Page Change History
MBFP PSD Permit Application Dated December 31, 2007

Page Numbers	Revision Date	Action	Description
	2/12/08	Superseded	Updated Table of Contents, Acronyms
(1-1) 1-2	2/12/08	Superseded	Updated emissions in Table 1.1
1-7 (1-8)	2/12/08	Superseded	Updated emissions in Table 1.2
2-9 (2-10)	2/12/08	Superseded	Added sentence (bottom of page) about heating CO2 vent stream
3-3 to 3-10	2/12/08	Superseded	Revised emissions and emission-related descriptions to address operating hour and fuel simplifications requested by WDEQ *
4-7 (4-8)	1/18/08	Superseded	Revised $/ton NOx removed based on revised emissions. (Last two sentences of 1st paragraph)
5-3 to 5-10	2/12/08	Superseded	Added discussions of: • --New 40 CFR Part 60, Subpart JJJJ regulations • --Wyoming Chapter 6, Section 5 permitting requirements Revised discussion of Subpart DDDDD NESHAP
6-1 to 6-48	2/12/08	Superseded	Revised chapter to reflect new AERMOD near field modeling results and incorporated relevant portions from Appendix J
7-1 (7-2)	1/18/08	Superseded	Removed first and last sentence of first paragraph after Note. Text removed was: *MBFP is proposing to construct a 13,000 barrel per day (BPD) Industrial Gasification & Liquefaction Plant near Medicine Bow, Wyoming.* *The proposed project is scheduled to start construction in the spring of 2008 with the construction being complete by December 2010.*
Appendix B	2/12/08	Superseded	Emission revisions requested by WDEQ * and page numbering changes
Appendix F	1/4/08	Superseded	Updated coal storage BACT analysis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Appendix I	2/12/08	Superseded	Revised to discuss far field modeling only (since near field modeling has been re-run)
Appendix J	2/12/08	Superseded	Moved and revised near field modeling discussions to Chapter 6; far field modeling description remains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.

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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
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_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HGT	Heavy gasoline treatment

Acronyms

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
$\mu g/m^3$	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
MPFP	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
NCDC	National Climate Data Center

Acronyms

neg.	Negligible
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NH_4NO_3	Ammonium nitrate
$(NH_4)_2SO_4$	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
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
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SO_x	Sulfur oxides

Acronyms

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

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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 3.2 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 (CO_2)
- 712 TPD of coarse slag

In addition to the salable 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 [NO_2]), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter with a diameter of less than 10 microns (PM_{10}). 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	194.93

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.

Table 1.2 – Annual HAP Emissions (tpy)

Pollutant	Emissions (tpy)
Acetaldehyde	0.38
Acrolein	0.06
Benzene	11.08
Carbonyl Sulfide	0.26
Ethyl Benzene	0.34
Formaldehyde	0.71
Hexane	1.29
Methanol	12.79
Naphthalene	0.01
PAH	0.02
Propylene Oxide	0.28
Toluene	1.81
Xylene	0.77
Other HAPs*	0.01
Total HAPs	**29.80**

*Other individual HAPs are less than 0.01 tpy each.

1.4 STANDARD INDUSTRIAL CLASSIFICATION

Two Standard Industrial Classification (SIC) Codes describe the activities associated with the MBFP Facility. These include:

1. 1222 Bituminous Coal Underground Mining
2. 1311 Crude Petroleum and Natural Gas (production of gas and hydrocarbon liquids through gasification)

Because the primary purpose, and source of revenue of the facility is to produce gasoline fuel, the main SIC code will be 1311.

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2.2.6.2 MTG Water Treatment Unit

The MTG water is processed to remove most organics and oxygenates so that it will meet GE specifications for process water recycle to the gasification unit.

The water from the MTG Unit is heated against hot stripped water in the Feed/Product Exchanger before entering the MTG Water Stripper. There, most of the oxygenates and any residual hydrocarbons are driven overhead as vapor. The stripper overhead is condensed by the air-cooled Stripper Overhead Condenser and the condensate is recovered in the Receiver. LP steam is used to drive the Stripper Reboiler. The aqueous stripper condensate, containing most of the oxygenates, is pumped from to the Power Block where it will be vaporized into one of the power plant fuel streams. Any insoluble organics are decanted in the Receiver and pumped to the slops system. Any trace non-condensables are sent to flare.

Because acetic acid and any heavier acids cannot be completely stripped from the water, provision is made for caustic injection into the stripper sump to neutralize the acids to ensure that the pH is above 5.5. The stripped, neutralized water from the bottom of the stripper is pumped by the Stripper Bottoms Pump, cooled in the Stripper Overhead Condenser against the feed water, and routed to one of the Gasification Units.

2.2.6.3 LPG Processing Unit

The MTG Process produces a significant LPG byproduct stream consisting of approximately 60 percent olefin and 40 percent paraffin materials. LPG average production is expected to be 27,171 lb/hr, which is approximately 3,380 BPD.

In the Plant's geographic area, LPG has no significant market value. Therefore, LPG will be used as in-plant fuel or a blending stock for RVP control. The RVP pressure specification changes month to month. Any LPG not used for RVP control will be used as fuel and can provide approximately 500 MMBtu/hr to the plant in summer. LPG fuel usage will reduce the quantity of natural gas or syngas used by the Plant.

2.3 CO_2 RECOVERY (2200) AND PRODUCTION

Under normal operations, a CO_2-rich stream exits the SELEXOL® Unit. At this point in the process, the CO_2 contains less than 10 parts per million (ppm) total sulfur. The CO_2 flows into the CO_2 Recovery Unit, where it is compressed in one of three parallel four-stage centrifugal compressor trains and dried in a drying unit installed upstream of the third stage compressor suction. Some of the CO_2 is then refrigerated to provide liquid coolant to the Methanol Synthesis and SELEXOL® Units. The remaining CO_2 is ready for sale.

During startup, shutdown, and malfunction (SSM) events at the site, the CO_2 exiting the SELEXOL® Unit may be vented either because the CO_2 does not meet downstream specifications or because the site does not have sufficient power to start the CO_2 compression trains. This venting will occur through the CO_2 Vent Stack until the gas meets specifications and the compressors have been started, at which point no further emissions will occur from this stack. When venting occurs, the vent stream will be heated to 75°F by heat exchangers using steam from the existing processes (no new fired heater is required).

2.4 SULFUR RECOVERY (3100) AND PRODUCTION

In the Sulfur Recovery Area, the H_2S and COS in the acid gas from the SELEXOL® Unit is converted to elemental sulfur. After recovery of the sulfur, the non-sulfur portions of the Claus gas are treated to remove residual sulfur species.

The acid gas feed to the Sulfur Recovery Unit (SRU) is first washed with stripped sour water. The washed acid gas is then injected into a reaction furnace, where it is partially combusted with oxygen from the Air Separation Unit. The combustion products, which include sulfur, H_2S, SO_2, and CO_2, are cooled in the waste heat boiler to produce MP steam, and then further cooled in a condenser, where elemental sulfur is condensed.

Since the reaction of H_2S and SO_2 to produce sulfur is limited by equilibrium, the vapors from the first sulfur condenser are reheated against MP steam and reacted to form more sulfur over a special catalyst. These reaction products are once again cooled to condense more sulfur. To maximize the conversion of the sulfur species to elemental sulfur, two more subsequent stages of reheat, reaction and sulfur condensation are included. This is a three-stage Claus process, and about 42 TPD of sulfur will be produced and sold.

The raw sulfur recovered from the condensers flows as a liquid to a below-ground concrete pit. Since the raw sulfur contains dissolved H_2S and other volatile sulfur species, a sulfur degassing system, including transfer pump, reaction vessel, and ejector is used to remove the volatiles. The purified sulfur is then pumped to liquid sulfur storage before being shipped as a liquid to the customer.

The unconverted gas from the last sulfur conversion stage (SRU tail gas) still contains about 5% of the sulfur in the feed acid gas, mostly COS and CS_2 that are difficult to convert to sulfur. To remove these sulfur species, the SRU tail gas passes through a hydrogenation reactor that reduces them to H_2S. The reducing gas (hydrogen and CO) is produced by partially combusting fuel gas in the Reducing Gas Generator. The effluent from the reducing gas generator is cooled by generating LP steam, and then washed with water before proceeding to tail gas treatment.

The SRU tail gas is compressed and injected at the inlet of the SELEXOL H_2S Stripper where it is combined with the SELEXOL H_2S flash gas. During normal operation, the SRU tail gas will be recycled back to the SELEXOL® Unit. However, SRU tail gas will be routed to one of the flares in the event of a SELEXOL® or Claus unit upset. There are no continuous or intermittent purge gas streams from the SELEXOL® Unit.

When tail gas from the Claus units is routed to the SELEXOL® Unit, there are no vapor emissions to atmosphere from the SELEXOL® Unit. The following three vapor streams originate in the SELEXOL® Unit and flow to other plant areas:

- CO_2 product stream — The CO_2 product stream is compressed and sent to a pipeline customer. In an emergency or shutdown this stream may be vented; however, the stream is vented from the CO_2 recovery area, not from the SELEXOL® Unit.
- Claus gas stream — The Claus Gas is reacted to produce elemental sulfur, with any residual gas recycled to the SELEXOL® Unit. In an emergency or shutdown situation, the stack gas is vented from the sulfur plant area, not from the SELEXOL® Unit.
- Treated syngas — The treated syngas stream flows to the methanol synthesis area.

Table 3.2 – Emission Units and Fugitive Sources

Description	Identification	Size	Use
Normally Operating Equipment and Fugitive Sources			
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	CS	N/A	Coal feedstock storage
SSM Equipment			
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.

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	8,760	---	---	---	---	60.18
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**	**194.93**

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	8760	---	---	---	---	60.18
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**	**195.13**

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.

Table 3.6 – Criteria Pollutant Emissions Resulting from Malfunctions and Other Events

Source ID	Description	Operating Hours [1]	Potential Emissions (tons)				
			NO_x	CO	VOC	SO_2	PM_{10}
CO_2 VS	CO_2 Vent Stack	50	---	83.97	0.23	---	---
FL-1	HP Flare	40 [2]	7.83	64.99	0.12	150.16	---
FL-2	LP Flare	8 [2]	0.01	0.00	0.00	14.40	---
GP-1	Gasifier Preheater	500 [3]	0.26	0.43	0.03	0.00	0.04

1. The hours shown are estimates of annual operating hours due to malfunctions.
2. Each flare is expected to combust vented gases for the number of hours shown; pilot operation will occur throughout the year.
3. During a non-cold startup year, only one of the five Gasifier Preheaters is expected to operate for up to 500 hours.

3.2.5 Emissions of PSD-Regulated Pollutants

The MTG process requires the syngas to be relatively pure in order to prevent the poisoning of the methanol synthesis catalyst. The clean syngas that is used in the MTG process is the same syngas used as fuel throughout the Plant. This cleaning is achieved by running the raw syngas from the gasifiers through a wet scrubber, which cools the raw gas and removes any particulates that are entrained in the gas stream. The raw (sour) gas then flows through the mercury vapor guard beds (mercury removal) and then through the Low Temperature Gas Cleanup process (SELEXOL® technology) where the raw syngas is further cleaned and where NH_3, H_2S, and COS are removed from the raw syngas. After the SELEXOL® process, the gas flows through a final sulfur guard bed to ensure the highest level of sulfur removal (<0.1 ppmv total sulfur).

Trace amounts of some contaminants may be emitted in very small quantities. During the feasibility study, certain trace contaminants were estimated and are shown below.

Contaminant	Concentration	Potential to Emit
Halogens (Cl_2 and F)	<0.01 ppmv	0.001 tpy
Sulfur as H_2S	<0.09 ppmv	0.009 tpy

At least 90 percent of the lead in the tail gas will be removed by the activated carbon beds that remove mercury. Based on 3 million tons (8,000 TPD) of coal gasified and lead content within the coal averaging 1.93 ppmw (determined by testing), total lead exiting the gasifiers would be 5.79 tpy. Based on a conservative estimate of 90 percent removal, lead emissions from the facility are estimated to be 0.579 tpy.

3.2.6 Source-Specific Calculation Methods

The following sections provide additional detail about calculation methods used to estimate emissions from certain types of sources.

3.2.6.1 Combustion Source Methods

Most Plant combustion sources can be fueled with either a fuel gas mixture or with natural gas. The fuel gas mixture includes fuel gas and LPG that are produced within the Plant and supplementary natural gas. Mixing of the fuel gas components occurs prior to the combustion chamber of the source. The fuel gas mixture will vary between seasons and due to catalyst efficiency. Methanol production is high when the catalyst is at its beginning of life (BOL), compared to end of life (EOL). Typical molar fractions of fuel gas mixture components are shown in Table 3.7.

Table 3.7 — Typical Fuel Gas Mixture Composition[1]

Fuel Component	Winter BOL	Winter EOL	Summer BOL	Summer EOL
Natural Gas	70.30%	63.01%	58.69%	50.82%
LPG	2.99%	2.75%	7.97%	7.19%
MTG Fuel Gas	4.76%	4.37%	5.94%	5.36%
Davy PSA Purge	16.87%	25.19%	21.05%	30.89%
Davy Fuel Gas 1	2.44%	2.13%	3.05%	2.61%
Davy Fuel Gas 2	2.65%	2.55%	3.30%	3.13%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**

1. Molar percentages are given. Based on three turbines operating.

Since the fuel gas mixture is plant-specific, emission factors are not available for the fuel gas mixture. However, since the fuel has a significant methane component and also includes large quantities of C3 and C4 fuels, use of natural gas emission factors is a reasonable approximation. Consequently, emission calculations for non-diesel combustion sources are based on natural gas emission factors. Even so, the differences in heating values between natural gas and the fuel gas mixture causes emissions to differ.

In some circumstances, combustion of the fuel gas mixture is impractical. This is particularly true during initial startup when the plant has not yet produced sufficient quantities of syngas and LPG. Detailed emission calculation spreadsheets (Appendix B) for the combustion turbines, auxiliary boiler, and heaters clearly indicate the number of hours during which natural gas or the fuel gas mixture is being fired. (KAW question – any revision needed here? The boiler and heater sheets make mention of it, but is it enough to say it's 'clearly' indicated?)

3.2.6.2 Storage Tanks

Storage tank emissions were calculated using the EPA TANKS Program, version 4.09.d, based on use of internal floating roof tanks. TANKS reports for each type of tank having significant emissions are included in Appendix B.

The RVP of product gasoline stored at the site will vary depending on the time of year. Month-to-month vapor pressure variability was accounted for in the calculations. Tanks containing no volatile organic components and those with insignificant emissions are listed on the Tanks detailed calculation page within Appendix B.

3.2.6.3 Equipment Leaks

Equipment leak estimates were calculated using the average emission factor approach described in EPA's "Protocol for Equipment Leak Emission Estimates" (EPA-453/R-95-017). EPA-approved Synthetic Organic Chemical Manufacturing Industry (SOCMI) factors were used for the calculations. Although use of the Refinery emission factors was considered, use of the Refinery factors was deemed inappropriate for the following reasons.

- The Plant process is a chemical synthesis process rather than a refinery process.
- SOCMI factors are recommended for use in all industries, except refineries.
- Even within refineries, SOCMI factors are recommended for chemical processes, such as production of methyl tertiary butyl ether (MTBE).
- The refinery emission factor equation usage guidelines specifically disallow corrections for methane concentrations exceeding 10 wt% and some process streams at the Plant will contain more than 10 wt% methane.

Process streams within the Plant were grouped according to composition and service type (gas, light liquid, heavy liquid) and the number of potential equipment leak components was estimated for each process stream group. All streams were assumed to contain fluids for 8,760 hr/yr. Within Appendix B, detailed equipment leak calculations show controlled and uncontrolled emissions. Controlled emissions were calculated using control effectiveness factors for valves in gas or light liquid service and pump seals in light liquid service. The control effectiveness factors are based on implementation of a monthly Leak Detection and Repair (LDAR) program and assume a leak definition of 10,000 ppm. As discussed in the BACT analysis, the Plant will implement an LDAR program.

3.2.6.4 Flares

Flaring emission calculations are based on procedures included in "TCEQ Guidance Document for Flares and Vapor Oxidizers" (RG-109, October 2000). This document provides emission factors for NO_x and CO and advises use of 98% destruction efficiency for VOCs / HAPs and H_2S.

The HP and LP Flares will be operated with continuous pilots. Consequently, normal operations include combustion emissions based on the design heat input for each flare and assume natural gas firing. Emissions from normal operation at both flares represent pilot gas combustion only, because no process streams will be routinely directed to either flare.

Emissions from large malfunction events were estimated for the HP and LP Flares, due to the possible significant nature of a malfunction event affecting these flares. Malfunction-related emissions from the HP Flare are based on directing all syngas to the flare, which is the largest stream, by volume, that could potentially be directed to the HP Flare. Malfunction-related events affecting the LP Flare for a potential worst-case (high flow rate, high H_2S content) vent stream that could be directed to the LP Flare.

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During most startup operations, the combustion turbines will be fired with fuel gas mixture. However, for the initial startup and some cold startup scenarios, natural gas will be used to fire the combustion turbines. SCR is not technically feasible during the initial startup operations due to the low temperature where the SCR would be applied. Whether firing natural gas or the fuel gas mixture, the SCR will be utilized as soon as the exhaust temperature reaches the operational range of the SCR.

Rank Control Technologies

Low NO_x burners, SCR, and diluent injection are the NO_x control technologies that are technically feasible for the proposed combustion turbines during normal operations when firing either the fuel gas mixture or natural gas.

Evaluate Control Options

The use of low NO_x burners and SCR was identified as the only technically feasible NO_x control technology for the proposed combustion turbines during normal operations. The low NO_x burners are expected to achieve 25 ppm NO_x in turbine exhaust. The use of SCR will further reduce NO_x emissions to 6 ppmvd (at 15% O_2) when firing syngas (fuel gas mixture). The nominal gross output for the 3 x 3 x 1 generator/HRSG/ steam turbine configuration is 400 MW. Therefore, the equivalent potential NO_x emission rate is approximately 0.135 lb/MWh, significantly lower than the applicable NSPS Subpart Da or KKKK limit of 1.0 and 3.6 lb/MWh respectively.

The use of low NO_x burners and diluent injection combined with SCR was identified as the only technically feasible combination of NO_x control technologies for the proposed combustion turbines during natural gas firing operations. These combined technologies will reduce NO_x emissions to 6 ppmvd (at 15% O_2).

With one exception, the proposed NO_x BACT limit of 6 ppmvd (corrected to 15% O_2) is well below emission limits found on the RACT/BACT/LAER Clearinghouse for similar turbines firing either syngas or tail gas. Appendix E provides a summary of emission control determinations for these turbines. For completeness, all RACT/BACT/LAER emission control determinations for process type 15.250 (explained in Appendix E) are included. The most stringent NO_x BACT limit for a combined cycle combustion turbine firing syngas or tail gas is 1.9 ppmvd (corrected to 15% O_2 and based on an annual average) for the Bayport Energy Facility. However, this facility utilizes DLN technology to achieve this level of NO_x emissions. For reasons described above, DLN is not technically feasible for the Plant. The next most stringent NO_x BACT limit is 8 ppmvd (corrected to 15% O_2 and based on a 30-day rolling average) for the Exxon Mobil Shute Creek facility. The Exxon-Mobil facility uses a proprietary mix of gas that includes syngas as one component. All other fueled combustion turbines shown in Appendix E have NO_x emission limits of 15 ppmvd (corrected to 15% O_2) or more.

As the first implementer of SCR technology on this type of turbine/fuel combination, the 6 ppmvd NO_x emission limit reflects a level of control within the accepted range of SCR control efficiencies (70-90 percent control efficiency). Specifically, a reduction from 25 ppmvd to 6 ppmvd is estimated, representing a long-term 76 percent reduction in NO_x from 80 percent SCR performance when the system is new and clean. Technical issues such as pressure loss in

the combustion turbine and ammonia slip argue against expecting the highest level of control efficiency for this innovative installation of SCR.

Moreover, the additional cost of reducing NO_x emissions to below 6 ppm has been estimated, although MBFP believes that achieving NO_x emissions less than 6 ppmvd (corrected to 15% O_2) is a technical feasibility issue rather than a cost issue. Variability in plant-generated fuel could potentially increase NO_x emissions and prevent burner optimization. Consequently, exhaust from the turbines may be somewhat higher than expected. With a 6-ppm NO_x limit, the facility will have some ability to compensate for high NO_x concentrations entering the SCR system by increasing NO_x removal efficiency beyond the 76 percent that would be achieved assuming 25 ppm NO_x concentration in the turbine exhaust. Based on equipment and operating costs provided by SNC Lavalin, the incremental cost of reducing NO_x emissions from 6 ppm to 4 ppm, is estimated to be $2,455/ton removed. This cost estimate is included as Appendix H.

Select NO_x Control Technology

The use of SCR with diluent injection is proposed as BACT for the proposed combustion turbines during normal operations to reduce NO_x emissions to 6 ppm when firing fuel gas mixture. The use of SCR with diluent injection is also proposed for natural gas combustion during start up operations. The proposed BACT NO_x limits are presented below for each combustion turbine.

> Proposed NO_x BACT Limit when burning fuel gas mixture: 6 ppmvd (corrected to 15% O_2)
>
> Proposed NO_x BACT Limit when burning natural gas: 6 ppmvd (corrected to 15% O_2)

The NO_x BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, NO_x emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between fuels. Potential emissions for startup and shutdown operations are provided in the Emissions Inventory and are evaluated as part of the air dispersion modeling analysis. See Section 4.3.5 for more information regarding startup operations.

4.3.2 Sulfur Dioxide BACT Analysis for the Combustion Turbines

The combustion turbines oxidize sulfur compounds in fuel primarily into sulfur dioxide (SO_2). Emissions can be controlled by limiting the fuel sulfur content or by removing SO_2 from the exhaust gas.

Identify Control Technologies

The following SO_2 control technologies were evaluated for the proposed Plant combustion turbines.

Based on 8,000 TPD (333.3 ton/hr) of dry coal feed, the emission limit would be 43.84 lb/hr. Particulate emissions from coal handling will be far less than this due to the fogging system.

Fugitive dust from coal handling and storage at the Mine will be controlled by using a fogging system in order to comply with emission standards for material handling and storage at WAQS&R Chapter 3, §2(f)(ii). The IGL Plant will have about 8 hours of covered onsite storage for coal.

During construction of the Facility and associated portal areas, steps to minimize fugitive dust must be taken [WAQS&R Chapter 3, §2(f)(i)]. MBFP will require construction contractors to use control measures, such as frequent watering and/or chemical stabilization, on an as-needed basis to reduce fugitive dust emissions. In addition, contractors will be instructed to promptly remove mud or dirt that is tracked onto paved roadways [WAQS&R Chapter 3, §2(f)(i)].

5.1.2.2 Section 3 Nitrogen Oxides

The Plant will construct and operate several new gas fired fuel burning sources, such as the combustion turbines, boiler, and heaters. Under WAQS&R Chapter 3, §3(a)(i), NO_x emissions from new gas fired fuel-burning equipment calculated as nitrogen dioxide (NO_2) may not exceed 0.20 lb/MMBtu of heat input.

NO_x emissions (calculated as NO_2) from the fuel-oil burning Firewater Pump engine will be limited to 0.30 lb/MMBtu because it will have a heat input greater than 1.0 MMBtu/hr [WAQS&R Chapter 3, §3].

Internal combustion engines having a heat input of less than 200 MMBtu/hr are exempt from the NO_x emission limits given above.

5.1.2.3 Section 4 Sulfur Oxides

Sulfur oxides (SO_x) emission limits apply only to fuel burning equipment that is fueled with coal or oil. Consequently, the Firewater Pump is the only equipment subject to these standards. The Firewater Pump will be required to meet a 3-hour limit of 0.8 lb/MMBtu and a 30-day average of 0.8 lb/MMBtu [WAQS&R Chapter 3, §4(b)].

5.1.2.4 Section 5 Carbon Monoxide

Wyoming's air quality regulations do not include specific CO emission limits for stationary sources. There is, however, a general duty to prevent any exceedance of CO ambient standards [WAQS&R Chapter 3, §5]. Modeling results provided in Section 6 demonstrate that the Plant will meet this requirement.

5.1.2.5 Section 6 Volatile Organic Compounds

VOC emissions shall be limited through the application of BACT [WAQS&R Chapter 3, §6(b)]. In some cases, WDEQ regulates VOC emissions by mandating use of a flare. When a flare is required to control of VOC emissions from vapor blowdown, emergency relief systems, or VOC emissions generated from storage or processing operations, the flare shall not exceed a 20%

opacity emission standard [WAQS&R Chapter 3, §6(b)]. In addition, the flare must be a smokeless flare and must have either an automatic igniter or a continuous pilot.

5.1.2.6 Section 7 Hydrogen Sulfide

Some Plant process streams contain H_2S and will be subject to WAQS&R Chapter 3, §7. Any exit process gas stream containing H_2S that is discharged to the atmosphere must be vented, incinerated, flared or otherwise disposed of such that ambient SO_2 and H_2S standards are not exceeded. Process streams containing H_2S are treated within the Plant process to remove the sulfur. However, in the event of a malfunction, a stream containing H_2S could be vented to a flare.

5.1.2.7 Section 8 Asbestos Activities

As a new facility, the Plant will minimize use of asbestos during facility construction. Furthermore, facility personnel are unlikely to remove asbestos-containing materials from the premises in the near future. However, activities that disturb asbestos would likely be subject to extensive compliance requirements found in WAQS&R Chapter 3, §8.

5.1.3 Chapter 6 Permitting Requirements

Section 2. Best Available Control Technology (BACT)

Per the WAQS&R, Chapter 6, §2(c)(v), no permit to construct will be issued until it is demonstrated that BACT will be utilized, with consideration of the technical practicability and economic reasonableness of reducing or eliminating the proposed facility's emissions. In accordance with this requirement, and those imposed by the PSD Program discussed below, BACT analyses for all emission sources are presented in Section Four of this application.

Section 3. Operating Permits

Potential emissions from the Plant and Mine exceed the 100-tpy threshold for triggering operating permit requirements under Chapter 6, Section 3. These regulations implement the Title V Operating Permit Program required by federal law. Per the timeline established in the WAQS&R, Chapter 6, §3(c), an application for an operating permit will be submitted within twelve months of facility startup.

Section 4. Prevention of Significant Deterioration

Potential emissions from the Plant and Mine exceed the 100-tpy threshold for triggering PSD permitting. Therefore, extensive provisions within WAQS&R Chapter 6, Section 4 will apply to the facility. This permit application process, associated modeling, and installation and operation of BACT will satisfy PSD compliance requirements applicable to construction and initial operation of the facility. When facility or operational modifications are planned, PSD review may be required.

Section 5. NESHAP Source Permits

Potential emissions from the Plant and Mine exceed the 25-tpy aggregate HAP threshold for triggering major source status under the NESHAP program, and the Plant is subject to several NESHAP standards including the 40 CFR Part 63, Subpart ZZZZ Reciprocating Internal Combustion Engine NESHAP and the Subpart DDDDD Industrial-Commercial-Institutional Steam Generating Unit NESHAP. Consequently, MBFP is also subject to WDEQ's permitting requirements for construction and modification of NESHAP sources, which are codified in WAQS&R, Chapter 6, Section 5. These regulations specify requirements for submitting pre-construction permit applications and providing notifications to the WDEQ, including a notification of compliance status.

This permit application satisfies the preconstruction permitting requirements of WAQS&R, Chapter 6, Section 5. In addition to other information submitted in this application, the following construction and operation schedule information specifically requested in Chapter 6, §5(a)(iii)(A)(II)(5–7) is provided below.

- Expected construction commencement date: As soon as air quality permit is issued.
- Expected construction completion date: July 1, 2012
- Expected initial startup date: July 1, 2012

5.1.4 Chapter 7 Monitoring Regulations

Some emission units at the Plant will be subject to Compliance Assurance Monitoring (CAM) requirements in WAQS&R Chapter 7, Section 3. These regulations are based on the USEPA 40 CFR Part 64 CAM regulations. CAM requirements generally apply to each emission unit that meets all of the following criteria (with some exceptions).

- The emission unit is located at a facility that is subject to the Title V operating permit program.
- The emission unit uses a control device to achieve compliance with an emission limit and whose pre-controlled emission levels exceed major source thresholds under the Title V operating permit program.
- The unit is not subject to a New Source Performance Standard (NSPS) or a National Emissions Standard for Hazardous Air Pollutants (NESHAP) standard that was promulgated after November 15, 1990.

If the facility is subject to CAM, the affected emission units will be subject to additional monitoring, recordkeeping, and reporting requirements. In addition, the facility must prepare a CAM Plan for each affected unit. A thorough CAM applicability review and proposed CAM Plans will be submitted with the initial operating permit application.

5.2 FEDERAL REGULATIONS

The following discussion summarizes federal air quality regulations that are potentially applicable to the Plant. Due to the unique processes used by this facility, it does not fall into an

industry-specific NSPS or NESHAP. However, some equipment at the facility will be subject to NSPS or NESHAP standards.

5.2.1 New Source Performance Standards (NSPS)

Subpart A: NSPS General Provisions

Subpart A identifies a number of monitoring, recordkeeping, and notification requirements that generally apply to all NSPS Subparts. Additionally, Subpart A specifies that performance (source) tests must be conducted within 60 days of achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup. Subpart A will apply in conjunction with any other applicable NSPS Subpart, unless otherwise noted in the specific NSPS.

Subpart Da Electric Utility Steam Generating Unit NSPS

The combustion turbines and HRSGs will not be subject to the Electric Utility Steam Generating Unit NSPS because the facility will not export power for sale. The facility is not an "electric steam generating unit," as defined in §60.41Da, which is the key applicability criteria for 40 CFR Part 60 Subpart Da.

Subpart Db Industrial-Commercial-Institutional Steam Generating Unit NSPS

The Auxiliary Boiler, which has a heat input of 66 MMBtu/hr, will be subject to Subpart Db emission limits for NO_x and PM.

Subpart J Petroleum Refinery NSPS

As mentioned in Section One, the Plant is classified as a Crude Petroleum and Natural Gas facility (1311) that produces gas and hydrocarbon liquids through gasification. The minor or support activity is underground mining of bituminous coal (1222).

Although the facility produces gasoline, it does not do so using a refining process. Therefore, it is not subject to the Petroleum Refinery NSPS (40 CFR Part 60, Subpart J). The Plant does not meet the regulatory definition of a "petroleum refinery" because it does not engage in ". . . producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives [§60.2]."

Subpart Kb Storage Vessels for Petroleum Liquids NSPS

Eleven tanks, listed in Table 5.2, at the Plant are expected to be subject to the petroleum storage vessel NSPS due to their large size and volatile contents. Subpart Kb regulations set tank design and operation requirements, as well and ongoing inspection requirements. The planned IFR tank design will meet Subpart Kb requirements. Plant personnel will comply with tank inspection, repair, and recordkeeping and recording requirements.

Table 5.2 – Subpart Kb Tanks List

Tank Name	Tank	Number of Tanks	Operating Temperature (°F)	Vapor Pressure At Operational Temperature (psia)	Liquid Capacity (Gallons)	Roof Type
Methanol Tanks	*TBD*	2	45	0.96	6,341,984	IFR
Gasoline Product Tanks	*TBD*	8	45	4.14	6,341,984	IFR
Heavy Gasoline Tank[1]	*TBD*	1	45	2.25	4,763,841	IFR

1. "Heavy" gasoline is estimated to have RVP of 3-5 psia.

Subpart Y Coal Preparation Plant NSPS

Under 40 CFR Part 60, Subpart Y, coal transfer, crushing, and drying activities are subject to particulate matter emission limits. Specifically, emissions from coal conveying equipment may no exceed 20 percent opacity. Use of fully covered conveyors and fogging of transfer points at the Plant should maintain compliance with Subpart Y particulate emission limits and opacity standards.

Subpart VV Equipment Leaks in the SOCMI Industry NSPS

The Plant does not meet the definition of a facility that is part of the Synthetic Organic Chemical Manufacturing Industry (SOCMI). Consequently, the Plant is not subject to this regulation.

Subpart IIII Stationary Compression Ignition Internal Combustion Engine NSPS

The diesel Firewater Pump will be subject to the compression ignition (diesel) engine NSPS. Compliance with this regulation is relatively simple for engine owners who purchase an engine that is certified by the engine manufacturer to meet new engine standards. MBFP will likely purchase a 2008 or later model year engine and will comply with this rule.

Subpart JJJJ Stationary Spark Ignition Internal Combustion Engine NSPS

The three Black-Start Generators will be subject to the spark ignition engine NSPS. In addition to purchasing engines that are certified by the engine manufacturer to meet the required new engine standards, MBFP will comply with performance testing, maintenance, and recordkeeping requirements and operate the engines in accordance with good air pollution control practices to minimize emissions. MBFP will conduct initial performance tests and, due to the limited usage of these units, will repeat performance tests every three years.

Subpart KKKK Stationary Combustion Turbines NSPS

The combustion turbines will be subject to NSPS codified in 40 CFR Part 60, Subpart KKKK. Affected units will include the three combustion turbines because they each have a heat input at peak load of more than 10 MMBtu/hr and will commence construction after February 18, 2005 [§60.4305(a)].

The combustion turbines will burn a mixture of fuel gas, LPG, and natural gas. Since more than 50 percent of the mixture will be natural gas, the turbines will be deemed to be firing natural gas [§60.4325]. Therefore, the NO_x emission limit will be based on a new turbine with a heat input of between 50 and 850 MMBtu/hr firing natural gas fuel. The applicable NO_x limit is 25 ppm (corrected to 15 percent oxygen) or 1.2 lb/MWh [40 CFR Part 60, Subpart KKKK, Table 1]. The turbines can meet the SO_2 compliance requirements by burning fuels with potential emissions of less than 0.060 lb SO_2/MMBtu [§60.4330(a)(2)]. Extensive monitoring, recordkeeping, and reporting are required by the rule. Because the combustion turbines will be subject to this recent NSPS, they will not be subject to CAM requirements.

5.2.2 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The Plant will be a major source of HAPs. Consequently, it may be subject to a variety of NESHAP regulations. The following discussion identifies NESHAPs that are potentially applicable to the facility.

Subpart ZZZZ Reciprocating Internal Combustion Engine NESHAP

Subpart ZZZZ within 40 CFR Part 63, will apply to all reciprocating internal combustion engines (RICE) at the Plant that have a site rating of more than 500 brake horsepower. The three Black-Start Generators, each nominally rated at 2,889 horsepower, will be subject to rule. However, many of the compliance requirements within Subpart ZZZZ may not apply to these units, depending on their use. They may qualify as "emergency use RICE" or as "limited use RICE," especially if they are used less than the amount of time assumed for emission estimation purposes in this permit application (250 hr/yr, each).

Subpart DDDDD Industrial-Commercial-Institutional Steam Generating Unit NESHAP

The Industrial-Commercial-Institutional Steam Generating NESHAP (40 CFR Part 63, Subpart DDDDD) is currently being implemented by the WDEQ via provisions in WAQS&R, Chapter 3, §3(b). Although federal implementation of this NESHAP has been vacated by a federal court decision, the WDEQ continues to enforce this NESHAP.

Regulatory requirements depend on the classification of each boiler and process heater at the Plant. Proposed equipment at the Plant will likely be classified as follows.

- New small gaseous fuel equipment: HGT Reactor Charge Heater
- New large gaseous fuel equipment: Auxiliary Boiler, Catalyst Regenerator, and Reactivation Heater

Based on these classifications, the HGT Reactor Charge Heater will be subject only to initial notification requirements. In contrast, the large gaseous fuel equipment will be subject to a CO emission limit of 400 ppmv (dry basis, corrected to 3 percent oxygen). Because each of the large gaseous fuel emission units at the Plant has a maximum heat input rate of less than 100 MMBtu/hr, installation of a continuous emission monitoring system (CEMS) will not be required. MBFP will comply with all applicable Subpart DDDDD notification, performance testing, recordkeeping, and reporting requirements.

5.2.3 Chemical Accident Prevention Provisions

The Chemical Accident Prevention Provisions in 40 CFR Part 68 set forth requirements concerning the prevention of accidental releases. All facilities with extremely hazardous substances have a "general duty" to prevent accidental releases. Consequently, the Plant must design and maintain a safe facility, including taking steps to prevent releases and minimizing the consequences of any releases that do occur.

In addition, a facility that has more than a threshold quantity of a regulated substance listed in §68.130 may be subject to a variety of compliance requirements in Part 68. Guidance on how to determine if a threshold quantity exists and exceptions for certain types of facilities, processes, and materials are provided in §68.115. For example, regulated substances in gasoline need not be considered when determining if a threshold quantity exists in a process. Thus, the gasoline in the MTG process and product storage tanks will not be included in the applicability determination. The proposed methanol tanks also will not be considered in the applicability determination because methanol is not on the list of regulated sources.

With the exception of H_2S, the proposed facility will not store or use any ammonia, chlorine, methyl mercaptan, or other chemicals included as "toxic substances" in §68.130. However, several processes will contain a mixture of H_2S and/or substances listed as "flammable substances" at §68.130 (methane, ethane, propane, etc.) with concentrations high enough to possibly qualify the entire process stream, per §68.115(b)(1) and (2). As a result, this regulation may apply to some processes at the Plant if the process in question (as defined at §68.3) contains more than a threshold quantity of the listed substance. Prior to beginning operation, MBFP will determine whether it is subject to Part 68 regulations and, if necessary, prepare a Risk Management Plan for the Plant.

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6.1 NEAR FIELD MODELING BACKGROUND

To assess likely near field air quality impacts, a dispersion modeling analysis was completed for areas within 10 km (near field) of the proposed facility. The analysis was completed in accordance with a protocol approved by WDEQ (05 March 2007). The air quality dispersion modeling analysis used the USEPA-approved AERMOD suite of programs including AERMOD (version 07026), AERMAP (version 06341) and AERMET (version 06341).

The analysis included:

1 Determination of emission inventory source characteristics;

2 Development of an appropriate receptor grid, beginning at the ambient air boundary, with digital elevation model (DEM) supplied terrain heights calculated using AERMAP;

3 Determination of applicable direction-specific downwash parameters using the Building Profile Input Program (BPIP) PRIME (BPIPPRIME) for the many tanks and other structures associated with the project sources;

4 Processing of local and representative surface and upper air meteorological data to form a five-year model ready data set in AERMET;

5 Modeling of proposed Plant emissions in AERMOD and comparison with threshold levels; and

6 Modeling of project and associated coal mining feedstock operations for comparison with ambient air quality levels.

Details of these steps are provided in following subsections.

Two modeling scenarios were performed: a cumulative NAAQS / WAAQS analysis that evaluates impacts due to sources directly related to the proposed Plant as well as the nearby Elk Mountain Mine operations, and nearby sources included in a WDEQ-supplied emission inventory, and a PSD increment analysis to evaluate impacts due to the proposed Plant and onsite mining.

6.2 DESCRIPTION OF THE PROPOSED PROJECT

6.2.1 Site Location

The 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, Wyoming as shown in Figure 1.1. The UTM coordinate (NAD27) of the center of Section 29 is 390634 meters E and 4624013 meters N. A topographic map of the facility area indicating Section 29 is shown in Figure 1.1. Photographs of the proposed site area are shown in Figure 6.1 and Figure 6.2, depicting the varying terrain.

The proposed project is classified as a 'Fuel Conversion Plant', which is one of the 28 major stationary sources for which the major source PSD threshold is 100 tpy for each criteria pollutant. As shown in Table 1.1 and Table 3.3, the estimated emissions from the facility exceed these levels for NO_x, CO, VOCs, and PM_{10}. Therefore, the project is subject to PSD review.

The project site is located in an area that is designated as attainment for all NAAQS.

Figure 6.1 – Plant Site Area, View from South Side

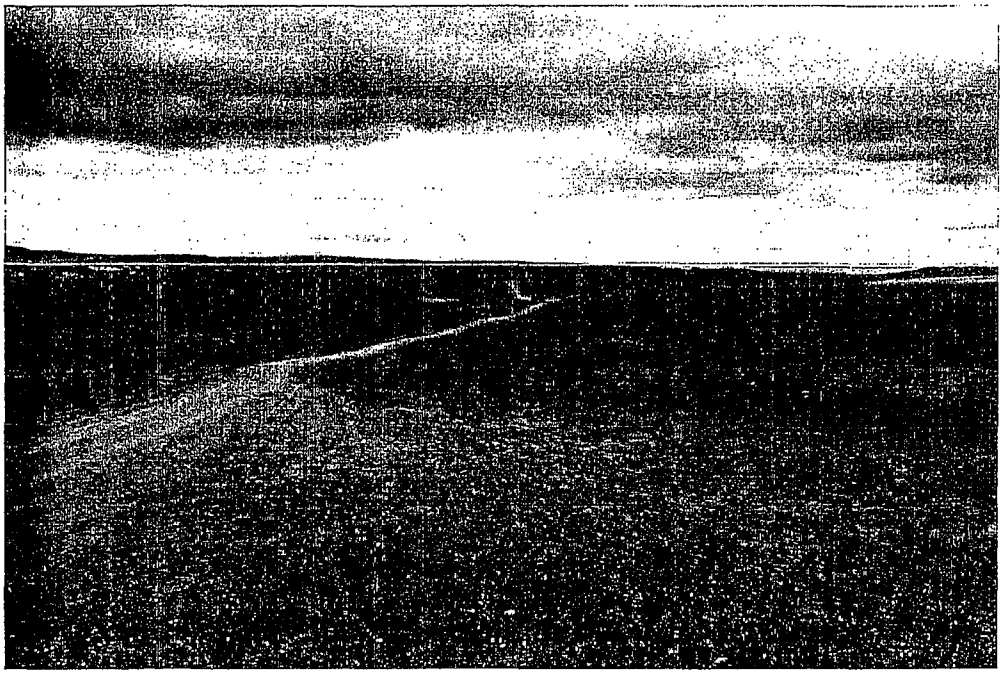


Figure 6.2 – Plant Site Area, View Over Coal Hills Toward Elk Mountain

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, SO_2, and PM_{10} 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	15.216

Specific source model emission rates and input parameters are shown in Table 6.2. Pollutants with short-term averaging periods (CO, SO_2, and PM_{10}) 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, SO_2, and PM_{10} 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 sources included in this nearby inventory have significant emission rates. Table 6.3 details the nearby point sources used for cumulative modeling.

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	0.000764	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	46.0 / 85.0*	1273	20	0.076 / 3.32*	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.

