



Statement of Basis

Minor Air Quality Operating Permit and Air Quality Construction Permit Modification

**Marshall 2 RNG, LLC
Veblen, South Dakota**

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1.0 Background

On May 31, 2022, the Department of Agriculture and Natural Resources (DANR) issued an air quality construction permit to Marshall 2 RNG, LLC (Marshall 2 RNG), for a renewable natural gas facility near Veblen, South Dakota. No changes have been made to the air quality construction permit since its issuance:

1.1 Existing Equipment

Table 1-1 provides a list of the units presently permitted which was taken from the air quality construction permit #28.000130-01C as issued on May 31, 2022.

Table 1-1 – Description of Permitted Units, Operations, and Processes

Unit	Description	Maximum Operating Rate	Control Device
#1	2021 or newer flare, fired with raw biogas	32 million Btu per hour	Not applicable

Table 1-2 provides a description of other units that were reviewed during the issuance of the air quality construction permit but were determined to be insignificant activities.

Table 1-2 – Description of Other Units, Operations, and Processes

Description	Maximum Operating Rate	Control Device
Boiler #1 – 2021 or later boiler, fired with natural gas	3.5 million Btu per hour	Not applicable
Boiler #2 – 2021 or later boiler, fired with natural gas	3.5 million Btu per hour	Not applicable
Anerobic digesters	700 standard cubic feet per minute	Not applicable
Biogas upgrading unit	700 standard cubic feet per minute	Not applicable

1.2 Proposed Changes

On April 16, 2026, Marshall 2 RNG submitted an application for a minor air quality operating permit. The application also included information on an emergency generator that has not been previously reviewed. Marshall 2 RNG provided additional information on the generator on June 15, 2026. DANR has changed its compliance demonstration requirements for biogas facilities; therefore, these requirements will be updated in this review. In order to permit some of these changes, the air quality construction permit #28.000130-01C will need to be modified. DANR will do the review for the minor air quality operating permit and the modified air quality construction permit at the same time for administrative ease. Table 1-3 provides a description of the proposed generator.

Table 1-3 – Description of Proposed Units, Operations, and Processes

Description	Maximum Operating Rate	Control Device
2024 Volvo Penta TAD1650GE emergency generator fired with diesel	498 kilowatts 677 horsepower	Not applicable

2.0 New Source Performance Standards

DANR reviewed the New Source Performance Standards in 40 CFR Part 60 and determined the following may be applicable.

2.1 Standards Applicable to Boilers – Subparts D, Da, Db, and Dc

There are four New Source Performance Standards for fossil fuel-fired steam generators. The four standards are applicable to the following steam generators:

1. **40 CFR Part 60, Subpart D:** applicable to a steam generator with a maximum operating rate of 250 million Btu per hour or more and commenced construction after August 17, 1971;
2. **40 CFR Part 60, Subpart Da:** Standards for Electric Utility Steam Generating Units. This subpart is applicable to each utility generating unit that is capable of combusting more than 73 megawatts (250 million Btu per hour) heat input of fossil fuel (either alone or in combination with any other fuel) that commenced construction, modification, or reconstruction after September 18, 1978;
3. **40 CFR Part 60, Subpart Db:** applicable to a steam generator with a maximum operating rate of 100 million Btu per hour or more and commenced construction after June 19, 1984; and
4. **40 CFR Part 60, Subpart Dc:** applicable to a steam generator with a minimum design heat input capacity equal to or greater than 10 million Btu per hour but less than or equal to 100 million Btu per hour and commenced construction after June 9, 1989.

The maximum heat input rates of the boilers are each less than 10 million Btu per hour; therefore, the boilers are not applicable to Subparts D, Da, Db, or Dc.

2.2 Standards for Stationary Compression Ignition Engines – Subpart IIII

The provisions of 40 CFR Part 60, Subpart IIII are applicable to owners and operators of stationary compression ignition internal combustion engines that meet one of the following:

1. Manufacturers of stationary compression ignition internal combustion engine with a displacement of less than 30 liters per cylinder where the model year is 2007 or later for engines that are not fire pump engines or model year 2008 or later for engines that are fire pump engines;
2. Owners or operators of stationary compression ignition internal combustion engine that commence construction after July 11, 2005 where the compression ignition internal

combustion engine is manufactured after April 1, 2006 and is not a fire pump engine or manufactured as a certified National Fire Protection Association fire pump engine after July 1, 2006; or

3. Owners or operators of stationary compression ignition internal combustion engine that modified or reconstructed their stationary compression ignition internal combustion engine after July 11, 2005.

The proposed emergency generator that was constructed after April 1, 2006, is considered a stationary compression ignition internal combustion engine, and is not a fire pump engine. Therefore, the proposed generator is applicable to this subpart and must meet the following conditions.

- New emergency generator that is not a fire pump;
- Displacement of less than 30 liters per cylinder;
- Greater than or equal to 130 kilowatts and less than or equal to 560 kilowatts;
- EPA Tier 3 Certified; and
- Emission standards in Table 2-1.

Table 2-1 – Emission Limits for Emergency Engines

	Nonmethane Hydrocarbon + Nitrogen Oxide	Carbon Monoxide	Particulate Matter
Grams per kilowatt-hour	4.0	3.5	0.2

2.3 Standards for Stationary Spark Ignition Engines – Subpart JJJJ

The provisions of 40 CFR Part 60, Subpart JJJJ is applicable to owners and operators of stationary spark ignition internal combustion engines that commence construction after June 12, 2006, where the stationary spark ignition internal combustion engines are manufactured:

1. On or after July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 horsepower (except lean burn non-emergency engines with a maximum engine power greater than or equal to 500 horsepower and less than 1,350 horsepower);
2. On or after January 1, 2008, for lean burn non-emergency engines with a maximum engine power greater than or equal to 500 horsepower and less than 1,350 horsepower;
3. On or after July 1, 2008, for non-emergency engines with a maximum engine power less than 500 horsepower;
4. On or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 kilowatts (25 horsepower); or
5. Owners and operators of stationary spark ignition internal combustion engines that commence modification or reconstruction after June 12, 2006.

The proposed generator is a compression ignition engine constructed after January 1, 2009. Therefore, this subpart is not applicable to the proposed generator.

2.4 Standards Applicable to Onshore Natural Gas Plants – Subpart KKK

The provisions of 40 CFR Part 60 Subpart KKK apply to affected facilities in onshore natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. A natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

Marshall 2 RNG's facility does not meet the definition of a natural gas processing plant under this subpart and construction of the facility commenced after August 23, 2011. Therefore, this subpart is not applicable to Marshall 2 RNG.

2.5 Standards Applicable to Onshore Natural Gas Plants – Subpart LLL

The provisions of 40 CFR Part 60 Subpart LLL are applicable to the following affected facilities that process natural gas: each sweetening unit, and each sweetening unit followed by a sulfur recovery unit which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

The provisions of this subpart are not applicable to Marshall 2 RNG because construction of the facility commenced after August 23, 2011.

2.6 Standards for Crude Oil and Natural Gas Facilities – Subpart OOOO

The provisions of 40 CFR Part 60 Subpart OOOOa establish emission standards and compliance schedules for the control of volatile organic compound (VOC) and sulfur dioxide (SO₂) emissions from affected facilities that commence construction, reconstruction, or modification after August 23, 2011, and on or before September 18, 2015.

The provisions of this subpart are not applicable to Marshall 2 RNG because construction of the facility commenced after September 18, 2015.

