



Received

APR 28 2008

Casper DEQ
URS Corporation
8181 East Tufts Avenue
Denver, CO 80237
Tel: 303.694.2770
Fax: 303.694.3946
Offices Worldwide

April 23, 2008

Chad Schlichtemeier
Wyoming Department of Environmental Quality
Air Quality Division / NSR Program Manager
Herschler Building
122 West 25th Street
Cheyenne, WY 82002



**Subject: Medicine Bow Fuel & Power LLC
Proposed Integrated Gasification and Liquefaction Plant
(PSD Air Quality Permit Application AP-5873)
Response to WDEQ Comments and Request for Additional Information**

Dear Mr. Schlichtemeier:

This submittal is in response to several questions asked during the course of WDEQ review for the proposed Medicine Bow Fuel & Power Integrated Gasification and Liquefaction (IGL) Facility (MBFP Facility) in Carbon County. Specifically, this submittal addresses questions about coal mine emissions and the near-field air dispersion modeling, startup/shutdown emissions, and planned flaring operations. Several revisions to the air quality permit application have been made in conjunction with these responses, and hardcopies of revision pages for the permit application are enclosed.

Request for Information re: Coal Mine Emissions

In a letter dated March 18, 2008, the WDEQ requested additional information through four questions related to coal mining emissions and air dispersion modeling details. The coal mine emissions in question are those from the underground Saddleback Hills (SBH) Mine from the south and east portals and the Elk Mountain Mine (EMM). As you know, the Saddleback Hills Mine is considered to be a support facility to the IGL Plant (Plant), and the Elk Mountain Mine is considered to be a neighboring facility owned and operated by Arch of Wyoming, LLC (Arch).¹ Answers to the four questions are detailed below.

¹ The term 'Carbon Basin Mines' represents the Elk Mountain surface mine and the Saddleback Hills underground mine. These mines were initially permitted together under construction permit CT-4136, issued to Arch of Wyoming, LLC (subsidiary of Arch Coal, Inc.) on December 20, 2005. Since permit issuance, DKRW has entered into an option agreement with Arch Coal to purchase the Saddleback Hills underground coal reserves and surface real property. The Elk Mountain surface mine area will be retained by Arch, who will continue to operate the Elk Mountain surface mine and market its coal. As a result of this arrangement, the WDEQ determined that the Saddleback Hills Mine will be a support facility to the proposed Plant. The Elk Mountain surface mine is considered as a neighboring source.

Q1. Modeled Emissions for the Carbon Basin Mines: Five area sources are used in the modeling to represent emissions from mining activities. The modeled PM₁₀ emission rates, in terms of grams per second per square meter (g/s/m²), are shown for each of these sources in the table below [table not included here]. Also shown are the equivalent emissions in terms of grams per second and tons per year based on the calculated area of each source. Appendix B in the permit application provides a calculation sheet for PM₁₀ emissions from mining activity with total emissions of 60.2 tons per year. This total only accounts for a fraction of the modeled emissions. The Division requests detailed information on the basis of the modeled emissions for each area source used in the modeling for NO_x, CO, SO₂, and PM₁₀.

A1: Response to this question is presented in three subsections.

PM₁₀ Emissions

Revised PM₁₀ emission calculation sheets are included with this submittal, to replace the Appendix B PM₁₀ emission calculation sheet referenced in this question. Mining emissions associated with the proposed MBFP Facility are those associated with the SBH Mine, as it will be a support facility for the Plant. Emission calculations for the EMM are not included in the permit application, because the EMM is not associated with the proposed MBFP Facility; rather, it is a neighboring facility that has already applied for and received a construction permit and is currently in operation.

As noted earlier in this section, the original mine plan for the Carbon Basin Mines was to develop both the EMM and the SBH Mine under one construction permit issued to Arch. However, as a result of the sale of underground coal reserves and surface real property, the mine plan for the SBH Mine (South and East Portals) was changed. Instead of initial coal processing at the portal sites followed by truck loading and hauling to the Seminoe II processing area in Hanna, WY, the mine plan changed in order to supply coal for the proposed Plant. Years one through three of the SBH Mine development will see coal production at the South Portal area, with temporary stack-out, truck loading, and hauling to the Seminoe II processing area. Starting in year three, coal production through the South Portal will be phased out and production will begin to be conveyed underground to the East Portal area, located within the proposed Plant fenceline. At the East Portal, coal will be conveyed and stockpiles will be created during year three. Plant startup is expected during development year four, and from this point onward, all coal produced from the SBH Mine will come out at the East Portal and will be conveyed, screened, and directed to the gasifiers in the Plant area.

The previously submitted emission calculations did not reflect this level of detail for the SBH Mine plan. Only the fugitive emissions for the East Portal area, representing emissions starting in development year four (normal plant operations) were presented. This is the 60.2 tons per year PM₁₀ emission rate referenced in Question 1. In order to completely reflect both point and fugitive source emissions related to the SBH mine,

revised calculations are submitted for the SBH Mine and should be inserted in Appendix B to replace the one-page emission sheet included earlier.

The revised SBH Mine emission calculations are organized as follows:

- Summary of all SBH emissions (point, fugitive, road haul) for development years one through four;

Year One

- South Portal fugitive emissions (noted as page 1 of 2);
- South Portal road haul emissions (noted as page 2 of 2);

Year Two

- South Portal fugitive emissions (noted as page 1 of 2) ;
- South Portal road haul emissions (noted as page 2 of 2) ;

Year Three

- South Portal fugitive emissions (noted as page 1 of 2) ;
- South Portal road haul emissions (noted as page 2 of 2) ;
- East Portal point source emissions, for conveying along a portion of the conveying system and coal stackouts;
- East Portal fugitive emissions, for coal stackout operations and stockpile wind erosion;

Year Four

- East Portal point source emissions for conveying to the Plant;
- East Portal fugitive emissions for coal stackout, dozer reclaim from emergency stockpile, and stockpile wind erosion.

NO_x, CO, and SO₂ Emissions

Regarding the NO_x, CO, and SO₂ emissions from the SBH Mine, an emission calculation sheet is provided, to be included in the application's Appendix B. These emissions are expected to occur from fuel combustion in on-site machinery at the SBH Mine portal areas. Primarily, the emissions will occur at the South Portal area as a result of transferring coal via front-end loader from the temporary stockpile into trucks during development years one through three. Onsite machinery fuel combustion emissions at the South Portal are expected to cease by year four. NO_x, CO, and SO₂ emissions from on-site machinery at the East Portal will begin in year four, as a result of occasional (i.e., non-routine) coal transfer from the emergency (dead) stockpile to the Plant.

It is uncertain how much fuel will be combusted in on-site machinery at either portal; therefore, these emission rates are based on emissions previously calculated for the Carbon Basin Mine permit. It is assumed that 5% of the total NO_x, CO, and SO₂ emissions expected for both the EMM and SBH Mine will occur at the South Portal during

development years one through three. On-site fuel combustion emissions at the East Portal, starting in year four, are expected to be negligible.

Modeled Emissions for Each Area Source

Mine emissions for the proposed MBFP Facility are modeled as area sources. Sources MineA_SP and MineA_EP represent the South Portal and East Portal areas of the SBH Mine, respectively. Sources MineA_S1 and MineA_S2 represent the two surface mine pit areas for the EMM neighboring source. As shown in Figure 6.3 of the permit application, area source MineA_S1 is located within the proposed facility's fenceline, but it will remain within the control of Arch and the coal produced from it will not be used at the IGL Plant.

Previously, these modeled source areas (MineA_SP, MineA_EP, MineA_S1, and MineA_S2) incorrectly included road hauling emissions associated with mining activities. This has been corrected with a revised dispersion model analysis, included with this submittal. In the revised analysis, the modeled area sources include only fugitive and point source emissions associated with mining-related activities in that area. Road haul emissions from the SBH Mine South Portal area and from the EMM surface pit areas are represented by a series of volume sources (V_1 through V_112) along the approximately 6.9-mile mine haul road to WY Highway 72. No road haul emissions are included for the SBH East Portal, because as explained earlier, none of the coal from the East Portal area will be sold.

Modeled emissions for the EMM Mine (MineA_S1, MineA_S2, V_1-112) are from previously submitted (by Arch) emission calculations for the Carbon Basin Mines. These calculations address both the EMM and the SBH Mine due to the fact that the original Arch mine plan included both mines, and the calculations were performed prior to the SBH Mine sale. In order to avoid double-counting PM₁₀ emissions associated with the SBH Mine, the previously submitted Carbon Basin emission calculations were modified to reflect a zero coal production rate from the SBH Mine. By doing this, only the PM₁₀ emissions associated with the EMM were calculated and represented in the model for these EMM area sources. As discussed in detail earlier in this section, emissions associated with the SBH Mine were re-calculated separately in order to match the mine's revised plan and are presented with the MBFP Facility permit application. The modified EMM emission calculations are not included with this submittal.

Year two of the project's development will result in the highest number of PM₁₀ emissions, due to fugitive dust from road haul operations. However, during year two, the Plant will not be operating and so emissions from the plant emission sources will be zero. Starting in development year 4, the plant will go through its initial startup year, but PM₁₀ emissions will be lower in that year due to cessation of road haul operations. The modeling analysis addresses impacts from development year 4 emissions (normal plant and SBH Mine East Portal operation, no emissions from South Portal).

Q2. Modeled Sources for the Carbon Basin Mines: Sources MineA_SP, MineA_EP, MineA_S1, and MineA_S2 were modeled with non-zero emission for the PM₁₀ WAAQS model runs and emission rates of zero for the PM₁₀ PSD increment runs. For the SO₂ increment runs, the MineA_EP source was included with a non-zero emission rate, but no other area source was modeled. Please provide the Division with justification for the emissions used in the model runs for PSD increment.

A2: Revised modeling analyses for PM₁₀ and SO₂ are included with this submittal, partially in response to this question. SBH Mine area sources MineA_SP and MineA_EP and EMM area sources MineA_S1 and MineA_S2 are included with both the PM₁₀ WAAQS and PSD increment model runs with non-zero emission rates as presented in the emission calculations described above for Question 1. In accordance with WDEQ policy, PM₁₀ fugitive emissions from these mine area sources, as well as the road haul fugitive emissions associated with the mines, are not included in the PM₁₀ short term (24-hr) WAAQS analysis or the PM₁₀ short term (24-hr) PSD increment analysis.

The revised SO₂ modeling analysis includes non-zero SO₂ emission rates for the mine area sources in both the WAAQS and short-term (3-hr and 24-hr) PSD increment model runs. The previously submitted long-term (annual) SO₂ PSD modeling analysis included non-zero SO₂ emission rates for all mine area sources; therefore, it was not re-done and is not included with this submittal.

Please also note the revised SO₂ WAAQS modeling analysis includes updated source parameters for the low pressure (LP) Flare. Per recent email correspondence with the WDEQ, the LP Flare is not included as a source in the SO₂ PSD increment runs included with this submittal. The LP Flare is more fully discussed in the following section on the Plant's draft Startup and Shutdown Emission Minimization Plan.

Q3: Area and Volume Source Parameters: please provide the Division with justification for the release heights and dimensions that were used to model the volume and area sources. Specifically, please describe how the actual physical dimensions of the sources relate to the dimension used in the model as based on EPA modeling guidance.

A3: The revised modeling analysis included revised release heights and dimensions for the mine areas. EMM PM₁₀ emissions (sources MineA_S1 and MineA_S2) are modeled using the "open pit" algorithm in AERMOD, at a pit depth of 100 feet and a 6-meter release height above the pit floor. These values were chosen as representative values for the Arch surface mine operations, which have begun and will continue operations during the SBH Mine development period.

The SBH Mine East Portal area source (MineA_EP) is modeled with a 12-meter emission release height. The South Portal area of the SBH Mine is not included with the model, because the model represents development year 4, and emissions from the South Portal area are expected to be zero during year 4.

Q4: Base Elevations for Modeled Sources: Please provide the Division with justification of the base elevations that were chosen for the point, area, and volume sources at the IGL plant. For example, were the elevations determined from DEM files within AERMAP, or were they provided by MBFP based on project plans?

A4: Base elevations for previous and the revised modeling analyses were determined using ArcGIS software, referencing 7.5-minute DEM files. Plant source heights were extracted using the ArcGIS "Spot" tool with 1-degree DEM data.

Startup and Shutdown Emissions Minimization Plan

In email correspondence on March 31, 2008, the WDEQ requested a startup/shutdown minimization plan for the Plant, as follows (excerpt from email):

"After talking with Chad regarding startup and shutdown operations at the Medicine Bow IGL Plant, Chad would like to see a startup/shutdown minimization plan for the CO₂ vent stack and HP/LP flares. This plan should include defining points (i.e. temperature, gas quality) which indicate when gas will no longer be vented or flared or when a unit is no longer in its startup period and is accepting gas which would otherwise be vented or flared."

The proposed Plant will be comprised of several different process units and numerous equipment that will have capability to be vented either to atmosphere or flare during startup, shutdown, and malfunction events in order to protect process equipment and ensure worker safety. Plant design is very complex, with many process streams dependent on both upstream and downstream operations, with various degrees of process control and operational requirements. Design work is proceeding at a rapid pace, but at this point in the Plant's design, a complete startup and shutdown emission minimization plan cannot be finalized. A confidential initial draft version of a startup and shutdown emission minimization plan is included with this submittal. As Plant design proceeds, particularly following the front-end engineering design (FEED) phase of the project, revisions will be made to the draft plan to reflect specific details regarding startup and shutdown operations and efforts that will be taken to minimize flaring and venting emissions. Please note that several items in the confidential draft document are typed in blue italicized font, denoting steps or actions to be confirmed during the FEED phase. Elements of the final startup and shutdown emission minimization plan will be incorporated in plant operating procedures. These specific procedures will be developed prior to initial startup, and operations staff will be trained prior to the initial plant startup on the procedures. Once finalized, the plan will be maintained and actively used to guide ongoing plant operations.

- Eight (8) copies of revised pages to be inserted into the permit application binders; and
- Eight (8) copies of the "Page Change History" document reflecting all changes made since submission of the December 31, 2007 amended application.

A separate CD will be submitted this week, containing an electronic file of the complete revised permit application ("MBFP Facility Permit Application 04-23-08.pdf").

Please contact me via phone at (303) 740-2684 or email to Katrina_Winborn@URSCorp.com if you need additional information or copies of the revised application. Alternatively, you can contact Susan Bassett at (303) 740-3824 or via email to Susan_Bassett@URSCorp.com.

Sincerely,

Katrina Winborn

Katrina Winborn, P.E.
Sr. Air Quality Specialist

cc: Robert Moss, DKRW
Susan Bassett, URS Corp.

Enclosures CD-ROM
Draft (Rev 0) Startup and Shutdown Emission Minimization Plan
Revised Permit Application Pages
Page Change History

Draft Startup
& Shutdown
Emission
Minimization
Plan not provided
in CFO Packet.
CS



DEQ 003257

Page Numbers	Revision Date	Action	Description
6-8	4/23/08	Superseded	Added road haul volume sources to Table 6.5 and footnote.
6-9 (6-10)	4/23/08	Superseded	Replaced Figure 6.3 with updated version, showing road haul sources associated with the EMM and SBH Mine
6-19 to 6-22	4/23/08	Superseded	Updated Tables 6.10, 6.11, and Figures 6-7, 6-8 for revised 3-hr and 24-hr SO ₂ modeling results
6-24 to 6-26	4/23/08	Superseded	Updated Tables 6.12, 6.13, and Figures 6-10, 6-11 for revised PM ₁₀ modeling results
6-1 to 6-48	2/12/08	Superseded	Revised chapter to reflect new AERMOD near field modeling results and incorporated relevant portions from Appendix J
6-19 to 6-30	3/3/08	Superseded	Revised near-field modeling criteria pollutant results based on revised modeling for years 2000 and 2003
6-33 to 6-36	3/3/08	Superseded	Revised near-field modeling HAP results based on revised modeling for years 2000 and 2003
7-1 (7-2)	1/18/08	Superseded	Removed first and last sentence of first paragraph after Note. Text removed was: <i>MBFP is proposing to construct a 13,000 barrel per day (BPD) Industrial Gasification & Liquefaction Plant near Medicine Bow, Wyoming.</i> <i>The proposed project is scheduled to start construction in the spring of 2008 with the construction being complete by December 2010.</i>
Appendix B	4/23/08	Superseded, Addition	Replace pages B-1 and B-2 to reflect updated coal storage & processing emission rates Replace page B-29 (SBH Mine, coal storage emission calculations) with renumbered page B-29(1) and additional pages for coal mining emission calculations (pages B-29(2) through B-29(16)). Page B-30 reprinted, due to pagination detail.
Appendix B	2/12/08	Superseded	Emission revisions requested by WDEQ * and page numbering changes
Appendix F	1/4/08	Superseded	Updated coal storage BACT analysis
Appendix H	1/18/08	Addition	Added incremental NO _x Removal Cost as Appendix H
Appendix I	2/12/08	Superseded	Revised to discuss far field modeling only (since near field modeling has been re-run)
Appendix J	2/12/08	Superseded	Moved and revised near field modeling discussions to Chapter 6; far field modeling description remains
Appendix N	1/18/08	Added	Added tabbed divider
Appendix O	2/13/08	Deleted	Delete Appendix O pages (see revised Appendix H)

* During a meeting on January 18, 2008, WDEQ requested emission changes to minimize recordkeeping and reporting requirements and simplify permit writing. For certain equipment, MBFP agreed to increase operating hours and base emission calculations on the highest-emitting fuel (natural gas) in order to streamline compliance. Consequently, potential emissions were increased. Notes reflecting actual equipment operations have been added to pertinent spreadsheets. WDEQ stated that BACT analyses would not be affected by these simplifying assumptions, and would instead be based on the actual operations of the equipment.