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	-	-

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 in the year 2010 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) PM_{10}, SO_2, 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/PM_{10} 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/m2)			
								NOx	CO	SO2	PM10
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	Area	Mine Area / South Portal	384525.3	4622056.4	2252	12.0	9.3	0.000004	0.0000034	0.00000007	0.000006
MineA_EP	Area	Mine Area / East Portal	389721.0	4623411.5	2134	12.0	9.3	0.000004	0.0000034	0.00000007	0.000006
MineA_S1	Area	Mine Area / Surface Mining (On-Site 2010)	389673.8	4623406.6	2134	12.0	9.3	0.0000137	0.0000115	0.00000023	0.0000134
MineA_S2	Area	Mine Area / Surface Mining (Off-Site 2010)	388228.6	4622113.5	2189	12.0	9.3	0.0000137	0.0000115	0.00000023	0.0000134

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

Figure 6.3 – Plant and Nearby Mining Area Sources

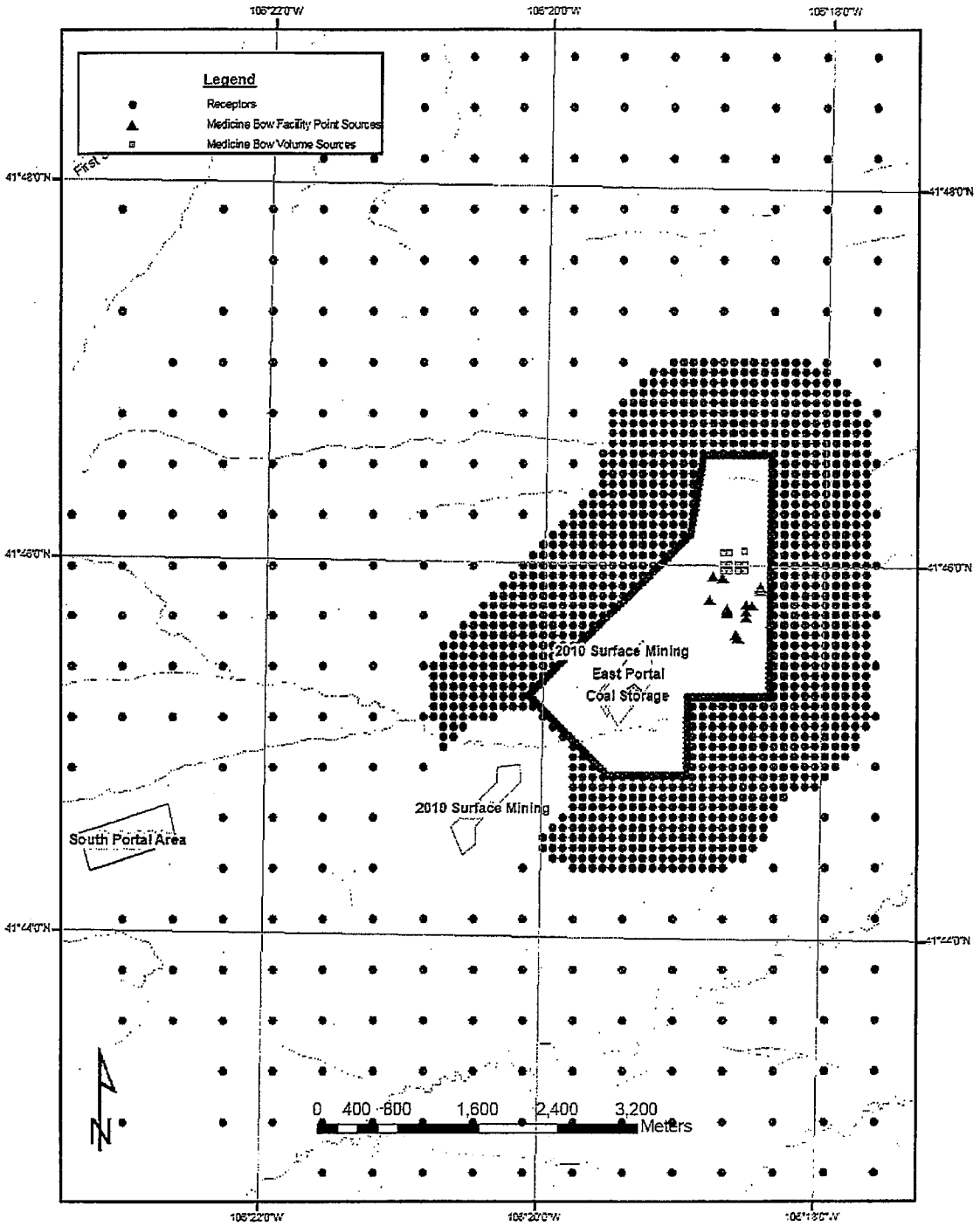
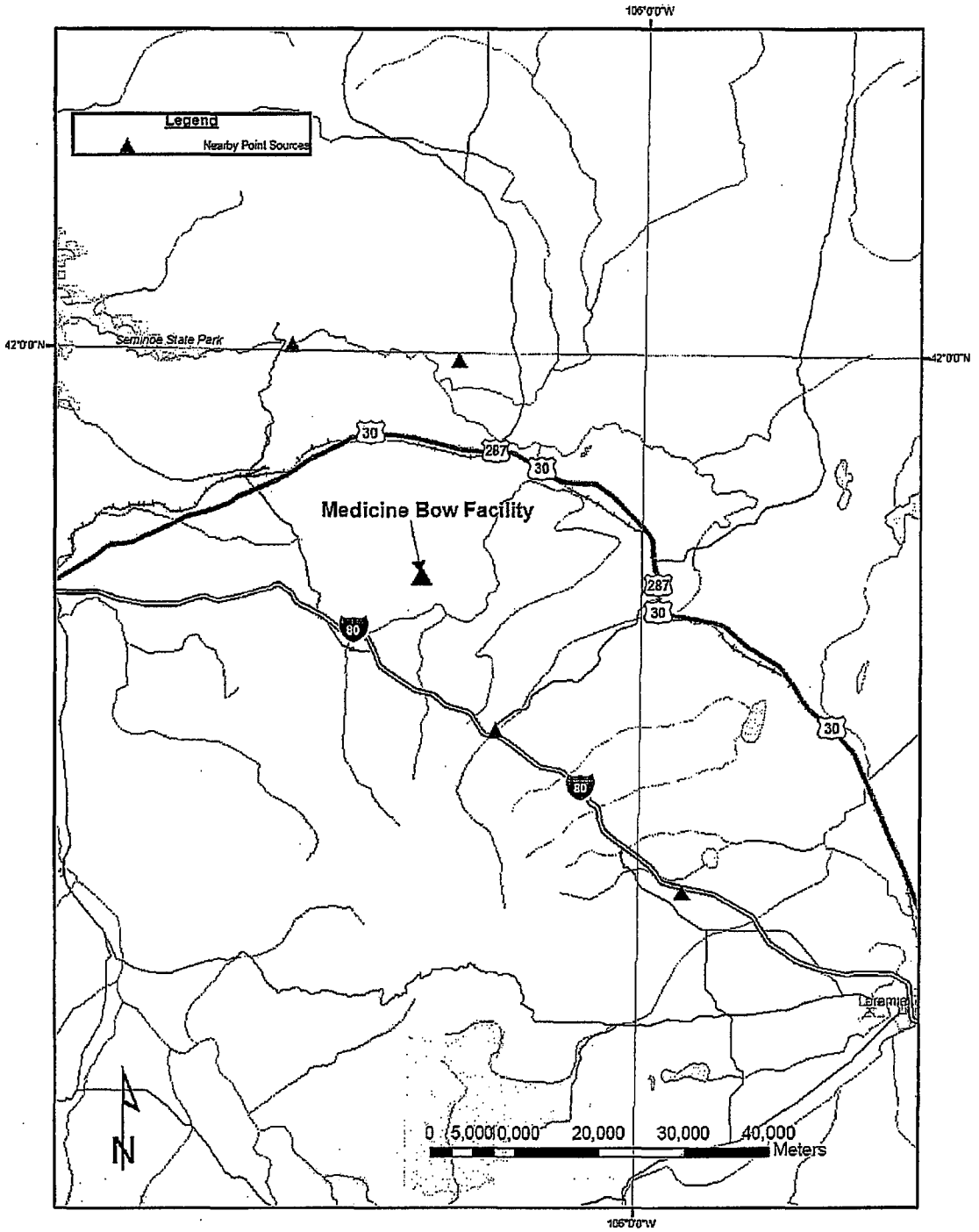


Figure 6.4 – Plant Location Relative to the WDEQ Provided Emission Inventory



6.3 STANDARDS, CRITERIA LEVELS, AND BASIC METHODOLOGY

The results of the air quality dispersion modeling analysis are compared with various ambient levels to assess potential impacts to local air quality resulting from the proposed Plant. The proposed Plant's source emissions must not cause an exceedance of any national or Wyoming ambient air quality standards, and the increase in ambient air concentrations must not exceed the allowable PSD increments.

The dispersion modeling analysis typically involves a two-step approach. The first step looks at the proposed facility's emission sources and is referred to as the significant impact analysis (SIA). Only the proposed facility is considered in the SIA analysis; nearby sources and background ambient air quality concentrations are not considered. The highest predicted off-site concentration for each pollutant and each averaging period is compared to the modeling significant impact levels (SILs) listed in Table 6.6. If the estimated concentration levels are below the applicable SIL, no further analysis is required and the source is considered to have an insignificant impact. For the proposed Plant, SIA modeling results indicated exceedance of the SILs for each of the pollutants shown in Table 6.6.

The next phase is more robust and includes the NAAQS / WAAQS and the PSD increment analyses, which require modeling the proposed Plant emission sources as well as nearby sources and taking the background air quality concentration into account. The NAAQS and WAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. The proposed Plant's source emissions cannot cause a NAAQS or WAAQS exceedance. A PSD increment is the maximum increase in ambient concentration that is allowed to occur above a baseline concentration for a pollutant. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. The NAAQS, WAAQS, and Class II PSD Increments are listed in Table 6.6. Because the proposed Plant emissions resulted in SIL exceedances for all modeled criteria pollutants, full NAAQS / WAAQS and PSD increment analyses were performed.

Table 6.6 – SILs, NAAQS, WAAQS, and PSD Class II Increments

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	NAAQS [1] / WAAQS ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)
Nitrogen Dioxide	Annual	1	100	25
Sulfur Dioxide	3-hour	25	1,300	512
	24-hour	5	365 / 260	91
	Annual	1	80 / 60	20
Particulate Matter <10 µm [PM_{10}]	24-hour	5	150	30
	Annual	1	Revoked / 50	17
Carbon Monoxide	1-hour	2,000	40,000	N/A
	8-hour	500	10,000	N/A

1. Primary NAAQS are noted in this table. Secondary NAAQS are addressed in Section 6.8 (Impacts to Soil and Vegetation).

For a new source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the background concentration and the estimated ambient impacts of the Plant's proposed emissions. A complete PSD increment "consumption" and NAAQS comparison evaluation was completed for this modeling analysis.

6.4 NEAR FIELD MODELING METHOD

Near field impact analysis modeling was conducted for Plant sources of NO_x, CO, SO_2 and PM_{10} emissions using the methodology outlined in the previous section. This section includes a detailed description of the modeling approach and data requirements for assessing air quality impacts due to the proposed Plant.

6.4.1 Model Selection and Setup

The air quality impacts were modeled at near field receptors using the latest version of the EPA regulatory model (AERMOD) (Version 07026). The AERMOD model is designed to predict ground-level pollutant concentrations from a wide variety of sources associated with industrial facility source types. AERMOD contains algorithms for: (1) dispersion in both the convective and stable boundary layers; (2) plume rise and buoyancy; (3) plume penetration into elevated inversions; (4) computation of vertical profiles of wind, turbulence, and temperature; (5) urban nighttime boundary layer; (6) treatment of receptors on all types of terrain from the surface up to and above the plume height; (7) treatment of building wake effects; (8) improved approaches for characterizing the fundamental boundary layer parameters, and (9) treatment of plume meander. The AERMOD modeling system consists of two pre-processors: AERMET which provides AERMOD with the meteorological information it needs to characterize the planetary boundary layer (PBL); and AERMAP, which characterizes the terrain, and generates receptor grids for AERMOD.

Pursuant to WDEQ modeling guidelines (2006a and 2006b), the regulatory default options were used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

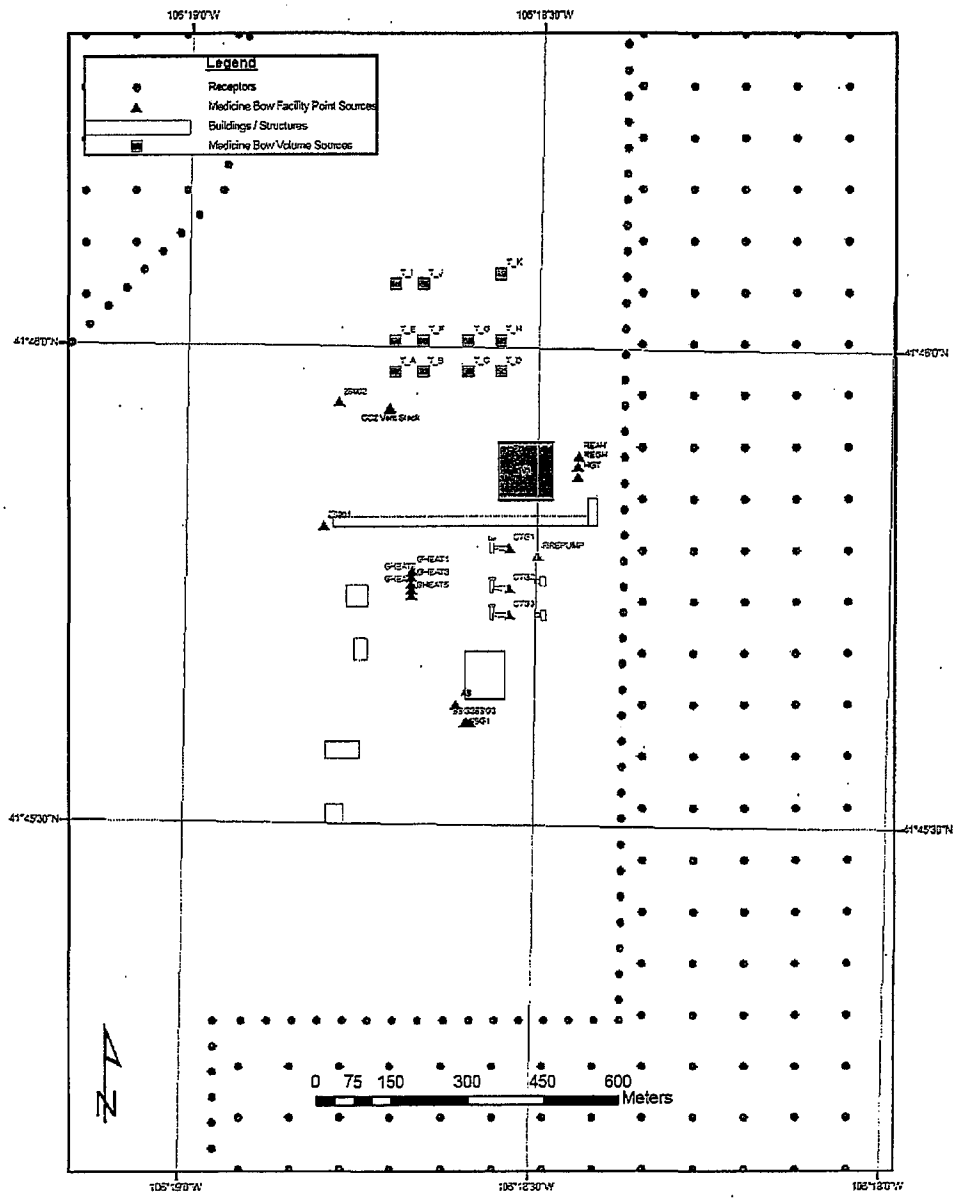
Emission sources at the Plant will be influenced by aerodynamic downwash. Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the AERMOD model. The USEPA Building Profile Input Program (BPIP version 04274), enhanced to include the PRIME algorithms as applicable to AERMOD, was used to conduct the good engineering practice (GEP) stack height analysis and to determine wind direction-specific building/structure dimensions.

The BPIP-PRIME program builds a mathematical representation of each building or structure to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10-degree intervals). If the BPIPPRIME program determines that a source is under the influence of several potential building wakes, the structure or combination of structures which has the greatest influence ($h_b + 1.5\ l_b$) is selected for input to the model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal

to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 l_b downwind, 2 l_b upwind, and 0.5 l_b crosswind. These criteria are based on recommendations by USEPA. The PRIME algorithm addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake.

Input to the BPIPPRIME program consisted of the location of Plant emission units and the coordinates and heights of the buildings and structures. The structures used in the analysis are shown in Figure 6.5 along with the source locations.

Figure 6.5 – GEP Stack Height Assessment Building and Source Location Depiction



6.4.2 Databases for Air Quality Assessment

The databases required for the air quality impact assessment included emissions inventory, meteorological data, receptor points, and terrain data. The emissions inventory was described in Section 6.2.2 and presented in Tables 6.2 through 6.5. The following sections describe the meteorological data, receptor points, and terrain data databases required to perform the air quality impact assessment.

6.4.3 Meteorological Data

Nearby sources of meteorological data (three surface sites and one upper air site) were identified, and six years of recent (2000–2005) meteorological data were obtained, reviewed for completeness, and the valid years were processed in AERMET. The surface sites included a nearby meteorological tower installation with automatic recording instrumentation located outside of Elmo, WY, about 24 km northwest of the Plant site, and two National Weather Service (NWS) ASOS sites, one located at the Rawlins Municipal Airport approximately 70 km west of the Plant location and one located at the Laramie Gen. Brees Airport approximately 73 km southeast of the Plant location.

Inter-Mountain Labs (IML) operated the Elmo meteorological station in accordance with *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R-99-005). IML performed semi-annual quality assurance audits on the station and the IML staff conducted quality control procedures on the data. IML submitted quarterly reports (including semiannual quality assurance audits) to Dennis Wuertz at Seminoe (Arch of Wyoming, LLC), who then submitted the reports to Bob Schick at the WDEQ. Cara Keslar in the Air Quality Monitoring Division may be contacted with regard to this data. The UTM coordinates (Zone 13, NAD27) of this station are 372052 meters E, 4638122 meters N.

In order to meet the completeness criteria for PSD-quality meteorological data, only 10 percent of the data in any given year can be missing. The Elmo, WY data was reviewed for completeness and the results are shown in Table 6.7. The Elmo data collected during 2002 does not satisfy the completeness criteria because only 64%, 40%, and 81% of the data were available during the 2nd, 3rd, and 4th quarters of the year. Therefore, 2000, 2001, 2003, 2004, and 2005 on-site data were used for the AERMET processing and AERMOD modeling.

Therefore, a five year meteorological data set was developed for the years 2000, 2001, and 2003–2005 with the Elmo site noted as the "on-site" location and the Laramie and Rawlins sites as the NWS surface locations, respectively. The Rawlins NWS site meteorology set for years 2000 and 2003 lacked sufficient cloud cover data necessary to establish completeness. Consequently, Rawlins NWS surface meteorology data was used only for the years 2001, 2004, and 2005. Because the Laramie NWS had complete cloud cover data for the two years for which the Rawlins data was incomplete, Laramie NWS surface meteorology was used for the years 2000 and 2003. The full five-year data set was processed in AERMET into model-ready format.

Table 6.7 – Site-Specific Elmo Meteorological Data Completeness

Months	Year	1st Quarter January-March	2nd Quarter April-June	3rd Quarter July-September	4th Quarter October-December
Total Hours per Quarter		2184 or 2160	2184	2208	2208
Number of Missing Hours	2000	0	193	0	1
	2001	0	2	0	1
	2002	159	787	1316	420
	2003	0	1	1	2
	2004	2	0	1	50
	2005	2	50	1	0
Percent Completed (%)	2000	100.0	91.2	100.0	100.0
	2001	100.0	99.9	100.0	100.0
	2002	92.6	64.0	40.4	81.0
	2003	100.0	100.0	100.0	99.9
	2004	99.9	100.0	100.0	97.7
	2005	99.9	97.7	100.0	100.0

Three years of hourly surface observations (2001, 2004, and 2005) from the Rawlins Municipal Airport, WY were obtained from the National Climatic Data Center (NCDC) in AERMET-compatible TD3505 format. The Rawlins NWS site is located approximately 70 km west of the proposed facility at UTM coordinates (NAD27) 317221 meters E and 4629697 meters N.

Two years of hourly surface observations (2000 and 2003) from the Laramie Gen. Brees Airport, WY were obtained from the NCDC in AERMET-compatible TD3505 format. The Laramie NWS site is located approximately 73 km southeast of the proposed facility at UTM coordinates (NAD83 Zone 13 North) 443640.9 meters E and 4573759.8 meters N.

The Rawlins and Laramie hourly surface meteorology data sets were reviewed to establish completeness. The result of the completeness review of the Rawlins and Laramie data is shown in Table 6.8. The frequency distribution of wind speed and direction for the Elmo, Rawlins, and Laramie combined / AERMET processed surface data is shown in Table 6.9.

Table 6.8 – Data Completeness Evaluation, Rawlins and Laramie NWS Hourly Surface Meteorological Data

Year	NWS Site	Number of Missing Hours	Percent Complete (%)
2000	Laramie	328	96.3
2001	Rawlins	504	94.2
2003	Laramie	151	98.3
2004	Rawlins	447	94.9
2005	Rawlins	514	94.1

Table 6.9 – Frequency Distribution of Wind Speed and Direction of the Elmo, Rawlins, and Laramie Hourly Surface Meteorological Data (2000, 2001, 2003–2005)

Wind Direction	Wind Speed						
	0.5 - 2.1	2.1 - 3.6	3.6 - 5.7	5.7 - 8.8	8.8 - 11.1	>= 11.1	Total
348.75 - 11.25	43	75	79	58	46	102	403
11.25 - 33.75	60	150	120	90	66	520	1006
33.75 - 56.25	75	245	260	223	292	3793	4888
56.25 - 78.75	64	428	608	752	965	10043	12860
78.75 - 101.25	47	539	1070	1280	1188	5847	9971
101.25 - 123.75	54	310	482	466	398	1537	3247
123.75 - 146.25	45	152	101	149	177	609	1233
146.25 - 168.75	33	126	98	70	76	191	594
168.75 - 191.25	64	129	148	108	83	200	732
191.25 - 213.75	37	248	464	491	324	393	1957
213.75 - 236.25	58	286	432	381	297	564	2018
236.25 - 258.75	43	205	212	218	244	1055	1977
258.75 - 281.25	44	185	161	149	178	930	1647
281.25 - 303.75	50	152	111	62	49	226	650
303.75 - 326.25	68	111	77	45	29	66	396
326.25 - 348.75	34	68	61	26	19	47	255
Sub-Total:	819	3409	4484	4568	4431	26123	43834
Calms:							0
Missing/Incomplete:							14
Total:							43848

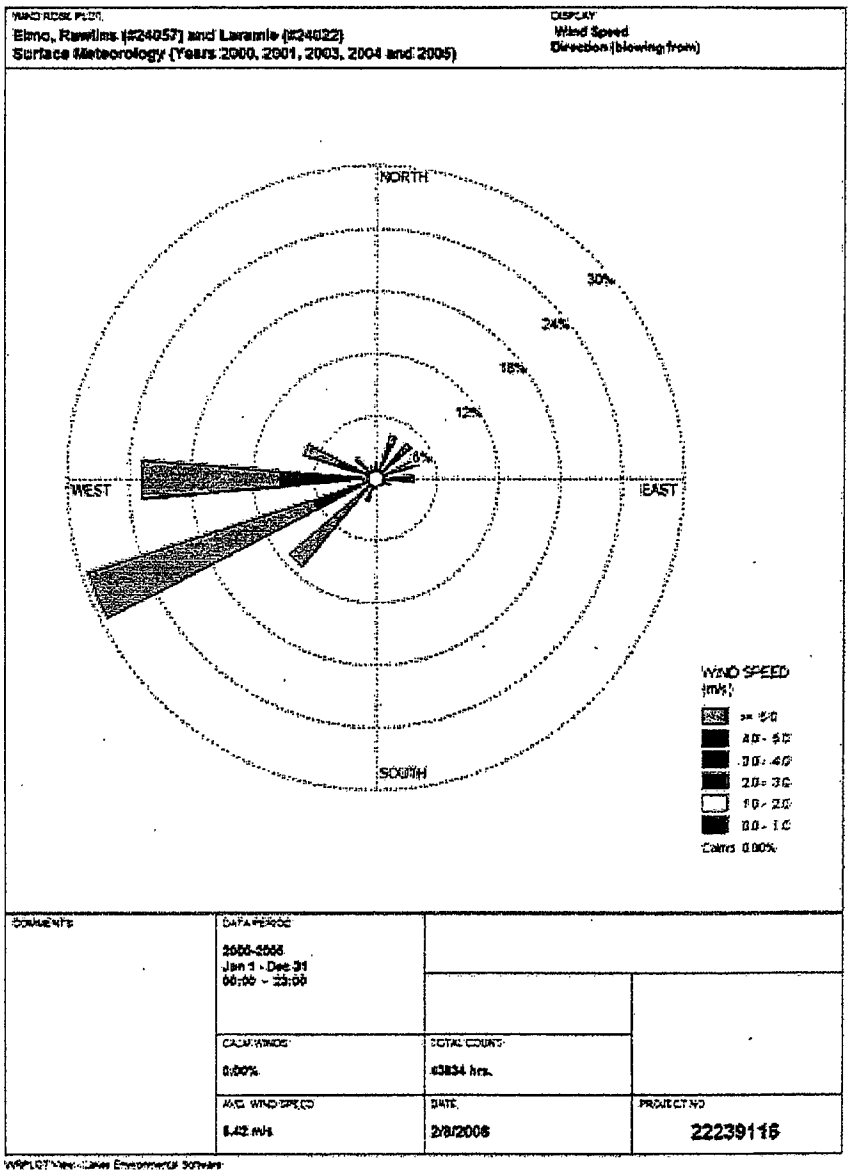
Upper air data are needed to estimate hourly mixing heights, which are required inputs to the AERMOD dispersion model. The most suitable NWS station to the project site that routinely performs upper air soundings is the NWS station in Riverton, WY (WBAN 24061), which is located approximately 250 km northwest of the proposed project site. The UTM coordinates (NAD27) of the Riverton NWS station are 217421 meters E and 4773109 meters N. Twice-daily upper air sounding data was obtained from the National Oceanic & Atmospheric Administration (NOAA), http://raob.fsl.noaa.gov/.

As discussed with WDEQ, the same five years (2000, 2001, 2003, 2004, and 2005) were used for both the NWS surface and upper air data in the AERMET processing so that the upper air data coincided with the surface data. Five parameters for each hour were collected at the Elmo, WY monitoring site, including wind direction (degree), wind speed (meters per seconds), sigma theta (degrees), temperature (Celsius), and precipitation (millimeters). Sensor elevations are 10 meters above grade level (agl) for wind speed and direction, 2 meters (agl) for temperature, and approximately 1 meter (agl) for precipitation.

An average of the desert scrubland and grassland surface characteristics values for albedo, the Bowen Ratio and surface roughness length were applied to AERMET Stage 3.

The windrose of the processed AERMET data based on the site-specific Elmo, Laramie, and Rawlins hourly surface meteorological data is shown in Figure 6.6.

Figure 6.6 – Wind Rose of AERMOD Input, Five-Year Period



6.4.4 Receptor Grid

The receptor grid used in the modeling analysis was designed to identify the maximum air quality impact due to the proposed project. The receptor grid began at the ambient air boundary and extended outward 10 km into ambient air. The following receptor spacing was used:

1 50 m spacing along the Plant's ambient air boundary;

2 100 m spacing from the boundary to 1 km;

3 500 m spacing from 1 km out from the proposed project to 5 km;

4 1 km spacing from 5 km to 10 km from the proposed project; and

5 500 meter from nearby mining area sources to closest receptor.

Receptor elevations were included for all receptor points and were obtained from digital elevation 7.5 minute topographic maps (http://data.geocomm.com). The DEM domain was extended to approximately 25 km from the proposed Plant to include the potential terrain of 10 percent slope or greater for complex terrain modeling. Source elevations were also obtained from the same data using AERMAP. The receptor grid is shown in Figure 6.3.

6.5 GROWTH ANALYSIS

During normal operations, the Plant is expected to employ 300 to 400 people with various trades. Many of these trades are commonly found in the coal mining industry. These employees are expected to live in the existing communities, such as Elk Mountain, Medicine Bow, Hanna, Saratoga, Rawlins, and Laramie. Carbon County has historically been a coal mining area with mining activity from the turn of the century through 2005. Population in the county has been declining since the 1990s (approximately 1,300) possibly resulting from the declining coal industry. The commercial support industries are already in place in Hanna and along the I-80 corridor.

6.6 CRITERIA POLLUTANT MODELING RESULTS

The following sections describe the results of the ambient air quality impact analysis. Modeling files are included in a CD-ROM provided along with this application. The README file included on the CD-ROM explains modeling file organization.

6.6.1 SO_2 Modeling Demonstration

Table 6.10 presents the maximum predicted 3-hour, 24-hour, and annual average SO_2 concentrations due to all cumulative source emissions. The second-highest concentration for each year is presented for the 3-hour and 24-hour averaging periods, while the maximum value for each annual average is presented. The total concentration (cumulative predicted concentration plus background) is compared to the NAAQS and WAAQS. As shown in the table, all predicted total concentrations are well below the respective NAAQS and WAAQS values.

Table 6.11 presents the maximum predicted 3-hour, 24-hour, and annual average concentrations due to project-specific source emissions and compares these values to the PSD increment. These emissions include on-site mining operations and emissions from Plant equipment. For the PSD increment comparison, each year's maximum concentration is selected for the 3-hour, 24-hour, and annual average time period. The predicted concentration is compared to the PSD increment directly, without including the background concentration. As shown in the table, all predicted concentrations are below the respective PSD increments.

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 SO_2 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]	2000	2/29	24	395455.4	4624205	305.53	31.4	336.93	N/A / 1300
	2001	2/8	24	395455.4	4624205	359.4	31.4	390.8	N/A / 1300
	2003	6/30	21	389455.4	4628205	393.74	31.4	425.14	N/A / 1300
	2004	5/16	06	388955.4	4627705	435.66	31.4	467.06	N/A / 1300
	2005	12/6	24	380955.4	4628205	397.15	31.4	428.55	N/A / 1300
24 Hour [1]	2000	11/30	24	392255.4	4625105	117.88	7.84	125.72	365 / 260
	2001	3/13	24	392955.4	4625205	160.66	7.84	168.5	365 / 260
	2003	12/13	24	391855.4	4625505	157.21	7.84	165.05	365 / 260
	2004	10/30	24	391955.4	4625005	162.51	7.84	170.35	365 / 260
	2005	11/13	24	392055.4	4625005	137.98	7.84	145.82	365 / 260
Annual	2000	N/A	N/A	391421.4	4624635	4.305	2.62	6.93	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	4.51	2.62	7.13	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.

Table 6.11 – Predicted SO_2 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	2000	12/4	9	385955.4	4614205	249.87	512
	2001	1/25	9	382955.4	4621205	257.11	512
	2003	12/5	9	380955.4	4625205	337.92	512
	2004	10/15	18	380955.4	4625205	291.23	512
	2005	2/18	9	380955.4	4628205	268.77	512
24 Hour	2000	9/23	24	389455.4	4624205	85.62	91
	2001	8/9	24	389655.4	4624605	86.36	91
	2003	4/1	24	391855.4	4625805	78.23	91
	2004	6/8	24	389755.4	4624205	72.69	91
	2005	8/4	24	389855.4	4624805	77.64	91
Annual	2000	N/A	N/A	391421.4	4624635	4.31	20
	2001	N/A	N/A	391421.4	4624585	4.51	20
	2003	N/A	N/A	391422.4	4624685	4.51	20
	2004	N/A	N/A	391420.4	4624485	4.01	20
	2005	N/A	N/A	391420.4	4624435	4.09	20

Figure 6.7 – 2003 Maximum SO_2 3-Hour Impacts (PSD)

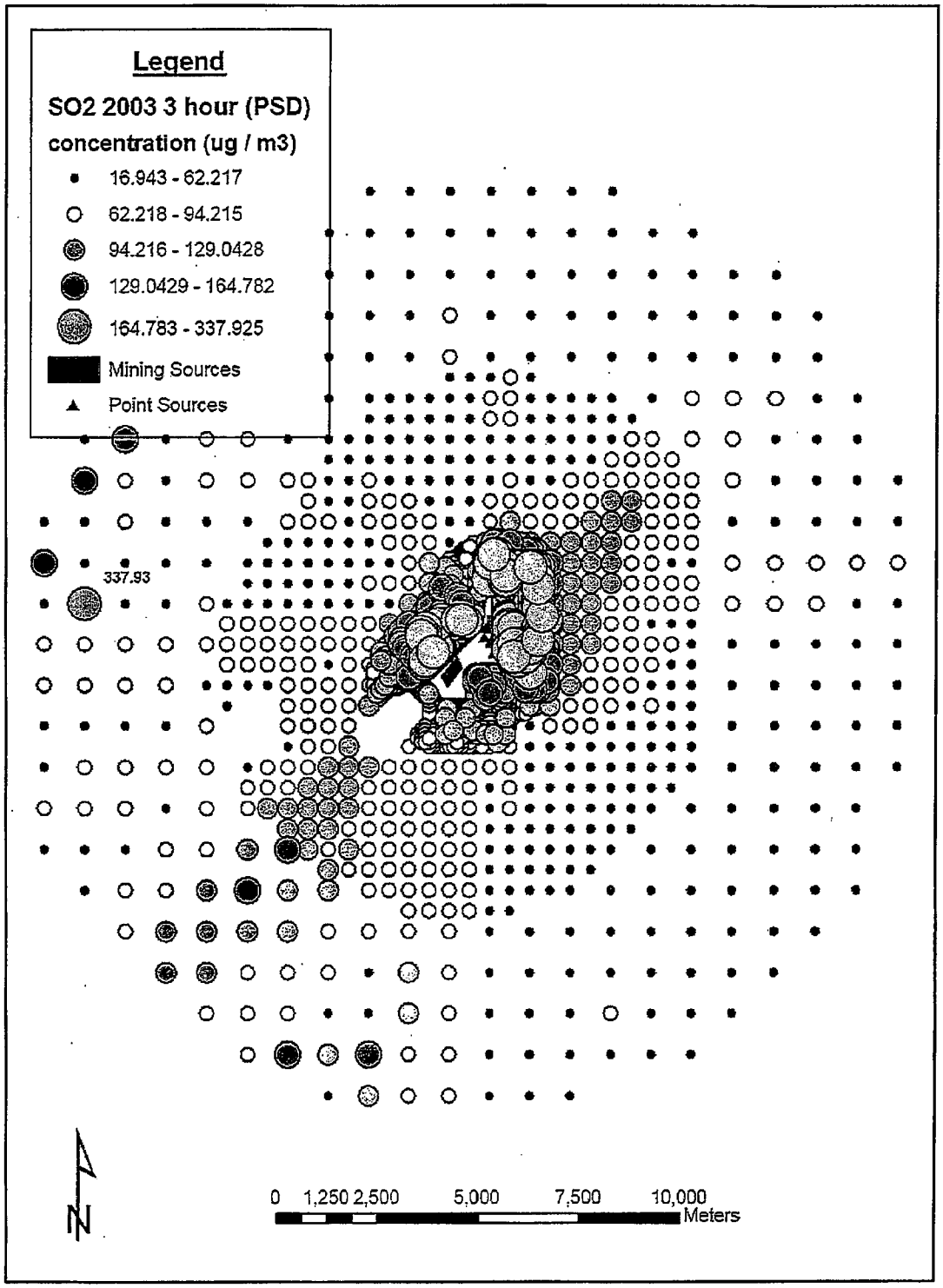


Figure 6.8 – 2001 Maximum SO_2 24-Hour Impacts (PSD)

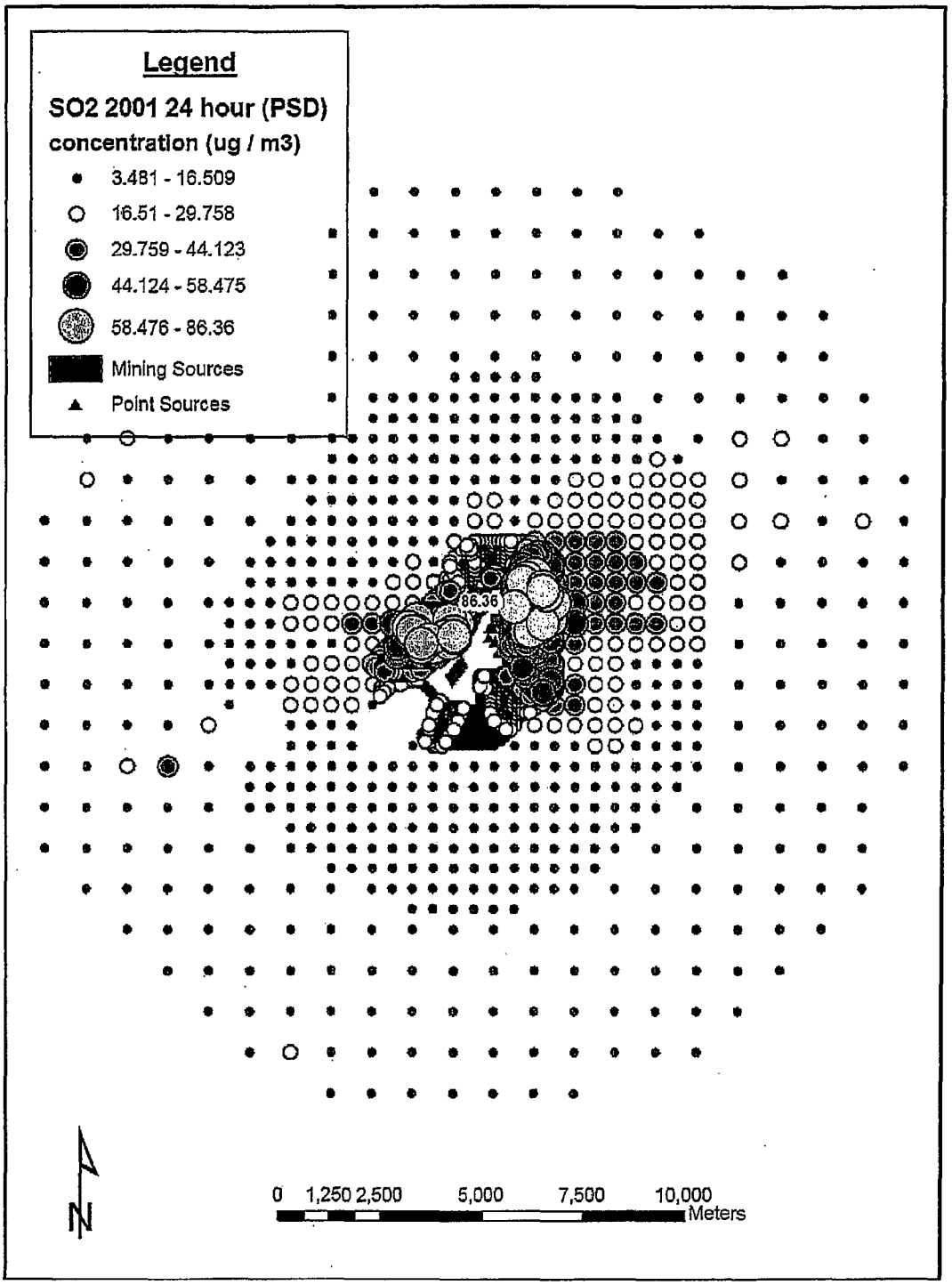
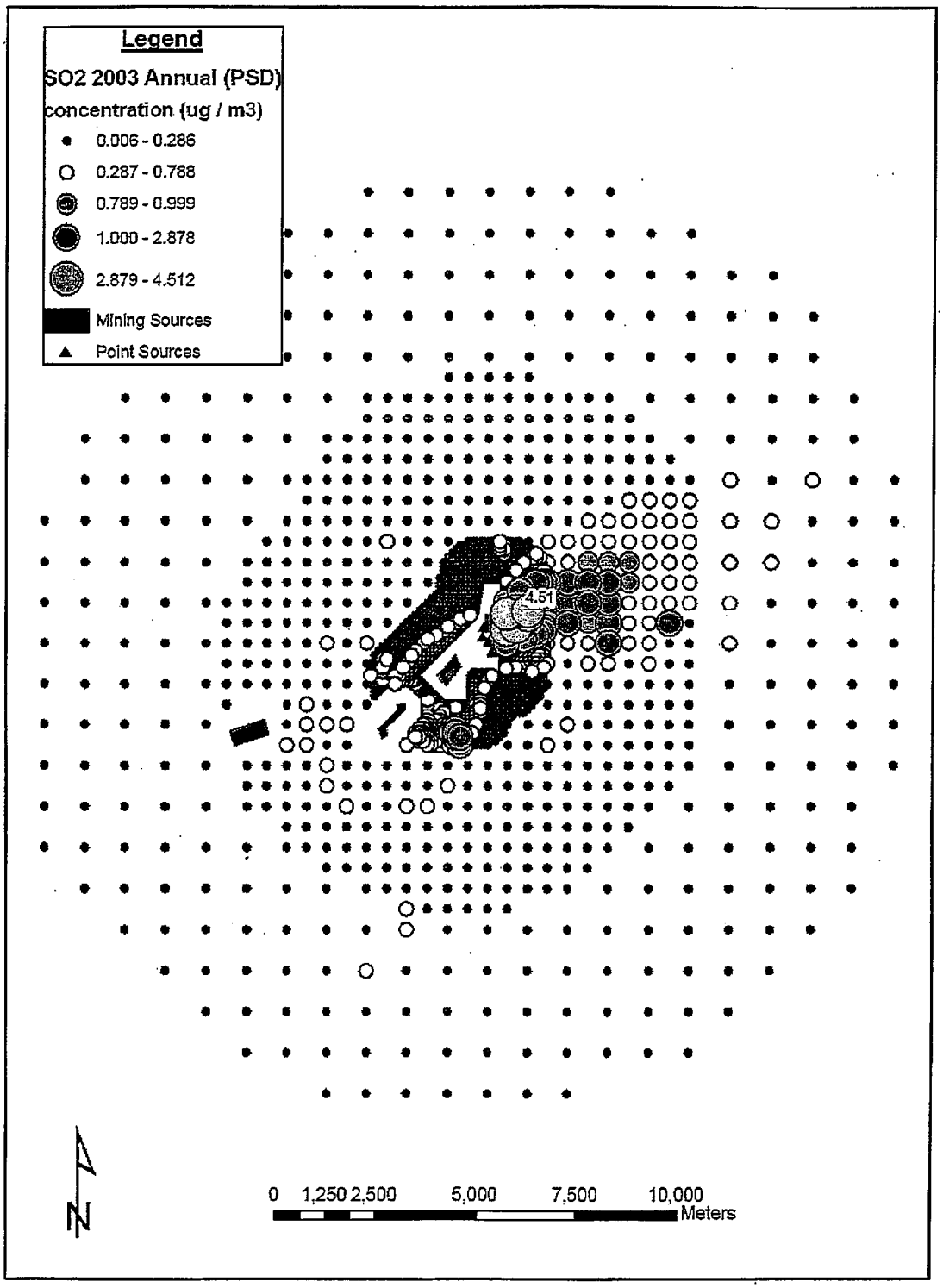


Figure 6.9 – 2003 Maximum SO_2 Annual Impacts (PSD)



6.6.2 PM/PM_{10} Modeling Demonstration

Table 6.12 presents the maximum predicted 24-hour and annual average cumulative PM/PM_{10} concentrations compared to the NAAQS and WAAQS. Emissions in this analysis include nearby mining operations and vehicle traffic and the proposed Plant. The predicted second-highest 24-hr value is presented, along with the highest predicted maximum annual value. Each of these values is added to the respective 24-hr and annual background concentration for comparison to the NAAQS and WAAQS. As shown in the table, all predicted total concentrations are below the respective NAAQS and WAAQS values.