2.7 Standards for Crude Oil and Natural Gas Facilities – Subpart OOOOb

The provisions of 40 CFR Part 60 Subpart OOOOb establish emission standards and compliance schedules for the control of greenhouse gas emissions from affected facilities that commence construction, reconstruction, or modification after December 6, 2022. An applicable facility is an onshore facility that is located within the Crude Oil and Natural Gas Production source category as defined in section 60.5430b. The definition given for a Natural Gas Production source category is "Natural gas production and processing, which includes the well and extends to, but does not include, the local distribution company custody transfer station."

The operations for the facility do not include a natural gas well. The provisions of this subpart are not applicable to Marshall 2 RNG because the operations at the facility do not meet the definition of a Natural Gas Production source category.

2.8 Emission Guidelines for Crude Oil and Natural Gas Facilities – Subpart OOOOc

The provisions of 40 CFR Part 60 Subpart OOOOc establish emission guidelines and compliance schedules for the control of greenhouse gas emissions from affected facilities that commence construction, reconstruction, or modification on or before December 6, 2022.

An applicable facility is an onshore facility that is located within the Crude Oil and Natural Gas Production source category as defined in section 60.5430c. The definition given for a Natural Gas Production source category is “Natural gas production and processing, which includes the well and extends to, but does not include, the local distribution company custody transfer station.”

The operations for the facility do not include a natural gas well. The provisions of this subpart are not applicable to Marshall 2 RNG because the operations at the facility do not meet the definition of a Natural Gas Production source category.

2.9 Other Applicable New Source Performance Standards

DANR reviewed the other New Source Performance Standards and determined there are no other standards applicable to Marshall 2 RNG’s facility at this time.

3.0 New Source Review

The Administrative Rules of South Dakota (ARSD) 74:36:10:01 state that New Source Review regulations apply to areas of the state which are designated as nonattainment pursuant to the Clean Air Act for any pollutant regulated under the Clean Air Act. Marshall 2 RNG’s digester facility is located near Veblen, South Dakota, which is in attainment or unclassifiable for all the pollutants regulated under the Clean Air Act. Therefore, Marshall 2 RNG is not subject to a New Source Review.

4.0 Prevention of Significant Deterioration

A Prevention of Significant Deterioration review applies to new major stationary sources and major modifications to existing major stationary sources in areas designated as attainment under Section 107 of the Clean Air Act for any regulated air pollutant. The following is a list of regulated air pollutants under the Prevention of Significant Deterioration program:

1. Total suspended particulate (PM);
2. Particulate with a diameter less than or equal to 10 microns (PM10);
3. Particulate with a diameter less than or equal to 2.5 microns (PM2.5);
4. Sulfur dioxide (SO₂);
5. Nitrogen oxides (NO_x);
6. Carbon monoxide (CO);
7. Ozone – measured as volatile organic compounds (VOCs);

8. Lead;
9. Fluorides;
10. Sulfuric acid mist;
11. Hydrogen sulfide;
12. Reduced sulfur compounds;
13. Total reduced sulfur; and
14. Greenhouse gases (carbon dioxide, methane, nitrous oxide, etc.).

If the source is considered one of the 28 named Prevention of Significant Deterioration source categories listed in Section 169 of the federal Clean Air Act, the major source threshold is 100 tons per year of any regulated air pollutant, except for greenhouse gases. The major source threshold for all other sources is 250 tons per year of any regulated air pollutant, except for greenhouse gases. Marshall 2 RNG is not one of the 28 named Prevention of Significant Deterioration source categories; therefore, the major source threshold for pollutants is 250 tons per year. A facility must trigger one of the major source thresholds for another regulated pollutant before greenhouse gas emissions can be considered under the Prevention of Significant Deterioration permitting program. This applies to both new Prevention of Significant Deterioration program sources as well as major source modifications.

4.1 Potential Emissions

DANR uses stack test results to determine air emissions whenever stack test data are available from the source or a similar source. When stack test results are not available, DANR relies on manufacturing data, material balance, EPA's Compilation of Air Pollutant Emission Factors (AP-42, Fifth Edition, Volume 1), information submitted in the application, or other methods to determine potential air emissions. Potential emissions for each applicable pollutant are calculated by assuming the unit operates every day of the year at the maximum design capacity (8,760 hours per year).

4.1.1 Potential Emissions – Anaerobic Digesters

The facility includes the operation of anaerobic digesters. The estimated maximum biogas generation rate is approximately 700 standard cubic feet per minute. Based on the current available information, the digesters do not produce particulate matter, sulfur dioxide, nitrogen oxide, volatile organic compounds, and carbon monoxide. Therefore, these emissions will not be evaluated for the digesters. The digesters do produce methane, which is a greenhouse gas. At this point, DANR will not evaluate greenhouse gases unless a Prevention of Significant Deterioration review for another pollutant is triggered first. The digesters do produce hydrogen sulfide, which could trigger a Prevention of Significant Deterioration review. Marshall 2 RNG is currently limited to a hydrogen sulfide content limit of 2,020 parts per million prior to flaring. Similar digester facilities operating in South Dakota typically indicate that the worst-case scenario sulfur content of the biogas produced by the digesters would be 6,500 parts per million. DANR will review the potential emissions under the worst-case scenario. Equation 4.1 was used to determine the potential hydrogen sulfide emissions from the digesters without any controls (e.g., flares).

Equation 4.1 – Digester Hydrogen Sulfide Emissions

$$\text{Potential Emissions} \left(\frac{\text{tons}}{\text{year}} \right) = \frac{G\text{Flow} \times 60 \times 8,760 \times F_{H_2S} \times CF_{AP42}}{2,000}$$

Where:

- GFlow = biogas generation rate in cubic feet per minute (e.g., 700 ft³/min)
- 60 = minutes per hour
- 8,760 = hours per year
- F_{H₂S} = the hydrogen sulfide content of the fuel (i.e., 6,500 parts per million or 0.0065);
- CF_{AP42} = AP-42 conversion factor (parts per million to pounds per million cubic feet);
= 34.08 pounds per pound-mole (molecular weight of H₂S) ÷ 385.1 million cubic feet per pound-mole (derived from ideal gas law at standard temperature and pressure) or 0.0885 pounds H₂S per cubic feet H₂S;
- 2,000 = pounds per ton.

Table 4-1 lists the potential regulated emissions from the digesters without controls.

Table 4-1 – Potential Emissions from Digesters (tons per year)

Description	H ₂ S
Digesters	105.8

4.1.2 Potential Emissions – Biogas System

The biogas system cleans and removes containments from the biogas. A flare is connected to the system to flare off biogas and off-spec renewable natural gas. Potential emissions for the flare will be based under the operating scenario where the biogas upgrading unit is not operational and that flare burns the biogas produced by the digesters. The flare has a maximum operating rate of 700 standard cubic feet per minute.

AP-42 does not have emission factors for combusting digester gas. Emissions from the open flare for particulate matter, nitrogen oxides, carbon monoxide, and volatile organic compounds are based on emission factors in AP-42, Chapter 2.4 – Municipal Solid Waste Landfills, Table 2.4-5, August 2024. The emission factors are shown in Table 4-2.

Table 4-2 – Emission Factors for Flares

	TSP	PM ₁₀	PM _{2.5}	NO _x	CO	VOC
AP-42 (lb/MMdscf of Methane)	17	17	17	38	58	4.1

Sulfur dioxide emissions from biogas combustion depend on the sulfur content of the fuel. Most digester facilities are assumed to have a worst-case scenario sulfur content of 6,500 parts per million. However, Marshall 2 RNG is currently permitted to a worst-case scenario sulfur content of 2,020 parts per million.

