Montana Department of Environmental Quality

Air, Energy & Mining Division

May 21, 2025

Adam Bennett
Big Sky Bioenergy, LLC
Big Sky Bioenergy Deer Lodge Facility
181 Greenhouse Rd.
Deer Lodge, Montana 59722

RE: Final and Effective Montana Air Quality Permit #5329-00

Sent via email: adam@pwrhouse.biz

Dear Adam Bennett:

Montana Air Quality Permit (MAQP) #5329-00 for the above-named permittee is deemed final and effective as of May 21, 2025, by the Montana Department of Environmental Quality (DEQ). All conditions of the Decision remain the same. A copy of final MAQP #5329-00 is enclosed.

For DEQ,

Eric Merchant, Supervisor
Air Quality Permitting Services Section
Air Quality Bureau
Air, Energy, and Mining Division
(406) 444-3626
eric.merchant2@mt.gov

Emily Hultin, Air Quality Engineering Scientist
Air Quality Permitting Services Section
Air Quality Bureau
Air, Energy, and Mining Division
(406) 444-2049
emily.hultin@mt.gov

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

Montana Air Quality Permit #5329-00

Big Sky Bioenergy, LLC
BSBE Deer Lodge Site
Section 4, Township 7 North, Range 9 West
270 W. Kagy, Unit E
Bozeman, MT 59715

Final and Effective Date:
May 21, 2025

MONTANA AIR QUALITY PERMIT

Issued To: Big Sky Bioenergy, LLC. 270 W. Kagy, Unit E Bozeman, MT 59715	MAQP: #5329-00 Application Complete: 03/10/2025 Preliminary Determination Issued: 04/15/2025 DEQ's Decision Issued: 05/05/2025 Permit Final: 05/21/2025

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Big Sky Bioenergy, LLC (BSBE), 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

The proposed BSBE facility will include a wood/wood residuals-fired (biomass) combined heat and power (CHP) boiler rated up to 110,000 bone dry tons/year (BDT/yr) with a multiclone, Electrostatic Precipitator (ESP), and associated equipment.

B. Plant Location

The facility is located in the SW quarter of Section 4, Township 7 North, Range 9 West, in Powell County, Montana. The physical location of the plant is 181 Greenhouse Rd, in Deer Lodge, Montana.

Section II: Conditions and Limitations

A. Emission Limitations

1. BSBE 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).

2. BSBE 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).

3. BSBE 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.2 (ARM 17.8.749).

4. BSBE shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart A and Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart A and Subpart Db).

5. BSBE shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 63, Subpart A and Subpart JJJJJJ. (ARM 17.8.342 and 40 CFR 63, Subpart A, Subpart JJJJJJ).

6. BSBE shall install, operate, and maintain a multiclone and an ESP with a guaranteed 95 percent filterable particulate matter (filterable PM) control efficiency on the CHP boiler (ARM 17.8.752).

7. Total filterable PM (PM > 10 microns, PM_{10}, $PM_{2.5}$) emissions from the CHP boiler shall be limited to a rate of 0.030 lb/MMBtu of heat input (40 CFR 63, Subpart JJJJJJ and ARM 17.8.752).

8. NOx emissions from the CHP boiler shall be limited to 0.180 lb/MMBtu (ARM 17.8.752).

9. CO emissions from the CHP boiler shall be limited to 0.113 lb/MMBtu (ARM 17.8.752).

10. VOC emissions from the CHP boiler shall be limited to 0.007 lb/MMBtu (ARM 17.8.752).

11. SO_2 emissions from the CHP boiler shall be limited to 0.045 lb/MMBtu (ARM 17.8.752).

B. Testing Requirements

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

2. BSBE must follow all applicable source testing requirements of 40 CFR 63, Subpart JJJJJJ (40 CFR 63, Subpart JJJJJJ).

3. BSBE will perform an initial source test within 180 days of startup, to demonstrate compliance with the applicable limits (40 CFR 63, Subpart JJJJJJ and 40 CFR 60, Subpart Db, ARM 17.8.752):

   a. Filterable PM (PM > 10 microns, PM_{10}, $PM_{2.5}$) limit of 0.030 lb/MMBtu
   b. NO_X limit of 0.18 lb/MMBtu
   c. CO limit of 0.113 lb/MMBtu
   d. VOC limit of 0.007 lb/MMBtu
   e. SO_2 limit of 0.045 lb/MMBtu

4. DEQ may require further testing (ARM 17.8.105).

C. Operational Reporting Requirements

1. BSBE shall supply DEQ with annual production information for all emission points, as required by DEQ in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to DEQ by the date required in the emission inventory request. Information shall be in the units required by DEQ. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. BSBE shall supply DEQ with annual COMs/CEMs reporting requirements as specified in 40 CFR 60, Subpart Db and 40 CFR 63, Subpart JJJJJJ (40 CFR 60, Subpart Db and 40 CFR 63, Subpart JJJJJJ).

3. BSBE shall notify DEQ of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include the addition of a new emissions unit, change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation. The notice must be submitted to DEQ, in writing, 10 days prior to 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).

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

D. Continuous Emissions Monitoring Systems

1. BSBE shall install, calibrate, maintain, and operate monitoring devices for the continuous measurement of the change in PM through the Multiclone and Electrostatic Precipitator (ESP). This continuous opacity monitoring system (COMS), devices must be certified by the manufacturer to be accurate within five percent and must be calibrated on an annual basis in accordance with the manufacturer's instructions (ARM 17.8.749 and 40 CFR 60, Subpart Db).

2. BSBE shall install, calibrate, maintain and operate continuous emission monitoring (CEMs) devices for the continuous measurement SO_2, NO_X, and CO concentrations, and either O_2 or CO_2 concentrations and shall record the output

of the systems. The CEMs must be certified on an annual basis in accordance with the manufacturer's instructions (40 CFR 60, Subpart Db ARM 17.8.752).

E. Notification

BSBE shall provide DEQ with written notification of the following information within the specified time periods (ARM 17.8.749):

1. Start-up date of construction of the installation of EU001, the CHP Boiler, within 15 days of construction commencement.
2. Commencement of operation of the EU001, CHP Boiler, within 15 days of start-up.
3. BSBE shall provide to DEQ any required notifications under 40 CFR 60, Subpart JJJJJJ.

SECTION III: General Conditions

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

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

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

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

E. Appeals – Any person or persons jointly or severally adversely affected by DEQ's decision may request, within 15 days after DEQ renders its decision, upon affidavit setting forth the grounds therefor, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay DEQ's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of DEQ's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, DEQ's decision on the application is final 16 days after DEQ's decision is made.

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

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

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

Montana Air Quality Permit Analysis
Big Sky Bioenergy, LLC
MAQP #5329-00

I. Introduction/Process Description

Big Sky Bioenergy (BSBE) owns and operates a combined heat and power (CHP) boiler. The facility is located in Deer Lodge, Montana. In Powell County, in the SW quarter of Section 4, Township 7 North, and Range 9 West. The facility is known as the BSBE Deer Lodge Facility.

A. Permitted Equipment

One combined heat and power (CHP) boiler with Multi-clone and Electrostatic Precipitator (ESP).

- The CHP boiler is rated up to 110,000 bone dry tons (BDT) per year of wood/wood residuals. Emissions from the CHP boiler are controlled by mechanical multi-clones and an electrostatic precipitator (ESP). Based on an anticipated heat content of 16 MM BTU/BDT and 8,760 hour per year the boiler would be rated at 201 MMBtu/hr.
- Associated Equipment

B. Source Description

The BSBE CHP boiler will gasify and combust sawdust and other wood residuals from the co-located Sun Mountain Lumber (SML) facility to produce steam and biochar. Biochar is black carbon that is produced from biomass sources. This transforms the biomass carbon into a more stable form (carbon sequestration). The steam generated by the CHP boiler will be supplied to the SML facility to provide heat for drying lumber in the kilns.

C. Response to Public Comments

No public comments were received.

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 DEQ. Upon request, DEQ will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

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

1. 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 DEQ, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by DEQ.

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

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

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

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

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

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

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

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

1. <u>ARM 17.8.304 Visible Air Contaminants</u>. 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. <u>ARM 17.8.308 Particulate Matter, Airborne</u>. (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, BSBD 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. <u>ARM 17.8.309 Particulate Matter, Fuel Burning Equipment</u>. 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. <u>ARM 17.8.310 Particulate Matter, Industrial Process</u>. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

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

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

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

    a. <u>40 CFR 60, Subpart A – General Provisions</u> apply to all equipment or facilities subject to an NSPS Subpart as listed below:

    b. <u>40 CFR 60, Subpart Db –</u> Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. This rule requires any facility to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1942, and that has a heat input capacity from fuels combusted in the unit of greater than 29 megawatts (MW) or 100MMBtu/hr and less than 250 MMBtu/hr and will install and operate a continuous opacity monitoring system (COMs). BSBE is subject to this subpart.

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

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

   b. 40 CFR 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources. This rule requires that all sources be subject to this if they own or operate an industrial, commercial, or institutional boiler, as defined in 40 CFR 63.11237, that is located at, or is a part of, an area source of hazardous air pollutants (HAP), as defined in 40 CFR 63.2, except as specified in 40 CFR 63.11195. BSBE is subject to this subpart.

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. BSBE 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 modified stack for BSBE is below the allowable 65-meter 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 DEQ. BSBE submitted the appropriate permit application fee for the current permit action.

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

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

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

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

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the potential to emit (PTE) greater than 25 tons per year of any pollutant. BSBE has a PTE greater than 25 tons per year of particulate matter (PM), oxides of sulfur (SO_X), oxides of nitrogen (NO_X), and carbon monoxide (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. BSBE submitted the required permit application for the current permit action. 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. BSBE submitted an affidavit of publication of public notice for the January 16, 2025, issue of the *Phillipsburg Mail*, a newspaper of general circulation in the Town of Phillipsburg, Montana in Powell County, as proof of compliance with the public notice requirements.

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

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

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

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving BSBE of the responsibility for complying

with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

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

11. ARM 17.8.762 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.

12. 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).

13. 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.

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

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 tons/year of any pollutant;

    b. PTE > 10 tons/year of any one hazardous air pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the DEQ may establish by rule; or

    c. PTE > 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (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 MAQP #5329-00 for BSBE, the following conclusions were made:

    a. The facility's PTE is greater than 100 tons/year for any pollutant.

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

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

    d. This facility is subject to the current NSPS subparts: 40 CFR 60, Subpart A and Db.

    e. This facility is subject to the current NESHAP standards: 40 CFR 63, Subpart A, Subpart JJJJJJ.

    f. This source is not a Title IV affected source, or a solid waste combustion unit.

    g. This source is an EPA designated Title V source.

Based on these facts, DEQ determined that BSBE is subject to the Title V operating permit program.

III. BACT Determination

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

A BACT analysis was submitted by BSBE in permit application #5329-00, addressing some available methods of controlling emissions from the CHP boiler. DEQ reviewed these methods, as well as previous BACT determinations. The following control options have been reviewed by DEQ in order to make the following BACT determinations.

Wood-fired Boiler BACT Background Information

BSBE is proposing the installation of a wood-fired boiler designed to process up to 110,000 BDT/yr of wood materials by burning or producing biochar. The highest emission rates are based on combustion of the entire wood-feed capacity, with a maximum design combustion heat input rate capacity of 200.9 MMBtu/hr. BSBE is proposing to control filterable PM emissions from the proposed boiler with a mechanical collector (multiclone) followed by an ESP. Further, BSBE proposes to control NO_X, CO, and VOC emissions through proper boiler design and operation. SO_2 emissions are a function of the sulfur content of the wood fuel.

A BACT analysis is provided for total filterable PM ($PM/PM_{10}/PM_{2.5}$), NO_X, CO and VOC, and SO_2 emissions from the wood-fired boiler. Research of the Environmental Protection Agency's (EPA) RACT/BACT/LAER clearinghouse (RBLC) was used for this analysis, based on BACT determinations for the past 10 years for boilers in the RBLC category 12.120. Table 1 contains a list of comparable BACT determinations from the RBLC. All the boilers listed in Table 1 are fired with wood and/or bark. If no BACT determination was listed in the RBLC for an individual pollutant, the table indicates 'na'. The first RBLC entry listed in Table 1 (ME-0040) is the best match for consideration regarding the proposed BSBE CHP boiler.

Table 1. RBLC BACT Determinations for Biomass Boilers

RBLC No.	Boiler Size (MMBtu/hr)	CO Limit (lb/MMBtu)	NO_X Limit (lb/MMBtu)	Total PM_{10} Limit (lb/MMBtu)	Total $PM_{2.5}$ Limit (lb/MMBtu)
ME-0040	167.3	0.30	0.15	0.047	0.047
TX-0842	149.25	0.50	na	na	na
MI-0421	110.0	0.33	0.86	0.26	0.15
MI-0425	110.0	0.33	0.86	0.26	0.15
MI-0448	110.0	0.33	1.55	0.26	0.15
ME-0039	149.0	0.40	na	na	na
LA-0335	154.2	1.81	na	na	na

BACT Analysis for Filterable PM ($PM/PM_{10}/PM_{2.5}$)

Step 1: Identify available control technologies

A variety of filterable PM control technologies are available for removing filterable PM from the wood-fired CHP boiler exhaust. The following available control technologies have been considered in this BACT analysis and are listed from least to most efficient, as follows:

- mechanical collector (multiclone)
- wet scrubber
- fabric filter baghouse (baghouse)
- electrostatic precipitator (ESP)

Step 2: Eliminate technically infeasible options

Wet scrubbers, baghouses, and ESPs are generally used in series with a mechanical collection system, such as the proposed multiclone.

The multiclone removes the bulk of the large filterable PM and cinders and reduces filterable PM loading on the secondary control equipment (i.e., wet scrubber, baghouse, or ESP). As stated, the use of a multiclone can be effective for the control of large filterable PM (> PM_{10}); however, a multiclone alone would not provide adequate control of PM_{10} and $PM_{2.5}$. The control efficiency of mechanically aided separation using a multiclone is approximately 30% for filterable PM (EPA Air Pollution Control Technology Fact Sheet). The use of mechanical collection such as the proposed mutliclone is deemed technically feasible for the control of filterable PM emissions from the proposed CHP boiler.

In a wet scrubbing process, liquid or solid particles are removed from a gas stream by transferring them to a liquid. Wet scrubbers are not commonly used on new wood-fired boiler installations such as the proposed CHP boiler. Further, according to the EPA's Air Pollution Control Technology Fact Sheet, the control efficiency for filterable PM of a venturi scrubber is 70%. The use of a wet scrubber is deemed technically feasible for the control of filterable PM emissions from the proposed CHP boiler.

Fabric filter baghouses are not commonly installed on wood-fired boilers, such as the CHP boiler, primarily because of fire risk. The fabric filter bags within the baghouse can become caked with a layer of wood ash containing unburned carbon. If a spark escaped the proposed multiclone, it could easily start a fire within the baghouse. Therefore, the use of a baghouse to control filterable PM emissions from the proposed CHP boiler would require use of an abort stack to be triggered whenever a spark was detected, or the spark detector equipment was being cleaned. Because of the increased fire risk and the need for a baghouse bypass system, use of a fabric filter baghouse is deemed technically infeasible for the proposed project and will not be considered further.

ESPs are commonly installed on wood-fired boilers such as the proposed CHP boiler and represent a technically feasible control option for filterable PM. ESP's remove particles from a gas stream by using electrical energy to charge particles either positively or negatively. The charge particles are then attracted to collector plates carrying the opposite charge. According to the EPA Air Pollution Control Technology Fact Sheets, ESPs have a control efficiency of 99 to 99.9%.

Step 3: Rank remaining control technologies by control effectiveness

The following control technologies are available and deemed technically feasible for the control of filterable PM from the proposed CHP boiler. The controls are listed from least to most efficient:

- mechanical collectors (multiclone): ~ 30% control efficiency
- wet scrubber: ~ 70% control efficiency
- electrostatic precipitator (ESP): 90-99%+ control efficiency

Step 4: Evaluate energy, environmental and economic considerations, top-down procedure

Wet scrubbers and ESPs are generally used in-series with a mechanical collector system, such as the proposed multiclone.

A multiclone would remove the bulk of large filterable PM (> PM_{10}) and cinders from the CHP boiler exhaust, thereby reducing filterable PM loading on the secondary control equipment (ESP, wet scrubber). Use of a multiclone can be effective for the control of filterable PM generally larger than PM_{10} and no additional environmental or economic consequences would be expected.

The use of a wet scrubber would create an additional wastewater stream, which may be considered an unacceptable environmental consequence at the Deer Lodge location. The wastewater would need to be managed and/or disposed of in an environmentally sound manner. Further, the wet scrubber would have lower filterable PM control efficiency than the proposed ESP; therefore, the use of a wet scrubber to control filterable PM emissions from the proposed CHP boiler will not be considered further in this BACT analysis.

ESP technology provides the highest level of filterable PM control available and is safe to use on a wood-fired boiler, such as the proposed CHP boiler. BSBE must install an ESP with a guaranteed filterable PM emission rate of 0.030 lb/MMBtu with a 95% control efficiency in order to comply with federal regulations (40 CFR 63, Subpart JJJJJJ). The proposed emission rate is consistent with the RBLC entry for ME-0040 (see Table 1, above) and would also meet the minimum requirements of 40 CFR 63, Subpart JJJJJJ.

BSBE is proposing to install a multiclone and an ESP for the control of filterable PM emissions from the wood-fired CFB boiler.

Step 5: Select Filterable PM (PM > 10 microns, PM_{10}, $PM_{2.5}$) BACT

Based on the above analysis, BACT for filterable PM emissions from the CHP boiler is deemed the use of multiclone and ESP. The ESP must achieve 95% filterable PM control efficiency, or better, to achieve an emission limit of 0.030 lb/MMBtu.

The EPA fact sheets used for evaluation of available PM control technology are included in Appendix C of this application. The multiclone and ESP emissions calculation methodologies are discussed in Section 3, above, and the complete calculations are shown in Appendix B of the permit application.

BACT Analysis for NO_X

As shown in Table 1, above, recent NO_x BACT Determinations included in the RBLC for Biomass Boilers vary widely, ranging from 0.15 lb/MMBtu to 1.55 lb/MMBtu. The RBLC listings do not provide details regarding the permitted NO_X emissions control technologies deemed BACT. The proposed wood-fired boiler will be designed to minimize NO_X formation in the combustion process. The proposed NO_X emission rate of 0.180 lb/MMBtu is comparable to the lowest NO_X emission rate in the RBLC of 0.15 lb/MMBtu and within the range of similar NO_X BACT determinations, as see in Table 1 above.

Step 1: Identify available control technologies

The following add-on controls for NO_X emissions are considered for the proposed wood-fired CHP boiler, listed from least to most efficient:

- Low NOx Boiler Configuration
- Flue Gas Recirculation (FGR)/Overfire Air (OFA)
- Selective Non-catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

Step 2: Eliminate technically infeasible options

FGR and OFA involve NO_X combustion techniques that reduce the formation of NO_X emissions in the boiler. Modern boilers, such as the proposed CHP boiler, incorporate multiple low-NO_x technologies to achieve emission rates as low as the rates being proposed. Specification of FGR/OFA is not expected to show improved emissions over the proposed emission rate of 0.18 lb/MMBtu. NOX limits are not common practice with new boilers such as the CHP boiler. Therefore, CHP boiler retrofit with FGR/OFA will not be considered further in this BACT analysis.

