DEQ
Montana Department
of Environmental Quality

PRELIMINARY DETERMINATION
ON PERMIT APPLICATION

November 16, 2020

Basin Electric Power Cooperative
Culbertson Generation Station
Culbertson, MT

Proposed Action: The Department of Environmental Quality (Department) proposes to issue a Modification, with conditions, to the above-named permittee. The permit will be assigned #4256-02.

Proposed Conditions: See attached.

Public Comment: Any member of the public desiring to comment must submit such comments in writing to the Air Quality Bureau (Bureau) of the Department at the address in the footer of this cover letter. Comments may address the Department's analysis and determination, or the information submitted in the application. In order to be considered, comments on this Preliminary Determination are due by December 3, 2020. Copies of the application and the Department's analysis may be inspected at the Bureau's office in Helena. For more information, you may contact the Department.

Departmental Action: The Department intends to make a decision on the application after expiration of the Public Comment period described above. A copy of the decision may be obtained by contacting the Bureau's office in Helena. The permit shall become final on the date stated in the Department's Decision on this permit, unless an appeal is filed with the Board of Environmental Review (Board).

Procedures for Appeal: The permittee may request a hearing before the Board. Any appeal must be filed before the final date stated above. The request for hearing shall contain an affidavit setting forth the grounds for the request. Any hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for hearing in triplicate to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, Montana 59620.

For the Department,

Julie A. Merkel

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JM:TMB
Enclosure

MONTANA AIR QUALITY PERMIT

Issued To: Basin Electric Power Cooperative 1717 East Interstate Ave. Bismarck, ND 58503-0564	Permit: #4256-02 Application Complete: 10/16/2020 Preliminary Determination Issued: 11/16/2020 Department's Decision Issued: Permit Final:

An air quality permit, with conditions, is hereby granted to Basin Electric Power Cooperative – Culbertson Generation Station (Basin Electric), 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. Permitted Equipment

Basin Electric operates a stationary electric power generation station to provide power to the electric power grid during daily and seasonal periods of peak demand. This station consists of a single, simple-cycle, combustion turbine generator (General Electric Model LMS100) powered by natural gas with a nominal power output capacity of 100 megawatts (MW). A complete list of permitted equipment is contained in Section I.A of the permit analysis.

B. Current Permit Action

On October 16, 2020, the Montana Department of Environmental Quality (Department) received a complete Montana Air Quality Permit (MAQP) application from Basin Electric Power Cooperative (Basin Electric) requesting a modification to MAQP #4256-01. Basin Electric requested that the annual operating capacity be changed to use a fuel flow rate rather than hours of operation for the limitation. The MAQP was also updated to reflect the current language used by the Department.

SECTION II: Conditions and Limitations

A. Emission Limitations

1. Emissions of nitrogen oxides (NOx) from the turbine generator shall not exceed 78.50 pounds per hour (lb/hr) based on a 1-hour average, effective during all periods of operation, including startup and shutdown (ARM 17.8.752).

2. Emissions of NOx from the turbine generator shall not exceed 25 parts per million dry volume (ppmvd) at 15% oxygen (O_2), based on a 1-hour average calculated over 4 continuous hours of operation, effective during all periods of operation, including startup and shutdown (ARM 17.8.340 and 40 CFR 60, Subpart KKKK).

3. Emissions of carbon monoxide (CO) from the turbine generator shall not exceed 21.50 lb/hr based on a 3-hour average, effective during all periods of operation, including startup and shutdown (ARM 17.8.752).

4. Emissions of volatile organic compounds (VOCs) from the turbine generator shall not exceed 1.33 lb/hr based on a 3-hour average, effective during all periods of operation, including startup and shutdown (ARM 17.8.752).

5. The combined sum of filterable and condensable emissions of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) from the turbine generator shall not exceed 6.00 lb/hr based on a 1-hour average, effective during all periods of operation, including startup and shutdown (ARM 17.8.752).

6. Operation of the turbine generator, including startup and shutdown, shall not exceed 3,233 million standard cubic feet (MMSCF) of natural gas consumption per rolling 12-month period. (ARM 17.8.749).

7. Basin Electric shall operate and maintain a water-injection system to control NOx emissions during the combustion process. Water-injection shall commence within 10 minutes of turbine startup and shall continue until 10 minutes or less prior to shutdown (ARM 17.8.752).

8. Basin Electric shall install, operate, and maintain a catalytic oxidizer to control emissions of CO and VOCs (ARM 17.8.752).

9. Basin Electric shall combust only pipeline quality natural gas in the turbine generator (ARM 17.8.752).

10. The turbine shall exhaust into a stack that is at least 85.6-feet tall from grade (ARM 17.8.749).

11. Basin Electric 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).

12. Basin Electric 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).

13. Basin Electric 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.12 (ARM 17.8.749).

14. Basin Electric shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart KKKK (ARM 17.8.340 and 40 CFR 60, Subpart KKKK).

B. Testing Requirements

1. Basin Electric shall test the turbine generator, using natural gas as a fuel, for NOx and CO, concurrently, within 180 days of initial startup of the turbine generator, or according to another testing/monitoring schedule as may be approved by the Montana Department of Environmental Quality (Department), to demonstrate compliance with the NOx and CO emission limits contained in Sections II.A.1, II.A.2, and II.A.3. The testing shall continue on an every 2-year basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 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. The Department may require further testing (ARM 17.8.105).

C. Operational Reporting Requirements

1. Basin Electric shall supply the Department with annual production information for all emission points**,** as required by the Department 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 the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. 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. Basin Electric shall notify the Department 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 the Department, in writing, 10 days prior to startup 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(l)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by Basin Electric 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 the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. Basin Electric shall document, by month, the quantity of natural gas consumed by the turbine generator, including startup and shutdown, in MMSCF. By the 25th day of each month, Basin Electric shall total the natural gas consumption for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.A.6. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

E. Continuous Emissions Monitoring Systems

1. Basin Electric shall install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_x monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in ppm (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart KKKK).

2. Basin Electric shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK, including requirements for CEMS installation, certification, quality assurance, and relative accuracy and performance testing (ARM 17.8.340 and 40 CFR 60, Subpart KKKK).

SECTION III: General Conditions

A. Inspection – Basin Electric shall allow the Department'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 (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this MAQP.

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

C. Compliance with Statutes and Regulations – Nothing in this MAQP shall be construed as relieving Basin Electric 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 MAQP revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA, and ARM 17.763.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department 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 the Department'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 MAQP by the Board postpones the effective date of the Department'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, the Department's decision on the application is final 16 days after the Department's decision is made.

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

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by Basin Electric may be grounds for revocation of this MAQP, 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 MAQP issuance and proceed with due diligence until the project is complete or the MAQP shall expire (ARM 17.8.762).

Attachment 2

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS (EER)

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit startup, shutdown, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as: (1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit startup, shutdown, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as: (1–(CEMS downtime in hours during the reporting period* /total hours of point source operation during reporting period)) x 100

* All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report all excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

EXCESS EMISSIONS REPORT

PART 1

a. Emission Reporting Period ____

b. Report Date ____

c. Person Completing Report ____

d. Plant Name ____

e. Plant Location ____

f. Person Responsible for Review and Integrity of Report ____________________________

g. Mailing Address for 1.f. ____

h. Phone Number of 1.f. ____

i. Total Time in Reporting Period ____

j. Total Time Plant Operated During Quarter ____________________________________

k. Permitted Allowable Emission Rates: Opacity ________________________________

SO2 ____________________ NOx ____________________ TRS ____________________

l. Percent of Time Out of Compliance: Opacity ________________________________

SO2 ______________________ NOx ______________________ TRS ____________________
_

m. Amount of Product Produced During Reporting Period ___________________________

n. Amount of Fuel Used During Reporting Period _________________________________

PART 2 – Monitor Information (Complete for each monitor).

a. Monitor Type (circle one): Opacity SO2 NOx O2 CO2 TRS Flow

b. Manufacturer ____

c. Model No. ____

d. Serial No. ____

e. Automatic Calibration Value: Zero ______________________ Span ______________________

f. Date of Last Monitor Performance Test ____________________________________

g. Percent of Time Monitor Available:

1) During reporting period ______________________________

2) During plant operation ______________________________

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values ________

____

i. Conversion Factor (f-Factor, etc.) ______________________________

j. Location of monitor (e.g. control equipment outlet)______________________________

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one): Opacity SO2 NOx TRS

b. Type of Control Equipment ______________________________

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)______________________________

____

d. Date of Control Equipment Performance Test ______________________________

e. Control Equipment Operating Parameter During Performance Test ______________________________

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____

____

____

PART 4 – Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 – Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 – Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 – Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 – Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE ______________________________

NAME ______________________________

TITLE ______________________________

DATE ______________________________

TABLE I

EXCESS EMISSIONS

Date	Time			Magnitude	Explanation/Corrective Action
	From	To	Duration		

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time			Problem/Corrective Action
	From	To	Duration	

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time			Operating Parameters	Corrective Action
	From	To	Duration		

TABLE IV

EXCESS EMISSIONS AND CEMS PERFORMANCE SUMMARY REPORT

Pollutant (circle one): SO2 NOx TRS H2S CO Opacity

Monitor ID ____

Emission data summary [1]	CEMS performance summary [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 =$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CEMS downtime 3. $\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 =$

1. For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
2. CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Montana Air Quality Permit (MAQP) Analysis
Basin Electric Power Cooperative – Culbertson Generation Station
MAQP #4256-02

I. Introduction/Process Description

Basin Electric Power Cooperative (Basin Electric) operates a stationary electric power generation station to provide power to the electric power grid during daily and seasonal periods of peak power demand. The facility is located approximately 7.2 miles northeast of Culbertson, Montana, about 16 miles due west of the Montana-North Dakota border. The legal description is Section 5, Township 28 North, Range 57 East, Roosevelt County, Montana. The facility is known as the Culbertson Generation Station.