Table 6.13 presents the results of the PM/PM_{10} PSD increment analysis. The maximum predicted 24-hr and annual PM/PM_{10} values are compared to the respective PSD increment. As shown in the table, all predicted concentrations are below the applicable PSD increment value.

Table 6.12 – Predicted PM/PM_{10} 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				
Annual	2000	N/A	N/A	390604.4	4623395	15.43	26	41.43	NA / 50
	2001	N/A	N/A	390604.4	4623395	17.75	26	43.75	NA / 50
	2003	N/A	N/A	390604.4	4623395	12.61	26	38.61	NA / 50
	2004	N/A	N/A	390604.4	4623395	17.82	26	43.82	NA / 50
	2005	N/A	N/A	390604.4	4623395	19.03	26	45.03	NA / 50
24 Hour	2000	11/23	24	389455.4	4622605	73.61	56	129.61	150 / 150
	2001	3/3	24	390604.4	4623395	85.41	56	141.41	150 / 150
	2003	2/24	24	389728.4	4622696	72.72	56	128.72	150 / 150
	2004	10/4	24	389445.4	4622979	74.35	56	130.35	150 / 150
	2005	9/13	24	390603.4	4623295	82.04	56	138.04	150 / 150

Table 6.13 – Predicted PM/PM_{10} 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		
Annual	2000	N/A	N/A	390604.4	4623395	4.78	17
	2001	N/A	N/A	390604.4	4623395	5.48	17
	2003	N/A	N/A	390604.4	4623395	3.53	17
	2004	N/A	N/A	390604.4	4623395	5.62	17
	2005	N/A	N/A	390604.4	4623395	6.15	17
24 Hour	2000	12/8	24	390455.4	4622405	27.61	30
	2001	3/3	24	390604.4	4623345	26.42	30
	2003	3/28	24	390604.4	4623395	22.02	30
	2004	2/21	24	390604.4	4623345	24.56	30
	2005	2/24	24	390603.4	4623245	27.46	30

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

Figure 6.10 – 2000 Maximum PM_{10} 24-Hour Impacts (PSD)

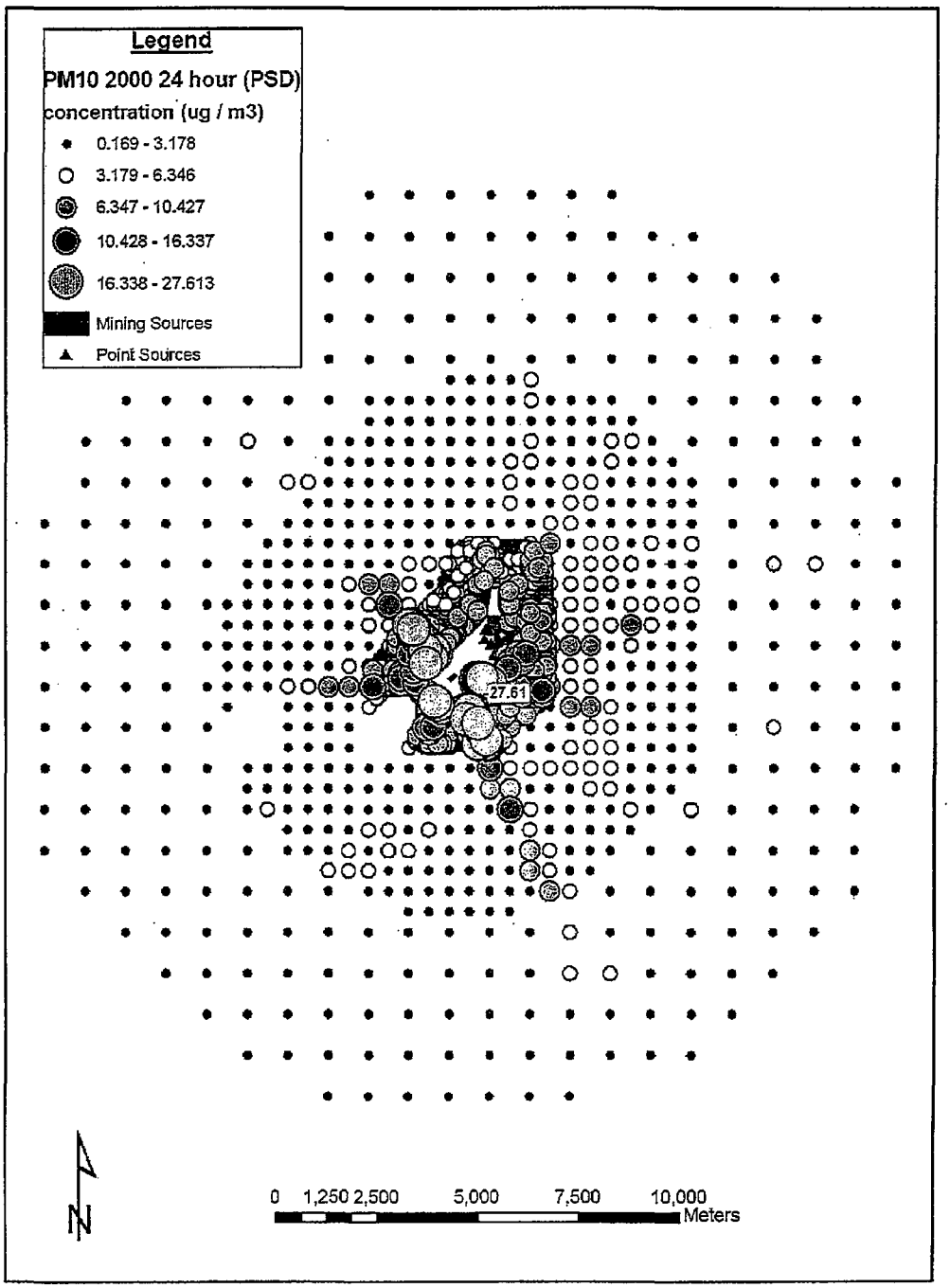
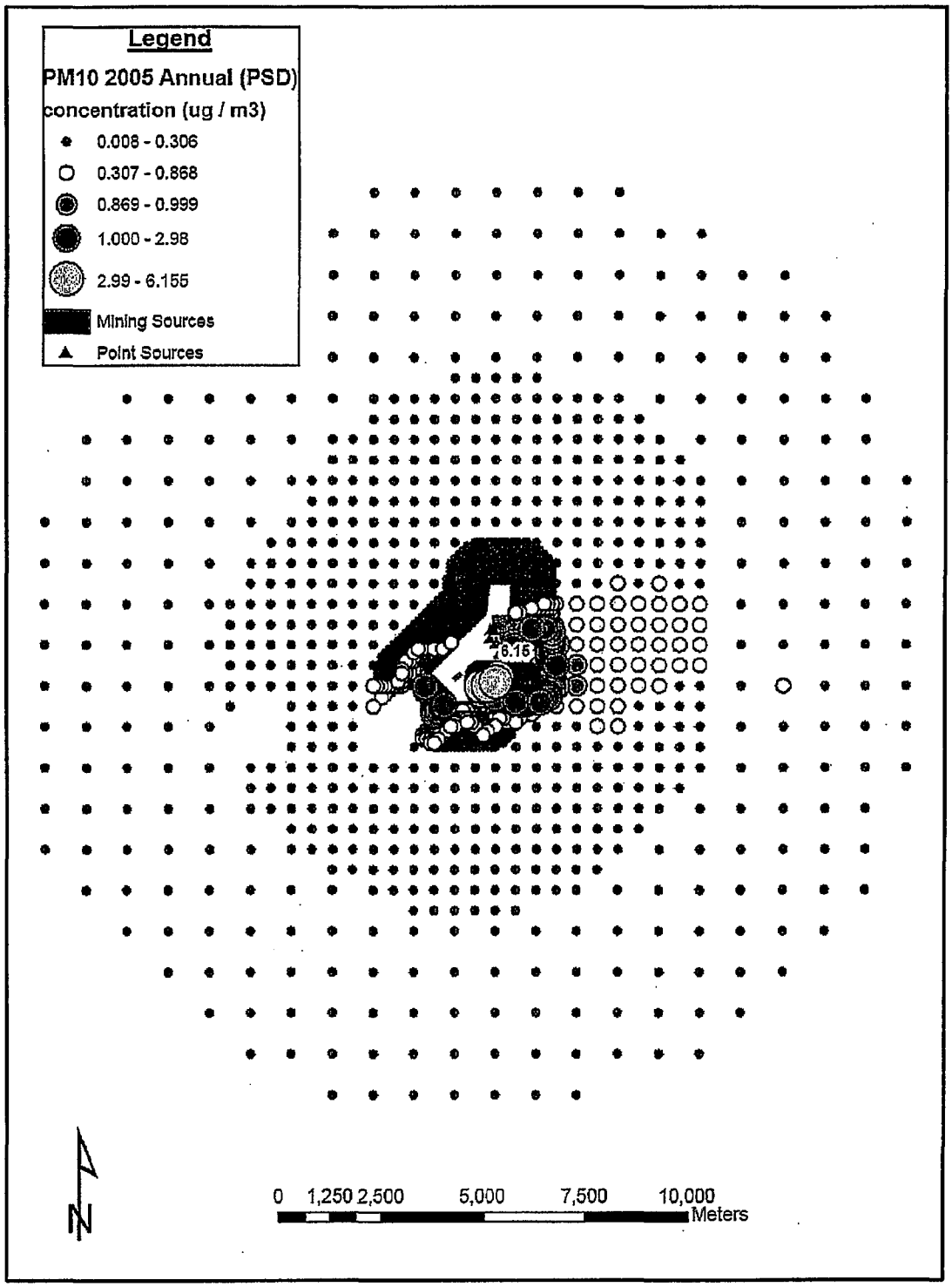


Figure 6.11 – 2005 Maximum PM_{10} Annual Impacts (PSD)



6.6.3 CO Modeling Demonstration

Table 6.14 presents the maximum predicted 1-hour and 8-hour average cumulative CO concentrations compared to the NAAQS and WAAQS. Emissions in this analysis include nearby point sources (from WDEQ emission inventory data), nearby mining operations and vehicle traffic, and the proposed Plant. The maximum predicted second-high values are presented and added to the respective 1-hour and 8-hour background concentrations for comparison to the NAAQS and WAAQS. As shown in the table, all predicted total concentrations are below the respective NAAQS and WAAQS values. No PSD increment analysis was conducted for CO, as no PSD increments exist for CO.

Table 6.14 – Predicted CO Concentrations Compared to the NAAQS / WAAQS

Averaging Period	Data Period			Receptor Location (m)		Predicted Concentration (ug/m3)	Background Concentration (ug/m3)	Total Concentration (Predicted + Background) (ug/m3)	NAAQS & WAAQS (ug/m3)
	Year	Month / Day	Hour	East	North				
8 Hour	2000	10/3	24	392955.4	4622205	3366.42	916	4,282.42	10,000
	2001	8/3	08	392455.4	4622705	4321.5	916	5,237.5	10,000
	2003	4/11	08	390255.4	4621705	3674.5	916	4,590.5	10,000
	2004	7/26	08	392955.4	4622205	3098.76	916	4,014.76	10,000
	2005	8/8	08	392455.4	4622705	3443.05	916	4,359.05	10,000
1 Hour	2000	10/23	24	392955.4	4622205	26917.83	1946	28,863.83	40,000
	2001	8/3	05	392455.4	4622705	33584.77	1946	35,530.77	40,000
	2003	7/15	04	390355.4	4621705	27086.87	1946	29,032.87	40,000
	2004	5/10	01	392455.4	4621705	21204.38	1946	23,150.38	40,000
	2005	8/8	04	392455.4	4622705	27289.27	1946	29,235.27	40,000

Figures 6.12 and 6.13 illustrate the second high CO 1-hour impacts with respect to the NAAQS and WAAQS.

Figure 6.12 – 2001 Second High CO 1-Hour Impacts (NAAQS)

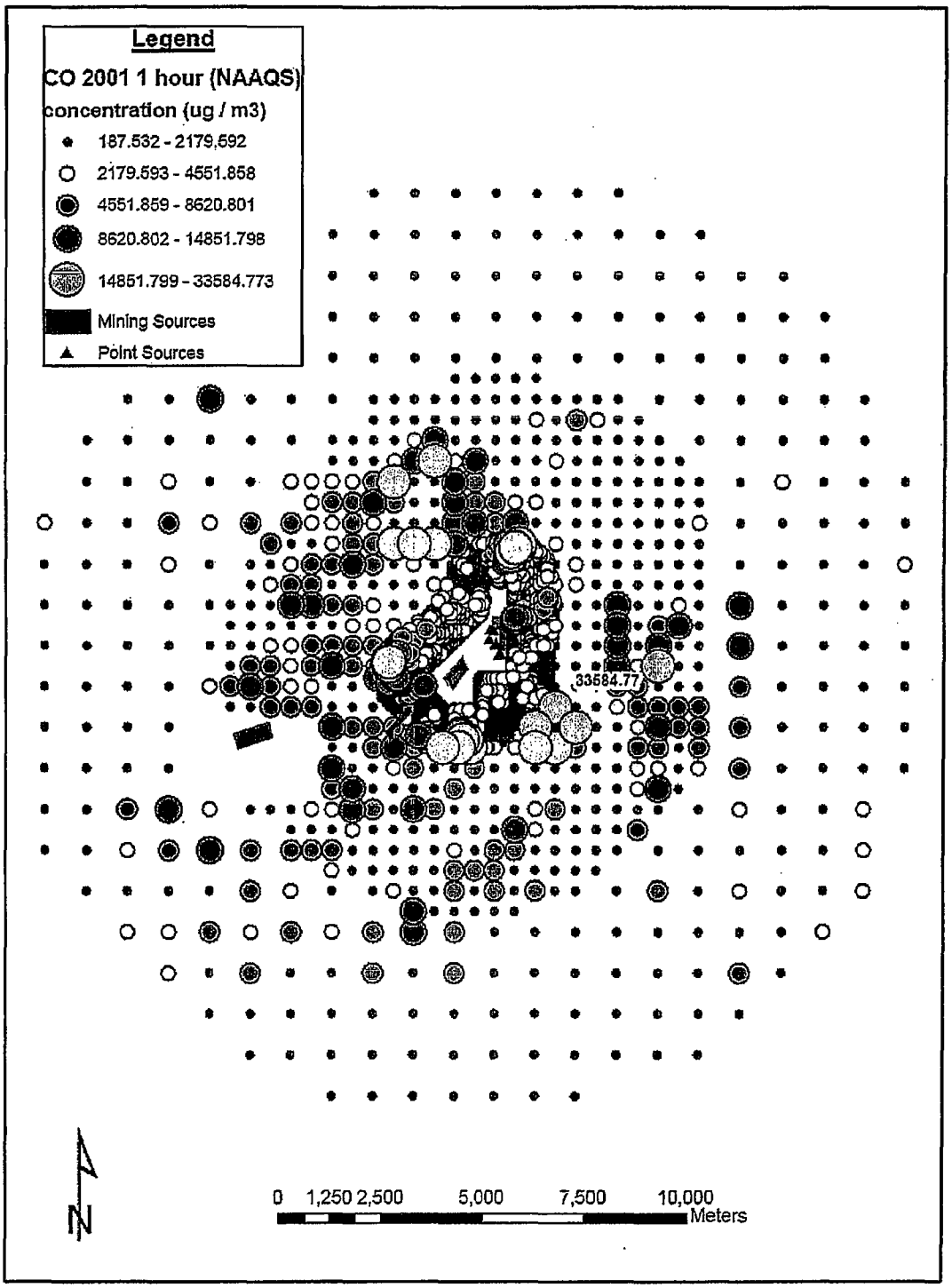
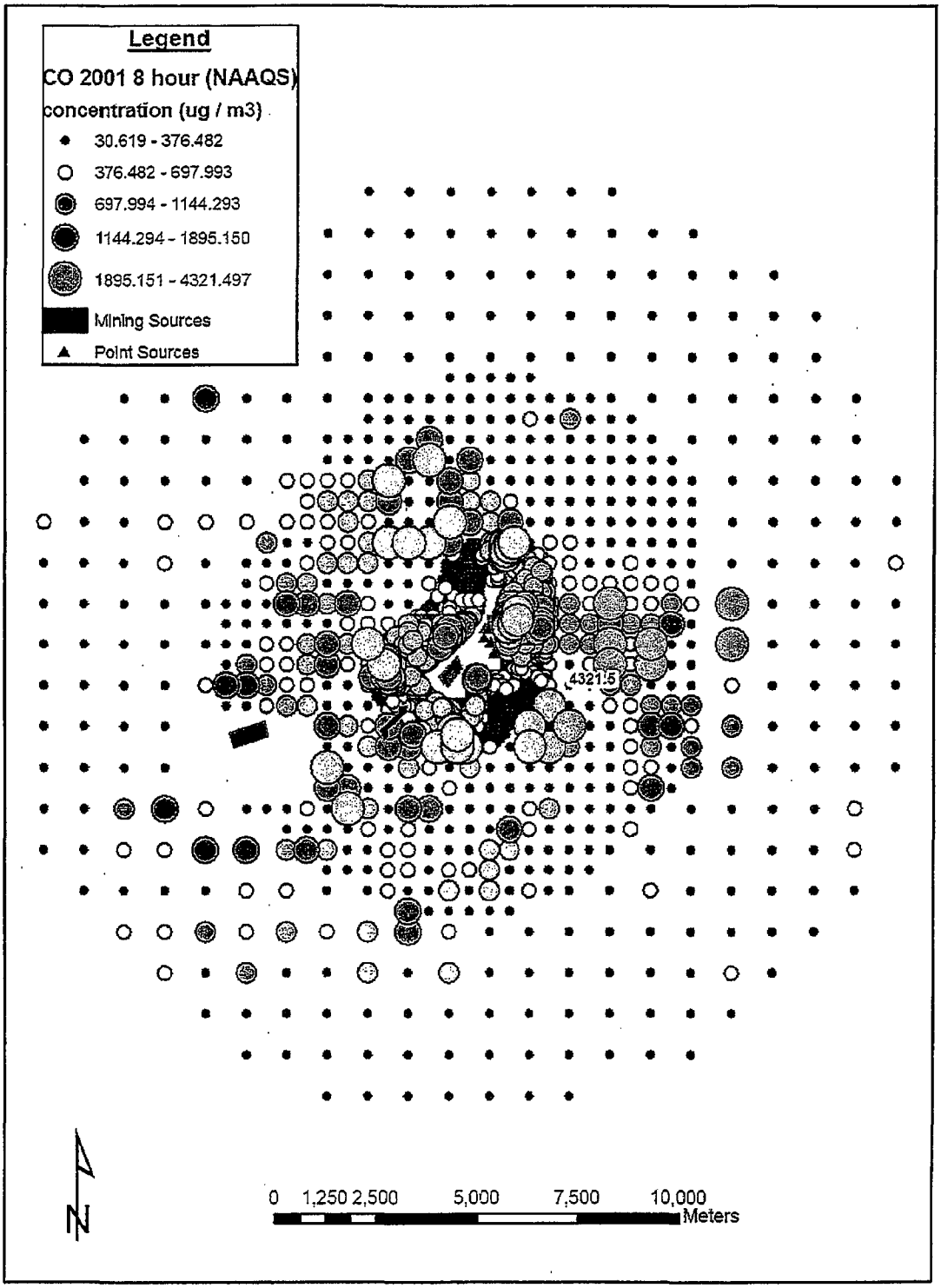


Figure 6.13 – 2001 Second High CO 8-Hour Impacts (NAAQS)



6.6.4 NO_x Modeling Demonstration

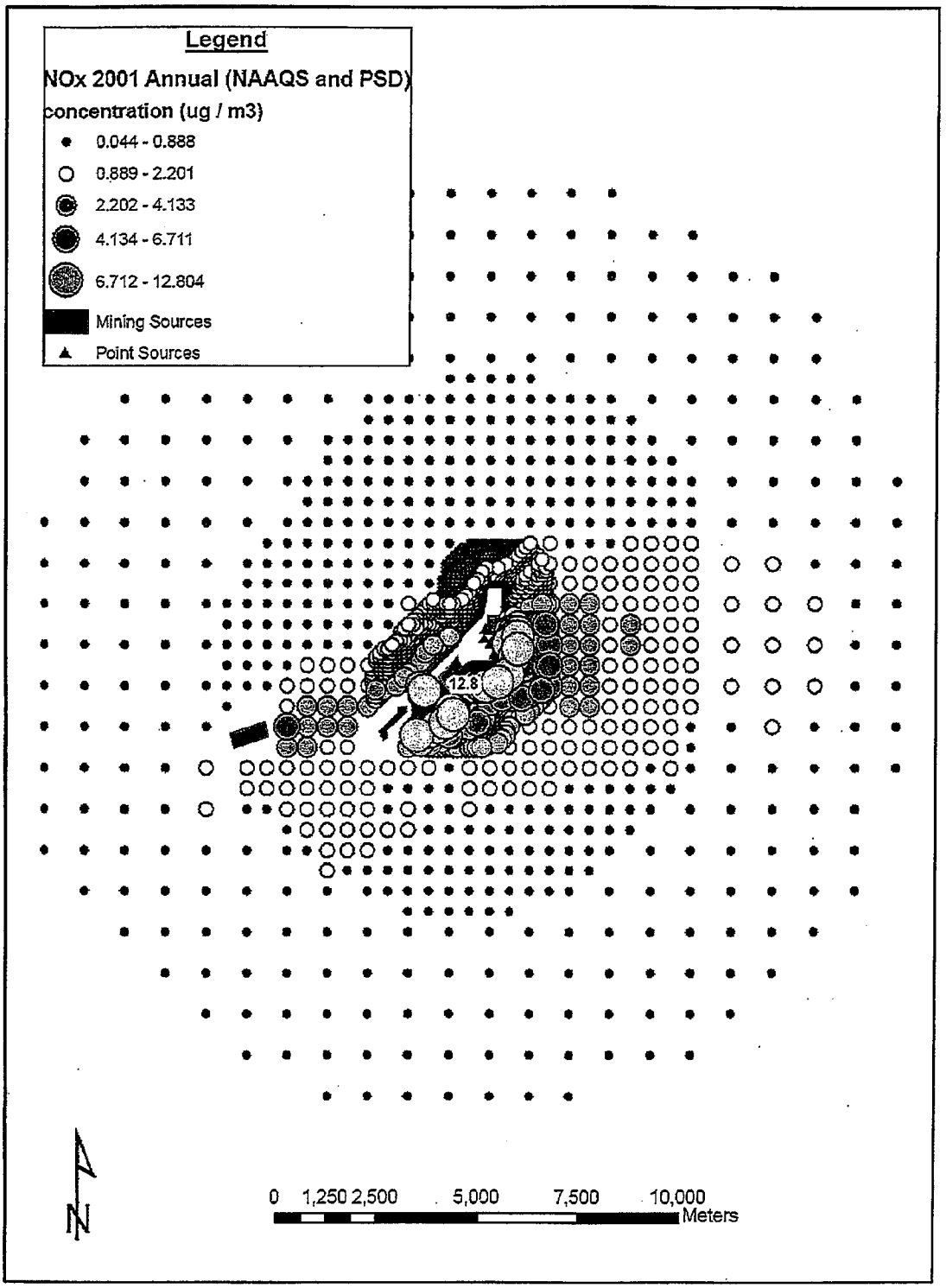
Table 6.15 presents the maximum predicted annual average NO_x concentrations compared to the NAAQS, WAAQS, and the NO_x PSD increment value. Emissions in this analysis include nearby point sources (from WDEQ emission inventory data), nearby mining operations and vehicle traffic, and the proposed Plant. The maximum predicted annual average concentrations are presented and added to the background concentration for comparison to the NAAQS and WAAQS. As shown in the table, all predicted total concentrations are well below the respective PSD increments, and the total concentrations fall well below the NAAQS and WAAQS.

Table 6.15 – Predicted NOx Concentrations Compared to the PSD Increment, NAAQS, and WAAQS

Averaging Period	Data Period	Receptor Location (m)		Predicted Concentration (ug/m3)	PSD Increment (ug/m3)	Background Concentration (ug/m3)	Total Concentration (Predicted + Background) (ug/m3)	NAAQS & WAAQS (ug/m3)
		East	North					
Annual	2000	389455.4	4622605	12.69	25	9.43	22.12	100
	2001	389455.4	4622605	12.80	25	9.43	22.23	100
	2003	389455.4	4622605	11.49	25	9.43	20.92	100
	2004	390604.4	4623395	11.60	25	9.43	21.03	100
	2005	390604.4	4623395	12.16	25	9.43	21.59	100

Figure 6.14 illustrates the maximum annual NO_x impacts.

Figure 6.14 – 2001 Maximum Annual NO_x Impacts (NAAQS and PSD)



6.7 HAP MODELING

HAP modeling was conducted using AERMOD and the five years of meteorological data described previously for the criteria pollutant modeling.

6.7.1 HAP Emission Sources

During normal operations, the largest HAP emission sources are fugitive emissions from equipment leaks and tanks. A ground-based volume source was modeled to represent fugitive HAP emissions associated with process equipment leaks. This fugitive HAP volume source is geographically located in the synthesis process areas of the Plant and was given a release height of 2 meters. Total equipment leak emissions for each pollutant were emitted from this allocated volume source. Table 6.4 has a complete listing of the volume sources for this modeling analysis.

For tank emissions, eleven volume sources were created for the storage tank emissions. Eight tanks will contain gasoline, two will store methanol, and the remaining tank is a heavy gasoline tank. Total emissions for each pollutant were divided equally among the eleven tank volume sources. Each tank volume source release height was set equal to the tank's height.

6.7.2 HAP Risk Assessment Procedures

HAP emissions were modeled and compared to the appropriate corresponding USEPA thresholds in order to evaluate the potential health risks due to short-term and long-term exposures. Benzene, formaldehyde, xylene, toluene, and methanol maximum 1-hour (short-term) averaged concentrations were compared to the Reference Exposure Levels (RELs) obtained from the EPA Air Toxics Database, Table 2 (EPA, 2005a). An REL is defined as the concentration level at or below which no adverse health effects are anticipated for specified exposure duration. The REL is designed to protect the most sensitive individuals in the population. Exceeding the REL does not automatically indicate an adverse health impact.

No RELs are available for ethyl benzene and n-hexane. Instead, the available Immediately Dangerous to Life or Health values divided by 100 (IDLH/100) were used. Dividing by 100 is a very conservative approach to reduce a pollutant's concentration threshold of concern to only 1 percent of the level that is considered to be "immediately dangerous." IDLH values are determined by the National Institute for Occupational Safety and Health (NIOSH) and were obtained from the EPA's Air Toxic Database (EPA, 2005a). The maximum of the two short-term (g/sec) emission rates due to cold startup and normal operations for each pollutant and source were modeled and are shown in Table 6.16. For example, for a particular pollutant, several sources' emissions will be highest during startup (generators) and other sources' emissions are highest during normal operations (tank operations at full plant production). For each type of source, the highest emission rates (from startup, malfunction or normal operations) were modeled simultaneously to conservatively estimate air quality impacts.

Table 6.16 – Source HAP Short-Term (Maximum) Emission Rates

Source ID [1] (in model)	Formaldehyde (g/sec)	Benzene (g/sec)	Methanol g/sec	n - Hexane (g/sec)	Toluene (g/sec)	Ethyl benzene (g/sec)	Xylene (g/sec)
CTG1	0.007	0.0012	0.0	0.0	0.013	0.00317	0.0063
CTG2	0.007	0.0012	0.0	0.0	0.013	0.00317	0.0063
CTG3	0.007	0.0012	0.0	0.0	0.013	0.00317	0.0063
GHEAT1	0.000195	0.0000054	0.0	0.00467	0.0000088	0.0	0.0
GHEAT2	0.000195	0.0000054	0.0	0.00467	0.0000088	0.0	0.0
GHEAT3	0.000195	0.0000054	0.0	0.00467	0.0000088	0.0	0.0
GHEAT4	0.000195	0.0000054	0.0	0.00467	0.0000088	0.0	0.0
GHEAT5	0.000195	0.0000054	0.0	0.00467	0.0000088	0.0	0.0
Z8901	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BSG1	0.1297	0.00052	0.0	0.000273	0.001	0.0	0.00045
BSG2	0.1297	0.00052	0.0	0.000273	0.001	0.0	0.00045
FIREPUMP	0.00057	0.00045	0.0	0.0	0.0002	0.0	0.000128
AB	0.00061	0.000017	0.0	0.0147	0.000028	0.0	0.0
REGH	0.0002	0.0000056	0.0	0.0048	0.000009	0.0	0.0
REAH	0.000115	0.0000032	0.0	0.00277	0.0000052	0.0	0.0
HGT	0.000021	0.0000006	0.0	0.0005	0.0000009	0.0	0.0
Z8902	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BSG3	0.1297	0.00052	0.0	0.000273	0.001	0.0	0.00045
CO2V	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T_A	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_B	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_C	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_D	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_E	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_F	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_G	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_H	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_I	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_J	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
T_K	0.0	0.00138	0.00624	0.0013	0.0015	0.000099	0.00042
V1	0.0	0.3	0.3	0.0	0.0	0.0	0.0

1. Tanks are shown as sources T_A through T_K. V1 is the equipment leak volume source.

6.7.3 HAP Modeling Results

6.7.3.1 Maximum 1-Hour HAP Concentrations

Table 6.17 shows the highest short-term (1-hour) averaged concentrations using worst-case assumptions and the corresponding RELs. Each of the seven modeled HAPs has a predicted maximum 1-hour concentration well below the applicable REL.

Table 6.17 – Source HAP Emission Rates

HAP	Maximum 1-hour Averaged Modeled Concentrations (µg/m³)	Reference Exposure Levels (RELs) (µg/m³)
Benzene[1]	311.5	1,300
Toluene[1]	5.73	37,000
Ethylbenzene[2]	0.38	35,000
Xylene[1]	1.61	22,000
n-Hexane[2]	5.0	39,000
Formaldehyde[1]	80.4	94
Methanol[1]	311.5	28,000

1. EPA Air Toxics Database, Table 2 (EPA, 2005b).

2. No REL available for these HAPs. Values shown are from (IDLH/100) EPA Air Toxics Database, Table 2 (EPA, 2005b).

6.7.3.2 *Maximum Annual HAP Concentrations*

Annually averaged modeled HAP concentrations due to normal operations were compared to the Reference Concentrations for Chronic Inhalation (RfCs). An RfC is defined by the EPA as the daily inhalation concentration (maximum annually averaged for this analysis) at which no long-term adverse health effects are expected. RfCs exist for both non-carcinogenic and carcinogenic effects on human health (EPA, 2005b). Annually averaged modeled benzene, methanol, toluene, ethylbenzene, xylene, n-hexane, and formaldehyde concentrations were compared to the non-carcinogenic RfCs shown in Table 6.18. Maximum annual predicted concentrations are well below the applicable RFCs for each pollutant.

Table 6.18 – Annually Averaged Modeled Concentrations

HAP	Maximum Annually Averaged Modeled Concentrations (µg/m³)	Non-Carcinogenic (RfCs) (µg/m³)[1]
Benzene	13.564	30
Toluene	0.1016	400
Ethyl benzene	0.0069	1000
Xylene	0.0287	100
n-Hexane	0.1173	200
Formaldehyde	0.0427	9.8
Methanol	13.607	4000

1. EPA Air Toxics Database, Table 1 (EPA, 2005c).

6.7.3.3 *Carcinogen Analysis*

RfCs for suspected carcinogens benzene and formaldehyde are expressed as unit risk factors (URS) and accepted methods for risk assessment are used to evaluate the incremental cancer risk for these pollutants. Since the closest residence, viewed in aerial photographs, is 3.3 km to the

south of the Plant, the maximum annually averaged modeled concentration predicted at a distance of 3 km and beyond for Benzene and the maximum annually averaged modeled concentration for Formaldehyde are multiplied by EPA's URFs (based on 70-year exposure), and then multiplied by an adjustment factor which represents the ratio of projected exposure time to 70 years.

The adjustment factors represent two scenarios: a most likely exposure (MLE) scenario and one reflective of the maximally exposed individual (MEI). The MLE duration is assumed to be 9 years, which corresponds to the mean duration that a family remains at a residence (EPA, 1993). This duration corresponds to an adjustment factor of 9/70 = 0.13. The duration of exposure for the MEI is assumed to be 70 years and the corresponding adjustment factor is 1.0.

A second adjustment is made for time spent at home versus time spent elsewhere. For the MLE scenario, the at-home time fraction is 0.64 (EPA, 1993), and it is assumed that during the rest of the day the individual will remain in an area where annually averaged HAP concentrations would be one-quarter as large as the maximum annual average concentration. Therefore, the MLE adjustment factor is calculated as follows.

$$\text{MLE Adjustment Factor} = (0.13) \times [(0.64 \times 1.0) + (0.36 \times 0.25)] = 0.095.$$

The MEI scenario assumes that the individual is at home 100 percent of the time, for the final adjustment factor of (1.0 x 1.0) = 1.0.

The values for the cancer risk assessment from benzene and formaldehyde emissions from the proposed Plant are shown in Table 6.19.

Table 6.19 – Cancer Risk Assessment Values

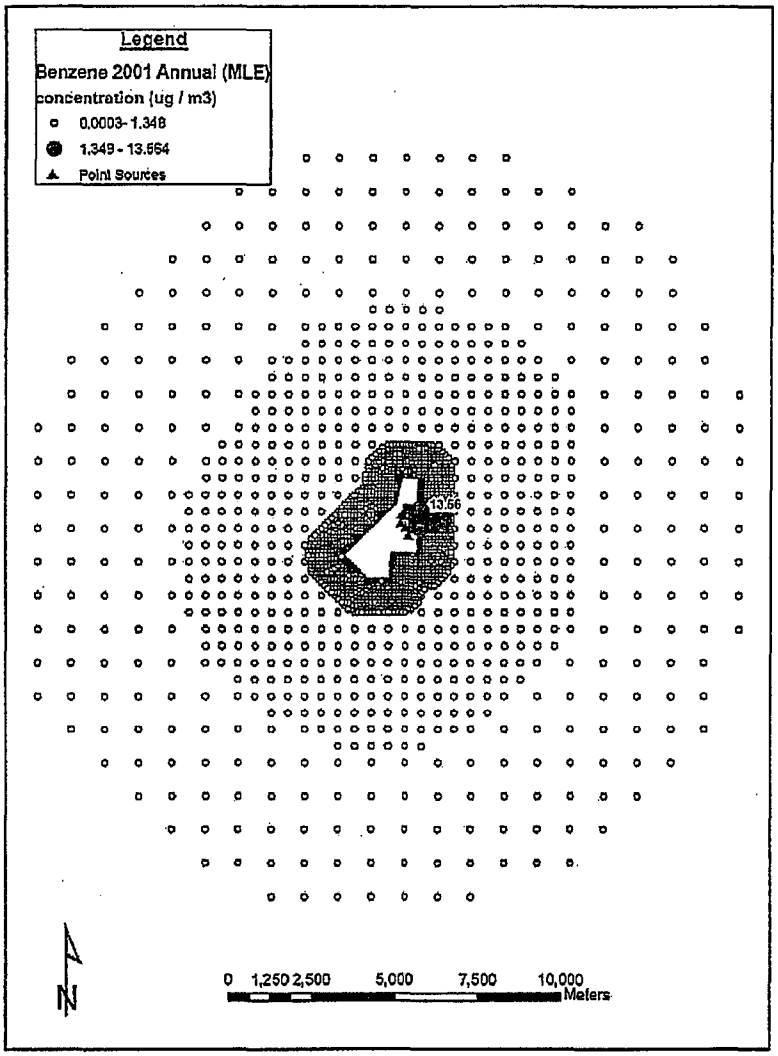
Analysis[1]	HAP	Carcinogenic RfC (Risk Factor)[2] ($1/\mu g/m^3$)	Exposure Adjustment Factor	Maximum Annually Averaged Modeled Concentrations ($\mu g/m^3$)	Estimated Long-Term Exposure Risk
MLE	Benzene	7.80E-06	0.095	0.23451	1.74E-07
MLE	Formaldehyde	5.50E-09	0.095	0.0427	2.23108E-11
MEI	Benzene	7.80E-06	1	0.23451	1.83E-06
MEI	Formaldehyde	5.50E-09	1	0.0427	2.3485E-10

1. EPA Air Toxics Database, Table 1 (EPA, 2005c).

Figures 6.15 and 6.16 show the receptor locations with respect to the Plant including the maximum annually averaged concentrations for benzene for each receptor. Concentration ranges are colored based on the incremental cancer risk analysis. Figure 6.15 corresponds to the MLE and Figure 6.16 corresponds to the MEI. Each blue dot represents receptors that have concentrations that are at a 1×10^{-6} (1-in-a-million) risk or greater of developing cancer. Yellow receptors indicate a lower risk of developing cancer. Formaldehyde concentrations do not translate to the 1×10^{-6} risk threshold and therefore are not shown graphically.

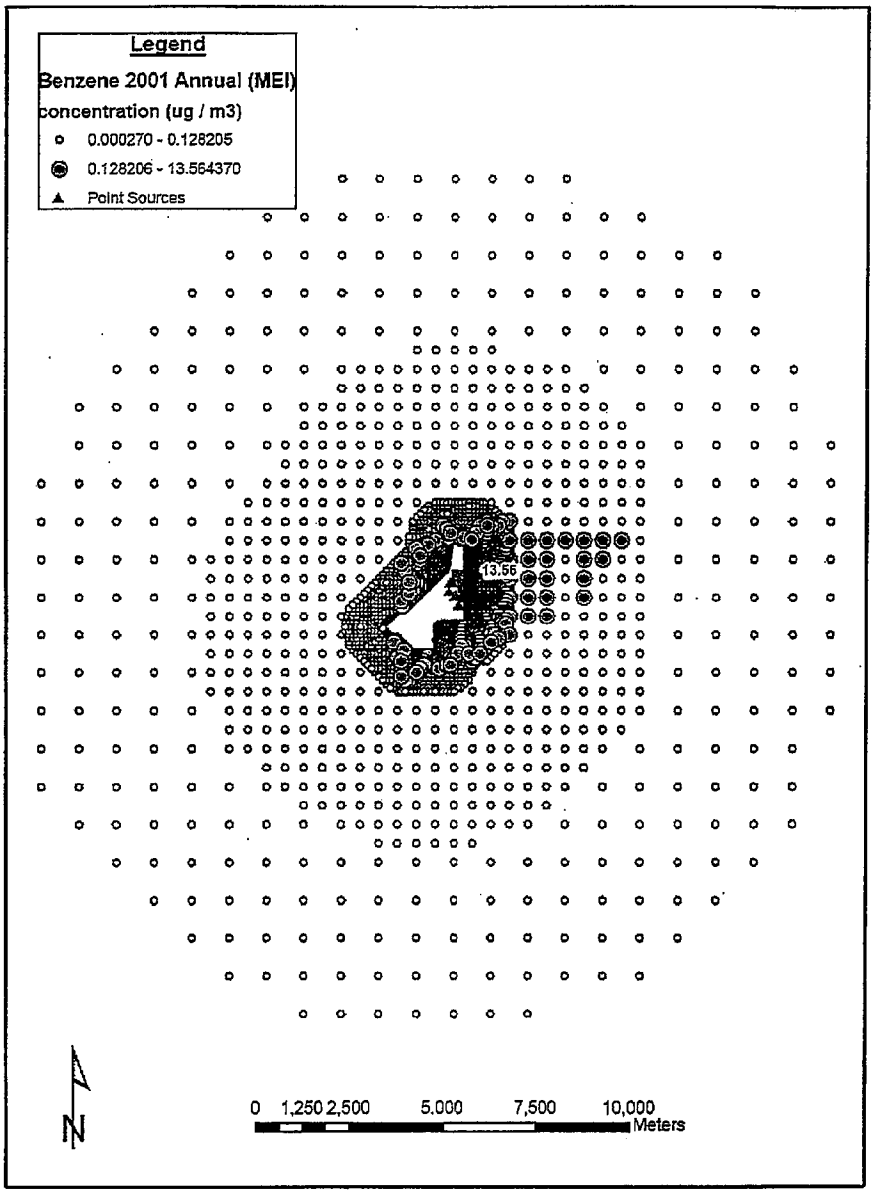
For the MLE analysis; a concentration of 1.349528 $\mu g/m^3$ corresponds to a 1×10^{-6} risk of developing cancer due to benzene exposure from Plant emissions.

Figure 6.15 – MLE Receptors for Benzene



For the MEI exposure analysis; a concentration of 0.128205 $\mu g/m^3$ corresponds to 1×10^{-6} risk.

Figure 6.16 – MEI Receptors for Benzene



6.7.4 HAP Conclusion

All maximum 1-hour and maximum annual predicted HAP concentrations are below the applicable RELs and RfCs, respectively. Based on these recognized EPA thresholds, short-term HAP exposure resulting from Plant emissions meets applicable criteria.

With regard to carcinogenic pollutants, predicted formaldehyde concentrations do not exceed a 1×10^{-6} risk at any modeled receptor. In contrast, benzene concentrations do exceed this risk

threshold at some locations. MLE greater than 1×10^{-6} risk occurs only along the east side of the Plant, while MEI exposure greater than 1×10^{-6} risk occurs along the south, east, and north Plant boundaries. The 1×10^{-6} MEI risk begins to fade away at 500 meters from the south and north Plant boundaries. To the east, MEI exposures greater than 1×10^{-6} risk extend beyond 500 meters out to 5 km.