Step 3: Rank remaining control technologies by control effectiveness

The following control technologies are available and deemed technically feasible for the control of NO_X emissions from the proposed CHP boiler. The controls are listed from least to most efficient:

- Low NOx Boiler configuration
- SNCR
- SCR

Both SNCR and SCR are technically available control technologies for reducing NO_X emissions from the wood-fired boiler.

The EPA's fact sheet for SNCR lists the range of control efficiency from 30% to 50%. As explained in further detail below, the assumed control efficiency for SNCR for this application is 34% when applied to the proposed low-NO_X boiler.

The EPA's fact sheet for SCR lists a range of control efficiency from 70% to 90%. As explained in further detail below, the assumed control efficiency for SCR for this application is 77.8% when applied to the proposed low-NO_X boiler.

Step 4: Energy, environmental and economic considerations, top-down procedure

The estimated costs of the remaining technologies are provided in Step 4 of the BACT analysis process and are based on EPA reference materials (see below). Calculated emission rate values are reported to three significant figures, and costs are reported to the nearest $100. Since EPA's cost information is from previous years, the costs have advanced to the comparable amount in 2025 dollars using the usinflationcalculator.com website.

Selective Non-catalytic Reduction (SNCR)
SNCR is a post combustion emissions control technology for reducing NO_X by injecting an ammonia type reactant into the furnace at a properly determined location. SNCR can use ammonia or urea as a NO_X reduction agent. Wood-fired boilers are typically controlled using ammonia as the reagent. The reference for SNCR control efficiency and cost is the SNCR chapter (Chapter 1) of the EPA Cost Manual for NO_X, revised in April 2019. The reference can be found on the US EPA's webpage titled Cost Reports and Guidance for Air Pollution Regulations. The EPA website also contains a Microsoft Excel workbook to implement the cost control guidance, but it was not used because it is not set up for woodfired boilers.

The SNCR process begins when ammonia (NH_3) is vaporized and injected into the heat of the boiler. Within the appropriate temperature range, the gas-phase ammonia decomposes into free radicals including NH_3 and NH_2. After a series of reactions, the ammonia radicals bind with NO_X and reduce it to N_2 and H_2O. NO_X consists of both NO and NO_2, with the stoichiometric reactions being slightly different. An estimated 90% of the NO_X emitted from wood combustion is emitted as NO, and 10% emitted as NO_2.

The rate of the SNCR reduction reaction determines the amount of NO_X removed from the flue gas. The important design and operational factors that affect the reduction of NO_X by an SNCR system include:

- Reaction temperature range
- Residence time available in the optimum temperature range
- Degree of mixing between the injected reagent and the combustion gases
- Uncontrolled NO_X concentration level
- Molar ratio of injected reagent to uncontrolled NO_X
- Ammonia slip

The NO_X reduction reaction occurs within a specific temperature range where adequate heat is available to drive the reaction. Installation of SNCR requires that the boiler design be able to accommodate the SNCR equipment at the installation point. Because the BSBE boiler is in the development phase, no additional costs are included for adapting the design for SNCR.

SNCR Efficiency Determination

The efficiency of SNCR for the proposed BSBE boiler is estimated based on equation 1.17 of the SNCR Control Cost Manual. The normalized stoichiometric ratio (NSR) indicates the actual amount of reagent needed to achieve the targeted NO_X reduction. The actual quantity of reagent is greater than the theoretical quantity due to reaction kinetics. Generally, the value of NSR ranges from 0.5-2.0 in industrial and utility boilers. Equation 1.17 of the SNCR reference can be used to estimate NSR based on the incoming NO_X concentration (NO_{XIN}) and the expected NO_X control efficiency (η_{NOx}).

$$NSR = [2.0 * NO_{XIN} + 0.7] * \eta_{NOx} / NO_{XIN}$$

Using the proposed boiler NO_X emission rate gives an NO_{XIN} value of 0.18 lb/MMBtu. With a goal control efficiency of 50%, η_{NOx} value of 0.5, the required NSR would be 2.94 as calculated below. This value of NSR is unacceptably high due to the potential levels of ammonia slip.

$$NSR = [2.0 * 0.18 + 0.7] * 0.5 / 0.18$$
$$= 2.94$$

The value of NSR for this analysis has been set at 2.0, which is the top of the range of NSR values listed in the reference. Using equation 1.17 with an assumed NSR of 2.0, the calculated value of η_{NOx} would be 0.34 or 34%.

$$\eta_{NOx} = [2.0 * 0.18] / [2 * 0.18 + 0.7]$$
$$= 0.34$$

The SNCR BACT calculations for this application have been performed using an NSR value of 2.0 and a control efficiency of 34%.

NO_X Removal Using SNCR

The proposed wood-fired boiler NO_X emission rate is 36.2 lb/hr and 158 tpy, and on a concentration basis is approximately 74 parts per million (ppm). The tonnage of NO_X removed annually is calculated using as follows:

$$NO_X \text{ removed/yr} = 158 \text{ tpy} * 34\%$$
$$= 53.7 \text{ tpy}$$

$$NO_X \text{ removed/hr} = 36.2 \text{ lb/hr} * 34\%$$
$$= 12.3 \text{ lb/hr}$$

SNCR Reagent Requirements and Cost

As shown in equation 1.13 of the SNCR reference, the NSR is the ratio of equivalent NH_3 injected to mols of uncontrolled NO_X. For estimation purposes, the mols of NO_X are equivalent to the mols of NO_2. Once NSR is estimated, the rate of reagent consumption or mass flow rate of the reagent ($m_{reagent}$), expressed as lb/hr, can be calculated using equation 1.18 of the reference.

$$M_{reagent} = [NO_{xin} * Q_B * NSR * M_{reagent})] / [M_{NOx} * SR_T]$$

NO_{XIN} and NSR are defined above. Q_B is the proposed boiler heat input rate of 200.9 MMBtu/hr. $M_{reagent}$ is the reagent molecular weight - 17.03 g/gmol for ammonia. M_{NOx} is the molecular weight of NO_2, which is 46.01. SR_T is the ratio of the equivalent mols of NH_3 per mole of reagent - the value is 1 for ammonia.

$$m_{reagent} = [0.18 \text{ lb/MMBtu} * 200.9 \text{ MMBtu/hr} * 2.0 * 17.03] / [46.01 * 1]$$
$$= 26.8 \text{ lb/hr}$$

According to Table 1-4 of the reference, the concentration of aqueous ammonia reagent normally supplied for SNCR is 19%. The mass flow rate of the aqueous reagent solution (m_{sol}) is calculated using equation 1.19 as follows:

$$m_{sol} = 26.8 \text{ lb/hr} \div 19\%$$
$$= 141 \text{ lb/hour}$$

The density of the 19% aqueous ammonia reagent solution is 58 lb/ft^3, and the volume of aqueous ammonia reagent required is calculated as follows:

$$141 \text{ lb/hr} \div 58 \text{ lb/ft}^3 * 7.48 \text{ gallon/ft}^3 = 18.2 \text{ gallons per hour}$$

When operating 8,760 hours per year, a total of 618 tons or 159,400 gallons of 19% aqueous ammonia would be required. For costing purposes, the cost information was obtained from the example problem for a utility boiler in Section 2.5 of the EPA SCR control cost reference. The cost of 29% ammonia solution was $0.293/gallon in 2016, which is $0.38/gallon in 2025 dollars. The cost of $0.38/gallon is used as the estimated cost of 19% aqueous ammonia for this analysis and is assumed to include the cost of transportation.

The estimated annual cost of ammonia reagent is:

159,400 gallons/yr * $0.38/gallon = $60,600/yr

SNCR Estimated Capital Costs

Table 1.3 of the EPA SNCR control cost reference lists capital cost data for boilers, including wood-fired boilers ranging in size from 245 to 900 MMBtu/hr. The corresponding capital costs range from $1,200 to $2,000 per MMBtu/hr, in 1999 dollars. For this analysis, an assumed initial capital cost of $1,600 per MMBtu/hr is used, which is inflated to $3,030 per MMBtu/hr in 2025 dollars.

According to the reference, the base cost for SNCR systems located at higher elevations should be increased by an elevation factor (ELEVF) based on the ratio of the atmospheric pressure between sea level and the location of the system. Equation 1.23 in the SNCR reference is used to calculate the atmospheric pressure at the site elevation in units of points per square inch actual (psia). For the Deer Lodge location with an elevation of 4,550 feet (mean sea level), the local pressure is calculated to be 12.44 psia. Based on equation 1.22, the elevation factor is 1.18, meaning that SNCR costs are increased by 18% to account for the higher elevation. Using the cost of $3,030 per MMBtu/hr, and applying the elevation factor, the base cost of the SNCR equipment is calculated as follows:

$$
\begin{aligned}
SNCR_{cost} &= \$3{,}030/(MMBtu/hr) * 200.9\ MMBtu/hr * 1.18 \\
&= \$718{,}300
\end{aligned}
$$

SNCR Total Capital Investment

Section 1.4.1.3 of the SNCR control cost reference includes cost calculation methodology for coal-fired industrial boilers. The cost information for a coal-fired boiler is used to approximate the SNCR costs for the proposed CHP wood-fired boiler, excluding some of the additional considerations for coal. Equation 1.31 calculates the total capital investment for SNCR (TCI) as 1.3 times the sum of the $SNCR_{COST}$, air pre-heater costs, and balance of plant costs. The air pre-heater cost is unique to coal installations and is not included.

The balance of plant cost (BOP_{cost}) includes cost items such as ID and booster fans, piping, and auxiliary power modifications necessary for the SNCR unit. BOP_{cost} is calculated based on SNCR equation 1.27 as follows:

$$
\begin{aligned}
BOPcost &= 320{,}000 \text{ x } (B_{MW})^{0.33} * (NO_X \text{ removed/hr})^{0.12} * BTF * RF \\
&= 320{,}000 \text{ x } (20.09)^{0.33} * (12.3\ lb/hr)^{0.12} * 0.75 * 0.8 \\
&= \$698{,}300
\end{aligned}
$$

B_{MW} is the boiler MW rating at full capacity, calculated by dividing Q_B by the net plant heat rate (NPHR) of 10 MMBtu/MW.

$$
\begin{aligned}
B_{MW} &= 200.9\ MMBtu/hr \div 10\ MMBtu/MWh \\
&= 20.09\ MW
\end{aligned}
$$

BTF is the boiler type factor, which is 0.75 for fluidized bed boilers and 1 for other boilers. Because of the biochar function, the BSBE boiler is being treated as a fluidized bed boiler.

$$
\begin{aligned}
BOP_{cost} &= 320{,}000 \text{ x } (20.09)^{0.33} * (12.3\ lb/hr)^{0.12} * 0.75 * 0.8 \\
&= \$698{,}300
\end{aligned}
$$

The TCI equation includes a factor of 1.3 to estimate engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees.

$$TCI = 1.3 * (\$718{,}300 + \$698{,}300) = \$1{,}841{,}600$$

The capital costs are annualized based on a 20-year return period and an 8% interest rate as shown below.

$$\$1{,}841{,}600 * (.08)/(1-(1.08^{-20})) = \$187{,}600/yr$$

Direct Annual Costs

Direct annual costs (DAC) account for purchase of reagent, maintenance, utilities (electrical power and water,), and any additional coal or ash disposal (not included). Equation 1.38 of the SNCR reference shows DAC as the sum of annual maintenance costs, annual reagent cost, annual electricity cost, and water and disposal costs. It is assumed that ammonia will be purchased in aqueous form, so the cost of water is not included. As calculated above, the estimated annual reagent cost is $60,600/yr.

Annual maintenance cost is estimated to be 1.5% of the TCI, as shown in equation 1.39 of the SNCR reference. For this analysis, the annual maintenance cost is $27,400.

The electrical power consumption of the SNCR, P, in kW, is estimated using equation 1.42 of the SNCR reference.

$$
\begin{aligned}
P &= [0.47 * NO_{XIN} * NSR * Q_B] / NPHR \\
&= [0.47 * 0.18 \text{ lb/MMBtu} * 2.0 * 200.9 \text{ MMBtu/hr}] / [10 \text{ MMBtu/MWh}] \\
&= 3.4 \text{ kWh}
\end{aligned}
$$

The annual cost of electricity is estimated using equation 1.43:

Annual electricity cost =
3.4 kWh * cost of electricity ($0.127/kWh) * 8760 hr/yr
= $3,800/yr

The combined components of the DAC are totaled below:

DAC =$60,600/yr – reagent cost
=$27,400/yr - maintenance cost
=$3,800/yr - electricity cost
=$91,800/yr – total

SNCR Total Annual Costs

Total annual costs (TAC) consist of direct annual costs, capital recovery costs, indirect costs (not included), and byproduct recovery credits (not applicable). In summary, the total annual cost of installing and operating SNCR on the BSBE boiler is estimated to be:

TAC = $91,800/yr + $187,600/yr
= $279,400/yr

The cost per ton of NO_X removed is the TAC divided by the tons of NO_X removed each year.
Cost per ton removed = $279,400/yr ÷ 53.7 tons/year
= $5,200 per ton of NO_X removed

Selective Catalytic Reduction (SCR)

Like SNCR, the SCR process is based on the chemical reduction of the NO_X molecule. The primary difference between SNCR and SCR is that SCR employs a metal-based catalyst with activated sites to increase the rate of the reduction reaction. The reference for SCR control efficiency and cost is the SCR chapter (Chapter 2) of the EPA Cost Manual for NO_X, revised in April 2019. The reference can be found in the US EPA webpage titled Cost Reports and Guidance for Air Pollution

Regulations. The EPA website also contains a Microsoft Excel workbook to implement the control cost guidance, but it was not used because it is not set up for wood-fired boilers.

According to the EPA SCR reference, SCR is typically implemented on stationary source combustion units requiring a higher level of NO_X reduction than achievable by SNCR or combustion controls. Theoretically, SCR systems can be designed for NO_X removal efficiencies near 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NO_X controls such as low-NO_X burner (LNB) or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/MMBtu.

SCR Removal Efficiency

The NO_X removal efficiency for this BACT analysis is based on the inlet NO_X concentration of 0.18 lb/MMBtu and the lowest possible boiler SCR outlet NO_X concentration of 0.04 lb/MMBtu. The NO_X removal efficiency (η_{NOX}) is calculated as follows:

$$\eta_{NOX} = (0.18 \text{ lb/MMBtu} – 0.04 \text{ lb/MMBtu}) / (0.18 \text{ lb/MMBtu}) = 0.778$$

$$\begin{aligned} NO_X \text{ removed/yr} &= 158 \text{ tpy} * 77.8\% \\ &= 123 \text{ tpy} \end{aligned}$$

$$\begin{aligned} NO_X \text{ removed/hr} &= 36.2 \text{ lb/hr} * 77.8\% \\ &= 28.2 \text{ lb/hr} \end{aligned}$$

On a boiler, a SCR system is typically installed in the flue gas duct, positioned between the furnace economizer and the air preheater; essentially, close to the boiler exit where the flue gas temperature is still high enough to facilitate the chemical reaction within the catalyst chamber. No additional costs for heating the flue gas are included in the SCR BACT analysis. Section 2.4.1.3 of the SCR Control Cost Manual includes cost calculation methodology for coal-fired industrial boilers. The coal cost information is used to approximate the SCR costs for a wood-fired boiler, with elimination of coal-specific costs. Equation 2.47 calculates the total capital investment for SCR boiler (TCI) as 1.3 times the sum of the $SNCR_{COST}$, air preheater costs, reagent preparation cost, and balance of plant costs. The air pre-heater cost is unique to coal installations and is not included. The TCI equation includes a factor of 1.3 to estimate engineering and construction management costs, installation, labor adjustment for the SCR, and contractor profit and fees.

$$TCI = 1.3 * (SCR_{COST} + RPC + BPC)$$

SCR cost (SCR_{COST}) is estimated using equation 2.48 of the SCR reference. The capital costs for the SCR base unit include costs for the inlet ductwork, the reactor and the required bypass equipment. Similarly to the SNCR cost calculation, the SCR cost includes an elevation factor of 1.18. It also includes a retrofit factor (RF) which is 0.8 for new construction.

The SCR costs are calculated as follows:

$$SCR_{COST} = 310{,}000 * (\eta_{NOX} / 80)^{0.2} * (0.1 * Q_B)^{0.92} * ELEVF * RF$$
$$SCR_{COST} = 310{,}000 * (0.778/80)^{0.2} * (0.1 * 200.9)^{0.92} * 1.18 * 0.8$$
$$= \$1{,}830{,}900$$

The reagent preparation cost (RPC) is calculated based on equation 2.49 of the SCR reference.

$$RPC = 564{,}000 * ((NO_{XIN} * Q_B) * \eta_{NOX})^{0.25} * RF$$
$$RPC = 564{,}000 * ((0.18 * 200.9)*0.778)^{0.25} * 0.8$$
$$= \$1{,}039{,}100$$

The balance of plant costs (BPC) includes cost items such as ID and booster fans, piping, and auxiliary power modifications necessary for the SCR unit. The BPC are calculated based on equation 2.51 as follows:

$$BPC = 529{,}000 * (0.1 \text{ x } Q_B \text{ x } CoalF)^{0.42} * ELEVF * RF$$

CoalF is the coal factor, which is set at 1 for non-coal fuel.

$$BPC = 529{,}000 \text{ x } (0.1 \text{ x } 200.9 \text{ x } 1)^{0.42} \text{ x } 1.18 \text{ x } 0.8$$
$$= \$1{,}760{,}700$$

$$TCI = 1.3 * (\$1{,}830{,}900 + \$1{,}039{,}100 + \$1{,}760{,}700)$$
$$= \$6{,}019{,}900$$

The capital costs are annualized based on a 20-year return period and an 8% interest rate as shown below.

$$\$6{,}019{,}900 * (.08)/(1-(1.08-20)) = \$613{,}100/yr$$

SCR Direct Annual Cost

Direct annual costs (DAC) consist of annual maintenance costs, annual reagent cost, annual electricity cost and annual catalyst replacement cost. Annual maintenance labor is estimated to be 0.5% of the TCI, according to the SCR reference. For this analysis, the annual maintenance cost is $30,100.

Based on equation 2.35 of the SCR reference, the rate of reagent consumption or mass flow rate of the reagent, $m_{reagent}$, generally expressed as pounds per hour (lb/hr), can be calculated as follows:

$$m_{reagent} = NO_{xin} * Q_B * \eta_{NOX} * SRF * M_{reagent} / M_{NOx}$$
$$m_{reagent} = [0.18 \text{ lb/MMBtu} * 200.9 \text{ MMBtu/hr} * 1.05 \text{ (SRF)} * 17.03 / 46.01]$$
$$= 14.05 \text{ lb/hr}$$

The stoichiometric ratio factor (SRF) indicates the actual amount of reagent needed in SCR to achieve the targeted NO_X reduction. Typical SRF values are higher than theoretical values due to the complexity of the reactions involving the catalyst and limited mixing.

According to the SCR reference, the value for *SRF* in a typical SCR system, using ammonia as reagent, is approximately 1.05.

