Figure 7.7-5. PM_{10} Highest Sixth-High Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

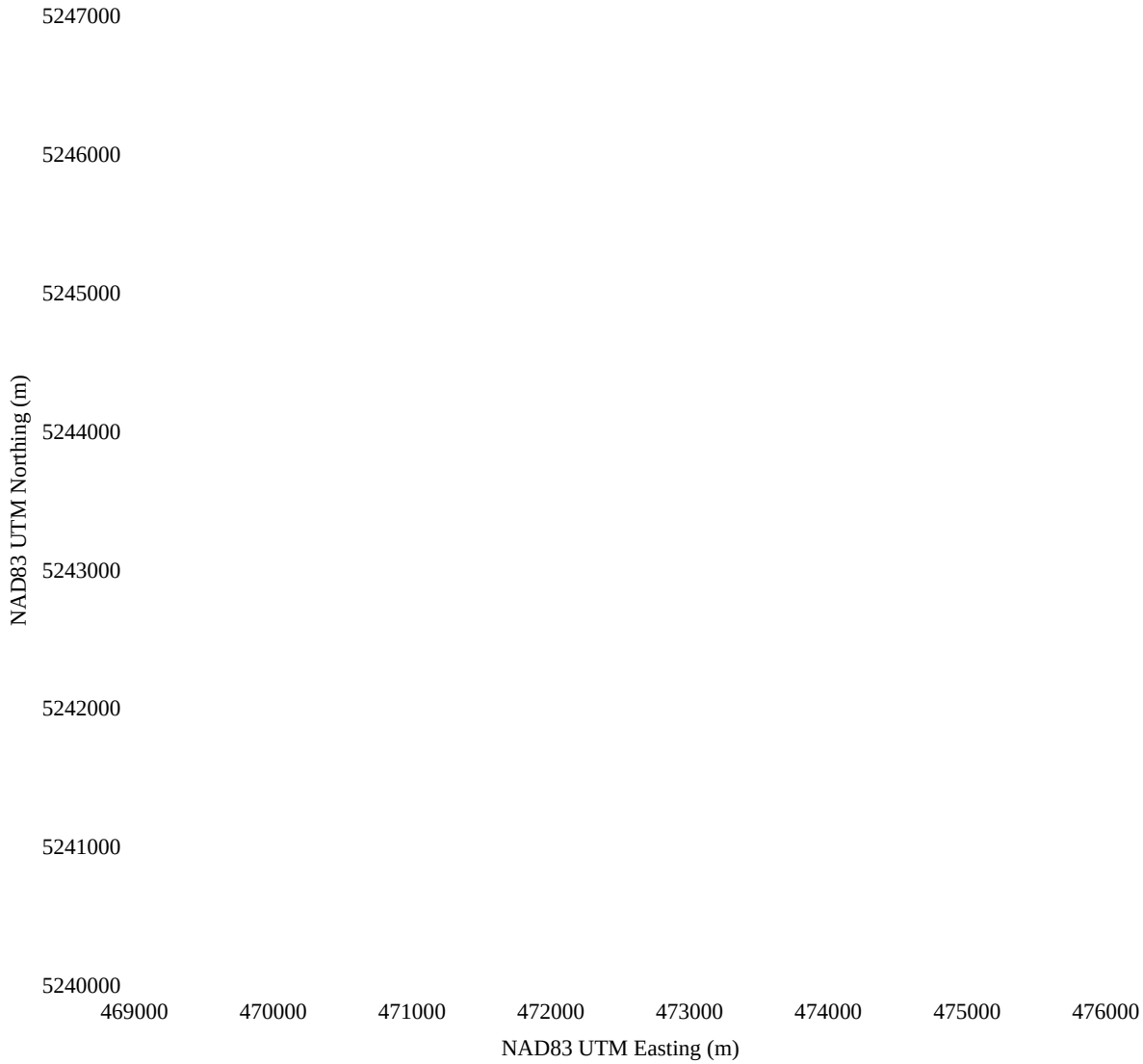


Figure 7.7-5
Figure 46
PM_{10} Highest Sixth-High Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Years 1972 through 1976

Figure 7.7-6. PM_{10} Maximum Annual Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

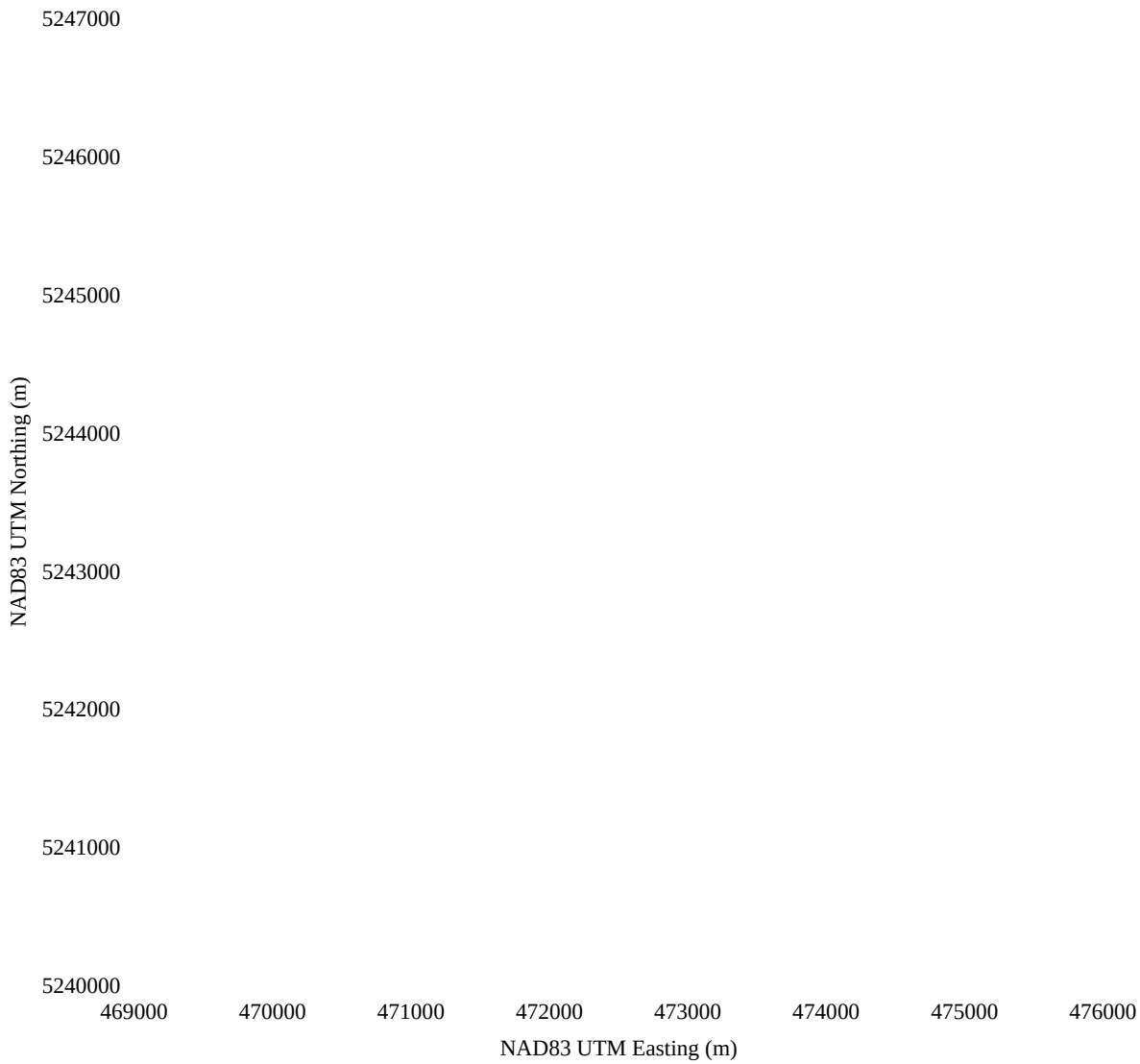


Figure 7.7-6
~~Figure 47~~
PM_{10} Maximum Annual Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1976

Figure 7.7-7. NO_X Annual Maximum Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

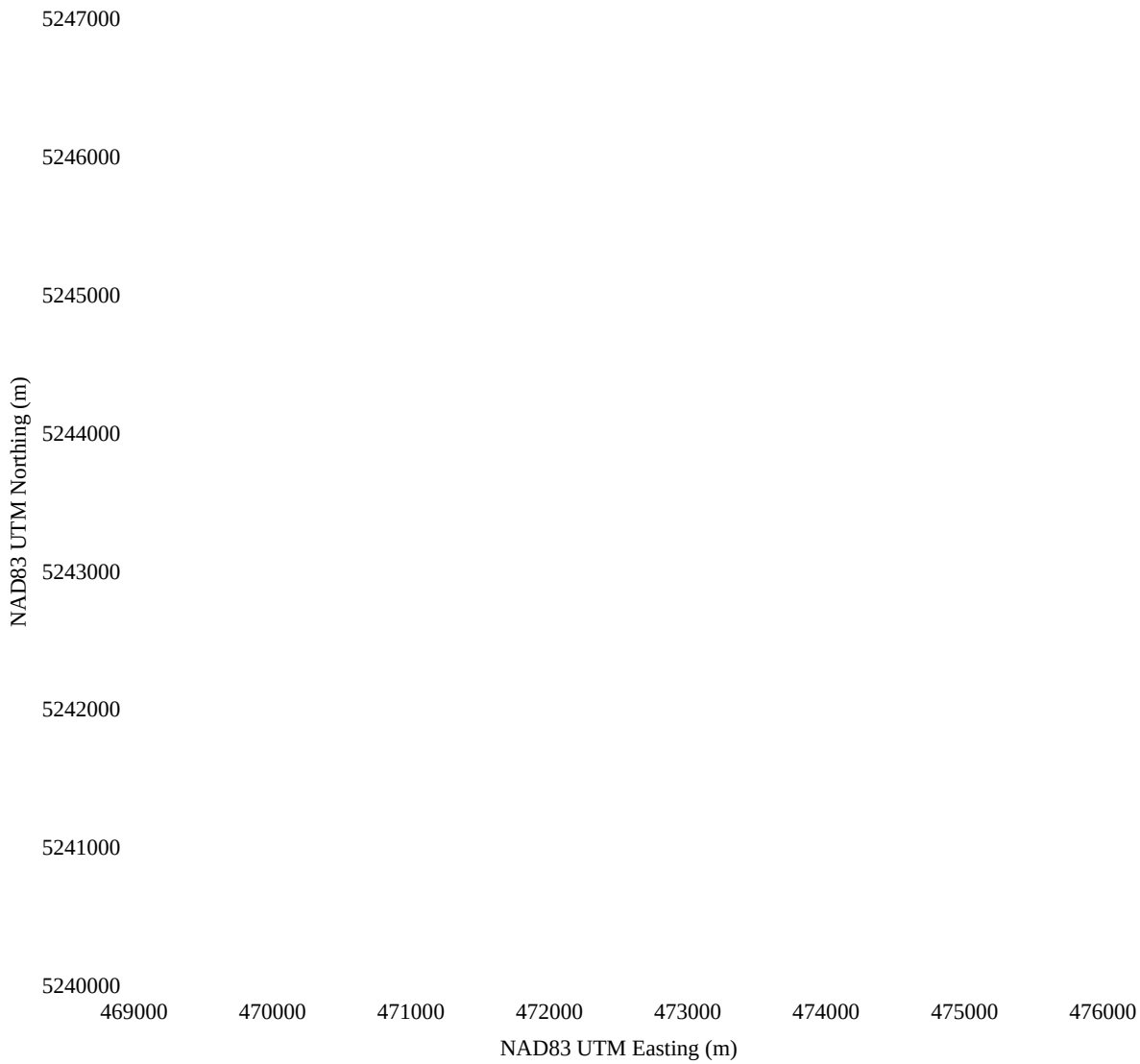


Figure 7.7-7
NO_X Annual Maximum Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1974