TABLE OF CONTENTS

- Appendix K NRCS Irrigated and Nonirrigated Yields by Map Unit for Carbon County,
Wyoming
- Appendix L NRCS Acreage and Proportionate Extent of the Soils for Carbon County,
Wyoming
- Appendix M NRCS Rangeland Productivity and Plant Composition
- Appendix N Mesoscale Model Simulations in Quasi-Forecast Mode of the Great Western
Storm of 16-20 March 2003

Acronyms

agl	Above grade level
AGR	Acid gas removal
AP-42	EPA AP-42 Emission Factors
AQRV	Air Quality Related Value
ASU	Air Separation Unit
AVO	Audio/visual/olfactory
BACT	Best Available Control Technology
BOL	Beginning of Life
BPD	Barrels per day
bpip	Building Profile Input Program
Btu	British thermal unit
CAA	Clean Air Act
CaCO ₃	Calcium carbonate
CAM	Compliance Assurance Monitoring
CDPHE	Colorado Department of Public Health and Environment
CFR	Code of Federal Regulations
Cl ₂	Chlorine
CO	Carbon monoxide
CO ₂	Carbon dioxide
COS	Carbonyl sulfide
CS ₂	Carbon disulfide
DAT	Deposition Analysis Thresholds
DEM	Digital Elevation Model
DLN	Dry Low NO _x
DME	Dimethyl ether
dscf	Dry standard cubic feet
EC	Elemental carbon
EFR	External floating roof
EMM	Elk Mountain Mine
EOL	End of life
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic precipitator
°F	Degrees Fahrenheit
F	Fluorine
FGD	Flue gas desulfurization
FGR	Flue gas recirculation
FLAG	Federal Land Managers Air Quality Related Values Working Group
ft	Feet
g	Gram
gal	Gallons
GE	General Electric Co.
GEP	Good Engineering Practice
GPM	Gallons per minute
H ₂	Hydrogen
H ₂ S	Hydrogen sulfide
HAP	Hazardous air pollutant

Acronyms

HGT	Heavy gasoline treatment
HHV	Higher heating value
HNO ₃	Nitric acid
HP	High pressure
hp	Horsepower
hr	Hour
hr/yr	Hours per year
HRSG	Heat recovery steam generator
IDLH	Immediately Dangerous to Life or Health
IFR	Internal floating roof
IGCC	Integrated gasification combined cycle
IGL	Industrial Gasification and Liquefaction
in	Inch
IWAQM	Interagency Working Group on Air Quality Modeling
km	kilometer
LAC	Level of acceptable extinction change
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/yr	Pounds per year
LDAR	Leak Detection and Repair
LHV	Lower heating value
LP	Low pressure
LPG	Liquefied petroleum gas
LTGC	Low-temperature gas cleanup
LULC	Land Use Land Cover
m	Meter
µg/m ³	Micrograms per cubic meter
m ³	Cubic meters
MACT	Maximum Achievable Control Technology
MDEA	Methyldiethanolamine
MEI	Maximally exposed individual
min	Minute
MLE	Most likely exposure
MMBtu	Million British thermal units
MMscf	Million standard cubic feet
MMscfd	Million standard cubic foot per day
MMtpy	Million tons per year
mol.	Molecular
MP	Medium pressure
MBFP	Medicine Bow Fuel and Power LLC
Mscf	Thousand standard cubic feet
MTBE	Methyl tertiary butyl ether
MTG	Methanol to gasoline
MW	Megawatts
MWh	Megawatt-hours
NAAQS	National Ambient Air Quality Standards

Acronyms

NCDC	National Climate Data Center
neg.	Negligible
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NH ₃	Ammonia
NH ₄ NO ₃	Ammonium nitrate
(NH ₄) ₂ SO ₄	Ammonium sulfate
NIOSH	National Institute for Occupational Safety and Health
NO ₂	Nitrogen dioxide
NO ₃	Nitrate
NO _x	Nitrogen oxides
NRCS	Natural Resources Conservation Service
NSCR	Non-selective catalyst reduction
NSPS	New Source Performance Standard
NSR	New Source Review
NWS	National Weather Service
ODEQ	Oregon Department of Environmental Quality
PBL	Planetary boundary layer
PM	Particulate matter
PM ₁₀	Particulate matter, less than 10 microns
ppmv	Parts per million by volume
ppmw	Parts per million by weight
PSD	Prevention of Significant Deterioration
psi	Pounds per square inch
psig	Pounds per square inch gauge
PTE	Potential to Emit
REL	Reference Exposure Level
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RfC	Reference Concentrations for Chronic Inhalation
RH	Relative humidity
RICE	Reciprocating internal combustion engine
RMP	Risk Management Plan
RVP	Reid vapor pressure
SBH	Saddleback Hills (Mine)
SCCs	Source Classification Codes
scf	Standard cubic feet
SCFH	Standard cubic foot per hour
scm	Standard cubic meters
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SILs	Significant Impact Levels
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur dioxide
SO ₄	Sulfate
SOA	Secondary Organic Aerosol

Acronyms

SOCMI	Synthetic Organic Chemical Manufacturing Industry
SO _x	Sulfur oxides
SRU	Sulfur Recovery Unit
SSM	Startup, shutdown, or malfunction
TANKS	U.S. Environmental Protection Agency Tanks Version 4.0
TBD	To be determined
TPD	Tons per day
tpy	Tons per year
UOP	UOP, LLC
URF	Unit risk factor
USDA	US Department of Agriculture
USGS	U.S. Geological Survey
USNPS	US National Park Service
UTM	Universal Transverse Mercator
VOC	Volatile organic compound
vol%	Volume percent
WAQS&R	Wyoming Air Quality Standards and Regulations
WDEQ	Wyoming Department of Environmental Quality
WRAP	Western Regional Air Partnership
wt%	Weight percent
yr	Year

Acronyms

[This page is intentionally blank.]

1.1 GENERAL FACILITY DESCRIPTION

Medicine Bow Fuel & Power LLC (MBFP) is proposing to construct an underground coal mine (Mine) and industrial gasification & liquefaction (IGL) plant (Plant) that will produce transportation fuels and other products near Medicine Bow, Wyoming in Carbon County. The Mine will process approximately 8,000 tons per day (TPD) of coal (on a dry basis) to produce a variety of liquid and gaseous fuels. The Mine will be a 3.25 million ton per year (MMtpy) adjacent underground coal mine known as the Saddleback Hills Mine that will supply the coal needed for the Plant.

The Plant will utilize coal, which will be gasified to produce synthesis gas (syngas) and produce various products. In order to achieve this outcome, the Plant will use several different technologies, including: General Electric's (GE) gasification technology for the quench gasification process, UOP LLC's (UOP) SELEXOL[®] acid gas removal process, and Davy Process Technology's (Davy) methanol synthesis process followed by the Exxon-Mobil methanol-to-gasoline (MTG) process.

Saleable products produced at the Plant during normal operation are anticipated to include approximately:

- 18,500 barrels per day (BPD) of regular gasoline to be transferred via pipeline to a nearby refinery
- 42 TPD of sulfur
- 198 million standard cubic feet per day (MMscfd) of carbon dioxide (CO₂)
- 712 TPD of coarse slag

In addition to the saleable products listed above, Plant operation will result in the production of the following fuels to be used onsite for power generation and process heating:

- Approximately 253 million British thermal units (MMBtu/hr) of fuel gas
- Approximately 400 to 500 MMBtu/hr of liquefied petroleum gas (LPG)

Efficient use of these fuels will provide much of the energy input needed to fuel an electric generation plant that will produce approximately 400 megawatts (MW) of electricity. The Plant will either import natural gas or divert syngas as necessary to support plant power needs not met by fuel gas, LPG, and process steam and is not expected to export power to the electrical grid. Three combustion turbines will be equipped with the best available pollution control technologies, which include low-NO_x burners, diluent injection, selective catalytic reduction (SCR), and oxidation catalyst to keep criteria pollutant emissions low.

Emission reduction technologies will be incorporated throughout the Plant. These controls are discussed in more detail in Sections 2 and 4. In addition, all roads and parking areas within the Plant fence will be either gravel or paved to control fugitive dust emissions.

This amended Prevention of Significant Deterioration (PSD) permit application contains fully updated information based on replacement of the previously planned Fischer-Tropsch and UOP upgrading processes with the Davy methanol synthesis unit and Exxon-Mobil MTG processes. This process change affects many process streams and emission calculations. Consequently, a

complete amended permit application is being submitted. This permit application contains information describing the Mine and Plant, facility emissions, applicable regulations, best available control technology (BACT) determinations, and air quality impact analyses. Wyoming Air Quality Permit Application Forms are included in Appendix A.

1.2 FACILITY LOCATION

The Mine and Plant (collectively, the MBFP Facility) will be located approximately 7.5 miles north of Interstate 80, exit 260 (Elk Mountain) on County Road #3 in Section 29 of Township 21 north and Range 79 west in Carbon County, south-central Wyoming. Figure 1.1 shows the general location of the facility. The MBFP Facility encompasses two separate areas. The Mine's South Portal is shown in Figure 1.2. The Mine's East Portal, near where the Plant will be located, is shown in Figure 1.3. Figure 1.4 shows the Plant process equipment layout.

1.3 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

The Clean Air Act (CAA) defines 28 major source categories that have a 100 ton per year (tpy) threshold for determining prevention of significant deterioration (PSD) major source status. This facility falls within the major source category of "Fuel Conversion Plant," and therefore is subject to the 100 tpy major source threshold. Annual emissions of criteria pollutant emissions are shown in Table 1.1 for normal operations without startup, shutdown, and malfunction (SSM) events. Estimates of the following pollutants are included: NO_x (nitrogen oxides, including nitrogen dioxide [NO₂]), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter with a diameter of less than 10 microns (PM₁₀). Emission calculation methods are summarized in Section 3 and detailed emission calculations are included in Appendix B.

Table 1.1 – Annual Criteria Pollutant Emissions (tpy)

NO _x	CO	VOC	SO ₂	PM ₁₀
251.63	176.75	200.18	32.65	195.84

Based on criteria pollutant emissions, this facility is considered to be a major source for the PSD Program (40 CFR §51.165) and the Title V Operating Permit Program (40 CFR Part 70).

Annual emissions of hazardous air pollutant (HAP) emissions from normal operations are shown in Table 1.2. HAPs with emissions greater than 0.01 tpy are included in the table. Because potential emissions of total HAPs exceed 25 tpy, the facility is a major source of HAPs and is subject to some National Emission Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR Parts 61 and 63.

This section describes the coal mining and industrial production processes. Because coal mining is common in the area, the coal mining description is relatively short. Due to its relative newness and complexity, the Plant is described in much more detail; Figure 2.1 illustrates the process.

2.1 COAL MINING

The Mine will produce approximately 3.25 MMtpy of coal using underground continuous and longwall mining techniques. Longwall mining machines consist of multiple coal shearers mounted on a series of self-advancing hydraulic ceiling supports. Longwall mining machines are about 800 feet in width and 5 to 10 feet tall. Longwall miners extract "panels", rectangular blocks of coal, as wide as the mining machinery and as long as 12,000 feet. The shearers cut coal from a wall face, which falls onto a conveyor belt for removal. As a longwall miner advances along a panel, the roof behind the miner's path is allowed to collapse.

The mined coal will exit the mine via the East Portal. The coal will be conveyed and stored in a 300,000-ton live storage area before being conveyed to the Plant. Coal handling conveyors C1 through C5 will be fully enclosed, and conveyors C6 through C10 will be $\frac{3}{4}$ -covered (not fully enclosed). All transfer points along all conveyors (C1 through C10) will be fogged to reduce emissions. An additional 300,000-ton emergency coal stockpile will be constructed. This emergency coal stockpile is considered dead storage and will not be added to or used unless the coal supply for the live storage is interrupted. Once the emergency stockpile is constructed, it will be compacted and sealed to prevent wind erosion and spontaneous combustion.

Figure 2.2 shows the above-ground coal handling process for stacking the coal and transferring it to the Plant.

2.2 GASOLINE PRODUCTION

Figure 2.1 contains a block flow diagram illustrating the Plant production process and associated support activities. Major processes required to produce gasoline are described in this section. Additional production steps for removing CO₂ and sulfur products are described in Sections 2.3 and 2.4, respectively. Ancillary operations, such as power generation, wastewater treatment, and other activities are described in Section 2.5.

2.2.1 Coal Preparation (1100)

The Plant process begins with coal feed preparation, shown on the left side of the process block flow diagram in Figure 2.2. Raw feed coal (run of mine) from the coal storage area is routed via an enclosed conveyor to the coal crusher. The crushed coal is screened to a maximum size of 1 inch, with oversized coal recycled back to the crusher. All transfer points are fogged to reduce emissions. The crushed and screened coal is conveyed and stored in three bins and is gravity flowed to the coal-grinding mill.

The coal is crushed with water and an additive to create a slurry, which will be pumped into the gasifier under high pressure. The coal preparation process is divided into three separate trains, each with the capacity to supply 40% of the total plant requirements. The slurry produced by any of the trains can be pumped to any of the five (5) downstream gasification trains. The coal

preparation section provides a total of 8,700 tons per day (TPD) of coal to the gasifiers (wet basis); this is equivalent to 8,000 TPD of coal on a dry basis.

Drainage, wash down, and leaks in the grinding area are collected in a below-grade concrete sump. An agitator keeps the solids in suspension for pumping. Any accumulated water/solids mixture is pumped to the slurry tank.

2.2.2 Gasification (1200)

The Plant will utilize five (5) gasifier trains. Each gasifier train will be sized to handle one-fourth of the Plant's total capacity. In normal operation, four gasifier trains will be in operation with the fifth in hot standby. The gasifiers are fueled by a coal/water slurry, calcium carbonate (CaCO_3), and 98 percent pure oxygen from the air separation unit (ASU).

The gasification reaction is conducted at a pressure of 1,000 psig and generates a temperature of approximately 2,500 degrees Fahrenheit ($^{\circ}\text{F}$). The combustion chamber is lined with refractory bricks, which maintain the outer shell of the gasifier in a temperature range of 545 $^{\circ}\text{F}$ to 600 $^{\circ}\text{F}$. Each gasifier is equipped with a dedicated preheater (Gasifier Preheaters 1 through 5). During the initial gasifier startup, and during any subsequent startup following refractory replacement, the gasifier preheater combusts natural gas and slowly heats the refractory to achieve the minimum temperature needed for combustion chamber operation. Each preheater has a firing rate of 21 MMBtu/hr and is fueled with natural gas.

Combustion products of the gasification reaction consist of raw syngas, together with small amounts of a number of impurities (including chlorides, sulfides, nitrogen, argon, and methane), liquid slag, and fine solid particles. These combustion products exit the combustion chamber and flow to a quench chamber where the combustion products are cooled and most of the particle fines are removed from the syngas. The molten slag solidifies and settles to the bottom of the chamber. If necessary, calcium carbonate can be added to the coal slurry as a fluxant to facilitate free flow of the molten slag in the gasifier. Solidified coarse slag is removed from the gasifier through a lock hopper system connected to the bottom of the quench chamber, and this stream sweeps the solidified slag through a slag crusher. The crushed slag is then recycled and reused or disposed. Approximately 980 TPD of slag will be produced and approximately 712 TPD of slag will be available for sale; the remainder is recycled to the slurry because of its Btu content. The syngas exits the gasifier through a side connection.

During any startup, shutdown, or malfunction (SSM) event, the syngas will be sent to the high-pressure flare. The syngas feed to the flare is expected to have a heat rate of approximately 2,000 Btu/lb.

2.2.3 Syngas Conditioning (1300)

Syngas conditioning includes two main treatment processes:

- Scrubbing to remove particulate from the syngas
- Low-temperature gas cleanup (LTGC)

2.2.3.1 Syngas Scrubbing

The Plant includes five (5) syngas conditioning trains, each sized for one-fourth of plant capacity. Each syngas conditioning train is integrated with a specific gasifier, with four (4) such trains operating and the fifth acting as a spare during normal operations. This description refers to one syngas conditioning train only.

