Montana Department of Environmental Quality

Air, Energy & Mining Division

Date of Posting: July 1, 2025

Janel Nelson
Hiland Partners Holding, Inc.
Bakken Generating Station
1000 Louisiana St, Ste 1000
Houston, TX 77002

RE: Final and Effective Montana Air Quality Permit #3331-14

Sent via email: janel.nelson@kindermorgan.com

Dear Ms. Nelson:

Montana Air Quality Permit (MAQP) #3331-14 for the above-named permittee is deemed final and effective as of July 1, 2025, by the Montana Department of Environmental Quality (DEQ). All conditions of the Decision remain the same. A copy of final MAQP #3331-14 is enclosed.

For DEQ,

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Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau

Montana Air Quality Permit #3331-14

Hiland Partners Holding, Inc.
Bakken Generating Station
Section 3, Township 23 North, Range 58 East
1000 Louisiana St, Ste 1000
Houston, TX 77002

Final and Effective Date:
July 1, 2025

MONTANA AIR QUALITY PERMIT

Issued To:	Hiland Partners Holdings LLC Bakken Gathering Plant 1000 Louisiana St., Ste 1000 Houston, TX 77002	MAQP: #3331-14 Administrative Amendment Received: 05/19/2025 DEQ's Decision on AA: 06/13/2025 Permit Final: 07/01/2025

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Hiland Partners Holdings LLC (HPH), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

Section I: Permitted Facilities

A. Plant Location

HPH owns and operates a natural gas processing plant located approximately 8 miles northwest of Sidney, Montana, in the NE ¼ of the NW ¼ of Section 3, Township 23 North, Range 58 East, in Richland County, Montana. The facility extracts natural gas liquids from field gas and is known as the Bakken Gathering Plant.

B. Current Permit Action

On May 19, 2025, the Department of Environmental Quality (DEQ) received a request for an Administrative Amendment (AA) from HPH. Included in the request was an update to HPH's address and incorporation of two previously approved De Minimis actions into their MAQP. The De Minimis actions allowed for the exchange of two 1,025 horsepower engines (C1 and C3) with two 950 horsepower engines.

On June 10, 2025, HPH supplemented their initial request for an AA. More specifically, pursuant to the applicable requirements of the Administrative Rules of Montana (ARM) 17.8.745(2), the additional submittal requested that DEQ amend the existing language in Section II.B.2 to support the De Minimis friendly nature of the permit.

DEQ also updated the facilities Potential to Emit and the permit to reflect current naming conventions.

Section II: Conditions and Limitations

A. Emission Limitations

1. HPH shall not operate more than eight natural gas-fired compressor engines at any given time. The maximum rated design capacities shall not exceed (ARM 17.8.749):

Unit 1	950 bhp
Unit 2	1,025 bhp
Unit 3	950 bhp
Unit 4	185 bhp
Unit 5	550 bhp
Unit 6	185 bhp
Unit 7	840 bhp
Unit 8	265 bhp

2. Emissions from compressor engine Units 1 – 3 shall not exceed 1.3 g/bhp-hr (ARM 17.8.749).

3. The compressor engine Units 1 – 3 shall each be a rich-burn natural gas-fired engine controlled with non-selective catalytic reduction (NSCR) units and air-to-fuel ratio (AFR) controllers. The lb/hr emission limits for each of the engines shall be determined using the following equation and pollutant specific g/bhp-hr emission factors (ARM 17.8.752):

   Equation:

   Emission Limit (lb/hr) = Emission Factor (g/bhp-hr) * maximum rated design capacity of engine (bhp) * 0.002205 pounds per gram (lb/g)

Emission Factors	Units 1 – 3
Nitrogen Oxides (NO_X)	1.0 g/bhp-hr
VOC	1.0 g/bhp-hr

4. The compressor engine Units 4 & 6 shall be rich-burn natural gas-fired engines controlled with an NSCR unit and an AFR controller. The lb/hr emission limits for the engine shall be determined using the following equation and pollutant specific g/bhp-hr emission factors (ARM 17.8.752):

   Equation:

   Emission Limit (lb/hr) = Emission Factor (g/bhp-hr) * maximum rated design capacity of engine (bhp) * 0.002205 pounds per gram (lb/g)

Emission Factors	Unit 4
NO_X	1.0 g/bhp-hr
CO	2.0 g/bhp-hr
VOC	1.0 g/bhp-hr

5. The compressor engine Unit 5 shall be a four-stroke rich-burn natural gas-fired engine controlled with NSCR units and AFR controllers. The lb/hr emission limits for each of the engines shall be determined using the following equation and pollutant specific g/bhp-hr emission factors (ARM 17.8.752):

Equation:

Emission Limit (lb/hr) = Emission Factor (g/hp-hr) * maximum rated design capacity of engine (bhp) * 0.002205 lb/g

Emission Factors	Units 5 – 6
NO_X	1.0 g/bhp-hr
CO	1.0 g/bhp-hr
VOC	1.0 g/bhp-hr

6. The compressor engine Unit 7 shall be four-stroke rich-burn natural gas-fired engines controlled with an NSCR unit and an AFR controller. The lb/hr emission limits for the engine shall be determined using the following equation and pollutant specific g/bhp-hr emission factors (ARM 17.8.752):

   Equation:

   Emission Limit (lb/hr) = Emission Factor (g/hp-hr) * maximum rated design capacity of engine (bhp) * 0.002205 lb/g

Emission Factors	Unit 7
NO_X	1.0 g/bhp-hr
CO	1.0 g/bhp-hr
VOC	0.7 g/bhp-hr

7. The compressor engine Unit 8 shall be a four-stroke rich-burn natural gas-fired engine controlled with an NSCR unit and an AFR controller. The lb/hr emission limits for this engine shall be determined using the following equation and pollutant specific g/bhp-hr emission factors (ARM 17.8.752):

   Equation:

   Emission Limit (lb/hr) = Emission Factor (g/bhp-hr) * maximum rated design capacity of engine (bhp) * 0.002205 lb/g

Emission Factors	Unit 8
NO_X	1.0 g/bhp-hr
CO	1.0 g/bhp-hr
VOC	0.5 g/bhp-hr

8. The natural gas-fired Hot Oil Heater shall be limited to a maximum heat input capacity of 44.82 million Btu per hour (MMBtu/hr) (ARM 17.8.749).

9. The natural gas-fired Hot Oil Heater shall comply with the following emission limits (ARM 17.8.752):

   NO_X 0.112 lb/MMBtu
   CO 0.045 lb/MMBtu

10. HPH shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

11. HPH shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308).

12. HPH shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.11 (ARM 17.8.749).

13. Loading tank trucks shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.749).

14. HPH shall control VOCs emitted from tank trucks during loading through use of a vapor return line (ARM 17.8.749 and 17.8.752).

15. HPH shall not operate the 1,135 bhp diesel-fired emergency/backup engine/generator more than 500 hours per rolling 12-month time period. HPH shall not operate this engine/generator as a part of routine operations (ARM 17.8.749).

16. HPH shall only burn diesel fuel with a sulfur content less than 0.5% in the 1,135 bhp emergency/backup engine/generator (ARM 17.8.752).

17. HPH shall control VOCs emitted from the 18 MMSCFD EG S-Con dehydrator through the use of a glycol flash tank and routing of flash tank gases to the existing 98%-efficient flare (ARM 17.8.752)

18. HPH shall limit the use of the flare to 110 MMSCF/yr of gas, on a 12-month rolling basis. Any calculations used to establish emissions shall be based on the most recent Environmental Protection Agency (EPA) AP-42 factors, unless otherwise allowed by DEQ (ARM 17.8.749 and ARM 17.8.1204).

19. HPH shall comply with all applicable standards, limitations, reporting, record keeping, and notification requirements contained in 40 Code of Federal Regulations (CFR) 60, Subpart A, General Provisions, and Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (ARM 17.8.340 and 40 CFR 60, Subpart A and Subpart KKK).

20. HPH shall comply with all applicable standards, limitations, reporting, record keeping, and notification requirements contained in 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Plants (ARM 17.8.340 and 40 CFR 60, Subpart Dc).

21. HPH shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements contained in 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and 40 CFR 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engine (ARM 17.8.340; 40 CFR 60, Subpart IIII and Subpart JJJJ).

22. HPH shall comply with any applicable standards, limitations, reporting, recordkeeping, and notification requirements contained in Title 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (ARM 17.8.342 and 40 CFR 63, Subpart ZZZZ).

B. Inspection and Repair Requirements

1. Each calendar month, all fugitive piping components (valves, flanges, pump seals, open-ended lines, etc.) shall be inspected for leaks. For purposes of this requirement, detection methods incorporating sight, sound, or smell are acceptable (ARM 17.8.105 and ARM 17.8.752).

2. HPH shall (ARM 17.8.105 and ARM 17.8.752):

   a. Make a first attempt at repair for any leak not later than 5 calendar days after the leak is detected; and

   b. Repair any leak as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in Section II.B.3.

3. Delay of repair of equipment for which a leak has been detected will be allowed if repair is technically infeasible without a source shutdown. Such equipment shall be repaired before the end of the first source shutdown after detection of the leak (ARM 17.8.752).

C. Testing Requirements

1. Each compressor engine shall be initially tested for NO_X and CO (the pollutants to be tested concurrently). The initial source testing shall be conducted within 180 days of the initial start-up date of the compressor engine(s). After the initial source test, additional testing shall continue on an every 4-year basis, or according to another testing/monitoring schedule as may be approved by DEQ in writing, to demonstrate compliance with NOx and CO lb/hr emission limits as calculated in Sections II.A.2, II.A.4, II.A.5, II.A.6 and II.A.7 (ARM 17.8.105 and ARM 17.8.749).

2. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. DEQ may require additional testing (ARM 17.8.105).

D. Operational Reporting Requirements

1. HPH shall supply DEQ with annual production information for all emission points, as required by DEQ in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis. Production information shall be gathered on a calendar-year basis and submitted to DEQ by the date required in the emission inventory request.

   Information shall be in the units required by DEQ. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. HPH shall document, by month, the hours of operation of the 1,135 bhp emergency/backup engine/generator. By the 25th day of each month, HPH shall calculate the total hours of operation of the 1,135 bhp emergency/backup engine/generator for the previous month. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section II.A.15. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

3. HPH shall document, by month, the amount of gas controlled by the flare, in MMSCF. By the 25th day of each month, HPH shall calculate the total amount of gas combusted by the flare for the previous month. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section II.A.18. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

4. HPH shall notify DEQ of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include the addition of a new emissions unit, change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation. The notice must be submitted to DEQ, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

5. All records compiled in accordance with this permit must be maintained by HPH as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by DEQ, and must be submitted to DEQ upon request (ARM 17.8.749).

6. HPH shall annually certify that its actual emissions are less than those that would require the source to obtain an air quality operating permit as required by ARM 17.8.1204(3)(b). The annual certification shall comply with the certification requirements of ARM 17.8.1207. The annual certification shall

be submitted along with the annual emission inventory information (ARM 17.8.749 and ARM 17.8.1204).

E. Recordkeeping Requirements

1. HPH shall maintain a record that only diesel fuel with a sulfur content less than 0.5% was burned in the 1,135 bhp emergency/backup engine/generator, for use in verifying compliance with the limitation in Section II.A.16 (ARM 17.8.749).

2. A record of each monthly leak inspection required by Section II.B.1 of this permit shall be kept on file with HPH. Inspection records shall include, at a minimum, the following information (ARM 17.8.749):

   a. Date of inspection;

   b. Findings (may indicate no leaks discovered or location, nature, and severity of each leak);

   c. Leak determination method;

   d. Corrective action (date each leak repaired and reasons for any repair interval in excess of 15 calendar days); and

   e. Inspector's name and signature.

3. All records compiled in accordance with this permit must be maintained by HPH as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by DEQ, and must be submitted to DEQ upon request (ARM 17.8.749).

Section III: General Conditions

A. Inspection – HPH shall allow DEQ's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (e.g., Continuous Emission Monitoring System (CEMS), Compliance Emission Rate Monitoring System (CERMS)) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if HPH fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving HPH of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, et seq. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement action as specified in Section 75-2-401, et seq., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by DEQ's decision may request, within 15 days after DEQ renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act.

The filing of a request for a hearing does not stay DEQ's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2- 211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of DEQ's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, DEQ's decision on the application is final 16 days after DEQ's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by DEQ at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by HPH may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

Montana Air Quality Permit (MAQP) Analysis
Hiland Partners Holdings LLC
Bakken Gathering Plant
MAQP #3331-14

I. Introduction/Process Description

Hiland Partners Holdings LLC (HPH) is permitted for the construction and operation of the Bakken Gathering Plant. The facility will extract natural gas liquids from field gas and is in the NE ¼ of the NW ¼ of Section 3, Township 23 North, Range 58 East, in Richland County, Montana.

A. Permitted Equipment

The facility consists of the following permitted equipment:

ID	Equipment
Unit 1	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 950 brake-horsepower (bhp)
Unit 2	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 1,025 bhp
Unit 3	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 950 bhp
Unit 4	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 185 bhp
Unit 5	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 550 bhp
Unit 6	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 185 bhp
Unit 7	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 840 hp
Unit 8	Natural gas-fired, rich-burn compressor engine with a maximum rated design capacity equal to or less than 265 bhp
Hot Oil Heater	Title 40 Code of Federal Regulations (40 CFR) 60, Subpart Dc, affected Natural gas-fired Hot Oil Heater with a maximum rated heat input capacity of 44.82 million British thermal units per hour (MMBtu/hr)
Fugitive	Fractionation Unit, deethanizer, depropanizer, debutanizer, and other plant-wide leaks
Russell Dehydrator	Ethylene Glycol (EG) dehydrator and associated still vent (8 million standard cubic feet per day (MMSCF/d))
SCON Dehydrator	EG dehydrator and associated still vent (18 MMSCF/d)
Truck Loading	Truck loading @ 4775 barrels per day (bbl/day) (increased by 1,000 bbl/day in MAQP#3331-07); submerged fill and vapor return lines
Tank #1	1 400 - barrel (bbl) condensate storage tank
Tank #3	1 1000 - gallon diesel storage tank
Emergency Generator	Diesel-fired emergency/backup engine/generator with a maximum rated design capacity equal to or less than 1,135 bhp.
Flare	Flare with 0.5 MMBtu/hr pilot

B. Source Description

The Bakken Gathering Plant extracts natural gas liquids from field gas. The fractionation unit (including a depropanizer and a debutanizer) consists of a Hot Oil Heater, several reboilers, multiple holding tanks, refrigeration compressors, and a truck loading station. The EG dehydration units remove moisture from the gas prior to transmission.

C. Permit History

On May 4, 2004, the Department of Environmental Quality (DEQ) received a complete MAQP Application from Hiland Partners, LLC (HPLLC) for the construction and operation of the Bakken Gathering Plant. **MAQP #3331-00** became final and effective on July 3, 2004.

On August 17, 2004, DEQ received a complete MAQP Application from HPLLC for the modification of MAQP #3331-00. Specifically, HPLLC requested the following: 1) to add a natural gas compressor engine with a maximum capacity equal to or less than 500 bhp; 2) to add a 1,135 bhp emergency/backup diesel-fired generator and an associated 500-gallon diesel storage tank; and 3) to remove the 10 MMBtu/hr Hot Oil Heater. **MAQP #3331-01** replaced MAQP #3331-00.

On June 14, 2005, DEQ received a letter from HPLLC for an administrative amendment to MAQP #3331-01. Specifically, HPLLC requested to add an 11 MMSCF/d refrigeration unit, a standby electric compressor, and a dehydrator reboiler and still vent. The potential emissions from the proposed equipment were less than the de minimis threshold at that time of 15 tons per year (tpy). The permit action updated the permit analysis (including the emission inventory) with the new equipment. **MAQP #3331-02** replaced MAQP #3331-01.

On November 10, 2005, DEQ received a letter from Hiland Partners, LP (HPL) for an administrative amendment to MAQP #3331-02. Specifically, HPL requested to change the corporate name on MAQP #3331-02 from HPLLC to Hiland Partners, LP and update the permit to reflect the current permit language and rule references used by DEQ. **MAQP #3331-03** replaced MAQP #3331-02.

On March 17, 2006, DEQ received an application from HPL for a number of process changes to eliminate production bottlenecks and ensure processing capability for 20 MMSCF/d of natural gas. The project included installation of two natural gas-fired compressor engines up to 185 bhp and 930 bhp, as well as other process improvements. The application included an administrative amendment request to reduce the maximum rating for Unit #1 from 1,478 bhp to 912 bhp. HPL submitted further information on April 17, 2006, including a request to reduce the maximum rating for Unit #2 from 1,478 bhp to 912 bhp, and permit the use of a flare for up to 35 million standard cubic feet per year (MMSCF/yr). **MAQP #3331-04** replaced MAQP #3331-03.

On May 25, 2007, DEQ received a complete application from HPL for the installation and operation of a 44.82 MMBtu/hr capacity natural gas-fired Hot Oil Heater and the removal of an existing 25 MMBtu/hr capacity Hot Oil Heater from permitted operations.

The proposed natural gas-fired Hot Oil Heater is an affected facility as defined in 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial- Institutional Steam Generating Units. Further, HPL requested an administrative permit amendment to reduce the permitted maximum rated design capacity of the Unit #7 natural gas-fired compressor engine from 930 bhp to 740 bhp. **MAQP #3331-05** became final on July 7, 2007, and replaced MAQP #3331-04.

On April 9, 2009, DEQ received a complete application from HPL for a permit modification to increase the listed maximum power rating for Compressor Engine Unit 5 from 500 bhp to 550 bhp. The application was in response to a compliance inspection in October 2008 that noted the capacity of Unit #5 was 550 bhp rather than the permitted 500 bhp. Also, this permit modification incorporates a de minimis request received by DEQ on February 5, 2009, to add a second fuel line/fuel source for the Hot Oil Heater. The second source of fuel will be the de-ethanizer tower. Gas from this source has a heat content of 1400 million British thermal units per million cubic feet (MMBtu/MMCF). The Hot Oil Heater at the Bakken plant is now capable of burning fuel from either source.

Finally, this permit modification updated permit conditions and language, and incorporates new and recently modified Federal New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, as applicable. **MAQP #3331-06** replaced MAQP #3331-05.

On October 8, 2009, DEQ received an application from Bison Engineering, Inc. (Bison), on behalf of HPL, for a permit modification to install one four-stroke, rich-burn design compressor engine with a rating equal to or less than 265 bhp, and to install an additional 33,600-gallon pressurized bullet tank for fractionated product. The additional tank would be for storage purposes and the truck loading capabilities would not increase.

On January 15, 2010, DEQ received a revised application from Bison, on behalf of HPL, for a permit modification to install one four-stroke, rich-burn design compressor engine with a rating equal to or less than 265 bhp, to install an additional 84,000 gallon (instead of the previously proposed 33,600 gallon) pressurized bullet tank for fractionated product, and to increase the truck loading capabilities at the facility by 1,000 barrels (bbl) per day.