DANR used Equation 4.2 and the estimated sulfur content to develop a sulfur dioxide emission factor based on the application of the ideal gas law under standard conditions and the assumption

that any sulfur in the biogas is in the form of hydrogen sulfide and that 100 percent of that sulfur converts to sulfur dioxide during combustion. The emission factor is shown in Table 4-3.

Equation 4.2 – Sulfur Dioxide Emission Factor Derivation for Flares

$$\text{Emission Factor} \left(\frac{\text{lbs SO}_2}{\text{MMscf}} \right) = \frac{F_{\text{H}_2\text{S}} \times CF_{\text{AP42}} \times WF_{\text{S/H}_2\text{S}}}{WF_{\text{S/SO}_2}}$$

Where:

- $F_{\text{H}_2\text{S}}$ = the hydrogen sulfide content of the fuel (i.e., 6,500 or 2,020 parts per million);
- CF_{AP42} = AP-42 conversion factor (parts per million to pounds per million cubic feet);
= 34.08 pounds per pound-mole (molecular weight of H_2S) $\div$ 385.1 million cubic feet per pound-mole (derived from ideal gas law at standard temperature and pressure);
= 0.088 pounds per million cubic feet, per parts per million
- $WF_{\text{S/H}_2\text{S}}$ = weight fraction of sulfur in hydrogen sulfide (i.e., 0.94 pounds of sulfur per pounds of hydrogen sulfide);
- $WF_{\text{S/SO}_2}$ = weight fraction of sulfur in sulfur dioxide (i.e., 0.50 pounds of sulfur per pounds of sulfur dioxide);

Table 4-3 – Sulfur Dioxide Emission Factor

	ppm	SO ₂
Pounds per million standard cubic feet	6,500	1,075.36
Pounds per million standard cubic feet	2,020	334.19

Potential emissions from the flare are calculated using Equation 4.3, the maximum operating rate of the flare (31,800 standard cubic feet per hour), the emission factors found in Tables 4-2 and 4-3, and 8,760 hours. The results are shown in Table 4-4.

Equation 4.3 – Potential Flare Emissions Calculation

$$\text{Potential Emissions} \left(\frac{\text{tons}}{\text{year}} \right) = \frac{\text{Capacity} \left(\frac{\text{scf}}{\text{hour}} \right) \times \text{Emission Factor} \left(\frac{\text{pounds}}{\text{MMscf}} \right) \times \text{Hours} \left(\frac{\text{hours}}{\text{year}} \right)}{1,000,000 \left(\frac{\text{scf}}{\text{MMscf}} \right) \times 2,000 \left(\frac{\text{pounds}}{\text{ton}} \right)}$$

Table 4-4 – Potential Emissions from Flare (tons per year)

Unit	TSP	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC
Flare	2.37	2.37	2.37	149.78	5.29	8.08	0.57

4.1.3 Potential Emissions – Generator

The generator produces emissions from combusting diesel as fuel. To convert from kilowatt to horsepower, the conversion factor of 0.746 kilowatts per horsepower was used. DANR converted the unit's kilowatt output rating to an estimated heat input rating using Equation 4.4, based on the following conversion factors of 3,413 Btu per kilowatt-hour, 1,000,000 Btu per million Btu, and the generator's efficiency assumed to be 35%. The result is shown in Table 4-5.

Equation 4.4 – Generator Conversion

$$\text{Input Capacity} \left(\frac{\text{MMBtu}}{\text{hour}} \right) = \frac{\text{Output (Kilowatt)} \times 3,413 \left(\frac{\text{Btu}}{\text{Kilowatt-hour}} \right)}{\text{Efficiency} \times 1,000,000 \left(\frac{\text{Btu}}{\text{MMBtu}} \right)}$$

Table 4-5 – Generator Heat Input Capacity

Output Capacity (kW)	Efficiency	Estimated Heat Input Capacity (MMBtu/hr)
498	35%	4.856

The generator has a maximum operating rate of 498 kilowatts (173 horsepower). AP-42 classifies generators with a heat rating less than or equal to 600 horsepower (447 kilowatts) as small industrial engines; therefore, the generator is not considered a small industrial engine. The emission factors for large industrial engines are derived from AP-42, 3.4, Table 3.4-1, April 2025, and shown in Table 4-6. The particulate matter, nitrogen oxide, carbon monoxide emission factors were derived from the New Source Performance Standard Subpart IIII requirements found in 40 CFR Part 1039, Appendix I for Tier III engines.

Table 4-6 – Emission Factors for Generators

	TSP	PM ₁₀	PM _{2.5}	SO ₂ ¹	NO _x	CO	VOC
AP-42 Large Engines (lb/MMBtu)	-	-	-	0.0015	-	-	0.09
Tier III Diesel Fuel (g/kW-hr)	0.2	0.2	0.2	-	4.0	3.5	-

¹ – Sulfur oxide emissions are a function of the sulfur content in the fuel (1.01 x Sulfur Content). The New Source Performance Standard Subpart IIII requires the generator to be fueled with ultra-low sulfur fuel 0.0015% sulfur by weight.

The diesel fired generator is for emergency-use only. Therefore, DANR will calculate potential emissions based on 500 operating hours per year.

Equation 4.5 calculates the generator's potential emissions for the factors from AP-42 of each pollutant based on the heat input, the listed emission factor in Table 4-6, and 500 operating hours per year. The results are summarized in Table 4-7.

Equation 4.5 – Generator Emissions based on AP-42

$$\text{Potential} \left(\frac{\text{tons}}{\text{year}} \right) = \frac{\text{input capacity} \left(\frac{\text{MMBtu}}{\text{Hour}} \right) \times \text{emission factor} \left(\frac{\text{pounds}}{\text{MMBtu}} \right) \times 500 \left(\frac{\text{hours}}{\text{year}} \right)}{2000 \left(\frac{\text{pounds}}{\text{ton}} \right)}$$

Equation 4.6 calculates the generator's potential emissions of each pollutant based on the emission factors from Subpart IIII in Table 4-6 and 500 operating hours per year. The results are summarized in Table 4-7.

Equation 4.6 – Generator Emissions based on Subpart IIII

$$\text{Potential} \left(\frac{\text{tons}}{\text{year}} \right) = \frac{\text{emission factor} \left(\frac{\text{grams}}{\text{kilowatt-hour}} \right) \times \text{kilowatts} \times 500 \left(\frac{\text{hours}}{\text{year}} \right)}{2000 \left(\frac{\text{pounds}}{\text{ton}} \right) \times 453.6 \left(\frac{\text{grams}}{\text{pound}} \right)}$$

Table 4-7 – Potential Emissions from Generator (tons per year)

Unit	TSP	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC
Generator	0.05	0.05	0.05	0.002	1.10	0.96	0.11

4.1.4 Potential Emissions – Boilers

Marshall 2 RNG operates two natural gas fired boilers. The emission factors for natural gas combustion are derived from AP-42, 1.4, Tables 1.4-1 and 1.4-2, July 1998, and are displayed in Table 4-8.

Table 4-8 – Emission Factors Natural Gas Combustion

	TSP	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC
Pounds per million cubic feet ¹	7.6	7.6	7.6	0.6	100	84	5.5
Pounds per million Btu	0.0075	0.0075	0.0075	0.0006	0.098	0.082	0.0054

¹ – To convert from pounds per million cubic feet to pounds per million Btu, divide by 1,020.