Raw syngas leaves the gasifier and is mixed with process condensate in the process line to prevent the buildup of solids and thoroughly wet the entrained solids to facilitate their removal in the syngas scrubber.

The syngas scrubber is a tower that contains a water sump in the bottom and four trays in the top. Wet syngas enters the scrubber below the first tray and flows downward into the water sump, which removes most of the solids in the gas, and then flows upward through the four trays. Process condensate is supplied to the top tray and flows downward, counter-currently washing the remaining solids from the syngas. From the scrubber trays, a de-mister removes any entrained water droplets, such that an essentially particulate-free syngas exits from the top of the syngas scrubber.

2.2.3.2 Low-Temperature Gas Cleanup

The low-temperature gas cleanup (LTGC) Unit is a single system sized for 100 percent of plant capacity. The two main purposes of this system are to:

- Cool the raw syngas while producing steam; and
- Provide other gas cleanup functions, including carbonyl sulfide (COS) hydrolysis and water gas shift.

The LTGC unit receives syngas from the four (4) operating syngas scrubber trains. The syngas is then cooled in a series of two exchangers [the Syngas Interchanger against reheating treated syngas from the SELEXOL[®] unit and the low pressure (LP) steam generator which produces LP steam]. The resulting partly condensed syngas is separated, and the condensate is pumped into the return condensate stream.

After the separation, the syngas is heated to 400°F with medium pressure (MP) steam and split into two streams. The syngas either enters a water shift reactor which converts CO and H₂O to CO₂ and H₂ and hydrolyzes COS or enters a reactor where COS is hydrolyzed to hydrogen sulfide (H₂S) and CO₂. The flows are balanced to adjust the H₂ to CO ratio of the syngas for optimal methanol synthesis. The two streams are then cooled in a series of two exchangers before entering knock-out drums. Syngas in the overhead vapor streams is routed to the SELEXOL[®] Acid Gas Removal Unit as a shifted and unshifted syngas stream.

The condensate from the LTGC area flows to a stripper, which also receives the condensate streams from the gasification system. The stripper removes almost all of the ammonia (NH₃), H₂S, and COS from the condensate, along with some dissolved hydrogen (H₂) and CO. The stripper overhead gas is blended with sour flash gases from the flash separators and compressed before going to the SELEXOL[®] Unit, so that the H₂ and CO can be recovered from the sour gas. The stripper bottoms water is returned to the syngas scrubber.

2.2.4 SELEXOL[®] Acid Gas Removal (2100)

The SELEXOL[®] process, licensed by UOP, has been selected as the acid gas removal technology. Two SELEXOL[®] process trains will provide the following functions for the shifted and unshifted streams:

- Removal of sulfur compounds (H₂S and COS) from the syngas to a level acceptable to the downstream Methanol Synthesis Unit,
- Recovery of most of the CO₂ in the syngas for further purification, and
- Recovery of a concentrated H₂S/COS stream to be sent to the Sulfur Recovery Unit (SRU).

The quenched sour syngas from the Syngas Conditioning Unit enters a mercury removal bed, and then is mixed with recycled stripped gas and flows to the SELEXOL[®] Feed/Product Exchanger to cool the feed gas against treated syngas and enhance the efficiency of absorption. The cooled feed gas flows through two successive absorbers; the first absorber removes H₂S and the second absorber removes CO₂. In each absorber, the syngas enters at the bottom of a packed bed and flows upward through the bed where it contacts cool solvent entering the top of the tower. In these absorbers, H₂S, COS, CO₂, and other gases such as H₂, are transferred from the gas phase to the liquid phase. The treated gas passes through de-entrainment devices at the top of the absorbers, as well as three water wash trays to minimize solvent carry-over. The treated syngas exits the top of the CO₂ absorber and is sent to the downstream Methanol Synthesis Unit.

Treated syngas leaving the SELEXOL[®] Unit is expected to contain less than 0.1 parts per million by volume (ppmv) total sulfur. Further sulfur reduction through the use of sulfur beds is required to protect the catalyst in the downstream Methanol Synthesis Unit from poisoning and the risk of sulfur spikes that could be caused by SELEXOL[®] Unit upsets. Each of the parallel beds is sized for full plant capacity. For best performance, the syngas is heated to 400°F before entering the guard bed.

The syngas from the guard beds is then sent to a compressor, where the syngas pressure is increased to the levels required in the Methanol Synthesis Unit. The syngas is then sent to the Methanol Synthesis Unit.

The SELEXOL[®] solvent from the H₂S Absorber is regenerated by stripping out less soluble gases, such as CO₂, H₂, and CO. The partially regenerated SELEXOL[®] solvent then flows to an H₂S stripper, where the remaining H₂S, CO₂, N₂, and other compounds are transferred from the liquid phase to the gas phase by contact with steam. The steam and liberated gases exit the stripper, and then flow upward through a demister and into the trayed section of the column. In the trayed section, the rising gas is contacted with counter-current flowing reflux water to cool and partially condense the hot overhead vapor, as well as reduce solvent entrainment. The overhead stream passes through a de-entrainment device and exits the top of the column. The overhead gas then passes through a condenser in order to condense and recover a portion of the overhead steam. The liquid and vapor phases are separated; the H₂S-rich acid gas exits the unit battery limits and is sent to the SRU, and the liquid is returned to the trayed section of the H₂S stripper.

3.1 SADDLEBACK HILLS MINE

Originally Arch of Wyoming LLC (subsidiary of Arch Coal, Inc.) permitted the Mine (underground) and the Elk Mountain (surface) Mines together under one air quality permit (Permit # CT-4136). The combined facilities were known as the Carbon Basin Mines. Arch Coal has entered into an option agreement to sell the underground coal reserve and surface real property to MBFP. Once MBFP exercises this option, Arch Coal has retained the rights to operate the Elk Mountain Mine and market the surface coal. As a result of this agreement, a determination was made by the Wyoming Department of Environmental Quality (WDEQ)/Air Quality Division (AQD) that the Saddleback Hills Mine was considered a support activity under the definition of a facility and should be included in the MBFP PSD application.

During the underground mine's development phase, approximately 2.5 million tons of coal will need to be mined over a 3-year period. The development phase constructs the underground infrastructure required to support the longwall mining system which will commence operations at approximately the time when the Plant achieves full capacity. During the development or construction phase of the mine, coal will be conveyed from the South Portal where it will be stored in a small stockpile. It is anticipated that this production will either be loaded into trucks at the South portal and hauled to the Seminole II train loadout in Hanna, Wyoming, or placed in the designated long term storage stockpile.

During the MBFP construction phase, development will also occur at the East Portal. The following activities will occur at the East Portal:

- Construction of the East Portal entry areas that will consist of a reinforced concrete retaining wall;
- Installation of conveyors from the portal face to the coal storage facilities (some conveyors will be fully enclosed, some will be ¾-covered);
- Construction of the coal storage facilities;
- Construction of a ¾-covered overland conveyor system from the coal storage facilities to the Plant;
- Construction of the Mine's office, maintenance shop, and warehouse facilities.

Emission sources associated with the Mine during the development phase are shown in Table 3.1.

Table 3.1 – Mine Development Particulate Emissions

Development Year	Coal Conveying and Loading PM ₁₀ (tpy)	Coal to Seminole II PM ₁₀ (tpy)
1	3.04	26.8
2	5.17	109.3
3	4.20	71.6

Only particulate emissions associated with the Mine are included in the table above. Emissions from mine area fuel combustion (on-site machinery) are based on calculations provided in Permit Application AP 2989 for the Carbon Basin Mines.

Detailed Mine Development emission calculation spreadsheets are included in Appendix B.

3.2 THE PLANT

3.2.1 Emission Sources

Emissions associated with this Plant include both point source and fugitive emission sources. The three combustion turbines account for the majority of NO_x, CO, SO₂, and PM₁₀ emissions, while storage tanks and equipment leaks emit the most VOCs and HAPs. Table 3.2 shows significant point and fugitive sources of emission.

Manufacturer specifications for the turbines and certain other equipment are included in Appendix C. With regard to the combustion turbines, a General Electric (GE) specification sheet has been included in Appendix C; this specification does not constitute a vendor guarantee from GE. Equipment-specific guarantees could not be obtained from vendors at this time. Guarantees for some equipment will be obtained at the time purchase contracts are signed.

Due to the long lead-time needed to design this Plant, specific manufacturers and models have not yet been identified for many equipment items, and manufacturer specifications are not yet available.

A list of other major equipment is included in Appendix D, along with a list of source classification codes (SCCs) for point source equipment.

Table 3.2 – Emission Units and Fugitive Sources

Description	Identification	Size	Use
<i>Normally Operating Equipment and Fugitive Sources</i>			
Combustion Turbine 1	CT-1	66 MW	Electrical and steam generation
Combustion Turbine 2	CT-2	66 MW	Electrical and steam generation
Combustion Turbine 3	CT-3	66 MW	Electrical and steam generation
Auxiliary Boiler	AB	66 MMBtu/hr	Steam generation (normal service is standby at 25% load to prevent freeze ups if there is a Plant shutdown)
Catalyst Regenerator*	B-1	21.53 MMBtu/hr	Catalyst regeneration (only during catalyst regeneration; average continuous rate is approximately 9 MMBtu/hr)
Reactivation Heater*	B-2	12.45 MMBtu/hr	Reactivation heating
HGT Reactor Charge Heater	B-3	2.22 MMBtu/hr	Reactor charge heating
HP Flare (pilot only)	FL-1	0.82 MMBtu/hr	For safety and VOC control
LP Flare (pilot only)	FL-2	0.20 MMBtu/hr	For safety and VOC control
Equipment Leaks	EL	N/A	N/A
Storage Tanks	Tanks	Various	Primarily methanol and gasoline storage
Coal Storage & Processing	CS	N/A	Coal conveyance & feedstock storage
<i>SSM Equipment</i>			
Gasifier Preheater 1*	GP-1	21 MMBtu/hr	Gasifier refractory preheating
Gasifier Preheater 2*	GP-2	21 MMBtu/hr	Gasifier refractory preheating
Gasifier Preheater 3*	GP-3	21 MMBtu/hr	Gasifier refractory preheating
Gasifier Preheater 4*	GP-4	21 MMBtu/hr	Gasifier refractory preheating
Gasifier Preheater 5*	GP-5	21 MMBtu/hr	Gasifier refractory preheating
Black-Start Generator 1*	Gen-1	2889 hp	Electrical generation
Black-Start Generator 2*	Gen-2	2889 hp	Electrical generation
Black-Start Generator 3*	Gen-3	2889 hp	Electrical generation
Firewater Pump Engine*	FW-Pump	575 hp	Supplies emergency firewater
CO ₂ Vent Stack*	CO ₂ VS	N/A	For malfunctions

* These emission units operate less than 8,760 hr/yr.

3.2.2 Normal Operations

Plant emissions are broken down into three categories (normal operation, cold startup/initial year emissions, and malfunctions). Annual emissions resulting from normal operations include emissions from equipment that operates continuously (8,760 hours per year) and equipment that operates on a regular basis. For example, the firewater pump engine may operate up to 500 hours in a typical year. Consequently, firewater pump engine emissions are included in the normal operation annual emission summary and are based on 500 hr/yr rather than 8,760 hr/yr. Note that the Auxiliary Boiler normally operates at only 25 percent load, on a hot standby basis.

SECTION THREE

Emission Estimates

However, emissions are based on 8,760 hr/yr operation at full load. Table 3.3 shows emissions resulting from normal operations and the maximum number of hours of operation per year. Detailed emission calculations are included in Appendix B.

Table 3.3 – Annual Criteria Pollutant Emissions Resulting from Normal Operations

Source ID	Description	Operating Hours (hr)	Potential Emissions (tpy)				
			NO _x	CO	VOC	SO ₂	PM ₁₀
CT-1	Power Generation	8,760	75.86	46.19	6.59	10.79	43.80
CT-2	Power Generation	8,760	75.86	46.19	6.59	10.79	43.80
CT-3	Power Generation	8,760	75.86	46.19	6.59	10.79	43.80
AB	Steam Generation ¹	8,760	14.17	23.81	1.56	0.17	2.15
B-1	Catalyst Regeneration	8,760 ²	4.62	7.77	0.51	0.06	0.70
B-2	Reactivation Heater	8,760 ²	2.67	4.49	0.29	0.03	0.41
B-3	HGT Reactor Charge Heater	8,760	0.48	0.80	0.05	0.01	0.07
Tanks	Product Storage	8,760	---	---	102.62	---	---
EL	Equipment Leaks	8,760	---	---	71.32	---	---
CS	Coal Storage & Processing	8,760	---	---	---	---	61.08
FW-Pump	Firewater Pump Engine ³	500	1.51	0.09	0.34	0.00	0.02
FL-1	HP Flare	8,760 ⁴	0.49	0.98	2.97	0.00	---
FL-2	LP Flare	8,760 ⁴	0.12	0.25	0.74	0.00	---
Total Emissions			251.63	176.75	200.18	32.65	195.84

1. Boiler will normally operate at 25% load, but potential emissions are based on continuous full load operation.
2. The catalyst regeneration heater and reactivation heaters will operate less than 8,760 hr/yr, but potential emissions are based on 8,760 hr/yr of operation.
3. The Firewater Pump combusts diesel fuel.
4. Based on continuous natural gas pilot for flares.

Table 3.4 shows annual HAP emissions resulting from normal operations. The largest HAP emission sources at the Plant are listed in the following table.

Table 3.4 – Annual HAP Emissions Resulting from Normal Operations

Pollutant	Facility-Wide Potential Emissions (tpy)	Largest Emission Source at Facility
Benzene	11.08	Equipment Leaks
Formaldehyde	0.71	Turbines
Hexane	1.29	Auxiliary Boiler ¹
Methanol	12.79	Equipment Leaks
Toluene	1.81	Turbines
Other HAPs	2.12	N/A
Total Emissions	29.80	

1. Note that HAP PTE emissions from the auxiliary boiler are calculated at continuous, full load operation. However, the boiler will normally operate at only 25% load but within compliance with its emission commitment (lb/MMBtu basis). The second-largest emission source contributing to hexane emissions at the facility will be storage tanks.

3.2.3 Cold Start/Initial Year Operations

Annual emissions have also been calculated for the initial year of operations (plant cold start). The complete Plant startup period may last as long as 180 days, and will involve bringing equipment online in a particular order. Emissions during the cold startup period will differ from those during a normal operating year. Certain equipment, such as Black-Start Generators and Gasifier Preheaters, will operate during cold startup. Individual emission units will have much shorter startup time periods; these unit-specific time periods are shown in Appendix B in the cold startup emission summary spreadsheet. Since the Plant will not have produced adequate in-plant fuels and power generation will ramp up slowly, most combustion equipment will initially burn only natural gas fuel, rather than the fuel mixture of fuel gas, LPG, and natural gas. Table 3.5 shows the annual emissions resulting from Cold Startup.

Table 3.5 – Annual Criteria Pollutant Emissions Resulting from Cold Startup

Source ID	Description	Operating Hours Fuel Gas Mixture/NG	Potential Emissions (tpy)				
			NO _x	CO	VOC	SO ₂	PM ₁₀
CT-1	Power Generation	7760 / 1000	76.68	46.61	6.64	10.90	43.80
CT-2	Power Generation	7760 / 1000	76.68	46.61	6.64	10.90	43.80
CT-3	Power Generation	7760 / 1000	76.68	46.61	6.64	10.90	43.80
Gen-1	Black-Start Generator 1	0 / 360	1.15	2.79	1.03	0.00	0.00
Gen-2	Black-Start Generator 2	0 / 360	1.15	2.79	1.03	0.00	0.00
Gen-3	Black-Start Generator 3	0 / 360	1.15	2.79	1.03	0.00	0.00
AB	Steam Generation	8000 / 760	14.17	23.81	1.56	0.17	2.15
B-1	Catalyst Regeneration	8760 / 0	4.62	7.77	0.51	0.06	0.70
B-2	Reactivation Heater	8000 / 760	2.67	4.49	0.29	0.03	0.41
B-3	HGT Reactor Charge Heater	8000 / 760	0.48	0.80	0.05	0.01	0.07
GP-1	Gasifier Preheater 1	0 / 500	0.26	0.43	0.03	0.00	0.04
GP-2	Gasifier Preheater 2	0 / 500	0.26	0.43	0.03	0.00	0.04
GP-3	Gasifier Preheater 3	0 / 500	0.26	0.43	0.03	0.00	0.04
GP-4	Gasifier Preheater 4	0 / 500	0.26	0.43	0.03	0.00	0.04
GP-5	Gasifier Preheater 5	0 / 500	0.26	0.43	0.03	0.00	0.04
Tanks	Product Storage	8760	---	---	102.62	---	---
EL	Equipment Leaks	8760	---	---	71.32	---	---
CS	Coal Storage & Processing	8760	---	---	---	---	61.08
FW-Pump	Firewater Pump Engine	500 ²	1.51	0.09	0.34	0.00	0.02
CO ₂ VS	CO ₂ Vent Stack	8760	---	314.89	0.84	---	---
FL-1	HP Flare	8760 ³	10.28	81.86	3.11	187.70	0.00
FL-2	LP Flare	8,760 ⁴	0.15	0.44	0.74	36.01	0.00
Total Emissions			268.64	584.48	204.56	256.69	196.04

1. Operating hours shown for firing fuel gas mixture and natural gas (NG) are based on expected operations. However, emissions are conservatively calculated based on firing natural gas, which is the higher emitting fuel.