On January 18, 2010, DEQ received notification (via email) from Bison, on behalf of HPL to request that the installation of the 84,000-gallon pressurized bullet tank for fractionated product be considered de minimis. According to the submitted potential to emit (PTE) calculations, the PTE for this project is estimated to be approximately 0.5 tpy. Based on the emission information provided, the proposed change associated with the installation of the pressurized tank meets the definition of de minimis change under the Administrative Rules of Montana (ARM) 17.8.745. On January 20, 2010, HPL and Bison were notified that DEQ determined the installation of this proposed tank is excluded from requiring a permit as described in ARM 17.8.745(1) because the tank's potential emissions are less than 15 tpy (the de minimis level at that time) and the proposal would not violate any conditions of HPL's current MAQP #3331-06.

In addition, DEQ agrees that the installation of the 84,000-gallon pressurized bullet tank does not warrant an administrative amendment and accepts this as a courtesy notice on the part of HPL. The 84,000-gallon pressurized tank was not a requirement for the installation of the 265 bhp engine, nor the increased truck loading capability, and would not require an operating permit revision under ARM 17.8.1224(5). **MAQP #3331-07** replaced MAQP #3331-06.

On July 14, 2014, DEQ received an application from Bison Engineering, Inc. (Bison), on behalf of HPL to modify MAQP #3331-07. The modification included replacement of the existing 740 brake horsepower (bhp) compressor engine with a four-stroke, rich-burn design compressor engine with a rating equal to or less than 840 bhp. The proposed action also included the installation of pollution controls on the 11 MMSCFD/d ethylene glycol (EG) dehydrator and associated still vent, consisting of a flash tank separator and routing the flash tank gases to the existing flare. **MAQP #3331-08** replaced MAQP #3331-07.

On September 30, 2015, DEQ received a request from Hiland Partners Holdings, LLC, to change the name from Hiland Partners, LP, to the current legal name of Hiland Partners Holdings, LLC, and to update contact information. **MAQP#3331-09** replaced MAQP#3331-08.

On July 25, 2016, DEQ received a request from Hiland Partners Holdings, LLC, to change the mailing address from PO Box 5103, Enid, OK 73702 to 370 Van Gordon Street, Lakewood, CO 80228. The permit action reflected this change and updated the permit language to reflect current permit language and references. **MAQP #3331-10** replaced MAQP #3331-09.

On April 11, 2017, DEQ received a request from HPH to modify their permit to correct the rated brake horsepower (bhp) to 1,025 bhp from 912 bhp for compressor engine Units 1-3. On August 30, 2016, HPH informed DEQ that a discrepancy between the permit listed horsepower and the nameplate horsepower for Units 1-3 had been discovered. Although it was contemplated if the error could be addressed through an administrative amendment to MAQP #3331-10, DEQ ultimately decided MAQP #3331-10 did not allow for installation or operation of Units 1-3 at their maximum rated capacity and as a result, DEQ issued Warning Letter #WL20170124-00194 to HPH for violation of ARM 17.8.743 and Section II.A.1. HPH issued a response to the warning letter on February 9, 2017, informing DEQ that a permit modification application was in process to correct the listed horsepower ratings.

HPH also requested to lower the CO emissions factor for Units 1-3. The existing CO emission factor for these units was 2.0 g/bhp-hr. Based on a number of years of emission testing records for these units, HPH believes that these units should be using a lower emission factor of 1. 7 g/bhp-hr, which would subsequently lower the pound per hour (lb/hr) emission limit.

The engine replacement project permitted in MAQP #3331-08 intended to install a unit that was manufactured prior to July 2007; however, the actual unit installed was the same bhp and model authorized in MAQP #3331-08 but manufactured after July 1, 2010.

Therefore, the engine was required to meet the emissions standards specified in Subpart JJJJ of the New Source Performance Standards (NSPS). The lower volatile organic compounds (VOC) emission rate of 0.7 g/bhp-hr is reflected in this permit action.

Finally, HPH never installed Condensate Storage Tank #2 at the site and requested that this unit be removed from the permit. The permit action reflected these modifications and updated rule references and language used by DEQ. **MAQP #3331-11** replaced MAQP #3331-10.

On June 26, 2019, DEQ received an Administrative Amendment request from HPH. HPH requested that the word "emergency" be removed from the permit when used to describe the facilities flare. During a recent De Minimis (DM) determination (3331-11_2019_06_06_DM), DEQ determined that the increase in flare throughput from 35 million standard cubic feet (MMscf) to 57 MMscf was considered DM and would not increase the facilities potential to emit (PTE) more than 5 tons per year. The Administrative Amendment removed the word "emergency" as it pertained to the flare and updated the facility PTE to reflect the additional emissions from the DM action as well as increased the throughput of the flare to 57 MMscf. **MAQP #3331-12** replaced MAQP #3331-11.

On May 8th, 2023, DEQ received a modification request from HPH. HPH asked for a permit revision to change emitting unit information, update potential to emit (PTE) calculations, and increase the throughput limit of the flare.

The carbon monoxide (CO) emission factors for Engines 1-3 were lowered from 1.7 to 1.3 grams per brake horsepower hour (g/bhp-hr) based on historical emissions testing. Engine 2 had the highest test result, 0.673 pounds per hour (lb/hr), which corresponded to a value of 0.298 g/bhp-hr. The 1.3 g/bhp-hr threshold is very conservative compared to 0.298, and the historical test results provide a large margin for maintaining compliance, so DEQ had high confidence that HPH would stay under the threshold.

The PTE was updated for various equipment which included condensate storage tank (400 barrel), diesel tank (1,000 gallon), fugitives, and dehydrator units. The flare throughput limit from 57 million standard cubic feet (MMscf) to 110 MMscf resulted in an increased PTE for all criteria pollutants; additionally, the flare CO emission factor was changed to align with the latest AP-42 standard. The heat content for various equipment was changed to 1,400 Btu/cubic feet (Btu/cf).
All criteria pollutants, excluding fugitives, stayed under 100 tons per year with the proposed modifications. **MAQP #3331-13** replaced MAQP #3331-12.

D. Current Permit Action

On May 19, 2025, DEQ received a request for an Administrative Amendment (AA) from Hiland Partners Holding, LLC, (HPH). Included in the request was an update to HPH's address and incorporation of two previously approved De Minimis actions. The De Minimis actions were for the exchange of two (2) 1,025 horsepower engines (C1 and C3) with two (2) 950 horsepower engines.

On June 10, 2025, HPH supplemented their initial request for an AA. More specifically, pursuant to the applicable requirements of the Administrative Rules of Montana (ARM) 17.8.745(2), the additional submittal requested that DEQ amend the existing language in Section II.B.2 to support the De Minimis friendly nature of the permit.

DEQ also updated the facilities Potential to Emit and the permit to reflect current naming conventions. **MAQP #3331-14** replaces MAQP 3331-13.

E. Additional Information

Additional information, such as applicable rules and regulations, Best Available Control Technology (BACT)/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from DEQ. Upon request, DEQ will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. <u>ARM 17.8.101 Definitions</u>. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. <u>ARM 17.8.105 Testing Requirements</u>. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of DEQ, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by DEQ.

3. <u>ARM 17.8.106 Source Testing Protocol</u>. The requirements of this rule apply to any emission source testing conducted by DEQ, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   HPH shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from DEQ upon request.

4. ARM 17.8.110 Malfunctions. (2) DEQ must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring;
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide;
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide;
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide;
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone;
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide;
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter;
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility;
9. ARM 17.8.222 Ambient Air Quality Standard for Lead; and
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}.
11. ARM 17.8.230 Fluoride in Forage

HPH must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, HPH shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per MMBtu fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. HPH will utilize pipeline-quality natural gas for operating its fuel burning equipment, which meets this limitation.

6. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, Title 40 Code of Federal Regulations (40 CFR) Part 60, Standards of Performance for New Stationary Sources (NSPS). This facility is considered an NSPS-affected facility under 40 CFR Part 60 and is subject to the requirements of the following Subparts:

   a. Subpart A - General Provisions. This subpart applies to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart KKK - Standards of Performance for Onshore Natural Gas Processing Plants: HPH is an NSPS-affected source because it meets the definition of a natural gas processing plant as defined in 40 CFR 60, Subpart KKK.

   c. Subpart Dc - Standards of Performance for Small Industrial-Commercial- Institutional Steam Generating Units. HPH is an NSPS-affected source because the natural gas-fired Hot Oil Heater with a maximum rated heat input capacity of 44.82 MMBtu/hr meets the definition of an affected source as defined in 40 CFR 60, Subpart Dc.

   d. Subpart XX – Standards of Performance for Bulk Gasoline Terminals. Owners and operators are subject to 40 CFR 60, Subpart XX if the bulk gasoline terminal has loading racks that deliver liquid product into gasoline tank trucks. Under 40 CFR 60, Subpart XX, gasoline is defined as any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater that is used as a fuel for internal combustion engines.

The product loaded at the facility is Y-grade fractionated natural gas liquids and does not fit the definition of gasoline; therefore 40 CFR 60, Subpart XX is not applicable to the Bakken Gathering Plant.

e. Subpart IIII - Standards of Performance for Compression Ignition Internal Combustion Engines. NSPS-affected engines at the HPH facility include any new or reconstructed stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the stationary CI ICE are manufactured after April 1, 2006, and are not fire pump engines, and stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005 (40 CFR 60, Subpart IIII). HPH operates a CI ICE for emergency use; however, the engine was constructed prior to the NSPS applicability date. The remaining engines are not subject to 40 CFR 60, Subpart IIII because they are not compression ignition engines. However, because this permit is written in a de minimis-friendly manner, this regulation may apply to future engines at the facility.

f. Subpart JJJJ - Standards of Performance for Spark Ignition Internal Combustion Engines. This rule contains provisions that apply to owners or operators of stationary spark ignition (SI) internal combustion engines (ICE) that commence construction, modification, or reconstruction after June 12, 2006, where the stationary ICE is manufactured after July 1, 2007, for engines greater than 500 bhp, or after July 1, 2008, for engines less than 500 bhp. The NSPS-affected engines at the HPH facility include any new or reconstructed stationary SI ICE.