Figure 7.7-8. CO 1-Hour Highest Second-High Impacts (µg/m^3) Mesaba One and Mesaba Two

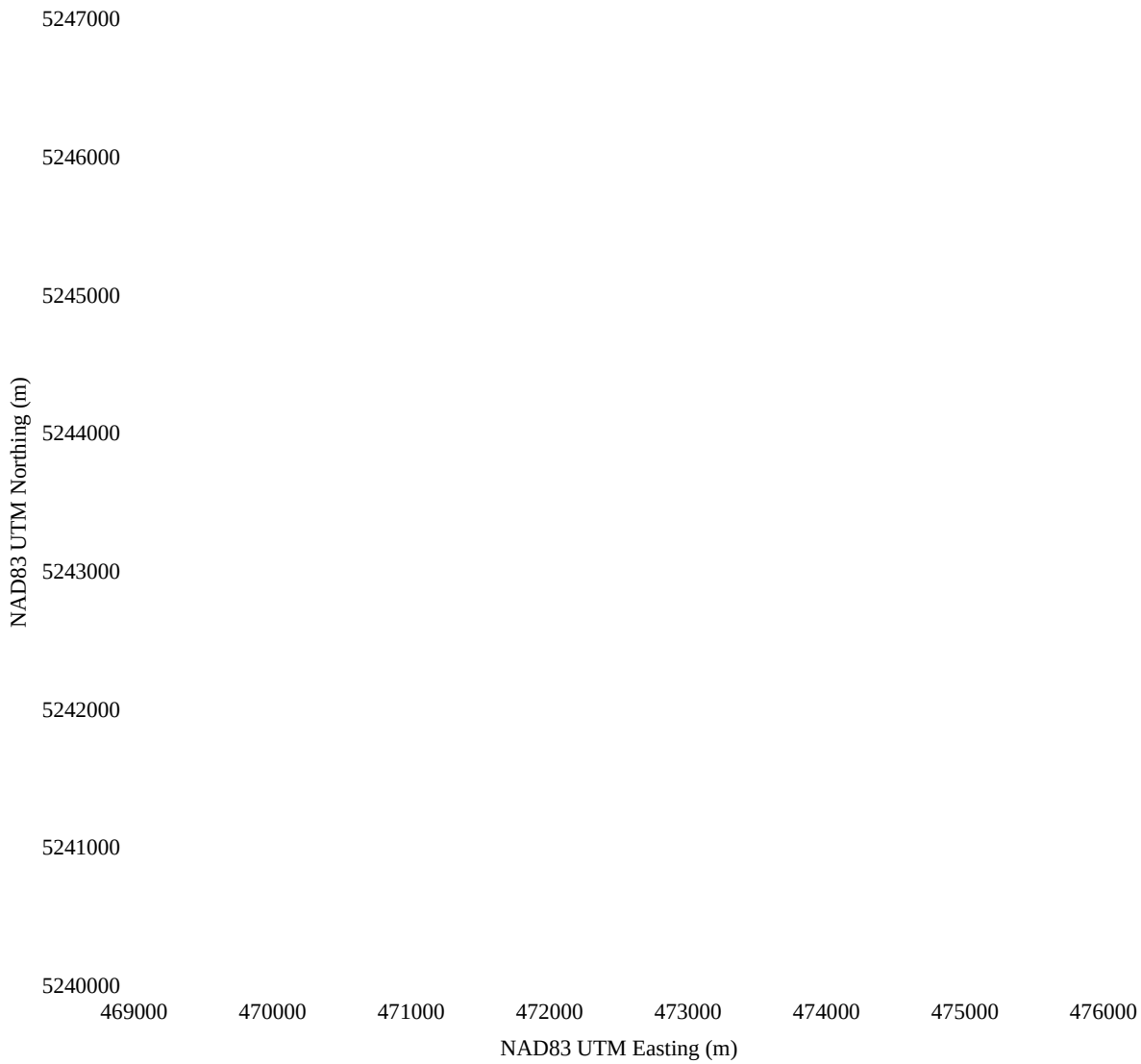


Figure 7.7-8
CO 1-Hour Highest Second-High Impacts (µg/m^3)
For Mesaba Project Phase I and II (Startup Operations)
Data Year 1975

7.8 Preconstruction Monitoring

Minnesota and federal PSD regulations specify "de minimis" monitoring concentrations. If these threshold levels will be exceeded by projected emissions from Mesaba One and Mesaba Two and/or are currently exceeded in the vicinity of the IGCC Power Station by existing sources, preconstruction monitoring may be appropriate to better quantify background air quality levels. The PSD de minimis monitoring concentrations are shown in Table 7.8-1, along with the maximum projected Mesaba One and Mesaba Two concentrations shown in Section 7.5 (see Table 7.5-1).

Table 7.8-1 indicates that Mesaba impacts for NO_2, CO, and ozone are below the de minimis monitoring concentrations. For SO_2 and PM_{10}, model-predicted impacts from Mesaba One and Mesaba Two exceed the threshold monitoring concentrations.

Background PM_{10} monitoring data are available in northeast Minnesota from Virginia, Duluth, and IMPROVE monitoring in the northern Minnesota Class I areas. Limited SO_2 data also exist from Ely MN and Voyageurs National Park. These data indicate that background PM_{10} and SO_2 levels are very low in northern Minnesota, and are generally below the de minimis monitoring levels. Existing air quality data are presented in Section 6.3 of this Application.

The results of the NAAQS compliance analysis presented above indicate that Mesaba One and Mesaba Two will not violate any air quality standards, and total ambient pollutant concentration levels will remain far below applicable limits. The existence of representative regional monitoring data, in combination with the low predicted impacts of Mesaba One and Mesaba Two, indicate that preconstruction monitoring is not necessary and would not contribute to a significant improvement in impact assessments. Similarly, adequate meteorological data are available from Hibbing and other regional monitoring sites. Because of these factors, the applicant requests a waiver of preconstruction monitoring requirements for Mesaba One and Mesaba Two.

Table 7.8-1
PSD Significant Monitoring Concentrations and Maximum Mesaba One and Mesaba Two

Pollutant	Averaging Time	Highest Mesaba Impact ($\mu g/m^3$)	De Minimis Monitoring Level ($\mu g/m^3$)
Sulfur Dioxide	24-hour	31.2	13
PM10	24-hour	27.9	10
Nitrogen Dioxide	Annual	2.6	14
Carbon Monoxide	8-hour	379	575
Ozone	1-hour	N/A	100 TPY VOC Emissions

7.9 Other Impacts

7.9.1 Visible Plume Effects

A complete analysis of Mesaba One and Mesaba Two impacts, including visibility, in Class I areas is presented in Section 8.0 of this application. In addition to the CALPUFF modeling of Class I impacts, the VISCREEN model was applied as a screening tool to assess the potential of visible plumes from Mesaba emissions sources. VISCREEN modeling was carried out for distances of 100 km from the site (the shortest distance to the newest Class I area, the BWCA) and 75 km. VISCREEN model results indicate whether pollutants in the combined plume from all Mesaba One and Mesaba Two sources could be visible against the sky or distant terrain under the most limiting meteorological conditions.

Modeled emissions from Mesaba One and Mesaba Two consisted of total NO_x, PM_{10}, and sulfate from combustion turbines and tank vent boilers. The 24-hour rates used for modeling were:

NO_x	663 lb/hr	=	83.56 g/s
PM_{10}	71 lb/hr	=	8.91 g/s
SO_4	30 lb/hr	=	3.78 g/s

VISCREEN model results are shown on the following two pages. The results are all less than the critical screening criteria, and it can be concluded that there will be no visible plume impacts at or near the nearest Class I areas.

7.9.2 Impacts of Cooling Towers

The evaporative cooling towers used by Mesaba One and Mesaba Two will discharge warm saturated air to the atmosphere as well as small quantities of liquid water droplets. The wet plumes are emitted vertically from 33 feet diameter fan stacks at an elevation of 48 feet above grade. Because of the buoyancy of the warm moist air and the vertical velocity imparted by the fans, the wet plumes will rise to significant heights above the ground.

Because cooling tower plumes consist of ambient air containing only evaporated water and very small quantities of liquid water from the plant cooling water system, there are negligible air pollutants contained in the emissions. The potential environmental impacts of cooling tower emissions are limited to fogging or icing at nearby locations, deposition of water droplets or snow crystals and solids from the circulating water, and visible condensed water plumes.

The most obvious impact of Mesaba cooling towers will be visible condensed water (steam) clouds. These will exist during periods of low air temperature and light winds. The steam clouds, which appear similar to small natural cumulus clouds, can rise to heights of several thousand feet above the ground in extremely cold weather, and can persist for several miles downwind. Because the steam plumes consist entirely of condensed water, they have no adverse effects other than their visual impact.

Experience with large cooling towers at power plants in cold climates has shown that fogging and icing impacts of mechanical draft towers similar to those used by Mesaba One and Mesaba

Two are minimal. Extensive research was carried out during the 1970s when many large cooling tower installations were constructed or proposed at power generating facilities. These studies led to development of mathematical models for prediction of cooling tower effects and the collection of field observations at operating towers. See Exhibit E. In general, it was found that environmental impacts are negligible except within 500 to 1000 feet of the towers. Because of the buoyancy of cooling tower emissions, they rise to heights above ground level and dissipate in the ambient air as they are transported by prevailing winds.

Relevant experience with cooling towers in Minnesota is available from Xcel Energy's SHERCO generating station near Becker, Minnesota. Detailed studies were carried out at SHERCO because the plant is located in close proximity to Interstate Highway 94 and Minnesota Highway 10. Modeling analyses were conducted during permitting of SHERCO Unit 3. These analyses predicted no significant impacts on nearby highways. Subsequent experience has shown that effects of SHERCO cooling towers have been limited to isolated observation of very light snow on a few occasions per year, but no significant fog or other impacts have been observed. See Exhibit E.

The SHERCO cooling tower facility is approximately twice as large as the Mesaba One and Mesaba Two cooling towers in terms of total heat dissipation to the atmosphere. Thus, despite the somewhat colder climate in northern Minnesota, there is no reason to anticipate off-site fog or icing impacts.