2. The Firewater Pump combusts diesel fuel.

3. Based on continuous natural gas pilot for flare; cold startup includes 50 hr/yr of vents to HP Flare.

3. Based on continuous natural gas pilot for flare; no vents to LP Flare are expected during cold startup.

3.2.4 Malfunctions and Other Events

Malfunctions and other events can cause unusual emissions during short periods of time. Table 3.6 includes four types of malfunctions. Detailed emission calculations for malfunction events are included in Appendix B.

operations. Another factor is that this carbon dioxide stream is a product. Design elements that maximize the reliability of the carbon dioxide stream and minimize startup, shutdown, and malfunction periods will reduce the frequency and duration of venting events. The venting is only anticipated for a few days during initial startup (approximately 250 hrs/yr for the first year). Since the plant will be started up at reduced load, the venting will be at a reduced rate (approximately 25% of the normal process stream flow rate). Venting is anticipated for only a few hours for subsequent warm starts, not to exceed 50 hrs/yr. Again, the venting would be at a reduced load (approximately 50% of the normal process stream flow rate).

Catalytic oxidation is not technically feasible based on the low temperature of the vent stream, approximately 100°F. Based on the temperature and large flow rate, an extremely large amount of energy would be necessary to oxidize the CO with a thermal oxidizer, and may not be possible due to the size of the stream, low temperature, and high concentration of CO₂ in the stream. RBLC ID WY-0042 contained a process identified as "Vent, CO₂ Product" where incineration was not feasible due to CO₂ concentration in the gas. RBLC ID WY-0056 contained a process identified as "CO₂ Product Vent, Train III" that also vented uncontrolled.

The total annual proposed CO emissions to be permitted from the CO₂ stack are 275 tpy for the initial year of operation. Subsequent years will be limited to 74 tpy of CO. The proposed VOC emissions are 0.02 tpy for the first year and 0.01 tpy for subsequent years. Based on the limited operating time and resultant emissions, further controls are not warranted. Thus, an optimized process design is considered BACT for this process vent.

4.10 GASIFIER PREHEATING CONTROL TECHNOLOGY REVIEW (STARTUP OPERATIONS ONLY)

During the initial startup operations, or if new refractory is in place in a gasifier, a designated 21 MMBtu/hr natural gas burner is used to preheat the refractory lining prior to commencing tail gas production. Potential emissions from the natural gas combustion in the gasifiers is exhausted from a preheat vent located on each gasifier. The primary potential emissions from the gasifier preheat vents are NO_x and CO. Each gasifier preheat vent has a potential to emit less than 1 ton per year of NO_x and CO as discussed in the emission inventory. Emissions of VOC and particulate will also be relatively small based on the short operating time, approximately one week for each gasifier, for initial startup (and refractory replacement) only. Subsequent startup operations will be warm starts and will not include this step. The expected operating hours for the gasifier preheaters are 500 hours per year per heater, for a total of 2,500 hours per year. Good combustion controls that optimize burner efficiency will minimize potential NO_x, CO, VOC and particulate emissions. Because a low-sulfur-fuel (natural gas) is being used for preheating, the potential emissions of SO₂ will also be small.

The use of a low-sulfur-fuel, restricted operating conditions, and good combustion practices are proposed as BACT for each of the five (5) gasifier preheat burners. Table 4.4 shows the proposed BACT emission rates for each gasifier preheater.

Table 4.4 – Gasifier Preheater BACT Analysis Summary

Pollutant	Proposed BACT	Proposed BACT Emission Limits (emission limits are per gasifier preheater)
NO _x	Low Sulfur Fuel Good Combustion Practices Restricted Operation (startup only)	NO _x Limit: 0.26 tpy
SO ₂		SO ₂ Limit: <0.01 tpy
CO		CO Limit: 0.43 tpy
VOC		VOC Limit: 0.03 tpy
PM		Particulate Limit: 0.04 tpy (PM ₁₀ - filterable)

4.11 BLACK-START GENERATOR CONTROL TECHNOLOGY REVIEW (STARTUP OPERATIONS ONLY)

The proposed Plant will include three (3) 1.6 MW natural gas fired generators for use during startup. The generators will be used for commissioning and initial startup. Key utility systems such as instrument air, water supply and purification, firewater, and nitrogen will be made operational prior to initiating the startup sequence for the process. It is especially important that the flare system be ready for service before any flammable gas is present. Once critical utilities are in service, one of the three gas turbines is started on natural gas. This will produce enough power to displace the Black-Start generators. The primary potential emissions from the Black-Start generators are NO_x and CO. Emissions of VOC and particulate will also be relatively small based on the short operating time and infrequent use (only initial startup and commissioning and upset conditions). The maximum hours per year proposed for the Black-Start generators are 250. Subsequent startup operations will be warm starts and are not anticipated to require firing of the Black-Start generators. Good combustion controls that optimize combustion efficiency will minimize potential NO_x, CO, VOC and particulate emissions. Because natural gas is being used, the potential emissions of SO₂ will also be small. Additionally, these natural gas fired generators will also be subject to and will comply with the NSPS for Stationary Compression Ignition Combustion Engines (Subpart III), as applicable.

The use of a natural gas, restricted operating conditions, and good combustion practices are proposed as BACT for the three Black-Start generators. Table 4.5 shows the proposed BACT emission rates for each Black-Start generator.

Table 4.5 – Black-Start Generator BACT Analysis Summary

Pollutant	Proposed BACT	Proposed BACT Emission Limits (emission limits are per generator)
NO _x	Natural Gas Fired Good Combustion Practices Restricted Operation (initial startup only)	NO _x Limit: 0.80 tpy
SO ₂		SO ₂ Limit: <0.01 tpy
CO		CO Limit: 1.93 tpy
VOC		VOC Limit: 0.72 tpy
PM		Particulate Limit: 0.0002 tpy (PM ₁₀ - filterable)

6.2.2 Source Emissions and Parameters

Modeled Plant emission rates were based on the activity levels and applied control technologies described in Sections 3 and 4 of this document. Conservative emission estimates were used to predict the maximum likely impacts for each modeled pollutant. Where practicable, combinations of operations were developed to allow operational flexibility for future Plant activities. For example, cold startup and operations after cold startup, and normal operations scenarios were evaluated to determine annual emissions for modeling.

Of the emitted criteria pollutants, VOC emissions, which are precursors to ozone, were not explicitly modeled. Modeling of VOC impacts is not performed for two reasons. First, no NAAQS are established for VOCs. Second, AERMOD does not have the capability to model the chemical reactions that form ozone in the atmosphere from VOCs. Given the relatively low ambient ozone concentrations in the area surrounding the Plant and the lack of significant industrial NO_x and VOC emissions nearby, no ozone analysis was performed.

Emissions of criteria pollutants NO_x, CO, SO₂, and PM₁₀ were explicitly modeled and the maximum total short-term emission rates for all sources are shown below in Table 6.1.

Table 6.1 – Maximum Combined Modeled Short-Term Emission Rates for All Sources in the Analysis

Total NO _x (g/sec) Modeled	Total CO (g/sec) Modeled	Total SO ₂ (g/sec) Modeled	Total PM ₁₀ (g/Sec) Modeled
14.691	853.108	1400.80	11.42/4.21

1. Emission rate modeled with long-term analysis, including all mining-related point and fugitive sources/emission rate modeled in short-term analysis, representing only mining-related point sources (no fugitives).

Specific source model emission rates and input parameters are shown in Table 6.2. Pollutants with short-term averaging periods (CO, SO₂, and PM₁₀) were modeled at maximum short-term rates for all operating scenarios. Note that for the LP Flare, a cold startup will not occur for a full day, but during those startup hours, the expected emissions from the LP Flare may substantially exceed its normal operation short-term emission rates. The short-term modeling analysis includes these higher short-term, startup-related, emissions from the LP Flare. Modeled pollutant emissions for the long-term (annual) NO_x, SO₂, and PM₁₀ analyses were based on additive operations across the highest emitting scenarios (7760 hr/yr of normal operations after startup plus 1,000 hr/yr of cold startup conditions).

Stack input parameters such as height, diameter, velocity, and temperature, are based on vendor information or established values for similar unit operations. Effective heights and diameters for the HP and LP flares during startup and normal operations were calculated and modeled per established modeling guidance documentation.

The full cumulative modeling analysis includes a nearby (35-km) source inventory, supplied by the WDEQ, for NO_x and CO sources. Although the relative spatial distances are large, the point

Table 6.2 – Modeled Plant Point Source Parameters

Emission Unit	Emission Unit / Model ID	Location UTM			Modeled Exhaust Parameters				Modeled Emission Rates (g/s)			
		X (m)	Y (m)	Z (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)	NO _x	CO	SO ₂	PM ₁₀
Turbine and HRSG Train 1	CTG1	391190.18	4624309.74	2133	45.73	366.49	7.65	5.79	2.206	1.434	0.336	1.26
Turbine and HRSG Train 2	CTG2	391190.18	4624231.74	2133	45.73	366.49	7.65	5.79	2.206	1.434	0.336	1.26
Turbine and HRSG Train 3	CTG3	391190.18	4624179.74	2133	45.73	366.49	7.65	5.79	2.206	1.434	0.336	1.26
Gasifier Preheater 1	GHEAT1	390998.86	4624266.35	2133	25.91	422.05	7.45	0.41	0.0074	0.218	0.0015	0.0197
Gasifier Preheater 2	GHEAT2	390998.46	4624253.85	2133	25.91	422.05	7.45	0.41	0.0074	0.218	0.0015	0.0197
Gasifier Preheater 3	GHEAT3	390998.18	4624241.85	2133	25.91	422.05	7.45	0.41	0.0074	0.218	0.0015	0.0197
Gasifier Preheater 4	GHEAT4	390997.86	4624229.85	2133	25.91	422.05	7.45	0.41	0.0074	0.218	0.0015	0.0197
Gasifier Preheater 5	GHEAT5	390997.46	4624217.35	2133	25.91	422.05	7.45	0.41	0.0074	0.218	0.0015	0.0197
HP Flare	Z8901	390824.94	4624353.31	2133.9	46.0 / 86.55 *	1273	20	0.152 / 13.64*	0.2956	409.4	946.02	0.0
Black-Start Generator 1	BSG1	391102.68	4623970.7	2133	30	767.6	1.96	0.41	0.033	1.95	0.0014	0.00019
Black-Start Generator 2	BSG2	391107.68	4623970.7	2133	30	767.6	1.96	0.41	0.033	1.95	0.0014	0.00019
Firewater Pump	FIREPUMP	391247.38	4624293.74	2133	6.1	739.27	45	0.15	0.0433	0.046	0.00076 4	0.0096
Auxiliary Boiler	AB	391085.81	4624005.5	2133	15.24	422.05	1.6	0.91	0.4076	0.685	0.005	0.062
Catalyst Regenerator	REGH	391329.29	4624467.64	2133	15.24	422.05	1.6	0.91	0.133	0.223	0.0016	0.0202
Reactivation Heater	REAH	391329.5505	4624486.43	2133	15.24	422.05	1.6	0.91	0.077	0.129	0.00092	0.0117
HGT Reactor Charge Heater	HGT	391329.29	4624447.64	2133	15.24	422.05	1.6	0.91	0.077	0.023	0.00016	0.002
LP Flare	Z8902	390856.48	4624591.43	2133.6	70.4 / 74.9*	1273	20	— / 4.43*	0.00437	2.44	453.75	0.0
Black-Start Generator 3	BSG3	391112.68	4623970.7	2133	30	767.6	1.96	0.41	0.033	1.95	0.0014	0.00019

Table 6.2 – Modeled Plant Point Source Parameters

Emission Unit	Emission Unit / Model ID	Location UTM			Modeled Exhaust Parameters				Modeled Emission Rates (g/s)			
		X (m)	Y (m)	Z (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)	NO _x	CO	SO ₂	PM ₁₀
CO ₂ Stack Vent	CO2V	390957.03	4624580.2	2133	30.48	296.88	6.99	1.83	0.0	423.21	0.0	0.0

* The second number indicates the flare’s effective stack height or effective diameter. Maximum modeled LP Flare (Source ID Z8902) height was 75 m (231 ft) for model year 2004 in the short-term NAAQS/WAAQS analysis, therefore, this will be the required height for the LP Flare.

Table 6.3 – Modeled Cumulative (Nearby) Point Source Parameters

Emission Unit / Model ID	Location UTM			Modeled Exhaust Parameters				Modeled Emission Rates (g/s)			
	X (m)	Y (m)	Z (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)	NO _x	CO	SO ₂	PM ₁₀
SRC36454	421705	4587401	2225.9	13.87	672.04	12.19	1.07	15.09	-	-	-
SRC36455	421705	4587401	2225.9	13.87	672.04	12.19	0.91	6.13	2.83	-	-
SRC36456	421705	4587401	2225.9	13.87	672.04	12.19	1.07	15.09	-	-	-
SRC36457	421705	4587401	2225.9	13.87	672.04	12.19	1.07	10.38	1.32	-	-
SRC36458	421705	4587401	2225.9	8.23	842.04	78.64	0.24	3.26	0.377	-	-
SRC36459	421705	4587401	2225.9	8.23	842.04	78.64	0.24	3.26	0.377	-	-
SRC36462	421705	4587401	2225.9	12.19	685.93	41.76	1.04	0.618	0.662	-	-
SRC36463	421705	4587401	2225.9	6.4	449.82	6.12	0.46	0.154	-	-	-
SRC37392	395304.8	4649701	2023.84	7.92	596.48	24.05	0.43	0.975	0.106	-	-
SRC37393	395304.8	4649701	2023.84	7.92	596.48	24.05	0.43	0.975	0.106	-	-
SRC37771	399740	4606350	2332.8	10.97	922.04	50.51	1.01	0.710	0.518	-	-
SRC36900	375778.9	4651513	2011	11.0	730.4	71.6	0.25	0.503	0.164	-	-
SRC36901	375778.9	4651524	2011	11.0	730.4	71.6	0.25	0.503	0.164	-	-
SRC36902	375778.9	4651536	2011	11.0	762.0	38.6	0.25	0.319	0.642	-	-
SRC36903	375778.9	4651547	2011	11.0	762.0	38.6	0.25	0.319	0.642	-	-

sources included in this nearby inventory have significant emission rates. Table 6.3 details the nearby point sources used for cumulative modeling.

6.2.2.1 Coal Mine Fugitive Emission Area Sources

Existing surface and planned underground coal mining operations are located within the facility's "ambient" boundary. MBFP has an option to purchase the coal it needs from Arch Coal of Wyoming, LLC (Arch). Arch operates the existing surface mine, The Elk Mountain Mine, under permit CT – 4136 (Wyoming), which includes the projected future annual emissions and locations of its aboveground mining operations. A copy of that permit was obtained from the WDEQ.

Emission factors from the Arch surface mine permit were used to calculate future emissions from the aboveground operation locations to be constructed to support the proposed underground Saddleback Hills Mine. Area sources were created to the west of the facility for these potential future emissions.

Table 6.4 shows the area source modeling parameters for the Plant's mining operations as well as the aboveground mining operations associated with the Elk Mountain and Saddleback Hills Mine for this analysis.

6.2.2.2 Industrial Gasification & Liquefaction Plant Volume Sources

Volume sources were used to represent HAP emissions associated with storage tanks and equipment leaks. Table 6.5 shows the modeling parameters for the volume sources and Figure 6.3 shows the complete layout of all sources related to the facility (including the Elk Mountain Mine operations).

Figure 6.4 shows the locations of the Plant and the nearby sources included in the inventory sent by the WDEQ.

6.2.3 Additional Emission Assumptions

The following conservative assumptions were used when conducting this modeling analysis.

- Normal operations at the facility will not include the Black-Start Generator emissions. Therefore, simultaneous / concurrent emissions that were modeled for the Black-Start generators and turbines are not likely to occur. In other words, several emission units / sources are not likely to emit concurrently with other sources.
- Vehicle tailpipe NO_x emissions associated with the nearby mining operations (Elk Mountain Mine) were included in the PSD increment and NAAQS analysis.
- Vehicle tailpipe, surface mining, and vehicle traffic (associated with haul roads) PM₁₀, SO₂, and CO emissions (Elk Mountain Mine) were included in the NAAQS analyses to determine cumulative impacts for each pollutant.
- Surface mining emissions are below ground level or surrounded by high walls that could prevent the release of PM/PM10 into the ambient domain; the area sources for the surface mining for this modeling analysis are above ground level.