Compressor engine Units 8 (265 bhp) and 7 (840 hp) commenced construction after June 12, 2006, however, Unit 8 has a maximum engine bhp less than 500 bhp and was manufactured before July 1, 2008, and Unit 7 has a maximum engine bhp greater than 500 bhp and was manufactured before July 1, 2007. Unit 8 has not been modified or reconstructed after that date and therefore is not subject to 40 CFR 60, Subpart JJJJ. HPH completed an engine replacement on Unit 7, which changed the engine from a 740 bhp engine to a 840 bhp engine. The engine installed as Unit 7 has a manufacture date after July 1, 2010, making it subject to NSPS JJJJ. Compressor engine Units 1 through 6 are not subject to 40 CFR 60, Subpart JJJJ because they have not been constructed, modified, or reconstructed after June 12, 2006. Because this permit is written in a de minimis-friendly manner, this regulation may apply to future engines at the facility.

8. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below.

a. 40 CFR 63, Subpart A – General Provisions apply to all equipment or facilities subject to a NESHAP Subpart as listed below:

b. 40 CFR 63, Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities. Owners or operators of oil and natural gas production facilities, as defined and applied in 40 CFR Part 63, shall comply with the applicable provisions of 40 CFR 63, Subpart HH. In order for a natural gas production facility to be subject to 40 CFR 63, Subpart HH requirements, certain criteria must be met. First, the facility must be a major or area source of hazardous air pollutants (HAPs) as determined according to paragraphs (a)(1)(i) through (a)(1)(iii) of 40 CFR 63, Subpart HH. Second, a facility that is determined to be either a major or area source for HAPs must also either process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer, or process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. Third, the facility must also contain an affected source as specified in paragraphs (b)(1) through (b)(4) of 40 CFR 63, Subpart HH. Finally, if the first three criteria are met, and the exemptions contained in paragraphs (e)(1) and (e)(2) of 40 CFR 63, Subpart HH do not apply, the facility is subject to the applicable provisions of 40 CFR 63, Subpart HH. Based on the information submitted by Bison, on behalf of HPH, the Bakken Gathering Plant is not a major source of HAPs. For area sources under 40 CFR 63, Subpart HH, the affected sources include each TEG glycol dehydration unit. The Bakken Gathering Plant operates dehydration units; however, they are EG dehydration units not TEG units and therefore does not operate an affected source under the area source provisions.

c. 40 CFR 63, Subpart HHH National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities. Owners or operators of natural gas transmission or storage facilities, as defined and applied in 40 CFR Part 63, shall comply with the standards and provisions of 40 CFR 63, Subpart HHH.

In order for a natural gas transmission and storage facility to be subject to 40 CFR 63, Subpart HHH requirements, certain criteria must be met. First, the facility must transport or store natural gas prior to the gas entering the pipeline to a local distribution company or to a final end user if there is no local distribution company.

In addition, the facility must be a major source of HAPs as determined using the maximum natural gas throughput as calculated in either paragraphs (a)(1) and (a)(2) or paragraphs (a)(2) and (a)(3) of 40 CFR 63, Subpart HHH. Second, a facility must contain an affected source (glycol dehydration unit) as defined in paragraph (b) of 40 CFR 63, Subpart HHH.

Finally, if the first two criteria are met, and the exemptions contained in paragraph (f) of 40 CFR 63, Subpart HHH, do not apply, the facility is subject to the applicable provisions of 40 CFR 63, Subpart HHH.

Based on the information submitted by Bison, on behalf of HPH, the Bakken Gathering Plant facility is not subject to the provisions of 40 CFR 63, Subpart HHH because the facility is not a major source of HAPs.

d. 40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The facility contains compressor engines which are affected sources under 40 CFR 63 Subpart ZZZZ. Compressor engine Units 1-3 and 5 are existing four-stroke rich-burn (4SRB) reciprocating internal combustion engines (RICE) with a site rating of more than 500 bhp and meet the definition of an affected source at a remote location. Compressor engine units 4 and 6 are existing 4SRB reciprocating internal combustion engines RICE with a site rating of less than or equal to 500 bhp and meet the definition of an affected source. Per 40 CFR 63.6595(a) an affected source that is an existing stationary RICE located at an area source of HAP emissions, must comply with the applicable emission limitations, operating limitations and other requirements of this section. Compressor engine units 7 and 8 are considered to be new stationary 4SRB RICE because construction commenced after June 12, 2006, and meet the definition of an affected source. Per 40 CFR 63.6590(c), an affected source that is a new or reconstructed stationary RICE located at an area source must meet the requirements of this part by meeting the NSPS requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR Subpart JJJJ for spark ignition engines.

e. 40 CFR 63, Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities. This rule establishes national emission limitations and management practices for HAPs emitted from area source gasoline distribution bulk terminals, bulk plants, and pipeline facilities. 40 CFR 63, Subpart CC defines gasoline as any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater that is used as a fuel for internal combustion engines.

The product loaded at HPH's Bakken Gathering Plant is Y-grade fractionated natural gas liquids and does not fit under the definition of gasoline; therefore, 40 CFR 63, Subpart BBBBBB does not apply to the Bakken Gathering Plant.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. HPH must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to DEQ. A permit fee in not required for the current permit action because the permit action is considered an administrative permit change.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to DEQ by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by DEQ. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. DEQ may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar- year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the PTE greater than 25 tpy of any pollutant.

   The Bakken Gathering Plant has a PTE greater than 25 tpy of nitrogen oxides (NO_X), CO, and VOC; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. This rule requires that a permit application be submitted prior to installation, modification, or use of a source. A permit application was not required for the current permit action because the permit change is considered an administrative change. This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. An affidavit of publication was not required for the current permit action because the permit change is considered an administrative change.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by DEQ must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis and determination is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by DEQ at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving HPH of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, et seq.

10. ARM 17.8.759 Review of Permit Applications. This rule describes DEQ's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.760 Additional Review of Permit Applications. This rule describes DEQ's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

12. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

13. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

14. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

15. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to DEQ.

16. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to DEQ for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this Subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this Subchapter would otherwise allow.

   This facility is not a major stationary source because this facility is not a listed source and the facility's PTE is below 250 tpy of any pollutant (excluding fugitive emissions).

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. PTE greater than 100 tpy of any pollutant;

   b. PTE greater than 10 tpy of any one HAP, PTE greater than 25 tpy of a combination of all HAPs, or lesser quantity as DEQ may establish by rule; or

   c. PTE greater than 70 tpy of particulate matter with an aerodynamic diameter of 10 microns or less (PM10) in a serious PM10 nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #3331-13 for HPH, the following conclusions were made:

   a. The facility's allowable PTE is less than 100 tpy for any pollutant.

   b. The facility's PTE is less than 10 tpy for any individual HAP and less than 25 tpy for all HAPs.

   c. This source is not located in a serious PM10 nonattainment area.

   d. This facility is subject to current NSPS (40 CFR 60, Subpart A, Subpart Dc, Subpart KKK and Subpart JJJJ).

   e. This facility is subject to a current NESHAP (40 CFR 63, Subpart ZZZZ).

   f. This source is not a Title IV affected source.

   g. This source is not a solid waste combustion unit.

   h. This source is not an Environmental Protection Agency (EPA) designated Title V source.

i. As allowed by ARM 17.8.1204(3), DEQ may exempt a source from the requirement to obtain an air quality operating permit by establishing federally enforceable limitations which limit that source's potential to emit.

i. In applying for an exemption under this section, the owner or operator of the source shall certify to DEQ that the source's potential to emit does not require the source to obtain an air quality operating permit.

ii. Any source that obtains a federally enforceable limit on potential to emit shall annually certify that its actual emissions are less than those that would require the source to obtain an air quality operating permit.

3. ARM 17.8.1207 Certification of Truth, Accuracy, and Completeness.

HPH shall annually certify that its actual emissions are less than those that would require the source to obtain an air quality operating permit as required by ARM 17.8.1204 (3)(b). The annual certification shall comply with requirements of ARM 17.8.1207. The annual certification shall be submitted along with the annual emission inventory information.

HPH has taken federally enforceable permit limits to keep potential emissions below major source permitting thresholds. Therefore, the facility is not a major source and, thus a Title V operating permit is not required. However, if minor sources subject to NSPS are required to obtain a Title V Operating Permit, HPH will be required to obtain a Title V Operating Permit.

DEQ determined that the annual reporting requirements contained in the permit are sufficient to satisfy this requirement.

III. BACT Determination

A BACT determination is required for each new or modified source. HPH shall install on the new or modified source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was not required for the current permit action because the current permit action is considered an administrative permit action.