Liquid water droplets emitted by cooling towers (referred to as "drift") constitute a very small fraction of the total emitted water. Drift droplets represent circulating cooling water from the tower and contain dissolved solids from the circulating water. Deposition of drift solids has been identified as a potential cooling tower impact where towers use saline water or water with a high solids content. The drift rate of the cooling towers serving Mesaba One and Mesaba Two will be very low (0.001 percent of the circulating water) and the solids content is also modest (2,740 ppm by weight). Thus, the total solids emission rate from cooling towers serving Mesaba One and Mesaba Two will be a maximum of nine pounds per hour. As shown by the PM_{10} modeling results, impacts of cooling tower particulate matter emissions on ambient air concentrations will be very small. Deposition of these particles on surrounding ground surfaces will be negligible.

There are no major highways, airports, or other sensitive facilities in the immediate proximity to the IGCC Power Station Footprint. Given data and experience at other cooling tower installations, it is concluded that there will be no significant fogging, icing, or drift deposition impacts of the cooling towers serving Mesaba One and Mesaba Two on off-site human activities or the environment. The only predicted impacts are the visual impact of steam plumes in cold, moist weather conditions, and occasional very light localized fallout of snow crystals during times of very low temperature.

7.10 Growth

Construction activities associated with Mesaba One and Mesaba Two will provide approximately 1,400 construction jobs during peak construction periods. Operation of the facility will require approximately 180 workers following construction of the Phase II IGCC Power Station, which is expected to be completed and fully operational in 2013. To the extent practical and consistent

with skill and operational requirements, employees will be hired from the buildings trades in the local labor market. There are numerous motels, lodges, and apartments in the surrounding communities with sufficient total capacity to accommodate pre and post-construction workforce needs.

According to the US Census Bureau, Itasca County had a population of 44,316 in 2004, with an increase of 7.7% between 1990 and 2000. The Itasca County Comprehensive Plan adopted in May 2000 indicates that population projections for the next 20 years vary from the population remaining flat to an increase of 9,000 new residents, which indicates a recognized potential for growth in the County. 59% of the 2004 population was between 18 and 65 years of age, which may generally be considered as the working age population. The 180 permanent employment positions will not be added all at once due to the phased nature of facility construction and startup, allowing for a gradual increase in employment rather than a one-time jump in employment. The number of permanent positions required is not expected to significantly affect population, labor, or housing trends in the Itasca County area. Similarly, this number is not expected to represent an unusual burden to the local utility services (potable water, sewer, roadway, etc.) or social services (schools, medical facilities, fire and police protection). Operation of the IGCC Power Station will not result in significant worker relocation into the area relative to the previously anticipated growth rate.

In summary, secondary growth is not expected to result in new significant emissions during either operation or construction of the IGCC Power Station.

7.11 Soils and Vegetation

The PSD regulation requires analysis of air quality impacts on sensitive vegetation and soil types. Evaluation of impacts on sensitive vegetation and soils was performed by comparing predicted IGCC Power Station impacts to screening levels presented in the 1980 EPA document titled: *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, December 1980, EPA 450/2-81-078). These screening levels represent the minimum concentrations in either plant tissue or soils at which adverse growth effects or tissue injury was reported in the literature. The procedures specify that predicted impact concentrations used for comparison account for facility impacts added to ambient background concentrations. Most of the designated vegetation screening levels are equivalent to or exceed PSD increments. The 3-hour and 1-hour SO_2 sensitive vegetation screening levels are more stringent than comparable NAAQS and State Ambient Air Quality Standards. Air quality modeling indicates that IGCC Power Station impacts will be below PSD increments and NAAQS (see Tables 7.6-2 and 7.7-1, respectively).

A comparison of the SO_2 sensitive vegetation screening levels with SO_2 impacts from the proposed IGCC Power Station is presented in Table 7.11-1. The comparison includes ambient background concentrations in the impact levels. Maximum impacts for the 1-hour and 3-hour averaging periods (see Table 7.5-1) are less than 20% of the allowable concentrations.

Table 7.11-1
Vegetative Sensitivity Screening for SO_2 Concentrations

Averaging Time	Background Concentration ($\mu g/m^3$)	Maximum Contribution from IGCC Power Station ($\mu g/m^3$)	Maximum Total Concentration ($\mu g/m^3$)	Sensitive Vegetation Screening Level ($\mu g/m^3$)
1-Hour	10	130.2	140.2	917
3-Hour	10	77.6	87.6	786

8. IMPACTS TO AIR QUALITY RELATED VALUES (AQRVS) IN CLASS I AREAS

8.1 Introduction

An air quality modeling analysis was conducted to estimate impacts of the Phase I and II IGCC Power Station (the Station) on air quality in Class I areas. The analysis addressed impacts to the Boundary Waters Canoe Area (BWCA), Voyageurs National Park (VNP) and the Rainbow Lakes Wilderness (RLW). The distance from the Station to the closest point in each of these Class I areas is approximately 61 miles (98 km) for the BWCA, 75 miles (121 km) for VNP, and 117 miles (188 km) for RLW. The next closest Class I area, Isle Royale National Park, is more than 300 km from the station, beyond the distance where long-range transport modeling has been shown to provide realistic impact predictions.

The Class I AQRV analyses addressed PSD Class I increments for SO_2, PM10, and NO_2, sulfur and nitrogen deposition, and visibility impairment (regional haze). The dispersion modeling analysis used standard EPA long-range transport modeling methodologies, and followed guidance as presented in EPA's Guideline on Air Quality Models, the IWAQM Phase 2 report, and the FLAG Phase I report. The analyses also incorporated suggestions and guidance received in pre-application meetings with the U.S. Forest Service and the National Park Service. Details of the AQRV analyses are presented in Appendix D of this Application.

8.2 Air Quality Model and Application

The CALPUFF air quality model was used for all Class I area analyses. CALPUFF is the approved EPA long-range transport model referenced in the Guideline on Air Quality Models. It consists of three components: the CALMET model for processing of meteorological data; CALPUFF for the transport and dispersion calculations; and CALPOST for analysis and post-processing of model results. Input options and data utilized in the models generally corresponded to default or recommended values. Table 8.2-1 provides a list of input parameters that are specific to the Mesaba application and that differ from standard default values.

8.2.1 Pollutant Emissions

Pollutant emission rates for CALPUFF modeling represent the maximum expected emissions from Mesaba One and Mesaba Two for the appropriate averaging times. Modeling parameters are given in Table 8.2-2.

Table 8.2-1
CALMET/CALPUFF Non-Default Input Parameters

Input Group	Parameter	Mesaba Selection	Explanation
CALMET			
5	IKINE	1	Kinemateic effects option used to better account for terrain effects
	RMAX 1	30 km	No default values
	RMAX 2	40 km	No default values
	RMAX 3	40 km	No default values
	TERRAD	15 km	No default values
	R1	5	No default values
	R2	15	No default values
CALPUFF			
3	Species Modeled	SO_2, SO_4, NO_x, EC, SOA, $PM_{2.5}$, HNO_3, NO_3	Modeled all species emitted by Mesaba sources, and others (HNO_3, NO_3) involved in plume chemistry
4	LSAMP	F	No gridded receptors (sampling grid) used
8	Part. Size	Mean = 0.48 Std. Dev. = 2	All particulate species assumed $PM_{2.5}$
11	MOZ	0	Constant ozone background
	BCK03	40.0 ppb	Representation background ozone concentration
	BCKNH3	1.0 ppb	Conservative background ammonia concentration (0.5 ppb recommended for forested lands)
12	NSPLIT	3	Puff-splitting used (default)

Table 8.2-2
Modeling Parameters For Mesaba One and Mesaba Two CALPUFF Modeling

Parameter	Combustion Turbines (each of four)	Tank Vent Boilers (each of two)
stack height (m)	45.72	64.01
stack diameter (m)	6.1	1.83
temp (K)	394.3	579.8
velocity (m/s) – short-term	20.1	8.46
annual	20.1	1.95
SO_2 - 3-hr (g/s)	19.15	0.94
24-hr	14.36	0.81
annual	9.58	0.45
NO_x - 3-hr (g/s)	19.66	2.46
24-hr	19.66	2.46
annual	19.91	0.76
Elemental Carbon (g/s) all time periods	0.787	0
Sulfate (g/s) all time periods	0.945	0
Organic aerosol (g/s) all time periods	1.397	0
$PM_{2.5}$ (g/s) all time periods	0	0.088
PM_{10} (g/s)	0	0

The operating scenario that will have maximum short-term impacts is normal operation of all Mesaba One and Mesaba Two combustion turbines at full capacity. During normal operation of Mesaba One and Mesaba Two, the only significant air pollutant emissions will be from the combustion turbines and tank vent boilers. During short-term upset conditions when untreated syngas could be flared, SO_2 emissions from the flares may exceed the combined SO_2 emissions from the CTGs during normal operations (see Appendix A, Exhibit A-2). This situation represents a low probability event because the Applicant is designing the gasification island to ensure that only treated syngas would be flared during start-ups. Further, during such abnormal upset conditions, flow of syngas to the CTGs would be interrupted and operation of the gasifier(s) would be reduced or shut down if the upset condition appeared significant (that is, threatened compliance) and/or persistent, thus limiting the need to flare large quantities of untreated syngas. Notwithstanding the increased short term emissions of SO_2 relative to normal baseload operations of the CTGs, NO_X and PM_{10} emissions from the total facility during such short term upsets will be reduced to levels below normal NO_X and PM_{10} emissions from the CTGs given the rapid turn down capability of the CTGs and gasifiers. A second scenario of interest concerns times when the combustion turbines would operate on natural gas rather than syngas. During such events, NO_X emission rates will be slightly higher than under syngas operation, but SO_2 emissions would be lower. Therefore, the normal operating scenario for Mesaba One and Mesaba Two represents the highest combined-source pollutant emission profile justifying use of normal operation as the worst-case scenario for both short-term and annual Class I area impacts, and the emission rates presented in Table 8.2-2 represent this operating scenario.

Speciation of particulate matter emissions from the combustion turbines, as shown in Table 8.2-2, was based on available data for Mesaba One and Mesaba Two sources and Federal Land Manager (FLM) guidance on emissions from natural gas-fired turbines. The total particulate matter emissions (filterable plus condensable) and total sulfuric acid emissions are from Mesaba design specifications. The partitioning of filterable and condensable fractions, elemental carbon emissions, and organic aerosol emissions were calculated using the FLM consensus methodology. All filterable particulate matter was assumed to be elemental carbon less than 2.5 microns in diameter. All particulate matter emissions from the Tank Vent Boilers were assumed to be $PM_{2.5}$. Calculations are shown in Appendix D.

Emissions from other Mesaba One and Mesaba Two sources (flares, auxiliary boilers, and fugitive PM10) will be negligible in comparison to the turbine and TVB emissions, and were not included in the CALPUFF modeling.

