern Ute Indian Tribal Council.

Comment 1:

On March 20, 2017, Southern Ute Indian Tribal Council submitted the following comment on the draft Part 71 permit:

"Section f(3) of the Statement of Basis indicates that the part 71 operating permit renewal will include a significant permit modification to create facility-wide emissions limits for individual HAP and total HAP to establish the source as a synthetic minor HAP source. According to the provisions in §49.153(3) of the rule tilted Part 49 – Indian Country: Air Quality Planning and Management, any synthetic minor limits established after August 30, 2011 must be established through a synthetic minor source permit. Additionally, continuing to establish synthetic minor emission limits in a Part

71 operating permit is not appropriate in that it allows a source to bypass the more stringent control technology and National Ambient Air Quality Standard reviews that would be required under the Tribal Minor New Source Review permitting program."

Response to Comment 1:

NNEPA interprets the reference in the comment letter to mean 40 CFR § 49.153(a)(3), which lays out the various scenarios when an owner or operator is required to obtain a synthetic minor source permit pursuant to the requirements of the Federal Minor New Source Review Program in Indian Country (40 CFR § 49.151 through § 49.165). None of those scenarios apply here, as explained below.

First, 40 CFR § 49.153(a)(3)(i) applies to the owner or operator of an existing major source that wishes to obtain a synthetic minor source permit in order to be considered as a synthetic minor source. As stated in Sections f(3) and f(4) of the Statement of Basis, the Tank Battery 21 area and the CO_2 Recycle Facility are considered two separate sources for HAP major source determination purposes, and neither is an existing major source. The Tank Battery 21 area had synthetic HAP minor source limits established in Operating Permit NN-OP 00-02, issued on July 30, 2007. The CO_2 Recycle Facility is an existing true HAP minor source and there are no HAP emission limits established for the CO_2 Recycle Facility in the current valid operating permit (#NN-OP 00-02-B, issued on February 27, 2012). Therefore, 40 CFR § 49.153(a)(3)(i) does not apply to these sources.

40 CFR § 49.153(a)(3)(ii) applies only to owners or operators wishing to construct a new synthetic minor source or to modify an existing synthetic minor source after August 30, 2011, the effective date of the rule. Again, these scenarios are not relevant because this Part 71 permit renewal action does not propose any new construction or modification to the existing sources. Similarly, 40 CFR § 49.153(a)(3)(iii) states that a synthetic minor established prior to August 30, 2011 under, for example, a Part 71 permit does not need to take any action unless a modification is proposed to take place after that date.

Finally, 40 CFR § 49.153(a)(3)(iv) provides that for existing synthetic minor sources, such as the Tank Battery 21 area, it is within the reviewing authority's discretion to determine at the time of a part 71 permit renewal whether to require the permittee to apply for a synthetic minor permit under 40 CFR § 49.158 or to remain under a part 71 permit. In this case, since the actual HAP emissions from Resolute Aneth Unit have been historically low, the permittee is confident that the *combined* HAP emissions from all the sources at this oil field will stay below the HAP major source threshold for a *single* source. Theoretically, each source could emit up to 25 tons/yr of total HAPs individually and together they could emit up to 50 tons/yr of total HAPs as a combined total before they would be considered major sources for HAPs. However, in this Part 71 permit renewal action, Resolute voluntarily took lower emission limits to limit the total HAP emissions from the Tank Battery 21 area, the CO_2 Recycle Facility, and headers 21-14, 21-15, 21-16, and 21- 22 to less than 9 tons/yr for a single HAP and less than 24 tons/yr for total HAPs. The purpose of the revised HAP limits is not to establish the synthetic minor source status for Tank Battery 21 area or for the CO_2 Recycle Facility. The purpose of these revised HAP emission limits is to further restrict the HAP emissions from this oil field operation, in order to further protect health and the environment. The revised emission limits are more stringent than what would be required if each of the Tank Battery

21 area and the CO_2 Recycle Facility was considered to be separate synthetic HAP minor sources. Therefore, there is no justification for requiring the permittee to apply for a synthetic minor source permit under 40 CFR § 49.158 and no likelihood that the source would be "bypassing" more stringent controls.

Therefore, the requirements of the Federal Minor New Source Review Program in Indian Country (40 CFR § 49.151 through § 49.165) do not apply to this permit action. No change has been made to the permit as a result of this comment.