IV. Emission Inventory

Tons/year						
Source	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**VOC**	**CO**	**SO_X**
950 bhp Waukesha F3524 S5 Compressor Engine Unit 1	0.68	0.68	9.17	9.17	11.93	0.02
1025 bhp Waukesha 7042GU Compressor Engine Unit 2	0.68	0.68	9.90	9.90	12.87	0.02
950 bhp Waukesha F3524 S5 Compressor Engine Unit 3	0.68	0.68	9.17	9.17	11.93	0.02

Tons/year						
Source	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**VOC**	**CO**	**SO_X**
185 bhp Waukesha 1197GU Compressor Engine Unit 4	0.13	0.13	1.79	1.79	3.57	0.00
550 bhp Caterpillar G398 TA LCR Compressor Engine Unit 5	0.37	0.37	5.31	5.31	5.31	0.01
185 bhp Waukesha 1197 Compressor Engine Unit 6	0.13	0.13	1.79	1.79	3.57	0.00
840 bhp Waukesha F3524 GSI Compressor Engine Unit 7	0.65	0.65	8.11	5.68	8.11	0.02
265 bhp Caterpillar G342 TA LCR Compressor Engine Unit 8	0.19	0.19	2.56	1.28	2.56	0.01
44.82-MMBtu/hr Natural Gas-fired Hot Oil Heater (1)	1.46	1.46	21.99	1.06	8.83	0.12
Dehydration S-con Unit -- Still Vent (18 MMSCF/d)	---	---	---	3.08	---	---
Dehydration Russell Unit -- Still Vent (8 MMSCF/d)	---	---	---	1.25	---	---
Fugitive Leaks (components, including fractionation unit)	---	---	---	22.68	---	---
Truck Loading (4775 bbl/day) – *fugitive* (controlled by submerged filling and VRU)	---	---	---	79.80	---	---
400-bbl Condensate Storage Tank #1 --Working & Breathing Loss --Flashing Loss	 --- ---	 --- ---	 --- ---	 0.98 1.26	 --- ---	 --- ---
1000-Gallon Diesel Storage Tank				0.07		
1135 bhp Cummins VTA28-G7 Emergency/Backup Generator	0.19	0.19	7.95	0.31	3.07	0.08
Flare (RESTRICTED to 110 MMSCF/yr) Flare Pilot (0.5MMBtu/hr)	0.57 0.02	0.57 0.02	5.24 0.21	10.78 0.01	23.9 0.18	0.05 0.001
Total	**5.75**	**5.75**	**83.18**	**165.35**	**95.79**	**0.35**
Total Title V (non-Fugitive)	**5.75**	**5.75**	**83.18**	**62.88**	**95.79**	**0.35**

(1) Emission inventory summary is based on a 1400 MMBtu/MMSCF fuel source and assumes PM_{10}/$PM_{2.5}$ emission factors are same as PM total.

Units 1 & 3: 950 bhp Compressor Engines (2 Engines)

Unit: **950 bhp Waukesha F3524 S5 Compressor Engine Unit 3**

Unit Rating:	950	hp
Engine type:	Rich burn	
Fuel Consumption[1]:	8.0	MMBtu/hr
Operating Schedule:	8,760	hr/yr
Natural gas HHV:	1,400	btu/scf
Estimated Fuel Use:	50.06	mmscf/yr

[1] Fuel consumption rate based on current permit.

Criteria Pollutant Emission Calculations

Control Device(s) NSCR AFR

Pollutant	Emission Factors[1, 2] Value	Units	Emission Factor Reference	Emissions (ton/yr)	Emissions (lb/hr)
NO_X [1]	1.00	g/hp-hr	Current Permit Limit	9.17	2.09
CO [1]	1.30	g/hp-hr	Current Permit Limit	11.93	2.72
VOC [1]	1.00	g/hp-hr	Current Permit Limit	9.17	2.09
PM_{10} / $PM_{2.5}$ Filterable[2]	9.50E-03	lb/MMBtu	EPA's AP-42 Chapter 3.2, Table 3.2-3 (7/00)	0.33	0.076
PM - Condensable	9.91E-03	lb/MMBtu	EPA's AP-42 Chapter 3.2, Table 3.2-3 (7/00)	0.35	0.079
PM Total[3]	1.94E-02	lb/MMBtu	EPA's AP-42 Chapter 3.2, Table 3.2-3 (7/00)	0.68	0.155
SO_2 [2]	5.88E-04	lb/MMBtu	EPA's AP-42 Chapter 3.2, Table 3.2-3 (7/00)	0.02	0.005

[1] NOx, CO, and VOC factors per MAQP 3331-12, except for CO. Hiland Partners is requested a revised, enforceable CO emission factor.
[2] PM and SO_2 Uncontrolled emission factors from 4-stroke, rich-burn (4SRB) engines from EPA's AP-42 Chapter 3.2, Table 3.2-3 (7/00)

Unit 2: 1,025 bhp Compressor Engine (1 Engine)

Brake Horsepower: 1,025 bhp
Hours of operation: 8760 hr/yr

<u>PM_{10}/$PM_{2.5}$ Emissions (filterable & condensable)</u>

Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 8.0MMBtu/hr (Maximum Design)
Calculations: 8.0 MMBtu/hr * 1.94E-02 lb/MMBtu = 0.1552 lb/hr
0.1552 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.68 ton/yr

NO_X Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 1025 bhp * 0.002205 lb/gram = 2.260 lb/hr
2.260 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 9.90 ton/yr

VOC Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 1025 bhp * 0.002205 lb/gram = 2.260 lb/hr
2.260 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 9.90 ton/yr

CO Emissions
Emission factor: 1.30 gram/bhp-hr (New Permit Limit)
Calculations: 1.30 gram/bhp-hr * 1025 bhp * 0.002205 lb/gram = 2.938 lb/hr
2.732 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 12.87 ton/yr

SO_2 Emission
Emission factor: 5.88E-04 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7.1 MMBtu/hr (Maximum Design)
Calculations: 7.1 MMBtu/hr * 5.88E-04 lb/MMBtu = 0.004 lb/hr
0.004 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.02 ton/yr

Units 4 and 6: 185 bhp Compressor Engines (2 Engines)
Brake Horsepower: 185 bhp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 1.48 MMBtu/hr (Maximum Design)
Calculations: 1.48 MMBtu/hr * 1.94E-02 lb/MMBtu = 0.029 lb/hr
0.029 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.13 ton/yr

NO_X Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 185 bhp * 0.002205 lb/gram = 0.41 lb/hr
0.41 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.79 ton/yr

VOC Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit
Limit) Calculations: 1.00 gram/bhp-hr * 185 bhp * 0.002205 lb/gram = 0.41 lb/hr
0.41 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.79 ton/yr

CO Emissions
Emission factor: 2.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 2.00 gram/bhp-hr * 185 bhp * 0.002205 lb/gram = 0.82 lb/hr
0.82 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 3.57 ton/yr

SO_2 Emission
Emission factor: 5.88E-04 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 1.48 MMBtu/hr (Maximum Design)
Calculations: 1.48 MMBtu/hr * 5.88E-04 lb/MMBtu = 0.0009 lb/hr
0.0009 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.004 ton/yr

Unit 5: 550 bhp Compressor Engine
Brake Horsepower: 550 bhp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 4.40 MMBtu/hr (Maximum Design)
Calculations: 4.40 MMBtu/hr * 1.94E-02 lb/MMBtu = 0.085 lb/hr
0.085 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.374 ton/yr

NO_X Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calc4ulations: 1.00 gram/bhp-hr * 550 bhp * 0.002205 lb/gram = 1.21 lb/hr
1.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 5.31 ton/yr

VOC Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 550 bhp * 0.002205 lb/gram = 1.21 lb/hr
1.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 5.31 ton/yr

CO Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 550 bhp * 0.002205 lb/gram = 1.21 lb/hr
1.21 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 5.31 ton/yr

SO_2 Emission
Emission factor: 5.88E-04 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 4.40 MMBtu/hr (Maximum Design)
Calculations: 4.40 MMBtu/hr * 5.88E-04 lb/MMBtu = 0.0026 lb/hr
0.0026 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.0113 ton/yr

Unit 7: 840 bhp Compressor Engine
Brake Horsepower: 840 bhp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7.69 MMBtu/hr (Maximum Design)
Calculations: 7.69 MMBtu/hr * 1.94E-02 lb/MMBtu = 0.149 lb/hr
0.149 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.65 ton/yr

NO_X Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 840 bhp * 0.002205 lb/gram = 1.85 lb/hr
1.85 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 8.11 ton/yr

VOC Emissions
Emission factor: 0.7 gram/bhp-hr (Subpart JJJJ / Permit Limit)
Calculations: 0.7 gram/bhp-hr * 840 bhp * 0.002205 lb/gram = 1.30 lb/hr
1.30 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 5.67 ton/yr

CO Emissions
Emission factor: 1.00 gram/bhp-hr (BACT Determination / Permit Limit)
Calculations: 1.00 gram/bhp-hr * 840 bhp * 0.002205 lb/gram = 1.85 lb/hr
1.85 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 8.11 ton/yr

SO_2 Emission

Emission factor:	5.88E-04 lb/MMBtu	(AP-42, Table 3.2-3, 7/00)
Fuel 4Consumption:	7.69 MMBtu/hr	(Maximum Design)
Calculations:	7.69 MMBtu/hr * 5.88E-04 lb/MMBtu = 0.0045 lb/hr	
	0.0045 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.02 ton/yr	

Unit 8: 265 bhp Compressor Engine

Brake Horsepower: 265 bhp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)

Emission Factor:	1.94E-02 lb/MMBtu	(AP-42, Table 3.2-3, 7/00)
Fuel Consumption:	2.2 MMBtu/hr	(Maximum Design)
Calculations:	2.2 MMBtu/hr * 1.94E-02 lb/MMBtu = 0.043 lb/hr	
	0.043 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.19 ton/yr	

NO_X Emissions

Emission factor:	1.00 gram/bhp-hr	(BACT Determination / Manufacturer)
Calculations:	1.00 gram/bhp-hr * 265 bhp * 0.002205 lb/gram = 0.58 lb/hr	
	0.58 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2.56 ton/yr	

VOC Emissions

Emission factor:	0.5 gram/bhp-hr	(BACT Determination / Manufacturer)
Calculations:	0.5 gram/bhp-hr * 265 bhp * 0.002205 lb/gram = 0.29 lb/hr	
	0.29 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.28 ton/yr	