8.2.2 Meteorological Data

The CALPUFF modeling analysis utilized meteorological data for the years 1990, 1992, and 1996. These are the same years used for other recent CALPUFF applications in northern Minnesota. Gridded meteorological fields used as input to the CALMET processor were MM4 (1990) and MM5 (1992, 1996) prognostic data acquired from the National Park Service (NPS). Additional surface, upper air, and precipitation data were used in CALMET to refine the meteorological fields. Hourly surface data from 13 stations were used along with precipitation data from 28 stations. Upper air data from two stations were used: St. Cloud MN and

International Falls MN for 1990 and 1992, and Minneapolis MN and International Falls for 1996. The surface and precipitation stations are listed in Appendix D.

8.2.3 Modeling Domain

The CALMET/CALPUFF modeling domain was a 700km by 500km area approximately centered on the Station site, with a four kilometer grid spacing. The coordinate system was Lambert Conformal. Receptor locations within each of the Class I areas were obtained from the National Park Service. Figure 7.7-8 shows the modeling domain, terrain elevation contours, and the modeling receptors. Figure 8.2-1 shows the locations of meteorological stations used for the CALMET processing.

Figure 8.2-1. CALMET Modeling Domain and Class I Areas Included in Analysis

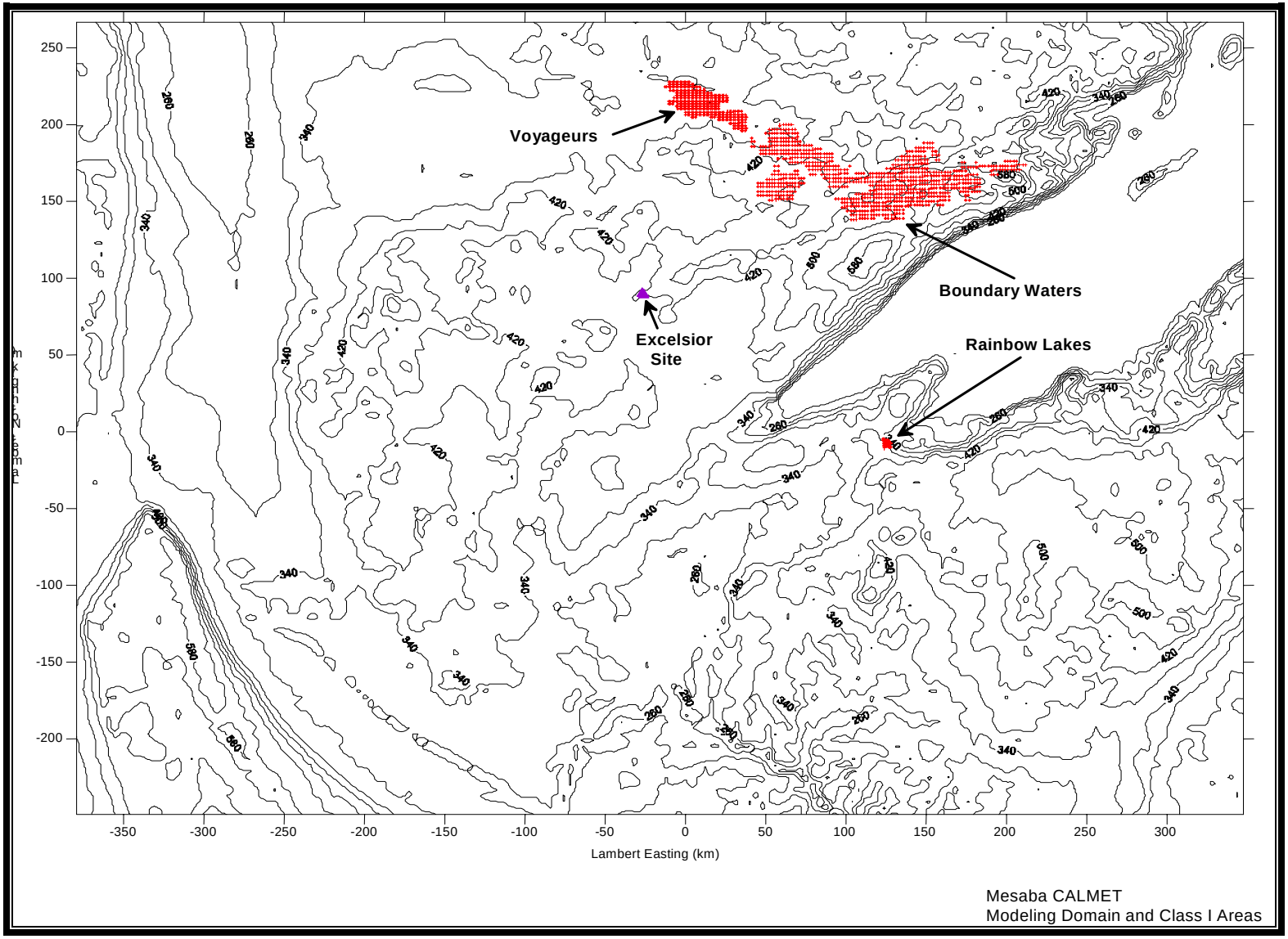
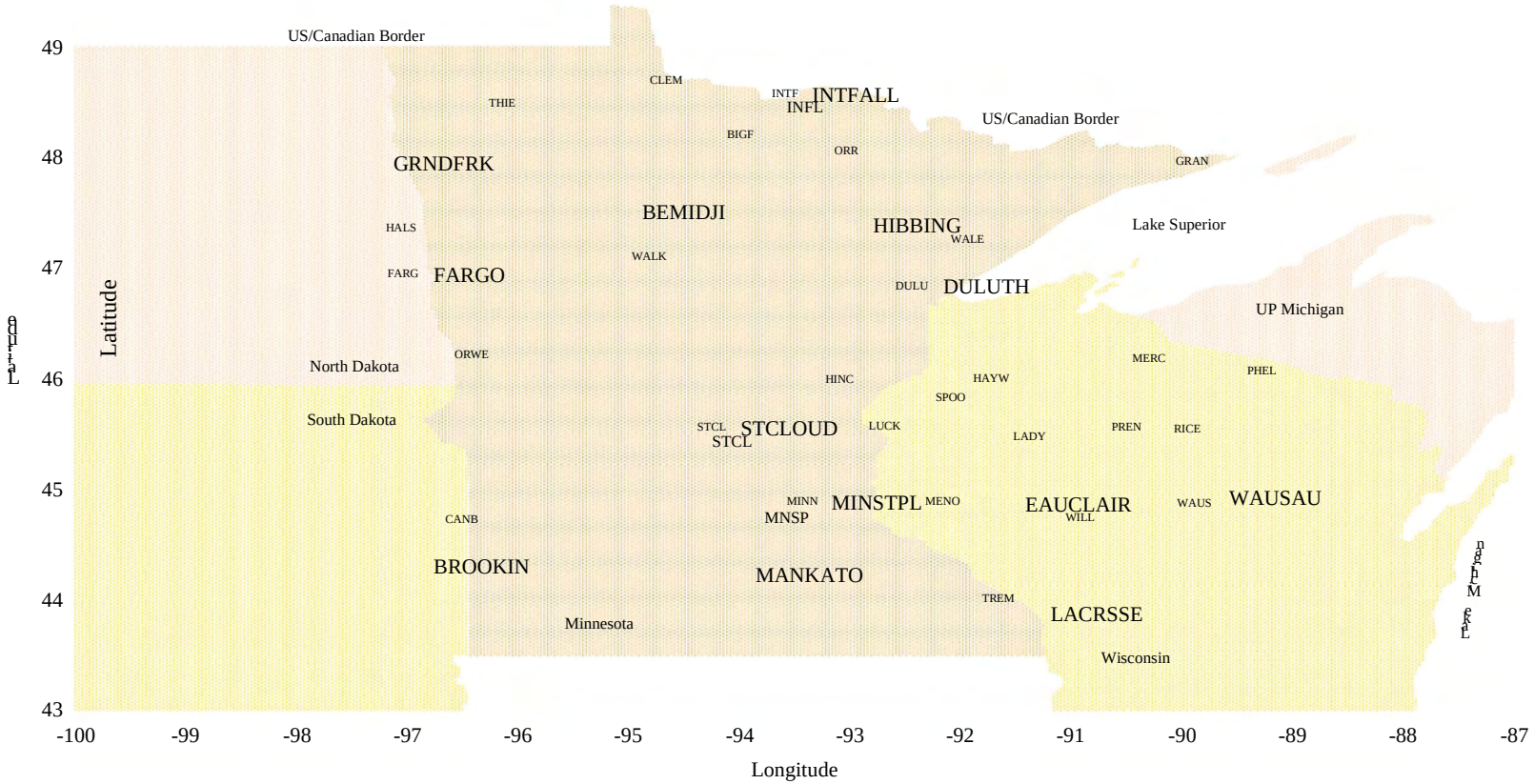


Figure 8.2-2. Meteorological Stations of Surface, Upper Air, and Precipitation Used for CALMET Modeling of Mesaba One and Mesaba Two



Surface Station
Upper Air Station
Precipitation Station

Meteorological Stations of Surface, Upper Air and Precipitation
Used For the Mesaba CALMETGrid

8.3 Class I Impacts and Increment Consumption

The CALPUFF model was used to calculate pollutant impacts at each receptor for each year of meteorological data, and for three-hour, 24-hour, and annual averaging periods. The two-phase Mesaba facility alone was modeled, with the stack parameters and emission rates shown in Table 8.2-2.

Class I PSD increments and Significant Impact Levels (SILs) exist for SO_2, NO_x, and PM10. Table 8.4-1 summarizes the highest CALPUFF model results for each Class I area, and shows the applicable Increment and SIL values. The data indicate that maximum Mesaba impacts are far below allowable increments for all pollutants and Class I areas. Impacts are also below the SIL in most cases, indicating that impacts will be insignificant and that no further analysis is necessary. However, for short-term SO_2 concentrations, impacts were indicated to exceed the SIL in the BWCA and VNP. Because the 3-hour and 24-hour SO_2 impacts could be significant, it was deemed necessary and appropriate to carry out a cumulative analysis, including other regional SO_2 increment sources, to verify and quantify total PSD increment consumption.

8.4 Cumulative Increment Analysis

The short-term cumulative SO_2 increment analysis used the CALPUFF model to calculate the combined impacts of all regional increment consuming and increment expanding sources at each of the Class I areas. In response to a request for SO_2 increment inventories, the MPCA provided emissions and stack data for those northern Minnesota sources with a potential for Class I impacts. The sources and net increment-consuming emissions are given in Table 8.4-2.

For some of the sources in Table 8.4-2, there are both positive (increment-consuming) and negative (increment-expanding) emissions. Only the net change in emissions is shown in the Table. Because the CALPUFF model cannot accommodate negative emission rates, it was necessary to model the positive and negative impacts in separate CALPUFF executions, and then determine the net impact on an hour by hour, receptor by receptor basis by post-processing of the CALPUFF SO_2 concentration results. To minimize computation time, some sources were combined in the model input. However, all combinations used the stack parameters appropriate to the major emission point, and separate applicable stack parameters were used for the positive and negative model runs.