The mass flowrate a 19% aqueous reagent solution (m_{sol}) is calculated using equation 1.19 as follows:

$$m_{sol} = 14.05 \text{ lb/hr} \div 19\% = 73.9 \text{ lb/hour}$$

The density of the 19% aqueous ammonia reagent solution is 58 lb/ft^3, and the volume of aqueous ammonia reagent required is calculated as follows:

$$73.9 \text{ lb/hr} \div 58 \text{ lb/ft}^3 * 7.48 \text{ gallon/ft}^3 = 9.53 \text{ gallons per hour}$$

When operating 8,760 hours per year, a total of 324 tons or 83,500 gallons of 19% aqueous ammonia would be required. For costing purposes, the cost information was obtained from the example problem for a utility boiler in Section 2.5 of the EPA SCR control cost reference. The cost of 29% ammonia solution was $0.293/gallon in 2016, which is $0.38/gallon in 2025 dollars. The cost of $0.38/gallon is used for this cost estimate. This value is assumed to include transportation. The estimated annual cost of ammonia reagent
is:

$$83{,}500 \text{ gallons/yr} * \$0.38\text{/gallon} = \$31{,}700\text{/yr}$$

The electrical power consumption of SCR on an industrial boiler, P, in kW, is estimated using equation 2.61 of the SCR reference.

$$\begin{aligned} P &= BMW * (1{,}000) * (0.0056) * (CoalF * HRF)^{0.43} \\ &= 20.09 \text{ MW} * (1{,}000) * (0.0056) * (1 * 1)^{0.43} \\ &= 112.5 \text{ kWh} \end{aligned}$$

The CoalF factor is substituted with 1 for non-coal fuels. HRF is the heat rate factor, which is equal to the NPHR/10. In this example, the HRF is equal to 1. BMW = 20.09 MWh.

The annual cost of electricity is estimated using equation 1.43:

$$\begin{aligned} \text{Annual electricity cost} &= 112.5 \text{ kWh} * \text{cost of electricity } (\$0.127\text{/kWh}) * 8760 \text{ hr/yr} \\ &= \$125{,}200\text{/yr} \end{aligned}$$

SCR Reactor Calculations are used to determine the catalyst volume (Volcatalyst). The SCR reference shows that the volume of catalyst, with all the adjustment factors, is roughly 4.4 ft^3/(MMBtu/hr). For the proposed boiler with Qb of 200.9 MMBtu/hr, the estimated catalyst value is 884 ft^3 or 25.0 m^3.

$CC_{replace}$ is the cost of catalyst replacement, in dollars per cubic meter ($/m^3). Based on the example problem for a utility boiler in Section 2.5 of the SCR reference, the catalyst cost, in 2016 dollars was $8,000/m^3. The value converted to 2025 dollars is $10,500/m^3.

According to the SCR reference, the cost for catalyst replacement in all the SCR reactors for a given boiler can be estimated with a simplified annual catalyst replacement methodology.

The replacement cost is estimated by assuming that one third of the total catalyst is replaced every year.

$$CC_{replace} = 25.0\ m^3/yr * \$10,500/m^3 = \$262,500/3\ years = \$87,500/yr$$

In summary, the direct annual costs of installing and operating SCR on the proposed boiler are estimated to be:

DAC = $30,100/yr - maintenance
+ $31,700/yr - reagent
+ $125,200/yr for SCR electricity
+ $87,500/yr for catalyst replacement
= $274,500/yr

SCR Total Annual Costs

Total annual costs (TAC) consist of direct annual costs, capital recovery costs and indirect costs (not included), and byproduct recovery credits (not applicable). In summary, the total annual cost of installing and operating SCR on the BSBE boiler is estimated to be:

TAC = $274,500/yr + $613,100/yr
= $887,600/yr

The cost per ton of NO_X removed is the TAC divided by the tons of NO_X removed each year.

Cost per ton removed = $887,600/yr ÷ 123 tons/year
= $7,200 per ton of NO_x removed

The final step of the BACT economic analysis is the comparative cost analysis of the technically feasible NO_X control options. This comparison is presented in Table 2.

Table 2. Wood Fired Boiler BACT Analysis – NO_X

Control Technology	**% Reduction**	**NO_X Reduction (tons/year)**	**Calculations**
Selective Catalytic Reduction	77.8%	123	158 tpy * 0.778
Selective Non-Catalytic Reduction	34%	53.7	158 tpy * 0.34
Proposed Boiler	0	0	158 tpy
SNCR Parameter	**SNCR Calculations**		
Total Capital Investment (TCI)	$1,841,600		
Capital Recovery Cost 20-Years at 8%	$1,841,600 * (.08)/(1-(1.08-20))= $187,600/yr		
Direct Annual Cost	$91,800/yr		
Total Annual Cost	$279,400/yr		

<table>
<tr><td colspan="2">SCR Capital and Install Cost</td><td colspan="3">$6,019,900</td></tr>
<tr><td colspan="2">Capital Recovery Cost</td><td colspan="3">$6,019,900 * (.08)/(1-(1.08-20))= $613,100/yr</td></tr>
<tr><td colspan="2">Total Annual Cost</td><td colspan="3">$274,500</td></tr>
<tr><th>Control Alternative</th><th>NO_X Reduction (tpy)</th><th>Total Annual Cost ($/yr)</th><th>Cost per Ton NO_X Removed ($/ton)</th><th>Incremental Control Cost ($/ton)</th></tr>
<tr><td>No Add-on Controls</td><td>0</td><td>Base</td><td>Base</td><td>Base</td></tr>
<tr><td>SNCR</td><td>53.7</td><td>$279,400</td><td>$5,200/ton</td><td>$5,200/ton</td></tr>
<tr><td>SCR</td><td>123</td><td>$887,600</td><td>$7,200/ton</td><td>$8,800/ton</td></tr>
</table>

Step 5: Select NO_x BACT

The wood-fired boiler NO_X BACT analysis above shows that the proposed design emission rate of the boiler is comparable to BACT NO_X emission limits for sources listed in the RBLC, see Table 1 above. The calculated cost per ton of NO_X removed is $5,200/ton for SNCR and $7,200/ton for SCR. In highly urbanized areas with high ambient NO_X concentrations, these cost values could indicate that SNCR or SCR is economically feasible. But at the Deer Lodge, Montana site, the excessive cost of add-on NO_X controls represents an economic hardship for the industry, with little environmental benefit.

In addition to cost calculations, the BACT analysis also considers any adverse environmental impacts from the available control technology. Both SNCR and SCR technologies would require the storage and use of aqueous ammonia solutions at the facility. The calculations have been based on a concentration of ammonia in the reagent solution that is not expected to create any safety problems for transportation or storage. The calculated electricity usage for SCR in particular is high and can lead to environmental impacts at the point of electricity generation.

The proposed boiler is designed for low-NO_X emissions without add-on controls. The proposed emission rate is consistent with the lowest BACT determination for the same class of boiler in the RLBC in the last 10 years. Therefore, BACT for NO_X emissions from the proposed wood-fired CHP boiler is good combustion and no add-on control to achieve a NOx emission rate of 0.180 lb/MMBtu.

BACT Analysis – CO and VOC

A top-down BACT analysis for the proposed wood-fired CHP boiler has been performed to determine the CO and VOC emission limits and appropriate control devices. CO and VOC emissions both result from incomplete combustion and are controlled using the same methodology. BSBE proposes to use combustion optimization to minimize formation of CO/VOC as products of incomplete combustion to achieve a CO emission rate of 0.113 lb/MMBtu and a VOC emission rate of 0.007 lb/MMBtu. The proposed boiler without controls will be considered the base case.

The EPA control cost manual does not have a section for CO control, but CO emissions are controlled using the same technology as VOC control. Chapter 2 for incinerators was last updated in September 2016, and EPA released the Air Pollution Control Cost Estimation Spreadsheet for Thermal and Catalytic Oxidizers, written in 2022 and updated in December 2024.

The spreadsheet allows users to estimate the capital and annualized costs for installing and operating oxidizers. Oxidizers control VOCs and HAPs from industrial waste gas streams by oxidizing organic compounds to carbon dioxide and water. For this analysis, the spreadsheet has been used for combined CO and VOC control. The cost per ton controlled is for control of the CO plus the VOC.

The calculation methodologies used in the EPA spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. The spreadsheet is intended to be used in combination with the Control Cost Manual. For a detailed description of the oxidizer control technology and cost methodology, see Section 3.2, Chapter 2 (Incinerators and Oxidizers) of the Air Pollution Control Cost Manual (as updated in 2016).

The spreadsheet can be used for thermal regenerative incinerators for a gas stream from 10,000 to 100,000 scfm and a fixed bed/Monolith Catalytic incinerator type. The EPA spreadsheet is designed to calculate the design parameters and costs for thermal and catalytic oxidizers used to control waste gas streams that have an oxygen content of at least 20%. If the oxygen content is less than 20%, the waste stream parameters should be adjusted to include auxiliary air sufficient to increase the oxygen content of the waste gas stream above 20%.

According to the KMW estimated emissions data, the oxygen content of the boiler exhaust will be 7.3%. The estimated exhaust volume of 56,000 scfm would need to be multiplied by the ratio of current oxygen content to target oxygen content to account for the auxiliary air before entering it into the spreadsheet, and the concentrations of CO and VOC would have to be decreased due to the 15-fold increase in flow volume.

$$Q = 56{,}000 \text{ scfm} * (20.9 - 7.3)/(20.9 - 20) = 846{,}222 \text{ scfm}$$

This flowrate value exceeds the range of valid results for the spreadsheet. The results of the spreadsheet calculations become absurd using the flow rate with 20% oxygen.

Step 1 - Identify All Control Technologies

Two types of oxidation processes are considered available for the reduction of CO/VOC emissions from the proposed wood-fired CHP boiler. The following post-combustion technologies for CO and VOC emissions control are considered, listed from least to most efficient:

- Thermal oxidation
- Catalytic oxidation

Step 2 - Eliminate Technically Infeasible Control Options

Thermal oxidizers are supplementary combustion chambers that complete the conversion of CO/VOC to carbon dioxide (CO_2) and water (H_2O) by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. Thermal oxidation requires temperatures of approximately 1,800°F to 2,000°F. The manufacturer-provided exhaust temperature for the proposed wood-fired CHP boiler is 300°F, downstream of the ESP.

The thermal oxidizer would necessarily be installed downstream of the particulate matter control to prevent fire. Use of thermal oxidation would require the combustion of supplemental fuel to reach the target temperatures. This technology is considered infeasible due to the relatively low concentrations of CO and VOC in the exhaust gas and the need for supplemental heat to drive the reaction.

Step 3 - Rank Control Technologies by CO/VOC Control Effectiveness

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°F to 900°F. For the catalytic oxidizer evaluation, the question of reheating the exhaust stream will be set aside. CO catalysts can also be used to reduce VOC and organic HAPs emissions. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and H_2O as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on wood-fired boilers has not been proven. For this analysis, a control efficiency of 80% has been assumed for CO and VOC. While higher efficiencies can be achievable (98-99%), it requires a larger catalyst volume and/or higher temperatures, therefore a lower control efficiency is assumed for this process (EPA Pollution Control Technology Fact Sheet).

Step 4: Energy, environmental and economic considerations, top-down procedure

BACT-determined emission controls consider economic feasibility as well as technical feasibility. The estimated cost of each technology per ton of CO and VOC removed is calculated to assist in the BACT analysis. The proposed boiler without additional CO/VOC control serves as the base case.

The exhaust information has been entered into the EPA's Air Pollution Control Cost Estimation Spreadsheet for Thermal and Catalytic Oxidizers, written in 2022 and updated in December 2024. The exhaust gas volume flowrate of 56,000 scfm has been used, although it does not meet the required 20% oxygen in the waste stream as described above. Output from the cost spreadsheet for a catalytic oxidizer is as follows:

The EPA cost spreadsheet was also run for the catalytic oxidizer case, and the output was as follows:

- Total Annual Cost (TAC) = $2,139,400 per year in 2025 dollars
- CO/VOC Pollutants Destroyed = 83.2 tons per year
- Cost Effectiveness: $25,700 per ton of pollutants removed in 2025 dollars

The proposed wood-fired boiler is designed to minimize the formation of CO and VOC during the combustion process. The cost of achieving further emissions reduction using a catalytic oxidation system is exceedingly high. As shown in Step 4, the estimated cost of installing and operation catalytic oxidation on the boiler exhaust is $25,700 per ton of CO/VOC removed.

This cost per ton is high compared to current Montana cost-effectiveness values that would trigger required installation of add-on controls. Therefore, the addition of catalytic oxidation to the proposed wood-fired CHP boiler is deemed not economically feasible for reducing CO/VOC emissions.

Step 5 – Select CO/VOC BACT

The proposed wood-fired CHP boiler is designed to minimize the formation of CO and VOC during the combustion process. The cost of achieving further emissions reduction using a catalytic oxidation system is exceedingly high. Therefore, BACT for the control of CO and VOC emissions from the proposed CHP boiler is good combustion practices no add-on control to achieve a CO emission limit of 0.113 lb/MMBtu and a VOC emission limit of 0.007 lb/MMBtu.

BACT Analysis - SO_2

BSBE proposes to construct, install, and operate a wood-fired CHP boiler. The following analyzes available SO_2 control technology options for the proposed CHP boiler. Control costs (cost per ton of air pollutant controlled) are calculated for each option. The control option that is selected should have controls or control costs similar to other recently permitted similar sources.

The control equipment description and cost analysis are based on the Thompson River Power BACT analysis submitted to DEQ in 2005 (MAQP #3175-09). The criteria used to assess the technical and economic feasibility of the SO_2 control alternatives include the economic data listed in Table 1. Table 2 lists the wood fuel characteristics determined for the BSBE project.

Table 1. BACT Economic Analysis Basis

ITEM	**VALUE**
CHP Heat Input Rate	200.9 MMBtu/hr
Control Device Capital Recovery Period	20 years
Capital Recovery Interest Rate	8 percent
Utilization Factor	90 percent
Hydrated Lime Cost	$65/ton
Sodium Hydroxide Cost (30 wt % solution)	$440/ton
Pebble Lime Cost	$65/ton
Anhydrous Ammonia Cost	$500/ton
Labor Cost	$42,000/shift-year
Water Cost	$0.1/1000 gallons
Waste Disposal Cost	$30/ton
Energy Cost	$0.09/kW-hr

Table 2. Wood Fuel Sulfur Content

Wood Parameters	Douglas Fir Bark Fuel Analyses	Douglas Fir Chip Fuel Analysis	Average Values for SO_2 BACT Analysis
WT % Sulfur	0.016	0.008	0.012
Btu/lb	5,129	5,994	5,562
lb SO_2/MMBtu	0.062	0.027	0.045

Research of the RBLC has been used for the wood-fired boiler SO_2 BACT analysis, based on BACT determinations for the past 20 years for boilers in the category 12.120 and having the similar size and fuel type as the proposed wood-fired CHP boiler.

Table 3 below contains a list of comparable BACT determinations from the RBLC. All the listed SO_2 BACT emission rates are higher than the emission factor of 0.045 lb/MMBtu used for the proposed CHP boiler.

Table 3. RBLC BACT Determinations for Biomass Boilers

RBLC No.	Boiler Size (MMBtu/hr)	SO_2 Limit	SO_2 Limit (lb/MMBtu)
FL-0332	458	0.06 lb/MMBtu	0.06
FL-0322	536	0.06 lb/MMBtu	0.06
FL-0318	198	0.06 lb/MMBtu	0.06
SC-0115	197	28.14 lb/hr	0.143
SC-0114	197	28.14 lb/hr	0.143
IA-0095	200	0.072 lb/MMBtu	0.072

Step 1: Identify available control technologies

SO_2 emissions can be controlled through limitations on fuel sulfur content and/or flue gas scrubbing. BSBE will burn wood in the proposed CHP boiler, which is an inherently low-sulfur fuel, therefore, fuel sulfur removal will not be considered. Additional control of SO_2 is based on the use of flue gas scrubbing technologies. The BACT analysis addresses the application of the following available flue gas scrubbing technologies, listed from most to least efficient:

- Regenerable or Byproduct Recovery (Dual Alkali, Magnesium Oxide, Wellman-Lord)
- Non-regenerable – High Capital Cost (lime/limestone wet and dry FGD and wet sodium FGD)
- Non-regenerable – Low Capital Cost (dry and wet sorbent injection using calcium and sodium compounds)
- Wet Sodium Scrubbing System
- Lime Spray Dryer Absorber System (LSD)
- Dry Sorbent Injection Scrubbing System (DSI)

Step 2 - Eliminate Technically Infeasible Control Options

Regenerable or Byproduct Recovery (Dual Alkali, Magnesium Oxide, Wellman-Lord): The advantages of the regenerable or byproduct recovery are that it minimizes waste disposal and has a high SO_2 removal capability.

Wet Lime or Limestone Scrubber System:
Wet limestone scrubbers and lime spray dryer absorbers are technologies screened for SO_2 removal. Typically, in the United States, these FGD systems are favored because of their simplicity of operation and equivalent removal capabilities compared to relatively complex byproduct recovery FGD systems. Because the combustion of wood results in a relatively small amount of SO_2, and assuming sodium sulfate salts can be disposed of in a safe and environmentally sound manner, wet sodium scrubbing will be evaluated further.

A wet lime or limestone scrubbing system can achieve over 90 to 95 percent removal. However, considering a wet lime or limestone scrubber for a 200 MMBtu/hr application using wood fuel would incur extremely high capital and operating costs for the removal of a small amount of SO_2 relative to large, utility coal-fired boilers. Therefore, on an economic basis, wet lime or limestone scrubbers will not be further evaluated in the BACT analysis as this technology costs would be greater than the use of other technologies discussed below. Wet lime or limestone scrubbers constitute a technically feasible control option and are further evaluated for the proposed project.

Lime Spray Dryer Scrubber System:
A lime spray dryer scrubber system has moderate capital equipment and costs compared to a wet lime or limestone FGD system. Because the proposed CHP boiler already has an ESP for PM control, the cost of the lime spray dryer system is further reduced. A lime spray dryer scrubbing system with particulate control can achieve 85 to 90 percent removal. Therefore, on an economic basis, the addition of a lime spray dryer scrubber will be evaluated further in the BACT analysis. However, because of the higher capital costs and space requirements for lime spray dryer absorber technologies, dry sorbent injection technology using hydrated lime and/or sodium carbonates is expected to be more cost effective where small amounts of SO_2 need to be removed. Therefore, the use of a hydrated lime/sodium bicarbonate dry injection system on the CHP boiler to control annual average SO_2 emissions by 50 to 90 percent is also being evaluated. The lime spray dryer scrubber system constitutes a technically feasible control option and is further evaluated for the proposed project.

Wet Sodium Scrubbing System (WSS). The wet sodium scrubbing system is a two-stage process that removes SO_2 from the flue gas through the use of a gas to liquid contact absorber following particulate control. The absorber module serves as the contact zone where alkaline additive (sodium hydroxide) and SO_2 in the flue gas react to form sodium sulfate reaction products. A liquid blow down from the circulating liquid loop is used to remove the accumulated sodium sulfate salts. A liquid waste is generated by this process, and this process uses the largest quantity of water of the FGD processes. WSS constitutes a technically feasible control option and is further evaluated for the proposed project.

Lime Spray Dryer Absorber System (LSD). The lime spray dryer absorber system is a two-stage process that removes SO_2 from the flue gas through the use of a spray dryer/absorber followed by particulate control. The absorber module serves as the initial contact zone where alkaline additive (calcium hydroxide) and SO_2 in the flue gas react to form dry reaction products. The majority of reaction products formed in the spray dryer flow out of the absorber module and into the particulate control equipment for removal with the fly ash. The absorber module is sized on the basis of gas flow rate and residence time. Residence times of approximately 10 seconds have proved sufficient to ensure adequate reaction product drying. The atomizers, which disperse the additive slurry, are sized on the basis of additive and tempering water feed necessary to achieve the required SO_2 removal level and outlet gas temperature. This process uses about a third less water than do the wet FGD processes. LSD constitutes a technically feasible control option and is further evaluated for the proposed project.