CO Emissions

Emission factor:	1.0 gram/bhp-hr	(BACT Determination / Manufacturer)
Calculations:	1.0 gram/bhp-hr * 265 bhp * 0.002205 lb/gram = 0.58 lb/hr	
	0.58 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2.56 ton/yr	

SO_2 Emission

Emission factor:	5.88E-04 lb/MMBtu	(AP-42, Table 3.2-3, 7/00)
Fuel Consumption:	2.2 MMBtu/hr	(Maximum Design)
Calculations:	2.2 MMBtu/hr * 5.88E-04 lb/MMBtu = 0.001 lb/hr	
	0.001 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.01 ton/yr	

44.82 MMBtu/hr Hot Oil Heater H-1

Hours of operation:	8760 hr/yr	
Fuel Heating Value:	1400 MMBtu/MMSCF	(Company Information)
Fuel Consumption:	44.82 MMBtu/hr	(Maximum Design)

$PM_{10}/PM_{2.5}$ Emissions (front and back half)

Emission Factor:	10.43 lb/MMSCF	(AP-42, Table 1.4-2, 7/98)
Calculations:	10.43 lb/MMSCF * 44.82 MMBtu/hr / 1400 MMBtu/MMSCF = 0.33 lb/hr	
	0.33 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.46 ton/yr	

NO_X Emissions

Emission factor:	0.112 lb/MMBtu	(BACT Limit / Permit Limit)
Calculations:	0.112 lb/MMBtu * 44.82 MMBtu/hr = 5.02 lb/hr	
	5.02 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 21.99 ton/yr	

VOC Emissions

Emission Factor:	7.6 lb/MMSCF	(AP-42, Table 1.4-2, 7/98)
Calculations:	7.6 lb/MMSCF * 44.82 MMBtu/hr / 1400 MMBtu/MMSCF = 0.24 lb/hr	

0.24 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.06 ton/yr

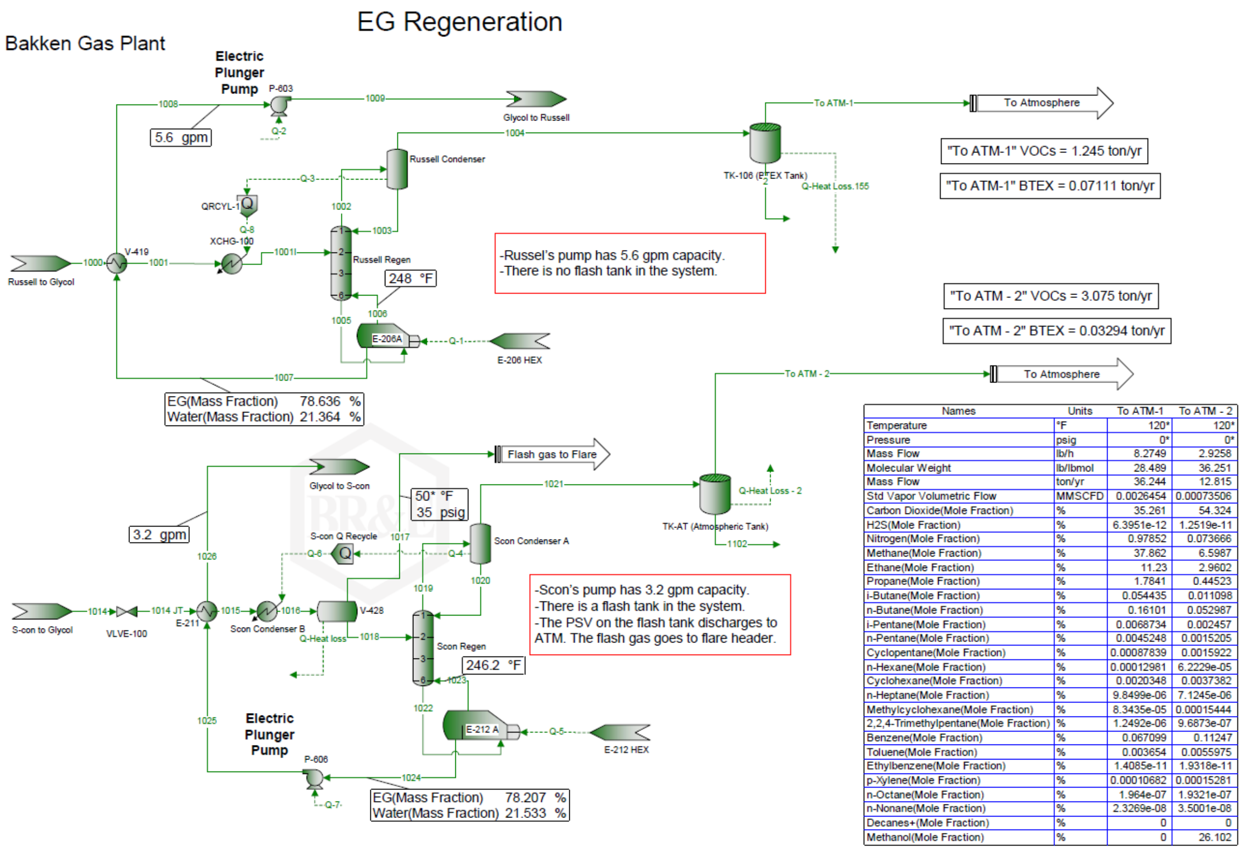
<u>CO Emissions</u>
Emission factor: 0.045 lb/MMBtu (BACT Limit / Permit Limit)
Calculations: 0.045 lb/MMBtu * 44.82 MMBtu/hr = 2.02 lb/hr
2.02 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 8.83 ton/yr

<u>SO_2 Emissions</u>
Emission Factor: 0.82 lb/MMSCF (AP-42, Table 1.4-2, 7/98)
Calculations: 0.82 lb/MMSCF * 44.82 MMBtu/hr / 1400 MMBtu/MMSCF = 0.03 lb/hr
0.03 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.12 ton/yr

Dehydration S-con and Russell Unit (18 MMSCFD and 8 MMSCFD) ***<u>Dehydrator Still Vent</u>***
Hours of operation: 8760 hr/yr

<u>VOC Emissions</u>

S-con Unit: 3.08 ton/yr, Russell Unit: 1.25 ton/yr (based on ProMax simulations, process flow diagram)



Names	Units	To ATM-1	To ATM - 2
Temperature	°F	120*	120*
Pressure	psig	0*	0*
Mass Flow	lb/h	8.2749	2.9258
Molecular Weight	lb/lbmol	28.489	36.251
Mass Flow	ton/yr	36.244	12.815
Std Vapor Volumetric Flow	MMSCFD	0.0026454	0.00073506
Carbon Dioxide(Mole Fraction)	%	35.261	54.324
H2S(Mole Fraction)	%	6.3951e-12	1.2519e-11
Nitrogen(Mole Fraction)	%	0.97852	0.073666
Methane(Mole Fraction)	%	37.862	6.5987
Ethane(Mole Fraction)	%	11.23	2.9602
Propane(Mole Fraction)	%	1.7841	0.44523
i-Butane(Mole Fraction)	%	0.054435	0.011098
n-Butane(Mole Fraction)	%	0.16101	0.052987
i-Pentane(Mole Fraction)	%	0.0068734	0.002457
n-Pentane(Mole Fraction)	%	0.0045248	0.0015205
Cyclopentane(Mole Fraction)	%	0.00087839	0.0015922
n-Hexane(Mole Fraction)	%	0.00012981	6.2229e-05
Cyclohexane(Mole Fraction)	%	0.0020348	0.0037382
n-Heptane(Mole Fraction)	%	9.8499e-06	7.1245e-06
Methylcyclohexane(Mole Fraction)	%	8.3435e-05	0.00015444
2,2,4-Trimethylpentane(Mole Fraction)	%	1.2492e-06	9.6873e-07
Benzene(Mole Fraction)	%	0.067099	0.11247
Toluene(Mole Fraction)	%	0.003654	0.0055975
Ethylbenzene(Mole Fraction)	%	1.4085e-11	1.9318e-11
p-Xylene(Mole Fraction)	%	0.00010682	0.00015281
n-Octane(Mole Fraction)	%	1.964e-07	1.9321e-07
n-Nonane(Mole Fraction)	%	2.3269e-08	3.5001e-08
Decanes+(Mole Fraction)	%	0	0
Methanol(Mole Fraction)	%	0	26.102

Fugitive Emissions

Component Fugitive Leak Emissions with Leak Detection and Repair Program

Equipment Type	Emission Factor [1] (lb/hr/source)	Facility Actual Count	Estimated, Buffered Count[2]	VOC[3] (%)	Uncontrolled VOC Emission Rate (lb/hr)	Uncontrolled VOC Emission Rate (tpy)	Control Efficiencies for LDAR [4]	Controlled VOC Emission Rate (lb/hr)	Controlled VOC Emission Rate (tpy)
Valves - Gas/Vapor	0.00992	768	922	43.25%	3.96	17.33	75%	0.99	4.33
Valves - Light Oil	0.00550	1140	1368	100.00%	7.52	32.96	75%	1.88	8.24
Relief Valves - Gas/Vapor	0.01940	74	89	43.25%	0.75	3.27	75%	0.19	0.82
Relief Valves - Light Oil	0.01650	38	46	100.00%	0.76	3.32	75%	0.19	0.83
Flanges - Gas/Vapor[5]	0.00086	474	569	43.25%	0.21	0.93	30%	0.15	0.65
Flanges - Light Oil[5]	0.000243	740	888	100.00%	0.22	0.95	30%	0.15	0.66
Connectors - Gas/Vapor[5]	0.00044	1897	2277	43.25%	0.43	1.90	30%	0.30	1.33
Connectors - Light Oil[5]	0.000463	2958	3550	100.00%	1.64	7.20	30%	1.15	5.04
Open Ended Lines - Gas/Vapor	0.00441	0	0	43.25%	0	0	0%	0	0
Open Ended Lines - Light Oil	0.00309	0	0	100.00%	0	0	0%	0	0
Other - Gas/Vapor	0.01940	0	0	43.25%	0	0	0%	0	0
Other - Light Oil	0.01650	0	0	100.00%	0	0	0%	0	0
Pump Seals - Light Oil	0.02866	18	22	100.00%	0.63	2.76	75%	0.16	0.69
Compressor Seals - Gas/Vapor	0.01940	8	10	43.25%	0.08	0.37	75%	0.02	0.09
Total		8115	9741		16.20	70.97		5.18	22.68

1. TCEQ Air Permit Technical Guidance for Chemical Sources: Fugitive Guidance, Table II: Facility/Compound Specific Fugitive Emission Factors, Oil and Gas Production Operation. (TCEQ-APDG 6422v2, Revised 06/18) "Other" includes compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents.