The net emissions changes for increment modeling should be the change in actual emissions for sources that are or have been in operation. The increment-consuming emissions in the MPCA inventories generally represent potential (maximum allowable) emissions. These were used directly in the cumulative increment analysis with one exception.

The allowable SO_2 short-term emission rate for the Minnesota Power Clay Boswell Unit # 4 is 6131 lb/hr. Because of the high value of this limit, historical CEMS data for the source were reviewed to better define actual SO_2 emissions. Based upon data for the period 2003 through

Table 8.4-1
PSD Increment Modeling Results for Mesaba Energy Project

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.3804	1.4547	1.5505	25.0	1.00	1.5505
SO_2 24-Hour	0.4554	0.3382	0.3589	5.0	0.20	0.4554
SO_2 Annual	0.0147	0.0127	0.0095	2.0	0.10	0.0147
NOx Annual	0.0174	0.0152	0.0109	2.5	0.10	0.0174
PM_{10} 24-Hour	0.0866	0.0617	0.0586	8.0	0.30	0.0866
PM_{10} Annual	0.0041	0.0037	0.0026	4.0	0.20	0.0041

Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.5911	1.0477	1.4836	25.0	1.00	1.5911
SO_2 24-Hour	0.2506	0.2943	0.4492	5.0	0.20	0.4492
SO_2 Annual	0.0128	0.0110	0.0113	2.0	0.10	0.0128
NOx Annual	0.0151	0.0125	0.0142	2.5	0.10	0.0151
PM_{10} 24-Hour	0.0537	0.0500	0.0745	8.0	0.30	0.0745
PM_{10} Annual	0.0037	0.0032	0.0031	4.0	0.20	0.0037

Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	0.7088	0.7567	0.7012	25.0	1.00	0.7567
SO_2 24-Hour	0.1806	0.1917	0.1711	5.0	0.20	0.1917
SO_2 Annual	0.0075	0.0083	0.0065	2.0	0.10	0.0083
NOx Annual	0.0081	0.0071	0.0068	2.5	0.10	0.0081
PM_{10} 24-Hour	0.0369	0.0462	0.0316	8.0	0.30	0.0462
PM_{10} Annual	0.0022	0.0028	0.0019	4.0	0.20	0.0028

Table 8.4-2
Modeled Increment Consuming SO_2 Emissions For Cumulative Class I Increment Analysis

Source	Net Increment SO_2 Emissions	
	lb/hr	g/s
Mesaba One and Mesaba Two		
3-hour	622.9	78.48
24-hour	468.7	59.06
Minnesota Power – Hibbard	416.8	52.51
Blandin Paper – Rapids Energy	417.0	52.54
Northshore Mining	-20.8	-2.62
Minnesota Power – Clay Boswell	1686	212.4
Potlatch Paper – Cloquet	-34.5	-4.35
Hibbing Taconite – Hibbing	772.3	97.31
Boise Cascade	141.6	17.84
Mesabi Nugget – Hoyt Lakes	225.6	28.42

June 2005, the 95th percentile 3-hour and 24-hour average emission rates were 1600 and 1565 lb/hr, respectively. Thus, maximum actual short-term SO_2 emissions rarely exceed about 1600 lb/hr. Accordingly, a conservative emission rate of 1686 lb/hr, equal to the annual average allowable emissions for Unit 4, was used for Clay Boswell in the cumulative analysis.

The results of the cumulative SO_2 increment analysis are shown in Table 8.5-1. The maximum predicted increment consumption in each of the Class I areas is shown to be well within the PSD Class I limits, and it is clear that Mesaba One and Mesaba Two will not cause or contribute to any violation of Class I PSD increments.

8.5 Deposition of Nitrogen and Sulfur

The CALPUFF results for each of the Class I areas were processed with CALPOST to calculate total annual deposition of nitrogen and sulfur at each receptor as a result of Mesaba One and Mesaba Two

Table 8.5-1
Mesaba One and Mesaba Two Cumulative SO_2 Increment Results (µg/m3)*

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (µg/m3)	Max (µg/m3)	Violation? (Y/N)
SO_2 3-Hour	6.1	7.0	5.8	25.0	7.0	NO
SO_2 24-Hour	2.6	2.1	2.2	5.0	2.6	NO
Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (µg/m3)	Max (µg/m3)	Violation? (Y/N)
SO_2 3-Hour	5.2	4.6	5.5	25.0	5.5	NO
SO_2 24-Hour	1.6	1.5	1.6	5.0	1.6	NO
Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (µg/m3)	Max (µg/m3)	Violation? (Y/N)
SO_2 3-Hour	4.5	4.3	4.7	25.0	4.7	NO
SO_2 24-Hour	1.4	1.2	1.3	5.0	1.4	NO

* High-second highs

emissions. Model results for annual impacts (maximum annual average emissions) were used following the methodology given in the IWAQM Phase I report. Total sulfur deposition is calculated from the wet and dry deposition of SO_2 and sulfate; total nitrogen is represented by the sum of nitrogen from wet and dry fluxes of nitric acid, nitrate, ammonium sulfate and ammonium nitrate, and the dry flux of NOx. Results are shown in Table 8.6-1.

Table 8.6-1
Maximum Annual Deposition of S and N from Mesaba One and Mesaba Two in Class I Areas (kg/ha-yr)

Class I Area/Year	Sulfur	Nitrogen
Boundary Waters Canoe Area		
1990	1.217×10^{-2}	9.549×10^{-3}
1992	9.797×10^{-3}	7.085×10^{-3}
1996	8.400×10^{-3}	6.217×10^{-3}
Voyageurs National Park		
1990	1.016×10^{-2}	7.864×10^{-3}
1992	1.110×10^{-2}	8.562×10^{-3}
1996	9.780×10^{-3}	7.835×10^{-3}

Class I Area/Year	Sulfur	Nitrogen
Rainbow Lakes Wilderness		
1990	5.188×10^{-3}	4.225×10^{-3}
1992	6.336×10^{-3}	4.617×10^{-3}
1996	5.936×10^{-3}	4.749×10^{-3}

8.6 Impacts on Soils, Waters, and Vegetation

Potential impacts to soils, waters, and vegetation in Class I areas were evaluated on the basis of the model-predicted pollutant concentrations and the magnitude of predicted annual deposition of sulfur and nitrogen. The evaluation for Mesaba One and Mesaba Two impacts at the BWCA, VNP, and RLW is presented in this section.

Screening criteria for potential air pollution impacts on vegetation have been given by the U.S. Forest Service. (Hanna, 1984.) According to the USFS "Green Line" screening values "were set at levels at which it was reasonably certain that no significant change would be observed in ecosystems that contain large numbers of sensitive components." The Green Line screening levels for SO_2 are 5 µg/m^3 maximum annual average and 100 µg/m^3 maximum three-hour average. Though the USFS screening levels were established specifically for Class I areas administered by the Forest Service (BWCA and RLW) it is reasonable to apply the same criteria to VNP, which is administered by the National Park Service (NPS) but does not have a published standard similar to the USFS. (USFS, 1991.)

Table 8.6-2 compares CALPUFF projections of Mesaba impacts and existing background concentrations to the Green Line screening levels for each Class I area. Current concentrations, Mesaba contributions, and the sum of the two are all well below the Green Line levels. It can therefore be concluded that there will be no threat to sensitive vegetation from Mesaba SO_2 emissions. There are no established screening criteria for NO_2 and PM10. However, as shown in Section 8.3, Class I area concentrations of NO_2 and PM_{10} from Mesaba One and Mesaba Two will be below significance levels and therefore can be expected to have negligible impacts.

The USFS has also established a Green Line screening value for ozone concentration. The green line level is a second-highest one-hour concentration during the growing season of 80 ppb. Existing background monitoring data indicate current concentrations near the Green Line level, but below the red line concentration of 120 ppb. Ozone modeling is not required for Mesaba One and Mesaba Two, but the modest level of VOC and NO_x emissions indicate that the IGCC Power Station will not cause a significant increase in ozone impacts in the Class I areas.

Criteria for assessment of deposition impacts are different for USFS areas (BWAC and RLW) and NPS areas (VNP). The NPS has established a Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr for both sulfur (S) and nitrogen (N) deposition for Class I areas in the eastern United States. The DAT is a level below which adverse impacts are not anticipated. As shown in Table 8.5-1, the CALPUFF model results for deposition in VNP are very close to the 0.01 DAT for S, and below the DAT for N. In the case of S, two of the three years modeled produced a total

sulfur deposition value slightly greater than 0.01, and the third year resulted in a value slightly below 0.01. When it is considered that the deposition values in Table 8.6-1 represent the highest deposition for any receptor in the Class I area, and that the annual emissions for Mesaba used in the model are very conservative (worst-case emissions assuming two phases operating 8760 hours per year), it can be concluded that it is unlikely that the DAT threshold for S deposition will be exceeded at any point in VNP. The DAT represents a screening level to assess any possibility of adverse impact, and is not a regulatory limit. Based upon these considerations, it has been concluded that S and N deposition from Mesaba One and Mesaba Two will not cause adverse effects in VNP.

Table 8.6-2
Comparison of Projected Class I SO_2 Concentrations to Green Line Screening Criteria for Vegetation Impacts

Class I Area	Background [1] (µg/m^3)		Max. Mesaba (µg/m^3)		Total (µg/m^3)		Green Line (µg/m^3)	
	3-hr	annual	3-hr	annual	3-hr	annual	3-hr	annual
Boundary Waters Canoe Area	10.8	1.2	1.55	.015	12.35	1.215	100	5
Voyageurs National Park	6.3	0.7	1.59	.013	7.89	.713	100	5
Rainbow Lake Wilderness	14.4	1.6	.76	.008	15.16	1.608	100	5

[1] Background SO_2 concentrations from Mesaba Nugget Class I Air Modeling Report, Barr Engineering Company, May 2005.

Table 8.6-3
Comparison of Projected S and N Deposition Rates to Green Line Criteria for Impacts to Terrestrial and Aquatic Ecosystems

Class I Area	Parameter	Background [1] (kg/ha-yr)	Maximum Mesaba Impact (kg/ha-yr)	Total (kg/ha-yr)	Green Line [2] Value (kg/ha-yr)
BWCA	Terrestrial				
	Total S Depo	2.85	.012	2.86	5-7
	Total N Depo	4.75	.010	4.76	5-8
	Aquatic				
	Total S Depo	2.85	.012	2.86	7.5-8
	S + 20% N	3.80	.014	3.81	9-10
RLW	Terrestrial				
	Total S Depo	2.98	.006	2.99	5-7
	Total N Depo	5.88	.005	5.89	5-8
	Aquatic				
	Total S Depo	2.98	.006	2.99	3.5-4.5
	S + 20% N	4.16	.007	4.17	4.5-5.5

[1]Background values from Mesabi Nugget Class I Air Modeling Report, Barr Engineering Company, May 2005.
[2]Green Line Values from Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wildernesses Cited as Class I Air Quality Areas, USFS, 1991.