Dry Sorbent Injection Scrubbing System (DSI). The dry sorbent injection scrubbing system is a two-stage process that removes both SO_2 and particulate from the flue gas through the use of flue gas ductwork residence time followed by a fabric filter. The alkali sorbent is injected into the boiler ductwork, the initial contact zone, where alkaline additive (lime, sodium carbonates, etc.) and SO_2 in the flue gas react to form dry reaction products. The reaction products formed in the ductwork flow into the particulate matter control equipment for removal with the fly ash. DSI constitutes a technically feasible control option and is further evaluated for the proposed project.

Step 3 - Rank Control Technologies by Control Effectiveness

Table 5 below presents the SO_2 emissions control hierarchy for the WSS, LSD, and DSI systems under evaluation. The expected emissions are based on the CHP boiler's annual average heat input of 200.9 MMBtu/hr.

Table 5. SO_2 Emissions Control Hierarchy

Control Option	Emissions			
	% Control	Emission Rate lb SO_2/MMBtu	SO_2 Emissions (tpy)	SO_2 Removed (TPY)
Uncontrolled (baseline)	0	0.045	39.6	0
DSI	80	0.0090	7.92	31.7
LSD	90	0.0045	3.96	35.6
WSS	95	0.0023	1.98	37.6

Step 4: Energy, environmental and economic considerations, top-down procedure

Flue gas desulfurization (FGD) systems are typically divided into regenerable (or byproduct recovery) and non-regenerable systems. Although regenerable systems minimize waste generation, these systems have very high capital and operating costs and are not used to any significant extent in the U.S. These systems are used where very large amounts of SO_2 are being removed and where waste disposal is not economically feasible. Likewise, non-regenerable FGD systems are typically divided into systems that have low capital costs and high capital costs. The high capital cost systems are economical where very high SO_2 removal rates are desired and large amounts of SO_2 must be removed. Low capital cost systems are economical where moderate to high SO_2 removal rates are desired and small amounts of SO_2 must be removed.

A wet lime or limestone scrubber for a ~ 200 MMBtu/hr application using wood fuel, such as the proposed CHP boiler, would incur extremely high capital and operating costs for the removal of a small amount of SO_2 relative to large, utility coal-fired boilers. Wet limestone scrubbing and lime spray drying FGD systems have the advantage of using low-cost widely available calcium-based additives. Wet sodium-based systems are economical where the liquid waste can be economically treated before discharge to a water source and the amount of SO_2 to be removed is small (cost of soda ash/sodium hydroxide is prohibitive relative to lime or limestone for moderate to high amounts of SO_2 removed). A wet lime or limestone scrubber system comprises relatively large equipment and capital costs compared to a lime spray dryer absorbing system. Therefore, wet lime or limestone scrubber systems are used for large coal-fired power plants where tens of thousands of tons per year of SO_2 is being removed. Therefore, on an economic basis, wet lime or limestone scrubbers will not be further evaluated in the BACT analysis as this technology would have comparable control efficiency but higher costs than the use of other technologies discussed below.

A lime spray dryer scrubber system has moderate capital equipment costs compared to a wet lime or limestone FGD system discussed previously. Because the proposed CHP boiler must employ an ESP for filterable PM control (BACT determination, see above filterable PM analysis), the cost of the lime spray dryer system is further reduced. A lime spray dryer scrubbing system with PM control can achieve 85 to 90 percent removal of SO_2. Therefore, on an economic basis, the addition of a lime spray dryer scrubber is appropriate. Further, because of the higher capital costs and space requirements for lime spray dryer absorber technologies, dry sorbent injection technology using hydrated lime and/or sodium carbonates is expected to be more cost effective where small amounts of SO_2 need to be removed. Therefore, the use of a hydrated lime/sodium bicarbonate dry injection system on the CHP boiler to control annual average SO_2 emissions by 50 to 90 percent is also being evaluated.

Cost Impact Analyses for SO_2 Controls

The estimated capital costs for the DSI, WSS and LSD are listed in Table 6. The table shows the capital costs for a complete SO_2 system for a similar sized boiler. The SO_2 control costs were taken from the 2005 SO_2 BACT analysis for Thompson River Power in Thompson Falls, Montana. The capital cost values have been advanced to 2025 dollars using an inflation rate multiplier of 1.61.

The capital costs are annualized based on a 20-year return period and an 8% interest rate as shown below:

$$\$756,312 * (.08)/(1-(1.08-20)) = \$77,032/yr$$

Table 6. Capital Costs for FGD Systems – 2025 Dollars

Cost Item	**DSI**	**WSS**	**LSD**
2025 Capital Cost (CC)	$525,217	$2,626,084	$5,829,907
Contingency (20) % of CC)	$105,043	$525,217	$1,165,981
2025 Direct Capital Cost (DCC)	$656,521	$3,282,605	$7,287,383
Indirect Costs (20 % of DCC)	$126,052	$630,260	$1,399,177
2025 Total Capital Cost	$756,312	$3,781,560	$8,395,065
Annualized Capital Cost	$77,032/yr	$385,160/yr	$855,056/yr

The annual estimated operational costs of the SO_2 control technologies are estimated in this step of the BACT process, based on EPA reference materials. Annual operating costs for the DSI, WSS and LSD systems are listed in Table 7. The cost information is based on the 2005 analysis for a 193 MMBtu/hr boiler burning coal with 0.07% sulfur and estimated heat content of 10,000 Btu/lb. Because wood fuel has lower sulfur content and lower BTU value, the costs are not directly applicable but provide a good approximation. The annual costs have been presented in the original 2005 values and have not been increased based on inflation.

In addition to annual expenses, Table 7 lists the annualized capital costs presented in Table 6. The total annual cost is divided by the tons of SO_2 removed from Table 5 to determine the cost effectiveness ($ per ton of pollutant removed).

Table 7. Approximate Annual Costs for FGD Systems

Cost Item	**2005 Costs Based on Coal: 0.07% S & 10,000 Btu/lb**		
	DSI	WSS	LSD
Annual Cost	$	$	$
Operating Personnel	375,000	750,000	750,000
Maintenance Personnel	375,000	750,000	750,000
Maintenance Supplies	20,000	281,000	625,000
Additive	178,000	2,061,000	327,000
Energy @ $0.09/KWH	21,000	237,000	276,000
Water @ $0.01/1000gal	7,000	1,420,000	913,000
Waste @ $30/ton	110,000	499,000	293,000
Capital Recovery Cost (Table 6)	77,000	385,000	855,000
Estimated Total Annual Cost	1,163,000	6,383,000	4,789,000
Economic Analysis			
SO_2 Removed, tpy (Table 5)	31.2	35.6	37.6
Removal Cost, $/ton	37,300	179,000	127,400

Step 5: Select SO_2 BACT

Documentation, including calculations, assumptions, and data used in making the SO_2 BACT determination are discussed below.

The addition of an SO_2 scrubbing system to the wood-fired CHP boiler would result in a cost per ton of pollutant removed value (i.e., cost effectiveness) that is far above the norm for Montana. As shown in Table 7, the cost effectiveness for DSI, which is the least expensive SO_2 scrubbing alternative, is $37,300/ton of SO_2 removed. In addition, SO_2 scrubbing would increase energy and water usage, and create a waste product that must be managed or disposed of in an environmentally sound manner, which would necessarily increase the cost of employing an SO_2 scrubbing technology.

The uncontrolled SO_2 emission rate for wood combustion is less than the BACT determinations for similar-sized wood-fired boilers listed in the RBLC as shown in Table 3. Based off the wood fuel characteristics determined for the BSBE project, from the wood fuel sulfur content, Douglas Fir Bark Fuel Analyses, this emission rate for SO_2 is deemed achievable in practice.

BSBE has determined that the current proposal with no add-on SO_2 control to achieve an SO_2 emission limit of 0.045 lb/MMBtu constitutes BACT for SO_2 emissions from the wood-fired CHP boiler.

IV. Emission Inventory

Table 1. Plant Wide Emissions Inventory

Emitting Unit	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_X	VOC	CO	HAPs
Combined Heat and Power Boiler with ESP	41.36	41.36	41.36	39.6	158.4	6.16	99.4	17.55
Fugitive Dust- Unpaved Roads	0.14	0.02	0.002	---	---	---	---	---
Total	41.5	41.39	41.36	39.60	158.40	6.16	99.40	17.55

Combined Heat and Power Boiler with a multiclone and ESP Calculations:

Boiler Combustion	8,760	Hours/Year	Max Potential Hours
	126,520	lb steam/hour	Peak 1-hour steam rate, calculated
	200.91	MMBtu/hr, calculated	(BDT * MMBtu/BDT)/ (hours per year)
	1,108,312	klb steam/yr	PTE annual steam production
	1,760,000	MMBtu/yr	PTE annual heat input
	110,000	BDT hog fuel/year	Given Value from Client
	16.0	MMBtu/BDT	Typical Value, not used
	1,588	Btu heat input per lb steam	Typical Value, not used
Criteria Pollutant Emissions			
PM/PM10/PM2.5 are considered equal for a well-controlled combustion source.			
Total PM/PM10/PM2.5			
Emission Factor:	0.047	lb/MMBtu	0.017 lb/MMBtu condensable
Emissions:	41.36	tons/year	MACT Subpart JJJJJJ limit is 0.03 lb/MMBtu filterable.
	9.44	lbs/hr	
Sulfur Dioxide:			
Emission Factor:	0.045	lb/MMBtu	KMW Case I, @11% oxygen
Emissions:	39.60	tons/year	
	9.04	lbs/hr	
Nitrogen Oxides (NOx)			
Emission Factor:	0.180	lb/MMBtu	KMW Case I, @11% oxygen
Emissions:	158.40	tons/year	
	36.16	lbs/hr	
Carbon Monoxide (CO)			
Emission Factor:	0.113	lb/MMBtu	KMW Case I, @11% oxygen
Emissions:	99.44	tons/year	
	22.70	lbs/hr	
Volatile Organic Compounds (VOC)			
Emission Factor:	0.007	lb/MMBtu	KMW Case I, @11% oxygen
Emissions:	6.16	tons/year	
	1.41	lbs/hr	

MACT Emission Limits, based on September 14, 2016 version of Area Boiler MACT.

Particulate Matter, filterable			
Emission Factor:	0.030	lb/MMBtu heat input	Table 1 to Subpart JJJJJJ of Part 63
Emissions:	26.40	tons/year	New biomass boiler at an area source of HAPS.
	6.03	lbs/hr	
	0.012	gr/dscf, calculated	60,056 acfm

Hazardous Air Pollutants (HAPS)

Operating Parameters:		
Actual Hours of Operation	hours/yr	8,760
Max Heat Input	MMBtu / hr	200.91
Annual Boiler Heat Input	MMBtu / yr	1,760,000

Emission Factors:

AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03)	CAS Number	HAP?	Emission Factor (lb/MMBtu)	Annual Emissions (tons/yr)	HAP Emissions (tons/yr)
Acenaphthene		N	9.1E-07	8.01E-04	
Acenaphthylene		N	5.0E-06	4.40E-03	
Acetaldehyde	75070	Y	8.3E-04	7.30E-01	7.30E-01
Acetone		N	1.9E-04	1.67E-01	
Acetophenone	98862	Y	3.2E-09	2.82E-06	2.82E-06
Acrolein	107028	Y	4.0E-03	3.52E+00	3.52E+00
Anthracene		N	3.0E-06	2.64E-03	
Benzaldehyde		N	8.5E-07	7.48E-04	
Benzene	71432	Y	4.2E-03	3.70E+00	3.70E+00
Benzoic acid		N	4.7E-08	4.14E-05	
bis(2-ethylhexyl)phthalate (DEHP)	117817	Y	4.7E-08	4.14E-05	4.14E-05
Bromomethane (methyl bromide)	74839	Y	1.5E-05	1.32E-02	1.32E-02
2-Butanone (MEK) - Removed from HAPS	78933	N	5.4E-06	4.75E-03	
Carbazole		N	1.8E-06	1.58E-03	
Carbon tetrachloride	56235	Y	4.5E-05	3.96E-02	3.96E-02
Chlorine	7782505	Y	7.9E-04	6.95E-01	6.95E-01
Chlorobenzene	108907	Y	3.3E-05	2.90E-02	2.90E-02
Chloroform	67663	Y	2.8E-05	2.46E-02	2.46E-02
Chloromethane (Methyl Chloride)	74873	Y	2.3E-05	2.02E-02	2.02E-02
2-Chloronaphthalene		N	2.4E-09	2.11E-06	
2-Chlorophenol		N	2.4E-08	2.11E-05	
Crotonaldehyde	123739	N	9.9E-06	8.71E-03	
Decachlorobiphenyl		N	2.7E-10	2.38E-07	
1,2-Dibromoethene		N	5.5E-05	4.84E-02	
Dichlorobiphenyl		N	7.4E-10	6.51E-07	
1,2-Dichloroethane (Ethylene Dichloride)	107062	Y	2.9E-05	2.55E-02	2.55E-02
Dichloromethane (Methylene chloride)	75092	Y	2.9E-04	2.55E-01	2.55E-01
1,2-Dichloropropane (Propylene dichloride)	78875	Y	3.3E-05	2.90E-02	2.90E-02
2,4 Dinitrophenol	51285	Y	1.8E-07	1.58E-04	1.58E-04
Dioxins and Furans, Not TCDD		N	1.7E-06	1.47E-03	
Heptachlor dibenzo-p-dioxins		N	*2.0E-09*		
Heptachlor dibenzo-p-furans		N	*2.4E-10*		
Hexachlorodibenzo-p-dioxins		N	*1.6E-06*		
Hexachlorodibenzo-p-furans		N	*2.8E-10*		
Octachlorodibenzo-p-dioxins		N	*6.6E-08*		
Octachlorodibenzo-p-furans		N	*8.8E-11*		
Pentachlorodibenzo-p-dioxins		N	*1.5E-09*		
Pentachlorodibenzo-p-furans		N	*4.2E-10*		
Dioxins and Furans, TCDD		Y	1.3E-09	1.16E-06	
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	Y	*8.6E-12*		
Tetrachlorodibenzo-p-dioxins		Y	*4.7E-10*		
2,3,7,8-Tetrachlorodibenzo-p-furans		Y	*9.0E-11*		
Tetrachlorodibenzo-p-furans		Y	*7.5E-10*		
Ethylbenzene	100414	Y	3.1E-05	2.73E-02	2.73E-02
Formaldehyde	50000	Y	4.4E-03	3.87E+00	3.87E+00
Heptachlorobiphenyl		N	6.6E-11	5.81E-08	
Hexachlorobiphenyl		N	5.5E-10	4.84E-07	
Hexanal		N	7.0E-06	6.16E-03	
Hydrogen chloride (Hydrochloric Acid)[1]	7647010	Y	2.4E-04	2.11E-01	0.21
Isobutyraldehyde		N	1.2E-05	1.06E-02	
Methane		N	2.1E-02	1.85E+01	

AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03)	CAS Number	HAP?	Emission Factor (lb/MMBtu)	Annual Emissions (tons/yr)	HAP Emissions (tons/yr)
2-Methylnaphthalene		N	1.6E-07	1.41E-04	
Monochlorobiphenyl		N	2.2E-10	1.94E-07	
Naphthalene	91203	Y	9.7E-05	8.54E-02	8.54E-02
2-Nitrophenol		N	2.4E-07	2.11E-04	
4-Nitrophenol	100027	Y	1.1E-07	9.68E-05	9.68E-05
Pentachloropbiphenyl		N	1.2E-09	1.06E-06	
Pentachlorophenol	87865	Y	5.1E-08	4.49E-05	4.49E-05
Perylene		N	5.2E-10	4.58E-07	
Phenanthrene		N	7.0E-06	6.16E-03	
Phenol	108952	Y	5.1E-05	4.49E-02	4.49E-02
Propanal = Propionaldehyde	123386	Y	6.1E-05	5.37E-02	5.37E-02
Polyaromatic Hydrocarbons (except 7-PAH group)		N	5.3E-06	4.62E-03	
Benzo(e)pyrene			*2.6E-09*		
Benzo(g,h,i)perylene			*9.3E-08*		
Benzo(j,k)fluoranthene			*1.6E-07*		
Fluoranthene			*1.6E-06*		
Fluorene			*3.4E-06*		
Polycyclic Organic Matter (POM) = 7-PAH Group		Y	2.9E-06	2.58E-03	2.58E-03
Benzo(a)anthracene		Y	*6.5E-08*		
Benzo(a)pyrene		Y	*2.6E-06*	2.29E-03	
Benzo(b)fluoranthene		Y	*1.0E-07*		
Benzo(k)fluoranthene		Y	*3.6E-08*		
Indeno(1,2,3,cd)pyrene		Y	*8.7E-08*		
Chrysene		Y	*3.8E-08*		
Dibenzo(a,h)anthracene		Y	*9.1E-09*		
Pyrene		N	3.7E-06	3.26E-03	
Styrene	100425	Y	1.9E-03	1.67E+00	1.67E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	Y	8.6E-12	7.57E-09	7.57E-09
Tetrachlorobiphenyl		N	2.5E-09	2.20E-06	
Tetrachloroethene		N	3.8E-05	3.34E-02	
o-Tolualdehyde		N	7.2E-06	6.34E-03	
p-Tolualdehyde		N	1.1E-05	9.68E-03	
Toluene	108883	Y	9.2E-04	8.10E-01	8.10E-01
Trichlorobiphenyl		N	2.6E-09	2.29E-06	
1,1,1-Trichloroethane (Methyl Chloroform)	71556	Y	3.1E-05	2.73E-02	2.73E-02
Trichloroethene (Trichloroethylene)	79016	Y	3.0E-05	2.64E-02	2.64E-02
Trichlorofluoromethane	75694	Y	4.1E-05	3.61E-02	3.61E-02
2,4,6-Trichlorophenol	88062	Y	2.2E-08	1.94E-05	1.94E-05
Vinyl Chloride	75014	Y	1.8E-05	1.58E-02	1.58E-02
o-Xylene	95476	Y	2.5E-05	2.20E-02	2.20E-02
Antimony	7440-36-0	Y	7.9E-06	6.95E-03	6.95E-03
Arsenic	7440-38-2	Y	2.2E-05	1.94E-02	1.94E-02
Barium	7440-39-3	N	1.7E-04	1.50E-01	
Beryilium	7440-41-7	Y	1.1E-06	9.68E-04	9.68E-04
Cadmium	7440-43-9	Y	4.1E-06	3.61E-03	3.61E-03
Chromium, total	16065-83-1	Y	2.1E-05	1.85E-02	1.85E-02
Chromium, hexavalent	18540-29-9	Y	3.5E-06	3.08E-03	3.08E-03
Cobalt	7440-48-4	Y	6.5E-06	5.72E-03	5.72E-03
Copper	7440-50-8	N	4.9E-05	4.31E-02	
Iron		N	9.9E-04	8.71E-01	
Lead(2)	7439-92-1	Y	4.8E-05	4.22E-02	4.22E-02
Manganese	7439-96-5	Y	1.6E-03	1.41E+00	1.41E+00
Mercury	7439-97-6	Y	3.5E-06	3.08E-03	3.08E-03
Molybdenum	7439-98-7	N	2.1E-06	1.85E-03	
Nickel	7440-02-0	Y	3.3E-05	2.90E-02	2.90E-02
Phosphorus	7223-14-0	Y	2.7E-05	2.38E-02	2.38E-02
Potassium		N	3.9E-02	3.43E+01	
Selenium	7782-49-2	Y	2.8E-06	2.46E-03	2.46E-03
Silver	7440-22-4	N	1.7E-03	1.50E+00	
Sodium		N	3.6E-04	3.17E-01	
Strontium		N	1.0E-05	8.80E-03	

Emission Factors:

AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03)	CAS Number	HAP?	Emission Factor (lb/MMBtu)	Annual Emissions (tons/yr)	HAP Emissions (tons/yr)
Tin	7440-31-5	N	2.3E-05	2.02E-02	
Titanium		N	2.0E-05	1.76E-02	
Vanadium	1314-62-1	N	9.8E-07	8.62E-04	
Yttrium		N	3.0E-07	2.64E-04	
Zinc		N	4.2E-04	3.70E-01	
				TOTAL HAPS	**17.55**
				MAX HAP (FORMALDEHYDE)	**3.87**
(1) Reference for the EF is stack test data					
(2) Lead: 0.23 lb/day, 0.0422 lb/hr.					