2. Actual component counts factored by Component Count Buffer as a conservative estimate. --> 20% Component Count Buffer

3. 43.25 % VOC fraction for gas stream based on current permit. Liquid fraction is assumed to be 100 % VOC.
4. Control Efficiency for LDAR from TCEQ Air Permit Technical Guidance for Chemical Sources: Fugitive Guidance, Tables III and V, LDAR Program 28M (TCEQ-APDG 6422v2, Revised 06/18): 10,000 ppm leak definition with quarterly monitoring.

5. Assume 80 % of connector count from LeaksDas are flanges and 20 % are connectors.

Truck Loading: Submerged Fill: (Dedicated Normal Service) with VRU Control

Equipment Parameters

ID Number	Throughput[1] gal/day	Throughput[1] bbl/day	Throughput[1] bbl/year
LOAD-1	200,550	4,775	1,742,875

AP-42 Section 5.2-4, Equation 1 Inputs

Loading Losses (LL) = 12.46*S*P*M/T

S	P[4] psia	M[4] lb/lb-mole	T[4] °R	LL lb/Mgal
0.60	8.31	62.00	530.00	7.27

Controlled loading operations efficiency factor (assume 70% to 90% depending on trucks)

$E_{factor} = (1-^{eff}/100)$ Equation (1) in Section 5.2.2)

Collection Efficiency[2,3] 70%

LLcor 2.1803 lb/Mgal

Emissions

VOC tons/day	VOC lb/day
0.22	437.25

VOC tons/year	VOC lb/yr
79.80	159596.34

Emissions Factor	Emission Factor Basis
VOC	
lb/bbl	AP-42 Section 5.2, Table 5.2-4 (7/2008)
0.0916	

1. Based on trucked in liquids throughput and outgoing throughput and a safety factor.
2. An efficiency factor of 70 % was utilized in the calculations
3. Truck loading vapors controlled by submerged filling and vapors routed back to pressurized vessles or to flare.
4. The factors match the current permit.

400 bbl Condensate Storage Tank (1 Tank)

4 Hours of operation: 8760 hr/yr

<u>VOC Emissions</u> *Working & Breathing*

Fixed-Roof Tank Emissions

Based on AP-42, November 2019, Section 7.1.3.1.

Tank Identification	Condensate Tank 1
Actual Location	*Bakken Gas Plant*
Location for Calculation Purposes	Williston, North Dakota
Type of Substance	Petroleum Distillate
Contents of Tank	Gasoline (RVP 13.5)
Tank/Roof Type	Cone
Aboveground/Underground?	Aboveground
Diameter, ft	12.0
Shell Height or Length, ft	20.0
Nominal Capacity, gal	*16,800*
Throughput, gallons/yr	43,000
Tank Paint Color	Tan
Tank Paint Condition	Average
Effective Diameter, ft (Eq. 1-14)	12.0
Geometric Capacity, gal	16,920
Maximum Liquid Height, ft	19.0
Minimum Liquid Height, ft	1.0
Average Liquid Height, ft	10.0
Cone Tank Roof Slope, ft/ft	0.0625
Dome Tank Roof Radius, ft	N/A
Dome Tank Roof Height, ft	N/A
Roof Outage, ft (Eq. 1-17 & 1-19)	0.125
Vapor Space Outage, ft (Eq. 1-16)	10.13
Vapor Space Volume, ft^3 (Eq. 1-3)	1145
Avg. Daily Minimum Ambient Temperature, F	29.04
Avg. Daily Maximum Ambient Temperature, F	53.82
Daily Total Solar Insolation Factor, Btu/ft^2/day	1218
Daily Average Ambient Temperature, F (Eq. 1-30)	41.4
Tank Paint Solar Absorbance, dimensionless	0.49
Daily Vapor Temperature Range, R (Eq. 1-7)	29.3
Daily Average Liquid Surf. Temperature, F (Eq. 1-28)	45.5
Daily Minimum Liquid Surf. Temp., F (Fig. 7.1-17)	38.2
Daily Maximum Liquid Surf. Temp., F (Fig. 7.1-17)	52.8
Daily Average Vapor Temperature, F (Eq. 1-33)	47.3
Liquid Bulk Temperature, F (Eq. 1-31)	43.2
Vapor Molecular Weight, lb/lbmol	62.0
Antoine's Coeficient A	N/A
Antoine's Coeficient B	N/A
Antoine's Coeficient C	N/A
TVP at Daily Avg. Liquid Surf. Temp., psia	5.4924
TVP at Daily Min. Liquid Surf. Temp., psia	4.7464
TVP at Daily Max. Liquid Surf. Temp., psia	6.3292
Vapor Pressure Calculation Method	AP-42 Figure 7.1-14b: RVP=13.5 ASTM Slope=3
Vapor Density, lb/ft^3 (Eq. 1-22)	0.062589
Daily Vapor Pressure Range, psi (Eq. 1-9)	1.583
Breather Vent Pressure Setting, psig	0.0300
Breather Vent Vacuum Setting, psig	-0.0300
Breather Vent Pressure Setting Range, psig (Eq. 1-10)	0.0600
Vent Setting Correction Factor (Eq. 1-41)	1.0000
Ambient Pressure, psia	13.8
Vapor Space Expansion Factor (Eq. 1-5)	0.2408
Vented Vapor Saturation Factor (Eq. 1-21)	0.2533
Annual Turnovers (Eq. 1-37)	2.82
Turnover Factor	1.00
Working Loss Product Factor	1.00
Standing Storage Loss, lb/yr (Eq. 1-2)	1596.14
Working Loss, lb/yr (Eq. 1-35)	359.74
Total Losses, lb/yr	1955.88

Working and Breathing Loss = 1955.88 (lb/yr) / 2000 (lb/ton) = 0.98 ton/yr

VOC Emissions *Flashing Loss:*

Company Name: **Hiland Partners Holdings LLC**　　Permit No.: **#3331-12**
Facility Name: **Bakken Plant - Condensat Tank 1**　　Date: **April 2023**

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios)

INPUTS:

			Earlier Application
Stock Tank API Gravity	57	**API**	**57**
Separator Pressure (psig)	200	**P**	**200**
Separator Temperature (°F)	80	**Ti**	**80**
Separator Gas Gravity at Initial Condition	0.6825	**SGi**	**0.68**
Stock Tank Barrels of Oil per day (BOPD)	2.80	**Q**	**15**
Stock Tank Gas Molecular Weight	19.82	**MW**	**19.82**
Fraction VOC (C3+) of Stock Tank Gas	0.5	**VOC**	**0.5**
Atmospheric Pressure (psia)	14.7	**Patm**	**14.7**

Reviewed 2014 to 2023 throughput
Max throughput in 2020 = 28350 gallons
Max throughput in 2020 * 1.50 = 42525 gallons
For PTE, assumed 43,000 gallons

43000 gallons/yr for PTE
1023.81 bbl/yr
2.80 bbl/day

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.73

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°API →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	95.55	scf/bbl	*for P + Patm =*	*214.7*

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lbs

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	2.5	TPY

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	1.26	TPY	*from "FLASHING" of oil from separator to tank press*