A. Permitted Equipment

The facility consists of a single General Electric LMS100 turbine generator. This turbine generator is a nominal 100-megawatt (MW), simple-cycle, combustion turbine generator that runs solely off natural gas. The GE LMS100 was chosen for its generation capacity, startup response time, and thermal efficiency not available in other power generation turbines of comparable capacity.

B. Source Description

The generation plant consists of a single, simple-cycle, aeroderivative combustion turbine and an electric generator driven by the turbine. The turbine draws in combustion air which is compressed and mixed with natural gas. The fuel-air mixture is ignited to produce compressed hot combustion gases which expand and rotate a shaft which turns a generator to produce electricity. The turbine only combusts natural gas which is supplied by an existing pipeline running through the Basin Electric property.

Emissions are limited by permit conditions that restrict operation of the turbine to no more than 3,233 million standard cubic feet (MMSCF) of natural gas combusted per year. Oxides of nitrogen (NOx) emissions are controlled by the combustion of pipeline quality natural gas and water injection during combustion. The facility does not incorporate add-on controls for emissions of sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), or particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Basin Electric is required by MAQP to combust only pipeline quality natural gas, which results in minimal SO_2 and PM_{10} emissions. A catalytic oxidizer treats post-combustion exhaust emissions to reduce carbon monoxide (CO) and volatile organic compounds (VOC).

C. Permit History

On January 21, 2009, the Montana Department of Environmental Quality (Department) issued MAQP 4256-00 for a stationary electric power generation station consisting of a single, simple-cycle, 100 megawatt, natural gas powered combustion turbine generator and associated equipment.

On September 8, 2015, the Department received a letter from Basin Electric Power Cooperative (BEPC) requesting an amendment to Montana Air Quality Permit (MAQP) #4256-00. BEPC requested that the permit language be changed to reflect the correct averaging period of the Title 40 Code of Federal Regulations (CFR) Part 60, Subpart KKKK emission limit for Oxides of Nitrogen applicable during start-up, operation, and shut-down of the power generating unit. The permit was also updated to reflect the current language used by the Department. **MAQP #4256-01 replaced MAQP #4256-00.**

D. Current Permit Action

On October 16, 2020, the Montana Department of Environmental Quality (Department) received a complete Montana Air Quality Permit (MAQP) application from Basin Electric Power Cooperative (Basin Electric) requesting a modification to MAQP #4256-01. Basin Electric requested that the annual operating capacity be changed to use a fuel flow rate rather than hours of operation for the limitation. The MAQP was also updated to reflect the current language used by the Department. **MAQP #4256-02 replaces MAQP #4256-01**.

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 Administrative Rules of Montana (ARM) and are available, upon request, from the Department. Upon request, the Department 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. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, 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 the Department.

   Based on the emissions from the turbine, the Department determined that initial testing for NOx and CO is necessary. Furthermore, based on the emissions from the turbine, the Department determined that additional testing every 2 years is necessary to demonstrate compliance with the NOx and CO emission limit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, 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).

   Basin Electric 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 the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department 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
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

Basin Electric 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, Basin Electric 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.

6. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.

7. 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.

8. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The turbine generator is considered an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following subparts.

    a. 40 CFR 60, Subpart A – General Provisions. This subpart applies to all equipment or facilities subject to an NSPS Subpart as listed below:

b. 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. This subpart applies to the proposed facility because Basin Electric proposes to install and operate a stationary combustion turbine with a heat input greater than 10 million British thermal units (MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005.

9. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.

10. 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 an NESHAP Subpart as may be listed below:

    b. 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines: This subpart applies to stationary combustion turbines located at a major sources of hazardous air pollutant (HAP) emissions which emits any single HAP at a rate of at least 10 tons per year (TPY), or a combination of HAPs of at least 25 TPY. This subpart does not apply to the Basin Electric combustion turbine generator because emissions of no single HAP meet or exceed 10 TPY, and any combination of HAPs do not meet or exceed 25 TPY.

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. Basin Electric must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the new or altered stack for the turbine generator is below the allowable 65-meter Good Engineering Practice (GEP) stack height.

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 the Department. A permit application fee was received on September 29, 2020 for this modification.

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 the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. 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. The Department 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 potential to emit (PTE) greater than 25 tons per year of any pollutant. The Basin Electric facility has a PTE greater than 25 TPY for NOx and CO; 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. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. A complete permit application was received by the Department on October 16, 2020. (7) 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 of public notice was submitted to the Department on October 16, 2020.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department 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 (Best Available Control Technology) shall be utilized. The required BACT analysis 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 the Department 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 Basin Electric 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 the Department'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 the Department'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 the Department.

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 tons per year 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 > 100 TPY of any pollutant;

b. PTE > 10 TPY of any one HAP, PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

c. PTE > 70 TPY of PM_{10} in a serious PM_{10} 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 Air Quality Permit #4256-00 for Basin Electric, the following conclusions were made:

   a. The facility's PTE is greater than 100 TPY for NOx.

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

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to a current NSPS (40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines).

   e. This facility is not subject to any current NESHAP standards.

   f. This source is a Title IV affected source; however, it is not a solid waste combustion unit.

   g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that Basin Electric is subject to the Title V operating permit program. Basin Electric applied for and was issued an initial Title V Operating Permit on December 14, 2010 and submitted a timely and complete renewal application on June 1, 2015, and on January 27, 2020.

III. BACT Determination

A BACT determination is required for each new or modified source. Basin Electric 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.

The proposed project will result in no change to hourly emission rates. However, the modification will increase the annual PTE for the turbine. The application described the emissions calculations and the newly defined proposed fuel-flow rate limit. It also evaluated any potential impacts to BACT and ambient air impacts. Most notably, it evaluated compliance with the 1-hour NO2 National Ambient Air Quality Standard (NAAQS) because the standard was established following the original MAQP application submittal.

Basin Electric proposed exempting SO2 emissions from a BACT analysis on this project because the proposed project would increase SO2 emissions less than 0.5 ton per year and result in facility-wide emissions of less than 2.5 tpy. In addition, no add-on control would prove cost-effective in reducing such a minimal amount of emissions, and no BACT analysis for other combustion turbine projects has identified anything other than the use of pipeline-quality natural gas as BACT for this pollutant. Therefore, Basin Electric proposed and the Department concurs that the continued use of pipeline-quality natural gas constitutes BACT for SO2.

Note that this section and the associated cost analyses are a revision and update to the BACT analysis that was originally conducted for the Basin Electric turbine in 2007. The cost analyses used to evaluate economic impacts are updated versions of the original cost analyses. Input parameters are revised, as applicable, and costs are updated to present day values using the Chemical Engineering Plant Cost Index (CEPCI). CEPCI values are dimensionless numbers used to update capital costs required for a chemical plant from a past date to a later time, following changes in the value of money due to inflation and deflation.

The following sections contain BACT analyses for other pollutant emissions from the proposed modification at the facility.

A. BACT for Turbine – NOx

NO_X is formed during the combustion of natural gas in the facility's combustion turbine unit. The formation of NO_X is dominated by the process called thermal NO_X formation. Thermal NO_X results from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. The rate of formation is sensitive to local flame temperature and, to a lesser extent, local oxygen concentrations. Virtually all thermal NO_X is formed in the region of the flame at the highest temperature. Maximum thermal NO_X production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

1. Identify Control Technologies

The following alternative control technologies and methods were identified as having practical potential for reducing NOx emissions from the CGS turbine.