Fugitive Dust – Unpaved Roads Calculations

Calculations based on AP-42 Section 13.2.2, rev. 12/06

Source	Class	Number Trips Per Year	Distance per Trip (miles)	VMT per Year	Avg. Vehicle Weight W	Weighted Vehicle Weight
Bochar Trucks	Unpaved, Loaded	1,313	0.22	289	36	18.00
	Unpaved, Empty	1,313	0.22	289	16	8.00
Other	Unpaved, Loaded	0	0.1	0	4	0.00
	Unpaved, Empty	0	0.1	0	1	0.00
			TOTAL	**578**		**26**

E = [k(s/12)^a*(w/3)^b]

	PM	PM10	PM2.5		
k =	4.9	1.5	0.15		
Composite s=	0.7	0.7	0.7	Log trucks drive ~0.7 miles on gravel road	
W =	26.00	26.00	26.00	(s=0.10%) and ~0.1 miles on logyard (s=4.8%).	
a=	0.7	0.9	0.9	Table 13.2.2-1, B13s02.2.	
b=	0.45	0.45	0.45		
Uncontrolled E=	1.75 lb/VMT	0.30 lb/VMT	0.03 lb/VMT		
Uncontrolled Eext=	1.00 lb/VMT	0.17 lb/VMT	0.02 lb/VMT	P=	156
				N=	365
Controlled E=	0.50 lb/VMT	0.09 lb/VMT	0.01 lb/VMT	Watering provides 50% control	

Total PM Emissions:	**0.14**	**tpy**
Total PM10 Emissions:	**0.025**	**tpy**
Total PM2.5 Emissions:	**0.002**	**tpy**

V. Existing Air Quality

The BSBE facility is located in Township 7N, Section 4, Range 9W, in Powell County, Montana. Powell County is classified as Attainment/Unclassifiable for all applicable National Ambient Air Quality Standards (NAAQS), as of the permit issuance date.

VI. Air Quality Impacts

This permit contains conditions and limitations that would protect air quality for the site and surrounding area. Modeling was conducted by BSBE for this permitting action. The full modeling results are on file with DEQ, a summary is included below in Section VII, Ambient Air Impact Analysis.

VII. Ambient Air Impact Analysis

Bison Engineering Inc. (Bison) performed an air quality modeling analysis for the proposed BSBE facility. The ambient air impact analysis was conducted, pursuant to the requirements of ARM 17.8.749, to demonstrate that the new facility unit will not cause or contribute to a violation of any Montana ambient air quality standard (MAAQS) or NAAQS. The proposed facility is not categorized as a major source for the purposes of New Source Review and is therefore not subject to the requirements of the Prevention of Significant Deterioration (PSD) program.

Allowable emissions from BSBE's CHP boiler are above the thresholds provided in DEQ's Draft Modeling Guideline for $PM_{2.5}$, PM_{10}, and NO_2 and thus warrant further analyses. Allowable emissions from the proposed CHP boiler were first modeled to determine if any model receptors exceeded the Significant Impact Levels (SILs) presented in Table VI-1. For those pollutant and averaging periods that exceed the applicable SILs, further modeling that includes nearby emission sources was conducted to demonstrate compliance with the applicable Montana ambient air quality standard (MAAQS) and national ambient air quality standard (NAAQS), also presented in Table-1.

Table 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	188	564
	Annual	1	100	94
PM_{10}	24-hour	5	150	150
	Annual	1	-	50
$PM_{2.5}$	24-hour	1.2	35	-
	Annual	0.13	9	-

The SIL and MAAQS/NAAQS modeling compliance demonstrations were conducted with EPA's preferred American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) and the associated preprocessors. The specific software versions and model options are outlined below:

- AERMOD version 23132: Air dispersion model.
- AERMET version 19191 (Data processed in 2020): processes NWS meteorological data for input to AERMOD.
- AERMINUTE version 15272 (Data processed in 2020): processes 1-minute NWS wind data to generate hourly average winds for input to AERMET.
- AERSURFACE version 13016 (Data processed in 2020): processes 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 12.09.

Regulatory default options were used for all model runs, and rural dispersion coefficients were applied, as all of Montana currently meets this criterion. All buildings from both the proposed BSBE facility and the nearby SML source were evaluated for building downwash on each modeled point source using BPIPPRM.
Five years of meteorological data (2015-2019) ready for use in AERMOD was constructed using representative surface and upper air data. Surface air data was obtained from the most representative National Weather Service (NWS) Automated Surface Observing Systems (ASOS) station, which was determined to be at the Missoula International Airport (WBAN 24153).

Though meteorological data is available from a weather station at the Deer Lodge City and County Airport, the station does not provide one-minute wind data necessary to run the AERMINUTE preprocessor. Comparison of wind speed and direction between the Missoula and Deer Lodge stations demonstrates that both sites have very similar characteristics. Over the length of the available and contemporaneous record, both sites demonstration a prevailing wind direction from the northwest, similar percentages of calm winds, and an average wind speed that differs by 0.2 mph. Given these characteristics, the Missoula International Airport was deemed a representative surface meteorology site for the BSBE facility in Deer Lodge.

The Great Falls, MT Upper Air station (WBAN 24143) was used for upper air data, and the ADJ_U* option was employed in AERMET to account for stable, low wind speeds.

A series of nested receptor grids with variable density based on distance from the proposed facility were used in the model to calculate the ambient air impacts around the project location. For the BSBE facility, which is located entirely within the property line of SML, the ambient air boundary (AAB) is defined as the extent of the SML property because the public is restricted from accessing the area either by physical barriers or SML personnel. Discrete receptors were placed at 25 m spacing along the AAB, 100 m spacing from the AAB to 1 km from the site, 250 m spacing from 1 km to 3 km from the site, 500 m spacing from 3 km to 10 km from the site, and 1000 m spacing from 10 km to 50 km from the site, totaling 10,047 receptor locations. Only the significantly impacted receptors (receptors with modeled concentrations equal to or greater than their respective SILs) were used for the cumulative NAAQS/MAAQS analyses.

In addition to the standard receptor network, a high spatial resolution "hot spot" receptor network was focused around the areas of greatest impact from the $PM_{2.5}$ 24-hr and NO_2 1-hr cumulative modeling. A second SIL analysis was performed on the hot spot receptors to identify only the receptors that were significantly impacted by emissions from the BSBE facility. An additional cumulative NAAQS/MAAQS modeling demonstration was then performed on the respective $PM_{2.5}$ and NO_2 hot spot receptor grids to better characterize the spatial variability of the highest modeled concentrations.

Receptor elevations and source elevations were determined using the terrain preprocessor AERMAP and elevation data based on 3D Elevation Program (3DEP) Digital Elevation Model (DEM) files from the United States Geological Survey (USGS).

The following NO_2, PM_{10}, and $PM_{2.5}$ monitoring sites were identified for use as background concentrations. Due to the lack of ambient air quality monitors in Deer Lodge, the NO_2 and PM_{10} monitors located in Lewistown were chosen as a representative rural site, and the years of 2020-2022 were used to calculate background concentrations. The Ncore monitor north of Helena was chosen as a representative background site for calculating $PM_{2.5}$ background concentrations using the years of 2021-2023. For PM_{10} and $PM_{2.5}$, the closest monitors are located in Butte, but it was determined that Butte is not an airshed that is representative of Deer Lodge due to comparatively much higher emissions and confined valley topography. For $PM_{2.5}$, background concentrations were calculated both including and excluding wildfire exceptional events to illustrate the impacts of wildfires on ambient air concentrations, as demonstrated in Table 2.

Table 2. Background Concentrations

<table>
<tr><th>Pollutant</th><th>Averaging Period</th><th colspan="2">Background Conc. (ug/m^3)</th><th>Basis</th><th>Site</th></tr>
<tr><td rowspan="2">NO_2</td><td>1-hour</td><td colspan="2">18.8 (10 ppb)</td><td rowspan="2">3-year annual avg.</td><td rowspan="3">Lewistown (30-027-006) 2020-2022</td></tr>
<tr><td>Annual</td><td colspan="2">1.88 (1 ppb)</td></tr>
<tr><td>PM_{10}</td><td>24-hour</td><td colspan="2">78</td><td>3-year n-th high 24-hour value[3]</td></tr>
<tr><td rowspan="2">$PM_{2.5}$</td><td>24-hour</td><td>30[1]</td><td>10[2]</td><td>98%-ile averaged over 3 years</td><td rowspan="2">Ncore (30-049-0004) 2021-2023</td></tr>
<tr><td>Annual</td><td>4.8[1]</td><td>3.3[2]</td><td>3-year annual avg.</td></tr>
</table>

(1)Concentrations includes all exceptional events data in the calculations.
(2)Concentrations excludes all exceptional events data in the calculations.
(3)Calculated using PM_{10} SIP Development Guideline-Table Look-up Method (EPA Table 6-1). See EPA-450/2-86-001.

Data with exceptional events removed was used for all purposes in this analysis. The background concentrations are added to the modeled concentrations in the NAAQS analysis.

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).

Source parameters were provided by BSBE. The only new source associated with the proposed facility is the CHP boiler, which was modeled as a point source and listed in Table 3.

Table 3. Onsite Source Descriptions

SrcID	Source Description	Source Category	Source Type
PHBLR	Wood-fired CHP Boiler	New	POINT

SIL Air Quality Analysis

NO_2, PM_{10}, and $PM_{2.5}$ emissions increases at the new project site were modeled and compared to applicable SILs. The annual, 24-hour, and 1-hour (as applicable) emissions increases are provided in Table 4.

Table 4. SIL Modeled Emissions Increases

SrcID	NO_2 1-hour (lb/hr)	NO_2 Annual (tpy)	PM_{10} 24-hour (lb/hr)	PM_{10} Annual (tpy)	$PM_{2.5}$ 24-hour (lb/hr)	$PM_{2.5}$ Annual (tpy)
PHBLR	36.16	158.381	9.44	41.347	9.44	41.347

Modeled NO_2, PM_{10}, and $PM_{2.5}$ Class II SIL results are presented in Table 5. Impacts exceeded applicable SILs for 1-hour and annual NO_2, 24-hour PM_{10}, and 24-hour and annual $PM_{2.5}$ pollutant averaging periods, therefore NAAQS/MAAQS analyses were performed each of those pollutants and averaging periods. For the pollutants exceeding the SIL, the significant impact area (SIA) was determined, which was the furthest distance of a modeled SIL-exceeded receptor from the source.

Table 5. Class II Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. (ug/m^3)	SIL (ug/m^3)	SIA (km)
NO_2	1-hour	122(1)	7.5	50.1
	Annual	1.61(2)	1	4.26
PM_{10}	24-hour	5.22(3)	5	3.88
	Annual	0.422(4)	1	-
$PM_{2.5}$	24-hour	3.67(5)	1.2	7.87
	Annual	0.372(6)	0.13	5.49

(1)Receptor with the maximum 5-year average of the maximum daily 1-hour concentration.
(2)Receptor with the maximum annual concentration in the 5-year period.
(3)Receptor with the maximum 24-hour concentration in the 5-year period.
(4)Receptor with the maximum annual concentration averaged across 5 years.
(5)Receptor with the maximum 24-hour concentration averaged across 5 years.
(6)Receptor with the maximum annual concentration averaged across 5 years.

NAAQS/MAAQS Air Quality Analysis

For NAAQS and MAAQS analyses, it was determined that the nearby SML source caused significant concentration gradients within the SIA, and the Lewistown and Ncore monitors do not capture SML emissions in their measured background concentrations. Emission sources at SML were therefore explicitly modeled along with the BSBE CHP boiler to determine the cumulative modeled impacts. Source parameters were provided by SML, and the sources were modeled either as "point" or "volume" sources. "POINTHOR" is a source type in AERMOD, like "POINT", but the pollutants exhaust from a horizontal vent. SML source descriptions are listed in Table 6.

Table 6. Offsite Source Descriptions

SrcID	Source Description	Source Category	Source Type
SUN_BLR	Hurst Hog Fuel Boiler	Offsite	POINT
C1	Jointer Cyclone	Offsite	POINTHOR
C2	Hog Blower Cyclone	Offsite	POINTHOR
C3	Shavings Bin Cyclone	Offsite	POINTHOR
K1	Dry Kiln	Offsite	POINT
K2	Dry Kiln	Offsite	POINT
K3	Dry Kiln	Offsite	POINT
K4	Dry Kiln	Offsite	POINT
K5	Dry Kiln	Offsite	POINT
K6	Dry Kiln	Offsite	POINT
K7	Dry Kiln	Offsite	POINT
K8	Dry Kiln	Offsite	POINT
K9	Dry Kiln	Offsite	POINT
K10	Dry Kiln	Offsite	POINT
K11	Dry Kiln	Offsite	POINT
K12	Dry Kiln	Offsite	POINT
K13	Dry Kiln	Offsite	POINT
K14	Dry Kiln	Offsite	POINT
K15	Dry Kiln	Offsite	POINT
K16	Dry Kiln	Offsite	POINT
K17	Dry Kiln	Offsite	POINT
K18	Dry Kiln	Offsite	POINT
K19	Dry Kiln	Offsite	POINT
K20	Dry Kiln	Offsite	POINT
K21	Dry Kiln	Offsite	POINT
K22	Dry Kiln	Offsite	POINT
K23	Dry Kiln	Offsite	POINT
K24	Dry Kiln	Offsite	POINT
K25	Dry Kiln	Offsite	POINT
K26	Dry Kiln	Offsite	POINT
K27	Dry Kiln	Offsite	POINT
K28	Dry Kiln	Offsite	POINT

K29	Dry Kiln	Offsite	POINT
K30	Dry Kiln	Offsite	POINT
K31	Dry Kiln	Offsite	POINT
K32	Dry Kiln	Offsite	POINT
K33	Dry Kiln	Offsite	POINT
K34	Dry Kiln	Offsite	POINT
K35	Dry Kiln	Offsite	POINT
K36	Dry Kiln	Offsite	POINT
K37	Dry Kiln	Offsite	POINT
K38	Dry Kiln	Offsite	POINT
K39	Dry Kiln	Offsite	POINT
K40	Dry Kiln	Offsite	POINT
K41	Dry Kiln	Offsite	POINT
K42	Dry Kiln	Offsite	POINT
K43	Dry Kiln	Offsite	POINT
K44	Dry Kiln	Offsite	POINT
K45	Dry Kiln	Offsite	POINT
K46	Dry Kiln	Offsite	POINT
K47	Dry Kiln	Offsite	POINT
K48	Dry Kiln	Offsite	POINT
BLOCKSAW	Log Block Saw	Offsite	VOLUME
DEBARK	Log Debarking	Offsite	VOLUME
HOGBIN	Hogfuel Loadout	Offsite	VOLUME
CHIPBIN	Chip Loadout	Offsite	VOLUME
SHAVEBIN	Shavings Loadout	Offsite	VOLUME
SAWBIN	Sawdust Loadout	Offsite	VOLUME
CHIPTB	Chip Bin Target Box	Offsite	VOLUME
SAWTB	Sawdust Bin Target Box	Offsite	VOLUME

The nearby source of SML is considered a co-contributing source to BSBE, and thus emission rates were modeled based on projected maximum production rather than the most recent 2-year average of actual emissions. The resulting modeled emissions are therefore greater than actual emissions at SML. The modeled emissions rates are displayed in Table 7.

Table 7. Modeled Emissions for NAAQS/MAAQS Analysis

SrcID	NO_2 1-hour (lb/hr)	NO_2 Annual (tpy)	PM_{10} 24-hour (lb/hr)	$PM_{2.5}$ 24-hour (lb/hr)	$PM_{2.5}$ Annual (tpy)
PHBLR	36.160	158.381	9.440	9.440	41.347
Total Onsite:		**158.381**			**41.347**
SUN_BLR	7.040	30.835	8.740	5.180	22.688
C1	-	-	0.876	0.738	1.918
C2	-	-	0.127	0.107	0.397
C3	-	-	0.504	0.424	1.103
K1	-	-	0.010	0.010	0.042
K2	-	-	0.010	0.010	0.042
K3	-	-	0.010	0.010	0.042
K4	-	-	0.010	0.010	0.042
K5	-	-	0.010	0.010	0.042
K6	-	-	0.010	0.010	0.042
K7	-	-	0.010	0.010	0.042
K8	-	-	0.010	0.010	0.042
K9	-	-	0.010	0.010	0.042
K10	-	-	0.010	0.010	0.042
K11	-	-	0.010	0.010	0.042
K12	-	-	0.010	0.010	0.042
K13	-	-	0.010	0.010	0.042
K14	-	-	0.010	0.010	0.042
K15	-	-	0.010	0.010	0.042
K16	-	-	0.010	0.010	0.042
K17	-	-	0.010	0.010	0.042
K18	-	-	0.010	0.010	0.042
K19	-	-	0.010	0.010	0.042
K20	-	-	0.010	0.010	0.042
K21	-	-	0.010	0.010	0.042
K22	-	-	0.010	0.010	0.042
K23	-	-	0.010	0.010	0.042
K24	-	-	0.010	0.010	0.042
K25	-	-	0.010	0.010	0.042
K26	-	-	0.010	0.010	0.042
K27	-	-	0.010	0.010	0.042
K28	-	-	0.010	0.010	0.042
K29	-	-	0.010	0.010	0.042

K30	-	-	0.010	0.010	0.042
K31	-	-	0.010	0.010	0.042
K32	-	-	0.010	0.010	0.042
K33	-	-	0.010	0.010	0.042
K34	-	-	0.010	0.010	0.042
K35	-	-	0.010	0.010	0.042
K36	-	-	0.010	0.010	0.042
K37	-	-	0.010	0.010	0.042
K38	-	-	0.010	0.010	0.042
K39	-	-	0.010	0.010	0.042
K40	-	-	0.010	0.010	0.042
K41	-	-	0.010	0.010	0.042
K42	-	-	0.010	0.010	0.042
K43	-	-	0.010	0.010	0.042
K44	-	-	0.010	0.010	0.042
K45	-	-	0.010	0.010	0.042
K46	-	-	0.010	0.010	0.042
K47	-	-	0.010	0.010	0.042
K48	-	-	0.010	0.010	0.042
BLOCKSAW	-	-	0.211	0.105	0.274
DEBARK	-	-	0.331	0.051	0.133
HOGBIN	-	-	0.008	0.001	0.003
CHIPBIN	-	-	0.016	0.005	0.005
SHAVEBIN	-	-	0.769	0.024	0.031
SAWBIN	-	-	0.008	0.001	0.003
CHIPTB	-	-	0.309	0.182	0.567
SAWTB	-	-	0.198	0.116	0.363
Total Offsite:		**30.835**			**29.486**
Total:		**189.216**			**70.833**

The results of the NAAQS analysis are shown in Table 8, which show that the modeled emissions comply with NO_2, PM_{10}, and $PM_{2.5}$ NAAQS standards.