Potential emissions from the boilers are calculated using Equation 4.7, the emission factors from Table 4-8, and the heat input of the boilers. The results are shown in Table 4-9.

Equation 4.7 – Potential Boiler Emissions

$$\text{Potential Emissions} \left(\frac{\text{tons}}{\text{year}} \right) = \frac{\text{Heat Input} \left(\frac{\text{MMBtu}}{\text{hour}} \right) \times \text{Emission Factor} \left(\frac{\text{pounds}}{\text{MMBtu}} \right) \times 8,760 \left(\frac{\text{hours}}{\text{year}} \right)}{2,000 \left(\frac{\text{pounds}}{\text{ton}} \right)}$$

Table 4-9 – Potential Emissions from Boiler (tons per year)

Description	TSP	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC
Boiler #1	0.11	0.11	0.11	0.01	1.50	1.26	0.08
Boiler #2	0.11	0.11	0.11	0.01	1.50	1.26	0.08
Total	0.22	0.22	0.22	0.02	3.00	2.52	0.16

4.1.5 Summary of Potential Emissions

Table 4-10 summarizes the facility-wide potential emissions.

Table 4-10 – Facility-wide Potential Emissions (tons per year)

Unit	TSP	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC	H ₂ S
Digesters	-	-	-	-	-	-	-	105.8
Flare	2.37	2.37	2.37	149.78	5.29	8.08	0.57	-
Generator	0.05	0.05	0.05	0.002	1.10	0.96	0.11	-
Boilers	0.22	0.22	0.22	0.0	3.00	2.52	0.16	-
Total	3	3	3	150	9	12	1	106

The threshold for Title V pollutants is 100 tons per 12-month rolling period; therefore, the hydrogen sulfide emissions are only considered when the potential emissions are greater than 100 tons per year. The hydrogen sulfide potential emissions are greater than 100 tons and Marshall 2 RNG could be considered a Title V source. Marshall 2 RNG accepted a maximum

biogas venting limit in order to limit hydrogen sulfide emissions to 79 tons per year. Equation 4.8 calculates that venting limit, which is 274,663,190 cubic feet per 12-month rolling period or 274.66 million cubic feet per 12-month rolling period.

Equation 4.8 – Digester Hydrogen Sulfide Limit

$$GFlow \left(\frac{ft^3}{year} \right) = \frac{2,000 \left(\frac{pounds}{ton} \right) \times 79 \left(\frac{tons}{year} \right)}{0.0065 \times 0.0885}$$

$$GFlow \left(\frac{ft^3}{year} \right) = 274.66 \text{ million} \left(\frac{ft^3}{year} \right)$$

Because Marshall 2 RNG has accepted a hydrogen sulfide emission limit for the digesters, the digesters must be permitted.

In the review for the air quality construction permit, Marshall 2 RNG was found to have the potential to emit greater than 100 tons per year of sulfur dioxide. However, Marshall 2 RNG agreed to federally enforceable limits to avoid a Title V air quality operating permit. Marshall 2 RNG is currently limited to an emission limit of 79 tons per year of sulfur dioxide. This limit is met with a hydrogen sulfide content limit (2,020 parts per million) on the biogas combusted by the flare. Marshall 2 RNG did not request to change these limits in application for a minor air quality operating permit. The potential limited emissions from the flare will be calculated based on the biogas combustion throughput (31,800 standard cubic feet per hour), Equation 4.3, and the emission factors from Table 4-2, and the limited emission factor in Table 4-3. The results are shown in Table 4-11.

Table 4-11 summarizes the facility-wide limited potential emissions.

Table 4-11 – Facility-wide Potential Limited Emissions (tons per year)

Unit	TSP	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC	H ₂ S
Digesters	-	-	-	-	-	-	-	79
Flare	2.37	2.37	2.37	46.55	5.29	8.08	0.57	-
Generator	0.05	0.05	0.05	0.002	1.10	0.96	0.11	-
Boilers	0.22	0.22	0.22	0.0	3.00	2.52	0.16	-
Total	3	3	3	47	9	12	1	79

4.2 Significant Deterioration Summary

Based on Table 4-11 with the limits on sulfur dioxide and hydrogen sulfide, Marshall 2 RNG's potential emissions are less than 250 tons per year. Therefore, Marshall 2 RNG is considered a minor source and is not applicable to the Prevention of Significant Deterioration program. As Marshall 2 RNG is not applicable to the Prevention of Significant Deterioration program, a review for greenhouse gas emissions is not warranted or required.

5.0 National Emissions Standards for Hazardous Air Pollutants

DANR reviewed the National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 61 and determined there are no standards applicable to Marshall 2 RNG's renewable natural gas facility.

6.0 Maximum Achievable Control Technology Standards

The federal Maximum Achievable Control Technology Standards are applicable to both major and area sources of hazardous air pollutants. A major source of hazardous air pollutants is defined as having the potential to emit 10 tons or more per year of a single hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An area source is a source that is not a major source of hazardous air pollutants.

6.1 Potential Hazardous Air Pollutant Emissions

DANR uses stack test results to determine air emissions whenever stack test data is available from the source or a similar source. When stack test results are not available, DANR relies on manufacturing data, material balance, EPA's Compilation of Air Pollutant Emission Factors (AP-42, Fifth Edition, Volume 1) document, the applicant's application, or other methods to determine potential air emissions.

6.1.1 Potential Hazardous Air Pollutant Emissions – Anaerobic Digesters

Based on the current available information, the digesters do not produce hazardous air pollutants. Therefore, no hazardous air pollutant emission calculations will be conducted for the digesters.

6.1.2 Potential Hazardous Air Pollutant Emissions – Biogas Flare

Marshall 2 RNG operates a flare to control biogas emissions during the processing. Because AP-42 does not provide hazardous air pollutant emission factors for biogas combustion, DANR will use the hazardous air pollutant emission factor for natural gas combustion. The hazardous air pollutant emission factor for natural gas combustion is derived from AP-42, 1.4, Table 1.4-3, July 1998, and is displayed in Table 6-1.

Table 6-1 – Emission Factors Natural Gas Combustion

	Hazardous Air Pollutants
Pounds per million cubic feet	1.888

Potential hazardous air pollutant emissions from the flare are calculated using Equation 4.3, the hazardous air pollutant emission factor from Table 6-1, and gas consumption rate of the flare. The results are shown in Table 6-2.

Table 6-2 – Potential Emissions from Flare (tons per year)

Description	Hazardous Air Pollutants
Flare	0.26

6.1.3 Potential Hazardous Air Pollutant Emissions – Generator

Marshall 2 RNG operates one diesel fired emergency generator. The hazardous air pollutant emission factor for large stationary engines is derived from AP-42, 3.4, Tables 3.4-3 and 3.4-4, April 2025, and is displayed in Table 6-3.

Table 6-3 – Emission Factors Natural Gas Combustion

	Hazardous Air Pollutants
Pounds per million Btu	0.00149

Potential hazardous air pollutant emissions from the generator are calculated using Equation 4.5, the hazardous air pollutant emission factor from Table 6-3, and heat input from Table 4-5. The results are shown in Table 6-4.

Table 6-4 – Potential Emissions from Generator (tons per year)

Unit	Hazardous Air Pollutants
Emergency Generator	0.002

6.1.4 Potential Hazardous Air Pollutant Emissions - Boilers

Marshall 2 RNG operates two natural gas fired boilers. The hazardous air pollutant emission factor for natural gas combustion will be used and is derived from AP-42, 1.4, Table 1.4-3, July 1998, and is displayed in Table 6-5.