Combustion Process Modifications:
- Proper System Design and Operation (baseline)
- Water or Steam Injection
- Dry Low-NO_X Burners
- Catalytic Combustion ($XONON_{TM}$)

Post-Combustion Exhaust Treatment Processes:
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Catalytic Adsorption (EMx_{TM})
- Wet Chemistry Scrubber ($LoTOx_{TM}$)

a. Proper System Design and Operation (base case)

Fuel costs are a major portion of the cost of electricity generation. Consequently, every effort is made to conserve energy and thereby reduce costs. One of the primary considerations that originally led Basin Electric to select the GE LMS100 engine was its best-of-class thermal efficiency. Efforts to maximize fuel efficiency also serve to reduce pollutant emissions: increasing the amount of electricity produced per unit of fuel decreases the amount of combustion-related pollutants emitted per unit of output.

b. Water or Steam Injection

Reducing peak flame temperatures in the turbine's combustion chamber will reduce thermal NOX formation. Steam or water injection is a common coolant to be injected into the turbine. Steam is not readily available for injection because CGS uses a simple cycle turbine, so high purity water is used. NOX reduction is proportional to the amount of water injected during operation. An additional benefit is increased air density at the turbine inlet, which increases mass flow through the turbine. Increasing the mass flow per unit of energy expended results in increased power output. This NOx reduction is generally balanced by an increase in CO and VOC emissions since lower flame temperatures tend to promote incomplete combustion. Water injection cannot commence immediately upon turbine startup but can be fully effective within ten minutes of startup.

c. Dry Low NOX Burners

Like water injection, the purpose of dry low NOX (DLN) burners is to lower the combustion temperatures in the turbine, thereby reducing thermal NOX formation. This is accomplished by premixing fuel and combustion air with a stoichiometric deficit of fuel prior to injection into the compressor. Additional fuel is then injected in stages throughout the combustion chamber of the turbine. This produces a lower heating value air/fuel mixture that will combust at lower temperatures, thereby reducing thermal NOX formation.

d. Catalytic Combustion (XONON tm)

Catalytic combustion (XONON) reduces NOX emissions by lowering combustion temperatures inside the turbine. A lean mix of air and fuel is combusted in a premixing burner to heat the incoming combustion air. More fuel is then mixed into the incoming air and reacted on a catalyst surface without flame, combusting the mixture at very low temperatures and producing little NOX.

e. Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique for chemically reducing NO and NO2 in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia (NH3) is used as the reducing agent. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Ammonia is injected into the flue gas upstream of a catalyst bed, and NOX and NH3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NOX decomposition reaction. Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), precious noble metals such as platinum and rhodium, zeolite, and ceramics. The control technology achieves optimal performance at flue gas temperatures between 575°F and 750°F. Excess air is injected at the turbine exhaust as needed to reduce temperatures to the optimum range. Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning. SCR has been demonstrated to achieve high levels of NOx reduction in the range of 70% to 90% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines (ICAC, 2000).

f. Selective Non-Catalytic Reduction

SNCR promotes the noncatalytic decomposition of NOX in the flue gas to nitrogen and water using a reducing agent, typically ammonia or urea. The reduction reactions take place at much higher temperatures than in an SCR, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process rapidly diminishes when operated outside the optimum temperature band, and additional ammonia slip or excess NOX emissions may result. The process has been used in North America since the early 1980s. Removal of NOX varies considerably for this technology, depending on inlet NOX concentrations, flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and the presence of interfering chemical substances in the gas stream. SNCR typically achieves control efficiencies in industrial applications of between 25 to 60 percent for urea-based systems and 61 to 65 percent in ammonia-based systems (EPA, 2019a).

g. Catalytic Adsorption (EMx_{TM})

EMxTM, formerly marketed as SCONOxTM, is a multipollutant, post-combustion control technology that uses a single catalyst to simultaneously limit emissions of CO, VOC, and NOx. It does so through a complex series of oxidation/reduction catalytic reactions. The catalyst oxidizes CO to CO2 and NO to NO2. The NO2 adsorbs on a potassium carbonate coating applied to the catalyst surface where it reacts to form potassium nitrate and potassium nitrite. These salts are then reduced to elemental nitrogen and water by introducing steam, CO2, and natural gas (to provide hydrogen). The EMxTM catalyst is sensitive to sulfur poisoning and may require installation of an upstream sulfur removal system.

h. Wet Chemistry Scrubber ($LoTOx_{TM}$)

BELCO's LoTOxTM NOX control technology uses an ozone generator to inject oxygen into the exhaust gas stream in a reaction duct to transform NO and NO2 into N2O3 or N2O5. These higher order nitrogen oxides are highly soluble in water. They can be removed from the exhaust stream with a wet scrubber as nitric and nitrous acids or, if using a caustic scrubbing solution, as nitrite or nitrate salts. Requirements of this system include oxygen and water supplies. A system for treating and disposing the scrubber effluent must also be provided. LoTOxTM is specifically designed for high-sulfur and high-particulate processes, as may be experienced in a refinery or coal-fired boiler.2 The estimated control efficiency of the system is 80-90% (manufacturer's data).

2. Eliminate Technically Infeasible NOx Control Options

a. Proper System Design and Operation (base case)

Proper system design and operation serve as the baseline for NOx emissions reduction and are clearly technically feasible.

b. Water or Steam Injection

The GE LMS100 gas turbine at CGS includes a water injection system. This technology is already available and technically feasible.

c. Dry Low NOX Burners

Dry Low NOx (DLN) burner technology is typically an alternative to water injection. Though DLN technology is commonly used on natural gas-fired turbines, GE had not developed a version of the LMS100 with a DLN burner when the turbine was originally constructed at the facility. DLN has since been developed for LMS100 turbines and is now a commercially available and technically feasible control option for LMS100 turbines.

Turbines equipped with DLN produce much more CO and other products of incomplete combustion than turbines with water injection. DLN control is considered comparable to the currently installed water injection system at CGS. It will not offer enough additional control to provide an economically practical control option. It was not further evaluated for BACT.

d. Catalytic Combustion ($XONON_{TM}$)

The XONONTM catalytic combustion technology is not commercially demonstrated, and therefore not available, for application to mid-size turbines such as the turbine at CGS. It is potentially not available at all except on a specific, small turbine. It is not technically feasible for this application.

e. Selective Catalytic Reduction

SCR has been applied in similar commercial applications and is considered to be technically feasible for this application.

f. Selective Non-Catalytic Reduction

The high temperature required for operation of an SNCR system, typically between 1,650°F and 1,800°F, is higher than the exhaust temperatures generated by the GE LMS100 turbine. Exhaust temperatures will range from 740°F to 840°F, depending on turbine load and ambient conditions. This technology is considered to be technically infeasible for this application.

g. Catalytic Adsorption (EMxTM)

The NOX conversion and absorption reactions of EMxTM result in a buildup of reaction products that must be removed to complete the destruction of NOx and effect catalyst regeneration. This process requires steam, making the technology applicable to combined cycle turbines but not simple cycle turbines. CGS operates a simple cycle combustion turbine and does not generate steam on site. Without steam, the EMx_{TM} catalyst would quickly foul and become inactive. In order to provide steam, the facility would have to combust additional fuel, offsetting the benefits of the emissions control system. EMxTM technology is potentially applicable to the CGS project and is deemed technically infeasible due to the absence of steam on-site.

h. Wet Chemistry Scrubber ($LoTOx_{TM}$)

LoTOx was specifically designed for use in high particulate and high sulfur content fuel combustion processes unlike the combustion environment in a natural gas-fired gas turbine. This technology is not considered to be commercially available for the CGS project and is technically infeasible.

. 3. Rank Remaining NOx Control Technologies by Control Effectiveness

Of the alternative NOx control technologies initially identified, the following technologies have been deemed technically infeasible for this application:

- Dry Low-NOx Burner
- Catalytic Combustion ($XONON_{TM}$)
- Selective Non-Catalytic Reduction
- Wet Chemistry Scrubber ($LoTOx_{TM}$)
- Catalytic Adsorption (EMx_{TM})

The following technologies have been deemed to be technically feasible and will be carried forward in the BACT analysis:

- Proper System Design and Operation
- Water or Steam Injection
- Selective Catalytic Reduction

Table III-1 lists control efficiencies for the remaining technically feasible control alternatives.

Table III-1

Control Technology	Estimated NO_x Emission Rate (ppm)	Percent Reduction
SCR	7.5 – 2.5	70% - 90%
Water Injection	25	N/A
Proper System Design and Operation	Baseline	Baseline

Basin Electric currently operates a combustion turbine that incorporates water injection for NOx emissions control. This technology, along with proper design and operation, will serve as the baseline for evaluation of additional controls. The remaining control alternative is water injection with add-on SCR control. It will be evaluated in detail in the following section.