Table 8. NAAQS Analysis Results

Pollutant	Avg. Period	Model Design Value (ug/m^3)	Monitor Design Value (ug/m^3)	Total Conc. (ug/m^3)	Primary NAAQS (ug/m^3)	% of NAAQS
NO_2	1-hour	93.5[(1)]	18.8	112.3	188	60%
	Annual	1.56[(2)]	1.88	3.44	100	3.4%
PM_{10}	24-hour	2.59[(3)]	78	80.59	150	54%
$PM_{2.5}$	24-hour	18.8[(4)]	10.0	28.8	35	82%
	Annual	4.10[(5)]	3.3	7.4	9	82%

(1)Receptor with the 8th-highest daily 1-hour max value averaged over 5 years.
(2)Receptor with the maximum annual concentration in the 5-year period.
(3)Receptor with the 6th-highest 24-hour concentration across the 5-year period.
(4)Receptor with the 8th-highest 24-hour concentration per year, averaged over 5 years.
(5)Receptor with the maximum annual concentration averaged across the 5-year period.

A demonstration of compliance with applicable MAAQS (ARM 17.8 Subchapter 2), displayed in Table 1, was performed for the 1-hour NO_2 and annual NO_2 standards, due to the modeled exceedance of the applicable SILs. The annual NO_2 MAAQS has a similar form to the NAAQS, so the results from the NAAQS analysis were used. The results of the MAAQS analysis are shown in Table 9, which show that the modeled emissions comply with NO_2 MAAQS standards.

Table 9. MAAQS Analysis Results

Pollutant	Avg. Period	Model Design Value (ug/m^3)	Monitor Design Value (ug/m^3)	Total Conc. (ug/m^3)	Primary NAAQS (ug/m^3)	% of NAAQS
NO_2	1-hour	107[(1)]	18.8	125.8	564	22%
	Annual	1.56[(2)]	1.88	3.44	94	3.7%

(1)Receptor with 2nd-highest 1-hour concentration across the 5 year period.
(2)Receptor with the maximum annual concentration in the 5-year period.

DEQ determined that the project-related NO_2, PM_{10}, and $PM_{2.5}$ emissions will not cause or contribute to an exceedance of a MAAQS or NAAQS. 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 DEQ and available upon request.

Based on the information provided and the conditions established in MAQP #5329-00, DEQ determined that the impact from this permitting action will be minor, and will not cause or contribute to a violation of any ambient air quality standard.

VIII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, DEQ conducted a private property taking and damaging assessment which is available for review in Item 21 of the attached environmental assessment.

IX. Environmental Assessment

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

FINAL ENVIRONMENTAL ASSESSMENT

May 5, 2025

Air Quality Bureau
Montana Department of Environmental Quality

PROJECT/SITE NAME: Big Sky Bioenergy, LLC. – BSBE Deer Lodge, Facility	
APPLICANT/COMPANY NAME: Big Sky Bioenergy, LLC.	
PROPOSED PERMIT/LICENSE NUMBER: 5329-00	
LOCATION: Section 4, Township 7 North, Range 9 West	**COUNTY: Powell**
PROPERTY OWNERSHIP: FEDERAL ____ STATE ____ PRIVATE _X___	

Table of Contents

Project Overview

COMPANY NAME:	Big Sky Bioenergy, LLC.
EA DATE:	May 5, 2025
SITE NAME:	BSBE Deer Lodge Facility
MAQP#:	5329
Version #:	00
Application Received Date:	12/18/2024

Location

Township 7 North, Range 9 West, Section 4
County: Powell
PROPERTY OWNERSHIP: FEDERAL STATE PRIVATE X

Compliance with the Montana Environmental Policy Act

Under the Montana Environmental Policy Act (MEPA), Montana agencies are required to prepare an environmental review for state actions that may have an impact on the human environment. The proposed action is considered to be a state action that may have an impact on the human environment and, therefore, the Department of Environmental Quality (DEQ) must prepare an environmental review. This Environmental Assessment (EA) will examine the proposed action and alternatives to the proposed action and disclose potential impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in Administrative Rules of Montana (ARM) 17.4.608. DEQ may not withhold, deny, or impose conditions on the Permit based on the information contained in this EA (§ 75-1- 201(4), MCA).

Proposed Action

Big Sky Bioenergy, LLC. (BSBE) has applied for a Montana Air Quality permit modification under the Clean Air Act of Montana permit a new facility to install and operate a combined heat and power (CHP) boiler. The state law that regulates air quality permitting in Montana is the Clean Air Act of Montana, §§ 75-2-101, et seq., (CAA) Montana Code Annotated (MCA). DEQ may not approve a proposed project contained in an application for an air quality permit unless the project complies with the requirements set forth in the CAA of Montana and the administrative rules adopted thereunder, ARMs 17.8.101 et. seq. The proposed action would be located on privately owned land, in Powell County, Montana. All information included in this EA is derived from the permit application, discussions with the applicant, analysis of aerial photography, topographic maps, and other research tools.

Purpose and Need

Under MEPA, Montana agencies are required to prepare an environmental review for state actions that may have an impact on the human environment. The Proposed Action is considered to be a state action that may have an impact on the human environment and, therefore, DEQ must prepare an environmental review. This EA will examine the proposed action and alternatives to the proposed action and disclose potential impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in ARM 17.4.608.

Table 1: Summary of Proposed Action

Proposed Action	
General Overview	This permitting action is to permit a new facility to install and operate a combined heat and power (CHP) boiler with an electrostatic precipitator (ESP).
Duration & Hours of Operation	**Construction:** Approximately 3 months to complete construction. **Operation:** Continuous operation.
Estimated Disturbance	New land disturbance would occur from this permitting action with the addition of a new structure to house the combined heat and power (CHP) boiler with electrostatic precipitator (ESP).
Construction Equipment	The following equipment is anticipated to be utilized (but not limited to): one bulldozer, one excavator, two dump trucks, one front end loader, one crane, two forklifts, two skidsteers, three concrete trucks, one compactor, two scissor lifts, one generator, one grader, one roller, and one paver.
Personnel Onsite	**Construction:** Temporary construction personnel will be onsite for the duration of the construction. **Operation:** Approximately 12 full time employees.
Location and Analysis Area	**Location**: Section 4, Township 7 North, Range 9 West, in Powell County, Montana **Analysis Area:** The area being analyzed as part of this environmental review includes the immediate project area (Figure 1), as well as neighboring lands surrounding the analysis area, as reasonably appropriate for the impacts being considered.
The applicant is required to comply with all applicable local, county, state, and federal requirements pertaining to the following resource areas.	
Air Quality	The applicant proposes to acquire a new air quality permit to install and operate a combined heat and power (CHP) boiler with ESP.
Water Quality	This permitting action would not affect water quality. BSBE is required to comply with the applicable local, county, state and federal requirements pertaining to water quality.
Erosion Control and Sediment Transport	This permitting action would not affect erosion control and sediment transport. BSBE is required to comply with the applicable local, county,

	state and federal requirements pertaining to erosion control and sediment transport.
Solid Waste	This permitting action would not affect solid waste in the area. BSBE is required to comply with the applicable local, county, state and federal requirements pertaining to solid waste.
Cultural Resources	This permitting action would not affect cultural resources. BSBE is required to comply with the applicable local, county, state and federal requirements pertaining to cultural resources.
Hazardous Substances	This permitting action would not contribute to any hazardous substances. BSBE is required to comply with the applicable local, county, state and federal requirements pertaining to hazardous substances.
Reclamation	This permitting action would not require any reclamation.

Cumulative Impact Considerations	
Past Actions	There are no past actions as this permitting action is to permit a new facility.
Present Actions	This permitting action is to permit a new facility to install and operate a combined heat and power (CHP) boiler with ESP.
Related Future Actions	DEQ is not currently aware of any future projects from BSBE. Any future projects would be subject to a new permit application.

See Figure 1 below for the project vicinity map location of the BSBE site and Figure 2 for a detailed view.

Figure 1: Project Vicinity Map

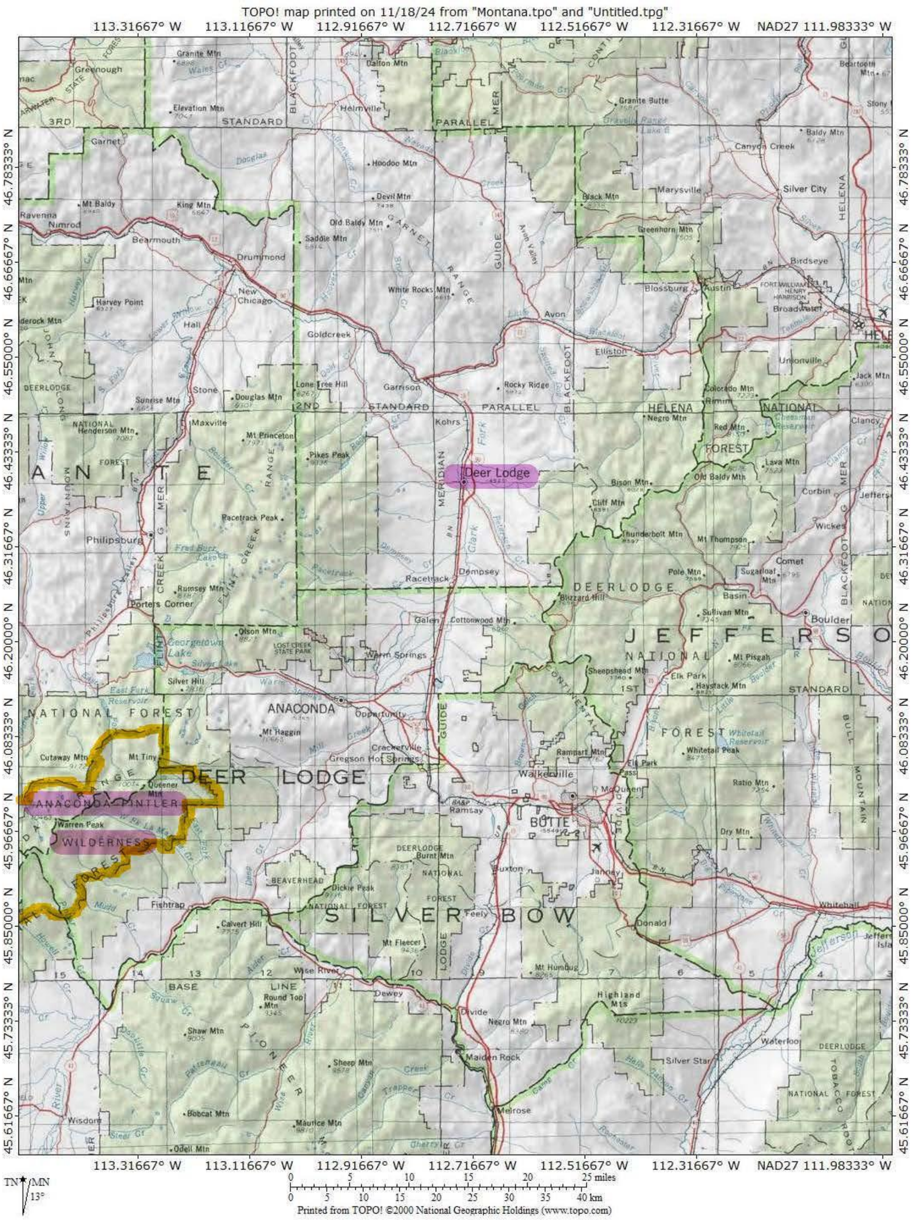

FIGURE 1: PROJECT VICINITY MAP

Figure 2: Site Location Map

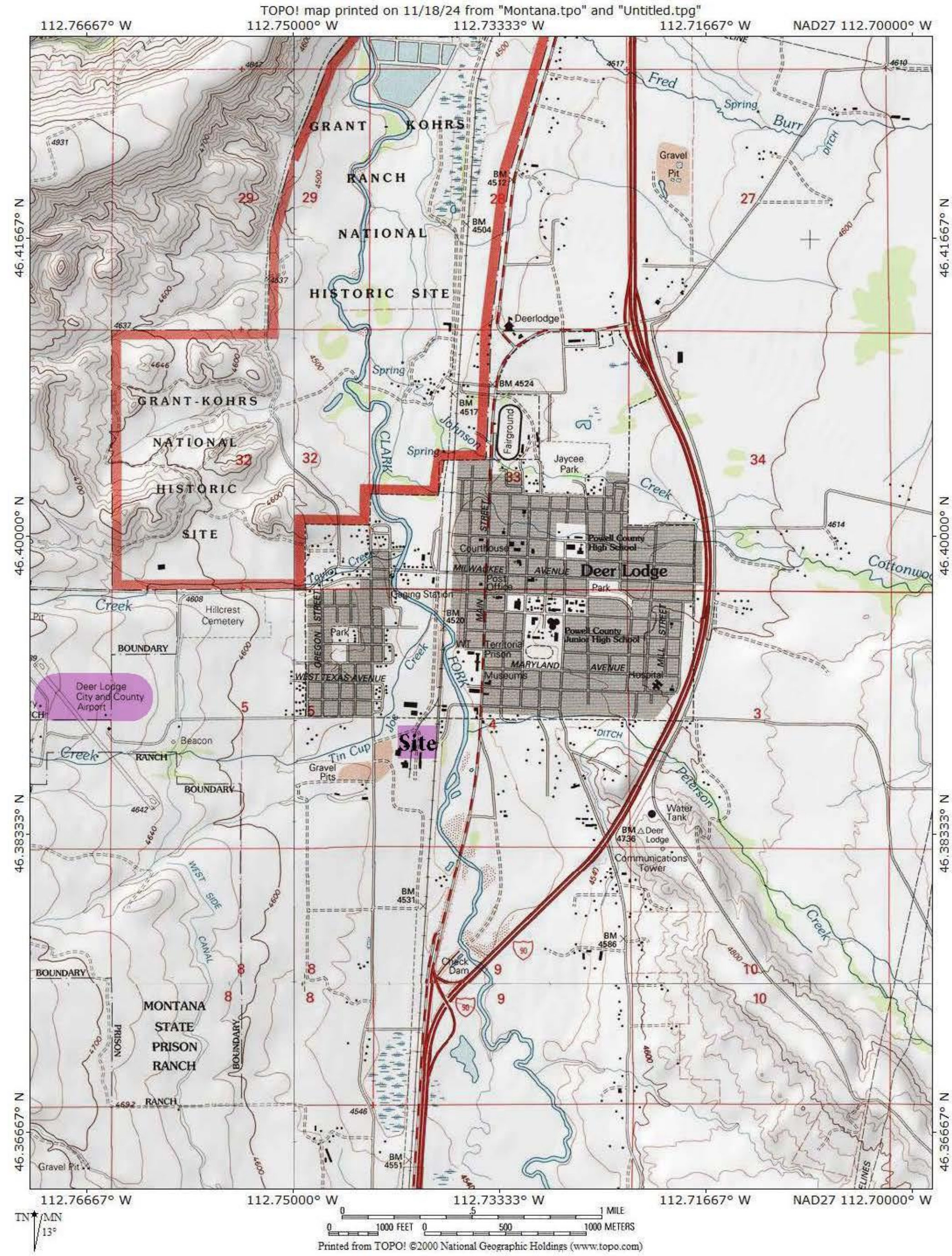

FIGURE 2: SITE LOCATION MAP

EVALUATION OF AFFECTED ENVIRONMENT AND IMPACT BY RESOURCE:

The impact analysis will identify and evaluate whether the impacts are direct or secondary impacts to the physical environment and human population in the area to be affected by the proposed project. Direct impacts occur at the same time and place as the action that causes the impact. Secondary impacts are a further impact to the human environment that may be stimulated, or induced by, or otherwise result from a direct impact of the action (ARM 17.4.603(18)). Where impacts would occur, the impacts will be described.

Cumulative impacts are the collective impacts on the human environment within the borders of Montana that could result from the Proposed Action when considered in conjunction with other past and present actions related to the Proposed Action by location and generic type. Related future impacts must also be considered when these actions are under concurrent consideration by any state agency through pre-impact statement studies, separate impact statement evaluation, or permit processing procedures. The activities identified in Table 1 were analyzed as part of the cumulative impacts assessment for each resource.

The duration is quantified as follows:

- Construction Impacts (short-term): These are impacts to the environment during the construction period. When analyzing duration, please include a specific range of time.

- Operation Impacts (long-term): These are impacts to the environment during the operational period. When analyzing duration, please include a specific range of time.

The intensity of the impacts is measured using the following:

++No impact: There would be no change from current conditions.

- Negligible: An adverse or beneficial effect would occur but would be at the lowest levels of detection.

- Minor: The effect would be noticeable but would be relatively small and would not affect the function or integrity of the resource.

- Moderate: The effect would be easily identifiable and would change the function or integrity of the resource.

- Major: The effect would alter the resource.

1. Geology and Soil Quality, Stability, and Moisture

The BSBE facility area is characterized by the Montana Bureau of Mines and Geology (MBMG) as being part of the Butte North 30' X 60' Quadrangle of Southwest Montana. This area is described as a complex area with Archean, Paleoproterozoic crystalline basement rock, Mesoproterozoic through Cretaceous metasedimentary and sedimentary rock, Cretaceous through Tertiary intrusive and volcanic rock, and Tertiary and Quaternary valley-fill and surficial deposits, all located within this quadrangle. At the BSBE site, this land is owned by Sun Mountain Lumber and has been previously disturbed by lumber mill activities.

Direct Impacts:

The permit application included additional information like analysis of aerial photography, topographic maps, information provided by BSBE and other research tools. This permitting action would not be considered a first-time disturbance by BSBE, as the land was previously an open lot that is being leased by BSBE from Sun Mountain Lumber (SML) and has previously been disturbed by lumber mill activities. Minor direct impacts would be expected because of the proposed project as it would include constructing a new building where there previously was not one.

Secondary Impacts:

Minor secondary impacts to geology, stability, and moisture would be expected because this action is new disturbance by BSBE with the construction of the new building. However, it is not first-time disturbance on the entire property that is owned by SML.

Cumulative Impacts:

Minor cumulative impacts to geology, stability, and moisture would be expected because of this permitting action. This is not considered first time disturbance as the land is owned by Sun Mountain Lumber, and leased to BSBE, and has been previously disturbed by lumber mill activities.

2. Water Quality, Quantity, and Distribution

The BSBE facility is located approximately 0.5 mile from the Clark Fork River. Discharges would not be released to ground or surface water. No fragile or unique water resources or values are present.

Direct Impacts:

BSBE has not submitted any other permit applications that DEQ is aware of related to this proposed permitting action.

No fragile or unique water resources or values are present in the area affected by the proposed project. No direct impacts to water quality and quantity, which are resources of significant statewide and societal importance, would be expected from this permitting action.

Secondary Impacts:
During operations, discharges would not be released to ground or surface water because of the proposed project. Further, as permitted, the proposed project would not be expected to cause or contribute to a violation of the applicable primary or secondary NAAQS. See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, no secondary impacts to water quality would be expected because of the proposed project. No new water resources would be required for normal operations of the affected new equipment. No secondary impacts to water quantity, quantity, and distribution would be expected from this permitting action.

Cumulative Impacts:
No major cumulative impacts to water quality, quantity, and distribution are anticipated from this permitting action. BSBE has not submitted any other permit applications that DEQ is aware of. Further, DEQ is unaware of any related actions under concurrent consideration by any state agency through preimpact statement studies, separate impact statement evaluation, or permit processing procedures.