For the USFS Class I areas (BWCA and RLW), different screening criteria are recommended for assessment of deposition impacts to terrestrial and aquatic ecosystems. For terrestrial impacts, Green Line criteria are total S deposition of 5 to 7 kg/ha-yr, and total N deposition of 5 to 8 kg/ha-yr. For aquatic impacts, the Green Line values differ for the two Class I areas because of the different chemistry of sensitive lakes in the two areas. The Green Line values, shown in Table 8.6-3, are expressed in terms of S deposition plus 20% of N deposition.

Table 8.6-3 summarizes projected deposition rates in the BWCA and RLW, calculated as background plus Mesaba One and Mesaba Two predicted deposition, and provides a comparison to the USFS Green Line values. It is shown that all deposition rates are within or below the acceptable Green Line levels. It can also be noted that all S deposition rates are below the State of Minnesota's limit for wet sulfate deposition of 11 kg/ha-yr (approximately 6 kg/ha-yr of total S deposition). It is therefore concluded that Mesaba One and Mesaba Two will not cause adverse impacts to terrestrial and aquatic ecosystems in the BWCA or RLW.

8.7 Regional Haze Analysis

A visibility/regional haze impact analysis was carried out for BWCA and VNP. Visibility analysis is not required for Rainbow Lakes. The recommended methodology for assessing visibility impacts according to the FLAG guidance involves the use of CALPOST to process the data on concentrations of pollutants from the CALPUFF modeling of 24-hour emissions. In CALPOST a daily value of light extinction is defined by the concentrations of each pollutant that can effect visibility, taking into account the efficiency of each particle type in scattering light, and the relative humidity which influences the size of hygroscopic pollutants (sulfates and nitrates). The 24-hour average light extinction caused by emissions from the modeled source(s) is then compared to the background light extinction, a value based upon "natural" or pristine unpolluted conditions for each Class I area.

The FLMs have established threshold changes in light extinction (as a percentage of natural background) that are believed to represent potential adverse impacts on visibility. These thresholds are 5% (a potentially detectable change) and 10% (a level that may represent an unacceptable degradation).

Table 8.7-1 presents results of the initial CALPUFF visibility analysis following the FLAG methodology, and using "Method 2" of CALPOST for calculation of visibility impacts. In Method 2, relative humidity data from the nearest surface weather station is used to calculate both source and background light extinction. Other methods, discussed below, use average relative humidity values, consider natural visibility impairment, and take into account average light extinction over a line-of-sight rather than extinction at a single receptor location.

The data in Table 8.7-1 indicate that calculated visibility impacts greater than 5 or 10% could occur at some point within the BWCA and VNP on a small number of days each

year. Because these data suggest a potential for detectable visibility degradation due to Mesaba emissions, additional analyses were carried out to better quantify and evaluate the possibility of visibility impacts. These analyses are described in following sections.

Table 8.7-1
Visibility Results for Mesaba One and Mesaba Two (FLAG Method 2 Analysis)

Year and Parameter	Boundary Waters Canoe Area	Voyageurs National Park
1990 Meteorological Data		
Days > 5%	39	16
Days > 10%	10	1
Maximum Change in light extinction	16.4%	11.8%
1992 Meteorological Data		
Days > 5%	36	25
Days > 10%	15	4
Maximum Change in light extinction	24.1%	19.0%
1996 Meteorological Data		
Days > 5%	17	18
Days > 10%	6	4
Maximum Change in light extinction	15.0%	22.5%

8.7.1 Visibility Considerations

Under 40 C.F.R. 51.301, an adverse impact on visibility is defined as "visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility." This definition indicates that a model-predicted extinction change exceeding a given threshold value does not necessarily imply an adverse impact. Some consideration should be given to local conditions at the time and location of the model result, and factors that may have contributed to the predicted impact.

There are several factors inherent in the FLAG Method 2 methodology that are conservative in the sense that they lead to the highest likely impact. These include:

- The extinction change calculated for a Class I area represents the largest change for any receptor within the area.

- The change is calculated relative to natural or pristine background: that is, the best visibility in the absence of any industrial pollution or abnormal natural events such as forest fires.
- No natural visibility impairment due to fog, precipitation, or clouds is considered.
- The calculations assume emissions from the modeled source, at the highest daily rate, for every hour and day of the year.

Possible errors in the CALPUFF model simulation should also be considered. There are various uncertainties in the CALPUFF dispersion models, all of which may lead to over- or under-prediction of concentrations at any given point and time. However, the atmospheric chemistry calculations in CALPUFF are the most critical, since they are responsible for predicted concentrations of sulfate and nitrate particles that largely define light extinction. Morris et al. have reported on an evaluation of the CALPUFF chemistry algorithms by comparison to measured concentrations and the more sophisticated CMAQ model. (Morris, et al., 2005.) They conclude that:

"The quantitative evaluation of the CALPUFF chemistry algorithms found that they greatly overstate the amount of nitrate in the atmosphere and sulfate is likely overstated in the winter and understated in the summer. An analysis of sulfate and nitrate concentration increments suggest that winter sulfate and nitrate impacts from individual sources (e.g. PSD or BART analysis) are overstated by both versions of the CALPUFF chemistry algorithms."

These conclusions are directly relevant to the present analysis, where the greatest visibility impacts were predicted in winter months, and the largest contribution to light extinction is generally from nitrate particles.

It should also be noted that relative humidity is a critical input to the light extinction calculation. Because of the hygroscopic nature of sulfate and nitrate particles, light extinction is greatly magnified under high humidity conditions. The CALPOST visibility calculation uses measured relative humidity at the nearest surface weather station to calculate the humidity effect of given concentrations of sulfate and nitrate particles. The nearest weather station is often some distance from the Class I area of concern, and the observed relative humidity may or may not be representative of the analysis area. Most important, high relative humidity values are frequently associated with fog, precipitation, and low clouds, all of which can create natural visibility impairment. The possible occurrence of these natural phenomena are not considered in the FLAG method 2 calculation. The association of high humidity and natural weather events with predicted Class I impacts is discussed below.

Finally, the definition of visibility impairment in 40 C.F.R. 51.301 refers to "any humanly perceptible change in visibility". It has generally been considered that a change in light extinction of 5 to 10% constitutes a noticeable change in viewing a scene through the atmosphere. However, it has been pointed out by Richards that this threshold is only appropriate over a line-of-sight equal to the natural visual range (for the Class I areas in this analysis, a distance on the order of 175 km). (Richards, 1999) For shorter sight lines, a 5 to 10% change in light extinction may not be perceptible. Or, a 5 to 10% local

increase in light extinction is not likely to be perceptible over a long sight path for which the average extinction is less.

The considerations discussed here indicate that the FLAG Method 2 visibility results in Table 8.7-1 are not definitive in suggesting that there could be adverse impacts of Mesaba One and Mesaba Two for a number of days per year in the BWCA and VNP. Most of these factors suggest that actual impacts may be substantially lower than indicated. Additional analyses are presented in the following section to provide further information on implications of the CALPUFF results.

8.7.2 Additional Visibility Analyses

There are currently no practical and acceptable ways to include all of the factors discussed above in making a more rigorous and realistic assessment of the probability of actual visibility impairment. However, some procedures have been suggested to account, in part, for potential errors or omissions in the FLAG calculations.

The CALPOST post-processing software contains several alternative algorithms for calculating the change in light extinction due to the modeled source. Method 6 substitutes monthly average relative humidity values (specific to each Class I area) for the hourly relative humidity data at nearby weather stations. This substitution mitigates, to some extent, the high extinction values calculated when very high humidity values are reported throughout the day at the nearest observation site. It is intended to account for the fact that the observed humidity may be unrepresentative of the Class I area, and that very high relative humidities are frequently associated with natural impairment by fog, clouds, and precipitation. The Method 6 calculation is recommended by the U.S. EPA for state regional haze BART analyses.

Method 7 is another modification of the standard Method 2 as it attempts to account for natural visibility reduction due to fog or precipitation. In Method 7, the actual measured visibility at the nearest weather station is used as background (instead of natural pristine background) on those hours when fog or precipitation are reported. Method 7 represents another attempt to account for natural visibility reduction in assessing the impact of man-made pollution.

A criticism of Method 7 is that it tends to minimize the effect of source-induced haze on days when natural impairment may only exist for a small part of the day. It is possible that the impact of the source could still be significant during other hours of the day. This is a valid point, but the FLAG procedures specify visibility calculation on a 24-hour daily basis, on the grounds that model predictions for any single hour are subject to significant error. If the 24-hour averaging is appropriate for the basic visibility calculation, it may be reasonable to also utilize some 24-hour averaging in the effect of natural visibility impairing events. Certainly the occurrence of fog or precipitation on specific hours at a nearby weather station indicates the likelihood of these events at other times and/or locations within the Class I area.

Table 8.7-2 shows the results of Method 6 and Method 7 visibility calculations for Mesaba One and Mesaba Two, with comparison to the Method 2 data. Both alternative

analyses indicate lower frequency and magnitude of impacts relative to Method 2. For Method 7, there are only two days of predicted impacts from three years of data exceeding 10% change in light extinction at the BWCA, and none at VNP.

In EPA's BART guidance for regional haze, the 98th percentile of light extinction predictions is recommended as a threshold for significant impact. This means that an average of seven days per year or more of impacts exceeding 5% indicates a significant impact. Under this criterion, the Method 7 results show no significant visibility impact of Mesaba One and Mesaba Two at either Boundary Waters or Voyageurs.

As discussed in the proceeding section, a perceptible change in visibility at the 5% level is properly defined over an extended line-of-sight equal to the background visual range. Calculations were made of the average change in light extinction over several 150 km sight lines for the day of highest predicted impact in the BWCA. Using Method 2, the highest Mesaba One and Mesaba Two impact was 24.1% on February 3, 1992 at a receptor near the southern BWCA boundary northeast of the IGCC Power Station. Three sight lines were evaluated: one from the highest receptor directly southwest to the IGCC Power Station, one in the opposite direction from the highest receptor away from the IGCC Power Station, and one extending across the BWCA in an approximate east-west orientation. A separate CALPUFF model run was made for receptors along the three sight lines, and average changes in light extinction were calculated, by Method 2, along each of the three lines. The results showed average extinction changes of 13% (toward Mesaba One and Mesaba Two); 9% (away from the IGCC Power Station), and 13.6% (across the BWCA). Though still significant, these calculated average changes are 50% or less than those at the maximum receptor.

Examination of the meteorology for this single "worst day" shows that temperatures in the BWCA were approximately 22 to 30 deg F, there were a few snow flurries, and a cloud cover of 100% existed at approximately 500 feet above the ground for much of the day. Fog was reported at Hibbing from midnight until 8 PM, with visibility between ½ and 5 miles; at International Falls, fog existed from midnight until 3 PM with visibility less than 1.2 miles until mid-afternoon. Under these conditions, natural conditions would have precluded access to extended scenic views for Park visitors.