4. Evaluate Most Effective NOx Controls and Document Results – Water Injection Plus SCR

a. Environmental Impacts

SCR presents several potential adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas would be emitted to the atmosphere. Of primary concern is the formation of ammonium sulfate, (NH4)2SO4. Ammonium sulfate is one constituent of particulate matter that will be addressed in the PM/PM10/PM2.5 BACT analysis. Ammonia slip is expected to result in an ammonia concentration of approximately 5 ppm at the input levels required to adequately control NOx emissions. In addition, transportation, storage, and handling of ammonia are potentially hazardous activities with safety and security implications. Finally, disposal of spent catalyst from the SCR unit is a potential environmental hazard.

b. Energy Impacts

Installation of an SCR system in the turbine exhaust train would increase back pressure that would reduce power output. Energy would also be required for pumping ammonia to the SCR. Additional power required (or salable power lost) is estimated to be 170 kW which equates to 714,000 kW-hr annually at the maximum proposed effective operating schedule of 4200 hours per year at maximum capacity. At the 2017 average retail price for electricity, the cost due to lost sales would be roughly $48,000 annually. Lost production efficiency would also increase pollutant emission rates relative to power production rate.

c. Economic Impacts

GE estimated the direct capital cost of an SCR for the CGS turbine at approximately $6,150,000 when it was originally designed in 2007 and prior to installation and construction. It is highly likely that a retrofit cost will be more expensive than this original quote to install SCR prior to installation of the turbine. However, the same quote was utilized in this updated BACT analysis and updated to the equivalent cost in 2019 using the Chemical Engineering Plant Cost Index (CEPCI). The estimated total annual cost for the system was calculated in accordance with EPA guidance (EPA, 2002b) to be $1,288,600 when adjusted for value in 2019. Assuming a control efficiency of 90 percent for the SCR and a maximum operating schedule of 4200 hours per year, the cost efficiency of an SCR in this application would be approximately $8,700 per ton of NOx removed. See Appendix B for detailed cost calculations.

Conclusion

The environmental and energy impacts described above are significant and reason to disqualify SCR as BACT for this application. A cost of $8,700 per ton of NOx removed is disproportionately high when compared to the cost of NOx control required of other similar sources. Application of SCR technology to the CGS turbine would result in an adverse economic impact not required of similar projects. This technology is not appropriate as BACT for this application.

. 5. Select NOx BACT

The turbine at CGS has operated using water injection for NOx control and has had no issue staying within compliance of the required NOx emission limit. Basin Electric proposes to maintain its BACT-derived NOx limit of 25 ppmvd, corrected to 15% O2, over a one-hour averaging period. This concentration equates to a maximum emission rate of 78.5 lb/hr. Basin Electric proposes that the limit will continue to be achieved using proper system design and operation, including water injection in the burner. Basin Electric proposes that the limit will also continue to be effective during all periods of operation, including startup and shutdown. The Department Concurs with Basin Electric's BACT proposal and determined that achieving a 78.5 lb/hr emission rate over a one-hour averaging period during all times of startup, operation and shutdown, as well as using water injuection to control NOx emissions is BACT.

BACT for Turbine – CO and VOC

CO and VOCs are formed from incomplete combustion of organic constituents within the natural gas in the facility's simple cycle turbine. Because CO and VOC are generated and controlled by the same mechanisms, they will be addressed in this section together. In an ideal process, complete combustion, or oxidation, of organics results in the emission of water and CO2. When organic compounds do not oxidize completely, the result is CO and various modified VOCs. Two general and nonexclusive approaches are available for reducing emissions of these compounds:

- Improve combustion conditions to facilitate complete combustion in the turbine burner, and
- Complete oxidation of the exhaust stream after it leaves the turbine burner.

Post-combustion CO/VOC control is accomplished via add-on equipment that creates an environment of high temperature and oxygen concentration to promote complete oxidation of the CO and organic compounds remaining in the exhaust. This can be facilitated at relatively lower temperatures by the use of certain catalyst materials.

1. Identify CO/VOC Control Technologies

A review of a variety of information sources indicates three control technologies with a practical potential for application to CGS for controlling CO and VOC emissions:

- Proper system design and operation
- Thermal oxidation
- Catalytic oxidation

a. Proper System Design and Operation (base case)

Reduction of CO emissions can be accomplished by controlling the combination of system temperatures through operation at maximum loads, increasing oxygen concentrations, maximizing combustion residence time, and improving mixing of the fuel, exhaust gases, and combustion air (oxygen). Maximizing heating efficiency, and subsequently minimizing fuel usage, will also minimize CO formation. All of these techniques also generally increase NOx emissions.

b. Thermal Oxidation

Thermal oxidizers are essentially supplementary combustion chambers that complete the conversion of CO/VOC to CO_2 and water by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. They require temperatures of approximately 1800°F to 2000°F. This high-temperature environment is produced by the combustion of supplemental fuel, generally natural gas. Thermal oxidizers are typically located downstream of a particulate control device if the exhaust stream contains high concentrations of particulate material. Reduced particulate loading improves thermal efficiency, since the particulate matter acts as a heat sink, and it reduces equipment maintenance requirements. Several design variations address different inlet concentrations, air flow rates, fuel efficiency requirements, and other operational variables. All of them function using the basic principles described above. One commonly used design is called a regenerative thermal oxidizer (RTO). This type of thermal oxidizer typically uses a bed of ceramic packing material to capture heat from the incineration process and preheat the incoming exhaust gas. This design improves thermal efficiency and reduces the amount of supplemental fuel that must be combusted. RTOs are capable of reducing CO/VOC emissions by 95 to 99 percent (EPA, 2003).

c. Catalytic Oxidation

Catalytic oxidizers employ the same principles as thermal oxidizers, but they use catalysts to lower the temperature required to effect complete oxidation. The optimum temperature range for catalytic oxidizers is generally 600 to 900°F. Because catalysts are prone to plugging and poisoning, catalytic oxidizers must be located downstream of a particulate control device if the exhaust stream contains appreciable concentrations of particulate matter. Even so, contaminants that are not removed by the particulate control equipment, or those that are not removed in sufficient quantity, can potentially poison the catalyst and reduce or eliminate its effectiveness. For this application, the turbine will be combusting natural gas, and particulate loading is not anticipated to be a problem. Like thermal oxidizers, catalytic oxidizer designs include many varieties to address specific operational conditions and requirements. Regenerative catalytic oxidizers (RCOs) improve thermal efficiency using a design similar to the RTO design. They are generally capable of 90 to 99 percent destruction or removal efficiency at steady state conditions (EPA, 2003).

2. Eliminate Technically Infeasible CO/VOC Control Options

a. Proper System Design and Operation

Proper system design and operation serve as the baseline for NOx emissions reduction and are clearly technically feasible.

b. Thermal and Catalytic Oxidation

The use of a catalytic or thermal oxidizer unit was evaluated for this application, and several technical difficulties were identified. First, for effective oxidation, gas inlet temperatures are required to be within a narrow window of acceptable temperatures. For an RTO unit, additional fuel would need to be combusted to bring the temperatures up to acceptable levels. Notwithstanding these technical difficulties, both of the control devices are considered to be technically feasible.

3. Rank Remaining CO/VOC Control Technologies by Control Effectiveness

Catalytic oxidizers and RTO units are expected to have CO and VOC control efficiencies ranging from 90 percent to 99 percent. For this BACT analysis, the minimum catalytic oxidizer control efficiency provided by an EPA fact sheet (EPA, 2003a) of 90 percent was applied for controlling CO and VOC emissions. Likewise, the minimum reported RTO control efficiency of 95 percent was applied for controlling CO and VOC emissions. Table III-2 summarizes the control efficiencies assumed for this analysis.

Table III-2: Ranked CO/VOC Control Technology Effectiveness Control Technology

Control Technology	Percent Reduction	
	CO	VOC
RTO	95%	95%
Catalytic Oxidizer	90%	90%

4. Evaluate Most Effective CO/VOC Controls and Document Results

a. Environmental Impacts

An RTO operates by combusting supplemental fuel to ensure complete combustion of residual CO and VOC in the exhaust gases. This supplemental combustion produces a small amount of additional CO and NOx. EPA emission factors (EPA, 2008a) yield emission rate estimates of 1.2 tons additional CO and 1.5 tons additional NOx annually as a result of operating an RTO at the CGS facility.

b. Energy Impacts

Operation of an RTO at the CGS facility is estimated to require approximately 29.5 million cubic feet of natural gas and 7000 MW-hr of electricity annually.

c. Economic Impacts

Using estimation methods developed by Vatavuk (Vatavuk, 1990), the capital investmentfor an installed RTO for the CGS turbine was estimated to be approximately $6,917,000. The total annual cost for the system was estimated to be $2,010,000 using general EPA cost estimating methods (EPA, 2002c). Assuming a control efficiency of 95 percent for the RTO and a maximum operating schedule of 4200 hours per year, the cost effectiveness of an RTO in this application would be approximately $4,676 per ton of CO removed and $75,749 per ton of VOC removed. According to EPA (EPA, 1990), it is appropriate to analyze the incremental cost of a control technology alternative in addition to analyzing the average cost-effectiveness as above.

Table III-3 shows the relevant cost and pollutant control values as well as the incremental cost for CO and VOCs. The annual cost of a catalytic oxidizer was estimated to be approximately $1,754,000. Also shown is the cost of $11,543 per ton of incremental CO that would be removed by using RTO instead of a catalytic oxidizer to control CO emissions from the CGS turbine. The incremental VOC removal rate would be approximately one ton; the incremental cost for VOC removal with RTO would then be approximately $182,694 per ton.