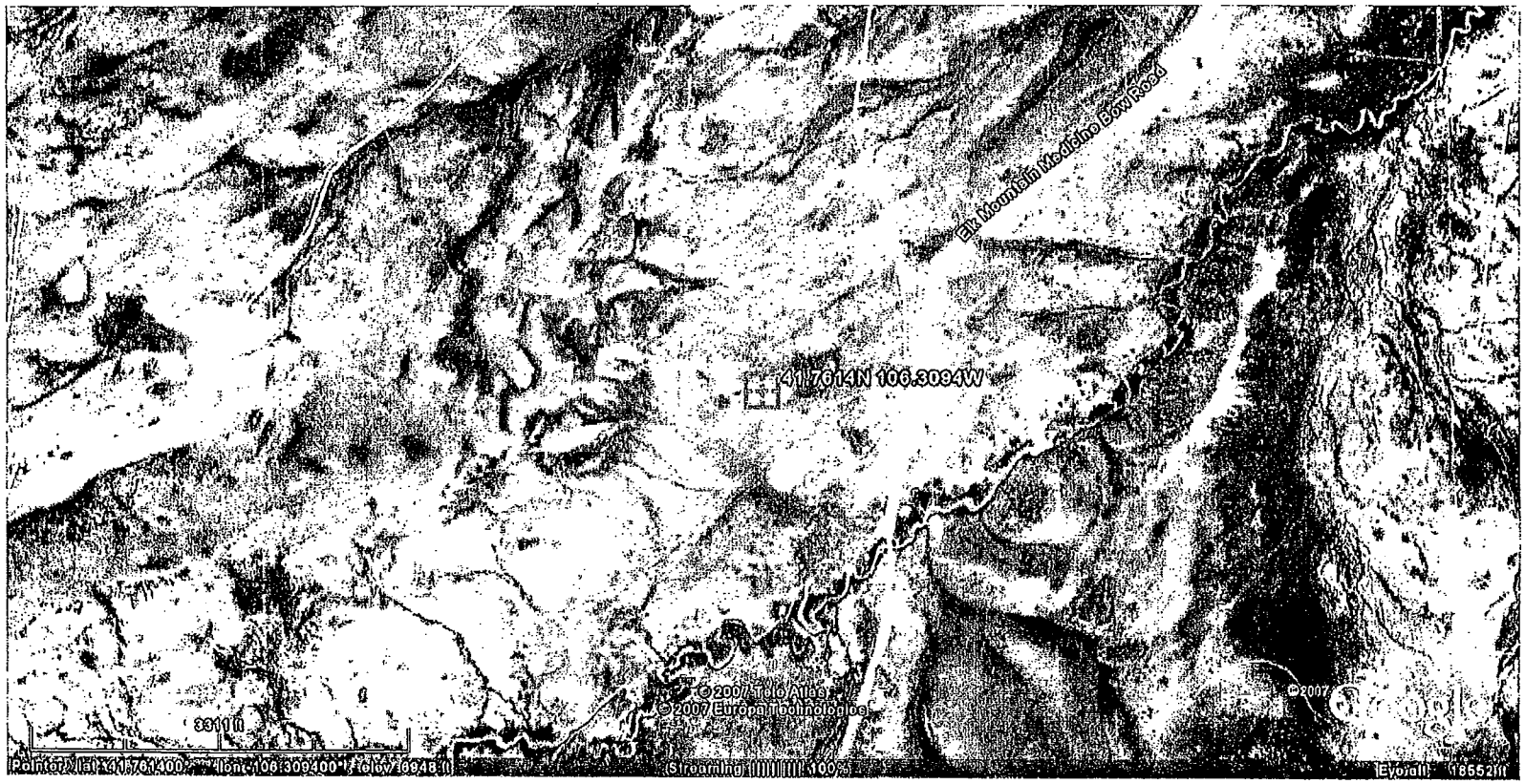
As mentioned earlier, the closest residence is 3.3 km to the south of the Plant. Consequently, occupants of this residence would have a less than 1×10^{-6} risk of developing cancer due to exposure to Plant emissions of benzene or formaldehyde. As shown in the wind rose in Figure 6.6, prevailing winds blow from the west or west-southwest more than 52 percent of the time. Winds blowing from the north are rare.

6.8 IMPACTS TO SOIL AND VEGETATION

Areas surrounding the proposed Plant are of limited agricultural and commercial value and are shown in Figure 6.17 (the facility source location is indicated by coordinates). The terrain in the immediate Plant vicinity is generally rolling with a fairly uniform land cover. Views of the area presented in Figures 6.1 and 6.2 and comparison with Figure 6.17 suggests the general lack of commercial or recreational use in the project vicinity.

The potential to emit from the Plant includes four criteria pollutants (CO, NO_x, SO_2, and PM/PM_{10}) that will be emitted in excess of PSD significant impact levels. The impacts of each of these pollutant emissions from the project are below the primary and secondary NAAQS shown. Secondary NAAQS standards are expressly designed to protect public welfare, including protection of soils, vegetation, and other environmental and man-made attributes.

Figure 6.17 - Aerial View of Land Use Immediately Surrounding the Plant



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6.8.1 Soil Impacts

The US Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS) has compiled a detailed list of agricultural yields and soil types for portions of Carbon County. Of the over 540,000 acres surveyed, land capability is classified as Class 3 or worse (no soils are designated as Class 5). Soil within the surveyed areas of the county is classified as follows:

- Class 3: Soils have severe limitations that reduce the choice of plants or that require special conservation practices, or both.
- Class 4: Soils have very severe limitations that reduce the choice of plants or that require very careful management, or both.
- Class 6: Soils have severe limitations that make them generally unsuitable for cultivation. Rangeland or forestry improvements can be applied.
- Class 7: Soils have very severe limitations that make them unsuitable for cultivation. They can be used for forestry or grazing, but rangeland improvements are impractical.
- Class 8: Soils and miscellaneous areas have limitations that nearly preclude their use for commercial crop production.

Only 1 percent of the surveyed land produces alfalfa or hay without using irrigation. With regard to irrigated land (accounting for a small portion of the county), the most productive land produces up to 5 tons of alfalfa per acre. Assuming a value of $130/ton of alfalfa, maximum cropland production value is $650/acre on the best-producing land included in the NRCS survey of Carbon County. Based on this information, most Carbon County land does not have significant commercial value. NRCS crop yields are provided in Appendix K. The NRCS soil survey is provided in Appendix L.

Little information on direct gaseous air pollutant effects on soil is available in the current literature. While certain soils can be an effective sink for gaseous pollutants such as NO_2 and some studies have been done, accurate methods for routinely quantifying the effects of NO_2 and other pollutants on soil in the field do not exist. The rate of adsorption is dependent on the distance from the source, concentrations in the air, soil properties, vegetative cover, and the prevailing hydrological and meteorological conditions. No significant impacts on soils from exposures to acidic gases such as NO_2 occur unless the soils experience a large decrease in buffering capacity and the pH of precipitation drops dramatically (Smith, 1981). Because NO_x ambient concentration increases attributable to the Plant and surrounding sources represent less than 13 percent of the secondary NAAQS for this pollutant, soil impacts are expected to be low.

6.8.2 Vegetation Impacts

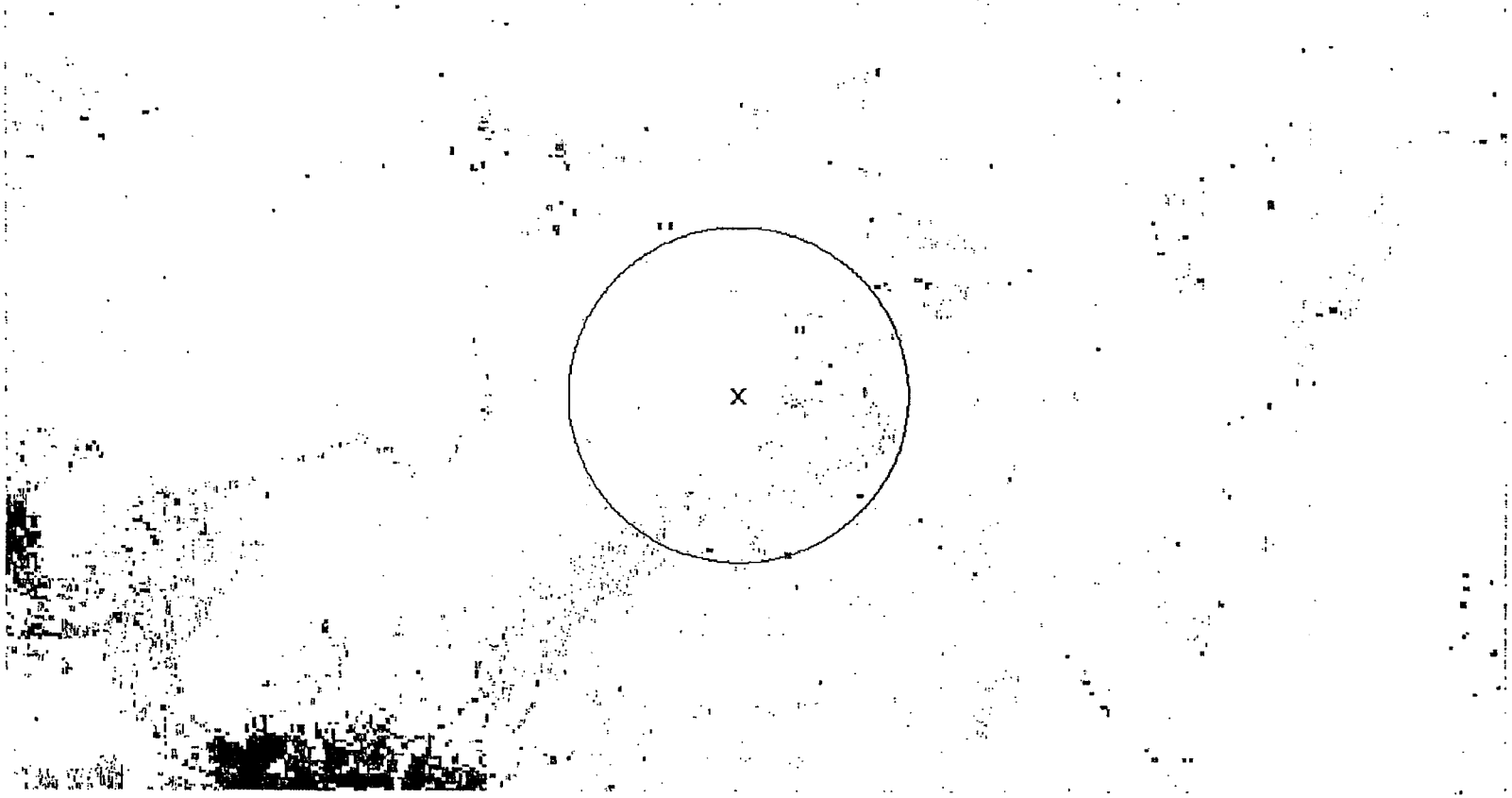
The Plant is located within a gently rolling landscape. The commercial productivity of the lands around the immediate Medicine Bow area is very low. There are some areas with limited agriculture within 10 km of the site. The closest cropland is approximately 2.3 km from the Plant. Primary land use and vegetation cover is depicted in Figure 6.18, which shows that the predominant land use is fallow or shrubland. Only a small percentage of the land surrounding the facility is cropland. A review of the Wyoming Department of Agriculture and livestock census suggests that Carbon County lands are generally low in productivity (see Appendix M).

Damage or injury to plants from air pollutants is caused primarily through foliage injury and not by absorption through the plant roots. As a result, ambient air concentrations of pollutants are the primary indicators of potential impact. The concentration of a pollutant and the duration of the exposure period are collectively referred to as the dose; the lowest dose that produces an effect is called the threshold dose. However, because of the relationship between concentration and time, there is no single threshold dose for an effect.

Reduction in yield, whether quantitative or qualitative, is also of prime importance but is difficult to measure. Foliar damage to root crops, for example, may bear no relationship to the amount of economic damage incurred. If injury occurs near harvest time, there may be no detectable yield loss (Capron and Mansfield, 1976).

Figure 6.18 - Land Use and Vegetation Cover near the Plant Site

(Light yellow denotes cropland, darker green is forest, blue is water, light tan is fallow, and dark tan is shrubland)



Distance Ring Radius is 10 km

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6.8.2.1 Effects of NO_X

The direct effects of NO_x on vegetation are usually associated with and confined to areas near specific industrial sources. For example, vegetation injury from exposure to high NO_2 concentrations has been observed near nitric acid factories and arsenals, but there is little published information regarding vegetation injury in the field due to NO or other NO_x (U.S. EPA, 1982a).

Many reports, however, have substantiated NO_x effects on vegetation grown in laboratory conditions (Hill and Bennett, 1970; Capron and Mansfield, 1976; Czeh and Nothdruft, 1951; Taylor et al., 1975; Kress, 1982). A threshold value of 191 $\mu g/m^3$ for long-term (10,000-hour) laboratory exposures of crops and trees has been widely used (U.S. EPA, 1982a). The maximum modeled NO_x increase from the proposed Plant and surrounding sources is low (12.80 $\mu g/m^3$ based on annual averaging) and well below the threshold value (191 $\mu g/m^3$). Therefore, no detrimental effects on vegetation in the project area will likely result from NO_x emissions from the Plant.

6.8.2.2 Effects of SO_2

SO_2 enters vegetation in gaseous form through openings in the plant's leaf surface called stomata. Once inside the leaf, SO_2 contacts wet, cellular membranes, and sulfites and sulfates may be formed. The formation of these compounds can cause changes in the plant's metabolic system that will produce physiological dysfunctions (U.S. EPA, 1982b).

Short-term (1-hour) peak SO_2 concentrations are particularly important when assessing potential vegetation impacts (Houston, 1974). Laboratory experiments have demonstrated greater relative toxicity of short-term exposures at high SO_2 concentrations than long-term exposures with the same total treatment (Zahn, 1970; McLaughlin et al., 1979; Sij, Kanemasu, and Goltz, 1974; Wilhour et al., 1978; Miller et al., 1979; Sprugel et al., 1980; Houston, 1974; Berry, 1972; Temple, 1972).

The maximum SO_2 concentration increase from the proposed Plant (4.51 $\mu g/m^3$ based on annual averaging) is far less than the lowest concentration of 240 $\mu g/m^3$ (Miller et al., 1979; Sprugel et al., 1980) that has been shown to reduce yield in the most sensitive agricultural crop, soybean, and the 390 $\mu g/m^3$ (Houston, 1974) forest species threshold.

6.8.2.3 Effects of PM/PM_{10}

Adverse impacts on vegetation from PM/PM_{10} are most often associated with sustained accumulation of particles such as dust or fly ash on the leaf surface. Such particle accumulation on leaves can result in reduced gas exchange, increased leaf temperature, reduced photosynthesis, and eventual yellowing and tissue desiccation (Parish, 1910; Darley, 1966).

The maximum modeled PM/PM_{10} impact from the proposed Plant is 6.15 $\mu g/m^3$ (annual average). At less than 13 percent of the WAAQS, this increase in particulate concentration is not expected to cause plant injury.

6.9 REFERENCES FOR CHAPTER 6

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7.1 BACKGROUND

NOTE: The far field modeling analysis presented in this section is based on emissions and process parameters described in the original Permit Application dated June 19, 2007. This analysis is presented in its entirety to comprehensively describe the modeling conducted for the June 2007 permit application. The far field modeling analysis was supplemented on October 17, 2007 in response to comments from the WDEQ. These responses are included in Appendix J.

MBFP believes that this far field criteria pollutant modeling analysis should be considered to be sufficient with regard to criteria pollutants emitted by the proposed facility based on the revised process design. A comparison of revised emission rates and previously modeled emission rates is presented in Appendix I.

As discussed in Section 1.2 of this application, the project is a major stationary source under the PSD program and therefore has completed an analysis of potential long-range impacts in support of a requested air quality construction permit.

Air quality impact analysis for Class I and sensitive Class II areas within 300 km from the project was conducted using the EPA long-range dispersion model, CALPUFF. The CALPUFF analysis included 8 Class I areas and 1 Class II area. The nearest Class I area, which is Mount Zirkel Wilderness, is located approximately 93 km southwest from the facility. Class I and sensitive Class II areas within 300 km from the facility are listed in Table 7.1. There is one sensitive Class II area within 300 km from the facility, named Savage Run, which is located approximately 60 km south from the facility.

In addition, soils and vegetation analysis was conducted. Additional impact analysis was not conducted because modeling results did not show significant air quality impact on Class I and sensitive Class II areas. Therefore, visibility analysis for scenic and important views and impact analysis for water was not conducted and the additional analyses areas are not listed in the Table 7-1.

Table 7.1 – Class I Areas and Sensitive Class II Areas Within 300 km

	Areas
Class I Areas	Rocky Mountain National Park, Rawah Wilderness, Flat Tops Wilderness, Eagles nest Wilderness, Mount Zirkel Wilderness, Maroon Bell-Snowmass Wilderness, Bridger Wilderness, and Fitzpatrick Wilderness
Sensitive Class II Areas	Savage Run

CALPUFF modeling runs were completed for each Class I or Class II area using a worst-case emission inventory. Detailed descriptions of the emission inventories for the modeling analysis were shown in Section 7.2.2.

7.2 DESCRIPTION OF PROPOSED PROJECT

7.2.1 Site Location

The 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, Wyoming. LULC shapefile plotted in ArcGIS shows that most of the area surrounded by the facility is shrub/brush. MBFP will be located in an area that is designated as attainment of all National Ambient Air Quality Standards (NAAQS). The project location for the site is shown in Figure 1.1.

7.2.2 Source Emissions

The facility will consist of the Plant and the Underground coal mine (Saddleback Hills). Construction of both the Plant and the Mine will take about three years. The combustion source at the site will be fuels with syngas during normal operation and pipeline quality natural gas during startup and in the event of a loss of fuel gas (syngas). The facility will require approximately 1000 hours to start all of the process. Once the facility is started, it will not shut down unless there are planned maintenance activity or in the event of a malfunction. The startup is discussed in more detail in Section 2.17 of this application.

Emissions sources will include three (3) combustions turbines, twelve (12) heaters, three (3) generators, one (1) firewater pump, one (1) Emergency Flare, one (1) CO_2 vent, and one (1) Sulfur Plant Incinerator. Detailed emission calculations for these sources are included in Appendix B.

7.2.3 Sources Included in CALPUFF Modeling

Required emissions in CALPUFF correspond with the needed analysis and include maximum short-term rates for increment and visibility impacts, as well as maximum annual emissions for species deposition and increment comparison. Because of the various operations involved and potential occurrence during a specific period, the CALPUFF modeled sources and emissions included potential overlapping operations.

The emission rate derivation is shown in Table 7.2 and the modeled emissions are shown in Table 7.3 (short-term) and Table 7.4 (annual). The overlapping scenarios include the Turbine/HRSG 3 aggregated NO_x emissions and the additive source emissions to account for normal and startup scenarios.

For example, in Table 7.2 the NO_x emission rates shown for source Turbine and HRSG Train 3 feature a higher rate than for the other two turbines. This is done to reflect startup scenarios that would include 18-hours of normal operations and 6-hours of startup operations. Aggregating the two and rating the hourly emissions for each type of operation returns the 24-hour emission rate shown. And the annual emission inventory includes both normal and startup sources, as operating with the annual hours provided.

The CALPUFF modeling also included speciation of emissions according to the National Park Service (NPS)'s Particulate Matter Speciation (PMS) method for natural gas combustion turbines. Applying the PMS methodology, 67% of total SO_2 was speciated into SO_2 and 33% of

Appendix B
Emission Calculations

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

Normal Operations (8760 hr/yr)

			Operation	Potential Emissions (tpy)					HAPs Emissions (tpy)																		
ID No.	Description	Usage	(hr/yr)	NO_x	CO	VOC	SO_2	PM_{10}	1,3-Butadiene	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, 86 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, 86 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, 86 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, 66 MMBtu/hr [1]	8,760	14.17	23.81	1.55	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	1.86E-01			5.64E-05			3.14E-04		1.74E-01
B-2	Reactivation Heater	Heater, 12 MMBtu/hr [1]	8,760	2.67	4.49	0.29	0.03	0.41					1.12E-04		6.42E-05		4.01E-03	9.62E-02			3.26E-05			1.82E-04		1.01E-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		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			3.79E-02		4.95E-01		2.38E+00				5.67E-01	1.80E-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	Fugitives	8,760					50.18																		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	7.39E-04	8.91E-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, 0.616 MMBtu/hr	8,760	0.49	0.98	2.97	2.10E-03																			0.00E+00
FL-2	LP Flare [2]	Flare, 0.204 MMBtu/hr	8,760	0.12	0.25	0.74	0.00																			
Total Emissions				251.83	176.75	209.18	32.65	194.93	0.00	0.38	0.06	0.00	11.08	0.26	0.00	0.34	6.71	1.29	0.00	12.79	0.01	0.02	0.28	1.81	0.77	29.80

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] SO_2 emissions from the Firewater Pump are are based on burning ultra-low sulfur diesel (15 ppm).
[3] Flare emissions include pilot emissions for 8760 hr/yr.

Malfunctions and Other Events

			Operation	Potential Emissions (tons)					HAPs Emissions (tpy)																	
ID No.	Description	Usage	(hours) [1]	NO_x	CO	VOC	SO_2	PM_{10}	1,3-Butadiene	Acetaldehyde	Acrolein	2,2,4-Trimethylpentane	Benzene	Carbonyl Sulfide	Dichlorobenzene	Ethyl Benzene	Formaldehyde	Hexane	Mercury	Methanol	Naphthalene	PAH	Propylene Oxide	Toluene	Xylene	TOTALS
CO2 VS	CO2 Vent Stack	CO2 Vent Stack	50		83.97	0.23							2.25E-01													2.25E-01
FL-1	HP / Emergency Flare	Flare, 0.616 MMBtu/hr	40	7.83	64.99	0.12	150.16																			0.00E+00
FL-2	LP Flare	Flare, 0.204 MMBtu/hr	8	1.15E-02	2.25E-04	6.79E-04	14.40																			
GP-1	Gasification Preheater	Heater, 21.00 MMBtu/hr	500	0.28	0.43	0.03	3.09E-03	0.04					1.08E-05		6.18E-06		3.86E-04	9.26E-03						1.75E-05		9.69E-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
Emission Summary Sheet

Initial Year Including Cold Startup Emissions

This sheet includes total emissions from a cold startup (second set of emissions) and from the remainder of the initial year of operations. The total emissions shown at the bottom of this sheet provide the total emissions for the initial year (or any year with a cold startup).

Normal Operations (After Startup)

ID No.	Description	Usage	Normal Operating Hours After Startup (hr/yr)	Potential Emissions (tpy)					HAPs Emissions (tpy)																		
				NO_x	CO	VOC	SO_2	PM_{10}	1,3-Butadiene	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	7,760	67.20	40.92	5.84	9.56	38.80	1.21E-03	1.12E-01	1.80E-02		3.37E-02			9.00E-02	2.00E-01		1.09E-04		3.66E-03	6.19E-03	8.16E-02	3.66E-01	1.80E-01	1.09E+00
CT-2	Turbine and HRSG Train 2	General Electric, 66 MW	7,760	67.20	40.92	5.84	9.56	38.80	1.21E-03	1.12E-01	1.80E-02		3.37E-02			9.00E-02	2.00E-01		1.09E-04		3.66E-03	6.19E-03	8.16E-02	3.66E-01	1.80E-01	1.09E+00
CT-3	Turbine and HRSG Train 3	General Electric, 66 MW	7,760	67.20	40.92	5.84	9.56	38.80	1.21E-03	1.12E-01	1.80E-02		3.37E-02			9.00E-02	2.00E-01		1.09E-04		3.66E-03	6.19E-03	8.16E-02	3.66E-01	1.80E-01	1.09E+00
AB	Auxiliary Boiler	Heater, 68 MMBtu/hr[1]	8,760	14.17	23.81	1.56	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 [1,2]	8,760	4.62	7.77	0.51	0.08	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	2.67	4.49	0.29	0.03	0.41					1.12E-04		6.42E-05		4.01E-03	9.62E-02			3.26E-05			1.82E-04		1.01E-01
B-3	HGT Reactor Charge Heater	Heater, 2 MMBtu/hr[1]	8,760	0.46	0.80	0.05	0.01	0.07					2.00E-05		1.14E-05		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		3.79E-02			4.95E-01		2.39E+00				5.67E-01	1.50E-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	Fugitives	8,760					50.18																		0.00E+00
FW-Pump	Firewater Pump[3]	Engine, 675 HP	500	1.51	0.09	0.34	1.52E-03	0.02	3.77E-05	7.39E-04	8.91E-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[4]	Flare Pilot, 0.816 MMBtu/hr	8,760	0.49	0.98	2.97	2.10E-03																			0.00E+00
FL-2	LP Flare[4]	Flare Pilot, 0.204 MMBtu/hr	8,760	0.12	0.25	0.74	0.00																			
Total Emissions (Partial Year of Normal Operations)				225.65	160.94	197.92	28.95	179.93	3.67E-03	3.38E-01	5.41E-02	0.00E+00	1.11E+01	2.60E-01	5.27E-04	3.08E-01	6.33E-01	1.29E+00	3.28E-04	1.28E+01	1.13E-02	1.86E-02	2.47E-01	1.67E+00	7.00E-01	29.38

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 natural gas.
During startup periods, the equipment will fire natural gas, and may or may not operate at full capacity. Emissions are based on operation at full load and 8,760 hrs/year as a conservative estimate.
[2] The catalyst regenerator heater (B-1) will not operate during startup conditions; it will operate only during times of normal facility operation. Therefore, in a startup year, the heater will operate less than 8,760 hrs. A full year of operation is assumed as a conservative emission estimate.
[3] SO_2 emissions from the Firewater Pump are are based on burning ultra-low sulfur diesel (15 ppm).
[4] Flare emissions include pilot emissions for 8760 hr/yr.

Cold Startup

ID No.	Description	Usage	Startup Operating Hours (hr/yr)	Potential Emissions (tpy)					HAPs Emissions (tpy)																		
				NO_x	CO	VOC	SO_2	PM_{10}	1,3-Butadiene	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	1,000	9.48	5.69	0.81	1.33	5.00	1.69E-04	1.57E-02	2.51E-03		4.71E-03			1.26E-02	2.79E-02		1.52E-05		5.10E-04	8.64E-04	1.14E-02	5.10E-02	2.51E-02	1.52E-01
CT-2	Turbine and HRSG Train 2	General Electric, 66 MW	1,000	9.48	5.69	0.81	1.33	5.00	1.69E-04	1.57E-02	2.51E-03		4.71E-03			1.26E-02	2.79E-02		1.52E-05		5.10E-04	8.64E-04	1.14E-02	5.10E-02	2.51E-02	1.52E-01
CT-3	Turbine and HRSG Train 3	General Electric, 66 MW	1,000	9.48	5.69	0.81	1.33	5.00	1.69E-04	1.57E-02	2.51E-03		4.71E-03			1.26E-02	2.79E-02		1.52E-05		5.10E-04	8.64E-04	1.14E-02	5.10E-02	2.51E-02	1.52E-01
Gen-1	Black-Start Generator	Caterpillar, 2889 HP	360	1.15	2.79	1.03	2.06E-03	2.71E-04	9.37E-04	2.93E-02	1.80E-02	8.77E-04	7.44E-04				1.85E-01	3.90E-04								1.43E-03	6.46E-04	2.36E-01
Gen-2	Black-Start Generator	Caterpillar, 2889 HP	360	1.15	2.79	1.03	2.06E-03	2.71E-04	9.37E-04	2.93E-02	1.80E-02	8.77E-04	7.44E-04				1.85E-01	3.90E-04								1.43E-03	6.46E-04	2.36E-01
Gen-3	Black-Start Generator	Caterpillar, 2889 HP	360	1.15	2.79	1.03	2.06E-03	2.71E-04	9.37E-04	2.93E-02	1.80E-02	8.77E-04	7.44E-04				1.85E-01	3.90E-04								1.43E-03	6.46E-04	2.36E-01
GP-1	Gasifier Preheater	Heater, 21.00 MMBtu/hr	500	0.26	0.43	0.03	3.09E-03	0.04					1.08E-05		6.18E-06		3.86E-04	9.26E-03						1.75E-05		9.69E-03
GP-2	Gasifier Preheater	Heater, 21.00 MMBtu/hr	500	0.26	0.43	0.03	3.09E-03	0.04					1.08E-05		6.18E-06		3.86E-04	9.26E-03						1.75E-05		9.69E-03
GP-3	Gasifier Preheater	Heater, 21.00 MMBtu/hr	500	0.26	0.43	0.03	3.09E-03	0.04					1.08E-05		6.18E-06		3.86E-04	9.26E-03						1.75E-05		9.69E-03
GP-4	Gasifier Preheater	Heater, 21.00 MMBtu/hr	500	0.26	0.43	0.03	3.09E-03	0.04					1.08E-05		6.18E-06		3.86E-04	9.26E-03						1.75E-05		9.69E-03
GP-5	Gasifier Preheater	Heater, 21.00 MMBtu/hr	500	0.26	0.43	0.03	3.09E-03	0.04					1.08E-05		6.18E-06		3.86E-04	9.26E-03						1.75E-05		9.69E-03
CO2 VS	CO2 Vent Stack	CO2 Vent Stack	250		314.89	0.84								8.44E-01												8.44E-01
FL-1	HP / Emergency Flare[1]	Venting to Flare, 0.816 MMBtu/hr	50	9.78	80.88	0.14	187.70																			0.00E+00
FL-2	LP Flare[1]	Venting to Flare, 0.204 MMBtu/hr	20	0.03	0.19	0.00	36.01																			0.00E+00
Total Emissions (Cold Startup Only, Partial Year)				42.99	423.55	6.64	227.74	15.20	3.32E-03	1.35E-01	6.16E-02	2.63E-03	1.64E-02	8.44E-01	3.09E-05	3.77E-02	6.41E-01	4.75E-02	4.55E-05	0.00E+00	1.53E-03	2.59E-03	3.42E-02	1.57E-01	7.73E-02	2.06

Notes:
[1] Flare operating hours include cold startup and malfunctions. Up to 60 hr/yr of venting to the HP Flare and up to 20 hr/yr of venting to the LP Flare are included. Pilot emissions are included above in the Normal Operations summary.

	Potential Emissions (tpy)					HAPs Emissions (tpy)																				
	NO_x	CO	VOC	SO_2	PM_{10}	1,3-Butadiene	Acetaldehyde	Acrolein	2,2,4-Trimethylpentane	Benzene	Carbonyl Sulfide	Dichlorobenzene	Ethyl Benzene	Formaldehyde	Hexane	Mercury	Methanol	Naphthalene	PAH	Propylene Oxide	Toluene	Xylene	TOTALS
TOTAL EMISSIONS FOR COLD STARTUP YEAR	268.64	584.48	204.56	256.69	195.13	0.01	0.47	0.12	0.00	11.08	1.10	0.00	0.35	1.27	1.33	0.00	12.79	0.01	0.02	0.28	1.82	0.76	31.44

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - Initial Year (Cold Start and Remainder Normal Operations [Base Load])

Source ID Number	Turbine and HRSG Train 1
Equipment ID	
Turbine Usage	Power Generation
Turbine Make	GE
Turbine Model	7EA
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Turbine
Emission Controls	SCR/Oxidation Catalyst
Design Output	66 MW
Site Operating Hours	7760 hr/yr
Exhaust Temperature	300 °F

	-12°F	45°F	85°F
Gas Heating Value	16399.6 Btu/lb	16399.6 Btu/lb	16399.6 Btu/lb
Gas Flow Rate	47,910 lb/hr	44,450 lb/hr	40,240 lb/hr
Gas Heat Rate	785.7 MMBtu/hr	729.0 MMBtu/hr	659.9 MMBtu/hr

Potential Emissions from Fuel Gas Mixture Operation (Normal operations, Partial year)

Pollutant	Emission Factor (ppmv, dry)	Emission Factor (lb/MMBtu)	Estimated Hourly Emissions -12°F (lb/hr)	45°F (lb/hr)	85°F (lb/hr)	Max Hourly Emissions (lb/hr)	Estimated Annual Emissions (tpy)	Source of Emission Factor
NOx	6	0.0234	18.40	17.44	16.12	18.40	67.20	Manf. Data[1]
CO	6	0.0143	11.20	10.62	9.81	11.20	40.92	Manf. Data[1]
VOC	1.4 (ppmv, wet)	0.0020	1.59	1.52	1.40	1.59	5.84	Manf. Data[1]
SO2		0.0034	2.67	2.48	2.24	2.67	9.56	AP-42[2]
PM10 Total		0.0127	10.00	10.00	10.00	10.00	38.80	Manf. Data[1]
Mercury	2.24E-06	3.81E-08	2.99E-05	2.84E-05	2.62E-05	2.99E-05	1.09E-04	Manf. Data[1]
1,3-Butadiene		4.30E-07	3.38E-04	3.13E-04	2.84E-04	3.38E-04	1.21E-03	AP-42[2]
Acetaldehyde		4.00E-05	3.14E-02	2.92E-02	2.64E-02	3.14E-02	1.12E-01	AP-42[2]
Acrolein		6.40E-06	5.03E-03	4.67E-03	4.22E-03	5.03E-03	1.80E-02	AP-42[2]
Benzene		1.20E-05	9.43E-03	8.75E-03	7.92E-03	9.43E-03	3.37E-02	AP-42[2]
Ethylbenzene		3.20E-05	2.51E-02	2.33E-02	2.11E-02	2.51E-02	9.00E-02	AP-42[2]
Formaldehyde		7.10E-05	5.58E-02	5.18E-02	4.69E-02	5.58E-02	2.00E-01	AP-42[2]
Naphthalene		1.30E-06	1.02E-03	9.48E-04	8.58E-04	1.02E-03	3.66E-03	AP-42[2]
PAH		2.20E-06	1.73E-03	1.60E-03	1.45E-03	1.73E-03	6.19E-03	AP-42[2]
Propylene Oxide		2.90E-05	2.28E-02	2.11E-02	1.91E-02	2.28E-02	8.16E-02	AP-42[2]
Toluene		1.30E-04	1.02E-01	9.48E-02	8.58E-02	1.02E-01	3.66E-01	AP-42[2]
Xylene		6.40E-05	5.03E-02	4.67E-02	4.22E-02	5.03E-02	1.80E-01	AP-42[2]

Exhaust Composition		Base Load, Temp. = -12°F		Base Load, Temp. = 45°F		Base Load, Temp. = 85°F	
Component	Mol. Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	1.03	0.41	1.03	0.41	1.03	0.41
Nitrogen	28.02	77.34	21.67	76.82	21.52	76.61	21.47
Oxygen	32.00	12.08	3.87	12.22	3.91	12.37	3.96
Carbon Dioxide	44.01	3.32	1.46	3.23	1.42	3.17	1.40
Water	18.02	6.23	1.12	6.71	1.21	6.73	1.21
		100.0	28.5	100.0	28.5	99.9	28.4

Calculation of dry mass flow rate:	Base Load, Temp. = 0°F		Base Load, Temp. = 45°F		Base Load, Temp. = 80°F	
Mass flow of exhaust =	2.03E+06	lb/hr	1.93E+06	lb/hr	1.78E+06	lb/hr
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =	71079.6	lb-mol/hr	67738.0	lb-mol/hr	62614.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =	4428.3	lb-mol/hr	4545.2	lb-mol/hr	4214.0	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =	8586.4	lb-mol/hr	8277.6	lb-mol/hr	7745.5	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=	66651.4	lb-mol/hr	63192.8	lb-mol/hr	58400.9	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =	12.9%		13.1%		13.3%	
total exhaust flow, acfm	499,773		476,277		440,256	

[1] Criteria pollutant emission factors provided by the manufacturer, but in some cases have been adapted from natural gas combustion. The NOx emission factor is corrected to 15% O2.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are very similar to the emissions produced during fuel gas combustion, so these emission factors should provide representative emission estimates.

Additional notes:

All gas flow rates and compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/17/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

The operating hours include 500 hours for malfunction and warm start-up.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - SSM Emissions, Natural Gas Firing (Cold Start-up)

Source ID Number	Turbine and HRSG Train 1
Design Output	66 MW
Cold Operating Hours	6 hr/yr
Normal Operating Hours	994 hr/yr
Natural Gas Heating Value	21515 Btu/lb
Natural Gas Flow Rate	36,495 lb/hr
Natural Gas Heat Rate	785.2 MMBtu/hr
Gas Flow Rate	0.77 MMscf/hr

Potential Emissions from Natural Gas Operation (Cold Startup, Partial year)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (ppmv, dry)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx (cold)		25	77.56	0.23	Manf. Data[1]
NOx (normal)		6	18.61	9.25	Manf. Data[1]
CO (cold)		10	18.89	0.06	Manf. Data[1]
CO (normal)		6	11.33	5.63	Manf. Data[1]
VOC		1.4 (ppmv, wet)	1.62	0.81	Manf. Data[1]
SO2	0.0034		2.67	1.33	Eng. Est.[4]
PM10 Total			10.00	5.00	Manf. Data[1]
Mercury		2.240E-06	3.03E-05	1.52E-05	Manf. Data[1]
1,3-Butadiene	4.30E-07		3.38E-04	1.69E-04	AP-42[2]
Acetaldehyde	4.00E-05		3.14E-02	1.57E-02	AP-42[2]
Acrolein	6.40E-06		5.03E-03	2.51E-03	AP-42[2]
Benzene	1.20E-05		9.42E-03	4.71E-03	AP-42[2]
Ethylbenzene	3.20E-05		2.51E-02	1.26E-02	AP-42[2]
Formaldehyde	7.10E-05		5.57E-02	2.79E-02	AP-42[2]
Naphthalene	1.30E-06		1.02E-03	5.10E-04	AP-42[2]
PAH	2.20E-06		1.73E-03	8.64E-04	AP-42[2]
Propylene Oxide	2.90E-05		2.28E-02	1.14E-02	AP-42[2]
Toluene	1.30E-04		1.02E-01	5.10E-02	AP-42[2]
Xylene	6.40E-05		5.03E-02	2.51E-02	AP-42[2]

Exhaust Composition — Base Load, Temp. = 0°F

Component	Mol. Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	0.9	0.36
Nitrogen	28.02	75.5	21.16
Oxygen	32.00	13.88	4.44
Carbon Dioxide	44.01	3.22	1.42
Water	18.02	6.5	1.17
		100.0	28.5

Calculation of dry mass flow rate:

Mass flow of exhaust =	2.06E+06	lb/hr	
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =		72132.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =		4688.6	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =		10012.0	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=		67444.3	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =		14.8%	

[1] Criteria pollutant emission factors provided by the manufacturer. The NOx emission factor is corrected to 15% O2. Cold operation emissions assume that the SCR / oxidation catalyst is not operating. Nitrogen injection is assumed; however, nitrogen may not be available until the Air separation Unit is operating.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines.

Additional notes:

These emissions are calculated assuming an ambient temperature of -12°F, which produces the worst case emission estimate.
All natural gas heat rates, flow rates, and exhaust compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/18/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - Normal Operations (Base Load)

Source ID Number	Turbine and HRSG Train 1
Equipment ID	
Turbine Usage	Power Generation
Turbine Make	GE
Turbine Model	7EA
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Turbine
Emission Controls	SCR/Oxidation Catalyst
Design Output	66 MW
Site Operating Hours	8760 hr/yr
Exhaust Temperature	300 °F

	-12°F	45°F	85°F
Gas Heating Value	16399.6 Btu/lb	16399.6 Btu/lb	16399.6 Btu/lb
Gas Flow Rate	47,910 lb/hr	44,450 lb/hr	40,240 lb/hr
Gas Heat Rate	785.7 MMBtu/hr	729.0 MMBtu/hr	659.9 MMBtu/hr

Potential Emissions from Fuel Gas Mixture Operation

Pollutant	Emission Factor (ppmv, dry)	Emission Factor (lb/MMBtu)	Estimated Hourly Emissions -12°F (lb/hr)	45°F (lb/hr)	85°F (lb/hr)	Max Hourly Emissions (lb/hr)	Estimated Annual Emissions (tpy)	Source of Emission Factor
NOx	6	0.0234	18.40	17.44	16.12	18.40	75.86	Manf. Data[1]
CO	6	0.0143	11.20	10.62	9.81	11.20	46.19	Manf. Data[1]
VOC	1.4 (ppmv, wet)	0.0020	1.59	1.52	1.40	1.59	6.59	Manf. Data[1]
SO2		0.0034	2.67	2.48	2.24	2.67	10.79	AP-42[2]
PM10 Total		0.0127	10.00	10.00	10.00	10.00	43.80	Manf. Data[1]
Mercury	2.24E-06	3.81E-08	2.99E-05	2.84E-05	2.62E-05	2.99E-05	1.23E-04	Manf. Data[1]
1,3-Butadiene		4.30E-07	3.38E-04	3.13E-04	2.84E-04	3.38E-04	1.37E-03	AP-42[2]
Acetaldehyde		4.00E-05	3.14E-02	2.92E-02	2.64E-02	3.14E-02	1.27E-01	AP-42[2]
Acrolein		6.40E-06	5.03E-03	4.67E-03	4.22E-03	5.03E-03	2.03E-02	AP-42[2]
Benzene		1.20E-05	9.43E-03	8.75E-03	7.92E-03	9.43E-03	3.81E-02	AP-42[2]
Ethylbenzene		3.20E-05	2.51E-02	2.33E-02	2.11E-02	2.51E-02	1.02E-01	AP-42[2]
Formaldehyde		7.10E-05	5.58E-02	5.18E-02	4.69E-02	5.58E-02	2.25E-01	AP-42[2]
Naphthalene		1.30E-06	1.02E-03	9.48E-04	8.58E-04	1.02E-03	4.13E-03	AP-42[2]
PAH		2.20E-06	1.73E-03	1.60E-03	1.45E-03	1.73E-03	6.98E-03	AP-42[2]
Propylene Oxide		2.90E-05	2.28E-02	2.11E-02	1.91E-02	2.28E-02	9.21E-02	AP-42[2]
Toluene		1.30E-04	1.02E-01	9.48E-02	8.58E-02	1.02E-01	4.13E-01	AP-42[2]
Xylene		6.40E-05	5.03E-02	4.67E-02	4.22E-02	5.03E-02	2.03E-01	AP-42[2]

Exhaust Composition		Base Load, Temp. = -12°F		Base Load, Temp. = 45°F		Base Load, Temp. = 85°F	
Component	Mol. Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	1.03	0.41	1.03	0.41	1.03	0.41
Nitrogen	28.02	77.34	21.67	76.82	21.52	76.61	21.47
Oxygen	32.00	12.08	3.87	12.22	3.91	12.37	3.96
Carbon Dioxide	44.01	3.32	1.46	3.23	1.42	3.17	1.40
Water	18.02	6.23	1.12	6.71	1.21	6.73	1.21
		100.0	28.5	100.0	28.5	99.9	28.4

Calculation of dry mass flow rate:	Base Load, Temp. = 0°F		Base Load, Temp. = 45°F		Base Load, Temp. = 80°F	
Mass flow of exhaust =	2.03E+06	lb/hr	1.93E+06	lb/hr	1.78E+06	lb/hr
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =	71079.6	lb-mol/hr	67738.0	lb-mol/hr	62614.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =	4428.3	lb-mol/hr	4545.2	lb-mol/hr	4214.0	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =	8586.4	lb-mol/hr	8277.6	lb-mol/hr	7745.5	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=	66651.4	lb-mol/hr	63192.8	lb-mol/hr	58400.9	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =	12.9%		13.1%		13.3%	
total exhaust flow, acfm	499,773		476,277		440,256	

[1] Criteria pollutant emission factors provided by the manufacturer, but in some cases have been adapted from natural gas combustion. The NOx emission factor is corrected to 15% O2.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are greater than or equal to the emissions produced during fuel gas combustion, so these emission factors should provide worst case emission estimates.