An analysis was carried out to characterize the times and meteorological conditions for those days on which CALPUFF, with Method 2, indicated light extinction changes exceeding five percent in either the BWCA or VNP. Hourly meteorological data from Hibbing were assumed to represent the BWCA, and data from International Falls were used for days of impacts at VNP. Days on which fog, precipitation, or low ceiling (less than 3000 feet) occurred were tabulated, along with relative humidity measurements at 6 AM and 12 noon. These times typically represent near highest and lowest humidity values for the day. Also listed for each day was the value of f(RH) used in the CALPOST light extinction calculation. f(RH) represents the daily mean value of the relative humidity parameter that accounts for growth of sulfate and nitrate particles; high values of f(RH) indicate high humidity conditions under which light scattering by these particles is dramatically increased. The value of f(RH) varies from 1.0 for humidity less than 37%, to 9.8 at the maximum CALPOST humidity of 95%.

Results of the meteorological analysis are presented in Table 8.7-3. The main conclusions evident from the Table are:

- Predicted impacts occur predominantly during the winter part of the year; 47 to 61% of all occurrences are indicated between November and March.
- A very high percentage of occurrences coincide with days of natural visibility degradation due to fog, precipitation, or low clouds. 82% to 100% of the days had some occurrence of these weather elements.
- All occurrences of predicted visibility impact were on days of very high relative humidity.

Of the 40 days (in three years) when an extinction change greater than 10% was indicated at either BWCA or VNP, only two days had no direct observations of natural visibility impairment. These days, both at the BWCA, were February 14, 1990 and January 10, 1992. On the first day, temperature was -20 deg F, with relative humidity ranging from 72 to 100% during the 24-hour day. On January 10, 1992, temperatures were near zero deg F, relative humidity ranged from 91 to 96%, and weather maps suggest that snow flurries related to a stationary front probably occurred in some parts of the BWCA. Given these facts, it seems likely that some natural visibility impairment existed in the BWCA, though none was observed at Hibbing.

Of course, the occurrence of natural visibility degradation on some hours of the day does not necessarily imply that visual impacts of Mesaba emissions could not exist during other periods of the day. There is no practical means of evaluating impacts on an hour-by-hour basis. But as noted above, since the visibility calculation is made on a daily average basis, it is reasonable to consider natural impacts also in terms of some spatial and time-averaged indicators. At the least, the data in Table 61 indicate that there were some natural visibility impacts within the Class I areas on nearly all days of predicted Mesaba One and Mesaba Two effects. The analysis shows that modeled impacts overwhelmingly occur on days of inclement weather. The high model-predicted light extinction values are always caused by high relative humidity measurements at the nearest weather station, and these high humidities may not be truly representative of larger-scale conditions within the Class I area. If the high humidity values are local anomalies, the CALPUFF impacts are overstated. If the humidity data are representative, they are indicative of a high probability of natural visibility impairment.

To summarize the Mesaba visibility impact analysis, CALPUFF modeling suggests some days of potential impact at both the BWCA and VNP. However, a number of very conservative elements exist in the FLAG evaluation methodology, and the CALPUFF model chemistry has been shown to significantly overestimate hygroscopic particle concentrations. In consideration of these facts and the meteorological analysis of impact days, it is concluded that Mesaba One and Mesaba Two will have detectable visibility effects on few if any days, and that impacts are extremely unlikely to interfere with the visual experience of park visitors.

Table 8.7-2
Mesaba CALPUFF Visibility Results

Speciated PM 12/5/2005	**1990 Method 2** > 5 %	**1990 Method 2** > 10 %	**1990 Method 2** Max %	**1992 Method 2** > 5 %	**1992 Method 2** > 10 %	**1992 Method 2** Max %	**1996 Method 2** > 5 %	**1996 Method 2** > 10 %	**1996 Method 2** Max %
Boundary Waters Wilderness	39	10	16.43	36	15	24.11	17	6	14.98
Voyageurs National Park	16	1	11.82	25	4	18.97	18	4	22.47
Speciated PM 12/5/2005	1990 **Method 6** > 5 %	1990 **Method 6** > 10 %	1990 **Method 6** Max %	1992 **Method 6** > 5 %	1992 **Method 6** > 10 %	1992 **Method 6** Max %	1996 **Method 6** > 5 %	1996 **Method 6** > 10 %	1996 **Method 6** Max %
Boundary Waters Wilderness	24	1	12.12	19	2	11.54	9	0	8.13
Voyageurs National Park	13	0	8.43	14	1	10.22	8	1	12.49
Speciated PM 12/5/2005	1990 **Method 7*** > 5 %	1990 **Method 7** > 10 %	1990 **Method 7** Max %	1992 **Method 7** > 5 %	1992 **Method 7** > 10 %	1992 **Method 7** Max %	1996 **Method 7** > 5 %	1996 **Method 7** > 10 %	1996 **Method 7** Max %
Boundary Waters Wilderness	11	1	10.43	7	1	19.22	2	0	7.63
Voyageurs National Park	3	0	7.93	2	0	6.13	3	0	8.13

* Hibbing MN used as primary weather station for Boundary Waters Wilderness, International Falls used for Voyageurs NP.

Table 8.7-3
Characteristics of Days with Predicted Visibility Impacts

Meteorological Characteristic	Boundary Waters Canoe Area		Voyageurs National Park	
	Days > 5%	Days > 10%	Days > 5%	Days > 10%
	Total 92 Days	Total 31 days	Total 59 days	Total 9 days
Percentage of days November through March	57%	61%	47%	56%
Percentage of days with precipitation	60%	68%	78%	100%
fog	54%	77%	64%	89%
ceiling < 3000 ft	68%	81%	69%	78%
Percentage of days with some natural visibility impairment	82%	94%	88%	100%
Average morning (0600) relative humidity	95%	97%	92%	94%
Average mid-day (1200) relative humidity	76%	85%	75%	83%
Mean daily f((RH)	5.34	6.45	4.73	5.91
equivalent relative humidity	91%	92.5%	90%	92%

Statistics for BWCA from hourly surface weather data at Hibbing MN; statistics for VNP from hourly surface data at International Falls, MN.

9. REFERENCES

Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wildernesses Cited as Class I Air Quality Areas. USFS General Technical Report NE-151, 1991.

Morris, R., S. Lau, and B. Koo, 2005: Evaluation of the CALPUFF Chemistry Algorithms. AWMA Annual Conference, Minneapolis MN, June 21 – 24, 2005.

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USDOE/NETL, 2002. Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report. December 2002. Science Applications International Corporation (SAIC)

10. AIR PERMIT APPLICATION FORMS

The permit application forms completed in support of this application are identified in Table 9.0-1 below.

Table 9.0-1
Permit Application Forms

Name of Form	Equipment or Facilities Covered (Phase I and II)	No. of Forms	Reserved.
CP-01 Cover Page	IGCC Power Station	1	
CR-01 Certification	IGCC Power Station	1	
CR-03 Confidentiality Certification	IGCC Power Station	1	
GI-01 Facility Information	IGCC Power Station	1	
GI-02 Process Flow Diagram	IGCC Power Station	1	
GI-03 Facility and Stack/Vent Diagram	IGCC Power Station	1	
GI-04 Stack/Vent Info	IGCC Power Station	1	
GI-05A Pollution Control Equip Info	IGCC Power Station	1	
GI-05B Emission Unit Info	IGCC Power Station	1	
GI-05D Fugitive Emission Source Info	IGCC Power Station	1	
GI-09 Requirements Form	IGCC Power Station	1	
GI-09A Requirements NESHAP (40 C.F.R. 63)	IGCC Power Station	1	
GI-09B Requirements NESHAP (40 C.F.R. 61)	IGCC Power Station	1	
GI-09C Requirements New Source Review	IGCC Power Station	1	
GI-09D Requirements NSPS	IGCC Power Station	1	
GI-09G Risk Management Programs For Chemical Accidental Release Prevention	IGCC Power Station	1	
GI-09H CAM (40 C.F.R. 64)	IGCC Power Station	1	
GI-09 I State Rules	IGCC Power Station	1	
HG-2003 Mercury Releases	IGCC Power Station	1	
EC-01 General Process/Unit Calculation	Flares, cooling towers	6	
		1	
		1	
		1	
		1	
		1	
		1	
EC-02 External Combustion (Boilers)	Aux boilers, tank vent boilers	4	
		1	
		1	
		1	

Table 9.0-1
Permit Application Forms Continued

EC-03 IC Engines	CTGs, diesel generators and FW pump engines	14	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
		1	
EC-13A Hazardous Air Pollutants (VOC)	IGCC Power Station, fugitive HAPs and VOC	1	
EC-13C Hazardous Air Pollutants (Fuel Combustion)	CTGs, tank vent boilers, flares	6	
		1	
		1	
		1	
		1	
		1	
		1	
EC-15 Fugitive Particulate Emission	Solid feed unloading, storage, handling and slag handling	1	
IA-01 Insignificant Activities List	IGCC Power Station	1	
AERA-01	Contained in Appendix E	1	
AERA-02	Contained in Appendix E	1	
AERA-03	Contained in Appendix E	1	
AERA-04	Contained in Appendix E	1	
AERA-05	Contained in Appendix E	1	

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **CP-01**

TOTAL FACILITY OPERATING PERMIT COVER PAGE

7/25/05

1a) AQ Facility ID No.: _____

1b) AQ File No.: _____

2) Facility Name: Mesaba One and Mesaba Two

THIS TOTAL FACILITY OPERATING PERMIT APPLICATION IS FOR: (check all that apply)

☐ A Part 70 permit (Minn. Rules pt. 7007.0200)

☐ A State permit (Minn. Rules pt. 7007.0250)

☐ with EMS provisions

☒ Construction of a New Facility
(Minn. Rules pt. 7007.0150, subp. 1)

☒ A Project subject to Prevention of Significant Deterioration (PSD)
(40 C.F.R. § 52.21)

CONFIDENTIALITY:

☐ This application contains material which is claimed to be confidential under Minnesota Statutes Chapter 13 and Section 116.075 and Minn. Rules pt. 7000.1300.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two

CERTIFICATION

I certify under penalty of law that the enclosed documents and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete.

I also certify, in accordance with Minnesota Rules 7007.0500, subp. 2 (K)(2) and subp. 2 (K)(3), that I have reviewed the procedures implemented by my facility to maintain compliance and that those procedures are, to the best of my knowledge and belief, reasonable to maintain compliance with all applicable requirements, including those that will become applicable during the term of the permit.