Table 6.4 – Area Source Modeling Parameters

Source ID (in model)	Source Type	Source Description	Corner Easting (X) (m)	Corner Northing (Y) (m)	Base Elevation (m)	Release Height (m)	Sigma z (initial dimension) (m)	Modeled Emission Rates (g/sec/m ²)			
								NOx	CO	SO ₂	PM ₁₀ ²
CoalStor	Area	On Site Coal Storage	389896.4	4623397.9	2133	20.0	9.3	0.0	0.0	0.0	0.000075
MineA_SP ¹	Area	Mine Area / South Portal	384525.3	4622056.4	2252	12.0	13.95	0.0	0.0	0.0	0.0
MineA_EP	Area	Mine Area / East Portal	389721.7	4623411.5	2134	12.0	13.95	0.000004	0.0000034	0.0000007	0.0000082/0.0000001
MineA_S1	Area	Mine Area / Surface Mining (On-Site)	389673.8	4623406.6	2134	12.0	NA	0.0000137	0.0000115	0.0000023	0.000007/0.0000057
MineA_S2	Area	Mine Area / Surface Mining (Off-Site)	388229.3	4622116.0	2189	12.0	NA	0.0000137	0.0000115	0.0000023	0.000007/0.0000057

Notes

1. The analysis reflects development year 4 operations, where normal plant operations have begun, and all coal produced at the Saddleback Hills Mine is brought out through the mine's East Portal (Source ID MineA_EP). Mine development emissions from the Saddleback Hills Mine South Portal (Source ID MineA_SP) will begin to decline in development year 3 and will cease in year 4.
2. Where two values are shown, the PM₁₀ modeled emissions rates represent total point source and fugitive source emissions included in the long-term (annual) analysis, and the point source emissions included in the short-term (24-hr) analyses.

Table 6.5 – Volume Source Modeling Parameters

Source ID (in model)	Source Type	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Release Height (m)	Sigma y (initial dimension) (m)	Sigma z (initial dimension) (m)	Modeled Emission Rates (g/sec)			
									NOx	CO	SO2	PM10
T_A	Volume	Gasoline Tank	390966.4	4624652	2133.2	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_B	Volume	Gasoline Tank	391021.3	4624652	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_C	Volume	Gasoline Tank	391109.2	4624652	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_D	Volume	Gasoline Tank	391175.2	4624652	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_E	Volume	Gasoline Tank	390966.4	4624712	2133.2	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_F	Volume	Gasoline Tank	391021.3	4624712	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_G	Volume	Gasoline Tank	391109.2	4624712	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_H	Volume	Gasoline Tank	391175.2	4624712	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_I	Volume	Methanol Tank	390966.4	4624822	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_J	Volume	Methanol Tank	391021.3	4624822	2133	14.6304	10.6325581	2.32	0.0	0.0	0.0	0.0
T_K	Volume	Heavy Gas Tank	391173.8	4624840	2133	14.6304	9.21488372	2.32	0.0	0.0	0.0	0.0
V1	Volume	Equipment Leaks	391224.369	4624457.507	2133	2.0	61.12	4.65	0.0	0.0	0.0	0.0
V_1 through V_112	Volume	Haul Roads	varying	varying	varying	2.0	1.63	2.79	0.0	0.0	0.0	0.0284/0.0 ¹

Notes

1. Haul road PM₁₀ emissions are fugitives, and per WDEQ policy, are not included in short-term (24-hr) modeling analyses.

Figure 6.3 – Plant and Nearby Mining Area Sources

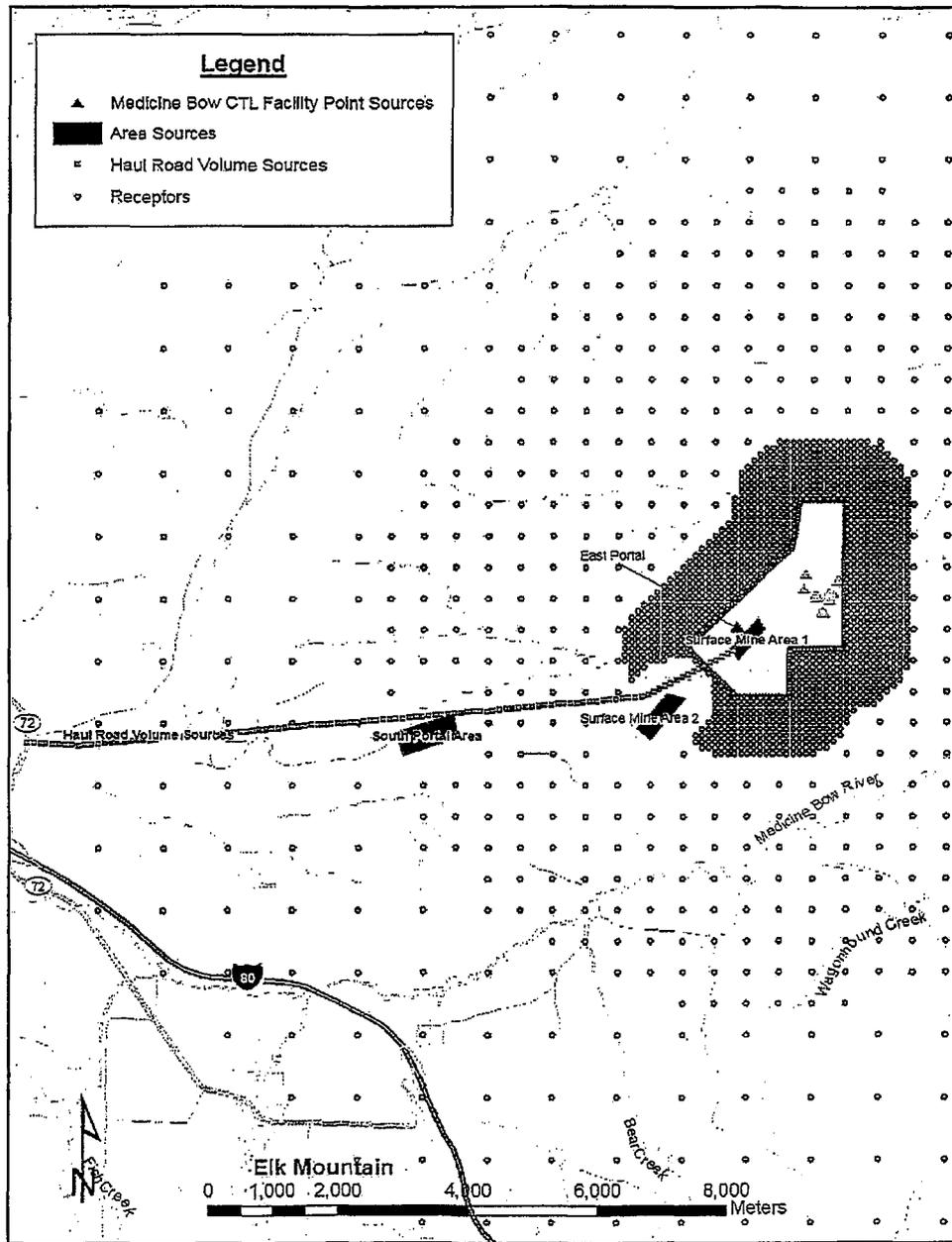
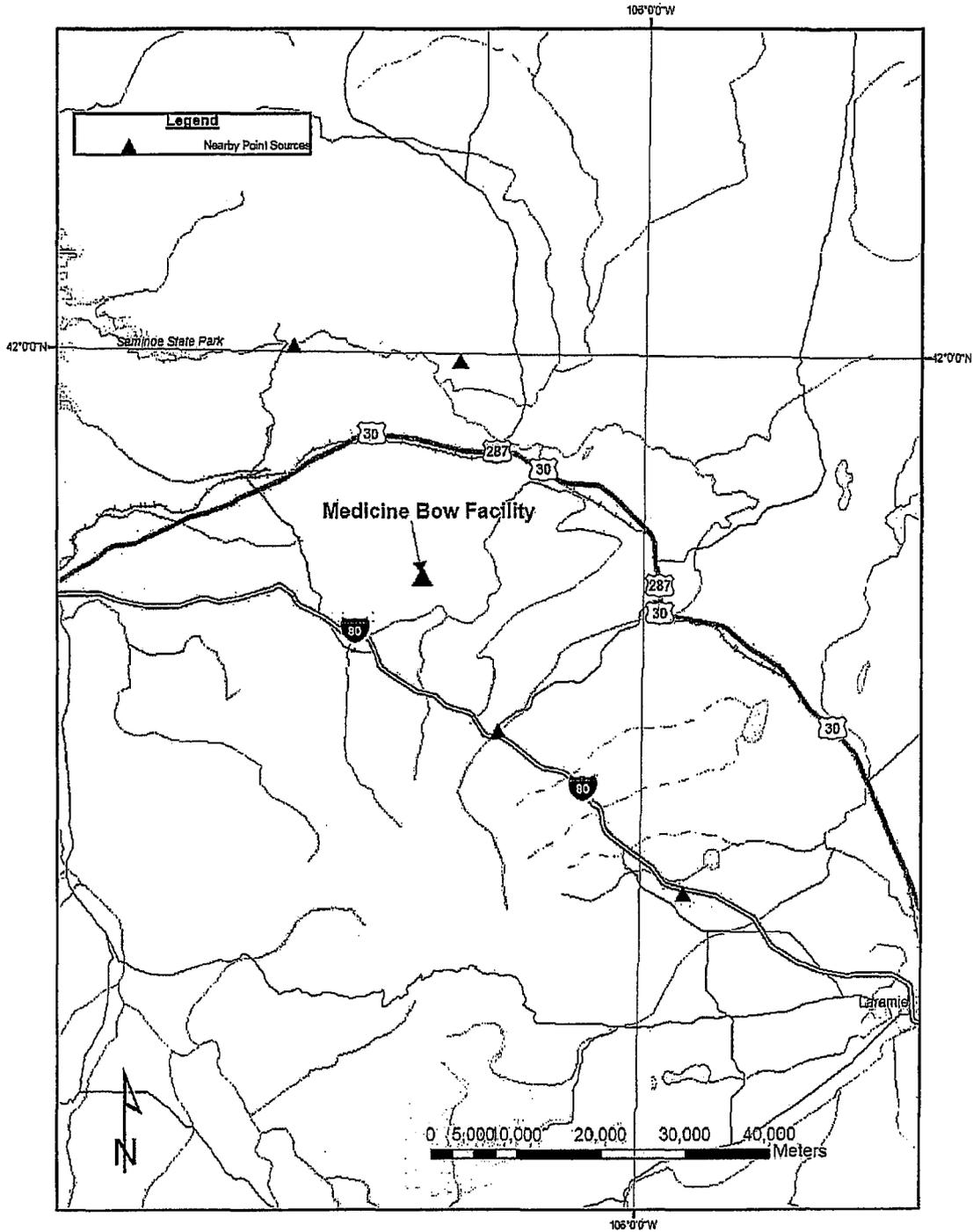


Figure 6.4 – Plant Location Relative to the WDEQ Provided Emission Inventory



SECTION SIX

Near Field Air Quality Impact Analysis

Figures 6.7, 6.8, and 6.9 illustrate maximum PSD increment impacts for 3-hour, 24-hour, and annual averaging times.

Table 6.10 – Predicted SO₂ Concentrations Compared to NAAQS / WAAQS

Averaging Period	Data Period			Receptor Location (m)		Predicted Cumulative Concentration (ug/m3)	Background Concentration (ug/m3)	Total Concentration (Cumulative + Background) (ug/m3)	NAAQS / WAAQS (ug/m3)
	Year	Month/Day	Hour	East	North				
3 Hour ^{1,2}	2000	8/6	03	388955.38	4627705	1108.55	31.4	1139.95	N/A / 1300
	2001	6/22	24	381955.38	4628205	1097.85	31.4	1129.25	N/A / 1300
	2003	7/26	06	389455.38	4628205	1008.50	31.4	1039.90	N/A / 1300
	2004	5/22	03	395455.38	4624205	1033.64	31.4	1065.04	N/A / 1300
	2005	8/1	06	381955.38	4628205	1034.36	31.4	1065.76	N/A / 1300
24 Hour ^{1,2}	2000	5/30	24	389972.38	4624361	190.70	7.84	198.54	365 / 260
	2001	10/19	24	392055.38	4625005	197.92	7.84	205.76	365 / 260
	2003	12/27	24	391955.38	4625205	201.96	7.84	209.80	365 / 260
	2004	12/26	24	395455.38	4624205	241.39	7.84	249.23	365 / 260
	2005	9/15	24	395455.38	4624205	205.98	7.84	213.82	365 / 260
Annual	2000	N/A	N/A	391421.4	4624635	4.25	2.62	6.87	80 / 60
	2001	N/A	N/A	391421.4	4624585	4.51	2.62	7.13	80 / 60
	2003	N/A	N/A	391422.4	4624685	4.43	2.62	7.05	80 / 60
	2004	N/A	N/A	391420.4	4624485	4.01	2.62	6.63	80 / 60
	2005	N/A	N/A	391420.4	4624435	4.09	2.62	6.71	80 / 60

1. Based on the second-highest maximum.
2. Short-term analyses based on actual LP Flare (Source ID Z8902) maximum height of 70 m (231 ft) for model year 2004; all other model years, flare maximum height was set less than this height.

Table 6.11 – Predicted SO₂ Concentrations Compared to PSD Increments

Averaging Period	Data Period			Receptor Location (m)		Predicted Concentration (ug/m3)	PSD Increment (ug/m3)
	Year	Month/Day	Hour	East	North		
3 Hour ¹	2000	12/8	06	389410.38	4623014	7.04	512
	2001	9/24	03	389410.38	4623014	11.28	512
	2003	5/7	03	389410.38	4623014	8.95	512
	2004	8/27	06	389445.38	4622979	10.24	512
	2005	8/21	06	389410.38	4623014	8.23	512
24 Hour ¹	2000	2/14	24	391455.38	4624505	1.58	91
	2001	9/24	24	389410.38	4623014	2.46	91
	2003	12/13	24	391455.38	4624505	1.97	91
	2004	1/7	24	391555.38	4624505	1.62	91
	2005	8/21	24	389516.38	4622908	2.02	91
Annual	2000	N/A	N/A	391421.4	4624635	4.25	20
	2001	N/A	N/A	391421.4	4624585	4.51	20
	2003	N/A	N/A	391422.4	4624685	4.43	20
	2004	N/A	N/A	391420.4	4624485	4.01	20
	2005	N/A	N/A	391420.4	4624435	4.09	20

1. Short-term analyses does not include LP Flare (Source ID Z8902).

Figure 6.7 – 2003 Maximum SO₂ 3-Hour Impacts (PSD)