Table 6-5 – Emission Factors Natural Gas Combustion

	Hazardous Air Pollutants
Pounds per million cubic feet ¹	1.888
Pounds per million Btu	0.00185

¹ – To convert from pounds per million gallons to pounds per million Btu, divide by 1,020.

Potential hazardous air pollutant emissions from the boilers are calculated using Equation 4.7, the hazardous air pollutant emission factor from Table 6-5, and the heat input of the boiler. The results are shown in Table 6-6.

Table 6-6 – Potential Emissions from Boiler (tons per year)

Description	Hazardous Air Pollutants
Boiler #1	0.0284
Boiler #2	0.0284

6.1.5 Summary of Potential Hazardous Air Pollutant Emissions

Table 6-7 provides a summary of the facility-wide potential hazardous air pollutant emissions.

Table 6-7 – Potential Emissions (tons per year)

Description	Hazardous Air Pollutants
Digesters	-
Flare	0.26
Generator	0.002
Boilers	0.057
Total	0.319

The potential hazardous air pollutant emissions are less than 10 tons per year for a single hazardous air pollutant and 25 tons per year for a combination of hazardous air pollutants. Therefore, Marshall 2 RNG is an area source of hazardous air pollutants.

6.2 Maximum Achievable Control Technology Standards

DANR reviewed the Maximum Achievable Control Technology standards under 40 CFR Part 63 and determined the following standards may be applicable to Marshall 2 RNG's facility.

6.2.1 Standards for Off-Site Waste and Recovery Operations – Subpart DD

The provisions of this subpart are applicable to owners and operators of plant sites that are a major source of hazardous air pollutants; and at the plant site is located one or more operations that receives off-site materials, and the operations is one off the waste management operations or recovery operations listed in the subpart. Marshall 2 RNG is considered an area source of hazardous air pollutants. Therefore, this subpart is not applicable to the facility.

6.2.2 Standards Applicable to Oil and Natural Gas Production Facilities – Subpart HH

The provisions of this subpart apply to owners and operators of emission points located at oil and natural gas production facilities that meet the specified criteria. For area sources, the affected source includes each triethylene glycol (TEG) dehydration unit located at the facility that meets the criteria. Marshall 2 RNG is an area source of hazardous air pollutants. Marshall 2 RNG does not operate a TEG dehydration unit; therefore, this subpart is not applicable to the facility.

6.2.3 Standards Applicable to Natural Gas Transmission and Storage – Subpart HHH

The provisions of this subpart are applicable to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants. Marshall 2 RNG is considered an area source of hazardous air pollutants. Therefore, this subpart is not applicable to the facility.

6.2.4 Standards Applicable to Boilers – Subpart DDDDD

The provisions of this subpart establish national emission and operating limits for hazardous air pollutants emitted from industrial, commercial, and institutional boilers and process heaters

located at a major source of hazardous air pollutant emissions. Marshall 2 RNG is considered an area source of hazardous air pollutants. Therefore, this subpart is not applicable to the facility.

6.2.5 Standards Applicable to Boilers – Subpart JJJJJ

On March 21, 2011, EPA finalized the Maximum Achievable Control Technology standard under 40 CFR Part 63, Subpart JJJJJ. This rule applies to all new or existing industrial, commercial, and institutional boilers located at an area source of hazardous air pollutants. An existing boiler is defined as a boiler where construction or reconstruction occurred prior to June 4, 2010.

Marshall 2 RNG operates two natural gas fired boilers constructed after 2010. In accordance with 40 CFR § 63.11195(e), a gas-fired boiler is exempt from the requirements of this subpart. A gas-fired boiler is defined as “...any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel”. Gaseous fuels include propane. Therefore, Marshall 2 RNG is not subject to this subpart provided natural gas is the only fuel burned in the boilers.

6.2.6 Standards Applicable to Generators – Subpart ZZZZ

In accordance with 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, an affected source is any existing, new, or reconstructed stationary reciprocating internal combustion engines located at a major or area source of hazardous air pollutant emissions, excluding stationary reciprocating internal combustion engines being tested at a stationary reciprocating internal combustion engines test cell/stand (40 CFR § 63.6590).

The emergency generator was constructed after June 12, 2006, and is located at an area source. Under 40 CFR § 63.6590(c) it states a new or reconstructed stationary engine located at an area source must meet the requirements of this part by meeting the requirements of 40 CFR Part 60, Subpart IIII, for compression ignition engines or 40 CFR Part 60, Subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part. Therefore, the emergency generator is subject to Subpart ZZZZ and must meet the requirements of this subpart by meeting the requirements of 40 CFR Part 60, Subpart IIII for compression ignition engines.

6.2.7 Other Maximum Achievable Control Technology Standards

DANR reviewed the other Maximum Achievable Control Technology Standards and determined there are no other standards applicable to Marshall 2 RNG at this time.

7.0 State Requirements

7.1 Permit Type

Any source operating in South Dakota that meets the definition of a major source for any criteria pollutant is required to obtain a Title V air quality operating permit. A major source is defined as having the potential to emit greater than 100 tons per year of a criteria pollutant, greater than or equal to 10 tons per year of a single hazardous air pollutant, or greater than or equal to 25 tons per year of a combination of hazardous air pollutants, or if the source is applicable to a New Source Performance Standards or Maximum Achievable Control Technology Standards. Based on Table 4-11, Marshall 2 RNG's potential emissions with limits are less than 100 tons per year for any criteria pollutant. Therefore, a Title V air quality operating permit is not required due to criteria pollutant emissions.

The New Source Performance Standard and Maximum Achievable Control Technology standard applicable to the facility were promulgated under sections 111 and 112 of the Clean Air Act. However, Administrative Rules of South Dakota 74:36:07:88 and 40 CFR § 63.6585(d), an area source (minor) is not required to obtain a Title V air quality operating permit if the only reason for the Title V air quality operating permit is the requirement of 40 CFR Part 60 Subpart IIII and/or 40 CFR Part 63 Subpart ZZZZ. Therefore, a Title V air quality operating permit is not required due to a federal standard.

Any source operating in South Dakota that meets the definition of a minor source under Administrative Rules of South Dakota 74:36:01:01(37) is required to obtain a minor air quality permit. In accordance with Administrative Rules of South Dakota 74:36:04:02.01, a minor source is exempt from obtaining a minor source operating permit if the source has the potential to emit 25 tons per year or less of any criteria pollutant, except lead, before the application of control equipment. As shown in Table 4-11, the potential emissions of a single criteria air pollutant are greater than 25 tons per year. Therefore, Marshall 2 RNG is required to obtain a minor air quality operating permit.

The minor air quality operating permit and the modified air quality construction permit will contain conditions that will limit biogas hydrogen sulfide content to a maximum of 2,020 parts per million prior to combustion. There will also be conditions that will limit actual sulfur dioxide and hydrogen sulfide emissions to less than or equal to 79 tons per year and a maximum biogas venting limit of 244.5 million cubic feet per year. Marshall 2 RNG will be required to test the hydrogen sulfide content of the biogas on a weekly basis, when the flare is in operation, to ensure the quarterly average is below the sulfur content limit. Marshall 2 RNG will also be required to submit quarterly reports.