Table III-3: Incremental Control Cost – RTO Versus Catalytic Oxidizer

Control Option	Annual Cost	CO Controlled Rate (tpy)	VOC Controlled Rate (tpy)
RTO	$2,007,722	23	1.4
Catalytic Oxidizer	$1,753,777	45	2.79
Difference	$253,945	22.00	1.39
Incremental Cost ($/ton)	---	**$11,543**	**$182,694**

Conclusion

The environmental and energy impacts described above are not, by themselves, reason to disqualify RTO as BACT for this application. The economic impact of using RTO technology is considered to be disproportionately adverse relative to other recent BACT determinations. It should be noted that a large portion of turbine applications use catalytic oxidizers.

5. Select CO BACT

Basin Electric proposes the continued use of a catalytic oxidizer as BACT for control of CO and VOC emissions from the CGS gas turbine. The oxidizer is currently used to reduce CO/VOC emissions by at least 90 percent. The resultant maximum potential emission rates are 11.3 ppmvd CO and 1.3 ppmvd VOC, corrected to 15% O2, over a three-hour averaging period. These concentrations equate to emission rates of 21.5 lb/hr and 0.029 lb/MMBtu of CO and 1.3 lb/hr and 0.002 lb/MMBtu of VOC. The limits would continue to be effective during all periods of operation, including startup and shutdown. The Department concurs with Basin Electric's BACT proposal of using a catalytic oxidizer to control CO and VOC emissions to meet the following limits: CO BACT limit of 21.5 lb/hr based on a 3-hour average, effective during all periods of operation including startup and shutdown; and, VOC BACT limit of 1.3 lb/hr VOC based on a 3-hour average, effective during all periods of operation including startup and shutdown.

C. BACT for Turbine – PM/PM10/PM2.5

1. Identify Particulate Control Technologies

Emissions of PM, PM10, and PM2.5 (particulate) from gas-fired combustion turbines could be reduced by using any of the following methods:

- Electrostatic precipitators (ESP), both wet and dry
- Centrifugal collectors
- Fabric filters (baghouses) with specialty bags
- Wet scrubbers
- Fuel selection

A discussion of each type of control technology is contained below.

a. Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particulate control device that uses electric forces to move particles out the gas stream and onto collector plates. The particles are given an electric charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from high voltage electrodes spaced throughout the exhaust stream.

b. Centrifugal Separators

Centrifugal separators, or cyclones, are commonly used as a “prefilter” before a primary particulate control device. They are also used to capture and recycle high-value process material. While cyclones are generally more effective at removing larger particles than smaller ones, cyclones have been designed to remove PM2.5 with up to 70 percent efficiency (EPA, 2003b). At high removal rates, increased power requirements due to increased pressure drop become a significant consideration.

c. Fabric Filters (Baghouses)

Baghouses consist of one or more isolated compartments containing rows of fabric filter bags or tubes. Gas flows pass through the fabric where the particulate is retained on the upstream face of the bags, while the cleaned gas stream is vented to the atmosphere or to another pollution control device. Filtering is accomplished through a combination of inertial impaction, impingement, and accumulated dust cake sieving. The captured particulate is typically removed from the filters via pneumatic pulses or by mechanical shakers.
Advantages to baghouses are the high collection efficiency, in excess of 99% for filterable particulate matter, and the collection of a wide range of particle sizes removed. The disadvantages are limits on gas stream temperatures above 550°F (for typical installations), high-pressure drops, difficulty handling gas or particles that are corrosive or sticky in nature, and minimal capture efficiency for condensable PM2.5 fractions of the exhaust gas stream.

d. Wet Scrubbers

Wet scrubbers typically use water to impact, intercept, or diffuse a particulate-laden gas stream. With impaction, particulate matter is accelerated and impacted onto a surface area or into a liquid droplet through devices such as venturis and spray chambers. When using interception, particles flow nearly parallel to the water droplets which allows the water to capture the particles. Interception works best for submicron particles. Spray augmented scrubbers and high-energy venturis employ this mechanism. Diffusion is used for particles smaller than 0.5 micron where there is a large difference between gas and AWMA’s Air Pollution Engineering Manual (1992), pages 236-237, assumes a build-up of filter cake to capture ammonium sulfate.

e. Fuel Selection

Particulate emissions from simple cycle combustion turbines result from inorganic compounds contained within the fuel and incomplete combustion of organic compounds. Condensable particulate formation is also a function of impurities in the fuel. Rates of filterable and condensable particulate emissions are inherently low when combusting natural gas because it is relatively free of inorganic impurities and combusts efficiently.

2. Eliminate Technically Infeasible Particulate Control Options

Though some of the identified alternative particulate control technologies are not well suited to this application, none is technically infeasible.

3. Rank Remaining Particulate Control Technologies by Control Effectiveness

The following particulate control efficiency ranges were obtained from the appropriate EPA Air Pollution Control Fact Sheets (EPA, 2003b; EPA, 2003c; EPA, 2003d; EPA, 2003e; EPA, 2003f).

Note that where no size-specific efficiencies were provided, it was assumed that the stated efficiency range applied to all three particulate size categories even though there are likely significant differences in some cases.

Table 5-4: EPA Reported Particulate Control Efficiency Ranges

Control Technology	PM	PM_{10}	$PM_{2.5}$
ESP, wet and dry	90-99+%	90-99+%	90-99+%
Cyclones	80-99%	60-95%	20-80%
Fabric filters	99-99.9%	99-99.9%	99-99.9%
Wet scrubbers	70-99+%	70-99+%	70-99+%
Fuel selection	Baseline		

4. Evaluate Most Effective Particulate Controls and Document Results

Because the amount of particulate available for control is quite small, it was assumed that all of the identified control alternatives would result in disproportionate adverse economic impacts. To test this hypothesis, a screening model was developed to identify the lowest potential economic impact. First, representative annual costs for each technology were collected from the appropriate EPA Air Pollution Control Fact Sheets (EPA, 2003b; EPA, 2003c; EPA, 2003d; EPA, 2003e; EPA, 2003f). Table III-5 lists the provided ranges of annualized costs, in 2002 dollars, for each control alternative.

Table III-5: EPA Reported Annual Cost Ranges

Control Technology	Cost Range ($/scfm)
ESP, wet and dry	4 – 40
Cyclones	1.3 – 13.5
Fabric filters	5 – 45
Wet scrubbers	5.7 – 193

Next, the lowest specific cost value and highest control efficiency were applied to the following formula to produce the lowest possible cost-effectiveness result.
Cost-effectiveness ($/ton) = Exhaust flow rate (scfm) * Specific cost ($/scfm)
Uncontrolled annual emission rate (ton) * Control efficiency Entering the following values yields a cost-effectiveness of $11,050 per ton of particulate removed:

- Exhaust flow rate = 107,100 scfm
- Specific cost = $1.3/scfm
- Uncontrolled annual emission rate = 12.6 tons
- Control efficiency = 99.9%

This is an unrealistically low value and would likely be much higher because it liberally applies the lowest cost value to the highest control efficiency regardless of control technology. Nonetheless, it demonstrates that all of the identified alternatives would result in disproportionate adverse economic impacts. None, except the baseline use of natural gas as a fuel, is appropriate as BACT for controlling particulate emissions from the CGS turbine.

5. Identify Particulate BACT

Basin Electric proposes to continue to combust natural gas using proper design and operation as BACT for control of PM, PM10, and PM2.5 emissions from the CGS gas turbine. The resultant maximum potential emission rates would continue to be 1.5 lb/hr and 0.002 lb/MMBtu of PM and 6.0 lb/hr and 0.008 lb/MMBtu each of PM10 and PM2.5. The limit would be effective during all periods of operation, including startup and shutdown. The Department concurs with Basin Electric's BACT proposal of combusting only pipeline quality natural gas to meet a 1.5 lb/hr PM limit and a 6.0 lb/hr PM10 limit as BACT.

IV. Emission Inventory

	Tons per Year [1]						
Emission Source	**PM [2]**	**PM_{10} [3]**	**$PM_{2.5}$ [3]**	**NO_x**	**CO**	**VOC**	**SO_2**
Natural Gas Turbine	3.6	12.6	12.6	164.9	45.2	2.8	2.3
Haul Roads	2.5	0.7	0.07	--	--	--	--
Total Emissions	**6.1**	**13.3**	**12.7**	**164.9**	**45.2**	**2.8**	**2.3**

1. Inventory based on permit conditions that limit turbine operation to 3,233 MMSCF of natural gas combusted per year and a maximum rated design capacity of 738.1 MMBtu/hr.
2. Filterable particulate matter only.
3. Combined sum of filterable and condensable particulates. It is assumed that all particulates are less than 2.5 microns due to combustion properties of natural gas; thus PM_{10}=$PM_{2.5}$.