3. Air Quality

For details about the existing air quality, see Section V of the Permit Analysis. This facility is located in the Unclassifiable/Attainment category.

Direct Impacts:
Expected emissions from the construction and operation of this permitting action are shown in the Permit Analysis Section within the Emission Inventory. An assessment of greenhouse gases (GHGs) is described in Section 23 of this draft EA.

Air quality standards, set by the federal government and DEQ are enforced by the Air Quality Bureau (AQB) and allow for pollutants at the levels permitted within the MAQP. The BSBE facility has emissions including particulate matter (PM) species, oxides of nitrogen (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), Hazardous Air Pollutants (HAPs), and GHG emissions.

Air pollution control equipment must be operated at the maximum design for which it is intended ARM 17.8.752(2). Limitations would be placed on the allowable emissions for the new emission sources. DEQ conducted a Best Available Control Technology (BACT) analysis for each emitting unit related to this permitting action. These proposed limits were reviewed by DEQ and incorporated into MAQP #5329-00, if necessary, as federally enforceable conditions. These permit limits cover NO_X, CO, SO_2, VOCs, PM, and HAPs with associated ongoing compliance demonstrations, as determined by DEQ.

Air quality standards are regulated by the federal Clean Air Act, 42 U.S.C. 7401 *et seq.* and the Montana CAA, § 50-40-101 *et seq.,* MCA, and are implemented and enforced by DEQ's AQB. As stated above, BSBE is required to comply with all applicable state and federal laws. Minor air quality impacts would be anticipated from the proposed action.

Secondary Impacts:
Impacts to air quality from the operation of the BSBE facility are to be restricted by an MAQP and therefore should have minor secondary air quality impacts.

Cumulative Impacts:
Cumulative impacts to air quality from the operation of the BSBE facility are to be restricted by an MAQP and therefore should have minor air quality impacts. Minor impacts are anticipated from this permitting action. The nearby area also has another stationary source, Sun Mountain Lumber, MAQP #2634-09, that contributes to the air quality in the area.

4. Vegetation Cover, Quantity, and Quality

No fragile or unique resources of values, or resources of statewide or societal importance, are present. The area around the BSBE facility is owned by Sun Mountain Lumber, and is industrial in nature, with little to no vegetation. DEQ conducted research using the Montana Natural Heritage Program (MTNHP) website and ran the query titled "Environmental Summary Report" dated January 8, 2025, which identified the following plant Potential Species of Concern (SOC) located in or near the affected facility: Mealy Primrose, Idaho Sedge, Wedge-leaf Saltbush, Fleshy Stitchwort, Flatleaf Bladderwort, Crawe's Sedge, Platte Cinquefoil, Panic Grass, High Northern Buttercup, Small Yellow Lady's-slipper, Long-sheath Waterweed, Linear-leaf Fleabane, Beaked Spikerush, Tufted Club-rush, and Meesia Moss.

The proposed action would be located within the existing footprint of the BSBE property.

The polygon area analyzed using the MTNHP website produces an area inherently larger than the specific disturbance area, so some additional species may be reported that are not necessarily present in the affected area, but nearby.

No important plant areas are present in the area.

Direct Impacts:
The information provided above is based on the information that DEQ had available at the time of draft EA preparation and information provided by the applicant. The permit application provided an analysis of aerial photography, topographic maps, geologic maps, soil maps, and other research tools. As the proposed action would be located within the

BSBE facility property boundary, minor impacts to vegetation cover are anticipated, as this permitting action is not considered first time disturbance and some vegetation will be lost with the addition of a new structure to house the CHP boiler and equipment. As this land is leased from SML, the property is located within the SML footprint, therefore that would not be considered first time disturbance for the entire property.

Secondary Impacts:

Minor secondary impacts to vegetation cover, quantity, and quality are expected since this is not new land disturbance. Therefore, since vegetation would be affected; it is anticipated to have minor secondary impacts.

Cumulative Impacts:

Minor cumulative impacts to vegetation cover, quantity, and quality are expected from this permitting action as it will reduce a small amount of vegetation cover, but the land is being leased from SML. Under the entirety of the SML property, this is not considered first time disturbance.

5. Terrestrial, Avian, and Aquatic Life and Habitats

As described earlier in Section 4., Vegetation Cover, the affected area is represented by agricultural and industrial operations and DEQ conducted research using the MTNHP website and ran the query titled “Environmental Summary Report” dated January 8, 2025, which identified the following species of concern (SOC): Bull Trout, Westslope Cutthroat Trout, Great Blue Heron, Bobolink, Lewis's Woodpecker, Long-billed Curlew, Little Brown Myotis, Long-legged Myotis, Bald Eagle, Evening Grosbeak, Cassin's Finch, Grizzly Bear, Bat Roost (Non-Cave), Hooded Merganser, North American Porcupine, Barrow's Goldeneye, American White Pelican, White-faced Ibis, Trumpeter Swan, Western Screech-Owl, Clark's Nutcracker, Black-necked Stilt, Canada Lynx, Fisher, American Goshawk, Brown Creeper, Golden Eagle, Gray-crowned Rosy-Finch, Flammulated Owl, Varied Thrush, Caspian Tern, Common Loon, Horned Grebe, Loggerhead Shrike, Tennessee Warbler, Suckley's Cuckoo Bumble Bee, Northern Hoary Bat, Western Spotted Skunk, Western Pearlshell, Keeled Mountainsnail, Spotted Bat, Broad-tailed Hummingbird, Ferruginous Hawk, Rufous Hummingbird, Silver-haired Bat, Black Tern, Veery, Monarch, Fringed Myotis, Western Pygmy Shrew, Short-eared Owl, Long-eared Myotis, Pileated Woodpecker, Western Toad, Black-crowned Night Heron, Common Poorwill, Dwarf Shrew, American Bittern, Ovenbird, North American Water Vole, Preble's Shrew, Townsend's Big-eared Bat, Wolverine, Common Tern, Forster's Tern, Harlequin Duck, Sage Thrasher, and Northern Leopard Frog.

The polygon area analyzed using the MTNHP website produces an area inherently larger than the specific disturbance area, so some additional species may be reported that are not necessarily present in this exact area, but nearby. Further, because the proposed action would occur within the footprint of the existing BSBE facility, and the affected area is industrial in nature, the identified Species of Concern would not be expected to locate within or use the affected area for part of their life cycle.

No important bird areas are present on the BSBE property.

Direct Impacts:

The potential impact to terrestrial, avian and aquatic life and habitats would be negligible, due to the long-term industrial nature of the site. While this is first time disturbance by BSBE, the land is owned by SML, and this is not considered first time disturbance on the property. Therefore, any direct impacts will be long-term and negligible.

Secondary Impacts:

Because the proposed action would occur within the existing footprint of the SML facility on land leased by BSBE and because the facility is industrial by nature, no secondary impacts to terrestrial, avian and aquatic life and habitats would be stimulated or induced by the direct impacts analyzed above as all actions are occurring within property boundaries and this is not considered first time disturbance by SML, even though it is considered first time disturbance by BSBE.

Cumulative Impacts:

The potential impact to terrestrial, avian and aquatic life and habitats would be negligible, due to the long-term industrial nature of the site. While this is first time disturbance by BSBE, the land is owned by SML, and this is not considered first time disturbance on the property. Therefore, any cumulative impacts will be long-term and negligible.

6. Unique, Endangered, Fragile, or Limited Environmental Resources

As described in Section 5 above, DEQ conducted a search using the MTNHP webpage. The search used a polygon that overlapped the site and produced the list of species of concern identified in Section 5. The project would not be in core, general, or connectivity sage grouse habitat, as designated by the Sage Grouse Habitat Conservation Program (Program) at: http://sagegrouse.mt.gov. This project is located approximately 0.5 miles from an area that is designated by the Sage Grouse Habitat Conservation Program as "Exempt Community Boundaries."

Direct Impacts:

Among the SOC identified by the MTNHP, these species would not be expected to be displaced by the proposed action as the land where the permitting action would occur is leased by BSBE and owned by SML and has been part of an existing industrial facility for years. Therefore, any potential direct impacts would be short-term and negligible.

Secondary Impacts:

The proposed action would have no secondary impacts to the identified species of concern because the permit conditions are protective of human and animal health and welfare, and the affected area is currently used for industrial operations and would not change the effect to existing habitats that may be present in the affected area.

Cumulative Impacts:

The proposed action would have minor cumulative impacts to endangered species because the permit conditions are protective of human and animal health and all lands involved in the proposed action are currently used for industrial operations and would not change the effect to the environment outside of the original construction of the facility.

7. Historical and Archaeological Sites

The Montana State Historic Preservation Office (SHPO) was contacted to conduct a file search for historical and archaeological sites within Section 4, Township 7 North, Range 9 West, which includes the area affected by the proposed project. SHPO provided a letter dated January 6, 2025, stating there have been a few previously recorded sites within the designated search location, but none located within the proposed project area. The following sites were listed:

Site Type 1	Site Type 2	NR Status
Historic Education		NR Listed
Historic Industrial Development	Historic District	NR Listed
Historic Architecture		Undetermined
Historic Mining	Historic Log Structure	Undetermined
Historic Political/Government		NR Listed
Historic Railroad		Eligible
Historic Railroad Building/Structure		Ineligible
Historic Vehicular/Foot Bridge		NR Listed
Historic Structure		Eligible
Historic Apartment House		NR Listed
Historic Road		Eligible

It is SHPO's position that any structure over fifty years of age is considered historic and is potentially eligible for listing on the National Register of Historic Places. If any structures are within the Area of Potential Effect, and are over fifty years old, SHPO recommends that they be recorded, and a determination of their eligibility be made prior to any disturbance taking place.

However, should structures need to be altered, or if cultural materials are inadvertently discovered during this proposed action, SHPO requests their office be contacted for further investigation.

Direct Impacts:

Although the search conducted by SHPO identified recorded cultural sites/resources in the search area, none of the identified sites are located in the proposed area for the BSBE facility. Therefore, no impacts to the identified sites would be expected because of the proposed project. Further, because the proposed project would occur within the footprint of the existing SML operations, the proposed project would not be expected to impact any new, previously unrecorded cultural resources that may exist in the affected area. Therefore, no direct impacts to historical and archaeological sites would be expected because of the proposed project.

Secondary Impacts:

No secondary impacts to historical and archaeological sites are anticipated since the proposed action is located on land currently in industrial use and no sites are located within the proposed permitting location.

Cumulative Impacts:

No cumulative impacts to historical and archaeological sites are anticipated since the proposed action is located on land currently in industrial use and no sites are located within the proposed permitting location.

8. Aesthetics

The proposed action would occur on private land owned by Sun Mountain Lumber (SML) and leased by BSBE near Deer Lodge, Montana. This area is mainly surrounded by agricultural activities and residential areas. The closest home and/or structure not associated with this project is approximately 700 feet away. Construction of the proposed project would last for approximately three months.

Direct Impacts:

BSBE's visual profile would change with the addition of an additional structure to house the CHP and associated equipment. The land is currently an empty lot being leased from SML. Therefore, this is not considered first time disturbance. BSBE will add a new structure as no structures currently exist on this lot being leased by BSBE. The SML facility is already in existence prior to the addition of the CHP boiler and structure from BSBE, so the area is still industrial by nature and will not be changing. The new structure will include the addition of a stack, all of which will change the overall aesthetics of the facility, which will be a long-term impact. However, the SML footprint is already industrial. There would be no increase in noise levels from this permitting action, aside from the construction of the new structure.

Once construction was completed, noise levels would not be discernable from the already existing industrial sounds of the area. Therefore, any direct impacts would be long-term and minor, and consistent with existing impacts.

Secondary Impacts:

There would be moderate secondary impacts on the aesthetics due to the addition of the stack and buildings. The area is industrial in nature, as it is landed owned by SML, and would be accordance with the existing industrial activities. Therefore, impacts would be long-term and minor.

Cumulative Impacts:

Long-term impacts will occur with the addition of the BSBE facility that were previously not on this lot. Major and long-term cumulative impacts are anticipated from the addition of the facility with associated stacks and new buildings. This is not considered first time disturbance at the property, as it has previously been disturbed by lumber mill activities.

9. Demands on Environmental Resources of Land, Water, Air, or Energy

The site is located on land owned by SML and leased by BSBE. See Sections 2, 3, and 4 of this EA for details regarding land, water, and air impacts.

Direct Impacts:

There would be a minor increase in demand for the environmental resources of land, air, and energy for these actions. Land usage was converted to be used for the addition of the CHP project. However, as the land is owned by SML, this property already requires these resources. Now that it is leased by BSBE, it will still require the same resources. There will be minor impacts on air and energy as the emissions increased with the addition of the CHP therefore the energy usage also increased with these actions. Any direct impacts would be long-term and minor, and consistent with the area.

Secondary Impacts:

Minor secondary impacts to demands on land, water, air, and energy are anticipated as a result of this permitting action due to this site already being an industrial in nature.

Cumulative Impacts:

Minor cumulative impacts to demands on land, water, air, and energy are anticipated as a result of this permitting action. Minor cumulative impacts are anticipated with the addition of the CHP boiler, in terms of land, air, and energy, as this causes an increase demand on all of those areas.

10. Impacts on Other Environmental Resources

The site is currently a part of the SML facility and is being leased by BSBE.

Direct Impacts:

No other environmental resources are known to have been identified in the area beyond those discussed above. Hence, there is no impact to other environmental resources.

Secondary Impacts:

No secondary impacts to other environmental resources are anticipated as a result of the proposed permitting action.

Cumulative Impacts:

No cumulative impacts to other environmental resources are anticipated as a result of the proposed permitting action.

11. Human Health and Safety

The applicant would be required to adhere to all applicable state and federal safety laws. The Occupational Safety and Health Administration (OSHA) has developed rules and guidelines to reduce the risks associated with this type of labor. Members of the public would not be allowed in the immediate proximity to the project during construction or operations and access to the public would continue to be restricted to this property. BSBE is located to the nearby Deer Lodge City County Airport runway. Based on the regulations in 14 CFR Part 77 – Safe, Efficient Use, and Preservation of the Navigable Airspace, BSBE determined that the proposed boiler stack height complies with this subpart.

Direct Impacts:

Negligible changes in impacts to human health and safety are anticipated as a result of this project action due to the industrial nature of the facility. The stack height does not interfere with the nearby Deer Lodge City County Airport runway and BSBE will submit to the Federal Aviation Administration (FAA) Form 7460-1 to notify the agency of the proposed stack construction.

Secondary Impacts:

No secondary impacts to human health and safety are anticipated as a result of the proposed permitting action due to the industrial nature of the facility.

Cumulative Impacts:

No cumulative impacts to human health and safety are anticipated as a result of the proposed permitting action due to the industrial nature of the facility.

12. Industrial, Commercial, and Agricultural Activities and Production

This site is used for industrial purposes as it was privately owned land by SML and is being leased by BSBE.

Direct Impacts:

This permitting action would not change the purpose of the property as it is currently being used for industrial purposes, with it being owned by SML. Any impacts on industrial, commercial, and agricultural activities and production in the area would be long-term and minor due to the addition of the new structure for the CHP boiler, which would increase industrial production of the facility and the affected area.

Secondary Impacts:

No secondary impacts to industrial, commercial, and agricultural activities and production are anticipated as a result of the proposed permitting action as this property is already an existing industrial facility.

Cumulative Impacts:

The cumulative impacts are minor as the facility currently used for industrial purposes on land that was already used for industrial purposes but will see an increase from the addition of the new structure for the CHP boiler.

13. Quantity and Distribution of Employment

There will be 12 permanent jobs at the BSBE site. All 12 will be new full-time jobs Approximately three months of construction will occur with this permitting action. Multiple temporary construction personnel will be onsite to complete the construction. Once construction is completed, all temporary construction personnel will no longer be onsite.

Direct Impacts:

The proposed action would be expected to have minor on the overall distribution of employment as the facility is new and will have additional employment because of this permitting action. However, nearby cities would be anticipated to fulfill those jobs and it would not be anticipated to cause an increase or decrease in any nearby populations.

Secondary Impacts:

Minor secondary impact to the quality and distribution of employment is expected on long-term employment from the proposed action as there will be 12 new employees are being added from this permitting action.

Cumulative Impacts:

There would be minor cumulative impacts on employment for this permitting action because 12 new employees would be added as a result of this permitting action. Once construction was completed, the construction personnel would no longer be onsite.

14. Local and State Tax Base and Tax Revenues

Local, state, and federal governments would be responsible for appraising the property, setting tax rates, collecting taxes, from the companies, employees, or landowners benefiting from this operation.

Direct Impacts:

The proposed action would be expected to have long-term and major impacts on the local and state tax base and tax revenues due to the addition of the new BSBE facility.

Secondary Impacts:

BSBE would be responsible for accommodation of any increased taxes associated with the operation of the modified facility. Minor secondary impacts to local and state tax base and tax revenues are anticipated as a result of the proposed permitting action.

Cumulative Impacts:

Major impacts to local and state tax base and tax revenues were anticipated with the construction and operation of a new facility in the area. BSBE would continue to be responsible for accommodation of any increased taxes associated with the operation of the new facility. Local, state, and federal governments would be responsible for appraising the property, setting tax rates, collecting taxes, from the companies, employees, or landowners benefiting from this operation. Therefore, any cumulative impacts would be major and consistent with existing impacts in the affected area.

15. Demand for Government Services

The area surrounding the BSBE site consists of residences and agricultural activities.

Direct Impacts:

The air quality permit has been prepared by state government employees as part of their day-to-day, regular responsibilities. Therefore, any direct impacts to demands for government services would be short-term, consistent with existing impacts, and negligible. Compliance review and assistance oversight by DEQ AQB would be conducted in concert with other area activity when in the vicinity of the proposed project. Therefore, any direct impacts would be long-term and negligible to minor, mainly through increased regulatory oversight by DEQ.

Secondary Impacts:

Initial and ongoing compliance inspections of facility operations would be accomplished by state government employees as part of their typical, regular duties and required to ensure the facility is operating within the limits and conditions listed in the air quality permit. Therefore, any secondary impacts to demands for government services would be long-term, consistent with existing impacts, and negligible.

Cumulative Impacts:

The air quality permit has been prepared by state government employees as part of their day-to-day, regular responsibilities. Following construction of the proposed facility, initial and ongoing compliance inspections of facility operations would be accomplished by state government employees as part of their typical, regular duties and required to ensure the facility is operating within the limits and conditions listed in the air quality permit. Therefore, any cumulative impacts to demands for government services would be short- and long-term, consistent with existing impacts, and negligible. Minor cumulative impacts are anticipated on government services with the proposed action and a minimal increase in impact would occur from the permitting and compliance needs associated with this permitted facility.

16. Locally-Adopted Environmental Plans and Goals

A review was conducted on January 6, 2024, to identify any locally adopted environmental plans or goals. A "2024 Deer Lodge Growth Policy" was located on the City of Deer Lodge Website. This updated plan helps the City Council, Planning Board, residents, potential new residents, and investors to make informed decisions concerning the economy, infrastructure, local services, and land use, throughout the Deer Lodge community. This document has the following sections to help people understand the rationale and how these goals will be achieved: Goals, Objectives, and Actions; Introduction; Population; Economy; Local Services and Public Facilities; Housing; Land Use; Resident Outreach. This document also includes previously achieved goals from the 2015 Growth Policy and outlines new goals. One of the main goals is the economy of this area. The document states that historically, the city's economy is based in natural resources, such as logging and timber mill industries, along with employment at the State Prison, but is working on making a transition to jobs that focus on services, tourism, and recreation (City of Deer Lodge: Growth Policy).