Additional notes:

All gas flow rates and compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/17/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - Initial Year (Cold Start and Remainder Normal Operations [Base Load])

Source ID Number	Turbine and HRSG Train 2
Equipment ID	
Turbine Usage	Power Generation
Turbine Make	GE
Turbine Model	7EA
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Turbine
Emission Controls	SCR/Oxidation Catalyst
Design Output	66 MW
Site Operating Hours	7760 hr/yr
Exhaust Temperature	300 °F

	-12°F	45°F	85°F
Gas Heating Value	16399.6 Btu/lb	16399.6 Btu/lb	16399.6 Btu/lb
Gas Flow Rate	47,910 lb/hr	44,450 lb/hr	40,240 lb/hr
Gas Heat Rate	785.7 MMBtu/hr	729.0 MMBtu/hr	659.9 MMBtu/hr

Potential Emissions from Fuel Gas Mixture Operation (Normal operations, Partial year)

Pollutant	Emission Factor (ppmv, dry)	Emission Factor (lb/MMBtu)	Estimated Hourly Emissions -12°F (lb/hr)	45°F (lb/hr)	85°F (lb/hr)	Max Hourly Emissions (lb/hr)	Estimated Annual Emissions (tpy)	Source of Emission Factor
NOx	6	0.0234	18.40	17.44	16.12	18.40	67.20	Manf. Data[1]
CO	6	0.0143	11.20	10.62	9.81	11.20	40.92	Manf. Data[1]
VOC	1.4 (ppmv, wet)	0.0020	1.59	1.52	1.40	1.59	5.84	Manf. Data[1]
SO2		0.0034	2.67	2.48	2.24	2.67	9.56	AP-42[2]
PM10 Total		0.0127	10.00	10.00	10.00	10.00	38.80	Manf. Data[1]
Mercury	2.24E-06	3.81E-08	2.99E-05	2.84E-05	2.62E-05	2.99E-05	1.09E-04	Manf. Data[1]
1,3-Butadiene		4.30E-07	3.38E-04	3.13E-04	2.84E-04	3.38E-04	1.21E-03	AP-42[2]
Acetaldehyde		4.00E-05	3.14E-02	2.92E-02	2.64E-02	3.14E-02	1.12E-01	AP-42[2]
Acrolein		6.40E-06	5.03E-03	4.67E-03	4.22E-03	5.03E-03	1.80E-02	AP-42[2]
Benzene		1.20E-05	9.43E-03	8.75E-03	7.92E-03	9.43E-03	3.37E-02	AP-42[2]
Ethylbenzene		3.20E-05	2.51E-02	2.33E-02	2.11E-02	2.51E-02	9.00E-02	AP-42[2]
Formaldehyde		7.10E-05	5.58E-02	5.18E-02	4.69E-02	5.58E-02	2.00E-01	AP-42[2]
Naphthalene		1.30E-06	1.02E-03	9.48E-04	8.58E-04	1.02E-03	3.66E-03	AP-42[2]
PAH		2.20E-06	1.73E-03	1.60E-03	1.45E-03	1.73E-03	6.19E-03	AP-42[2]
Propylene Oxide		2.90E-05	2.28E-02	2.11E-02	1.91E-02	2.28E-02	8.16E-02	AP-42[2]
Toluene		1.30E-04	1.02E-01	9.48E-02	8.58E-02	1.02E-01	3.66E-01	AP-42[2]
Xylene		6.40E-05	5.03E-02	4.67E-02	4.22E-02	5.03E-02	1.80E-01	AP-42[2]

Exhaust Composition		Base Load, Temp. = -12°F		Base Load, Temp. = 45°F		Base Load, Temp. = 85°F	
Component	Mol. Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	1.03	0.41	1.03	0.41	1.03	0.41
Nitrogen	28.02	77.34	21.67	76.82	21.52	76.61	21.47
Oxygen	32.00	12.08	3.87	12.22	3.91	12.37	3.96
Carbon Dioxide	44.01	3.32	1.46	3.23	1.42	3.17	1.40
Water	18.02	6.23	1.12	6.71	1.21	6.73	1.21
		100.0	28.5	100.0	28.5	99.9	28.4

Calculation of dry mass flow rate:	Base Load, Temp. = 0°F		Base Load, Temp. = 45°F		Base Load, Temp. = 80°F	
Mass flow of exhaust =	2.03E+06	lb/hr	1.93E+06	lb/hr	1.78E+06	lb/hr
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =	71079.6	lb-mol/hr	67738.0	lb-mol/hr	62614.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =	4428.3	lb-mol/hr	4545.2	lb-mol/hr	4214.0	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =	8586.4	lb-mol/hr	8277.6	lb-mol/hr	7745.5	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=	66651.4	lb-mol/hr	63192.8	lb-mol/hr	58400.9	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =	12.9%		13.1%		13.3%	
total exhaust flow, acfm	499,773		476,277		440,256	

[1] Criteria pollutant emission factors provided by the manufacturer, but in some cases have been adapted from natural gas combustion. The NOx emission factor is corrected to 15% O2.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are very similar to the emissions produced during fuel gas combustion, so these emission factors should provide representative emission estimates.

Additional notes:

All gas flow rates and compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/17/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

The operating hours include 500 hours for malfunction and warm start-up.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - SSM Emissions, Natural Gas Firing (Cold Start-up)

Source ID Number	Turbine and HRSG Train 2
Design Output	66 MW
Cold Operating Hours	6 hr/yr
Normal Operating Hours	994 hr/yr
Natural Gas Heating Value	21515 Btu/lb
Natural Gas Flow Rate	36,495 lb/hr
Natural Gas Heat Rate	785.2 MMBtu/hr
Gas Flow Rate	0.77 MMscf/hr

Potential Emissions from Natural Gas Operation (Cold Startup, Partial year)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (ppmv, dry)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx (cold)		25	77.56	0.23	Manf. Data[1]
NOx (normal)		6	18.61	9.25	Manf. Data[1]
CO (cold)		10	18.89	0.06	Manf. Data[1]
CO (normal)		6	11.33	5.63	Manf. Data[1]
VOC		1.4 (ppmv, wet)	1.62	0.81	Manf. Data[1]
SO2	0.0034		2.67	1.33	Manf. Data[1]
PM10 Total			10.00	5.00	Manf. Data[1]
Mercury		2.240E-06	3.03E-05	1.52E-05	Manf. Data[1]
1,3-Butadiene	4.30E-07		3.38E-04	1.69E-04	AP-42[2]
Acetaldehyde	4.00E-05		3.14E-02	1.57E-02	AP-42[2]
Acrolein	6.40E-06		5.03E-03	2.51E-03	AP-42[2]
Benzene	1.20E-05		9.42E-03	4.71E-03	AP-42[2]
Ethylbenzene	3.20E-05		2.51E-02	1.26E-02	AP-42[2]
Formaldehyde	7.10E-05		5.57E-02	2.79E-02	AP-42[2]
Naphthalene	1.30E-06		1.02E-03	5.10E-04	AP-42[2]
PAH	2.20E-06		1.73E-03	8.64E-04	AP-42[2]
Propylene Oxide	2.90E-05		2.28E-02	1.14E-02	AP-42[2]
Toluene	1.30E-04		1.02E-01	5.10E-02	AP-42[2]
Xylene	6.40E-05		5.03E-02	2.51E-02	AP-42[2]

Exhaust Composition — Base Load, Temp. = 0°F

Component	Mol. Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	0.9	0.36
Nitrogen	28.02	75.5	21.16
Oxygen	32.00	13.88	4.44
Carbon Dioxide	44.01	3.22	1.42
Water	18.02	6.5	1.17
		100.0	28.5

Calculation of dry mass flow rate:

Mass flow of exhaust =	2.06E+06	lb/hr	
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =		72132.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =		4668.6	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =		10012.0	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=		67444.3	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =		14.8%	

[1] Criteria pollutant emission factors provided by the manufacturer. The NOx emission factor is corrected to 15% O2. Cold operation emissions assume that the SCR / oxidation catalyst is not operating. Nitrogen injection is assumed.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines.

Additional notes:

These emissions are calculated assuming an ambient temperature of -12°F, which produces the worst case emission estimate.
All natural gas heat rates, flow rates, and exhaust compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/18/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - Normal Operations (Base Load)

Source ID Number	Turbine and HRSG Train 2
Equipment ID	
Turbine Usage	Power Generation
Turbine Make	GE
Turbine Model	7EA
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Turbine
Emission Controls	SCR/Oxidation Catalyst
Design Output	86 MW
Site Operating Hours	8760 hr/yr
Exhaust Temperature	300 °F

	-12°F	45°F	85°F
Gas Heating Value	16399.6 Btu/lb	16399.6 Btu/lb	16399.6 Btu/lb
Gas Flow Rate	47,910 lb/hr	44,450 lb/hr	40,240 lb/hr
Gas Heat Rate	785.7 MMBtu/hr	729.0 MMBtu/hr	659.9 MMBtu/hr

Potential Emissions from Fuel Gas Mixture Operation

Pollutant	Emission Factor (ppmv, dry)	Emission Factor (lb/MMBtu)	Estimated Hourly Emissions -12°F (lb/hr)	45°F (lb/hr)	85°F (lb/hr)	Max Hourly Emissions (lb/hr)	Estimated Annual Emissions (tpy)	Source of Emission Factor
NOx	6	0.0234	18.40	17.44	16.12	18.40	75.86	Manf. Data[1]
CO	6	0.0143	11.20	10.62	9.81	11.20	46.19	Manf. Data[1]
VOC	1.4 (ppmv, wet)	0.0020	1.59	1.52	1.40	1.59	6.59	Manf. Data[1]
SO2		0.0034	2.67	2.48	2.24	2.67	10.79	AP-42[2]
PM10 Total		0.0127	10.00	10.00	10.00	10.00	43.80	Manf. Data[1]
Mercury	2.24E-06	3.81E-08	2.99E-05	2.84E-05	2.62E-05	2.99E-05	1.23E-04	Manf. Data[1]
1,3-Butadiene		4.30E-07	3.38E-04	3.13E-04	2.84E-04	3.38E-04	1.37E-03	AP-42[2]
Acetaldehyde		4.00E-05	3.14E-02	2.92E-02	2.64E-02	3.14E-02	1.27E-01	AP-42[2]
Acrolein		6.40E-06	5.03E-03	4.67E-03	4.22E-03	5.03E-03	2.03E-02	AP-42[2]
Benzene		1.20E-05	9.43E-03	8.75E-03	7.92E-03	9.43E-03	3.81E-02	AP-42[2]
Ethylbenzene		3.20E-05	2.51E-02	2.33E-02	2.11E-02	2.51E-02	1.02E-01	AP-42[2]
Formaldehyde		7.10E-05	5.58E-02	5.18E-02	4.69E-02	5.58E-02	2.25E-01	AP-42[2]
Naphthalene		1.30E-06	1.02E-03	9.48E-04	8.58E-04	1.02E-03	4.13E-03	AP-42[2]
PAH		2.20E-06	1.73E-03	1.60E-03	1.45E-03	1.73E-03	6.98E-03	AP-42[2]
Propylene Oxide		2.90E-05	2.28E-02	2.11E-02	1.91E-02	2.28E-02	9.21E-02	AP-42[2]
Toluene		1.30E-04	1.02E-01	9.48E-02	8.58E-02	1.02E-01	4.13E-01	AP-42[2]
Xylene		6.40E-05	5.03E-02	4.67E-02	4.22E-02	5.03E-02	2.03E-01	AP-42[2]

Exhaust Composition		Base Load, Temp. = -12°F		Base Load, Temp. = 45°F		Base Load, Temp. = 85°F	
Component	Mol. Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	1.03	0.41	1.03	0.41	1.03	0.41
Nitrogen	28.02	77.34	21.67	76.82	21.52	76.61	21.47
Oxygen	32.00	12.08	3.87	12.22	3.91	12.37	3.96
Carbon Dioxide	44.01	3.32	1.46	3.23	1.42	3.17	1.40
Water	18.02	6.23	1.12	6.71	1.21	6.73	1.21
		100.0	28.5	100.0	28.5	99.9	28.4

Calculation of dry mass flow rate:	Base Load, Temp. = 0°F		Base Load, Temp. = 45°F		Base Load, Temp. = 80°F	
Mass flow of exhaust =	2.03E+06	lb/hr	1.93E+06	lb/hr	1.78E+06	lb/hr
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =	71079.6	lb-mol/hr	67738.0	lb-mol/hr	62614.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =	4428.3	lb-mol/hr	4545.2	lb-mol/hr	4214.0	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =	8586.4	lb-mol/hr	8277.6	lb-mol/hr	7745.5	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=	66651.4	lb-mol/hr	63192.8	lb-mol/hr	58400.9	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =	12.9%		13.1%		13.3%	
total exhaust flow, acfm	499,773		476,277		440,256	

[1] Criteria pollutant emission factors provided by the manufacturer, but in some cases have been adapted from natural gas combustion. The NOx emission factor is corrected to 15% O2.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are greater than or equal to the emissions produced during fuel gas combustion, so these emission factors should provide worst case emission estimates.

Additional notes:

All gas flow rates and compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/17/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - Initial Year (Cold Start and Remainder Normal Operations [Base Load])

Source ID Number	Turbine and HRSG Train 3
Equipment ID	
Turbine Usage	Power Generation
Turbine Make	GE
Turbine Model	7EA
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Turbine
Emission Controls	SCR/Oxidation Catalyst
Design Output	66 MW
Site Operating Hours	7760 hr/yr
Exhaust Temperature	300 °F

	-12°F	45°F	85°F
Gas Heating Value	16399.6 Btu/lb	16399.6 Btu/lb	16399.6 Btu/lb
Gas Flow Rate	47,910 lb/hr	44,450 lb/hr	40,240 lb/hr
Gas Heat Rate	785.7 MMBtu/hr	729.0 MMBtu/hr	659.9 MMBtu/hr

Potential Emissions from Fuel Gas Mixture Operation (Normal operations, Partial year)

Pollutant	Emission Factor (ppmv, dry)	Emission Factor (lb/MMBtu)	Estimated Hourly Emissions -12°F (lb/hr)	45°F (lb/hr)	85°F (lb/hr)	Max Hourly Emissions (lb/hr)	Estimated Annual Emissions (tpy)	Source of Emission Factor
NOx	6	0.0234	18.40	17.44	16.12	18.40	67.20	Manf. Data[1]
CO	6	0.0143	11.20	10.62	9.81	11.20	40.92	Manf. Data[1]
VOC	1.4 (ppmv, wet)	0.0020	1.59	1.52	1.40	1.59	5.84	Manf. Data[1]
SO2		0.0034	2.67	2.48	2.24	2.67	9.56	AP-42[2]
PM10 Total		0.0127	10.00	10.00	10.00	10.00	38.80	Manf. Data[1]
Mercury	2.24E-06	3.81E-08	2.99E-05	2.84E-05	2.62E-05	2.99E-05	1.09E-04	Manf. Data[1]
1,3-Butadiene		4.30E-07	3.38E-04	3.13E-04	2.84E-04	3.38E-04	1.21E-03	AP-42[2]
Acetaldehyde		4.00E-05	3.14E-02	2.92E-02	2.64E-02	3.14E-02	1.12E-01	AP-42[2]
Acrolein		6.40E-06	5.03E-03	4.67E-03	4.22E-03	5.03E-03	1.80E-02	AP-42[2]
Benzene		1.20E-05	9.43E-03	8.75E-03	7.92E-03	9.43E-03	3.37E-02	AP-42[2]
Ethylbenzene		3.20E-05	2.51E-02	2.33E-02	2.11E-02	2.51E-02	9.00E-02	AP-42[2]
Formaldehyde		7.10E-05	5.58E-02	5.18E-02	4.69E-02	5.58E-02	2.00E-01	AP-42[2]
Naphthalene		1.30E-06	1.02E-03	9.48E-04	8.58E-04	1.02E-03	3.66E-03	AP-42[2]
PAH		2.20E-06	1.73E-03	1.60E-03	1.45E-03	1.73E-03	6.19E-03	AP-42[2]
Propylene Oxide		2.90E-05	2.28E-02	2.11E-02	1.91E-02	2.28E-02	8.16E-02	AP-42[2]
Toluene		1.30E-04	1.02E-01	9.48E-02	8.58E-02	1.02E-01	3.66E-01	AP-42[2]
Xylene		6.40E-05	5.03E-02	4.67E-02	4.22E-02	5.03E-02	1.80E-01	AP-42[2]

Exhaust Composition		Base Load, Temp. = -12°F		Base Load, Temp. = 45°F		Base Load, Temp. = 85°F	
Component	Mol. Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	1.03	0.41	1.03	0.41	1.03	0.41
Nitrogen	28.02	77.34	21.67	76.82	21.52	76.61	21.47
Oxygen	32.00	12.08	3.87	12.22	3.91	12.37	3.96
Carbon Dioxide	44.01	3.32	1.46	3.23	1.42	3.17	1.40
Water	18.02	6.23	1.12	6.71	1.21	6.73	1.21
		100.0	28.5	100.0	28.5	99.9	28.4

Calculation of dry mass flow rate:	Base Load, Temp. = 0°F		Base Load, Temp. = 45°F		Base Load, Temp. = 80°F	
Mass flow of exhaust =	2.03E+06	lb/hr	1.93E+06	lb/hr	1.78E+06	lb/hr
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =	71079.6	lb-mol/hr	67738.0	lb-mol/hr	62614.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =	4428.3	lb-mol/hr	4545.2	lb-mol/hr	4214.0	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =	8586.4	lb-mol/hr	8277.6	lb-mol/hr	7745.5	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=	66651.4	lb-mol/hr	63192.8	lb-mol/hr	58400.9	lb-mol/hr
Vol.% O2, dry = O2 molar flow / Exhaust molar flow =	12.9%		13.1%		13.3%	
total exhaust flow, acfm	499,773		476,277		440,256	

[1] Criteria pollutant emission factors provided by the manufacturer, but in some cases have been adapted from natural gas combustion. The NOx emission factor is corrected to 15% O2.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are greater than or equal to the emissions produced during fuel gas combustion, so these emission factors should provide worst case emission estimates.

Additional notes:

All gas flow rates and compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/17/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

The operating hours include 500 hours for malfunction and warm start-up.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - SSM Emissions, Natural Gas Firing (Cold Start-up)

Source ID Number	Turbine and HRSG Train 3
Design Output	66 MW
Cold Operating Hours	6 hr/yr
Normal Operating Hours	994 hr/yr
Natural Gas Heating Value	21515 Btu/lb
Natural Gas Flow Rate	36,495 lb/hr
Natural Gas Heat Rate	785.2 MMBtu/hr
Gas Flow Rate	0.77 MMscf/hr

Potential Emissions from Natural Gas Operation (Cold Startup, Partial year)

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor (ppmv, dry)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
NOx (cold)		25	77.56	0.23	Manf. Data[1]
NOx (normal)		6	18.61	9.25	Manf. Data[1]
CO (cold)		10	18.89	0.06	Manf. Data[1]
CO (normal)		6	11.33	5.63	Manf. Data[1]
VOC		1.4 (ppmv, wet)	1.62	0.81	Manf. Data[1]
SO2	0.0034		2.67	1.33	Manf. Data[1]
PM10 Total			10.00	5.00	Manf. Data[1]
Mercury		2.240E-06	3.03E-05	1.52E-05	Manf. Data[1]
1,3-Butadiene	4.30E-07		3.38E-04	1.69E-04	AP-42[2]
Acetaldehyde	4.00E-05		3.14E-02	1.57E-02	AP-42[2]
Acrolein	6.40E-06		5.03E-03	2.51E-03	AP-42[2]
Benzene	1.20E-05		9.42E-03	4.71E-03	AP-42[2]
Ethylbenzene	3.20E-05		2.51E-02	1.26E-02	AP-42[2]
Formaldehyde	7.10E-05		5.57E-02	2.79E-02	AP-42[2]
Naphthalene	1.30E-06		1.02E-03	5.10E-04	AP-42[2]
PAH	2.20E-06		1.73E-03	8.64E-04	AP-42[2]
Propylene Oxide	2.90E-05		2.28E-02	1.14E-02	AP-42[2]
Toluene	1.30E-04		1.02E-01	5.10E-02	AP-42[2]
Xylene	6.40E-05		5.03E-02	2.51E-02	AP-42[2]

Exhaust Composition — Base Load, Temp. = 0°F

Component	Mol. Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	0.9	0.36
Nitrogen	28.02	75.5	21.16
Oxygen	32.00	13.88	4.44
Carbon Dioxide	44.01	3.22	1.42
Water	18.02	6.5	1.17
		100.0	28.5

Calculation of dry mass flow rate:

Mass flow of exhaust =	2.06E+06	lb/hr	
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =		72132.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =		4688.6	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =		10012.0	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=		67444.3	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =		14.8%	

[1] Criteria pollutant emission factors provided by the manufacturer. The NOx emission factor is corrected to 15% O2. Cold operation emissions assume that the SCR / oxidation catalyst is not operating. Nitrogen injection is assumed.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines.

Additional notes:

These emissions are calculated assuming an ambient temperature of -12°F, which produces the worst case emission estimate.
All natural gas heat rates, flow rates, and exhaust compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/18/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Turbine Detail Sheet - Normal Operations (Base Load)

Source ID Number	Turbine and HRSG Train 3
Equipment ID	
Turbine Usage	Power Generation
Turbine Make	GE
Turbine Model	7EA
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Turbine
Emission Controls	SCR/Oxidation Catalyst
Design Output	66 MW
Site Operating Hours	8760 hr/yr
Exhaust Temperature	300 °F

	-12°F	45°F	85°F
Gas Heating Value	16399.6 Btu/lb	16399.6 Btu/lb	16399.6 Btu/lb
Gas Flow Rate	47,910 lb/hr	44,450 lb/hr	40,240 lb/hr
Gas Heat Rate	785.7 MMBtu/hr	729.0 MMBtu/hr	659.9 MMBtu/hr

Potential Emissions from Fuel Gas Mixture Operation

Pollutant	Emission Factor (ppmv, dry)	Emission Factor (lb/MMBtu)	Estimated Hourly Emissions -12°F (lb/hr)	45°F (lb/hr)	85°F (lb/hr)	Max Hourly Emissions (lb/hr)	Estimated Annual Emissions (tpy)	Source of Emission Factor
NOx	6	0.0234	18.40	17.44	16.12	18.40	75.86	Manf. Data[1]
CO	6	0.0143	11.20	10.62	9.81	11.20	46.19	Manf. Data[1]
VOC	1.4 (ppmv, wet)	0.0020	1.59	1.52	1.40	1.59	6.59	Manf. Data[1]
SO2		0.0034	2.67	2.48	2.24	2.67	10.79	AP-42[2]
PM10 Total		0.0127	10.00	10.00	10.00	10.00	43.80	Manf. Data[1]
Mercury	2.24E-06	3.81E-08	2.99E-05	2.84E-05	2.62E-05	2.99E-05	1.23E-04	Manf. Data[1]
1,3-Butadiene		4.30E-07	3.38E-04	3.13E-04	2.84E-04	3.38E-04	1.37E-03	AP-42[2]
Acetaldehyde		4.00E-05	3.14E-02	2.92E-02	2.64E-02	3.14E-02	1.27E-01	AP-42[2]
Acrolein		6.40E-06	5.03E-03	4.67E-03	4.22E-03	5.03E-03	2.03E-02	AP-42[2]
Benzene		1.20E-05	9.43E-03	8.75E-03	7.92E-03	9.43E-03	3.81E-02	AP-42[2]
Ethylbenzene		3.20E-05	2.51E-02	2.33E-02	2.11E-02	2.51E-02	1.02E-01	AP-42[2]
Formaldehyde		7.10E-05	5.58E-02	5.18E-02	4.69E-02	5.58E-02	2.25E-01	AP-42[2]
Naphthalene		1.30E-06	1.02E-03	9.48E-04	8.58E-04	1.02E-03	4.13E-03	AP-42[2]
PAH		2.20E-06	1.73E-03	1.60E-03	1.45E-03	1.73E-03	6.98E-03	AP-42[2]
Propylene Oxide		2.90E-05	2.28E-02	2.11E-02	1.91E-02	2.28E-02	9.21E-02	AP-42[2]
Toluene		1.30E-04	1.02E-01	9.48E-02	8.58E-02	1.02E-01	4.13E-01	AP-42[2]
Xylene		6.40E-05	5.03E-02	4.67E-02	4.22E-02	5.03E-02	2.03E-01	AP-42[2]

Exhaust Composition		Base Load, Temp. = -12°F		Base Load, Temp. = 45°F		Base Load, Temp. = 85°F	
Component	Mol. Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.	Volume %	Weighted Mol Wt.
Argon	39.94	1.03	0.41	1.03	0.41	1.03	0.41
Nitrogen	28.02	77.34	21.67	76.82	21.52	76.61	21.47
Oxygen	32.00	12.08	3.87	12.22	3.91	12.37	3.96
Carbon Dioxide	44.01	3.32	1.46	3.23	1.42	3.17	1.40
Water	18.02	6.23	1.12	6.71	1.21	6.73	1.21
		100.0	28.5	100.0	28.5	99.9	28.4

Calculation of dry mass flow rate:	Base Load, Temp. = 0°F		Base Load, Temp. = 45°F		Base Load, Temp. = 80°F	
Mass flow of exhaust =	2.03E+06	lb/hr	1.93E+06	lb/hr	1.78E+06	lb/hr
Molar flow of exhaust = Mass flow of exhaust / Mol Wt =	71079.6	lb-mol/hr	67738.0	lb-mol/hr	62614.9	lb-mol/hr
Molar flow of water = Vol.% H_2O * Exhaust molar flow =	4428.3	lb-mol/hr	4545.2	lb-mol/hr	4214.0	lb-mol/hr
Molar Flow of O2= Vol.% O2 * Exhaust molar flow =	8586.4	lb-mol/hr	8277.6	lb-mol/hr	7745.5	lb-mol/hr
Molar flow of Exhaust, dry = Exhaust molar flow - H20 molar flow=	66651.4	lb-mol/hr	63192.8	lb-mol/hr	58400.9	lb-mol/hr
Vol .% O2, dry = O2 molar flow / Exhaust molar flow =	12.9%		13.1%		13.3%	
total exhaust flow, acfm	499,773		476,277		440,256	

[1] Criteria pollutant emission factors provided by the manufacturer, but in some cases have been adapted from natural gas combustion. The NOx emission factor is corrected to 15% O2.

[2] EPA AP-42, Volume I, Fifth Edition - April 2000, Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are greater than or equal to the emissions produced during fuel gas combustion, so these emission factors should provide worst case emission estimates.

Additional notes:

All gas flow rates and compositions are based on information provided by GE. (Information provided by Paul Rood of SNC Lavalin via email on 12/17/07.)

Average VOC molecular weight assumed to be 46 lb-mol/lb.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Auxillary Boiler Detail Sheet

Source ID Number	
Equipment Usage	Auxillary Boiler
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	Low Nox Burner
Design Heat Rate	66.00 MMBtu/hr
Operating Hours	8760 hrs/yr
Natural Gas Rates	
Note: boiler will fire natural gas during cold start (760 hours); normally, it will operate at lower (25%) load and fire a lower-Btu fuel gas mixture (vent gas).	
Fuel Heating Value	1,020 Btu/scf
NG Potential Fuel Usage	0.0647 MMscf/hr

Potential Emissions (firing natural gas at 100% load)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	3.24	14.17	AP-42[1]
CO	84.00	0.08	5.44	23.81	AP-42[1]
VOC	5.50	5.4E-03	0.36	1.56	AP-42[2]
SO2	0.60	5.9E-04	0.04	0.17	AP-42[2]
PM10	7.60	7.5E-03	0.49	2.15	AP-42[2]
Benzene	2.1E-03	2.1E-06	1.36E-04	5.95E-04	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	7.76E-05	3.40E-04	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	4.85E-03	2.13E-02	AP-42[3]
Hexane	1.8E+00	1.8E-03	1.16E-01	5.10E-01	AP-42[3]
Naphthalene	6.1E-04	6.0E-07	3.95E-05	1.73E-04	AP-42[3]
Toluene	3.4E-03	3.3E-06	2.20E-04	9.64E-04	AP-42[3]

1. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-1, Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion.
2. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-2, Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion.
3. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Heater Detail Sheet

Source ID Number	Catalyst Regenerator
Equipment Usage	Process Heater
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	Low NOx Burner
Design Heat Rate	21.53 MMBtu/hr
Note: will only fire 3.58 MMBtu/hr during standby operations, anticipated to be approximately 7,800 hr/yr	
Operating Hours	8,760 hr/yr
Fuel Heating Value	1,020 Btu/scf
NG Potential Fuel Usage[1]	0.021 MMscf/hr

Potential Emissions (firing natural gas)[1]

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	1.06	4.62	AP-42[2]
CO	84.00	0.08	1.77	7.77	AP-42[2]
VOC	5.50	5.4E-03	0.12	0.51	AP-42[3]
SO2	0.60	5.9E-04	0.01	0.06	AP-42[3]
PM10	7.60	7.5E-03	0.16	0.70	AP-42[3]
Benzene	2.1E-03	2.1E-06	4.43E-05	1.94E-04	AP-42[4]
Dichlorobenzene	1.2E-03	1.2E-06	2.53E-05	1.11E-04	AP-42[4]
Formaldehyde	7.5E-02	7.4E-05	1.58E-03	6.93E-03	AP-42[4]
Hexane	1.8E+00	1.8E-03	3.80E-02	1.66E-01	AP-42[4]
Naphthalene	6.1E-04	6.0E-07	1.29E-05	5.64E-05	AP-42[4]
Toluene	3.4E-03	3.3E-06	7.18E-05	3.14E-04	AP-42[4]

1. This heater will operate only on a fuel gas mixture, during normal operations. It will not operate during startup operations. PTE emission rates are calculated here based on natural gas firing, as a conservatively high estimate. The heating value of the fuel gas mixture will be lower than that for natural gas. Refer also to notes 3 and 4 below.
2. NOx emissions are estimated based on vendor specifications.
3. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-2, Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion. Note: These emission factors are for for natural gas combustion, which is expected to produce emissions of these pollutants that are than or equal to the emissions produced during fuel gas mixture combustion, so these emission should provide conservative emission estimates.
4. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion. Note: These emission factors are for natural gas combustion, which is expected to produce emissions of these pollutants that are greater than or equal to the emissions produced during fuel gas mixture combustion,so these emission factors provide conservative emission estimates.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Heater Detail Sheet

Source ID Number	Reactivation Heater (B-2)
Equipment Usage	Process Heater
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	Low NOx Burner
Design Heat Rate	12.45 MMBtu/hr
Expected Operating Hours	1,456 hr/yr normal 760 hr/yr cold start 2,216 annual hours
Operating Hours for PTE Emission Calculation	8,760 hr/yr
Natural Gas Usage	
Note: heater will fire natural gas during cold start; however, during normal operations, it will fire a lower-Btu fuel gas mixture.	
Fuel Heating Value	1,020 Btu/scf
NG Potential Fuel Usage	0.0122 MMscf/hr

Potential Emissions (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMbtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	0.61	2.67	AP-42[1]
CO	84.00	0.08	1.03	4.49	AP-42[1]
VOC	5.50	5.4E-03	0.07	0.29	AP-42[2]
SO2	0.60	5.9E-04	0.01	0.03	AP-42[2]
PM10	7.60	7.5E-03	0.09	0.41	AP-42[2]
Benzene	2.1E-03	2.1E-06	2.56E-05	1.12E-04	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	1.46E-05	6.42E-05	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	9.15E-04	4.01E-03	AP-42[3]
Hexane	1.8E+00	1.8E-03	2.20E-02	9.62E-02	AP-42[3]
Naphthalene	6.1E-04	6.0E-07	7.45E-06	3.26E-05	AP-42[3]
Toluene	3.4E-03	3.3E-06	4.15E-05	1.82E-04	AP-42[3]

1. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-1, Emission Factors for Nitrogen (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion.
2. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-2, Emission Factors for Criteria and Greenhouse Gases from Natural Gas Combustion.
3. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Heater Detail Sheet

Source ID Number	HGT reactor Charge Heater (B-3)
Equipment Usage	Process Heater
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	Low NOx Burner
Design Heat Rate	2.22 MMBtu/hr
Operating Hours	**8,760** hr/yr
Natural Gas Usage	
Note: heater will fire natural gas during cold start (760 hours); however, during normal operations, it will fire a lower-Btu fuel gas mixture.	
Fuel Heating Value	1,020 Btu/scf
NG Potential Usage	0.0022 MMscf/hr

Potential Emissions (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	0.11	0.48	AP-42[1]
CO	84.00	0.08	0.18	0.80	AP-42[1]
VOC	5.50	5.4E-03	0.01	0.05	AP-42[2]
SO2	0.60	5.9E-04	0.00	0.01	AP-42[2]
PM10	7.60	7.5E-03	0.02	0.07	AP-42[2]
Benzene	2.1E-03	2.1E-06	4.57E-06	2.00E-05	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	2.61E-06	1.14E-05	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	1.63E-04	7.15E-04	AP-42[3]
Hexane	1.8E+00	1.8E-03	3.92E-03	1.72E-02	AP-42[3]
Naphthalene	6.1E-04	6.0E-07	1.33E-06	5.82E-06	AP-42[3]
Toluene	3.4E-03	3.3E-06	7.40E-06	3.24E-05	AP-42[3]

1. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-1, Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion.
2. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-2, Emission Factors for Criteria and Greenhouse Gases from Natural Gas Combustion.
3. EPA AP-42, Volume I, Fifth Edition - July 1998, Table 1.4-3, Emission Factors for Speciated Organic Compounds from Natural Gas Combustion.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Stack Detail Sheet

Source ID Number	CO2 Vent Stack	
Equipment Usage	Vent for Off-Spec CO2	
Equipment Make	TBD	
Equipment Model	TBD	
Serial Number	TBD	
Installation Date	TBD	
Emission Controls	None	
Potential Operation during initial startup	250	hr/yr
Potential Operation during malfunctions	50	hr/yr
Total Vent Stream Flowrate	21,731	lb-mol/hr
	8,248,270	scf/hr
Actual Vent Stream Flowrate		
assume T=40 deg F, P=50 psia	38,862	acfm
Initial Startup		
Vent Gas Molar Flow Rate during startup	5,433	lb-mol/hr
Vent Gas Molecular Weight	43.1	lb/lb-mol
Vent Gas H20 Molar Flow Rate	0.20%	lb-mol/hr
Vent Gas Molar Flow Rate (dry)	5422	lb-mol/hr
Vent Gas Flow Rate (dry)	2,057,945	scf/hr
Malfunction		
Vent Gas Molar Flow Rate during malfunctio	7,244	lb-mol/hr
Vent Gas Molecular Weight	43.1	lb/lb-mol
Vent Gas H20 Molar Flow Rate	0.20%	lb-mol/hr
Vent Gas Molar Flow Rate (dry)	7229	lb-mol/hr
Vent Gas Flow Rate (dry)	2,743,926	scf/hr

Stack Parameters, for Modeling		
Stack:	100	ft, height
	3	ft, diameter
Velocity:	91.68	ft/s
	27.94	m/s
Temperature	75	deg F
Vent Pressure	50	psia

Potential Emissions from SSM Operation

Pollutant	Emission Factor ppmv	Estimated Hourly Emissions: Initial Startup (lb/hr)	Estimated Hourly Emissions: Malfunction (lb/hr)	Max Hourly Emissions (lb/hr)	Cold Startup Total Annual Emissions (tpy)	Malfunction Total Annual Emissions (tpy)	Source of Emission Factor
CO	16,560	2,519.09	3,358.79	3,358.79	314.89	83.97	Vendor[1]
VOC (COS)	20.7	6.75	9.00	9.00	0.84	0.23	Vendor[1]

[1] CO and VOC emissions are estimated based on vendor specifications.

Additional notes:

Vent gas molar flow rates are from information in email from James Knox, 1/25/08, based on updated UOP data.

VOC is in the form of carbonyl sulfide (COS), which is a HAP.

Annual emissions for this source have been estimated both for the first year of operation, which will include the initial startup emissions and malfunction emissions, and for subsequent years of operation, which will include only malfunction emissions.

The total potential flow rate from this source will only occur if all four gasifiers were operating at full load and both CO2 compressors were to fail. The flow rate at initial startup is estimated to be one-fourth of the total potential flow rate since at most only one gasifier will be operating at full load before the CO2 compression system is operational. The flow rate during a malfunction is estimated to be one-third of the total potential flow rate since at most only one of the three CO2 compressors could fail without a reduction in the production by the gasifiers.

Vent Gas MW Calculation (data from 1/25/08 email)						
Chemical	lb/hr	lb-mol/hr	mol frac	MW	MW*mol frac	ppmv
CO	10,076	360	0.016560	28	0.464	16,560
H2	615	307	0.014145	2	0.028	14,145
CO2	924,654	21,015	0.967051	44	42.550	967,051
H2O	638	35	0.001630	18	0.029	1,630
CH4	56	3	0.000160	16	0.003	160
Ar	322	8	0.000371	39.95	0.015	371
N2	37	1	0.000061	28	0.002	61
H2S	1	0	0.000001	34	0.000	1
COS	27	0	0.000021	60	0.001	21
total	936,425	21,731			43.092	

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
HP Flare Detail Sheet

Source ID Number	Flare		
Equipment Usage	Emergency Flare/HP Flare		
Equipment Make	TBD		
Equipment Model	TBD		
Serial Number	TBD		
Installation Date	TBD		
Emission Controls	None		
Gas Flow Rate [1]	2,943,142 lb/hr	Syngas to flare (wet)	48" Diameter
Gas Heat Content [1]	2,000 Btu/lb		
Flare Firing Rate	5,886 MMBtu/hr	(low BTU gas)	
Hours of Operation	40 hrs/yr	Malfunctions	
	10 hrs/yr	Initial Year (Cold Starts)	
Pilot Fuel Flow Rate	800 scf/hr		
Pilot Fuel Heat Content	1,020 Btu/scf	Natural Gas (High BTU gas)	
Flare Pilot Firing Rate	0.816 MMBtu/hr		
Hours of Operation, Pilot	8,760 hrs/yr	Continuous pilot	

Estimated Flare Gas Composition During Coal Firing

Component	Flow Rate (lb/hr)	*Mol Wt. lb/lb-mol*
CO	750,294	*28*
H2	48,330	*2*
CO2	489,061	*44*
H2O	1,625,990	*18*
CH4	1,199	*16*
Ar	14,974	*40*
N2	6,305	*28*
H2S	3,922	*34*
COS	270	*60*
NH3	2,797	*17*
Total	2,943,142	

Potential Emissions [2]

Pollutant	Emission Factors		Destruction Efficiency	Estimated Emissions Pilot (Normal Operation)[8]		Estimated Emissions Cold Start & Malfunctions		Estimated Emissions Malfunctions only	
	Low BTU gas (lb/MMBtu)	High BTU gas (lb/MMBtu)	(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
NOx [3]	0.0641	0.1380		0.11	0.5	391.30	9.8	391.30	7.8
CO [4]	0.5496	0.2755		0.22	1.0	3,235.10	80.9	3,249.31	65.0
VOC [5,6]			98%	0.68	3.0	5.40	0.1	6.08	0.1
SO2 [7]		0.0006		4.80E-04	2.1E-03	7,508.07	187.7	7,508.07	150.16

Notes:
1. Flare gas composition, heat content, and flow rate are all from the Feasibility Study, dated 12/12/06.
2. These emissions are based on the calculation methodology and emission factors presented in the TCEQ Guidance Document for Flares and Vapor Oxidizers (RG-109, October 2000). NOx, CO, and VOC emissions include constant pilot gas flow (natural gas).
3. NOx emissions were calculated as a sum of the thermal and fuel generated NOx. Thermal NOx emissions were calculated using an emission factor from Table 4 (similar to CO) for an unassisted flare burning low Btu gas. Thermal NOx emissions from the continuous pilot were calculated using the Table 4 emission factor for high BTU gas. The fuel NOx emissions were calculated using the guidance in Table 4 that indicates NOx is 0.5 wt% of inlet NH3.
4. The CO emission factor is from Table 4 in the TCEQ Guidance Document and is for an unassisted flare burning low Btu gas. CO emissions for the continuous pilot were calculated using the TCEQ Table 4 emission factor for high BTU gas.
5. Fuel VOC emissions were calculated based on guidance in the TCEQ Guidance Document which indicates that 98% of VOCs entering the flare in the fuel will be combusted. The emissions are equal to 2 percent of the incoming flow of COS.
6. VOCs from pilot gas combustion are calculated assuming natural gas density of 0.0424 lb/scf, and destruction efficiency of 98%
7. SO2 emissions are a sum of the SO2 from the H2S combustion and from the COS combustion. Table 4 indicates that 98% of incoming H2S is converted to SO2, and since COS is a VOC, 98% of that compound will also be combusted and converted to SO2.
8. Emissions from normal operations represent only the continuous pilot, since normal operation does not include high pressure vents to flare.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
LP Flare Detail Sheet

Source ID Number	Flare		
Equipment Usage	Emergency Flare/LP Flare		
Equipment Make	TBD		
Equipment Model	TBD		
Serial Number	TBD		
Installation Date	TBD		
Emission Controls	None		
Gas Flow Rate [1]	3,989 lb/hr	Selexol Reflux Drum vent	24" diameter
Gas Heat Content [1]	8,831 Btu/lb		
Flare Firing Rate	35 MMBtu/hr	(low BTU gas)	
Hours of Operation	8 hrs/yr	Malfunctions	
	12 hrs/yr	Cold Starts	
Pilot Fuel Flow Rate	200 scf/hr		
Pilot Fuel Heat Content	1,020 Btu/scf	Natural Gas (High BTU gas)	
Flare Pilot Firing Rate	0.204 MMBtu/hr		
Hours of Operation, Pilot	8,760 hrs/yr	Continuous pilot	

Estimated Flare Gas Composition During Coal Firing

Component	Flow Rate (lb/hr)	*Mol Wt. lb/lb-mol*
CO	160	*28*
H2	399	*2*
CO2	1,157	*44*
H2O	199	*18*
CH4	0	*16*
Ar	0	*40*
N2	0	*28*
H2S	1,955	*34*
COS	0	*60*
NH3	120	*17*
Total	3,989	

Potential Emissions [2]

Pollutant	Emission Factors		Destruction Efficiency	Estimated Emissions Pilot (Normal Operation)[7]		Estimated Emissions Cold Start		Estimated Emissions Cold Start & Malfunction[8]		Estimated Emissions Malfunctions Only	
	Low BTU gas (lb/MMBtu)	High BTU gas (lb/MMBtu)	(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
NOx [3]	0.0541	0.1380		0.03	0.1	2.86	0.0	2.86	0.0	2.88	0.0
CO [4]	0.5496	0.2755		0.06	0.2	19.36	0.1	19.36	0.2	0.06	0.0
VOC [5]			98%	0.17	0.7	0.00	0.0	0.00	0.0	0.17	0.0
SO2 [6]		0.0006		1.20E-04	5.3E-04	3,601.15	21.6	3,601.15	36.0	3,601.15	14.4

Notes:
1. Flare gas composition and flow rate are from Flare RV Log, December 2007
2. These emissions are based on the calculation methodology and emission factors presented in the TCEQ Guidance Document for Flares and Vapor Oxidizers (RG-109, October 2000). NOx, CO, and VOC emissions include constant pilot gas flow (natural gas).
3. Fuel NOx emissions were calculated using TCEQ guidance (Table 4) that indicates NOx is 0.5 wt% of inlet NH3. Thermal NOx contribution from the process vent stream is assumed to be negligible; for the pilot gas, thermal NOx is calculated using the TCEQ Table 4 emission factor for high BTU gas.
4. CO emissions for the continuous pilot were calculated using the TCEQ Table 4 emission factor for high BTU gas. TCEQ Table 4 emission factor for high BTU gas. CO emissions are from the pilot fuel only.
5. VOCs from pilot gas combustion are calculated assuming natural gas density of 0.0424 lb/scf, and destruction efficiency of 98% .
6. SO2 emissions are a sum of the SO2 from the H2S combustion and from the COS combustion.Table 4 indicates that 98% of incoming H2S is converted to SO2, and since COS is a VOC, 98% of that compound will also be combusted and converted to SO2.
7. Emissions from normal operations represent only the continuous pilot, since normal operation does not include low pressure vents to flare.
8. The initial year (i.e., cold start) emissions represent emissions from the low pressure vent gas to the flare. Emissions are estimated for the worst-case (high flow rate, high H2S content) vent stream directed to the LP Flare, and include both cold start and malfunction hours.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Preheater Detail Sheet

Source ID Number	Gasifier Preheater 1
Equipment Usage	Refractory Preheating
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	None
Design Heat Rate	21.00 MMBtu/hr
Cold Startup	
Gas Heating Value	1020 Btu/scf
Gas Potential Operation	500 hr/yr
Gas Potential Fuel Usage	2.06E-02 MMscf/hr

Potential Emissions from Startup Operation (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	1.03	0.26	AP-42[1]
CO	84.00	0.08	1.73	0.43	AP-42[1]
VOC	5.50	5.4E-03	0.11	0.03	AP-42[2]
SO2	0.60	5.9E-04	0.01	3.09E-03	AP-42[2]
PM10	7.60	7.5E-03	0.16	0.04	AP-42[2]
Benzene	2.1E-03	2.1E-06	4.32E-05	1.08E-05	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	2.47E-05	6.18E-06	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	1.54E-03	3.86E-04	AP-42[3]
Hexane	1.8E+00	1.8E-03	3.71E-02	9.26E-03	AP-42[3]
Toluene	3.4E-03	3.3E-06	7.00E-05	1.75E-05	AP-42[3]

[1] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-1. Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion

[2] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

[3] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-3. Emission Factors For Speciated Organic Compounds From Natural Gas Combustion

Additional notes:

The average heating value for natural gas is used in these calculations (as provided in Section 1.4 of AP-42).