GE LMS100 Turbine Generator

PM Emissions (Filterable only)

Note: "Filterable PM" emissions in this inventory refers to the particulate matter collected in the "front-half" of the U.S. EPA Method 5 reference test (40 CFR Part 60, Appendix A), which collects PM from the probe and filter. This does not include the material that condenses in the impinger. The filterable PM emission factor was derived from the GE-reported worst-case uncontrolled emissions for PM_{10} and $PM_{2.5}$ (assumed equivalent since most particulates will be less than 2.5 microns). However, because the GE value for $PM_{10/2.5}$ represents the sum of condensable and filterable particulate matter (i.e., Total PM) the component of filterable PM was determined using a ratio of filterable-to-total PM based on AP-42 emission factors for gas-fired turbine generators (AP-42, Table 3.1-2a, 4/00). Detailed calculations are provided below.

Total $PM_{10/2.5}$ (filterable + condensable) = 6.0 lb/hr (uncontrolled, GE data)
Turbine Maximum Heat Input = 738.1 MMBtu/hr
Total $PM_{10/2.5}$ Emission Factor for the GE LMS100 = 6.0 lb/hr ÷ 738.1 MMBtu/hr = 0.0081 lb/MMBtu.

Calculations for ratio of filterable-to-total PM based on AP-42 emission factors for stationary gas turbines:
Condensable PM = 0.0047 lb/MMBtu (water-steam injection per footnote l, AP-42, Table 3.1-2a, 4/00)
Filterable PM = 0.0019 lb/MMBtu (water-steam injection per footnote l, AP-42, Table 3.1-2a, 4/00)
Total PM = 0.0066 lb/MMBtu (water-steam injection per footnote l, AP-42, Table 3.1-2a, 4/00)
Ratio of filterable-to-total PM = 0.0019 lb/MMBtu ÷ 0.0066 lb/MMBtu = 0.288

Apply ratio to GE factor for total PM to obtain filterable PM emission factor:
Filterable PM emission factor = 0.288 * 0.0081 lb/MMBtu = 0.0023 lb/MMBtu

Inventory calculation:
(3400 hrs) * (738.1 MMBtu/hr) * (0.0023 lb/MMBtu) * (0.0005 tons/lb) = 2.94 tons

PM_{10} Emissions (Filterable and condensable)

Emission factor derived based on the GE-reported worst-case uncontrolled PM of 6.0 lb/hr:

6.0 lb/hr ÷ 738.1 MMBtu/hr = 0.0081 lb/MMBtu.
Calculation: (3400 hrs) * (738.1 MMBtu/hr) * (0.008129 lb/MMBtu) * (0.0005 tons/lb) = 10.20 tons

$PM_{2.5}$ Emissions (Filterable and condensable)

Emission factor derived based on the GE-reported worst-case uncontrolled PM of 6.0 lb/hr:
6.0 lb/hr ÷ 738.1 MMBtu/hr = 0.008129 lb/MMBtu.
Calculation: (3400 hrs) * (738.1 MMBtu/hr) * (0.008129 lb/MMBtu) * (0.0005 tons/lb) = 10.20 tons

NOx Emissions

Emission factor derived based on the GE-reported worst-case NOx of 78.53 lb/hr with water injection:
78.53 lb/hr ÷ 738.1 MMBtu/hr = 0.1064 lb/MMBtu.
Calculation: (3400 hrs) * (738.1 MMBtu/hr) * (0.1064 lbs/MMBtu) * (0.0005 tons/lb) = 133.51 tons

CO Emissions

Emission factor derived based on the GE-reported worst-case uncontrolled CO of 215.26 lb/hr:
215.26 lb/hr ÷ 738.1 MMBtu/hr = 0.291 lb/MMBtu.
Control Efficiency = 90% (catalytic oxidizer)
Calculation: (3400 hrs) * (738.1 MMBtu/hr) * (0.291 lb/MMBtu) * (0.0005 tons/lb) * (1-90/100) = 36.51 tons

VOC Emissions

Emission factor derived based on the GE-reported worst-case uncontrolled VOC of 13.28 lb/hr:
13.28 lb/hr ÷ 738.1 MMBtu/hr = 0.018 lb/MMBtu.
Control Efficiency = 90% (catalytic oxidizer)
Calculation: (3400 hrs) * (738.1 MMBtu/hr) * (0.018 lb/MMBtu) * (0.0005 tons/lb) * (1-90/100) = 2.26 tons

SO_2 Emissions

Note: Potential maximum SO_2 emissions for the turbine were calculated using a mass balance approach that assumed maximum allowable amount of sulfur in pipeline quality natural gas and complete transformation and emission as SO_2.

Assumptions/Constants:
0.5 gr sulfur / 100 scf (40 CFR 72.2 definition for "pipeline quality natural gas").
738.1 MMBtu/hr, LHV, design basis fuel flow per GE.
959 Btu/scf, LHV, natural gas content per GE.
32 lb/lb-mol S
64 lb/lb-mol SO2

Emission rate using mass balance: (738.1 MMBtu/hr) * (10^6 Btu / MMBtu) * (1/959 Btu/scf) * (0.5 gr S / 100 scf) * (lb / 7000 gr) * (64 lb/lb-mol SO2 / 32 lb/lb-mol S) = 1.10 lb SO2 / hr
Emission Factor: (1.10 lb SO2 / hr) * (1 / 738.1 MMBtu/hr) = 0.00149 lb SO2/MMBtu
Calculation: (3400 hrs) * (738.1 MMBtu/hr) * (0.00149 lb/MMBtu) * (0.0005 tons/lb) = 1.87 tons

Haul Roads

Vehicle Miles Traveled (VMT) per Day = 5 VMT/day (Estimate)
VMT per hour = (5 VMT/day) * (day/24 hr) = 0.21 VMT/hr
Hours of Operation = 3,400 hours

PM Emissions:

Predictive equation for emission factor for unpaved roads at industrial sites per AP 42, Ch. 13.2.2, 11/06.
Emission Factor = $k * (s / 12)^a * (W / 3)^b$ = 14.13 lb/VMT
Where: k = constant = 4.9 lb/VMT (Value for PM_{30}/TSP, AP 42, Table 13.2.2-2, 11/06)
s = surface silt content = 8.5 % (Mean value for construction sites, AP 42, Table 13.2.2-1, 11/06)
W = mean vehicle weight = 54 tons (1994 average loaded/unloaded or a 40 ton truck)
a = constant = 0.7 (Value for PM_{30}/TSP, AP 42, Table 13.2.2-2, 11/06)

b = constant = 0.45 (Value for PM_{30}/TSP, AP 42, Table 13.2.2-2, 11/06)
Control Efficiency = 50% (Water spray or chemical dust suppressant)
Calculation: (3400 hours) * (0.21 VMT/hr) * (14.13 lb/VMT) * (ton/2000 lb) * (1-50/100) = 2.50 tons

<u>PM10 Emissions:</u>

Predictive equation for emission factor for unpaved roads at industrial sites per AP 42, Ch. 13.2.2, 11/06.
Emission Factor = $k * (s / 12)^a * (W / 3)^b$ = 4.04 lb/VMT
Where: k = constant = 1.5 lb/VMT (Value for PM_{10}, AP 42, Table 13.2.2-2, 11/06)
s = surface silt content = 8.5 % (Mean value for construction sites, AP 42, Table 13.2.2-1, 11/06)
W = mean vehicle weight = 54 tons (1994 average loaded/unloaded or a 40 ton truck)
a = constant = 0.9 (Value for PM_{10}, AP 42, Table 13.2.2-2, 11/06)
b = constant = 0.45 (Value for PM_{10}, AP 42, Table 13.2.2-2, 11/06)
Control Efficiency = 50% (Water spray or chemical dust suppressant)
Calculation: (3400 hours) * (0.21 VMT/hr) * (4.04 lb/VMT) * (ton/2000 lb) * (1-50/100) = 0.72 tons

V. Existing Air Quality

The turbine generator facility is located approximately 7.2 miles northeast of Culbertson, Montana, about 16 miles due west of the Montana-North Dakota border. The legal description is Section 5, Township 28 North, Range 57 East, Roosevelt County, Montana. The air quality of this area is classified as either "better than national standards" or unclassifiable/attainment with respect to National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. The closest Prevention of Significant Deterioration (PSD) Class I areas are the Fort Peck Indian Reservation (FPIR) at approximately 10.8 miles away minimum distance, and the Medicine Lake Wilderness Area (MLWA) at approximately 14.5 miles away minimum distance. The next closest Class I area is the UL Bend Wilderness Area at approximately 88 miles to the southwest.

VI. Air Quality Impacts

The Department determined that there will be no impacts from this permitting action because this permitting action does not change the allowable emissions from the source. Therefore, the Department believes this action will not cause or contribute to a violation of any ambient air quality standard.