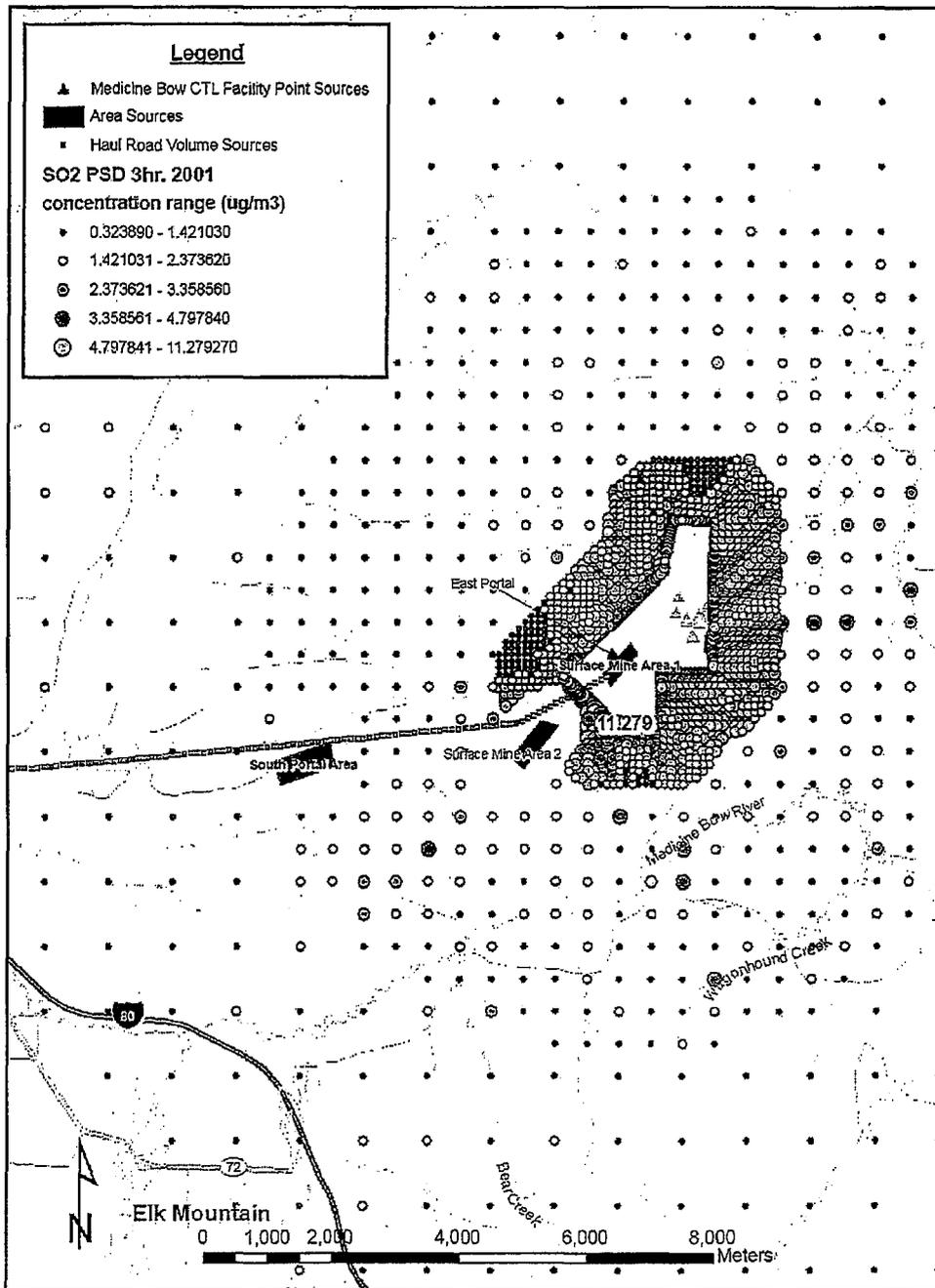
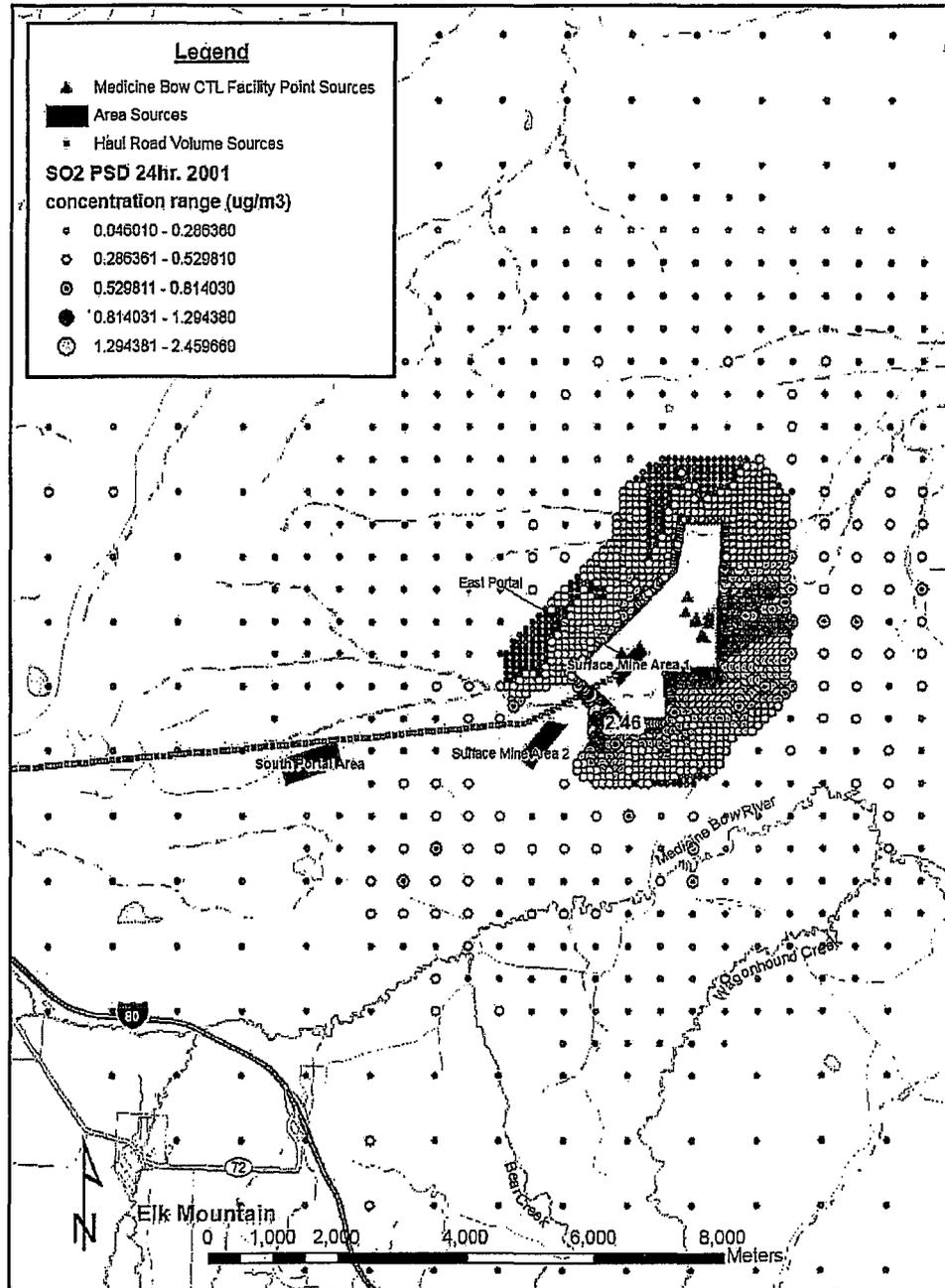


Figure 6.8 – 2000 Maximum SO₂ 24-Hour Impacts (PSD)



Figures 6.10 and 6.11 illustrate maximum PSD increment impacts for 24-hour and annual averaging times.

Figure 6.10 – 2005 Maximum PM₁₀ 24-Hour Impacts (PSD)

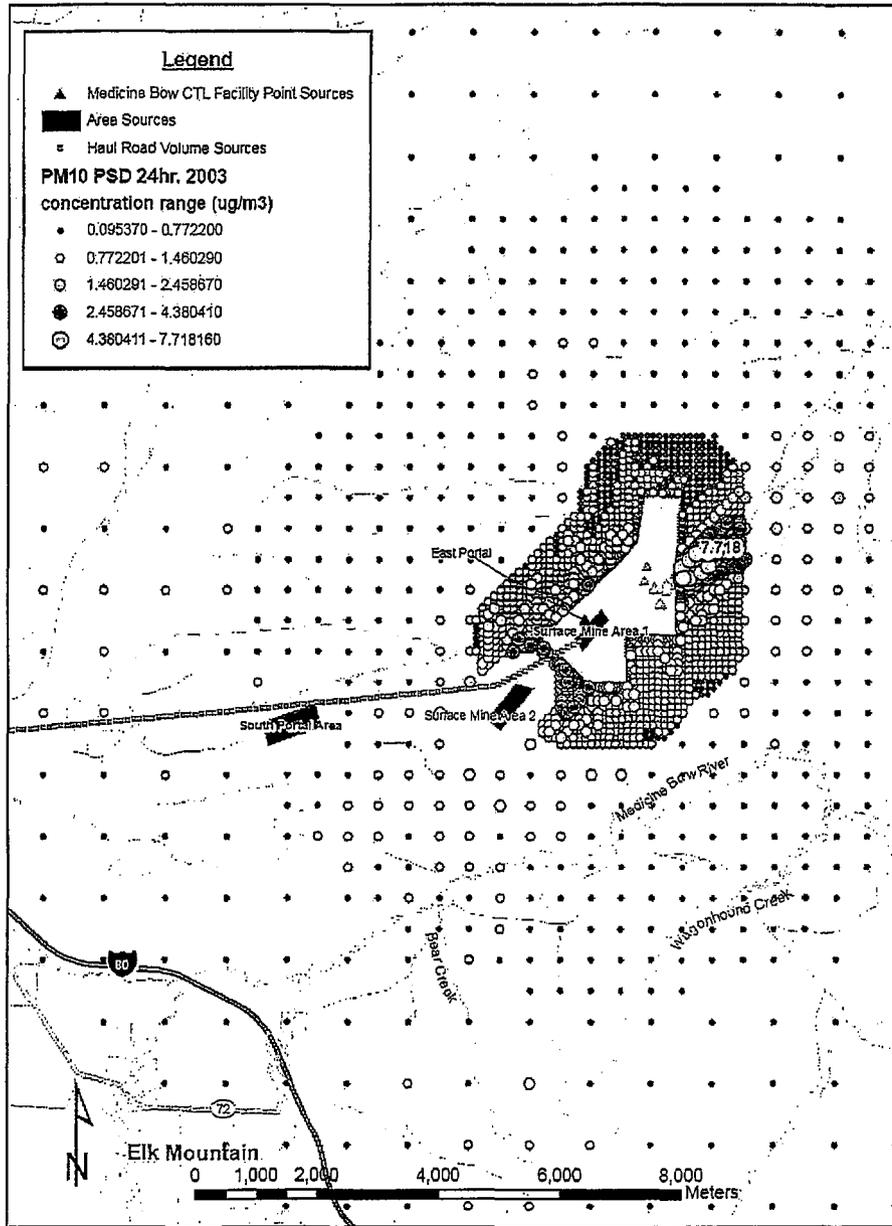
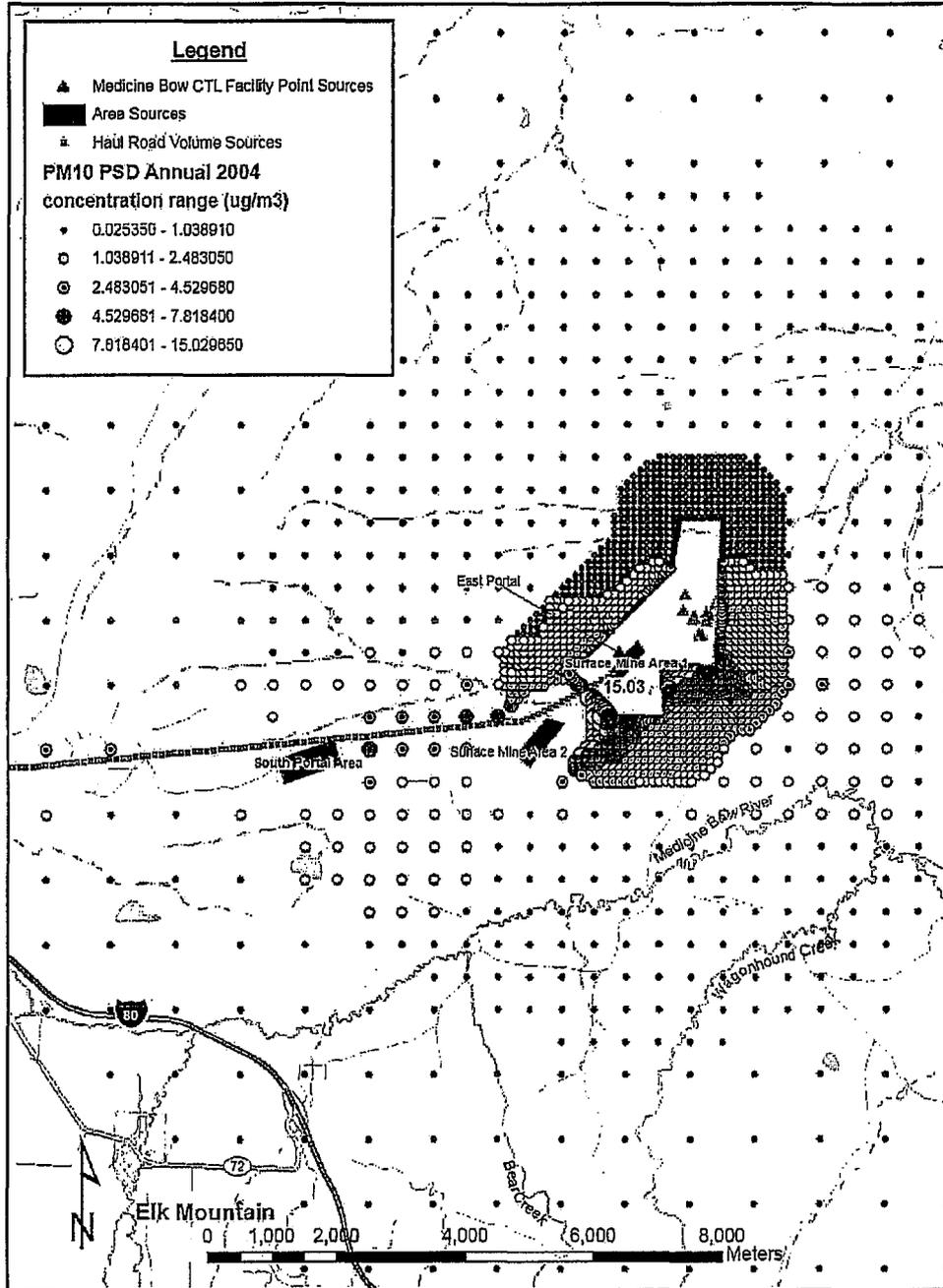


Figure 6.11 – 2005 Maximum PM₁₀ Annual Impacts (PSD)



Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Emission Summary Sheet

Normal Operations (8760 hr/yr)

ID No.	Description	Usage	Operation (hr/yr)	Potential Emissions (t/yr)					HAPs Emissions (t/yr)																	
				NO _x	CO	VOC	SO ₂	PM ₁₀	1,2-Dichlorobenzene	Acetaldehyde	Acrolein	2,2,4-Trimethylpentane	Benzene	Carbonyl Sulfide	Dichlorobenzene	Ethyl Benzene	Formaldehyde	Hexane	Mercury	Methanol	Naphthalene	PAH	Propylene Oxide	Toluene	Xylene	TOTALS
CT-1	Turbine and HRSG Train 1	General Electric, 66 MW	8,760	75.86	46.19	6.59	10.79	43.80	1.37E-03	1.27E-01	2.03E-02		3.81E-02			1.02E-01	2.25E-01		1.23E-04		4.13E-03	6.98E-03	9.21E-02	4.13E-01	2.03E-01	1.23E+00
CT-2	Turbine and HRSG Train 2	General Electric, 66 MW	8,760	75.86	46.19	6.59	10.79	43.80	1.37E-03	1.27E-01	2.03E-02		3.81E-02			1.02E-01	2.25E-01		1.23E-04		4.13E-03	6.98E-03	9.21E-02	4.13E-01	2.03E-01	1.23E+00
CT-3	Turbine and HRSG Train 3	General Electric, 66 MW	8,760	75.86	46.19	6.59	10.79	43.80	1.37E-03	1.27E-01	2.03E-02		3.81E-02			1.02E-01	2.25E-01		1.23E-04		4.13E-03	6.98E-03	9.21E-02	4.13E-01	2.03E-01	1.23E+00
AB	Auxiliary Boiler	Heater, 68 MMBtu/hr ¹	8,760	14.17	23.81	1.58	0.17	2.15					5.95E-04	3.40E-04		2.13E-02	5.10E-01				1.73E-04			9.64E-04		5.33E-01
B-1	Catalyst Regenerator Heater	Heater, 21.53 MMBtu/hr ¹	8,760	4.62	7.77	0.51	0.06	0.70					1.94E-04		1.11E-04	6.93E-03	1.66E-01				5.64E-05			3.14E-04		1.74E-01
B-2	Reactivation Heater	Heater, 12 MMBtu/hr ¹	8,760	2.87	4.49	0.29	0.03	0.41					1.12E-04		6.42E-05	4.01E-03	9.62E-02				3.29E-05			1.83E-04		1.61E-01
B-3	HGT Reactor Charge Heater	Heater, 2 MMBtu/hr ¹	8,760	0.48	0.80	0.05	0.01	0.07					2.00E-05	1.14E-05		3.79E-02	7.15E-04	1.72E-02			5.82E-06			3.24E-05		1.79E-02
Tanks	Storage Tanks	Product Storage	8,760			102.62							5.27E-01			4.95E-01								5.67E-01	1.60E-01	4.17E+00
EL	Equipment Leaks	Fugitives	8,760			71.32							1.04E+01	2.60E-01							1.04E+01					2.11E+01
CS	Coal Storage & Processing	Conveyance (pnlrt) & Fugitives	8,760					61.08																		0.00E+00
FW-Pump	Firewater Pump ²	Engine, 575 HP	500	1.51	0.09	0.34	1.52E-03	0.02	3.77E-05	7.38E-04	8.61E-05		8.99E-04			1.14E-03					8.17E-05		2.49E-03	3.94E-04	2.75E-04	6.14E-03
FL-1	HP / Emergency Flare ³	Flare, 0.819 MMBtu/hr	8,760	0.49	0.98	2.97	2.10E-03																			0.00E+00
FL-2	LP Flare ³	Flare, 0.204 MMBtu/hr	8,760	0.12	0.25	0.74	0.00																			0.00E+00
Total Emissions				251.63	176.75	200.18	32.55	195.84	0.00	0.38	0.66	0.00	11.08	0.28	0.00	0.34	0.71	1.28	0.00	12.78	0.01	0.02	0.28	1.81	0.77	29.88

Notes:
¹ Emissions from auxiliary boiler and process heaters assume operation at full design capacity, firing natural gas; however, the equipment may not always fire at full load, and in many cases, will be firing a lower-BTU fuel gas mixture instead of
² SO₂ emissions from the Firewater Pump are based on burning ultra-low sulfur diesel (15 ppm).
³ Flare emissions include pilot emissions for 8760 hr/yr.