7.2 Insignificant Activities

In accordance with Administrative Rules of South Dakota (ARSD) 74:36:20:04 and 74:36:04:03, the following emission units are exempt from inclusion in the air quality operating permit unless the source has requested federally enforceable permit conditions related to the emission unit to

avoid needing a Part 70 operating permit, Prevention of Significant Deterioration preconstruction permit, or New Source Review preconstruction permit:

1. One or more incinerators of less than 100 pounds per hour combined burning capacity that combust municipal or household waste;
2. A mobile internal combustion engine, including engines in autos, trucks, tractors, airplanes, locomotives, and boats;
3. Laboratory equipment used exclusively for chemical or physical analysis;
4. A unit that has a heat input capability of not more than 3,500,000 Btu per hour, except for units fueled with wood or coal;
5. An air conditioning or ventilating system not designed to remove air pollutants from equipment;
6. Routine housekeeping or plant upkeep activities such as painting buildings, retarring roofs, or paving parking lots;
7. A unit that has the potential to emit two tons or less per year of any criteria pollutant before the application of control equipment. However, the criteria pollutant emissions from the unit must be included in determining whether the source is a major source; and
8. A unit that has the potential to emit two tons or less per year of any hazardous air pollutant. However, the hazardous air pollutant emissions from the unit must be included in determining whether the source is a major source.

Marshall 2 RNG's operations include two small natural gas fired boilers and anaerobic digesters. The boilers have the potential to emit less than 2 tons per year of any criteria air pollutant. Therefore, the boilers are considered exempt and not required to be permitted. The anaerobic digesters will have a limit on how much raw biogas can be vented per 12-month rolling period; therefore, they are now required to be permitted.

7.3 State Emission Limits

Administrative Rules of South Dakota 74:36:06:02 establishes state emission limits for total suspended particulate matter and sulfur dioxide. State emission limits are applicable to fuel burning and process industry units. Units classified as insignificant activities are not applicable to the state emission limits. In accordance with Administrative Rules of South Dakota 74:36:01:01(31), a fuel burning unit means a furnace, boiler, apparatus, stack, or any of their components used in the process of burning fuel or other combustible material for the primary purposes of producing heat or power by indirect heat transfer. The flare uses direct heat to burn the gas from the digesters. The flare is not used to heat or power any other units or operations; therefore, the state emission limits for particulate matter emissions are not applicable. The emergency generator is subject to New Source Performance Standard Subpart IIII which has sulfur dioxide and particulate matter limits and is exempt from these state emission limits. The digesters are not considered process industry or fuel burning units; therefore, they are exempt from the state emission limits.

7.3.1 Visible Emission Limit

Visible emissions are applicable to units that discharge into the ambient air. In accordance with

Administrative Rules of South Dakota 74:36:12, a facility may not discharge into the ambient air more than 20 percent opacity for all units. Marshall 2 RNG must control the opacity at less than 20 percent for all units.

7.4 Performance Tests

In accordance with Administrative Rules of South Dakota 74:36:11:02, the Secretary may require a performance test, if necessary, to demonstrate compliance with the state's emission limits. The air quality construction permit will contain a hydrogen sulfide concentration limit. Compliance with this limit will be based on periodic hydrogen sulfide content testing of the biogas being routed out of the digester. Therefore, a performance test will not be required. However, permit conditions will be included in the permit that will allow DANR to require a performance test if DANR believes a performance test is necessary in the future to demonstrate compliance.

7.5 Standards for Flares

Typically, DANR includes flare requirements, from 40 CFR Part 60.18(b), in the permit. However, the flare requirements are more related to flares used specifically as control devices. The flare at Marshall 2 RNG's facility will be used to burn biogas and not for controlling a process in order to meet a permit limit. Marshall 2 RNG will not have a limit based specifically on the flare operating. Therefore, DANR will not include the flare requirements in the permit.

8.0 Recommendation

Marshall 2 RNG is required to operate the renewable natural gas facility within the requirements stipulated in the following regulations:

- ARSD 74:36:04 – Operating Permits for Minor Sources;
- ARSD 74:36:06 – Regulated Air Pollutant Emissions;
- ARSD 74:36:07 – New Source Performance Standard;
- ARSD 74:36:08 – Maximum Achievable Control Technology Standards;
- ARSD 74:36:11 – Performance Testing;
- ARSD 74:36:12 – Control of Visible Emissions; and
- ARSD 74:36:20 – Construction Permits for New Sources or Modifications.

Based on the information submitted in the air quality permit application, DANR recommends approval of a minor air quality operating permit and a modified air quality construction permit for Marshall 2 RNG's renewable natural gas facility near Veblen, South Dakota. The proposed permit changes to air quality construction permit #28.000130-01C can be seen in Appendix A. Questions regarding this permit review should be directed to Connor Weber, Engineer III, Department of Agriculture and Natural Resources – Air Quality Program.

Appendix A

Modifications to Air Quality Construction Permit #28.000130-01C

The following changes to the existing permit represent changes that meet the definition of a permit modification. Additions to the existing permit are represented in blue, bold, and underlined and deletions are represented in red with overstrikes. In the case where permit conditions are deleted or added between permit conditions, the permit conditions will be renumbered appropriately when the permit is issued.

Under the South Dakota Air Pollution Control Regulations

Pursuant to Chapter 34A-1-21 of the South Dakota Codified Laws and the Air Pollution Control Regulations of the State of South Dakota and in reliance on statements made by the owner designated below, a permit to construct and operate is hereby issued by the Secretary of the Department of Agriculture and Natural Resources. This permit authorizes such owner to construct and operate the permitted unit(s) at the location designated below and under the listed conditions.

A. Owner

1. Company Name and Mailing Address

Marshall 2 RNG, LLC
44450 State Highway 25
Veblen, South Dakota 57270

2. Actual Source Location if Different from Above

44450 State Highway 25
Veblen, South Dakota 57270

3. Permit Contact

~~Dale Brandstetter, Project Manager~~ **Margo Carr**
~~(585)-278-4799~~ **(609) 500-4514**

4. Facility Contact

~~Dale Brandstetter, Project Manager~~ **Margo Carr**
~~(585)-278-4799~~ **(609) 500-4514**

5. Responsible Official

~~Dale Brandstetter, Project Manager~~ **Tim Lowry, Senior Vice President
& Chief Legal Officer**

~~(585) 278-4799~~ [\(609\) 561-9000](tel:(609) 561-9000)

B. Permit Revisions

~~Not applicable~~

Modification to update responsible official, add emergency generator, and update operational and emission limits.

C. Description of Construction Activity

Biogas production facility.

1.0 Standard Conditions

1.1 Construction and operation of source

In accordance with Administrative Rules of South Dakota (ARSD) 74:36:20:15(9), the owner or operator shall construct and operate the units, controls, and processes as described in Table 1-1 in accordance with the statements, representations, and supporting data contained in the complete permit application received August 30, 2021, and April 16, 2026, unless modified by the conditions of this permit. Except as otherwise provided herein, the control equipment in Table 1-1 shall be operated at all times in accordance with the manufacturer's specification and in a manner that achieves compliance with the conditions of this permit. The application consists of the application forms, supporting data, and supplementary correspondence. If the owner or operator becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in an application, such information shall be promptly submitted.