The PAH emission factor is a sum of all the constituent PAH emission factors in Table 1.4-3.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Preheater Detail Sheet

Source ID Number	Gasifier Preheater 2	
Equipment Usage	Refractory Preheating	
Equipment Make	TBD	
Equipment Model	TBD	
Serial Number	TBD	
Installation Date	TBD	
Emission Controls	None	
Design Heat Rate	21.00	MMBtu/hr
Cold Startup		
Gas Heating Value	1020	Btu/scf
Gas Potential Operation	500	hr/yr
Gas Potential Fuel Usage	2.06E-02	MMscf/hr

Potential Emissions from Startup Operation (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	1.03	0.26	AP-42[1]
CO	84.00	0.08	1.73	0.43	AP-42[1]
VOC	5.50	5.4E-03	0.11	0.03	AP-42[2]
SO2	0.60	5.9E-04	0.01	3.09E-03	AP-42[2]
PM10	7.60	7.5E-03	0.16	0.04	AP-42[2]
Benzene	2.1E-03	2.1E-06	4.32E-05	1.08E-05	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	2.47E-05	6.18E-06	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	1.54E-03	3.86E-04	AP-42[3]
Hexane	1.8E+00	1.8E-03	3.71E-02	9.26E-03	AP-42[3]
Toluene	3.4E-03	3.3E-06	7.00E-05	1.75E-05	AP-42[3]

[1] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-1. Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion

[2] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

[3] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-3. Emission Factors For Speciated Organic Compounds From Natural Gas Combustion

Additional notes:

The average heating value for natural gas is used in these calculations (as provided in Section 1.4 of AP-42).

The PAH emission factor is a sum of all the constituent PAH emission factors in Table 1.4-3.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Preheater Detail Sheet

Source ID Number	Gasifier Preheater 3
Equipment Usage	Refractory Preheating
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	None
Design Heat Rate	21.00 MMBtu/hr
Cold Startup	
Gas Heating Value	1020 Btu/scf
Gas Potential Operation	500 hr/yr
Gas Potential Fuel Usage	2.06E-02 MMscf/hr

Potential Emissions from Startup Operation (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	1.03	0.26	AP-42[1]
CO	84.00	0.08	1.73	0.43	AP-42[1]
VOC	5.50	5.4E-03	0.11	0.03	AP-42[2]
SO2	0.60	5.9E-04	0.01	3.09E-03	AP-42[2]
PM10	7.60	7.5E-03	0.16	0.04	AP-42[2]
Benzene	2.1E-03	2.1E-06	4.32E-05	1.08E-05	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	2.47E-05	6.18E-06	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	1.54E-03	3.86E-04	AP-42[3]
Hexane	1.8E+00	1.8E-03	3.71E-02	9.26E-03	AP-42[3]
Toluene	3.4E-03	3.3E-06	7.00E-05	1.75E-05	AP-42[3]

[1] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-1. Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion

[2] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

[3] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-3. Emission Factors For Speciated Organic Compounds From Natural Gas Combustion

Additional notes:

The average heating value for natural gas is used in these calculations (as provided in Section 1.4 of AP-42).

The PAH emission factor is a sum of all the constituent PAH emission factors in Table 1.4-3.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Preheater Detail Sheet

Source ID Number	Gasifier Preheater 4
Equipment Usage	Refractory Preheating
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	None
Design Heat Rate	21.00 MMBtu/hr
Cold Startup	
Gas Heating Value	1020 Btu/scf
Gas Potential Operation	500 hr/yr
Gas Potential Fuel Usage	2.06E-02 MMscf/hr

Potential Emissions from Startup Operation (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	1.03	0.26	AP-42[1]
CO	84.00	0.08	1.73	0.43	AP-42[1]
VOC	5.50	5.4E-03	0.11	0.03	AP-42[2]
SO2	0.60	5.9E-04	0.01	3.09E-03	AP-42[2]
PM10	7.60	7.5E-03	0.16	0.04	AP-42[2]
Benzene	2.1E-03	2.1E-06	4.32E-05	1.08E-05	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	2.47E-05	6.18E-06	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	1.54E-03	3.86E-04	AP-42[3]
Hexane	1.8E+00	1.8E-03	3.71E-02	9.26E-03	AP-42[3]
Toluene	3.4E-03	3.3E-06	7.00E-05	1.75E-05	AP-42[3]

[1] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-1. Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion

[2] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

[3] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-3. Emission Factors For Speciated Organic Compounds From Natural Gas Combustion

Additional notes:

The average heating value for natural gas is used in these calculations (as provided in Section 1.4 of AP-42).

The PAH emission factor is a sum of all the constituent PAH emission factors in Table 1.4-3.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Preheater Detail Sheet

Source ID Number	Gasifier Preheater 5
Equipment Usage	Refractory Preheating
Equipment Make	TBD
Equipment Model	TBD
Serial Number	TBD
Installation Date	TBD
Emission Controls	None
Design Heat Rate	21.00 MMBtu/hr
Cold Startup	
Gas Heating Value	1020 Btu/scf
Gas Potential Operation	500 hr/yr
Gas Potential Fuel Usage	2.06E-02 MMscf/hr

Potential Emissions from Startup Operation (firing natural gas)

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMscf)	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	50.00	0.05	1.03	0.26	AP-42[1]
CO	84.00	0.08	1.73	0.43	AP-42[1]
VOC	5.50	5.4E-03	0.11	0.03	AP-42[2]
SO2	0.60	5.9E-04	0.01	3.09E-03	AP-42[2]
PM10	7.60	7.5E-03	0.16	0.04	AP-42[2]
Benzene	2.1E-03	2.1E-06	4.32E-05	1.08E-05	AP-42[3]
Dichlorobenzene	1.2E-03	1.2E-06	2.47E-05	6.18E-06	AP-42[3]
Formaldehyde	7.5E-02	7.4E-05	1.54E-03	3.86E-04	AP-42[3]
Hexane	1.8E+00	1.8E-03	3.71E-02	9.26E-03	AP-42[3]
Toluene	3.4E-03	3.3E-06	7.00E-05	1.75E-05	AP-42[3]

[1] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-1. Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion

[2] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion

[3] EPA AP-42, Volume I, Fifth Edition - September 1998, Table 1.4-3. Emission Factors For Speciated Organic Compounds From Natural Gas Combustion

Additional notes:

The average heating value for natural gas is used in these calculations (as provided in Section 1.4 of AP-42).

The PAH emission factor is a sum of all the constituent PAH emission factors in Table 1.4-3.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Generator Detail Sheet

Source ID Number	Black-Start Generator 1	
Engine Usage	Startup Generators	
Engine Make	Caterpillar	
Engine Model	TBD	
Serial Number	TBD	
Installation Date	TBD	
Engine Configuration	Natural Gas	
Emission Controls	None	
Design Rating	1650	ekW
Site Rated Horsepower	2889	BHP
Fuel Heating Value	1020	Btu/scf
Heat Rate	19.49	MMBtu/hr
Engine Heat Rate	6748	Btu/hp-hr
Potential Operation	360	hr/yr
Potential Fuel Usage	6.88	MMscf/yr

At 100% load (worst case emissions)

Potential Emissions

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(g/hp-hr)	(lb/hr)	(tpy)	
NOx		1	6.37	1.15	Manf. Data[1]
CO		2.43	15.48	2.79	Manf. Data[1]
VOC		0.9	5.73	1.03	Manf. Data[1]
SO2	0.000588		0.0115	0.002	AP-42[2]
PM10 Total	0.000077		0.0015	0.00027	AP-42[2]
1,3-Butadiene	2.67E-04		5.21E-03	9.37E-04	AP-42[2]
2,2,4-Trimethylpentane	2.50E-04		4.87E-03	8.77E-04	AP-42[2]
Acetaldehyde	8.36E-03		1.63E-01	2.93E-02	AP-42[2]
Acrolein	5.14E-03		1.00E-01	1.80E-02	AP-42[2]
Benzene	4.40E-04		8.58E-03	1.54E-03	AP-42[2]
Biphenyl	2.12E-04		4.13E-03	7.44E-04	AP-42[2]
Ethylbenzene	3.97E-05		7.74E-04	1.39E-04	AP-42[2]
Formaldehyde	5.28E-02		1.03E+00	1.85E-01	AP-42[2]
Methanol	2.50E-03		4.87E-02	8.77E-03	AP-42[2]
n-Hexane	1.11E-04		2.16E-03	3.90E-04	AP-42[2]
Toluene	4.08E-04		7.95E-03	1.43E-03	AP-42[2]
Xylene	1.84E-04		3.59E-03	6.46E-04	AP-42[2]

[1] Manfacturers Specification.
[2] EPA AP-42, Volume I, Fifth Edition - October 1996, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Generator Detail Sheet

Source ID Number	Black-Start Generator 2	
Engine Usage	Startup Generators	
Engine Make	Caterpillar	
Engine Model	TBD	
Serial Number	TBD	
Installation Date	TBD	
Engine Configuration	Natural Gas	
Emission Controls	None	
Design Rating	1650	ekW
Site Rated Horsepower	2889	BHP
Fuel Heating Value	1020	Btu/scf
Heat Rate	19.49	MMBtu/hr
Engine Heat Rate	6748	Btu/hp-hr
Potential Operation	**360**	hr/yr
Potential Fuel Usage	6.88	MMscf/yr

At 100% load (worst case emissions)

Potential Emissions

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(g/hp-hr)	(lb/hr)	(tpy)	
NOx		1	6.37	1.15	Manf. Data[1]
CO		2.43	15.48	2.79	Manf. Data[1]
VOC		0.9	5.73	1.03	Manf. Data[1]
SO2	0.000588		0.0115	0.002	AP-42[2]
PM10 Total	0.000077		0.0015	0.00027	AP-42[2]
1,3-Butadiene	2.67E-04		5.21E-03	9.37E-04	AP-42[2]
2,2,4-Trimethylpentane	2.50E-04		4.87E-03	8.77E-04	AP-42[2]
Acetaldehyde	8.36E-03		1.63E-01	2.93E-02	AP-42[2]
Acrolein	5.14E-03		1.00E-01	1.80E-02	AP-42[2]
Benzene	4.40E-04		8.58E-03	1.54E-03	AP-42[2]
Biphenyl	2.12E-04		4.13E-03	7.44E-04	AP-42[2]
Ethylbenzene	3.97E-05		7.74E-04	1.39E-04	AP-42[2]
Formaldehyde	5.28E-02		1.03E+00	1.85E-01	AP-42[2]
Methanol	2.50E-03		4.87E-02	8.77E-03	AP-42[2]
n-Hexane	1.11E-04		2.16E-03	3.90E-04	AP-42[2]
Toluene	4.08E-04		7.95E-03	1.43E-03	AP-42[2]
Xylene	1.84E-04		3.59E-03	6.46E-04	AP-42[2]

[1] Manfacturers Specification.
[2] EPA AP-42, Volume I, Fifth Edition - October 1996, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Generator Detail Sheet

Source ID Number	Black-Start Generator 3	
Engine Usage	Startup Generators	
Engine Make	Caterpillar	
Engine Model	TBD	
Serial Number	TBD	
Installation Date	TBD	
Engine Configuration	Natural Gas	
Emission Controls	None	
Design Rating	1650	ekW
Site Rated Horsepower	2889	BHP
Fuel Heating Value	1020	Btu/scf
Heat Rate	19.49	MMBtu/hr
Engine Heat Rate	6748	Btu/hp-hr
Potential Operation	360	hr/yr
Potential Fuel Usage	6.88	MMscf/yr

At 100% load (worst case emissions)

Potential Emissions

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(g/hp-hr)	(lb/hr)	(tpy)	
NOx		1	6.37	1.14645	Manf. Data[1]
CO		2.43	15.48	2.78588	Manf. Data[1]
VOC		0.9	5.73	1.03181	Manf. Data[1]
SO2	0.000588		0.0115	0.002	AP-42[2]
PM10 Total	0.000077		0.0015	0.00027	AP-42[2]
1,3-Butadiene	2.67E-04		5.21E-03	9.37E-04	AP-42[2]
2,2,4-Trimethylpentane	2.50E-04		4.87E-03	8.77E-04	AP-42[2]
Acetaldehyde	8.36E-03		1.63E-01	2.93E-02	AP-42[2]
Acrolein	5.14E-03		1.00E-01	1.80E-02	AP-42[2]
Benzene	4.40E-04		8.58E-03	1.54E-03	AP-42[2]
Biphenyl	2.12E-04		4.13E-03	7.44E-04	AP-42[2]
Ethylbenzene	3.97E-05		7.74E-04	1.39E-04	AP-42[2]
Formaldehyde	5.28E-02		1.03E+00	1.85E-01	AP-42[2]
Methanol	2.50E-03		4.87E-02	8.77E-03	AP-42[2]
n-Hexane	1.11E-04		2.16E-03	3.90E-04	AP-42[2]
Toluene	4.08E-04		7.95E-03	1.43E-03	AP-42[2]
Xylene	1.84E-04		3.59E-03	6.46E-04	AP-42[2]

[1] Manfacturers Specification.
[2] EPA AP-42, Volume I, Fifth Edition - October 1996, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Engine Detail Sheet

Source ID Number	Firewater Pump
Engine Usage	Firewater Pump Engine
Engine Make	TBD
Engine Model	TBD
Serial Number	TBD
Installation Date	TBD
Engine Configuration	Fuel Oil
Emission Controls	None
Design Rating	575 BHP
Fuel Heating Value	18300 Btu/lb
Fuel Density	7.34 lb/gal
Heat Rate	3.85 MMBtu/hr
Potential Operation	**500** hr/yr
Potential Fuel Usage	28.70 gal/hr

Potential Emissions from Fuel Oil Operation

Pollutant	Emission Factor		Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(g/hp-hr)	(lb/hr)	(tpy)	
NOx		4.75	6.02	1.51	Vendor[1]
CO		0.29	0.37	0.09	Vendor[1]
VOC	0.35		1.35	0.34	AP-42[2]
SO2			6.06E-03	1.52E-03	Eng. Est.[3]
PM10 Total		0.06	7.61E-02	0.02	Vendor[1]
1,3-Butadiene	3.91E-05		1.51E-04	3.77E-05	AP-42[4]
Acetaldehyde	7.67E-04		2.96E-03	7.39E-04	AP-42[4]
Acrolein	9.25E-05		3.57E-04	8.91E-05	AP-42[4]
Benzene	9.33E-04		3.60E-03	8.99E-04	AP-42[4]
Formaldehyde	1.18E-03		4.55E-03	1.14E-03	AP-42[4]
Naphthalene	8.48E-05		3.27E-04	8.17E-05	AP-42[4]
Propylene	2.58E-03		9.94E-03	2.49E-03	AP-42[4]
Toluene	4.09E-04		1.58E-03	3.94E-04	AP-42[4]
Xylene	2.85E-04		1.10E-03	2.75E-04	AP-42[4]
Total HAPs			**2.46E-02**	**6.14E-03**	

[1] NOx, PM, and CO emissions are estimated based on vendor specifications.

[2] EPA AP-42, Volume I, Fifth Edition - October 1996, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines.

[3] SO2 emissions are estimated based on 15 ppm S and assuming that 100% of S is converted to SO2.

[4] EPA AP-42, Volume I, Fifth Edition - October 1996, Table 3.3-2, Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Tank Detail Sheet

Potential VOC Emissions

Source ID	Source Name	Tank Capacity (gal)	Annual Throughput (gal/yr)	Product	Total VOC Emissions (lb/yr)	VOC Emission Rates		HAP Emission Rates							
						(lb/hr)	(tpy)	Hexane (lb/yr)	Benzene (lb/yr)	Toluene (lb/yr)	Ethylbenzene (lb/yr)	Xylene (-m) (lb/yr)	Methanol (lb/yr)	TOTAL (lb/yr)	TOTAL (tpy)
TBD	Slops Tank	7,000	42,000	Misc.	606.6	0.07	0.3	19.65	4.69	4.24	0.33	1.39	0	30.30	0.0
TBD	Methanol Tank #1	6,341,984	25,367,936	Methanol	2,285	0.26	1.1	0	0	0	0	0	2,285	2284.56	1.1
TBD	Methanol Tank #2	6,341,984	25,367,936	Methanol	2,285	0.26	1.1	0	0	0	0	0	2,285	2284.56	1.1
TBD	Gasoline Product #1	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #2	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #3	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #4	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #5	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #6	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #7	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Gasoline Product #8	6,341,984	36,254,859	Product Gasoline	23,511	2.68	11.8	110.01	118.82	128.05	8.54	35.98	0	401.40	0.2
TBD	Heavy Gasoline Tank	4,763,841	36,761,340	Heavy Gasoline	9,637	1.10	4.8	80.89	87.32	94.76	6.48	27.56	0	297.01	0.1
TBD	Methanol Off-Spec Tank	5,000	30,000	Methanol	206	0.02	0.1	0	0	0	0	0	205.86	205.86	0.1
TBD	Gasoline Off-Spec Tank	5,000	30,000	Product Gasoline	2,143	0.24	1.1	10.01	10.8	11.43	0.72	3.04	0.00	36	0.0
					TOTAL	23.43	102.6	0.495315	0.526685	0.567415	0.037925	0.159915	2.38749		4.175
								HAP-Specific TPY							

Notes:
All emissions were calculated using the EPA TANKS Program, version 4.09.d.
Annual hours of operation were assumed to be 8760.

Insignificant Emission Sources - Tanks

TBD	MTG Water Tank
TBD	Liquid Sulfur Storage Tank #1
TBD	Liquid Sulfur Storage Tank #2
03T-002	Grey Water Tank
03T-003	Slurry Additive Tank
01T-104	Mill Discharge Tank
01T-105	Slurry Tank
02T-001	Injector Coolant Tank
03T-001	Settler
03T-004	Filter Feed Tank
03T-005	Filtrate Tank
TBD	Glycol Storage Tank

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Arch Coal Company, Saddleback Hills Mine
BACT Option 1 (In-Pit Stacking Tubes) PM-10 Emissions

Emission Source	Type	Description			Control	Additional Information
Dozer Reclaim	**Fugitive**	**Cat D11 Dozer**			**None**	
		Emission Factor	8.0	Lb/Hr		*WDEQ 2002 Guidance*
		Total Throughput	3,200,000	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 x Op Hrs)/2000
		PM-10 Emissions	**2.40**	**Tons/Yr**		30% of TSP
Coal Stacker	**Fugitive**	**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	3,200,000	Tons/Yr		*Total Coal Through Storage*
		TSP Emissions	10.20	Tons/Yr		*E=(EFx% sus x MD/2000)x(1-CF)*
		PM-10 Emissions	**3.06**	**Tons/Yr**		*30% of TSP*
Coal Reclaim	**Fugitive**	**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	3,200,000	Tons/Yr		*Total Coal Through Storage*
		TSP Emissions	0.00	Tons/Yr		*E=(EFx% sus x MR/2000)x(1-CF)*
		PM-10 Emissions	**0.00**	**Tons/Yr**		*30% of TSP*
Coal Stockpile	**Fugitive**	**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			*Seminoe Mine 5-Year Average*
		Control Factor	0.00%			
		TSP Emissions	182.40	Tons/Yr		*E=(EF x AWS x %sus x PS x*
		PM-10 Emissions	**54.72**	**Tons/Yr**		*((365-WD)/365) x (1-CF))/2000*
TOTAL PM-10 EMISSIONS			**60.2**	**Tons/Yr**		

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

		Controlled Emissions		*Uncontrolled Emsisions*	
		SOCMI Factors		SOCMI Factors	
Process Stream	Service Type	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**

	Controlled Emissions		*Uncontrolled Emsisions*	
	SOCMI Factors		SOCMI Factors	
Individual HAPs	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**

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Controlled HAP Summary

Controlled Emissions (SOCMI Factors)

Process Stream	COS (lb/hr)	COS (ton/yr)	MeOH (lb/hr)	MeOH (ton/yr)	Benzene* (lb/hr)	Benzene* (ton/yr)
Acid Gas	2.13E-02	9.34E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flare KO Drum Drainage	1.29E-03	5.66E-03	0.00E+00	0.00E+00	3.67E-01	1.61E+00
Gasifier Vent	3.67E-02	1.61E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Gasoline (Gas)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.26E-01	3.18E+00
Gasoline (Light Liquid)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.26E+00	5.52E+00
Gasoline (Heavy Liquid)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.94E-02	8.51E-02
LPG	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Methanol Gas	0.00E+00	0.00E+00	2.36E-01	1.04E+00	0.00E+00	0.00E+00
Methanol Pure Liquid	0.00E+00	0.00E+00	1.48E-01	6.50E-01	0.00E+00	0.00E+00
Methanol Product (MeOH 1)	0.00E+00	0.00E+00	1.79E+00	7.85E+00	0.00E+00	0.00E+00
Methanol Product (MeOH 2)	0.00E+00	0.00E+00	5.21E-02	2.28E-01	0.00E+00	0.00E+00
Methanol Product (MeOH 3)	0.00E+00	0.00E+00	5.19E-02	2.27E-01	0.00E+00	0.00E+00
Methanol Product (MeOH 5)	0.00E+00	0.00E+00	9.03E-02	3.95E-01	0.00E+00	0.00E+00
Mixed Fuel Gas	0.00E+00	0.00E+00	4.23E-03	1.85E-02	0.00E+00	0.00E+00
MTG Fuel Gas	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.15E-02	5.03E-02
Propylene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total	**5.94E-02**	**2.60E-01**	**2.37E+00**	**1.04E+01**	**2.38E+00**	**1.04E+01**

* Benzene is assumed from emissions of C6-C10 aromatics.

Uncontrolled HAP Summary

Uncontrolled Emissions (SOCMI Factors)

Process Stream	COS (lb/hr)	COS (ton/yr)	MeOH (lb/hr)	MeOH (ton/yr)	Benzene* (lb/hr)	Benzene* (ton/yr)
Acid Gas	2.79E-02	1.22E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Flare KO Drum Drainage	1.73E-03	7.59E-03	0.00E+00	0.00E+00	4.92E-01	2.15E+00
Gasifier Vent	4.92E-02	2.15E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Gasoline (Gas)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.10E-01	3.99E+00
Gasoline (Light Liquid)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.66E+00	1.17E+01
Gasoline (Heavy Liquid)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.94E-02	8.51E-02
LPG	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Methanol Gas	0.00E+00	0.00E+00	2.92E-01	1.28E+00	0.00E+00	0.00E+00
Methanol Pure Liquid	0.00E+00	0.00E+00	3.28E-01	1.44E+00	0.00E+00	0.00E+00
Methanol Product (MeOH 1)	0.00E+00	0.00E+00	3.39E+00	1.49E+01	0.00E+00	0.00E+00
Methanol Product (MeOH 2)	0.00E+00	0.00E+00	1.23E-01	5.40E-01	0.00E+00	0.00E+00
Methanol Product (MeOH 3)	0.00E+00	0.00E+00	1.23E-01	5.38E-01	0.00E+00	0.00E+00
Methanol Product (MeOH 5)	0.00E+00	0.00E+00	1.15E-01	5.02E-01	0.00E+00	0.00E+00
Mixed Fuel Gas	0.00E+00	0.00E+00	1.44E-02	6.32E-02	0.00E+00	0.00E+00
MTG Fuel Gas	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.41E-02	6.18E-02
Propylene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total	**7.88E-02**	**3.45E-01**	**4.39E+00**	**1.92E+01**	**4.10E+00**	**1.80E+01**

* Benzene is assumed from emissions of C6-C10 aromatics.

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Acid Gas Process Stream

Stream Name: Acid Gas
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.00%	0.00E+00	0.00%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	55.94%	1.27E-02	47.86%	
H2O	7732-18-5	N	N	18.02	3.37%	1.87E-03	7.05%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	40.16%	1.18E-02	44.37%	
COS	463-58-1	Y	Y	60.07	0.28%	4.68E-05	0.18%	
NH3	7664-41-7	N	N	17.03	0.25%	1.45E-04	0.55%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	2.66E-02	100.00%	

Weight % TOC	0.28%
Weight % VOC	0.28%
Weight % HAP	0.28%

Fugitive Emissions - SOCMI Factors

Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	Controlled Emissions: TOC Emission Rate (kg/hr)	Controlled Emissions: VOC Emission Rate (kg/hr)	Controlled Emissions: Hours of Operation	Controlled Emissions: VOC Emissions (tpy)	Uncontrolled Emissions: VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	204	0.0004	0.0004	8760	4.30E-03	3.30E-02
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		27	0.0079	0.0079	8760	7.62E-02	7.62E-02
Connectors	0.00183		130	0.0007	0.0007	8760	6.45E-03	6.45E-03
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		16	0.0007	0.0007	8760	6.51E-03	6.51E-03
Totals				0.01	0.01		0.09	0.12

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors

HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	Controlled Emissions: HAP Emissions (lb/hr)	Controlled Emissions: HAP Emissions (ton/yr)	Uncontrolled Emissions: HAP Emissions (lb/hr)	Uncontrolled Emissions: HAP Emissions (ton/yr)
COS	0.28%	0.28%	8760	2.13E-02	9.34E-02	2.79E-02	1.22E-01
Cl2	0.00%	0.28%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	0.28%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	0.28%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	0.00%	0.28%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.02	0.09	0.03	0.12

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Flare KO Drum Drainage Process Stream

Stream Name: Flare KO Drum Drainage
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	22.46%	8.02E-03	29.34%	
H2	1333-74-0	N	N	2.02	1.16%	5.77E-03	21.11%	
CO2	124-38-9	N	N	44.01	18.13%	4.12E-03	15.08%	
H2O	7732-18-5	N	N	18.02	7.50%	4.16E-03	15.23%	
CH4	74-82-8	N	N	16.04	0.03%	2.05E-05	0.07%	
Ar	7440-37-1	N	N	39.95	0.37%	9.29E-05	0.34%	
N2	7727-37-9	N	N	28.01	0.12%	4.25E-05	0.16%	
H2S	7783-06-4	N	N	34.08	0.16%	4.72E-05	0.17%	
COS	463-58-1	Y	Y	60.07	0.06%	9.44E-06	0.03%	
NH3	7664-41-7	N	N	17.03	0.01%	3.15E-06	0.01%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	23.93%	2.09E-03	7.66%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	4.20%	3.74E-04	1.37%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	5.77%	5.14E-04	1.88%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	16.11%	2.06E-03	7.54%	Assumed Benzene
TOTALS					100.00%	2.73E-02	100.00%	

Weight % TOC	50.09%
Weight % VOC	50.06%
Weight % HAP	16.16%

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	68	0.0264	0.0264	8760	2.55E-01	1.96E+00
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		8	0.4167	0.4165	8760	4.02E+00	4.02E+00
Connectors	0.00183		48	0.0440	0.0440	8760	4.24E-01	4.24E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		4	0.0301	0.0300	8760	2.90E-01	2.90E-01
Totals				0.52	0.52		4.99	6.70

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.06%	50.06%	8760	1.29E-03	5.66E-03	1.73E-03	7.59E-03
Cl2	0.00%	50.06%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	50.06%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	50.06%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	16.11%	50.06%	8760	3.67E-01	1.61E+00	4.92E-01	2.15E+00
Total				0.37	1.61	0.49	2.16

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Gasifier Vent Process Stream

Stream Name: Gasifier Vent
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	44.91%	1.60E-02	35.98%	
H2	1333-74-0	N	N	2.02	2.33%	1.15E-02	25.88%	
CO2	124-38-9	N	N	44.01	36.27%	8.24E-03	18.49%	
H2O	7732-18-5	N	N	18.02	15.00%	8.33E-03	18.68%	
CH4	74-82-8	N	N	16.04	0.07%	4.09E-05	0.09%	
Ar	7440-37-1	N	N	39.95	0.74%	1.86E-04	0.42%	
N2	7727-37-9	N	N	28.01	0.24%	8.50E-05	0.19%	
H2S	7783-06-4	N	N	34.08	0.32%	9.45E-05	0.21%	
COS	463-58-1	Y	Y	60.07	0.11%	1.89E-05	0.04%	
NH3	7664-41-7	N	N	17.03	0.01%	6.30E-06	0.01%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Paraffins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	4.46E-02	100.00%	

Weight % TOC	0.18%
Weight % VOC	0.11%
Weight % HAP	0.11%

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	957	0.0013	0.0008	8760	8.14E-03	8.26E-02
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		112	0.0209	0.0132	8760	1.28E-01	1.28E-01
Connectors	0.00183		804	0.0026	0.0017	8760	1.61E-02	1.61E-02
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		55	0.0015	0.0009	8760	9.04E-03	9.04E-03
Totals				0.03	0.02		0.16	0.22

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.11%	0.11%	8760	3.67E-02	1.61E-01	4.92E-02	2.15E-01
Cl2	0.00%	0.11%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	0.11%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	0.11%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	0.00%	0.11%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.04	0.16	0.05	0.22

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Gasoline (Gas) Process Stream

Stream Name: Gasoline (Gas)
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.00%	0.00E+00	0.00%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.00%	0.00E+00	0.00%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	47.85%	4.19E-03	41.52%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	8.39%	7.48E-04	7.41%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	11.54%	1.03E-03	10.19%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	32.21%	4.12E-03	40.87%	Assumed Benzene
TOTALS					100.00%	1.01E-02	100.00%	

Weight % TOC	**100.00%**
Weight % VOC	**100.00%**
Weight % HAP	**32.21%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	50	0.0388	0.0388	8760	3.75E-01	2.88E+00
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		9	0.9360	0.9360	8760	9.04E+00	9.04E+00
Connectors	0.00183		26	0.0476	0.0476	8760	4.59E-01	4.59E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Totals				1.02	1.02		9.87	12.38

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	32.21%	100.00%	8760	7.26E-01	3.18E+00	9.10E-01	3.99E+00
Total				0.73	3.18	0.91	3.99

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Gasoline (Light Liquid) Process Stream

Stream Name: Gasoline (Light Liquid)
Service Type: Light Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.00%	0.00E+00	0.00%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.00%	0.00E+00	0.00%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Paraffins	N/A	Y	N	114.23	47.85%	4.19E-03	41.52%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	8.39%	7.48E-04	7.41%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	11.54%	1.03E-03	10.19%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	32.21%	4.12E-03	40.87%	Assumed Benzene
TOTALS					100.00%	1.01E-02	100.00%	

Weight % TOC	100.00%
Weight % VOC	100.00%
Weight % HAP	32.21%

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	487	0.3140	0.3140	8760	3.03E+00	1.89E+01
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	24	0.1481	0.1481	8760	1.43E+00	4.61E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compressor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		348	0.6368	0.6368	8760	6.15E+00	6.15E+00
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		45	0.6750	0.6750	8760	6.52E+00	6.52E+00
Totals				1.77	1.77		17.12	36.22

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	32.21%	100.00%	8760	1.26E+00	5.52E+00	2.66E+00	1.17E+01
Total				1.26	5.52	2.66	11.67

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Gasoline (Heavy Liquid) Process Stream

Stream Name: Gasoline (Heavy Liquid)
Service Type: Heavy Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.00%	0.00E+00	0.00%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.00%	0.00E+00	0.00%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	47.85%	4.19E-03	41.52%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	8.39%	7.48E-04	7.41%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	11.54%	1.03E-03	10.19%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	32.21%	4.12E-03	40.87%	Assumed Benzene
TOTALS					100.00%	1.01E-02	100.00%	

Weight % TOC	**100.00%**
Weight % VOC	**100.00%**
Weight % HAP	**32.21%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		6	0.0014	0.0014	8760	1.33E-02	1.33E-02
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		6	0.0110	0.0110	8760	1.06E-01	1.06E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		1	0.0150	0.0150	8760	1.45E-01	1.45E-01
Totals				0.03	0.03		0.26	0.26

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	32.21%	100.00%	8760	1.94E-02	8.51E-02	1.94E-02	8.51E-02
Total				0.02	0.09	0.02	0.09

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
LPG Process Stream

Stream Name: LPG
Service Type: Light Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	8.34%	2.98E-03	13.04%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.00%	0.00E+00	0.00%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	3.60%	5.00E-04	2.19%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	21.86%	7.79E-03	34.13%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	37.82%	6.51E-03	28.49%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	28.36%	5.06E-03	22.15%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	2.28E-02	100.00%	

Weight % TOC	91.66%
Weight % VOC	91.66%
Weight % HAP	0.00%

Fugitive Emissions - SOCMI Factors

Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	Controlled Emissions: TOC Emission Rate (kg/hr)	Controlled Emissions: VOC Emission Rate (kg/hr)	Controlled Emissions: Hours of Operation	Controlled Emissions: VOC Emissions (tpy)	Uncontrolled Emissions: VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	28	0.0165	0.0165	8760	1.60E-01	9.98E-01
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	2	0.0113	0.0113	8760	1.09E-01	3.52E-01
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		20	0.0335	0.0335	8760	3.24E-01	3.24E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		4	0.0550	0.0550	8760	5.31E-01	5.31E-01
Totals				0.12	0.12		1.12	2.21

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors

HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	Controlled Emissions: HAP Emissions (lb/hr)	Controlled Emissions: HAP Emissions (ton/yr)	Uncontrolled Emissions: HAP Emissions (lb/hr)	Uncontrolled Emissions: HAP Emissions (ton/yr)
COS	0.00%	91.66%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	91.66%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	91.66%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	91.66%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	0.00%	91.66%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.00	0.00	0.00	0.00

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Methanol Gas Process Stream

Stream Name: Methanol Gas
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.02%	6.44E-06	0.02%	
H2	1333-74-0	N	N	2.02	0.00%	3.19E-06	0.01%	
CO2	124-38-9	N	N	44.01	0.30%	6.92E-05	0.22%	
H2O	7732-18-5	N	N	18.02	3.16%	1.75E-03	5.49%	
CH4	74-82-8	N	N	16.04	0.03%	1.59E-05	0.05%	
Ar	7440-37-1	N	N	39.95	0.06%	1.61E-05	0.05%	
N2	7727-37-9	N	N	28.01	0.03%	1.14E-05	0.04%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	96.19%	3.00E-02	94.01%	
Ethanol	64-17-5	Y	N	46.07	0.05%	1.04E-05	0.03%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.03%	7.31E-06	0.02%	
Methyl Acetate	79-20-9	Y	N	74.08	0.08%	1.10E-05	0.03%	
Propanol	71-23-8	Y	N	60.10	0.02%	4.00E-06	0.01%	
Butanol	71-36-3	Y	N	74.12	0.02%	2.60E-06	0.01%	
Acetone	67-64-1	Y	N	58.08	0.00%	3.31E-07	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	1.33E-07	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	3.19E-02	100.00%	

Weight % TOC	**96.42%**
Weight % VOC	**96.40%**
Weight % HAP	**96.19%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	5	0.0037	0.0037	8760	3.61E-02	2.78E-01
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		1	0.1003	0.1003	8760	9.68E-01	9.68E-01
Connectors	0.00183		2	0.0035	0.0035	8760	3.41E-02	3.41E-02
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Totals				0.11	0.11		1.04	1.28

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	96.19%	96.40%	8760	2.36E-01	1.04E+00	2.92E-01	1.28E+00
C6 - C10 Aromatics	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.24	1.04	0.29	1.28

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Methanol Pure Liquid Process Stream

Stream Name: Methanol Pure Liquid
Service Type: Light Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.00%	0.00E+00	0.00%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.00%	0.00E+00	0.00%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	100.00%	3.12E-02	100.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	3.12E-02	100.00%	

Weight % TOC	100.00%
Weight % VOC	100.00%
Weight % HAP	100.00%

Fugitive Emissions - SOCMI Factors

Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	*Controlled Emissions* TOC Emission Rate (kg/hr)	*Controlled Emissions* VOC Emission Rate (kg/hr)	*Controlled Emissions* Hours of Operation	*Controlled Emissions* VOC Emissions (tpy)	*Uncontrolled Emissions* VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	16	0.0103	0.0103	8760	9.96E-02	6.22E-01
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	2	0.0123	0.0123	8760	1.19E-01	3.84E-01
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compressor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		8	0.0146	0.0146	8760	1.41E-01	1.41E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		2	0.0300	0.0300	8760	2.90E-01	2.90E-01
Totals				0.07	0.07		0.65	1.44

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors

HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	*Controlled Emissions* HAP Emissions (lb/hr)	*Controlled Emissions* HAP Emissions (ton/yr)	*Uncontrolled Emissions* HAP Emissions (lb/hr)	*Uncontrolled Emissions* HAP Emissions (ton/yr)
COS	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	100.00%	100.00%	8760	1.48E-01	6.50E-01	3.28E-01	1.44E+00
C6 - C10 Aromatics	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.15	0.65	0.33	1.44

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Methanol Product (MeOH 1) Process Stream

Stream Name: Methanol Product (MeOH 1)
Service Type: Light Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.02%	6.44E-06	0.02%	
H2	1333-74-0	N	N	2.02	0.00%	3.19E-06	0.01%	
CO2	124-38-9	N	N	44.01	0.30%	6.92E-05	0.22%	
H2O	7732-18-5	N	N	18.02	3.16%	1.75E-03	5.49%	
CH4	74-82-8	N	N	16.04	0.03%	1.59E-05	0.05%	
Ar	7440-37-1	N	N	39.95	0.06%	1.61E-05	0.05%	
N2	7727-37-9	N	N	28.01	0.03%	1.14E-05	0.04%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	96.19%	3.00E-02	94.01%	
Ethanol	64-17-5	Y	N	46.07	0.05%	1.04E-05	0.03%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.03%	7.31E-06	0.02%	
Methyl Acetate	79-20-9	Y	N	74.08	0.08%	1.10E-05	0.03%	
Propanol	71-23-8	Y	N	60.10	0.02%	4.00E-06	0.01%	
Butanol	71-36-3	Y	N	74.12	0.02%	2.80E-06	0.01%	
Acetone	67-64-1	Y	N	58.08	0.00%	3.31E-07	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	1.33E-07	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Paraffins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	3.19E-02	100.00%	

Weight % TOC	**96.42%**
Weight % VOC	**96.40%**
Weight % HAP	**96.19%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	134	0.0833	0.0833	8760	8.04E-01	5.03E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	22	0.1309	0.1308	8760	1.26E+00	4.07E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		96	0.1694	0.1693	8760	1.63E+00	1.63E+00
Open-ended Lines	0.00170		16	0.0262	0.0262	8760	2.53E-01	2.53E-01
Sampling Connections	0.01500		28	0.4050	0.4049	8760	3.91E+00	3.91E+00
Totals				0.81	0.81		7.86	14.90

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	96.19%	96.40%	8760	1.79E+00	7.85E+00	3.39E+00	1.49E+01
C6 - C10 Aromatics	0.00%	96.40%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				1.79	7.85	3.39	14.86

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Methanol Product (MeOH 2) Process Stream

Stream Name: Methanol Product (MeOH 2)
Service Type: Light Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.08%	2.89E-05	0.08%	
H2	1333-74-0	N	N	2.02	0.02%	1.09E-04	0.34%	
CO2	124-38-9	N	N	44.01	0.42%	9.63E-05	0.30%	
H2O	7732-18-5	N	N	18.02	3.32%	1.84E-03	5.74%	
CH4	74-82-8	N	N	16.04	0.08%	4.81E-05	0.15%	
Ar	7440-37-1	N	N	39.95	0.44%	1.09E-04	0.34%	
N2	7727-37-9	N	N	28.01	0.18%	6.42E-05	0.20%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	95.46%	2.98E-02	92.84%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	3.21E-02	100.00%	

Weight % TOC	95.54%
Weight % VOC	95.46%
Weight % HAP	95.46%

Fugitive Emissions - SOCMI Factors

Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	*Controlled Emissions* TOC Emission Rate (kg/hr)	*Controlled Emissions* VOC Emission Rate (kg/hr)	*Controlled Emissions* Hours of Operation	*Controlled Emissions* VOC Emissions (tpy)	*Uncontrolled Emissions* VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	10	0.0062	0.0062	8760	5.94E-02	3.71E-01
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		10	0.0175	0.0175	8760	1.69E-01	1.69E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Totals				0.02	0.02		0.23	0.54