Direct Impacts:

BSBE's facility is on property owned by SML. This permitting action, feeds into the historical economy of the area, that of timber mill/logging industries. This permitting action does not correlate to the new vision of focusing on services, tourism, and recreation in the area. However, it would help boost the local economy by bringing a new business to the area, thereby supplying more local jobs in an industry that exists in the area. This permitting action would have a minor impact on the growth plan, as the city is trying to diversify away from the logging/timber mill industry but would still boost the economy.

Secondary Impacts:

Some locally adopted environmental plans and goals in the area will be affected by the proposed action, as the facility fits with the historical economic sector of the City of Deer Lodge but does not fit with the goal of moving into the services, tourism, and recreation fields. Therefore, minor impacts would be expected because of the proposed project.

Cumulative Impacts:

DEQ conducted a search of the City of Deer Lodge website on January 6, 2025, and a "2024 Deer Lodge Growth Policy" was located. Minor impacts are anticipated from this permitting action as the addition of this facility would boost the economy, which is one of the key goals listed in the growth policy, but it would fit in with the historical nature of the economy for the City of Deer Lodge. It does not fit with the future plans of transitioning to a focus in services, tourism, and recreation. Therefore, minor cumulative impacts to locally adopted environmental plans and goals are anticipated as a result of the proposed permitting action.

17. Access to and Quality of Recreational and Wilderness Activities

The BSBE facility is located approximately 50 miles from the closest wilderness area, the Hoodoo Mountain Wilderness Study Area. The Elkhorn Wilderness Study Area and the Quigg West Wilderness Study Area are located approximately 90 miles away.

Direct Impacts:

There would be no impacts to the access to wilderness activities as none are in the vicinity of the proposed action. Therefore, no direct impacts to access to and quality of wilderness activities would be expected because of the proposed project. The affected area is industrial by nature and little to no recreational opportunities exist in the area affected by the proposed project. Therefore, no direct impacts would be expected. Access to the wilderness areas would not change with this permitting action. Recreation in the area would not be impacted by this permitting action. No wilderness area is located in a close enough proximity for recreationalists to see any change in aesthetics with the addition of the BSBE facility. Therefore, no direct impacts would be expected.

Secondary Impacts:

No wilderness areas are located nearby or accessed through this land owned by SML and leased by BSBE. The nearest designated wilderness area is the Hoodoo Mountain Wilderness Study Area, located approximately 50 miles from the affected site. Therefore, no secondary impacts to access to and quality of wilderness activities would be expected because of the proposed project. No secondary impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed permitting action which is wholly contained within the boundary of the BSBE property.

Cumulative Impacts:

No wilderness areas are located nearby or accessed through this land owned by SML and leased by BSBE. The nearest designated wilderness area is the Hoodoo Mountain Wilderness Study Area located approximately 50 miles from the affected site. Therefore, no cumulative impacts to access to and quality of wilderness activities would be expected because of the proposed project. No cumulative impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed permitting action which is wholly contained within the boundary of the BSBE property.

18. Density and Distribution of Population and Housing

The City of Deer Lodge, Montana has approximately 2,938 residents (U.S. Census Bureau).

Direct Impacts:

BSBE will employ 12 full time employees at this facility. This permitting action would not be anticipated to result in an increase in the local population by the small increase. have an expected-on employment at the BSBE facility. The nearby town of Deer Lodge, and/or the surrounding area would be anticipated to fulfill these additional needs for housing. Therefore, minor direct impacts to density and distribution of population and housing are anticipated because of the proposed action.

Secondary Impacts:

BSBE would need new staff to operate the facility, but the proposed project would not be expected to result in a potential increase in the local population. Minor secondary impacts to density and distribution of population and housing are anticipated as a result of the proposed permitting action as it is a small amount of new employees being added.

Cumulative Impacts:

BSBE would need new staff to operate the facility and the proposed project would not be expected to result in a potential increase in the local population. Minor cumulative impacts to density and distribution of population and housing are anticipated as a result of the proposed permitting action as 12 new employees would be added as result of this permitting action.

19. Social Structures and Mores

Based on the required information provided by BSBE, DEQ is not aware of any native cultural concerns that would be affected by the proposed action on this existing facility.

Direct Impacts:

The proposed action is located on an existing industrial site and no changes to or disruption of native or traditional lifestyles would be expected because of the proposed project. Therefore, no impacts to social structure and mores are anticipated.

Secondary Impacts:

No secondary impacts to social structures and mores are anticipated as a result of the proposed actions due to the existing industrial nature of the facility.

Cumulative Impacts:

No cumulative impacts to social structures and mores are anticipated as a result of the proposed actions. Cumulative impacts are anticipated to be negligible as the location is already in industrial use. The addition of the new CHP boiler and structure will be new disturbance by BSBE, but not first-time disturbance on the entire SML property.

20. Cultural Uniqueness and Diversity

Based on the required information provided by BSBE, DEQ is not aware of any unique qualities of the area that would be affected by the proposed action at this existing facility.

Direct Impacts:

BSBE would employ new staff to accommodate the proposed action, but the proposed project would not be expected to result in an increase or decrease in the local population. Therefore, no direct impacts to the existing cultural uniqueness and diversity of the affected population would be expected because of the proposed project.

Secondary Impacts:

The existing nature of the area affected by the proposed project is industrial. Further, the addition of new staff under the proposed action and thus the proposed project would not be expected to result in an increase or decrease in the local population. Therefore, no secondary impacts to the existing cultural uniqueness and diversity of the affected population are anticipated as a result of the proposed action.

Cumulative Impacts:

The existing nature of the area affected by the proposed project is industrial. Further, the addition of new staff under the proposed action and thus the proposed project would not be expected to result in an increase or decrease in the local population. Therefore, no cumulative impacts to the existing cultural uniqueness and diversity of the affected population are anticipated as a result of the proposed action.

21. Private Property Impacts

The proposed action would take place on privately-owned land. The analysis below in response to the Private Property Assessment Act indicates no impact. DEQ does not plan to deny the application or impose conditions that would restrict the regulated person's use of private property so as to constitute a taking. Further, if the application is complete, DEQ must take action on the permit pursuant to § 75-2-218(2), MCA. Therefore, DEQ does not have discretion to take the action in another way that would have less impact on private property—its action is bound by a statute.

There are private residences in the nearby area of the proposed action. The closest residence, including homes or structures, is located approximately 700 feet away from the project site.

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

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

22. Other Appropriate Social and Economic Circumstances

Direct Impacts:

DEQ is unaware of any other appropriate short-term social and economic circumstances in the affected area that may be directly affected by the proposed project. Therefore, no further direct impacts would be anticipated.

Secondary Impacts:

The proposed project would allow for the operation of the CHP boiler by BSBE at the leased site from SML. Any impacts to air quality would be long-term and minor.

DEQ is unaware of any other appropriate short-term social and economic circumstances in the affected area that may be directly affected by the proposed project. Therefore, no further secondary impacts would be anticipated.

Cumulative Impacts:

DEQ is unaware of any other appropriate short-term social and economic circumstances in the affected area that may be directly affected by the proposed project. Therefore, no further cumulative impacts would be anticipated.

23. Greenhouse Gas Assessment

Issuance of this permit would authorize BSBE to be a permitted facility with a combined heat and power (CHP) boiler with ESP.

The analysis area for this resource is limited to the activities regulated by the issuance of MAQP#5329-00, which is to permit the facility with the addition of the combined heat and power (CHP) boiler. The amount of biomass fuel utilized at this site may be impacted by a number of factors including seasonal weather impediments and equipment malfunctions. To account for these factors DEQ has calculated the max amount of emissions using 8760 hours per year of operation.

For the purpose of this analysis, DEQ has defined greenhouse gas emissions as the following gas species: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and many species of fluorinated compounds. The range of fluorinated compounds includes numerous chemicals which are used in many household and industrial products. Other pollutants can have some properties that also are similar to those mentioned above, but the EPA has clearly identified the species above as the primary GHGs. Water vapor is also technically a greenhouse gas, but its properties are controlled by the temperature and pressure within the atmosphere, and it is not considered an anthropogenic species.

The combustion of biomass fuel at the site would release GHGs primarily being carbon dioxide (CO_2), nitrous oxide (N_2O) and much smaller concentrations of uncombusted fuel components including methane (CH_4) and other volatile organic compounds (VOCs).

DEQ has calculated GHG emissions using the EPA Simplified GHG Calculator version May 2023, for the purpose of totaling GHG emissions. This tool totals carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) and reports the total as CO_2 equivalent (CO_2e) in metric tons CO_2e. The calculations in this tool are widely accepted to represent reliable calculation approaches for developing a GHG inventory.

Direct Impacts:

Operation of the biomass fueled CHP boiler with ESP, at the BSBE facility would produce exhaust fumes containing GHGs.

DEQ estimates that approximately 2,207 metric tons of CO2e would be produced per year. To account for variability due to the factors described above, DEQ has calculated the maximum amount of emissions using a factor of 8760 hours per year for operation. Using the Environmental Protection Agency's (EPA) simplified GHG Emissions Calculator for mobile sources, approximately 865 metric tons of CO_2e would be produced per year. Construction for this permitting action would product approximately 147 metric tons of CO2e.

Secondary Impacts:

GHG emissions contribute to changes in atmospheric radiative forcing, resulting in climate change impacts. GHGs act to contain solar energy loss by trapping longer wave radiation emitted from the Earth's surface and act as a positive radiative forcing component (BLM 2021).

Per EPA's website "Climate Change Indicators", the lifetime of carbon dioxide cannot be represented with a single value because the gas is not destroyed over time. The gas instead moves between air, ocean, and land mediums with atmospheric carbon dioxide remaining in the atmosphere for thousands of years, due in part to the very slow process by which carbon is transferred to ocean sediments. Methane remains in the atmosphere for approximately 12 years. Nitrous oxide has the potential to remain in the atmosphere for about 109 years (EPA, Climate Change Indictors). The impacts of climate change throughout the southeastern area of Montana include changes in flooding and drought, rising temperatures, and the spread of invasive species (BLM 2021).

Cumulative Impacts:

Montana recently used the EPA State Inventory Tool (SIT) to develop a greenhouse gas inventory in conjunction with preparation of a possible grant application for the Community Planning Reduction Grant (CPRG) program. This tool was developed by EPA to help states develop their own greenhouse gas inventories, and this relies upon data already collected by the federal government through various agencies. The inventory specifically deals with carbon dioxide, methane, and nitrous oxide and reports the total as CO_2e. The SIT consists of eleven Excel based modules with pre-populated data that can be used with default settings or in some cases, allows states to input their own data when the state believes their own data provides a higher level of quality and accuracy. Once each of the eleven modules is filled out, the data from each module is exported into a final “synthesis” module which summarizes all of the data into a single file. Within the synthesis file, several worksheets display the output data in a number of formats such as GHG emissions by sector and GHG emissions by type of greenhouse gas.

DEQ has determined the use of the default data provides a reasonable representation of the greenhouse gas inventory for the various sectors of the state, and the estimated total annual greenhouse gas inventory by year. The SIT data from EPA is currently only updated through the year 2021, as it takes several years to validate and make new data available within revised modules. DEQ maintains a copy of the output results of the SIT.

DEQ has determined that the use of the default data provides a reasonable representation of the GHG inventory for all of the state sectors, and an estimated total annual GHG inventory by year. At present, Montana accounts for 47.77 million metric tons of CO_2e based on the EPA SIT for the year 2021. This project may contribute up to 2,207 metric tons per year of CO2e. The construction phase of this project would contribute less than one metric ton of CO2e per year. The estimated emission of 2,207 metric tons of CO2e from this project would contribute 0.0049% of Montana’s annual CO2e emissions.

GHG emissions that would be emitted as a result of the proposed activities would add to GHG emissions from other sources. The No Action Alternative would not contribute approximately any GHG emissions, as the proposed No Action Alternative would be to deny the permit and not allow the operation of the CHP boiler with ESP on site. The current land use of the area is industrial as it is land owned by SML and leased by BSBE.

Reference

Bureau of Land Management (BLM) 2021. Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends from Coal, Oil, and Gas Exploration and Development on the Federal Mineral Estate. Available at: https://www.blm.gov/content/ghg/2021/. Accessed February 28, 2024.

PROPOSED ACTION ALTERNATIVES:

No Action Alternative:

In addition to the analysis above for the proposed action, DEQ is considering a “no action” alternative. The “no action” alternative would deny the approval of the proposed permitting action. The applicant would lack the authority to conduct the proposed activity. Any potential impacts that would result from the proposed action would not occur. The no action alternative forms the baseline from which the impacts of the proposed action can be measured.

Other Ways to Accomplish the Action:
In order to meet the project objective to permit this facility with the addition of the CHP boiler with ESP, has no other way to accomplish this action outside of not having this equipment on-site, which would then result in the facility not needing an MAQP.

If the applicant demonstrates compliance with all applicable rules and regulations as required for approval, the "no action" alternative would not be appropriate. Pursuant to, § 75-1-201(4)(a), (MCA) DEQ "may not withhold, deny, or impose conditions on any permit or other authority to act based on" an environmental assessment.

CONSULTATION

DEQ engaged in internal and external efforts to identify substantive issues and/or concerns related to the proposed project. Internal scoping consisted of internal review of the environmental assessment document by DEQ staff. External scoping efforts also included queries to the following websites/databases/personnel:

MAQP#5329-00 Application, EPA State Inventory Tool, the EPA GHG Calculator Tool, the Montana Natural Heritage Program Website, the Montana Cadastral Mapping Program, the State of Montana GIS Mapping Program, the City of Deer Lodge website, and the State Historical Preservation Office.

PUBLIC INVOLVEMENT:

The public comment period for this permit action was from April 15, 2025, through April 30, 2025.

OTHER GOVERNMENTAL AGENCIES WITH JURSIDICTION:

The proposed project would be located on private land. All applicable state and federal rules must be adhered to, which, at some level, may also include other state, or federal agency jurisdiction.

This environmental review analyzes the proposed project submitted by the Applicant. The project would be negligible and would be fully reclaimed to the permitted postmining land uses at the conclusion of the project and thus would not contribute to the long-term cumulative effects in the area.

NEED FOR FURTHER ANALYSIS AND SIGNIFICANCE OF POTENTIAL

IMPACTS

When determining whether the preparation of an environmental impact statement is needed, DEQ is required to consider the seven significance criteria set forth in ARM 17.4.608, which are as follows:

- The severity, duration, geographic extent, and frequency of the occurrence of the impact;
- The probability that the impact will occur if the proposed action occurs; or conversely, reasonable assurance in keeping with the potential severity of an impact that the impact will not occur;
- Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts – identify the parameters of the proposed action;
- The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values;
- The importance to the state and to society of each environmental resource or value that would be affected.
- Any precedent that would be set as a result of an impact of the proposed action that would commit the department to future actions with significant impacts or a decision in principle about such future actions; and
- Potential conflict with local, state, or federal laws, requirements, or formal plans.

CONCLUSIONS AND FINDINGS

DEQ finds that this action results in minor impacts to air quality and GHG emissions in Powell County, Montana.

The severity, duration, geographic extent and frequency of the occurrence of the impacts associated with the proposed air quality project would be limited. The proposed action would not result in first time disturbance, as the land is owned by the SML facility and has been previously disturbed.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed actions for any environmental resource. DEQ does not believe that the proposed activities by the Applicant would have any growth-inducing or growth-inhibiting aspects, or contribution to cumulative impacts. The proposed site does not appear to contain known unique or fragile resources.
There are no unique or known endangered fragile resources in the project area. No underground disturbance would be required for this project.

There would be major impacts to view-shed aesthetics as the facility would be constructed where there previously was not one.

Demands on the environmental resources of land, water, air, or energy would not be significant, as it is already on land owned by SML that is an operational facility.

Impacts to human health and safety would not be significant as access roads would be closed to the public and because the site is on Privately Owned Land by SML. The public is not allowed on the BSBE site that is leased from SML.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed activities on any environmental resource.

Issuance of a Montana Air Quality Permit to the Applicant does not set any precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions If the Applicant submits another modification or amendment, DEQ is not committed to issuing those revisions. DEQ would conduct an environmental review for any subsequent permit modifications sought by the Applicant that require environmental review. DEQ would make permitting decisions based on the criteria set forth in the Clean Air Act of Montana.

Issuance of the Permit to the Applicant does not set a precedent for DEQ's review of other applications for Permits, including the level of environmental review. The level of environmental review decision is made based on case-specific consideration of the criteria set forth in ARM 17.4.608.

Finally, DEQ does not believe that the proposed air quality permitting action by the Applicant would have any growth-inducing or growth inhibiting impacts that would conflict with any local, state, or federal laws, requirements, or formal plans.

Based on a consideration of the criteria set forth in ARM 17.4.608, the proposed operation is not predicted to significantly impact the quality of the human environment. Therefore, preparation of an EA is the appropriate level of environmental review for MEPA.

Environmental Assessment and Significance Determination Prepared By:

Emily Hultin, Air Quality Engineering Scientist

Environmental Assessment Reviewed By:

Eric Merchant, Air Permitting Services Section Supervisor

Approved By:

Eric Merchant, Air Permitting Services Section Supervisor
Date: April 14, 2025

REFERENCES

1. Big Sky Bioenergy, LLC (BSBE) application for the new permit of MAQP#5329-00 received December 18, 2024
2. Sun Mountain Lumber MAQP #2634-09
3. (2024, February). *City of Deer Lodge: Growth Policy* [Review of *City of Deer Lodge: Growth Policy*]. City of Dear Lodge Montana. https://www.cityofdeerlodgemt.gov/media/2106
4. *Home Page*. (2025). Deer Lodge MT. https://www.cityofdeerlodgemt.gov/
5. Bureau, U. C. (2023, June 29). *Search Results*. Census.gov. https://www.census.gov/search-results.html?q=population+of+Deer+Lodge+city%2C+Montana&page=1&stateGeo=none&searchtype=web&cssp=SERP&_charset_=UTF-8
6. Bureau of Land Management (BLM) 2021. Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends from Coal, Oil, and Gas Exploration and Development on the Federal Mineral Estate. Available at: https://www.blm.gov/content/ghg/2021/. Accessed February 28, 2024.

ABBREVIATIONS and ACRONYMS

AQB -	Air Quality Bureau
ARM -	Administrative Rules of Montana
BACT -	Best Available Control Technology
BMP -	Best Management Practices
BSBE-	Big Sky Bioenergy, LLC.
CAA -	Clean Air Act of Montana
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
DEQ -	Department of Environmental Quality
DNRC -	Department of Natural Recourses and Conservation
EA -	Environmental Assessment
EIS -	Environmental Impact Statement
EPA -	U.S. Environmental Protection Agency
FCAA-	Federal Clean Air Act
MAQP -	Montana Air Quality Permit
MCA -	Montana Code Annotated
MEPA -	Montana Environmental Policy Act
MTNHP -	Montana Natural Heritage Program
NO_X -	Oxides of Nitrogen
PM -	Particulate Matter
PM_{10} -	Particulate Matter with an Aerodynamic Diameter of 10 Microns and Less
$PM_{2.5}$ -	Particulate Matter with an Aerodynamic Diameter of 2.5 Microns and Less
PPAA -	Private Property Assessment Act
Program -	Sage Grouse Habitat Conservation Program
PSD -	Prevention of Significant Deterioration
SHPO -	Montana State Historic Preservation Office
SOC -	Species of Concern
SO_2 -	Sulfur Dioxide
SML -	Sun Mountain Lumber
tpy -	Tons Per Year
U.S.C. -	United States Code
VOC -	Volatile Organic Compound