Malfunctions and Other Events

ID No.	Description	Usage	Operation (hours) ¹	Potential Emissions (tons)					HAPs Emissions (t/yr)																	
				NO _x	CO	VOC	SO ₂	PM ₁₀	1,2-Dichlorobenzene	Acetaldehyde	Acrolein	2,2,4-Trimethylpentane	Benzene	Carbonyl Sulfide	Dichlorobenzene	Ethyl Benzene	Formaldehyde	Hexane	Mercury	Methanol	Naphthalene	Propylene Oxide	Toluene	Xylene	TOTALS	
CO2 VS	CO2 Vent Stack	CO2 Vent Stack	50		83.87	0.23									2.25E-01											2.25E-01
FL-1	HP / Emergency Flare	Flare, 0.819 MMBtu/hr	40	7.83	64.99	0.12	150.10																			0.00E+00
FL-2	LP Flare	Flare, 0.204 MMBtu/hr	8	1.15E-02	2.25E-04	6.79E-04	14.40																			0.00E+00
GP-1	Gasification Preheater	Heater, 21.00 MMBtu/hr	500	0.26	0.43	0.03	3.02E-03	0.04					1.08E-05	6.18E-06		3.86E-04	9.28E-03								1.75E-05	8.69E-03

Notes:
¹ The hours shown are annual estimates, except for the Gasification Preheater which is based on 500 hours per preheating event for one gasifier.

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Mine - Mine Emissions Summary (PM₁₀)**

Project Year	Notes
Year 1	No plant operations during this year
Year 2	No plant operations during this year
Year 3	Partial plant operations during this year
Year 4	Plant operations have begun.

South Portal PM ₁₀ (tpy)		
point	road haul	other fugitives
0	26.80	3.04
0	109.31	5.17
0	71.63	4.20
0	0	0

East Portal PM ₁₀ (tpy)		
point	road haul	other fugitives
0	0	0
0	0	0
0.10	0	10.51
0.86	0	60.23

Totals PM ₁₀ (tpy)			
point	road haul	other fugitives	Grand Total
0.00	26.80	3.04	29.84
0.00	109.31	5.17	114.48
0.10	71.63	14.70	86.43
0.86	0.00	60.23	61.08

Additional Comments:

South Portal emission sources are fugitives and road haul (transport) to Seminole II processing area.
At South Portal, fugitives are from coal stackout, wind erosion from stockpile, and truck loading via front-end loader.
South Portal emissions are due to mine development activity; after plant operations commence, emissions from South Portal are expected to cease.

East Portal emissions are fugitive and point sources. No transport from East Portal to offsite processing is planned.
Fugitive emissions are from stackout, wind erosion from stockpiles, and dozer reclaim to conveyor belt (from emergency stockpile).
Point source emissions are from conveyor drop points, controlled with water fogger.
East Portal Conveyors C1 through C10 will be completely enclosed.
East Portal Conveyors C6 through C10 will have three-quarter (3/4) cover, rather than being completely enclosed.

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Mine - Emissions from On-Site Fuel Combustion**

Development Year	Carbon Basin Mine (2004 Application)			Percentage to SBH Mine ¹	SBH Mine South Portal			SBH Mine East Portal ²
	NOx [tpy]	CO [tpy]	SO2 [tpy]		NOx [tpy]	CO [tpy]	SO2 [tpy]	NOx, CO, SO2 [tpy]
Year 1	238.7	200.4	4.1	5%	12	10	0.2	0
Year 2	238.7	200.4	4.1	5%	12	10	0.2	0
Year 3	238.7	200.4	4.1	5%	12	10	0.2	0
Year 4	238.7	200.4	4.1	5%	0	0	0	Negl

Notes

1. Percentage assumed attributable to on-site fuel combustion at SBH Mine. Previous fuel consumption values were based on coal transfer operations at SBH Mine to support mine plan to transport and sell coal at offsite location. Due to mine plan changes, the amount of fuel consumption is expected to be less than originally planned.
2. During development years, no on-site fuel combustion is expected at East Portal. Once normal Plant operations begin in Year 4, some on-site fuel combustion may occur as a result of moving coal from the emergency (dead) stockpile to the conveying system. However, this is expected to be an infrequent activity; thus, annual emissions will be negligible.

Saddleback Hills Mine – Emission Calculations

Year One

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Detail Sheet - South Portal Emissions
Fugitive Emissions**

Production Rates are based on the 2007 Mine Plan Revisions

Total production, Years 1-3 2,538,000 tons

Development Emission Summary (South Portal)

Year	Coal Handling Emissions	Transportation Fugitive Emissions
	PM10 (tpy)	PM10 (tpy)
1	3.04	28.8
2	5.17	109.3
3	4.20	71.6

Year 1

Year 1 - Page 1 of 2

Production rate = 218,000 tpy; All coal to be sold at Hanna, WY

Emissions from handling coal at South Portal - stackout and truck loading

Coal Stacker	Coal Dumping to Stockpile	Temporary, portable stacker (stacking tube)	Fugitive
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	50.00%	Estimated
	Material Dumped	218,000 Tons/Yr	Total Coal Through Storage
	TSP Emissions	0.69 Tons/Yr	$E=(EF \times \% \text{ sus} \times MD/2000) \times (1-CF)$
	PM-10 Emissions	0.21 Tons/Yr	30% of TSP
Coal Stockpile	Wind Erosion on Stockpiles	Water	Fugitive
	Emission Factor	1.2 Lb/Acre/Hr	WDEQ Emission Factor
	Pile Size	1.0 Acres	Estimate (assume 10,000 ton pile)
	Fraction Suspended	0.75	WDEQ Emission Factor
	Hours	8,760 Hours	Total Annual
	Ave. Wind Speed	5.03 meters/Sec	Adjusted for in-pit
	Wet Days	60	Seminole Mine 5-Year Average
	Control Factor	50%	assumed
	TSP Emissions	8.28 Tons/Yr	$E=(EF \times AWS \times \% \text{ sus} \times PS \times ((365-WD)/365) \times (1-CF))/2000$
PM-10 Emissions	2.48 Tons/Yr		
Dozer Reclaim	Cat D11 Dozer to Trucks	No emission controls	Fugitive
	Emission Factor	8.0 Lb/Hr	WDEQ 2002 Guidance
	Total Throughput	218,000 Tons/Yr	Total Coal Through Storage
	Dozed Throughput	218,000 Tons/Yr	
	Dozer Productivity	750 Tons/Hr	Estimate
	Operating Hrs	291 Hrs	Productivity/Throughput
	TSP Emissions	1.16 Tons/Yr	$E=(EF \times Op \text{ Hrs})/2000$
	PM-10 Emissions	0.35 Tons/Yr	30% of TSP
Total South Portal PM₁₀ Emissions		Conversions:	
		453.6 g/lb	8760 hr/yr
PM ₁₀ = 3.04 tpy		2000 lb/ton	3600 sec/hr
0.087 g/sec			

Production rate = 218,000 tpy; All coal to be sold at Hanna, WY

Emissions from the transport of coal with highway trucks on plant roads (South Portal to Seminole II)

These roadways are reconstructed gravel roads for the purpose of connecting loadout with public roads using Wyoming hauling emission factor, with a tire factor adjustment for highway hauler

Input Data

Plant road silt content (s) = 5.1 %
 Tire factor = 3.5

Mean speed 40 mph
 Grader hrs - Carbon Basin Road 975 hrs
 Grader hrs - Seminole II Road 2,000 hrs

Reference

AP-42 table 13.2.2-1 (gravel-upgraded roadway)
 Assuming each pair is equivalent to a single large truck tire, a truck and pup combination have 14 equivalent tires, for a tire factor of 14/4 = 3.5
 Mine estimate

Conversions:

453.6 g/lb 8760 hr/yr
 2000 lb/ton 3600 s/hr

CARBON BASIN COAL TRANSPORT ROAD

Emission Factor 11.57 lb/VMT
 Number of Wet Days 100
 Truck Capacity 70 tons
 Truck Speed 40 mph
 Surface Silt Content 5.1 %
 Tire Correction Factor 3.5
 Percent Suspended (%) 62
 Control Factor (%) 60
 Control Method Water/Chemicals

Coal Hauled 0.218 MMtpy
 Vehicle Miles Traveled 18,686 VMT
 RT Haul Distance 6.0 miles
PM-10 Emissions (tpy) 12.97

SEMINOLE II COAL TRANSPORT ROAD

Emission Factor 11.57 lb/VMT
 Number of Wet Days 100
 Truck Capacity 70 tons
 Truck Speed 40 mph
 Surface Silt Content 5.1 %
 Tire Correction Factor 3.5
 Percent Suspended (%) 62
 Control Factor (%) 60
 Control Method Water/Chemicals

Coal Hauled 0.218 MMtpy
 Vehicle Miles Traveled 12,457 VMT
 RT Haul Distance 4.0 miles
PM-10 Emissions (tpy) 8.648

CARBON BASIN TRANSPORT ROAD REPAIR

Emission Factor 32 lb/hr
 Number of Wet Days 100
 Control Factor (%) 50
 Control Method Water
 Grader Hours/Year 975
PM-10 Emissions (tpy) 1.70

SEMINOLE II TRANSPORT ROAD REPAIR

Emission Factor 32 lb/hr
 Number of Wet Days 100
 Control Factor (%) 50
 Control Method Water
 Grader Hours/Year 2,000
PM-10 Emissions (tpy) 3.48

CARBON BASIN TRANSPORT ROAD EMISSIONS

TOTALS	PM10	TSP
tpy	14.7	48.9
g/s	0.4	1.4

SEMINOLE II TRANSPORT ROAD EMISSIONS

TOTALS	PM10	TSP
tpy	12.1	40.4
g/s	0.3	1.2

Saddleback Hills Mine – Emission Calculations

Year Two

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Detail Sheet - South Portal Emissions
Fugitive Emissions**

Production Rates are based on the 2007 Mine Plan Revisions

Total production, Years 1-3 2,538,000 tons

Development Emission Summary (South Portal)

Year	Coal Handling Emissions	Transportation Fugitive Emissions
	PM10 (tpy)	PM10 (tpy)
1	3.04	26.8
2	5.17	109.3
3	4.20	71.6

Year 2

Year 2 - Page 1 of 2

Production rate = 1,050,000 tpy; All coal to be sold at Hanna, WY

Emissions from handling coal at South Portal - stackout and truck loading

Coal Stacker	Coal Dumping to Stockpile	Temporary, portable stacker (stacking tube)	Fugitive
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	50.00%	Estimated
	Material Dumped	1,050,000 Tons/Yr	Total Coal Through Storage
	TSP Emissions	3.35 Tons/Yr	$E=(EF \times \% \text{ sus} \times MD/2000) \times (1-CF)$
	PM-10 Emissions	1.00 Tons/Yr	30% of TSP
Coal Stockpile	Wind Erosion on Stockpiles	Water	Fugitive
	Emission Factor	1.2 Lb/Acre/Hr	WDEQ Emission Factor
	Pile Size	1.0 Acres	Estimate (assume 10,000 ton pile)
	Fraction Suspended	0.75	WDEQ Emission Factor
	Hours	8,760 Hours	Total Annual
	Ave. Wind Speed	5.03 meters/Sec	Adjusted for in-pit
	Wet Days	60	Seminole Mine 5-Year Average
	Control Factor	50%	assumed
	TSP Emissions	8.28 Tons/Yr	$E=(EF \times AWS \times \% \text{ sus} \times PS \times ((365-WD)/365) \times (1-CF))/2000$
PM-10 Emissions	2.48 Tons/Yr		
Dozer Reclaim	Cat D11 Dozer to Trucks	No emission controls	Fugitive
	Emission Factor	8.0 Lb/Hr	WDEQ 2002 Guidance
	Total Throughput	1,050,000 Tons/Yr	Total Coal Through Storage
	Dozed Throughput	1,050,000 Tons/Yr	
	Dozer Productivity	750 Tons/Hr	Estimate
	Operating Hrs	1,400 Hrs	Productivity/Throughput
	TSP Emissions	5.60 Tons/Yr	$E=(EF \times \text{Op Hrs})/2000$
	PM-10 Emissions	1.68 Tons/Yr	30% of TSP
Total South Portal PM₁₀ Emissions		Conversions:	
		453.6 g/lb	8760 hr/yr
PM ₁₀ = 5.17 tpy		2000 lb/ton	3600 sec/hr
0.149 g/sec			

Production rate = 1,050,000 tpy; All coal to be sold at Hanna, WY

Emissions from the transport of coal with highway trucks on plant roads (South Portal to Seminoe II)

These roadways are reconstructed gravel roads for the purpose of connecting loadout with public roads using Wyoming hauling emission factor, with a tire factor adjustment for highway hauler

Input Data

Plant road silt content (s) = 5.1 %
 Tire factor = 3.5

Mean speed 40 mph
 Grader hrs - Carbon Basin Road 975 hrs
 Grader hrs - Seminoe II Road 2,000 hrs

Reference

AP-42 table 13.2.2-1 (gravel-upgraded roadway)
 Assuming each pair is equivalent to a single large truck tire, a truck and pup combination have 14 equivalent tires, for a tire factor of 14/4 = 3.5
 Mine estimate

Conversions:

453.6 g/lb 8760 hr/yr
 2000 lb/ton 3600 s/hr

CARBON BASIN COAL TRANSPORT ROAD

Emission Factor 11.57 lb/VMT
 Number of Wet Days 100
 Truck Capacity 70 tons
 Truck Speed 40 mph
 Surface Silt Content 5.1 %
 Tire Correction Factor 3.5
 Percent Suspended (%) 62
 Control Factor (%) 60
 Control Method Water/Chemicals

Coal Hauled 1.050 MMtpy
 Vehicle Miles Traveled 90,000 VMT
 RT Haul Distance 6.0 miles
PM-10 Emissions (tpy) 62.48

SEMINOE II COAL TRANSPORT ROAD

Emission Factor 11.57 lb/VMT
 Number of Wet Days 100
 Truck Capacity 70 tons
 Truck Speed 40 mph
 Surface Silt Content 5.1 %
 Tire Correction Factor 3.5
 Percent Suspended (%) 62
 Control Factor (%) 60
 Control Method Water/Chemicals

Coal Hauled 1.050 MMtpy
 Vehicle Miles Traveled 60,000 VMT
 RT Haul Distance 4.0 miles
PM-10 Emissions (tpy) 41.652

CARBON BASIN TRANSPORT ROAD REPAIR

Emission Factor 32 lb/hr
 Number of Wet Days 100
 Control Factor (%) 50
 Control Method Water
 Grader Hours/Year 975
PM-10 Emissions (tpy) 1.70

SEMINOE II TRANSPORT ROAD REPAIR

Emission Factor 32 lb/hr
 Number of Wet Days 100
 Control Factor (%) 50
 Control Method Water
 Grader Hours/Year 2,000
PM-10 Emissions (tpy) 3.48

CARBON BASIN TRANSPORT ROAD EMISSIONS

TOTALS	PM10	TSP
tpy	64.2	213.9
g/s	1.8	6.2

SEMINOE II TRANSPORT ROAD EMISSIONS

TOTALS	PM10	TSP
tpy	45.1	150.5
g/s	1.3	4.3

Saddleback Hills Mine – Emission Calculations

Year Three

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Detail Sheet - South Portal Emissions
Fugitive Emissions**

Production Rates are based on the 2007 Mine Plan Revisions

Total production, Years 1-3 2,538,000 tons

Development Emission Summary (South Portal)

Year	Coal Handling Emissions	Transportation Fugitive Emissions
	PM10 (tpy)	PM10 (tpy)
1	3.04	26.8
2	5.17	109.3
3	4.20	71.6

Year 3

Year 3 - Page 1 of 2

Production rate = 1,270,000 tpy; 600,000 tons to be sent via underground tunnel to East Portal
670,000 tpy of remaining coal to be sold at Hanna, WY from South Portal