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors

HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	*Controlled Emissions* HAP Emissions (lb/hr)	*Controlled Emissions* HAP Emissions (ton/yr)	*Uncontrolled Emissions* HAP Emissions (lb/hr)	*Uncontrolled Emissions* HAP Emissions (ton/yr)
COS	0.00%	95.46%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	95.46%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	95.46%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	95.46%	95.46%	8760	5.21E-02	2.28E-01	1.23E-01	5.40E-01
C6 - C10 Aromatics	0.00%	95.46%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.05	0.23	0.12	0.54

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Methanol Product (MeOH 3) Process Stream

Stream Name: Methanol Product (MeOH 3)
Service Type: Light Liquid
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.07%	2.57E-05	0.08%	
H2	1333-74-0	N	N	2.02	0.02%	1.16E-04	0.36%	
CO2	124-38-9	N	N	44.01	0.42%	9.65E-05	0.30%	
H2O	7732-18-5	N	N	18.02	3.62%	2.01E-03	6.25%	
CH4	74-82-8	N	N	16.04	0.08%	5.15E-05	0.16%	
Ar	7440-37-1	N	N	39.95	0.48%	1.16E-04	0.36%	
N2	7727-37-9	N	N	28.01	0.19%	6.76E-05	0.21%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	95.12%	2.97E-02	92.28%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Paraffins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	3.22E-02	100.00%	

Weight % TOC	**95.21%**
Weight % VOC	**95.12%**
Weight % HAP	**95.12%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Light Liquids	0.00403	84.00%	10	0.0061	0.0061	8760	5.92E-02	3.70E-01
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compressor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Connectors	0.00183		10	0.0174	0.0174	8760	1.68E-01	1.68E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Totals				0.02	0.02		0.23	0.54

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	95.12%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	95.12%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	95.12%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	95.12%	95.12%	8760	5.19E-02	2.27E-01	1.23E-01	5.38E-01
C6 - C10 Aromatics	0.00%	95.12%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.05	0.23	0.12	0.54

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Methanol Product (MeOH 5) Process Stream

Stream Name: Methanol Product (MeOH 5)
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	15.02%	5.36E-03	7.09%	
H2	1333-74-0	N	N	2.02	9.73%	4.83E-02	63.83%	
CO2	124-38-9	N	N	44.01	3.93%	8.92E-04	1.18%	
H2O	7732-18-5	N	N	18.02	0.05%	3.03E-05	0.04%	
CH4	74-82-8	N	N	16.04	2.78%	1.73E-03	2.29%	
Ar	7440-37-1	N	N	39.95	47.22%	1.18E-02	15.63%	
N2	7727-37-9	N	N	28.01	19.58%	6.99E-03	9.24%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	1.70%	5.29E-04	0.70%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	0.00%	0.00E+00	0.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	7.56E-02	100.00%	

Weight % TOC	4.47%
Weight % VOC	1.70%
Weight % HAP	1.70%

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	125	0.0043	0.0016	8760	1.59E-02	1.22E-01
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		16	0.0745	0.0282	8760	2.72E-01	2.72E-01
Connectors	0.00183		136	0.0111	0.0042	8760	4.08E-02	4.08E-02
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		27	0.0181	0.0069	8760	6.63E-02	6.63E-02
Totals				0.11	0.04		0.40	0.50

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	1.70%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	1.70%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	1.70%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	1.70%	1.70%	8760	9.03E-02	3.95E-01	1.15E-01	5.02E-01
C6 - C10 Aromatics	0.00%	1.70%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.09	0.40	0.11	0.50

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Mixed Fuel Gas Process Stream

Stream Name: Mixed Fuel Gas
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	1.88%	6.70E-04	1.36%	
H2	1333-74-0	N	N	2.02	2.06%	1.02E-02	20.76%	
CO2	124-38-9	N	N	44.01	3.38%	7.68E-04	1.56%	
H2O	7732-18-5	N	N	18.02	0.01%	7.40E-06	0.02%	
CH4	74-82-8	N	N	16.04	39.92%	2.49E-02	50.67%	
Ar	7440-37-1	N	N	39.95	15.43%	3.86E-03	7.87%	
N2	7727-37-9	N	N	28.01	7.59%	2.71E-03	5.52%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.99%	3.09E-04	0.63%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	2.02%	6.73E-04	1.37%	
Ethylene	74-85-1	Y	N	28.05	0.20%	6.96E-05	0.14%	
Propane	74-98-6	Y	N	44.10	7.00%	1.59E-03	3.23%	
Propylene	115-07-1	Y	N	42.08	0.36%	8.56E-05	0.17%	
Isobutane	75-28-5	Y	N	58.12	16.30%	2.80E-03	5.71%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	2.32%	4.14E-04	0.84%	
Isopentane	78-78-4	Y	N	72.15	0.47%	6.53E-05	0.13%	
C4 - C12 Paraffins	N/A	Y	N	114.23	0.08%	6.80E-06	0.01%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	4.91E-02	100.00%	

Weight % TOC	**69.65%**
Weight % VOC	**27.71%**
Weight % HAP	**0.99%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	90	0.0487	0.0194	8760	1.87E-01	1.44E+00
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Relief Valves-Gas/Vapor	0.10400		1	0.0724	0.0288	8760	2.78E-01	2.78E-01
Connectors	0.00183		11	0.0140	0.0056	8760	5.39E-02	5.39E-02
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Totals				0.14	0.05		0.52	1.77

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	27.71%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	27.71%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	27.71%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.99%	27.71%	8760	4.23E-03	1.85E-02	1.44E-02	6.32E-02
C6 - C10 Aromatics	0.00%	27.71%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.00	0.02	0.01	0.06

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
MTG Fuel Gas Process Stream

Stream Name: MTG Fuel Gas
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	34.27%	1.22E-02	34.25%	
H2	1333-74-0	N	N	2.02	0.01%	6.11E-05	0.17%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.39%	2.17E-04	0.61%	
CH4	74-82-8	N	N	16.04	22.67%	1.41E-02	39.56%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	8.92%	2.97E-03	8.31%	
Ethylene	74-85-1	Y	N	28.05	5.69%	2.03E-03	5.68%	
Propane	74-98-6	Y	N	44.10	6.95%	1.58E-03	4.41%	
Propylene	115-07-1	Y	N	42.08	0.30%	7.24E-05	0.20%	
Isobutane	75-28-5	Y	N	58.12	2.52%	4.34E-04	1.21%	
N-Butane	106-97-8	Y	N	58.12	0.43%	7.48E-05	0.21%	
Butylene	25167-67-3	Y	N	56.11	0.78%	1.39E-04	0.39%	
Isopentane	78-78-4	Y	N	72.15	5.20%	7.21E-04	2.02%	
C4 - C12 Paraffins	N/A	Y	N	114.23	7.48%	6.54E-04	1.83%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	2.69%	2.39E-04	0.67%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	1.31%	1.17E-04	0.33%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.38%	4.91E-05	0.14%	Assumed Benzene
TOTALS					100.00%	3.57E-02	100.00%	

Weight % TOC	65.33%
Weight % VOC	33.74%
Weight % HAP	0.38%

Fugitive Emissions - SOCMI Factors

Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	*Controlled Emissions* TOC Emission Rate (kg/hr)	*Controlled Emissions* VOC Emission Rate (kg/hr)	*Controlled Emissions* Hours of Operation	*Controlled Emissions* VOC Emissions (tpy)	*Uncontrolled Emissions* VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	60	0.0304	0.0157	8760	1.52E-01	1.17E+00
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		4	0.5958	0.3077	8760	2.97E+00	2.97E+00
Relief Valves-Gas/Vapor	0.10400		2	0.1359	0.0702	8760	6.77E-01	6.77E-01
Connectors	0.00183		88	0.1052	0.0543	8760	5.24E-01	5.24E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		2	0.0196	0.0101	8760	9.77E-02	9.77E-02
Totals				0.89	0.46		4.42	5.44

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors

HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	*Controlled Emissions* HAP Emissions (lb/hr)	*Controlled Emissions* HAP Emissions (ton/yr)	*Uncontrolled Emissions* HAP Emissions (lb/hr)	*Uncontrolled Emissions* HAP Emissions (ton/yr)
COS	0.00%	33.74%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	33.74%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	33.74%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	33.74%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	0.38%	33.74%	8760	1.15E-02	5.03E-02	1.41E-02	6.18E-02
Total				0.01	0.05	0.01	0.06

Medicine Bow Fuel & Power Industrial Gasification & Liquefaction Plant
Propylene Process Stream

Stream Name: Propylene
Service Type: Gas
Hours of Operation: 8760
This piping is included in the LDAR program.

Chemical Name	CAS Number	VOC	HAP	Molecular Weight (lb/lb-mol)	Weight %	Mole Fraction	Mole Percent	
CO	630-08-0	N	N	28.01	0.00%	0.00E+00	0.00%	
H2	1333-74-0	N	N	2.02	0.00%	0.00E+00	0.00%	
CO2	124-38-9	N	N	44.01	0.00%	0.00E+00	0.00%	
H2O	7732-18-5	N	N	18.02	0.00%	0.00E+00	0.00%	
CH4	74-82-8	N	N	16.04	0.00%	0.00E+00	0.00%	
Ar	7440-37-1	N	N	39.95	0.00%	0.00E+00	0.00%	
N2	7727-37-9	N	N	28.01	0.00%	0.00E+00	0.00%	
H2S	7783-06-4	N	N	34.08	0.00%	0.00E+00	0.00%	
COS	463-58-1	Y	Y	60.07	0.00%	0.00E+00	0.00%	
NH3	7664-41-7	N	N	17.03	0.00%	0.00E+00	0.00%	
O2	7782-44-7	N	N	32.00	0.00%	0.00E+00	0.00%	
SO2	7446-09-5	N	N	64.06	0.00%	0.00E+00	0.00%	
Cl2	7782-50-5	N	Y	70.91	0.00%	0.00E+00	0.00%	
HCl	7647-01-0	N	Y	36.46	0.00%	0.00E+00	0.00%	
MeOH	67-56-1	Y	Y	32.04	0.00%	0.00E+00	0.00%	
Ethanol	64-17-5	Y	N	46.07	0.00%	0.00E+00	0.00%	
Dimethyl Ether	115-10-6	Y	N	46.07	0.00%	0.00E+00	0.00%	
Methyl Acetate	79-20-9	Y	N	74.08	0.00%	0.00E+00	0.00%	
Propanol	71-23-8	Y	N	60.10	0.00%	0.00E+00	0.00%	
Butanol	71-36-3	Y	N	74.12	0.00%	0.00E+00	0.00%	
Acetone	67-64-1	Y	N	58.08	0.00%	0.00E+00	0.00%	
MEK	78-93-3	Y	N	72.11	0.00%	0.00E+00	0.00%	
Ethane	74-84-0	N	N	30.07	0.00%	0.00E+00	0.00%	
Ethylene	74-85-1	Y	N	28.05	0.00%	0.00E+00	0.00%	
Propane	74-98-6	Y	N	44.10	0.00%	0.00E+00	0.00%	
Propylene	115-07-1	Y	N	42.08	100.00%	2.38E-02	100.00%	
Isobutane	75-28-5	Y	N	58.12	0.00%	0.00E+00	0.00%	
N-Butane	106-97-8	Y	N	58.12	0.00%	0.00E+00	0.00%	
Butylene	25167-67-3	Y	N	56.11	0.00%	0.00E+00	0.00%	
Isopentane	78-78-4	Y	N	72.15	0.00%	0.00E+00	0.00%	
C4 - C12 Parafins	N/A	Y	N	114.23	0.00%	0.00E+00	0.00%	Assumed Octane
C4 - C12 Olefins	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Octene
C6 - C10 Naphthenes	N/A	Y	N	112.21	0.00%	0.00E+00	0.00%	Assumed Cyclooctane
C6 - C10 Aromatics	N/A	Y	Y	78.11	0.00%	0.00E+00	0.00%	Assumed Benzene
TOTALS					100.00%	2.38E-02	100.00%	

Weight % TOC	**100.00%**
Weight % VOC	**100.00%**
Weight % HAP	**0.00%**

Fugitive Emissions - SOCMI Factors				*Controlled Emissions*				*Uncontrolled Emissions*
Equipment Type	SOCMI Emission Factor[1] (kg/hr-source)	% Control With LDAR[2]	Source Count	TOC Emission Rate (kg/hr)	VOC Emission Rate (kg/hr)	Hours of Operation	VOC Emissions (tpy)	VOC Emissions (tpy)
Valves-Gas	0.00597	87.00%	40	0.0310	0.0310	8760	3.00E-01	2.31E+00
Valves-Light Liquids	0.00403	84.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Valves-Heavy Liquids	0.00023		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Light Liquids	0.01990	69.00%	0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Pump Seals-Heavy Liquids	0.00862		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Compresssor Seals-Gas	0.22800		8	1.8240	1.8240	8760	1.76E+01	1.76E+01
Relief Valves-Gas/Vapor	0.10400		4	0.4160	0.4160	8760	4.02E+00	4.02E+00
Connectors	0.00183		8	0.0146	0.0146	8760	1.41E-01	1.41E-01
Open-ended Lines	0.00170		0	0.0000	0.0000	8760	0.00E+00	0.00E+00
Sampling Connections	0.01500		2	0.0300	0.0300	8760	2.90E-01	2.90E-01
Totals				2.32	2.32		22.35	24.36

[1] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 2-1).
[2] EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates (Table 5-2). Assumes monthly monitoring with leak definition of 10,000 ppmv.

HAP Emissions - SOCMI Factors				*Controlled Emissions*		*Uncontrolled Emissions*	
HAP	Individual HAP Weight %	VOC Weight %	Hours of Operation	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)	HAP Emissions (lb/hr)	HAP Emissions (ton/yr)
COS	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cl2	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HCl	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MeOH	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
C6 - C10 Aromatics	0.00%	100.00%	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Total				0.00	0.00	0.00	0.00

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Med Bow F&P Gasoline Tank
City:	Medicine Bow
State:	Wyoming
Company:	Medicine Bow Fuel & Power LLC
Type of Tank:	Internal Floating Roof Tank
Description:	Finished gasoline product tank; total 8 identical tanks.

Tank Dimensions

Diameter (ft):		150.00
Volume (gallons):		6,341,984.00
Turnovers:		5.72
Self Supp. Roof? (y/n):	N	
No. of Columns:		9.00
Eff. Col. Diam. (ft):		1.00

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Rim-Seal System

Primary Seal:	Vapor-mounted
Secondary Seal	None

Deck Characteristics

Deck Fitting Category:	Typical	
Deck Type:	Bolted	
Construction:	Panel	
Deck Seam:	Panel: 5 x 7.5 Ft	
Deck Seam Len. (ft):		5,831.58

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed	1
Automatic Gauge Float Well/Unbolted Cover, Ungasketed	1
Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask.	9
Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed	1
Roof Leg or Hanger Well/Adjustable	58
Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open	1
Stub Drain (1-in. Diameter)/Slit Fabric Seal 10% Open	180

Appendix F
Coal Storage BACT Cost Analysis

Best Available Control Technology (BACT) Analysis
Coal Storage and Reclaim Facility
Saddle Back Hills Mine
Carbon County, Wyoming

Arch Coal Company

April 5, 2007

Prepared by:

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Summary

Three options were considered to provide 300,000 tons of live coal storage, as required by the longwall operation and the companion coal-to-liquids plant.

1. Stacking tubes located in the pit excavated for the underground portal (reference drawing no. 6945-L010)
2. Stacking tubes located on the surface next to the pit (reference drawing no. 6945-L020)
3. Covered slot storage (reference drawing no. 6945-L030)

The first two options differ in the placement of the stacking tubes. In Option 1 the storage facility is on the pit floor, with the excavated spoils placed in a large berm on the west and north sides of the pit. This configuration is intended to reduce storage pile erosion and resulting PM_{10} emissions, by sheltering the pile from prevailing winds. Support for this approach is provided at the end of this document.

Option 1 would reduce PM_{10} emissions by roughly 25% relative to Option 2. With a calculated, incremental PM_{10} emissions control cost of $6,902 per ton, Option 1 is proposed as BACT. Option 3 would eliminate PM_{10} emissions from the storage facility, but the additional capital cost would result in an incremental PM_{10} emissions control cost of $54,119 per ton relative to Option 1. This option is therefore considered infeasible.

Analysis

Table 1 presents a top-down comparison between first Options 3 and 1, then between Options 1 and 2. Facility designs and capital costs for all three options were developed by Roberts & Schaefer. Operating costs were provided by Arch Coal Company. A mine life of 20 years was used in the analysis, along with a discount rate of 8% per year. Capital and operating costs were converted to levelized annual costs to enable direct comparison between options. PM_{10} emissions were projected for each option based on emission factors approved by the Wyoming Department of Environmental Quality. Incremental emissions control costs between any two options were obtained from dividing differential levelized costs by differential emissions.

Tables 2 and 3 show the calculation of PM_{10} emissions for Options 1 and 2, respectively (Option 3 would generate no emissions). The maximum production throughput is assumed to be 3.2 million tons per year. Sources of emissions for both options include the stacking tubes, dozer activity to groom the storage pile and assist the reclaim operations, and wind erosion from the storage pile. The reclaim system is designed with passive controls (100% control) to eliminate emissions from that source.

TABLE 1

Saddleback Hills Mine Storage System

BACT Analysis: In-Pit Tube Stacker vs. Covered Slot Storage

	Option 3: Covered Slot Storage	Option 1: Tube Stacker in Pit	Option 3 vs. Option 1 Comparison
Capital Cost	$157,200,000	$84,700,000	
Mine Life (Years)	20	20	
Discount Rate (annual cost of capital)	8.0%	8.0%	
Net Present Value of Annual O&M Cost	$0	$7,363,611	
Levelized Annual Cost	$7,860,000	$4,603,181	
Annual PM-10 Emissions (tpy)	0.0	60.2	
Differential Emissions Control (tpy)			60.2
Differential Technology Cost per Year			$3,256,819
Incremental Control Cost (per ton PM-10)			**$54,119**

BACT Analysis: In-Pit Tube Stacker vs. Surface Tube Stacker

	Option 1: Tube Stacker in Pit	Option 2: Tube Stacker Surf.	Option 1 vs. Option 2 Comparison
Capital Cost	$84,700,000	$82,200,000	
Mine Life (Years)	20	20	
Discount Rate (annual cost of capital)	8.0%	8.0%	
Net Present Value of Annual O&M Cost	$7,363,611	$7,363,611	
Levelized Annual Cost	$4,603,181	$4,478,181	
Annual PM-10 Emissions (tpy)	60.2	78.3	
Differential Emissions Control (tpy)			18.1
Differential Technology Cost per Year			$125,000
Incremental Control Cost (per ton PM-10)			**$6,902**

Common assumptions used for Options 1 and 2 are:

1. All emission sources except wind erosion are identical for both options
2. Dozer operations on the storage pile average 2,000 hours per year
3. Stacking tubes are credited with 50% emissions control in comparison to a free drop
4. Maximum storage pile extent is 11 acres
5. The number of wet days (defined as having 0.01" of precipitation or more) per year is 60, taken from five years of meteorological data at the nearby Seminoe mine.

TABLE 2

BACT Option 1 (In-Pit Stacking Tubes) PM-10 Emissions

Emission Source	Type	Description			Control	Additional Information
Dozer Reclaim	**Fugitive**	**Cat D11 Dozer**			**None**	
		Emission Factor	8.0	Lb/Hr		*WDEQ 2002 Guidance*
		Total Throughput	3,200,000	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 x Op Hrs)/2000
		PM-10 Emissions	**2.40**	**Tons/Yr**		30% of TSP
Coal Stacker	**Fugitive**	**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	3,200,000	Tons/Yr		*Total Coal Through Storage*
		TSP Emissions	10.20	Tons/Yr		*E=(EFx% sus x MD/2000)x(1-CF)*
		PM-10 Emissions	**3.06**	**Tons/Yr**		*30% of TSP*
Coal Reclaim	**Fugitive**	**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	3,200,000	Tons/Yr		*Total Coal Through Storage*
		TSP Emissions	0.00	Tons/Yr		*E=(EFx% sus x MR/2000)x(1-CF)*
		PM-10 Emissions	**0.00**	**Tons/Yr**		*30% of TSP*
Coal Stockpile	**Fugitive**	**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			*Seminoe Mine 5-Year Average*
		Control Factor	0.00%			
		TSP Emissions	182.40	Tons/Yr		*E=(EF x AWS x %sus x PS x*
		PM-10 Emissions	**54.72**	**Tons/Yr**		*((365-WD)/365) x (1-CF))/2000*
TOTAL PM-10 EMISSIONS			**60.2**	**Tons/Yr**		

The difference in emissions between Options 1 and 2 is due entirely to the sheltering effect of locating the storage facility in the pit and shielding it with a spoil berm on the windward side. Average wind speed at ground level is assumed to be 6.7 meters per second, based on monitoring history at the nearby Seminoe Mine. The assumption of a 25% reduction in average wind speed under Option 1 results in a PM_{10} emissions reduction of 18.1 tons per year.

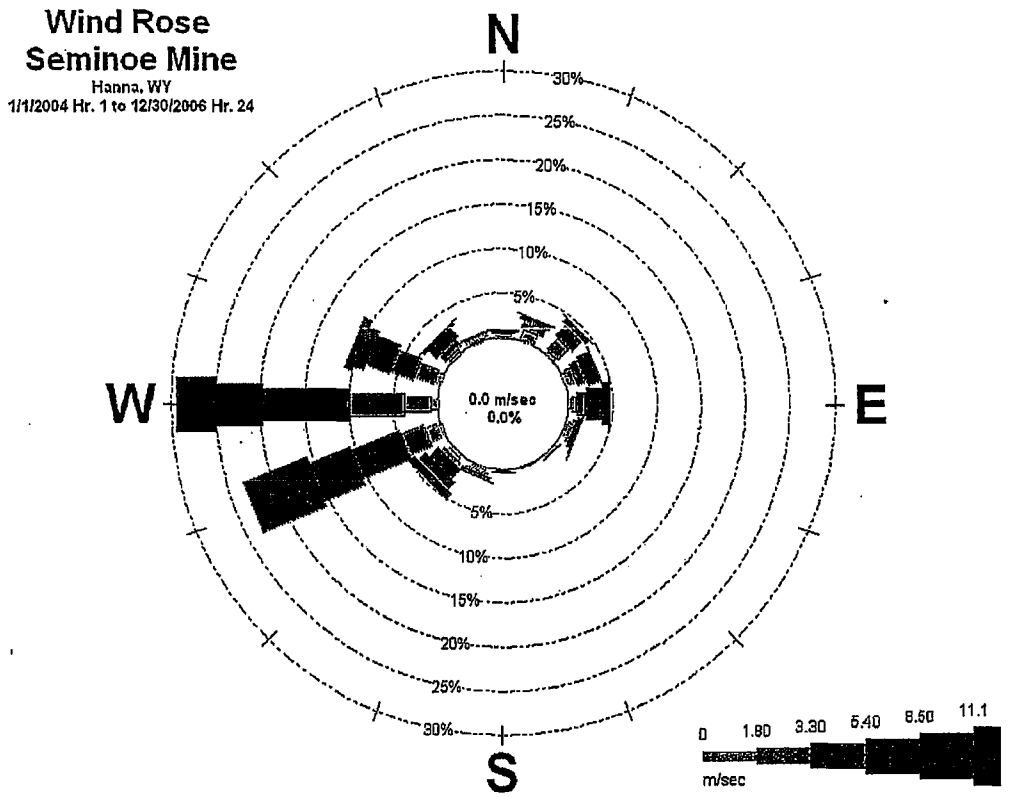
TABLE 3

BACT Option 2 (On-Surface Tube Stacker) PM-10 Emissions

Emission Source	Type	Description		Control	Additional Information
Dozer Reclaim	**Fugitive**	**Cat D11 Dozer**		**None**	
		Emission Factor	8.0	Lb/Hr	*WDEQ 2002 Guidance*
		Total Throughput	3,200,000	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 x Op Hrs)/2000
		PM-10 Emissions	**2.40**	**Tons/Yr**	30% of TSP
Coal Stacker	**Fugitive**	**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	3,200,000	Tons/Yr	*Total Coal Through Storage*
		TSP Emissions	10.20	Tons/Yr	*E=(EFx% sus x MD/2000)x(1-CF)*
		PM-10 Emissions	**3.06**	**Tons/Yr**	*30% of TSP*
Coal Reclaim	**Fugitive**	**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	3,200,000	Tons/Yr	*Total Coal Through Storage*
		TSP Emissions	0.00	Tons/Yr	*E=(EFx% sus x MR/2000)x(1-CF)*
		PM-10 Emissions	**0.00**	**Tons/Yr**	*30% of TSP*
Coal Stockpile	**Fugitive**	**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	6.70	meters/Sec	*Avg wind speed at surface*
		Wet Days	60		*Seminoe Mine 5-Year Average*
		Control Factor	0.00%		
		TSP Emissions	242.77	Tons/Yr	*E=(EF x AWS x %sus x PS x*
		PM-10 Emissions	**72.83**	**Tons/Yr**	*((365-WD)/365) x (1-CF))/2000*
TOTAL PM-10 EMISSIONS			**78.3**	**Tons/Yr**	

The assumed reduction in wind speed is based on anticipated wind shielding from the pit walls and surrounding spoil pile, as shown on drawing no. 6945-L010. The spoil berm would extend in an "L" shape from the southwestern corner of the pit to the northeastern end of the pit. The top of the berm would be at 7,081 ft. elevation, with the pushed storage pile top at 7,060 ft. elevation. The prevailing winds in this area are from the west and the west-southwest, as typified by the most recent 3-year summary from the Seminoe Mine (see Figure 1 below). The combination of berm, highwall and natural terrain would afford some shielding against wind originating anywhere between southwest and east-northeast. As implied by Figure 1, this constitutes the majority of the winds in this area.

FIGURE 1



In 2004, Inter-Mountain Laboratories conducted a study of the wind sheltering effect in an existing pit at the Bridger Coal Mine. This study was driven by a proposal to locate a 240,000-ton storage pile and stacking tube facility near the portal of an underground mine. The proposal was subsequently approved. The Bridger pit is oriented in an east-west direction, while prevailing winds are from the west-southwest. It is approximately 200 ft. from the pit floor to the top of the highwall on the north side of the pit. A spoil pile and access ramp border the south side of the pit.

In order to assess the degree of wind shelter provided by the Bridger pit, a wind monitor was placed in the pit near the probable storage site. For reference, a second wind monitor was placed at the top of the highwall several hundred feet northeast of the proposed storage site. After monitoring ten-minute average wind speeds at both these sites from 12/31/2003 to 2/06/2004, the data were collected and analyzed. During this period, wind speeds averaged as follows:

Highwall 10-minute averages ---------- 10.0 mph
In-Pit 10-minute averages ---------- 5.5 mph

Regular met station hourly averages ---------- 9.5 mph

At the regular met station, three-year wind speeds (1/1/2002 through 12/31/2004) averaged 10.3 mph. Given this longer time period, the in-pit average wind speed was compared to the met station average (rather than the highwall average) over the 5-week interval. In making this comparison, a statistical analysis revealed less variability in wind speed ratios than wind speed differences. For these reasons, the ratio of in-pit average wind speed to met station average wind speed over the 5-week monitoring period was applied to the three-year average wind speed:

$$\frac{5.5}{9.5} * 10.3 = 5.96 \frac{miles}{hour} * \frac{88}{60} * 0.3048 = 2.66 \frac{meters}{second}$$ (58% of the 3-year surface average)

Since the accepted PM_{10} emissions factor for wind erosion is directly proportional to average wind speed, in-pit storage in the Bridger case would control roughly 40% of stockpile erosion emissions.

Additional research results were consulted to confirm the effect of wind shields. The University of Nebraska and U.S. Soil Conservation Service examined the influence of windbreaks on average wind speeds (University of Nebraska Extension EC 91-1763-B). Tests showed a 30% reduction in wind speed at a downwind distance of 10 times the height of a solid barrier.

An erosion study conducted by the U.S. Environmental Protection Agency led to an assumed 50% reduction in wind speed (and a 75% reduction in emissions due to nonlinear effects). The study utilized a 3-sided enclosure with 50% porosity (Sierra Research, 2003, *Final BACM Technological And Economic Feasibility Analysis*, report prepared for the San Joaquin Valley Unified Air Pollution Control District, March 21).

In relation to these other studies, a more conservative 25% reduction in wind speed was claimed for the Saddleback in-pit storage option. The Bridger pit is roughly twice as deep as the combination of pit and spoil berm at Saddleback (although the pit orientation relative to prevailing wind is quite similar). The University of Nebraska study oriented the wind barrier perpendicular to the wind direction, which would apply only to a portion of the winds at Saddleback. The EPA study used a 3-sided enclosure, whereas the Saddleback berm is configured more like a 2-sided enclosure.

SADDLEBACK HILLS MINE SURFACE FACILITY

Preliminary Cost Estimates

The following preliminary cost estimates, with an accuracy of ± 20%, are based on three active storage options that were considered:

- Option 1 reflects a 300,000 ton active storage pile with stacking tubes and live reclaim located in a sheltered area located between the high wall and an earthen berm.
- Option 2 reflects a 300,000 ton active storage pile with stacking tubes and live reclaim located in an open area that is un-sheltered from wind erosion.
- Option 3 reflects 300,000 ton totally enclosed slot storage with 100% live storage.

	Option #1	*Option #2*	*Option #3*
Ancillary Buildings	$30,746,100	$30,742,800	$30,654,000
Road and Ditches & Civil	$8,554,700	$5,096,400	$5,030,400
Material Handling	$45,399,200	$46,360,800	$43,701,600
Enclosed Slot Storage	$0	$0	$77,814,000
Total	**$84,700,000**	**$82,200,000**	**$157,200,000**
+20%	$101,640,000	$98,640,000	$188,640,000
-20%	$67,760,000	$65,760,000	$125,760,000

Appendix H

Incremental NO_x Removal Cost for SCR

INCREMENTAL NOx REMOVAL COST FOR SCR

NOx Removal Cost to 6 ppm (76% Removal)			Costs [1]	
Catalyst Cost [1]	650,000	USD		
Catalyst Life [1]	3	years	Ammonia	202,295 USD/yr
Power Usage	160	KW	Vaporizer Power	98,015 USD/yr
Cost of Power [1]	0.07	$/kW-hr	Catalyst	240,890 USD/yr
Hours per year	8760	hr/yr	**Total**	**541,200 USD/yr**
Interest Rate	7.00	%		
Ammonia Usage [1]	46.20	gal/hr		
Cost of Ammonia [1]	0.50	USD/gal		
Uncontrolled NOx	316.08	ton/yr	(Based on normal operations, prior to SCR, fuel gas mixture)	
NOx Emissions	75.86	ton/yr		
Tons NOx Removed	240.22	ton/yr		

NOx Removal Cost to 4 ppm (84% Removal)			Costs [1]	
Catalyst Cost [1]	750,000	USD		
Catalyst Life [1]	3	years	Ammonia	219,152 USD/yr
Power Usage	173	KW	Vaporizer Power	106,183 USD/yr
Cost of Power [1]	0.07	$/kW-hr	Catalyst	277,950 USD/yr
Hours per year	8760	hr/yr	**Total**	**603,285 USD/yr**
Interest Rate	7.00	%		
Ammonia Usage [1]	50.00	gal/hr		
Cost of Ammonia [1]	0.50	USD/gal		
Uncontrolled NOx	316.08	ton/yr	(Based on normal operations, prior to SCR, fuel gas mixture)	
NOx Emissions	50.57	ton/yr		
Tons NOx Removed	265.51	ton/yr		

Incremental Cost to Reduce NOx From 6 ppm to 4 ppm

Annual Cost for Achieving 4 ppm	603,285	USD/yr
Annual Cost for Achieving 6 ppm	541,200	USD/yr
Incremental Cost	**62,085**	**USD/yr**
NOx Removed When Achieving 4 ppm	265.51	tons/yr
NOx Removed When Achieving 6 ppm	240.22	tons/yr
Incremental NOx Removal	**25.29**	**tons/yr**
Incremental Cost	**2,455**	**USD/ton**

[1] Information provided by Paul Rood, Process Engineer at SNC Lavalin, on November 16, 2007.

Appendix I

Analysis of Criteria Pollutant Far Field Modeling Sufficiency

Appendix I

Analysis of Criteria Pollutant Far Field Modeling Sufficiency

1.1 INTRODUCTION

Medicine Bow Fuel & Power LLC (MBFP) believes that the far field criteria pollutant modeling performed for the June 19, 2007 permit application remains sufficient for the revised permit application. The following pollutant-specific discussions compare modeled emission rates to emissions rates included in this revised application.

Emissions from the industrial gasification and liquefaction plant (the Plant) have been revised due to a number of process and equipment changes. Emission unit changes are summarized in Table I-1. The combustion turbines are the largest emitters of nitrogen oxides (NO_x), carbon monoxide (CO), and sulfur dioxide (SO_2) during normal operations. The turbines are also the largest point source emitters of particulate matter with a diameter of less than 10 microns (PM_{10}). Combustion turbine stack parameters are not expected to change significantly. Consequently, prior far field modeling of turbine emissions should be adequate.

With regard to other emission sources, many units do not change. However, the Sulfur Recovery Unit (SRU) incinerator has been removed from the process. Furthermore, many process heaters have been deleted while a few new process heaters have been added.

Table I-1 – Emission Unit Changes

Description	Identification	Size
Equipment with no Capacity Changes		
Combustion Turbine 1	CT-1	66 MW
Combustion Turbine 2	CT-2	66 MW
Combustion Turbine 3	CT-3	66 MW
Black Start Generator 1[1]	Gen-1	2889 hp
Black Start Generator 2[1]	Gen-2	2889 hp
Black Start Generator 3[1]	Gen-3	2889 hp
Firewater Pump Engine[1]	FW-Pump	575 hp
CO_2 Vent Stack[1]	CO_2 VS	N/A
High Pressure Flare	FL-1	0.2 MMBtu/hr (for pilot)
Added Equipment		
Auxiliary Boiler[2]	AB	66.0 MMBtu/hr
Catalyst Regenerator[1, 3]	B-1	21.5 MMBtu/hr
Reactivation Heater[1]	B-2	12.5 MMBtu/hr
HGT Reactor Charge Heater[1]	B-3	2.2 MMBtu/hr
Low Pressure Flare	FL-2	0.2 MMBtu/hr (for pilot)

Table I-1 – Emission Unit Changes

Description	Identification	Size
Removed Equipment		
Fractionation Feed Heater	H-5401	87 MMBtu/hr
Catalytic Dewaxing Charge Unit	H-5301	3.9 MMBtu/hr
Unicracker Feed Heater	H-5201	16.3 MMBtu/hr
Unicracker Intermediate Heater	H-5202	44.2 MMBtu/hr
Unionfiner Feed Heater	H-5101	5.1 MMBtu/hr
Unionfiner Intermediate Heater	H-5102	6.4 MMBtu/hr
Sulfur Recovery Unit Incinerator	H-3102	11.2 MMBtu/hr
Modified Equipment		
Gasifier Preheater 1[1,4]	GP-1	21 MMBtu/hr
Gasifier Preheater 2[1,4]	GP-2	21 MMBtu/hr
Gasifier Preheater 3[1,4]	GP-3	21 MMBtu/hr
Gasifier Preheater 4[1,4]	GP-4	21 MMBtu/hr
Gasifier Preheater 5[1,4]	GP-5	21 MMBtu/hr

1. This equipment operates less than 8,760 hr/yr. However, in some cases, potential emissions are calculated based on 8,760 hr/yr in order to simplify compliance.
2. The auxiliary boiler usually operates on standby at 25% load to prevent freeze ups if there is a Plant shutdown. The equivalent continuous heat input rate would be approximately 21 MMBtu/hr.
3. The catalyst regenerator operates only during catalyst regeneration; the average equivalent continuous rate will be approximately 9 MMBtu/hr.
4. Gasifier preheater heat input capacity was increased from 15 MMBtu/hr to 21 MMBtu/hr for each preheater.

Table I-2 summarizes proposed maximum emission rates within this revised application and compares them to modeled emission rates. Emission rates are given in terms of grams per second (g/sec) for easy comparison to modeled rates. Emission rates do not include the following malfunctions: emergency venting to the High Pressure or Low Pressure Flares and CO_2 venting during the first plant startup and as a result of malfunctions thereafter.

Table I-2 – Revised Emissions Compared to CALPUFF Modeled Emissions

Pollutant	Revised Plant-Wide Emission Rate (tpy)	Revised Plant-Wide Annual Emission Rate (g/sec)	Modeled Plant-Wide Annual Emission Rate (g/sec)	Emission Rate Increase From Modeled Rates (g/sec)
NO_x	251.63 [1]	7.24	7.28	-0.04
SO_2	32.65 [1]	0.94	0.81	0.13
PM/PM_{10}	194.93 [2]	5.61	8.96	-3.35

1. Does not include emergency venting to the High Pressure Flare or startup, shutdown, or malfunction (SSM) venting to the Low Pressure Flare.

1.2 FAR FIELD MODELING

Far field modeling was performed in 2006 using CALPUFF to predict air quality impacts relating to visibility and nitrogen and sulfur deposition. The modeled pollutants that contribute to these air quality impacts are NO_x, SO_2, and PM_{10}. Plant-wide gram per second emissions of NO_x, and PM_{10} decreased. However, SO2 emissions increased slightly.

1.2.1 NO_x Modeling

As shown in Table I-2, maximum Plant-wide NO_x emission rates are approximately 0.04 g/sec less than the emission rates used for CALPUFF modeling. The largest NO_x emitters at the Plant continue to be the three combustion turbines. These turbines account for more than 90 percent of total annual emissions during normal operations.

Since there is a decrease in emissions and equipment changes will occur in largely the same areas as the modeled emission sources, MBFP believes that no additional NO_x modeling is necessary.

1.2.2 SO_2 Modeling

Removal of the Sulfur Recovery Unit (SRU) incinerator deleted the largest single source of normal operation SO_2 emissions from the original process. However, this reduction in SO_2 emissions has been largely offset by increases in SO_2 emissions from the three combustion turbines. The combustion turbine emission increases derive in part from firing more natural gas, which has a greater sulfur concentration than the syngas that was originally expected to be fired in the turbines. In addition, the SO_2 emission factor for natural gas firing that was used in the emission calculations submitted with the original June 19, 2007 permit application was too low.

As shown in Table I-2, modeled Plant SO_2 emissions are slightly less than revised emission estimates, with modeled emissions of 0.81 g/sec, compared to revised emissions of 0.94 g/sec. Based on previous CALPUFF modeling, SO_2 emissions result in low deposition and are a minor component of visibility impacts.

1.2.3 PM/PM_{10} Modeling

While coal storage PM_{10} emissions have not changed (because coal usage has not changed), PM_{10} emissions from combustion sources have decreased substantially. Removal of the SRU incinerator accounts for a large share of the PM_{10} emission decrease. The modeled emission rate for Plant point sources was 8.96 g/sec compared to revised estimated emissions of 5.61 g/sec (including Plant point and area source emissions from coal storage).

Appendix J

Responses to WDEQ July 17, 2007 Far Field Modeling Comments

Responses to WDEQ July 17, 2007 Far Field Modeling Comments

1. CALMET Files on DVD

Comment. An examination of the terrain and landuse output files shows that both include blocks of missing data (see figure below showing terrain for the modeling domain). The applicant should obtain complete data for the domain, revise the MAKEGO portion of the CALMET processing and submit the revised input/output files to the Division. [graphic has been deleted]

Response. The files are included within the MAKEGEO file folder.

2. Section 7: Far-Field Air Quality Impact Analysis

Comment. The letter from the Division dated March 5, 2007 provided comments on the CALPUFF protocol, including item B.6 which requested an analysis of the final CALMET wind field: *"At a minimum, the analysis should include an examination of the wind flows for selected times and vertical layers. The flows produced by CALMET should be compared to observed flows as seen in archived weather maps and/or compared to expected flows (e.g., downslope winds during stable conditions at night). Other parameters such as precipitation can also be compared to observed conditions."* No analysis was provided with the application.

Response. After running CALMET, the resulting data fields were analyzed using the PRTMET utility to illustrate the assimilated wind and temperature fields within the domain for quality assurance purposes. PRTMET enables the user to extract meteorological data fields such as wind speed and direction, temperature, and mixing height on an hourly "snapshot" or average basis.

Part of the quality assurance process determined whether wind patterns were influenced by terrain; this is a good indication of whether meteorological data is properly located relative to the terrain. Figure 1 shows area contours, with pink shaded areas representing high terrain. PRTMET quality assurance graphics are included in Figures 2 through 9 for an approximate 10 km grid to demonstrate that the selection of CALMET control options resulted in a reasonable simulation of the meteorology within the domain. Particularly good instances of terrain influenced flow can be seen in Figure 2 (March 19, 2003 – hour 3) at the following locations:

East -220, North -200
East -220, North -20
East 150, North 150
East 75, North 0

Another good example of terrain influenced flow can be seen in Figure 6 (June 19, 2003 – hour 3) at the following locations:

East -275, North 75
East 50, North -125
East 75, North 0
East -275, North -25

The time for one of the hourly wind field vector snapshots was chosen based on the worst visibility impairment day from CALPUFF modeling. The largest extinction change occurred at the Savage Run sensitive Class II area on March 19, 2003. Meteorological conditions on March 19, 2003 were unusual due to a major winter storm. Appendix N includes "Mesoscale Model Simulations in Quasi-Forecast Mode of the Great Western Storm of 16-20 March 2003." This document summarizes meteorological conditions during that time. The document is also available on the CD-ROM as "Meso_Model_Great_Storm_2004.pdf."

Since March 19th conditions represent winds flowing toward Class I areas in Colorado, the other snapshot was chosen based on the worst visibility impairment day for Class I areas in Wyoming such as the Bridger Wilderness area and the Fitzpatrick Wilderness area. The largest extinction change in both Class I areas in Wyoming occurred on June 19, 2003.

These snapshot days also represent one day for summer (June 19, 2003) and one day for winter (March 19, 2003). Two hours on each day were plotted: 0300 Mountain Standard Time (MST) and 1500 MST. Furthermore, for each time period, a surface wind field, corresponding to Level 1, and an upper air wind field, corresponding to Level 8, was plotted. Plots developed in this study are shown in Table 1. These wind fields appeared to accurately capture terrain, slope, and seasonal effects expected within the modeling domain, and demonstrated generally smooth translations and continuous Mesoscale flow. These characteristics validated the spatial behavior of the meteorological data set throughout the modeling domain.

Table 1 - List of Wind Vector Plots

Date	March 19, 2003	June 19, 2003
Hour	3,15	3,15
Vertical layer	1,8	1,8

Windroses from the CALMET model output and the surface observation station data sets indicated general agreement in wind directions, frequencies, and speeds. Windroses for March 2003 from several surface observation stations such as Aspen, Laramie General Brees Field (Laramie), Craig-Moffat stations were plotted and are shown in Figures 11 through 13. The locations of the selected stations are shown in the Figure 10. The list of windroses developed in this study is included in Table 2. Windrose plots from surface observation stations and the CALMET-predicted output are shown in Figures 11 through 13 and indicate good agreement between surface observations and CALMET predicted output.