Table 1-1 – Description of Permitted Units, Operations, and Processes

Unit	Description	Maximum Operating Rate	Control Device
#1	2021 or newer flare, fired with raw biogas	32 million Btu ~~s~~ per hour	Not applicable
<u>#2</u>	<u>Anaerobic digesters. Biogas generated from the digesters may be routed to the atmosphere, gas upgrading unit, or the flare (Unit #1).</u>	<u>700 standard cubic feet per minute</u>	<u>Flare (Unit #1)</u>
<u>#3</u>	<u>2024 Volvo Penta TAD1650GE emergency generator fired with diesel</u>	<u>498 kilowatts</u> <u>677 horsepower</u>	<u>Not applicable</u>

4.0 Recordkeeping and Reporting

4.4 Monthly records

In accordance with ARSD 74:36:20:15(10), the owner or operator shall calculate and record the following amounts each month:

1. The amount of sulfur dioxide, in tons, emitted into the ambient air from the permitted units during the month. A 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values. The amount of sulfur dioxide emitted to the ambient air from permitted units shall be calculated using ~~sulfur content of raw biogas, formulas, emission factors, and methods described in the statement of basis~~ a mass balance equation incorporating the sulfur content of biogas determined by the records in permit condition 4.4(2) and 4.4(3);
2. The amount of biogas that is combusted in the flare, Unit #1, during the month. A 12-month rolling total shall be calculated every month using that month's value and the previous 11 months' values;
3. Sulfur content of the biogas as determined by averaging the weekly sulfur content testing described in permit condition 7.4; and
4. The amount of biogas produced during the month. A 12-month rolling total shall be calculated every month using the month's value and the previous 11 months' values and during the 12-month period for that month.;
5. The amount of biogas vented during the month. A 12-month rolling total shall be calculated every month using the month's value and the previous 11 months' values and during the 12-month period for that month.; and
6. Instances where the facility was not operating and a sulfur content reading was not taken.
7. ~~Sulfur content of raw biogas as determined by quarterly sulfur content testing;~~
8. ~~The amount of raw biogas produced during the month and during the 12-month period for that month; and~~
9. ~~The number of hours the flare is operated.~~

4.5 Quarterly reporting

In accordance with ARSD 74:36:20:15(10), the owner or operator shall submit ~~a~~ quarterly reports s to the Secretary ~~by the end of each calendar quarter~~. The quarterly reports s shall contain the following information:

1. Name of facility, permit number, reference to this permit condition, identifying the submittal as a quarterly report, and calendar dates covered in the reporting period;
2. The amount of sulfur dioxide emissions, in tons, emitted into the ambient air from the permitted units during ~~the each~~ month and ~~during each the~~ 12-month ~~rolling total period~~ for ~~that each~~ month in the reporting period;
3. The amount of hydrogen sulfide emissions, in tons, emitted into the ambient air from the permitted units during each month and the 12-month rolling total for each month in the reporting period;
4. The amount of biogas that is combusted in the flare, Unit #1, each month, and the 12-month rolling total for each month in the reporting period;
5. Monthly average sulfur content of biogas as determined by every weekly sulfur content test taken during the calendar month as described in permit condition 7.4;
6. Instances where the facility is not operating, and a sulfur content reading is not taken;
7. The amount of biogas produced during each month and the 12-month rolling total for each month in the reporting period; and

8. The amount of biogas vented during each month and the 12-month rolling total for each month in the reporting period.
- ~~9. Sulfur content of raw biogas as determined by quarterly sulfur content testing;~~
- ~~10. The amount of raw biogas produced during the month and during the 12-month period for that month; and~~
- ~~11. The number of hours the flare operated during the quarterly reporting period.~~

The quarterly report must be postmarked no later than 30 days after the end of the reporting period (i.e., April 30th, July 30th, October 30th, and January 30th).

5.0 Control of Regulated Air Pollutants

~~5.3 Total suspended particulate matter limits~~

~~In accordance with ARSD 74:36:06:02(1), the owner or operator shall not allow the emission of total suspended particulate matter in excess of the emission limit specified in Table 5-1 for the appropriate permitted unit, operations, and process.~~

~~Table 5-1—Total Suspended Particulate Emission Limit~~

~~Unit~~	~~Description~~	~~Emission Limit~~
~~#1~~	~~Flare~~	~~0.5 pounds per million Btu heat input~~

5.34 Circumvention not allowed

In accordance with ARSD 74:36:20:24, the owner or operator may not install, use a device, or use a means that conceals or dilutes an air emission that would otherwise violate this permit. This includes operating a unit or control device that emits air pollutants from an opening other than the designed stack, vent, or equivalent opening.

5.45 Minimizing emissions

In accordance with ARSD 74:36:20:15(9), the owner or operator shall at all time, when practicable, maintain and operate all permitted units in a manner that minimizes air pollution emissions.

7.0 Title V Air Quality Operating Permit Exemption

7.1 Plant-wide sulfur dioxide limit

In accordance with ARSD 74:36:20:15(9), the owner or operator shall not emit into the ambient air greater than or equal to 79 tons per 12-month rolling period of sulfur dioxide. Compliance with this limit is determined by the biogas sulfur content limit for Unit #1 in permit condition 7.3.

7.2 Plant-wide hydrogen sulfide limit

In accordance with ARSD 74:36:20:15(9), the owner or operator shall not emit into the ambient air greater than or equal to 79 tons per 12-month rolling period of hydrogen sulfide.

7.32 Sulfur content limit of raw biogas combustion

In accordance with ARSD 74:36:20:15(9), the owner or operator shall only combust raw biogas in Unit #1 with a hydrogen sulfide content of 2,020 parts per million or less.

7.3 Monitoring sulfur content of raw biogas quarterly

~~In accordance with ARSD 74:36:20:15(10), the owner or operator shall collect samples of the inlet raw biogas for the flare once per quarter, if the flare is operated, to determine the sulfur content. The sample shall be collected at a point between the anaerobic digesters and the flare inlet. A copy of the analyses shall be submitted with quarterly reports.~~

7.4 Monitoring sulfur content of biogas monthly

In accordance with ARSD 74:36:20:15(10), the owner or operator shall collect samples of the biogas prior to combustion during the calendar month to determine the average sulfur content. Samples shall be collected on a weekly or more frequent basis to calculate the monthly average sulfur content. If the facility is not operated during a week, then a sulfur content sample will not be required that week. The monthly average is to be calculated using each sulfur content sample taken during the month while the facility was in operation. The samples shall be collected at a point prior to combustion and be conducted by either an EPA approved test method, a continuous hydrogen sulfide monitor, or a portable analyzer. Physical samples shall be analyzed by an EPA approved test method (e.g., ASTM D5504, D4468, D1072, etc.). If a continuous hydrogen sulfide monitor or portable analyzer is used, the device must be maintained based on the manufacturer's instructions and certified annually. If the monthly average result from the device indicates an exceedance of the sulfur content limit in permit condition 7.3, the owner or operator shall take a sample and analyze the samples using an EPA approved test method. A copy of all analyses results shall be submitted with quarterly reports.

7.5 Monitoring device recordkeeping

In accordance with ARSD 74:36:20:15(10), the owner or operator shall maintain records of the results of calibrations and certification of the device(s) used in permit condition 7.4 to monitor the sulfur content of the biogas. These records must include the methods used for calibration and certification of the device(s).

7.6 Biogas venting limit

In accordance with ARSD 74:36:20:15(9), the owner or operator shall not vent more than 244.5 million standard cubic feet of biogas per 12-month rolling period.

7.47 Title V air quality operating permit exemption

In accordance with ARSD 74:36:20:15(9), the owner or operator is exempt from needing a Title V air quality operating permit. Any relaxation or exceedance of a permit condition that increases air emissions of sulfur dioxide or ~~carbon monoxide~~ hydrogen sulfide emissions greater than 79 tons per 12-month period is considered a modification and may require a Title V air quality operating permit.