Emissions from handling coal at South Portal - stackout and truck loading

Coal Stacker	Coal Dumping to Stockpile	Temporary, portable stacker (stacking tube)	Fugitive
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	50.00%	Estimated
	Material Dumped	670,000 Tons/Yr	Total Coal Through Storage
	TSP Emissions	2.14 Tons/Yr	$E=(EF \times \% \text{ sus} \times MD/2000) \times (1-CF)$
	PM-10 Emissions	0.64 Tons/Yr	30% of TSP
Coal Stockpile	Wind Erosion on Stockpiles	Water	Fugitive
	Emission Factor	1.2 Lb/Acre/Hr	WDEQ Emission Factor
	Pile Size	1.0 Acres	Estimate (assume 10,000 ton pile)
	Fraction Suspended	0.75	WDEQ Emission Factor
	Hours	8,760 Hours	Total Annual
	Ave. Wind Speed	5.03 meters/Sec	Adjusted for in-pit
	Wet Days	60	Seminole Mine 5-Year Average
	Control Factor	50%	assumed
	TSP Emissions	8.28 Tons/Yr	$E=(EF \times AWS \times \% \text{ sus} \times PS \times ((365-WD)/365) \times (1-CF))/2000$
	PM-10 Emissions	2.48 Tons/Yr	
Dozer Reclaim	Cat D11 Dozer to Trucks	No emission controls	Fugitive
	Emission Factor	8.0 Lb/Hr	WDEQ 2002 Guidance
	Total Throughput	670,000 Tons/Yr	Total Coal Through Storage
	Dozed Throughput	670,000 Tons/Yr	
	Dozer Productivity	750 Tons/Hr	Estimate
	Operating Hrs	893 Hrs	Productivity/Throughput
	TSP Emissions	3.57 Tons/Yr	$E=(EF \times \text{Op Hrs})/2000$
	PM-10 Emissions	1.07 Tons/Yr	30% of TSP
Total South Portal PM₁₀ Emissions		Conversions:	
PM ₁₀ = 4.20 tpy	453.6 g/lb	8760 hr/yr	
0.121 g/sec	2000 lb/ton	3600 sec/hr	

Production rate = 1,270,000 tpy; 600,000 tons to be sent via underground tunnel to East Portal

Emissions from the transport of coal with highway trucks on plant roads (South Portal to Seminole II)

These roadways are reconstructed gravel roads for the purpose of connecting loadout with public roads using Wyoming hauling emission factor, with a tire factor adjustment for highway hauler

Input Data

Plant road silt content (s) = %
 Tire factor =

Mean speed mph
 Grader hrs - Carbon Basin Road 975 hrs
 Grader hrs - Seminole II Road 2,000 hrs

Reference

AP-42 table 13.2.2-1 (gravel-upgraded roadway)
 Assuming each pair is equivalent to a single large truck tire, a truck and pup combination have 14 equivalent tires, for a tire factor of 14/4 = 3.5
 Mine estimate

Conversions:

453.6 g/lb 8760 hr/yr
 2000 lb/ton 3600 s/hr

CARBON BASIN COAL TRANSPORT ROAD

Emission Factor 11.57 lb/VMT
 Number of Wet Days
 Truck Capacity 70 tons
 Truck Speed 40 mph
 Surface Silt Content 5.1 %
 Tire Correction Factor 3.5
 Percent Suspended (%)
 Control Factor (%)
 Control Method Water/Chemicals

Coal Hauled 0.670 MMtpy
 Vehicle Miles Traveled 57,429 VMT
 RT Haul Distance 6.0 miles
PM-10 Emissions (tpy) 39.87

SEMINOLE II COAL TRANSPORT ROAD

Emission Factor 11.57 lb/VMT
 Number of Wet Days
 Truck Capacity 70 tons
 Truck Speed 40 mph
 Surface Silt Content 5.1 %
 Tire Correction Factor 3.5
 Percent Suspended (%)
 Control Factor (%)
 Control Method Water/Chemicals

Coal Hauled 0.670 MMtpy
 Vehicle Miles Traveled 38,286 VMT
 RT Haul Distance 4.0 miles
PM-10 Emissions (tpy) 26.578

CARBON BASIN TRANSPORT ROAD REPAIR

Emission Factor 32 lb/hr
 Number of Wet Days 100
 Control Factor (%)
 Control Method Water
 Grader Hours/Year 975
PM-10 Emissions (tpy) 1.70

SEMINOLE II TRANSPORT ROAD REPAIR

Emission Factor 32 lb/hr
 Number of Wet Days 100
 Control Factor (%)
 Control Method Water
 Grader Hours/Year 2,000
PM-10 Emissions (tpy) 3.48

CARBON BASIN TRANSPORT ROAD EMISSIONS

TOTALS	PM10	TSP
tpy	41.6	138.6
g/s	1.2	4.0

SEMINOLE II TRANSPORT ROAD EMISSIONS

TOTALS	PM10	TSP
tpy	30.1	100.2
g/s	0.9	2.9

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Mine - East Portal, Point Source Emissions
Point Source Emissions**

Production Rates are based on the 2007 Mine Plan Revisions

Activity at East Portal: bring coal out from underground mine; material handling, screening, send to gasifier (following Plant startup in Year 4). During Development Years 1-3, coal will be stockpiled; at start of Plant operations, coal will be directed to gasifier.

Year 3

Production rate = 300,000 tpy; to "run of mine" stockpiles (no coal to plant gasifiers)
300,000 tpy; to emergency (bankers) stockpile (no coal to plant gasifiers)

Material Handling Emissions (coal):		
$PM_{10} = k (0.032) ((U/5)^{1.3} / (M/2)^{1.4})$	<i>AP-42, Section 13.2.4 Aggregate handling factors</i>	
$k = 0.35$	<i>AP-42, Section 13.2.4 Aggregate handling factors</i>	
$U = 14$ mph	<i>Seminole II Measurement</i>	
$M = 6.9$ %	<i>AP-42 Table 13.2.4-1, Western Sfc Coal Mining, median</i>	
$PM_{10} = 8E-04$ lb/ton		
Conveying by belt from conveyor C1 to C2 (material transfer) Controlled by fogger		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.023$ tpy		
Conveying by belt from conveyor C2 to C3 (material transfer) Controlled by fogger		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.02$ tpy		
Conveying by belt from conveyor C3 to C4 (material transfer) Controlled by fogger		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.01$ tpy		
Conveying by belt from reclaim conveyor C5 to C6 (material transfer) Controlled by fogger		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.01$ tpy		
Conveying by belt from conveyor C6 to Screener (material transfer) Controlled by fogger		
<i>Note: Conveyor C6 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.01$ tpy		
Conveying by belt from Screener to conveyor C7 (material transfer) Controlled by fogger		
<i>Note: Conveyor C7 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.01$ tpy		
Conveying by belt from conveyor C7 to C8 (material transfer) Controlled by fogger		
<i>Note: Conveyors C7, C8, & C9 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.01$ tpy		
Conveying by belt from hopper to conveyor C10 material transfer) Controlled by fogger		
<i>Note: Conveyor C10 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%	<i>AP-42, Section 13.2.4.4</i>	
$PM_{10} = 0.01$ tpy		
Total East Portal Point Source PM_{10} Emissions		
$PM_{10} = 0.10$ tpy	Conversions:	
0.003 g/sec	453.6 g/lb	8760 hr/yr
	2000 lb/ton	3600 sec/hr

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
 Saddleback Hills Mine, East Portal Fugitive Emissions
 Fugitive Emission Calculations
 (BACT Option: In-Pit Stacking Tubes)

Emissions starting in Year 3: 300,000 tons to "run of mine" stockpiles
 300,000 tons to emergency (bankers) stockpile

Emission Source	Description	Control	Additional Information
Dozer Reclaim	Cat D11 Dozer	None	
	Emission Factor	8.0 Lb/Hr	WDEQ 2002 Guidance
	Total Throughput	0 Tons/Yr	No dozer reclaim in Year 3
	Dozed Throughput	0 Tons/Yr	
	Dozer Productivity	750 Tons/Hr	Estimate for 300,000 Ton Pile
	Operating Hrs	0 Hrs	Productivity/Throughput
	TSP Emissions	0.00 Tons/Yr	$E=(EF \times Op \text{ Hrs})/2000$
	PM-10 Emissions	0.00 Tons/Yr	30% of TSP
Coal Stacker	Coal Dumping to Stockpile	Stacking Tubes	
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	50.00%	Estimated
	Material Dumped	600,000 Tons/Yr	Total Coal Through Storage
	TSP Emissions	1.91 Tons/Yr	$E=(EF \times \% \text{ sus} \times MD/2000) \times (1-CF)$
	PM-10 Emissions	0.57 Tons/Yr	30% of TSP
Coal Reclaim	Vibratory & Pile Activator Feeder	Passive Control	
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	100.00%	Estimated
	Material Reclaimed	300,000 Tons/Yr	Coal directed on to Emergency Pile
	TSP Emissions	0.00 Tons/Yr	$E=(EF \times \% \text{ sus} \times MR/2000) \times (1-CF)$
	PM-10 Emissions	0.00 Tons/Yr	30% of TSP
Coal Stockpile	Wind Erosion on Stockpiles	Water	
	Emission Factor	1.2 Lb/Acre/Hr	WDEQ Emission Factor
	Pile Size	2.0 Acres	Estimated
	Fraction Suspended	0.75	WDEQ Emission Factor
	Hours	8,760 Hours	Total Annual
	Ave. Wind Speed	5.03 meters/Sec	Adjusted for in-pit
	Wet Days	60	Seminole Mine 5-Year Average
	Control Factor	0.00%	
	TSP Emissions	33.10 Tons/Yr	$E=(EF \times AWS \times \% \text{ sus} \times PS \times ((365-WD)/365) \times (1-CF))/2000$
	PM-10 Emissions	9.93 Tons/Yr	
TOTAL PM-10 EMISSIONS		10.5 Tons/Yr	

Saddleback Hills Mine – Emission Calculations

Year Four

**Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Saddleback Hills Mine - East Portal, Point Source Emissions
Point Source Emissions**

Production Rates are based on the 2007 Mine Plan Revisions

Activity at East Portal: bring coal out from underground mine; material handling, screening, send to gasifier (following Plant startup in Year 4). During Development Years 1-3, coal will be stockpiled; at start of Plant operations, coal will be directed to gasifier.

Year 4

Production rate = 3,250,000 tpy

Material Handling Emissions (coal):		
$PM_{10} = k(.0032) ((U/5)^{1.3} / (M/2)^{1.4})$		AP-42, Section 13.2.4 Aggregate handling factors
k = 0.35		AP-42, Section 13.2.4 Aggregate handling factors
U = 14 mph		Seminole II Measurement
M = 6.9 %		AP-42 Table 13.2.4-1, Western Sfc Coal Mining, median
$PM_{10} = 8E-04 \text{ lb/ton}$		
Conveying by belt from conveyor C1 to C2 (material transfer)		Controlled by fogger
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.123 \text{ tpy}$		
Conveying by belt from conveyor C2 to C3 (material transfer)		Controlled by fogger
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.12 \text{ tpy}$		
Conveying by belt from conveyor C3 to C4 (material transfer)		Controlled by fogger
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.12 \text{ tpy}$		
Conveying by belt from reclaim conveyor C5 to C6 (material transfer)		Controlled by fogger
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.12 \text{ tpy}$		
Conveying by belt from conveyor C6 to Screener (material transfer)		Controlled by fogger
<i>Note: Conveyor C6 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.12 \text{ tpy}$		
Conveying by belt from Screener to conveyor C7 (material transfer)		Controlled by fogger
<i>Note: Conveyor C7 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.12 \text{ tpy}$		
Conveying by belt from conveyor C7 to C9 (material transfer)		Controlled by fogger
<i>Note: Conveyors C7, C8, & C9 will be 3/4 covered, rather than completely enclosed.</i>		
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.12 \text{ tpy}$		
Conveying by belt from hopper to conveyor C10 material transfer)		Controlled by fogger
<i>Note: Conveyor C10 will be 3/4 covered, rather than completely enclosed.</i>		
<i>Assume only 1.2 Mmtpy directed from emergency stockpile to reclaim hopper</i>		
Fogger control value = 90%		AP-42, Section 13.2.4.4
$PM_{10} = 0.05 \text{ tpy}$		
Total East Portal Point Source PM_{10} Emissions		Conversions:
$PM_{10} = 0.86 \text{ tpy}$		453.6 g/lb 8760 hr/yr
0.025 g/sec		2000 lb/ton 3600 sec/hr

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
 Saddleback Hills Mine, East Portal Fugitive Emissions
 Fugitive Emission Calculations
 (BACT Option: In-Pit Stacking Tubes)

Emissions starting in Year 4

All coal through processing equipment to IGL Plant gasifiers

Emission Source	Description	Control	Additional Information
Dozer Reclaim	Cat D11 Dozer	None	
	Emission Factor	8.0 Lb/Hr	WDEQ 2002 Guidance
	Total Throughput	3,250,000 Tons/Yr	Total Coal Through Storage
	Dozed Throughput	1,500,000 Tons/Yr	Portion to Dead Storage
	Dozer Productivity	750 Tons/Hr	Estimate for 300,000 Ton Pile
	Operating Hrs	2,000 Hrs	Productivity/Throughput
	TSP Emissions	8.00 Tons/Yr	$E=(EF \times Op \text{ Hrs})/2000$
	PM-10 Emissions	2.40 Tons/Yr	30% of TSP
Coal Stacker	Coal Dumping to Stockpile	Stacking Tubes	
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	50.00%	Estimated
	Material Dumped	3,250,000 Tons/Yr	Total Coal Through Storage
	TSP Emissions	10.36 Tons/Yr	$E=(EF \times \% \text{ sus} \times MD/2000) \times (1-CF)$
	PM-10 Emissions	3.11 Tons/Yr	30% of TSP
Coal Reclaim	Vibratory & Pile Activator Feeder	Passive Control	
	Emission Factor	0.017 Lb/Ton	WDEQ Emission Factor
	% Suspended	0.75	WDEQ Emission Factor
	Control Factor	100.00%	Estimated
	Material Reclaimed	3,250,000 Tons/Yr	Total Coal Through Storage
	TSP Emissions	0.00 Tons/Yr	$E=(EF \times \% \text{ sus} \times MR/2000) \times (1-CF)$
PM-10 Emissions	0.00 Tons/Yr	30% of TSP	
Coal Stockpile	Wind Erosion on Stockpiles	Water	
	Emission Factor	1.2 Lb/Acre/Hr	WDEQ Emission Factor
	Pile Size	11.0 Acres	Calculated from Pile Size
	Fraction Suspended	0.75	WDEQ Emission Factor
	Hours	8,760 Hours	Total Annual
	Ave. Wind Speed	5.03 meters/Sec	Adjusted for in-pit
	Wet Days	60	Seminole Mine 5-Year Average
	Control Factor	0.00%	
	TSP Emissions	182.40 Tons/Yr	$E=(EF \times AWS \times \% \text{ sus} \times PS \times ((365-WD)/365) \times (1-CF))/2000$
	PM-10 Emissions	54.72 Tons/Yr	
TOTAL PM-10 EMISSIONS	60.2 Tons/Yr		

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Equipment Leaks Emission Summary

Process Stream	Service Type	Controlled Emissions		Uncontrolled Emissions	
		SOCMI Factors		SOCMI Factors	
		VOC Emissions (ton/yr)	HAP Emissions (ton/yr)	VOC Emissions (ton/yr)	HAP Emissions (ton/yr)
Acid Gas	Gas	0.09	0.09	0.12	0.12
Flare KO Drum Drainage	Gas	4.99	1.61	6.70	2.16
Gasifier Vent	Gas	0.16	0.16	0.22	0.22
Gasoline (Gas)	Gas	9.87	3.18	12.38	3.99
Gasoline (Light Liquid)	Light Liquid	17.12	5.52	36.22	11.67
Gasoline (Heavy Liquid)	Heavy Liquid	0.26	0.09	0.26	0.09
LPG	Light Liquid	1.12	0.00	2.21	0.00
Methanol Gas	Gas	1.04	1.04	1.28	1.28
Methanol Pure Liquid	Light Liquid	0.65	0.65	1.44	1.44
Methanol Product (MeOH 1)	Light Liquid	7.86	7.85	14.90	14.86
Methanol Product (MeOH 2)	Light Liquid	0.23	0.23	0.54	0.54
Methanol Product (MeOH 3)	Light Liquid	0.23	0.23	0.54	0.54
Methanol Product (MeOH 5)	Gas	0.40	0.40	0.50	0.50
Mixed Fuel Gas	Gas	0.52	0.02	1.77	0.06
MTG Fuel Gas	Gas	4.42	0.05	5.44	0.06
Propylene	Gas	22.35	0.00	24.36	0.00
Total		71.32	21.10	108.86	37.52

Individual HAPs	Controlled Emissions		Uncontrolled Emissions	
	SOCMI Factors		SOCMI Factors	
	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
Carbonyl Sulfide (COS)	0.06	0.26	0.08	0.35
Methanol (MeOH)	2.37	10.40	4.39	19.22
C6 - C10 Aromatics (Assumed to be Benzene)	2.38	10.44	4.10	17.96
Total	4.82	21.10	8.57	37.52