Table 2 - List of Windroses (March 1 –March 31, 2003)

Station Name	Data Period (Total Count) March 1 – March 31, 2003		Location of the Station	
	Observation	CALMET-Predicted	Observation (Latitude, Longitude)	CALMET-Predicted (Grid Cell)
Aspen	672 hours	743 hours	39.217N, 106.867W	93, 12
Laramie	715 hours	743 hours	41.313N, 105.674W	118, 71
Craig-Moffat	684 hours	743 hours	40.5N, 107.533W	79, 48

Figure 1 - 3-D Terrain Elevation Contours

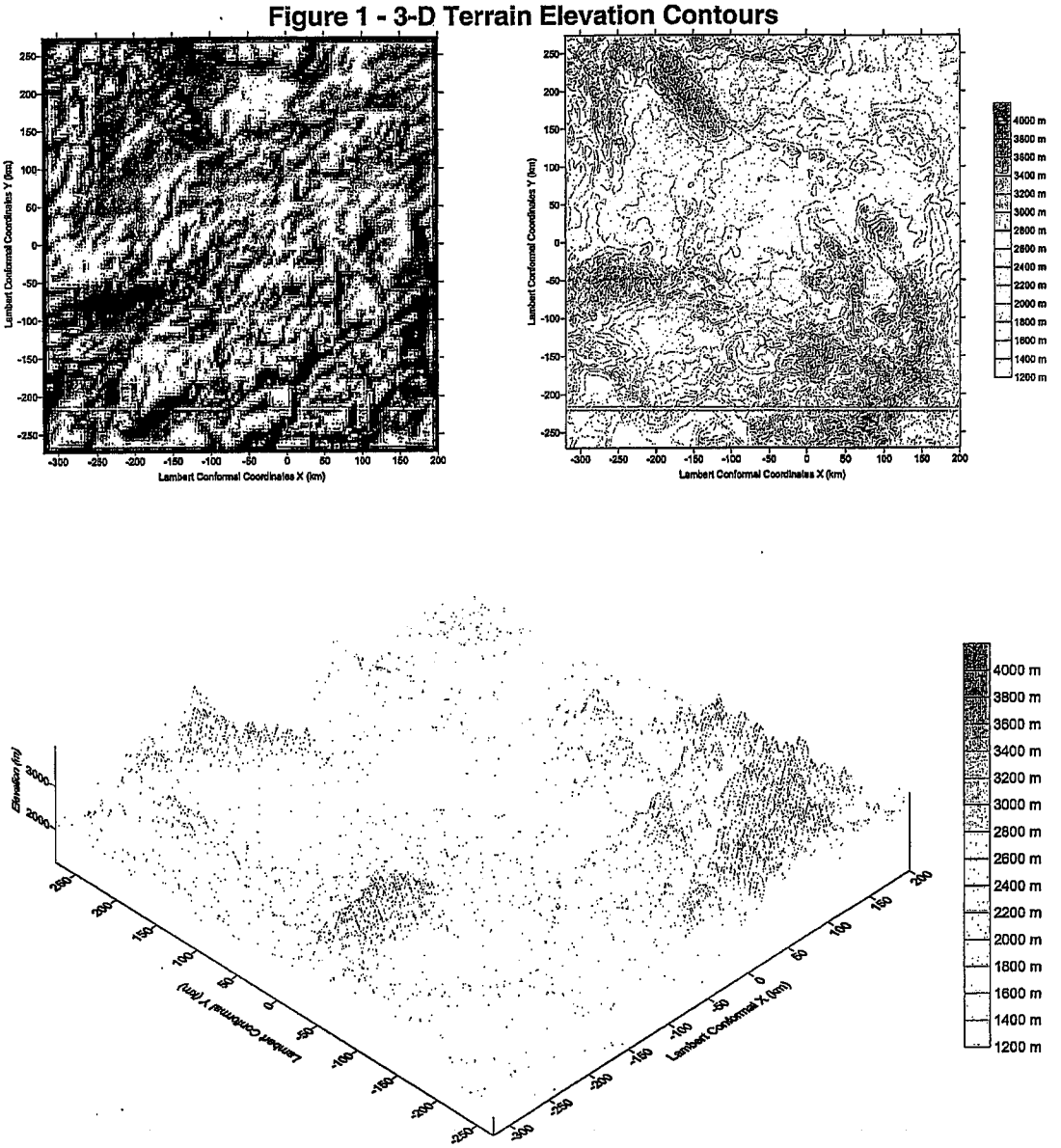


Figure 2 - Surface Air Windfield March 19, 2003, Hour 3, Layer 1

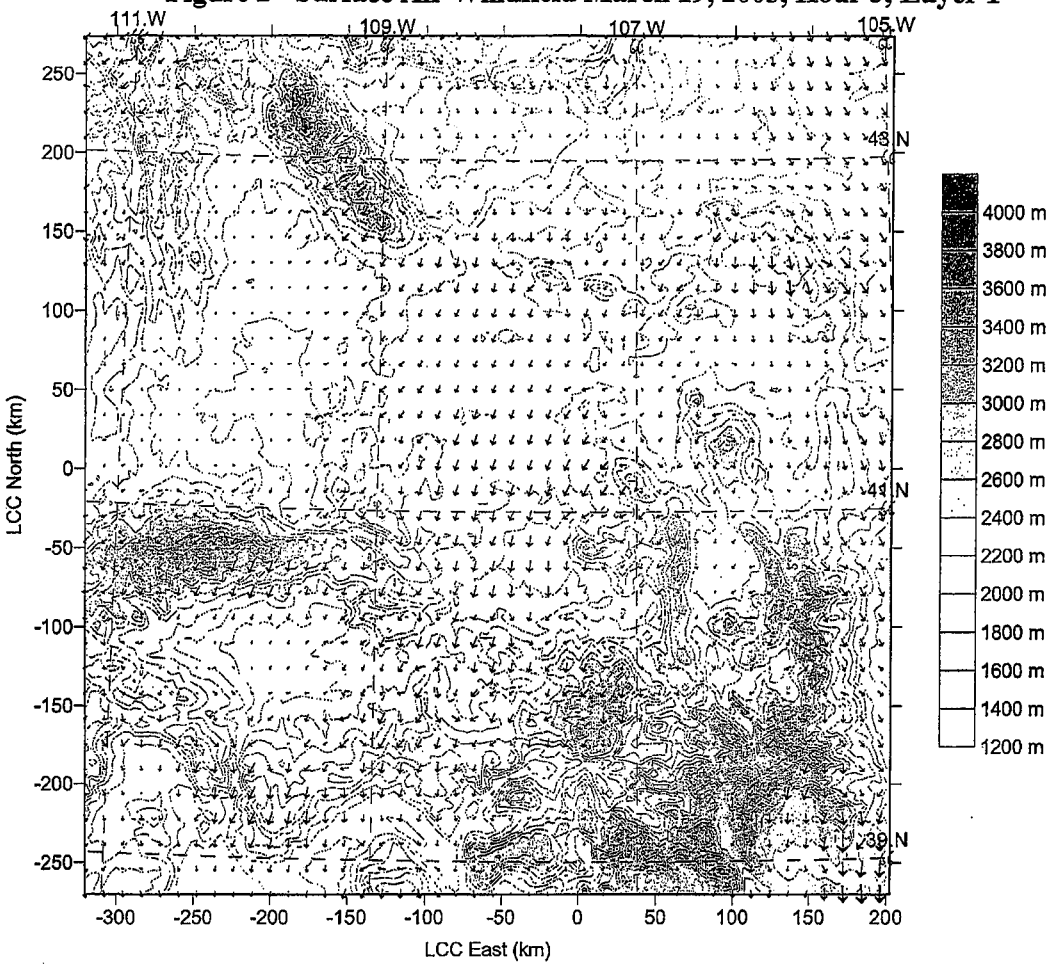


Figure 3 - Surface Air Windfield March 19, 2003, Hour 15, Layer 1

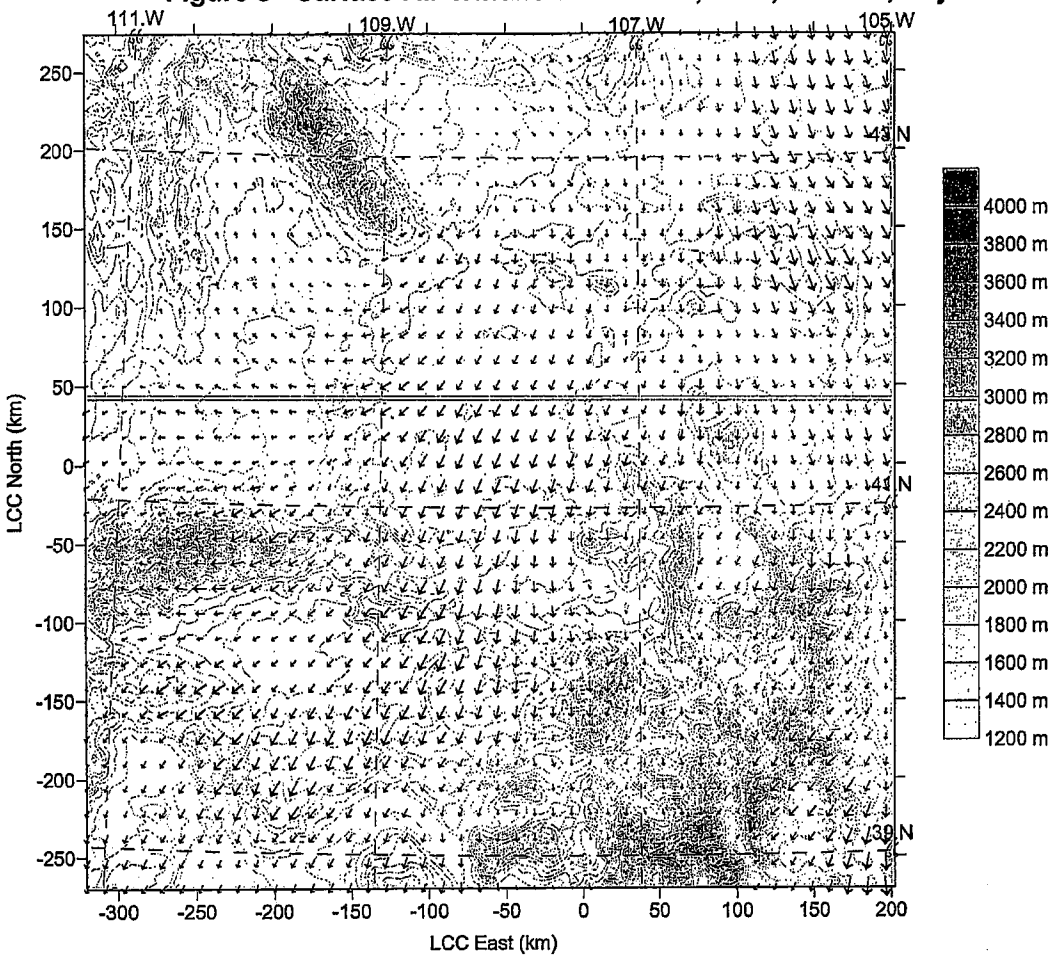


Figure 4 - Upper Air Windfield March 19, 2003, Hour 3, Layer 8

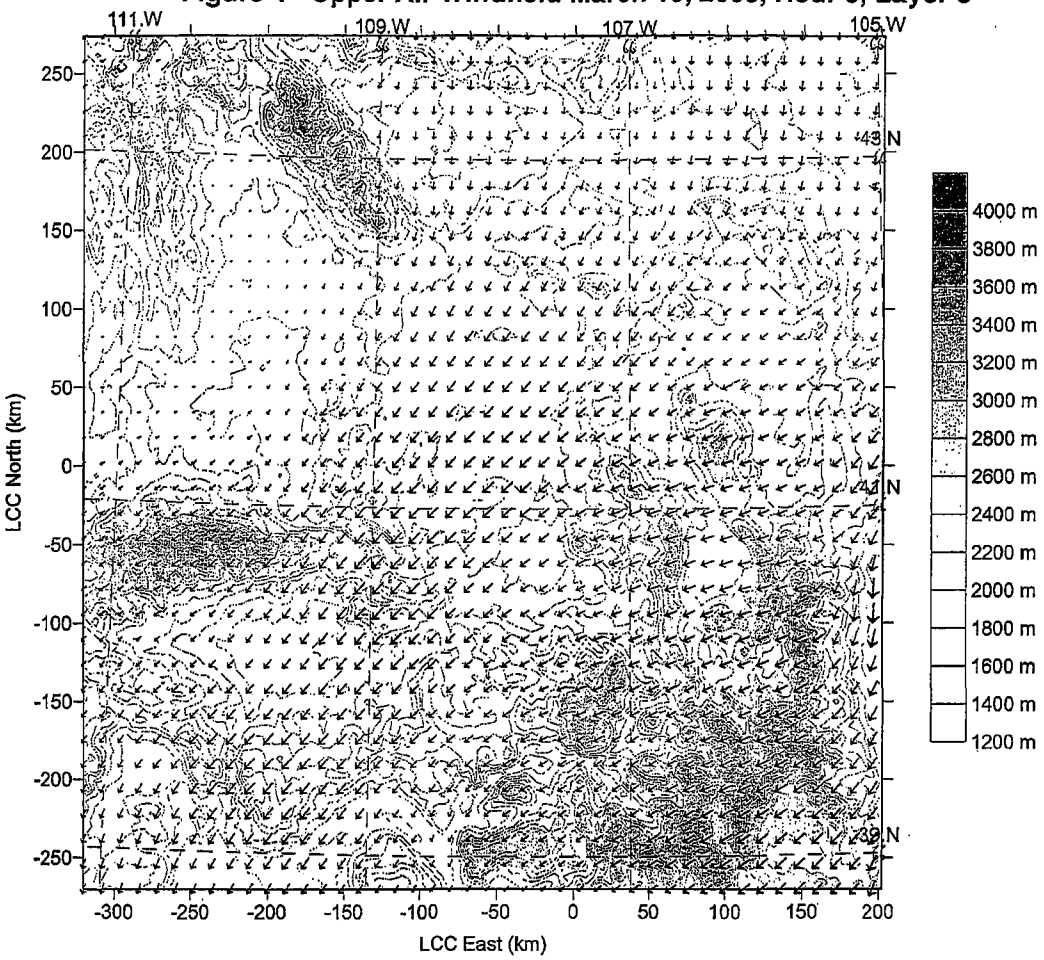


Figure 5 - Upper Air Windfield March 19, 2003, Hour 15, Layer 8

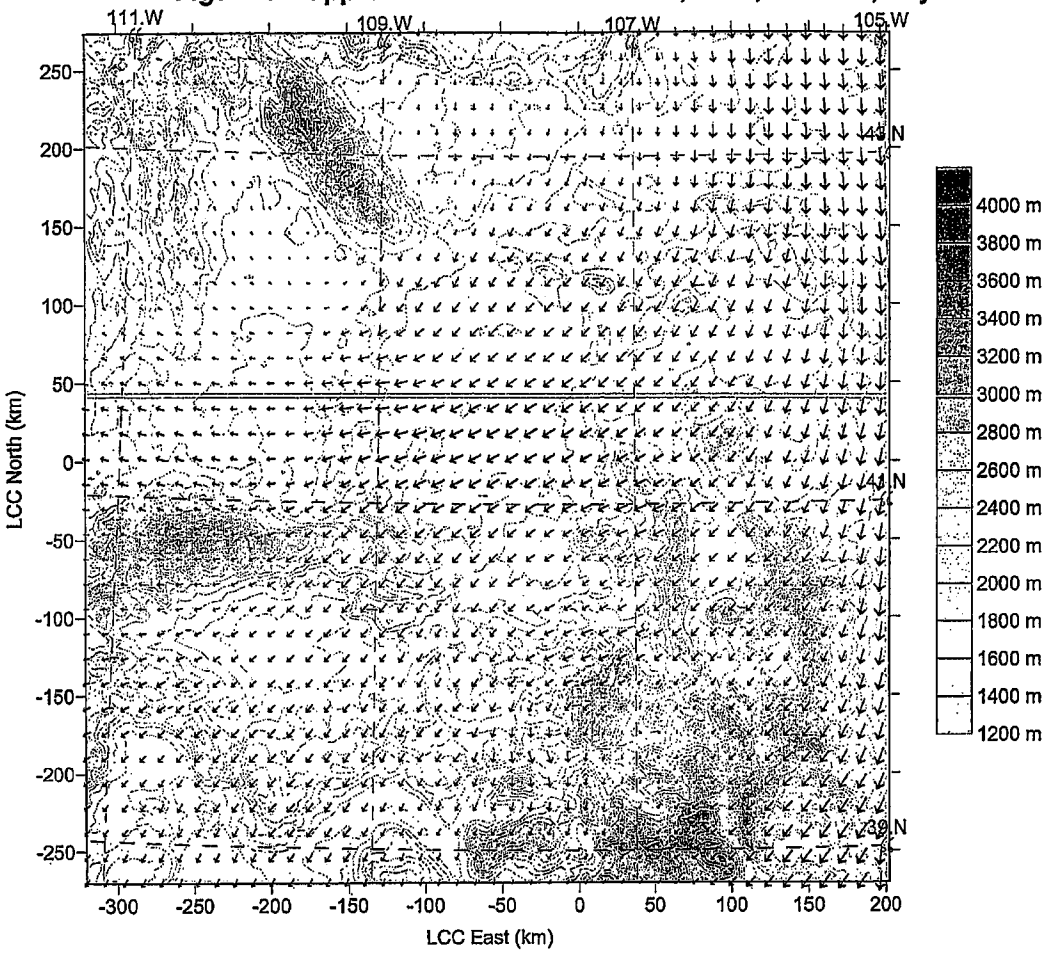


Figure 6 - Surface Air Windfield June 19, 2003, Hour 3, Layer 1

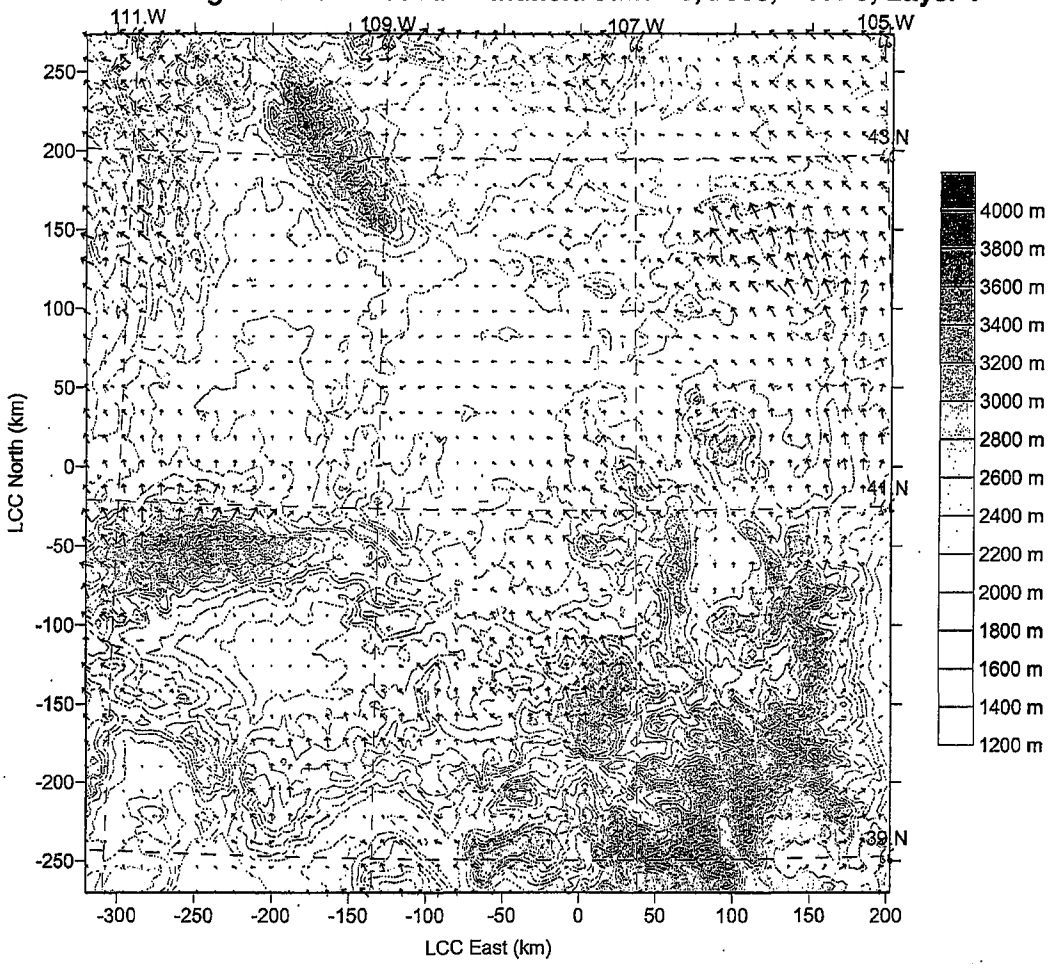


Figure 7 - Surface Air Windfield June 19, 2003, Hour 15, Layer 1

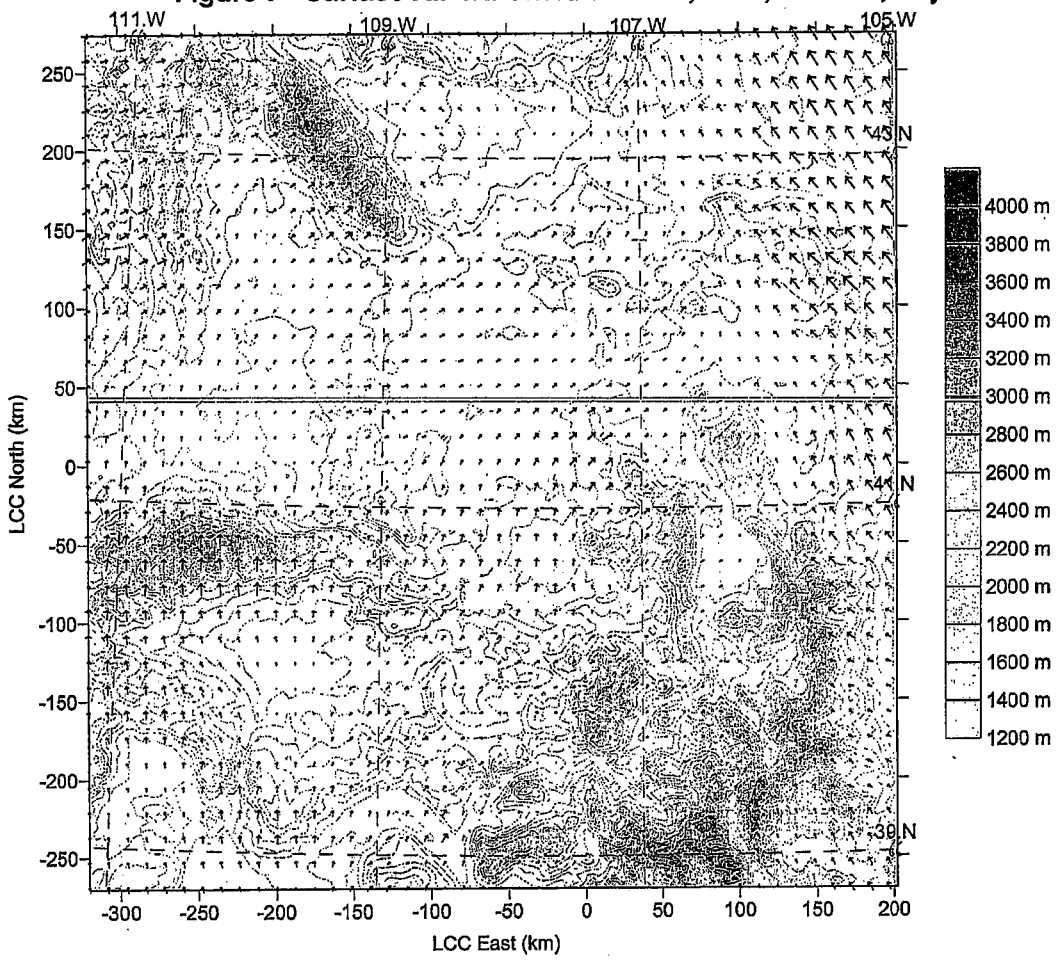


Figure 8 - Upper Air Windfield June 19, 2003, Hour 3, Layer 8

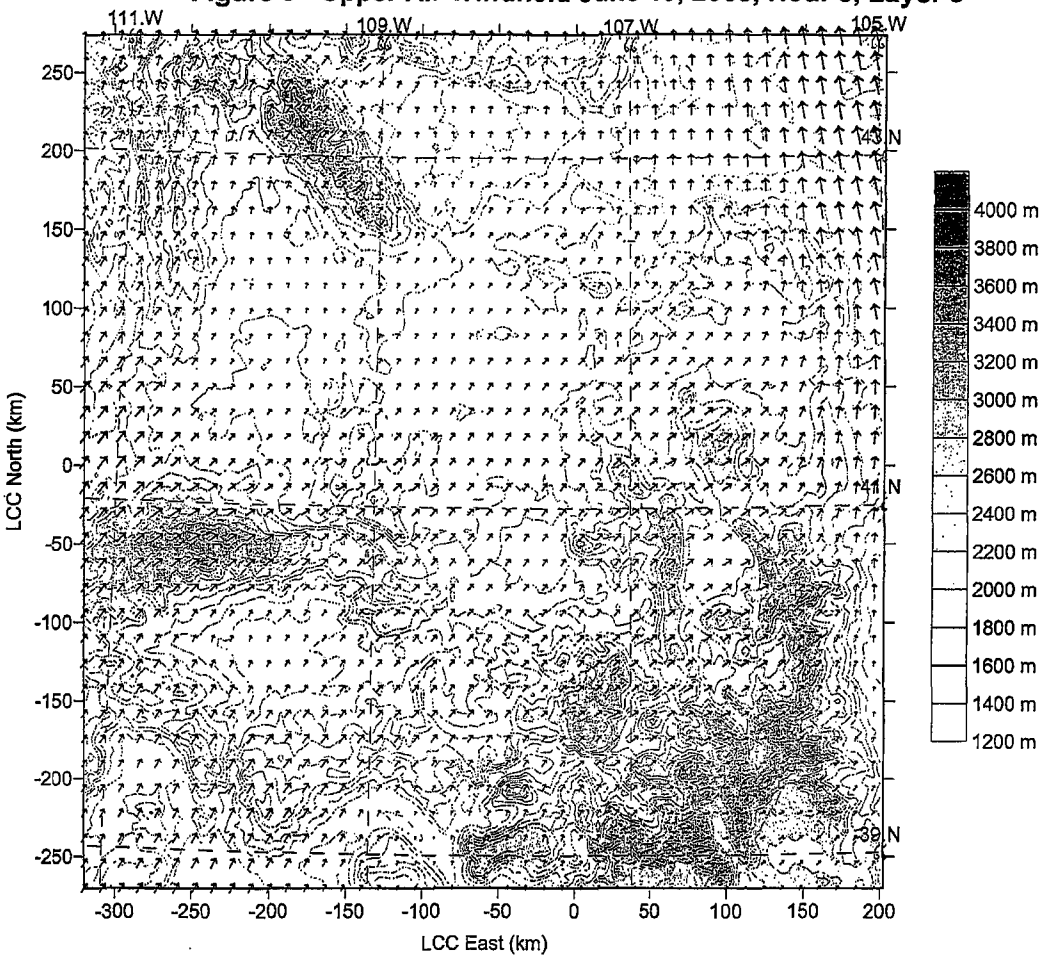


Figure 9 - Upper Air Windfield June 19, 2003, Hour 15, Layer 8

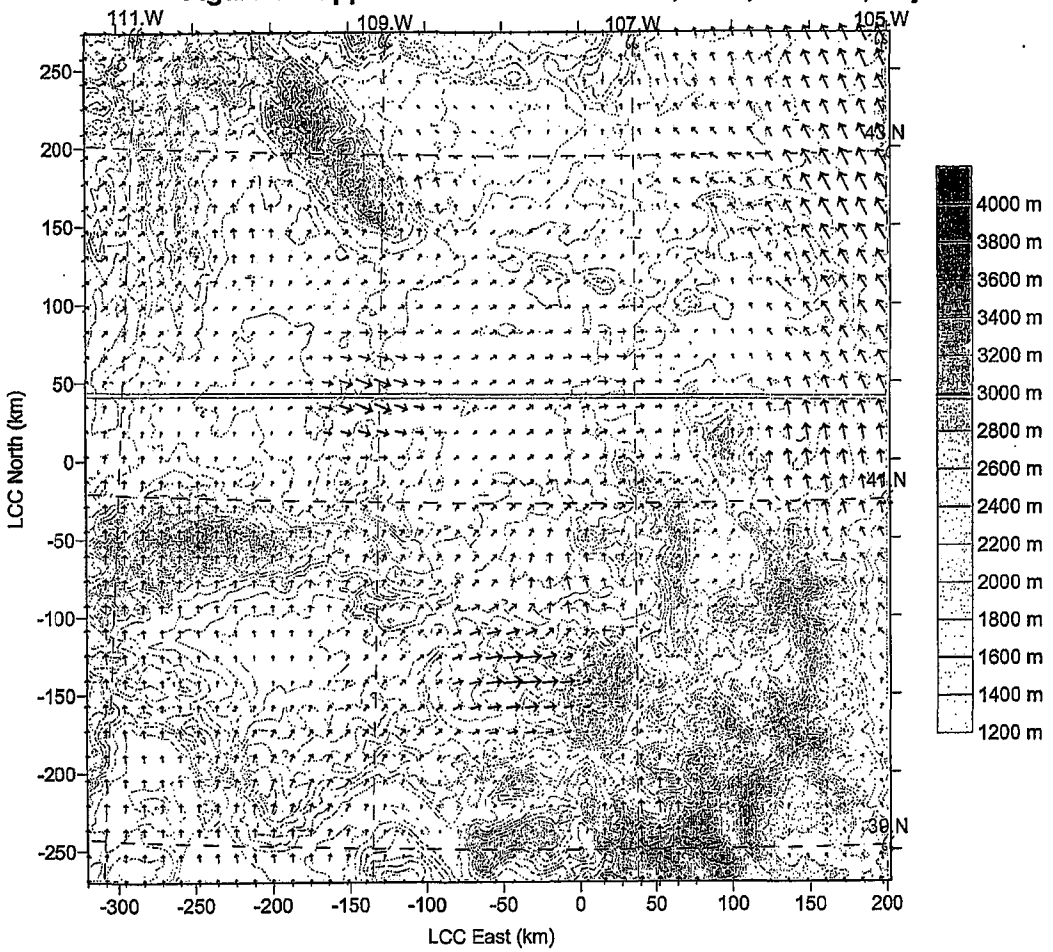


Figure 10- Location of Selected Surface Observation Stations

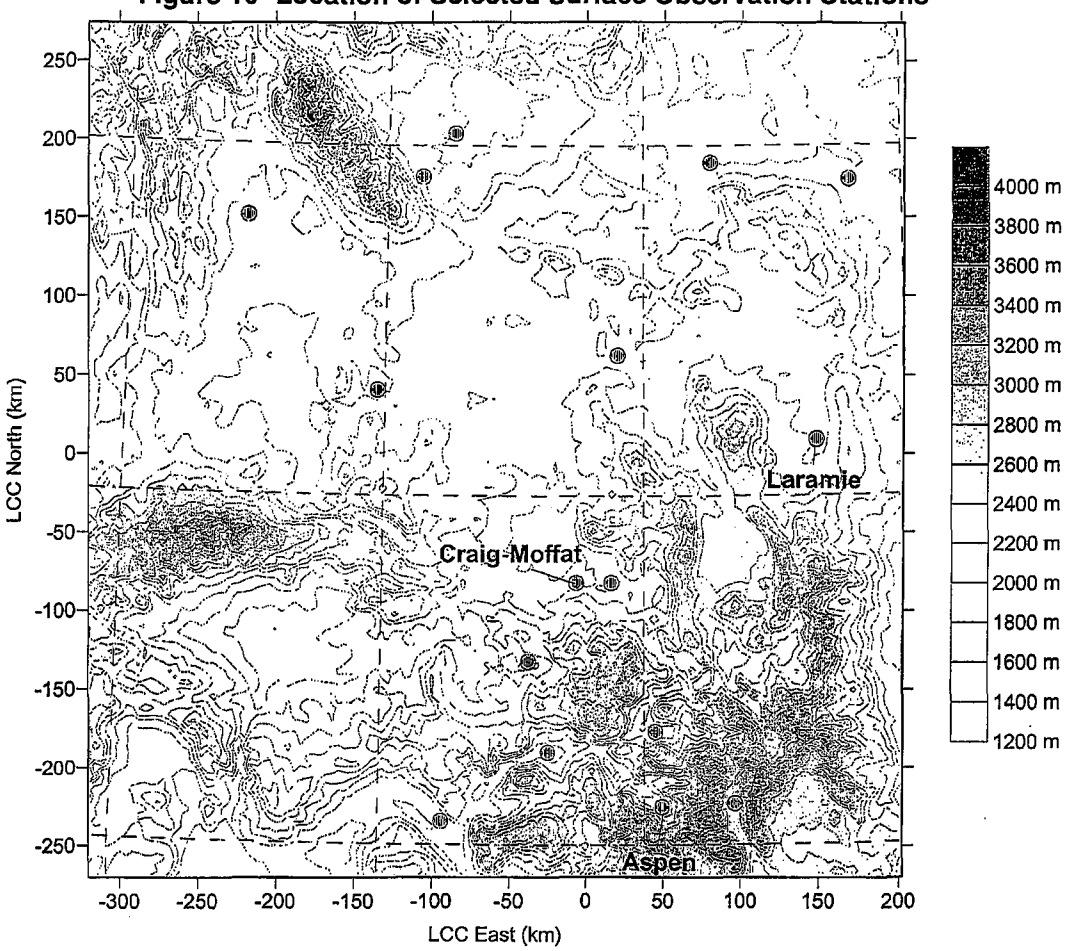
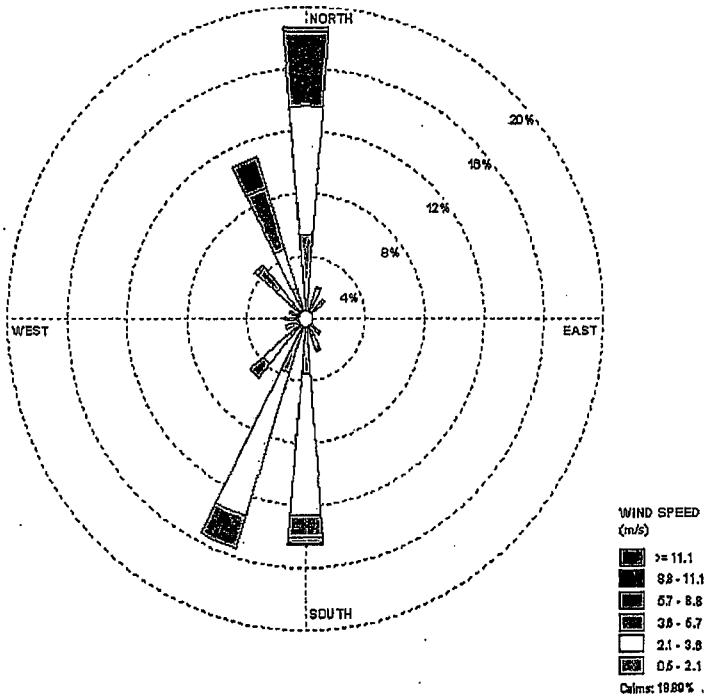


Figure 11 - Aspen field Windroses (March, 2003)

Aspen Field Observation Station Windrose -672 hours



Aspen Field CALMET-predicted Windrose (grid cell:93, 12)-743 hours

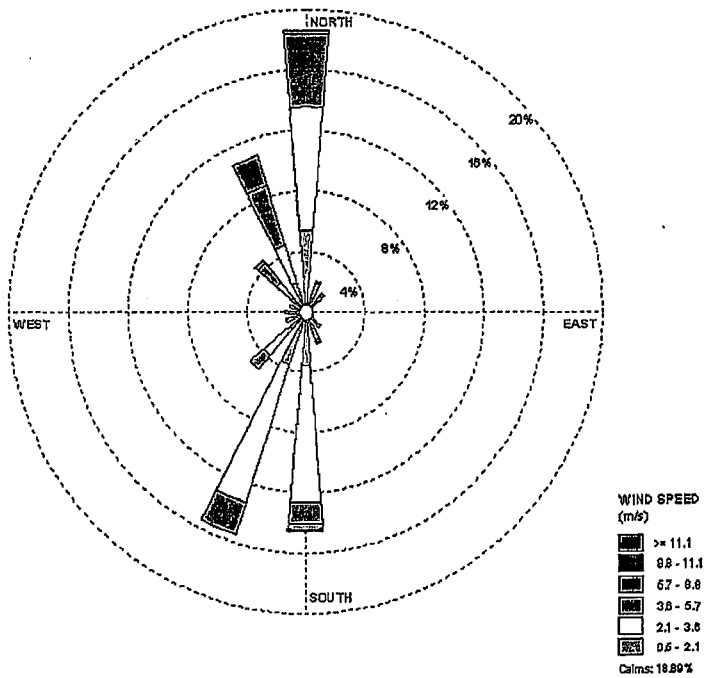
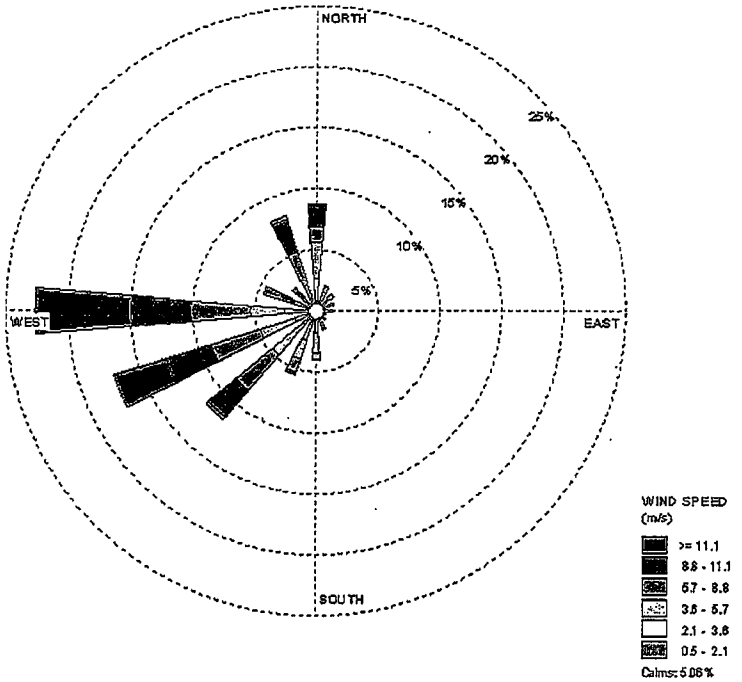


Figure 12 - Laramie field Windroses (March, 2003)

Laramie Field Observation Station Windrose-715 hours



Laramie Field CALMET-predicted Windrose (grid cell:118, 71)-743 hours

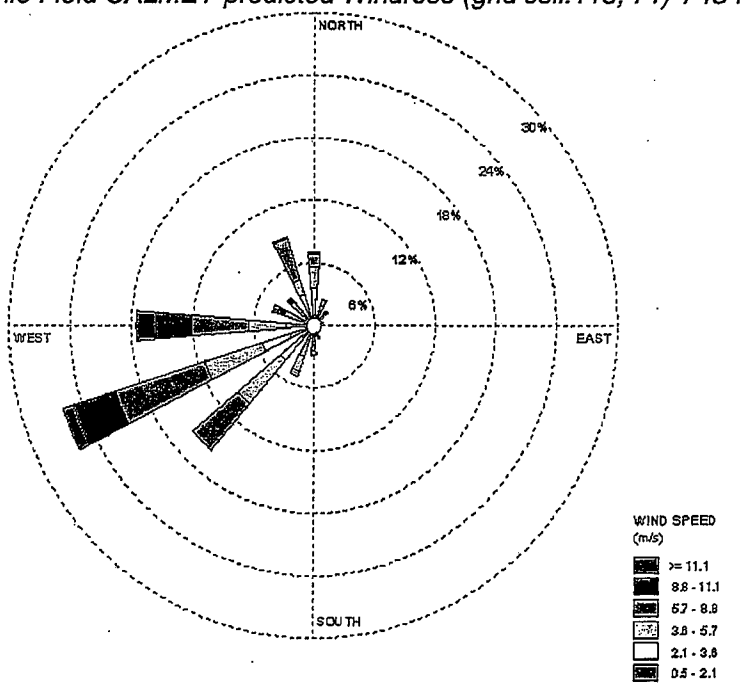
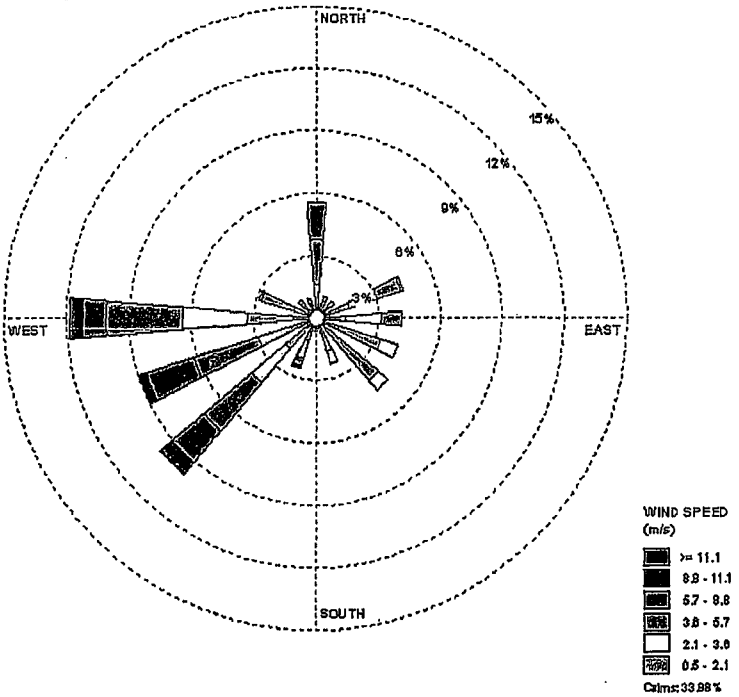


Figure 13 - Laramie field Windroses (March, 2003)

Craig-Moffat Field Observation Station Windrose-684 hours



Craig-Moffat Field CALMET-predicted Windrose (grid cell:79,48)-743 hours