8.0 NSPS Subpart III – Unit #3

8.1 Emergency engine limits

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR §§ 60.4202(a), 60.4205(b), and 60.4206, the owner or operator shall operate and maintain the emergency engine that achieves the emission limits in Table 8-1 over the entire life of the emergency engine.

Table 8-1 – Emission Limits for Emergency Engines (grams per kilowatt-hour)

<u>Unit</u>	<u>Nonmethane Hydrocarbon + Nitrogen Oxide</u>	<u>Carbon Monoxide</u>	<u>Particulate Matter</u>
<u>#3</u>	<u>4.0</u>	<u>3.5</u>	<u>0.20</u>

8.2 Fuel requirements for emergency engines

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4207(b), the owner or operator shall only combust diesel fuel in Unit #3 that meets the following per gallon standards:

1. Maximum sulfur content of 15 parts per million; and
2. Minimum cetane index of 40; or
3. Maximum aromatic content of 35 volume percent.

The owner or operator may use any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, until depleted.

8.3 Operating requirements for emergency engines

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4211(a), the owner or operator shall comply with the following, except as specified in permit condition 8.6:

1. Operate and maintain Unit #3 according to the manufacturer's emission-related written instructions;
2. Change only those emission-related settings permitted by the manufacturer; and
3. Meet the applicable requirements in 40 CFR Part 1068.

8.4 Compliance with emergency engine emission limits

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4211(c), the owner or operator shall demonstrate compliance with the emission limits in permit condition 8.1 by purchasing an engine certified to meet the emission limits in permit condition 8.1 and install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in permit condition 8.6.

8.5 Annual operation of emergency engine

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4211(f), the owner or operator shall operate Unit #3 as follows:

1. There is no time limit on the use of Unit #3 in emergency situations;

2. Unit #3 may be operated for up to 50 hours per calendar year in non-emergency situations. Except as provided in paragraph (3) of this permit condition, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the owner or operator to an electric grid or otherwise supply power as part of a financial arrangement with another entity; and
3. The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:
 - a. The engine is dispatched by the local balancing authority or local transmission and distribution system operator;
 - b. The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region;
 - c. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines;
 - d. The power is provided only to the owner or operator itself or to support the local transmission and distribution system; and
 - e. The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the owner or operator.

8.6 Alternative requirements for emergency engines

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4211(g), if the owner or operator does not install, configure, operate, and maintain Unit #3 according to the manufacturer's emission-related written instructions or changes the emission-related settings in a way that is not permitted by the manufacturer, the owner or operator shall demonstrate compliance as follows:

1. Maintain a maintenance plan and records of conducted maintenance;
2. To the extent practicable, maintain and operate Unit #3 in a manner consistent with good air pollution control practice for minimizing emissions;
3. Conduct an initial performance test to demonstrate compliance with the emission limits in Table 8-1 within 1 year of initial startup or within 1 year of such action; and
4. If Unit #3 is greater than 500 horsepower, the owner or operator shall conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable limits in Table 8-1.

8.7 Performance test requirements for emergency engines

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR §§ 60.4212(a) and (c), and 60.4214(f), if the owner or operator conducts a performance test to demonstrate compliance with Table 8-1, the following procedures shall be followed:

1. The performance test must be conducted according to the in-use testing procedures in 40 CFR Part 1039, Subpart F, for emergency engines with a displacement of less than 10 liters per cylinder, and according to 40 CFR Part 1042, Subpart F, for emergency engines with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2 emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in 40 CFR Part § 60.4213, as appropriate; and
2. Exhaust emissions from Unit #3 shall not exceed the “NTE” numerical requirements, rounded to the same number of decimal places as the applicable emission limit in Table 8-1 and determined by Equation 8-1.

Equation 8-1 – NTE formula

$$NTE = 1.25 \times STD$$

Where:

- NTE = Numerical requirement for each pollutant identified in Table 8-1; and
- STD = Emission limit for each pollutant identified in Table 8-1.

The results of the performance test must be submitted within 60 days after the test has been completed. The test results shall be submitted in accordance to the following:

1. Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (<https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert>) at the time of the test. Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to Permit Condition 8.11 of this section. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website; and
2. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test. The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to Permit Condition 8.11 of this section.

8.8 Non-resettable hour meter

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4209(a), the owner or operator shall install, maintain, and operate a non-resettable hour meter on Unit #3 prior to initial startup.

8.9 Recordkeeping for 2011 or later emergency engines

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4214(b), the owner or operator shall maintain records for 2011 or later emergency engines. The owner or operator shall record the date, start time, and end time of operation using the non-resettable hour meter and the reason Unit #3 was in operation during that time.

8.10 Annual reporting for emergency engines greater than 100 horsepower

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4214(d), if the owner or operator operates Unit #3 for the purposes specified in paragraph (3) of permit condition 8.5, the owner or operator shall submit an annual report. The annual report shall contain the following:

1. Company name and address where Unit #3 is located;
2. Date of the report and beginning and ending dates of the reporting period;
3. Unit #3's site rating and model year;
4. Latitude and longitude of Unit #3 in decimal degrees reported to the fifth decimal place; and
5. Hours spent for operation for the purposes specified in paragraph (3) of permit condition 8.5, including the date, start time, and end time. The report must also identify the entity that dispatched Unit #3 and the situation that necessitated the dispatch of Unit #3.

If the annual report is required for a particular calendar year, it must be submitted no later than March 31 of the following calendar year. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time the report is due, the written report must be submitted to the Secretary.

8.11 Report Notification Submittal Procedures

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4214(g), if an owner or operator is required to submit notifications or reports following the procedure specified in this permit condition, the owner or operator must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). The EPA will make all the information submitted through CEDRI available to the public without further notice to the owner or operator. Do not use CEDRI to submit information the owner or operator claims as CBI. Although the EPA does not expect persons to assert a claim of CBI, if you an owner or operator wishes to assert a CBI claim for some of the information in the report or notification, the owner or operator must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in this permit condition. Clearly mark the part or all of the information claimed to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI

claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. The owner or operator must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this permit condition:

1. The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the SOCMI NSPS Sector Lead. Owners and operators who do not have their own file sharing service and who require assistance with submitting large electronic files that exceed the file size limit for email attachments should email oaqpscbi@epa.gov to request a file transfer link; and
2. If an owner or operator cannot transmit the file electronically, the owner or operator may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the SOCMI NSPS Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

8.12 Outage Notification Submittal Electronically

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4214(h), owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, owners and operators must meet the requirements outlined in this permit condition:

1. The owner or operator must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems;
2. The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due;
3. The outage may be planned or unplanned;
4. The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting;

5. The owner or operator must provide to the Administrator a written description identifying:
 - a. The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;
 - b. A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
 - c. A description of measures taken or to be taken to minimize the delay in reporting; and
 - d. The date by which the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted;
6. The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator; and
7. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

8.13 Notification Submittal for Force Majeure

In accordance with ARSD 74:36:07:88, as referenced to 40 CFR § 60.4214(i), owners and operators required to electronically submit notifications or reports through CEDRI in the EPA's CDX may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, owners and operators must meet the requirements outlined in this permit condition:

1. An owner or operator may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage);
2. The owner or operator must submit notification to the Administrator in writing as soon as possible following the date the owner or operator first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting;
3. The owner or operator must provide to the Administrator:
 - a. A written description of the *force majeure* event;
 - b. A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;
 - c. A description of measures taken or to be taken to minimize the delay in reporting; and

- d. The date by which the owner or operator proposes to report, or if the owner or operator has already met the reporting requirement at the time of the notification, the date the report was submitted; and
- 4. The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator; and
- 5. In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.