1000 Gallon Diesel Storage Tank (1 Tank)

Hours of operation: 8760 hr/yr

Fixed-Roof Tank Emissions

Based on AP-42, November 2019, Section 7.1.3.1

Tank Identification	Diesel Tank	
Actual Location	*Bakken Gas Plant*	
Location for Calculation Purposes	Williston, North Dakota	
Type of Substance	Petroleum Distillate	
Contents of Tank	Gasoline (RVP 6)	**Gasoline (RVP 6) was chosen as a conservative measure for calculations.**
Tank/Roof Type	Cone	
Aboveground/Underground?	Aboveground	
Diameter, ft	4.0	
Shell Height or Length, ft	11.0	
Nominal Capacity, gal	*1,000*	***Current permit notes a 500 gallon tank but correct capacity is 1000 gallons.***
Throughput, gallons/yr	29,250	**20250 gallons = (58.50 gallons/hr * 500 hr limit)**
Tank Paint Color	White	
Tank Paint Condition	Average	
Effective Diameter, ft (Eq. 1-14)	4.0	
Geometric Capacity, gal	1,034	
Maximum Liquid Height, ft	10.0	
Minimum Liquid Height, ft	1.0	
Average Liquid Height, ft	5.5	
Cone Tank Roof Slope, ft/ft	0.0625	
Dome Tank Roof Radius, ft	N/A	
Dome Tank Roof Height, ft	N/A	
Roof Outage, ft (Eq. 1-17 & 1-19)	0.042	
Vapor Space Outage, ft (Eq. 1-16)	5.54	
Vapor Space Volume, ft^3 (Eq. 1-3)	70	
Avg. Daily Minimum Ambient Temperature, F	29.04	
Avg. Daily Maximum Ambient Temperature, F	53.82	
Daily Total Solar Insolation Factor, Btu/ft^2/day	1218	
Daily Average Ambient Temperature, F (Eq. 1-30)	41.4	
Tank Paint Solar Absorbance, dimensionless	0.25	
Daily Vapor Temperature Range, R (Eq. 1-7)	23.4	
Daily Average Liquid Surf. Temperature, F (Eq. 1-28)	43.5	
Daily Minimum Liquid Surf. Temp., F (Fig. 7.1-17)	37.6	
Daily Maximum Liquid Surf. Temp., F (Fig. 7.1-17)	49.4	
Daily Average Vapor Temperature, F (Eq. 1-33)	44.4	
Liquid Bulk Temperature, F (Eq. 1-31)	42.3	
Vapor Molecular Weight, lb/lbmol	69.0	
Antoine's Coefficient A	N/A	
Antoine's Coefficient B	N/A	
Antoine's Coefficient C	N/A	
TVP at Daily Avg. Liquid Surf. Temp., psia	2.0582	
TVP at Daily Min. Liquid Surf. Temp., psia	1.8047	
TVP at Daily Max. Liquid Surf. Temp., psia	2.3403	
Vapor Pressure Calculation Method	AP-42 Figure 7.1-14b: RVP=6 ASTM Slope=3	
Vapor Density, lb/ft^3 (Eq. 1-22)	0.026253	
Daily Vapor Pressure Range, psi (Eq. 1-9)	0.536	
Breather Vent Pressure Setting, psig	0.0300	
Breather Vent Vacuum Setting, psig	-0.0300	
Breather Vent Pressure Setting Range, psig (Eq. 1-10)	0.0600	
Vent Setting Correction Factor (Eq. 1-41)	1.0000	
Ambient Pressure, psia	13.8	
Vapor Space Expansion Factor (Eq. 1-5)	0.0870	
Vented Vapor Saturation Factor (Eq. 1-21)	0.6232	
Annual Turnovers (Eq. 1-37)	34.57	
Turnover Factor	1.00	
Working Loss Product Factor	1.00	
Standing Storage Loss, lb/yr (Eq. 1-2)	36.18	
Working Loss, lb/yr (Eq. 1-35)	102.64	
Total Losses, lb/yr	138.83	**0.069 tons per year**

[1] Blue text represents default options from AP-42

Standing Loss	36.18	lb/year
	0.018	tpy
Working Loss	102.64	lb/year
	0.051	tpy
Total Loss	0.069	tpy

1135 bhp Emergency/Backup Diesel Generator (1 Generator)

Brake Horsepower: 1135 bhp
Max. Fuel Combustion Rate: 58.50 gal/hr (Permit Application)
Hours of operation: 500 hr/yr (Permit Limit)

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission factor: 0.30 gram/bhp-hr (BACT Determination / Manufacturer's Data / Permit Limit)
Calculations: 0.30 gram/bhp-hr * 1135 bhp * 0.002205 lb/gram = 0.75 lb/hr
0.75 lb/hr * 500 hr/yr * 0.0005 ton/lb = 0.19 ton/yr

NO_X Emissions
Emission factor: 12.7 gram/bhp-hr (BACT Determination / Manufacturer's Data / Permit Limit)
Calculations: 12.7 gram/bhp-hr * 1135 bhp * 0.002205 lb/gram = 31.78 lb/hr
31.78 lb/hr * 500 hr/yr * 0.0005 ton/lb = 7.95 ton/yr

VOC Emissions
Emission factor: 0.5 gram/bhp-hr (BACT Determination / Manufacturer's Data / Permit Limit)
Calculations: 0.5 gram/bhp-hr * 1135 bhp * 0.002205 lb/gram = 1.25 lb/hr
1.25 lb/hr * 500 hr/yr * 0.0005 ton/lb = 0.31 ton/yr

CO Emissions
Emission factor: 4.9 gram/bhp-hour (BACT Determination / Manufacturer's Data / Permit Limit)
Calculations: 4.9 gram/bhp-hour * 1135 bhp * 0.002205 lb/gram = 12.26 lb/hr
12.26 lb/hr * 500 hr/yr * 0.0005 ton/lb = 3.07 ton/yr

SO_2 Emission
Emission factor: 0.13 gram/bhp-hour (BACT Determination / Manufacturer's Data / Permit Limit)
Calculations: 0.13 gram/bhp-hour * 1135 bhp * 0.002205 lb/gram = 0.33 lb/hr
0.33 lb/hr * 500 hr/yr * 0.0005 ton/lb = 0.08 ton/yr

Flare

Pilot
Pilot: 0.5 MMBTU/hr (Maximum fuel combustion rate – Permit Application)
Fuel Heating Value: 1400 MMBtu/MMSCF (Company Information)
AP-42 Heating Value: 1020 MMBtu/MMSCF
Heating Value Ratio: 1.373
Hours of Operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions
Emission Factor: 7.6 lb/MMSCF (AP-42, Table 1.4-2, 7/98)
Adjusted Emission Factor: 10.4 lb/MMSCF (Heating Value Ratio)
Calculations: 10.4 lb/MMSCF * 0.50 MMBtu/hr / 1400 MMBtu/MMSCF = 0.00371 lb/hr
0.00371 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.0163 ton/yr

NO_X Emissions
Emission factor: 100 lb/MMSCF (AP-42, Table 1.4-1, 7/98)
Adjusted Emission Factor: 137 lb/MMSCF (Heating Value Ratio)
Calculations: 137 lb/MMSCF * 0.50 MMBtu/hr / 1400 MMBtu/MMSCF = 0.0489 lb/hr
0.0489 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.214 ton/yr

VOC Emissions
Emission Factor: 5.5 lb/MMSCF (AP-42, Table 1.4-2, 7/98)
Adjusted Emission Factor: 7.55 lb/MMSCF (Heating Value Ratio)

Calculations: 7.55 lb/MMSCF * 0.50 MMBtu/hr / 1400 MMBtu/MMSCF = 0.00270 lb/hr
0.00270 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.0118 ton/yr

CO Emissions
Emission factor: 84 lb/MMSCF (AP-42, Table 1.4-1, 7/98)
Adjusted Emission Factor: 115 lb/MMSCF (Heating Value Ratio)
Calculations: 115 lb/MMSCF * 0.50 MMBtu/hr / 1400 MMBtu/MMSCF = 0.0411 lb/hr
0.0411 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.180 ton/yr

SO_2 Emissions
Emission Factor: 0.6 lb/MMSCF (AP-42, Table 1.4-2, 7/98)
Adjusted Emission Factor: 0.824 lb/MMSCF (Heating Value Ratio)
Calculations: 0.824 lb/MMSCF * 0.50 MMBtu/hr / 1400 MMBtu/MMSCF = 0.000294 lb/hr
0.000294 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.00129 ton/yr

Gas Combustion
Plant Gas: 110 MMSCF/year – RESTRICTION
Fuel Heating Value: 1400 MMBtu/MMSCF (Company Information)
AP-42 Heating Value: 1020 MMBtu/MMSCF
Heating Value Ratio: 1.373

$PM_{10}/PM_{2.5}$ Emissions
Emission Factor: 7.6 lb/MMSCF (AP-42, Table 1.4-2, 7/98)
Adjusted Emission Factor: 10.4 lb/MMSCF (Heating Value Ratio)
Calculations: 10.4 lb/MMSCF * 110 MMSCF/yr / 2000 lb/ton = 0.572 ton/yr

NO_X Emissions
Emission factor: 0.068 lb/MMBtu (AP-42, Section 13.5, Table 13.5-1, 2/18)
Calculations: 0.068 lb/MMBtu * 1400 MMBtu/MMSCF * 110 MMSCF/yr / 2000 lb/ton = 5.24 ton/yr

VOC Emissions - as total hydrocarbons (HC)
Emission Factor: 0.14 lb HC/MMBtu (AP-42, Section 13.5, Table 13.5-1, 2/18)
Calculations: 0.14 lb HC/MMBtu * 1400 MMBtu/MMSCF * 110 MMSCF/yr/2000 lb/ton = 10.78 ton/yr

CO Emissions
Emission factor: 0.31 lb/MMBtu (AP-42, Section 13.5, Table 13.5-1, 2/18)
Calculations: 0.31 lb/MMBtu * 1400 MMBtu/MMSCF * 110 MMSCF/yr / 2000 lb/ton = 23.9 ton/yr

SO_2 Emissions
Emission Factor: 0.6 lb/MMSCF (AP-42, Table 1.4-2, 7/98)
Adjusted Emission Factor: 0.824 lb/MMSCF (Heating Value Ratio)
Calculations: 0.824 lb/MMSCF * 110 MMSCF/yr / 2000 lb/ton = 0.0453 ton/yr

V. Existing Air Quality

The facility is located in the NE ¼ of the NW ¼ of Section 3, Township 23 North, Range 58 East in Richland County, Montana. The air quality of this area is classified as either better than National Standards or unclassifiable/attainment for the National Ambient Air Quality Standards (NAAQS) for criteria pollutants.

VI. Air Quality Impacts

The DEQ determined that there will be no impacts from this permitting action because this permitting action is considered an administrative action. Therefore, the DEQ believes this action will not cause or contribute to a violation of any ambient air quality standard.

VII. Ambient Air Impact Analysis

Based on the information provided and the conditions established in MAQP #3331-14, the DEQ determined that there will be no impacts from this permitting action.

VIII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, DEQ conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, DEQ determined there are no taking or damaging implications associated with this permit action.

IX. Environmental Assessment

This permitting action will not result in an increase of emissions from the facility and is considered an administrative action; therefore, an Environmental Assessment is not required.

Analysis Prepared By: John P. Proulx
Date: May 22, 2025