VII. Ambient Air Impact Analysis

Bison Engineering (Bison) conducted air quality modeling for the proposed project as part of the Basin Electric Power Cooperative air quality permit application. This ambient air impact analysis was conducted, pursuant to the requirements of ARM 17.8.749, to demonstrate that the proposed modification would not cause or contribute to a violation of any state or federal ambient air quality standard. The proposed project is not categorized as a major Prevention of Significant Deterioration (PSD) modification.

The project emission increases do not exceed the modeling thresholds contained in MDEQ's draft modeling guidance, nor do they exceed the PSD significant emission rates (SERs) for any pollutant. A modeling demonstration accompanied the 2009 permit application (MAQP #4256-00), in which modeling was performed on pollutants that exceeded draft guidance thresholds ($PM_{2.5}$ and NO_2), and were shown to comply with applicable standards. The 1-hour NO_2 NAAQS was promulgated by the Environmental Protection Agency (EPA) in 2010, therefore a modeling analysis was performed for the current action (MAQP #4256-02) to demonstrate compliance with the 1-hour NO_2 standard. The applicable standards are shown in table VII-1.

Table VII-1 Applicable standards

Pollutant	Averaging Period	Class II SIL ($\mu g/m^3$)	Primary NAAQS ($\mu g/m^3$)	MAAQS ($\mu g/m^3$)
NO_2	1-hour	7.5 (4 ppb)	188 (100 ppb)	564 (0.30 ppm)

The SIL and NAAQS compliance demonstrations were conducted using the latest available version of EPA-approved American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) and associated preprocessors. Specifically:

- AERMOD version 19191: Air dispersion model.
- AERMET version 19191: processes NWS meteorological data for input to AERMOD.
- AERMINUTE version 15272: processes 1-minute NWS wind data to generate hourly average winds for input to AERMET.
- AERSURFACE version 13016: processes 1992 National Land Cover Data surface characteristics for input to AERMET.
- AERMAP version 18081: Processes National Elevation Data from the USGS to determine elevation of sources and receptors for input into AERMOD.
- BPIPPRM version 04274: characterizes building downwash for input to AERMOD.
- Oris Solution's BEEST Graphical User Interface, Version 12.02.

Regulatory default options were used for all model runs. Rural dispersion coefficients were applied, as all of Montana currently meets this criterion. All buildings at the site were evaluated for building downwash on each modeled point source, using BPIPPRM.

Five years of metrological data (2014-2018) ready for use in AERMOD was constructed using representative surface and upper air data. Surface air data was obtained from the closest National Weather Service (NWS) station, which is located approximately 55 miles to the west-southwest of the project site, at the L.M. Clayton Airport station in Wolf Point, MT (WBAN 94017). This NWS station also provided the automated surface observing system (ASOS) one-minute data used with AERMINUTE. The Glasgow, MT upper air station (WBAN 94008) was used for upper air data. The ADJ_U* option was employed in AERMET to account for stable, low wind speeds.

A series of nested receptor grids were used in the model to calculate the ambient air impacts around the project location. Discrete receptors were placed at 25 m spacing along the ambient air boundary, 50 m spacing from the ambient air boundary to 500 m from the site, 100 m spacing from 500m to 1 km from the site, 250 m spacing from 1 km to 3 km from the site, and 500 m spacing from 3 km to 10 km from the site, and 1,000 m spacing from 10 km to 50 km, totaling 13,236 receptor locations. Only the significantly impacted receptors (receptors with modeled concentrations equal to or greater than their respective SILs) were used for the refined analyses.

Source and receptor elevations were determined using the terrain preprocessor AERMAP and elevation data based on 1/3 arc-second (approximately 10 m resolution) National Elevation Dataset (NED) from the United States Geological Survey (USGS).

The following NO_2 monitoring site was identified for use as a background concentration. The "Sidney – 201" (30-083-0002) was selected as the most representative site, as it is the closest location of recent monitored NO_2 concentrations. Because the site was relocated from its old location in 2017 ("Sidney – Oil Field" 30-083-0001), a complete three-year design value was not available. Basin Electric used the available 2018 contribution to the design value from

MDEQ's 2019 Air Quality Monitoring Network Plan, which is a conservative representation of the NO_2 1-hour design value at the monitoring site. This background concentration is displayed in Table VII-2.

Table VII-2 Background concentration

Pollutant	Averaging Time	Background Conc. (µg/m^3)	Basis	Site
NO_2	1-hour	22.6 (12 ppb)	98%-ile of daily 1-hour max	Sidney - 201 (30-083-0002) (years: 2018)

For the NO_2 modeling analyses, Tier 2 (Ambient Ratio Method, ARM2) was employed in AERMOD, with the EPA default minimum and maximum ambient ratios of 0.5 and 0.9, respectively (ratio of NO_2/NO_x).

Basin Electric modeled the turbine as a "point" source in AERMOD and its description and model identification is displayed in Table VII-3.

Table VII-3 Onsite Source Descriptions

SrcID	Source Description	Source Category
TRBN4200	LMS100 GE Turbine	Onsite Source

PSD Class II Air Quality Analysis

Maximum 1-hour NO_2 emissions were modeled for the proposed modification. Table VII-4 shows the stack parameters used for the preliminary SIL analysis.

Table VII-4 SIL Modeled Emissions

SrcID	NO_2 1-hour (g/s)	Stack height (m)	Stack Temperature (K)	Stack velocity (m/s)	Stack Diameter (m)
TRBN4200	9.891 (78.5 lb/hr)	26.213	695.370	14.600	3.505

Modeled 1-hour NO_2 Class II SIL results are presented in Table VII-5. NO_2 1-hour SILs were exceeded, therefore a NAAQS/MAAQS analysis was performed.

Table VII-5 Class II Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. (µg/m^3)	SIL (µg/m^3)
NO_2	1-hour	27.78(1)	7.5

(1)Modeled concentration is the maximum 5-year average of the maximum daily 1-hour concentration.

NAAQS/MAAQS Air Quality Analysis

Bison identified a potential competing source as Northern Border Pipeline Company Compressor Station No. 3 (NBPC facility) adjacent to the Basin Electric property. The NBPC facility operates a compressor station under MAQP #2974-04 and Operating Permit #OP2974-12. The offsite source descriptions are shown in Table VII-6.

Table VII-6 Offsite Source Descriptions

SrcID	Source Description
NBPCT	Northern Border Pipeline Combustion Turbine

Maximum 1-hour NO_2 emissions were modeled for the proposed modification at Basin Electric. The NBPC facility includes a gas-fired 40,350-hp combustion turbine, which was modeled at its worst-case scenario, based on MAQP #2974-04 conditions. These emissions rates and stack parameters are displayed in Table VII-7.

Table VII-7 Modeled Emissions for NAAQS Analysis

SrcID	NO_2 1-hour (g/s)	Stack height (m)	Stack Temperature (K)	Stack velocity (m/s)	Stack Diameter (m)
TRBN4200	9.891 (78.5 lb/hr)	26.213	695.370	14.600	3.505
NBPCT	9.828 (78 lb/hr)	16.764	672.039	21.336	3.353

The results of the NAAQS analysis are shown in Table VII-8, which show that the modeled emissions comply with the NO_2 1-hour NAAQS standards.

Table VII-8 NAAQS Analysis Results

Pollutant	Avg. Period	Model Design Value (μg/m^3)	Monitor Design Value (μg/m^3)	Total Conc. (μg/m^3)	Primary NAAQS (μg/m^3)	% of NAAQS
NO_2	1-hour	20.3[(1)]	22.6	42.8	188	23%

[(1)]The receptor that had the 8th-highest daily 1-hr max value averaged over 5 years.

Compliance with the 1-hour NO_2 MAAQS (ARM 17.8.211) was determined, based on the 1-hour NO_2 NAAQS being more conservative.

The Department determined that the project-related NO_2 increases (with offsite facility NO_2 source emissions) will not cause or contribute to a federal or state ambient air quality standard. This decision was based on the air dispersion modeling with qualitative/quantitative analyses. The full modeling analysis submitted with the MAQP application is on file with the Department.

VIII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department 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? (e.g., 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, the Department determined there are no taking or damaging implications associated with this permit action.

VIII. Environmental Assessment

An Environmental Assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Air, Energy & Mining Division
Air Quality Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

ENVIRONMENTAL ASSESSMENT (EA)

Issued To: Basin Electric Power Cooperative – Culbertson Generation Station

Air Quality Permit Number: 4256-02

EA Draft: November 16, 2020
EA Final:
Permit Final:

1. *Legal Description of Site*: Section 5, Township 28 North, Range 57 East, Roosevelt County, Montana.

2. *Description of Project*: The proposed action is to issue a Montana Air Quality Permit #4256-02 allowing a change to the operating limits of the Culbertson Generating Station.

   The first component – a power generation facility with a natural gas-fired combustion turbine generator (CTG) – would be constructed to provide peaking capacity to Basin Electric's power portfolio. The Project design was based on use of a General Electric LMS100 high efficiency, simple cycle gas turbine. The CTG would have a nominal power output capacity rating of 100 MW and would normally operate between 50 and 100 percent of rated capacity. Operation of the facility would be limited to no more than 3233 million standard cubic feet (MMscf) of natural gas consumption per any rolling twelve-month period.

   Natural gas is provided by the Northern Border Pipeline Company (NBPC) from an existing gas line that passes through the 165 acre parcel of land upon which the CTG facility would be located. NBPC also owns and operates an existing natural gas compressor station on property adjacent to the proposed CTG facility. Approximately 100 gallons per minute (gpm) of water are required for operation and maintenance of the CTG. This would be provided by Dry Prairie Rural Water Authority from an existing water pipeline approximately three miles north of the proposed CTG facility.

   Air emissions from the facility consist of combustion gases from the CTG.

3. *Objectives of Project*: Basin Electric has requested that the operating limits be based on natural gas consumed rather than operating hours per 12-month rolling period.

4. *Alternatives Considered*: Basin Electric has considered the alternative of no action, but as this change will not result in additional emissions, that alternative was not considered necessary.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions, including a BACT analysis, would be included in Permit #4256-02.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit

conditions are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. *The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.*

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Aquatic and Terrestrial Life and Habitats

Wildlife habitat diversity in and near the Project is low, and is dominated (about 80 percent of the area) by cultivated fields re-seeded with introduced grasses and dryland hay. There are no aquatic habitats on the site. Consequently, no fish are present and wildlife species richness is comparatively low. Since this project will result in no changes to facility emissions, the impact is considered minor.

B. Water Quality, Quantity and Distribution

The Project site lies in the Charlie-Little Muddy watershed. The Missouri River flows west to east and is about nine miles to the south of the site. Contributory surface water in the area of the site includes Shell Creek which flows north to south and lies roughly one-half mile to the east of the site, and an unnamed creek which also flows north to south and lies roughly one to two miles west of the site. Both creeks empty into Clover Creek which flows west and joins the Missouri near Culbertson. Flow data are not available for either Shell Creek or the unnamed creek, but both are mapped as ephemeral.

Groundwater conditions beneath the site are described in literature references and interpreted from existing well information. The Groundwater Information Center (GWIC) database, maintained by the Montana Bureau of Mines and Geology (MBMG), was queried for wells in the area of the site. A total of 96 wells were found in all of T28N R57E. The wells in the database include 20 domestic and 37 stockwater wells. The remaining wells include 25 monitoring wells, 11 that are unused, 2 listed as other, and 1 unknown.

Aquifers in the area include coarser grained zones in the glacial deposits and the Fort Union Formation that are under confined conditions. Well logs found in the well search with aquifer designations include 11 designated as Fort Union, 6 as Pleistocene Glacial Outwash, 2 as Glacial Drift, and 1 as Quaternary Alluvium. However, upon reviewing logs with associated lithology, it is apparent that the majority of the wells in the area are completed in the Fort Union Formation. A review of water level and well construction data indicates that the water-bearing zones exploited by wells in the area are all confined.

Overall depths of wells in the area average 68 feet, with the deepest being 280 feet. Static water levels range from 19 to 167 feet, with an average of 73 feet. Yields average 57 gpm, with a maximum of 800 gpm, although this high yield is in glacial drift and appears anomalous.

Groundwater contours were developed from water level data from 22 wells in the area. The contours show that groundwater flows to the south at a gradient of roughly 0.012. Using the average hydraulic conductivity of 217 ft/d obtained from the specific capacity data, this equates to a groundwater velocity of 13 ft/d.

In general, the groundwater beneath the site is poor in quality. Water quality data were obtained from two wells to the south of the site completed in the unconsolidated material, and from three wells to the east and west of the site completed in the Fort Union Formation. The data show that the unconsolidated and Fort Union groundwater have similar water quality. Water is high in total dissolved solids (TDS), sodium, and sulfate. Drinking water standards are exceeded in multiple samples for sodium and sulfate (secondary maximum contaminant levels (SMCL)), although the levels are below the standard for stockwater.

Following is an assessment of adverse effects that could result from the Project on water quality within the surrounding watershed.

There will be no change in the current water usage for this facility associated with this modification. No water supplies in the area would be impacted by the Project.

C. Geology and Soil Quality, Stability and Moisture

This modification to the operating limits will have no effect on the geology, soil quality, stability and moisture in the area as this is an existing facility and the emission limits will not change.

D. Vegetation Cover, Quantity, and Quality

This modification to the operating limits will have no effect on the vegetation in the area as this is an existing facility and the emission limits will not change .

E. Aesthetics

This modification to the operating limits will have no effect on the aesthetics of the area.

F. Air Quality

This modification to the operating limits will not increase the facility emission limits, and therefore will have no effect on the air quality in the area There was a high level additional impact analysis done for NO_X and this modification will not change the emissions limits.

G. Unique Endangered, Fragile, or Limited Environmental Resources

This modification to the operating limits will have no effect on the unique, endangered, fragile, or limited environmental resources in the area as this is an existing facility and the emission limits will not change.

H. Demands on Environmental Resource of Water, Air and Energy

As described in Section 7.B of this EA, impacts to area water resources is zero because the demands for water would not change with this modification. In addition, as described in Section 7.F of this EA, any impact to the air resource in the area of the facility is also zero because the air emissions limits from the facility would not be changed due to this modification.

I. Historical and Archaeological Sites

The Department contacted the Montana Historical Society, State Historic Preservation Office (SHPO) in an effort to identify any historical, archaeological, or paleontological sites or findings near the proposed project. SHPO records indicate there have been no previously recorded sites within the designated search locales. SHPO determined that a cultural resource inventory is unwarranted at this time. Another indicator of cultural or historic significance is listing or eligibility for listing on the National Register of Historic Places. No sites of archeological, tribal, or historical value that are listed or eligible for listing on the National Register of Historical

Places (NRHP) have been identified that would be impacted by the project. The project is not known or anticipated to have any significant adverse cumulative effects on cultural resources.

Prior to commencing fieldwork, the Montana State Historic Preservation Office's Cultural Resources Annotated Bibliography System and Cultural Resources Information System databases were queried to determine if previous archaeological research had been conducted nearby. That file search revealed that five cultural resource projects had been completed in the area (Anderson, 1985; Passmann, 1999; Hall, 2002a; Brumley, 2005; Gray, 2007). Those resulted in the identification of cultural properties, including three small-scale historic coal mines, farmsteads, the Great Northern Railway, and an electric transmission line.

Only the transmission line lies in proximity to the Basin Electric's Project area. The Williston to Wolf Point line (24RV698) crosses the NE¼ Section 29, Township 28 North, Range 57 East, immediately south of the Substation site. That 115 kV line was originally installed in 1949; however, it has undergone periodic maintenance and many poles, insulators, cross-arms, and braces have been replaced. Because the property has diminished integrity and lacks significance, its recorder determined it to be ineligible for National Register listing (Hall, 2002b:1-3). The line was recently reconstructed.

None of these sites is affected by this modification to the operating limits of the facility.

J. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from this project on the physical and biological aspects of the human environment would be minor because the proposed modification to the operating limits will result in no changes to the facility emissions.

8. *The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.*

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS:
The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed project would not have any effect on social structures and mores of the proposed area of operation. The emissions limits will not be changed by this modification.

B. Cultural Uniqueness and Diversity

Facility operation would cause no disruption to the cultural uniqueness and diversity of the human environment in the area of operation because the source emissions limits will not be changed.

C. Local and State Tax Base and Tax Revenue

In general, socioeconomic impacts from the modification of the permit will be none as this is an existing facility and the emission limits will not change.

D. Agricultural or Industrial Production

This permit modification will not have any adverse impacts to regional land use since it is only changing how the operation is limited from hours to million cubic feet of natural gas per year.

E. Human Health

The proposed modification would not result in the change of emission limits of air pollutants as this is an existing facility and the emission limits will not change.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed modification to this permit will have no impacts to access and quality of recreational and wilderness activities because the modification is only changing how the operating limitation is calculated.

G. Quantity and Distribution of Employment

This modification will not change employment in the area as this is an existing facility and as this is an existing facility and the emission limits will not change.

H. Distribution of Population

No change as this is an existing facility and as this is an existing facility and the emission limits will not change.

I. Demands for Government Services

No change as this is an existing facility and as this is an existing facility and the emission limits will not change.

J. Industrial and Commercial Activity

No change as this is an existing facility and as this is an existing facility and the emission limits will not change.

K. Locally Adopted Environmental Plans and Goals

No change as this is an existing facility and as this is an existing facility and the emission limits will not change.

L. Cumulative and Secondary Impacts

Overall, this modification will have no cumulative and secondary impacts on the social and economic aspects of the human environment as this is an existing facility and as this is an existing facility and the emission limits will not change.

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