Owner:		**Operator:**	
Mr./Ms.	Robert S. Evans II	Mr./Ms.	Robert S. Evans II
Title:	Vice President-Environmental Affairs	Title:	Vice President-Environmental Affairs
Signature:		Signature:	
Date:	June 19, 2006	Date:	June 19, 2006

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **CR-03**

CONFIDENTIALITY CERTIFICATION

5/3/05

1) AQ Facility ID No.: _____

2) Facility Name and Address: Not Applicable; No data claimed to be confidential

NOTICE OF PUBLIC AVAILABILITY OF DATA SUBMITTED TO THE MPCA

The information you submit to the MPCA with your permit application is available to the public under state and federal laws, except for certain specific kinds of information meeting statutory standards for confidential treatment. However, to have your information treated confidentially by the MPCA, you must certify that the information qualifies for confidential treatment and explain why. This document describes the most relevant laws that allow the MPCA to treat application information confidentially, and the steps you must take to obtain confidential treatment of your data. If you do not seek confidential treatment of any data, you do not need to return this form.

CERTIFYING DATA FOR THE CONFIDENTIAL USE OF THE MPCA

Information in a permit application may be considered confidential (or non-public) if any state law makes it so. The two legal provisions most likely to apply to permit applications protect the following kinds of data:

> Data furnished to the agency that relates to (a) sales figures, (b) processes or methods of production **unique** to the owner or operator, OR (c) information which would tend to affect adversely the competitive position of said owner or operator. (Minn. Stat. § 116.075, subd. 2)
>
> Data including a formula, pattern, compilation, program, device, method, technique or process (1) that was supplied by the affected individual or organization, (2) that is the subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, AND (3) that derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. (Minn. Stat. § 13.37, subd. 1(b))

However, even if the information falls under one of the above categories, if it is considered emissions data (defined in 40 C.F.R. § 2.301), then the information is considered public. Both the Clean Air Act and Environmental Protection Agency (EPA) regulations require that “emission data” submitted to the MPCA under Title V or Minnesota’s State Implementation Plan must be available to the public. In addition, EPA has issued guidance on what type of information it generally considers to be emission data (Federal Register Vol. 56, No. 35; February 21, 1991).

Please note that only **specific** data within an application can be considered confidential and not the entire application or permit. The procedures below describe how confidential information must be submitted to the MPCA. If you do not follow these procedures, the MPCA will not provide any special protections for your application, and it is possible that your information could be released to the public.

CERTIFICATION

To certify data for the confidential use of the MPCA, a responsible official must read the following, certify to its truth by filling in the signature block below, and provide the stated attachments.

> I certify that the enclosed permit application(s) and all attachments have been reviewed by me and do contain confidential material. I understand that only specific data can be considered confidential and not the entire application or permit. I certify that I have enclosed the following to comply with the proper procedure for confidential material:
>
> a. I have enclosed a statement identifying which data contained in my application I consider confidential, and I have explained why I believe the information qualifies for confidential (or non-public) treatment under Minnesota Statutes.
>
> b. I have explained why the data for which I am seeking confidential treatment should not be considered "emissions data" which the MPCA is required to make available to the public under federal law.
>
> c. I have enclosed an application containing all pertinent information to allow for completion and issuance of my permit. This document has been clearly marked "confidential".
>
> d. I have enclosed a second copy of my application with the confidential data blacked out (not omitted or deleted entirely). It is evident from this copy that information was there, but that it is not for public review. This document has been clearly marked "public copy".

Permittee Responsible Official:		**Co-Permittee Responsible Official (if applicable)**	
Mr. / Ms.	_____	Mr. / Ms.	_____
Title:	_____	Title:	_____
Signature:	_____	Signature:	_____
Date:	_____	Date:	_____

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-01**

FACILITY INFORMATION

5/3/05

1a) AQ Facility ID No.: _____

1b) AQ File No.: _____

2) Facility Name: Mesaba One and Mesaba Two

3) Facility Location:

Street Address: _____

City: Taconite State: MN ZIP Code: _____ County: Itasca

Mailing Address: 11100 Wayzata Boulevard
Suite 305
City: Minnetonka State: MN ZIP Code: 55305

4) Corporate/Company Owner:

Name: MEP-I LLC & MEP-II LLC

Mailing Address: 11100 Wayzata Boulevard
Suite 305
City: Minnetonka State: MN ZIP Code: 55305

Owner Classification: ☒ Private ☐ Local Govt ☐ State Govt. ☐ Federal Govt. ☐ Utility

5) Corporate/Company Operator (if different than owner):

Name: _____

Mailing Address: _____

City: _____ State: _____ ZIP Code: _____

6) Co-permittee (if applicable):

Name: _____

Mailing Address: _____

City: _____ State: _____ ZIP Code: _____

7) Legally responsible official for this permit/facility:

Mr/Ms: Robert S. Evans II Phone: (952) 847-2355

Title: Vice President-Environmental Affairs Fax: (952) 847-2373

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☒ Other address (specify) Email address: BobEvans@excelsiorenergy.com

8) Contact person for this permit:

Mr/Ms: Mr. Robert S. Evans II Phone: (952) 847-2355

Title: Vice President-Environmental Affairs Fax: (952) 847-2373

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☐ Other address (specify) _____

E-mail address: BobEvans@excelsiorenergy.com

9) All billings for annual fees should be addressed to:

Mr/Ms: Mr. Robert S. Evans II Phone: (952) 847-2355

Title: Vice President-Environmental Affairs Fax: (952) 847-2355

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☐ Other (specify) _____

10) Standard Industrial Classification (SIC) Code and description for the facility and North American Industry Classification System (NAICS) Code and description:

Primary SIC code: 4911 / Electrical services

Secondary (if applicable): _____ / _____

Tertiary (if applicable): _____ / _____

Primary NAICS code:: 221112 / Fossil Fuel Electric Power Generation

11) Primary product produced (or activity performed) at the facility is:

Electricity

12) Facility is: ☒ Stationary ☐ Portable

13) Check the one that applies best to your facility:

☒ New facility planned or under construction (first permit application)

☐ Existing facility, applying for renewal of a total facility Air Quality operating permit issued by the MPCA

☐ Existing facility, and have never had a total facility operating permit, but have had another type of Air Quality permit issued by the MPCA

☐ Existing facility, but have never had a total facility operating permit or any other type of Air Quality permit issued by the MPCA

14) Is environmental review required (either an Environmental Assessment Worksheet (EAW) or an Environmental Impact Statement (EIS)) for this facility? Call the Minnesota Environmental Quality Board for more information (1-800-657-3794, or 296-8253 in the Twin Cities metro area).

☒ Yes ☐ No

Note: If you answered "Yes" to this question, you may also be required to perform a state air toxics review for your facility. Please call (800) 646-6247 or (651) 297-2274.

15) Are you required to submit a Toxics Release Inventory (Form R) under SARA Title 313 for this facility? Call the Minnesota Department of Public Safety, Emergency Response Commission for more information (651-297-7372).

☒ No ☐ Yes, but we are not required to submit a pollution prevention plan under Minn. Stat. § 115D.07;

☐ Yes, and we are required to submit a pollution prevention plan and have submitted the most recently required progress report to the Emergency Response Commission under Minn. Stat. § 115D.09.

16) Is this facility within 50 miles of another state or the Canadian border:

☐ Yes (specify which ones) _____ ☒ No

17) Brief description of the facility or proposed facility to be permitted (attach additional sheet if necessary):

IGCC Electric Power Generating Station - See Section 2 of Permit Application for detailed description.

18) Are you proposing any alternative operating or emissions trading scenarios in this application (see Minn. R. 7007.0800, subp. 10 and 11)?

☐ Yes ☒ No

If yes, attach a description of your proposal, including a statement on how the proposal will meet all applicable requirements (in particular, please address federal New Source Review requirements, if applicable). See Form GI-09(C).

19) Person preparing this permit application:

Mr. / Ms. Mr. Robert S. Evans II

Title: Vice President-Environmental Affairs E-mail address: BobEvans@excelsiorenergy.com

Phone: (952) 847-2355 Fax: (952) 847-2373 Date: June 19, 2006

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two

3) Flow Diagram: See Figures 2.3-1 and 2.3-2 in permit application.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-03**

FACILITY AND STACK/VENT DIAGRAM

2/16/05

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two

3) Facility and Stack/Vent Diagram: See Figures 1.6-5, 2.3-1, and 2.3-2 in permit application.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-04**
STACK/VENT INFORMATION
7/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

TBD = Specifications to be determined during Front End Engineering Design period.

3a) SV ID No.	**3b)** Operator's Description	**3c)** Height of Opening From Ground (ft.)	**3d)** Inside Diameter in ft. (left column only) or Length x Width in ft. (both columns)		**3e)** Design Flow Rate at Exit (acfm)	**3f)** Exit Gas Temperature (° F)	**3g)** Rate/Temp Information Source	**3h)** Discharge Direction
001	CTG/HRSG, Phase I	150	20		1,240,000	250	M	U
002	CTG/HRSG, Phase I	150	20		1,240,000	250	M	U
003	Auxiliary Boiler, Phase I	40	5		37,500	300	E	U
004	ASU Cooling Tower, Phase I (each of 5 cells)	48	33		1,370,000	104	M	U
005	Power Block Cooling Tower, Phase I (each of 12 cells)	48	33		1,370,000	104	M	U
006	Emergency Diesel Generator - Gasification Island, Phase I	TBD	TBD		TBD	TBD		
007	Emergency Diesel Generator - Power Block, Phase I	TBD	TBD		TBD	TBD		
008	Emergency Firewater Pump Engine, Phase I	TBD	TBD		TBD	TBD		

009	Emergency Firewater Pump Engine, Phase I	TBD	TBD		TBD	TBD		
010	Tank Vent Boiler, Phase I	210	6		47,100	584	E	U
011	Flare, Phase I	185	5.5		(NA)	(NA)	E	U
012	Feed Bin Baghouse, Phase I	TBD	TBD		TBD	TBD		U
013	CTG/HRSG, Phase II	150	20		1,240,000	250	M	U
014	CTG/HRSG, Phase II	150	20		1,240,000	250	M	U
015	Auxiliary Boiler, Phase II	40	5		37,500	300	E	U
016	ASU Cooling Tower, Phase II (each of 5 cells)	48	33		1,370,000	104	M	U
017	Power Block Cooling Tower, Phase II (each of 12 cells)	48	33		1,370,000	104	M	U
018	Emergency Diesel Generator - Gasification Island, Phase II	TBD	TBD		TBD	TBD		
019	Emergency Diesel Generator - Power Block, Phase II	TBD	TBD		TBD	TBD		
020	Emergency Firewater Pump Engine, Phase II	TBD	TBD		TBD	TBD		
021	Emergency Firewater Pump Engine, Phase II	TBD	TBD		TBD	TBD		
022	Tank Vent Boiler, Phase II	210	6		47,100	584	E	U
023	Flare, Phase II	185	5.5		(NA)	(NA)	E	U
024	Feed Bin Baghouse, Phase II	TBD	TBD		TBD	TBD		U

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-05A**
POLLUTION CONTROL EQUIPMENT INFORMATION
07/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

IGCC Power Station represents inherently low emitting technological process providing superior emissions control across all criteria and non-criteria pollutants.

3a) Control Equip ID No.	**3b)** CE Type Code	**3c)** Description	**3d)** Manufacturer	**3e)** Model No.	**3f)** Pollutants Controlled	**3g)** Capture Efficiency	**3h)** Destruct/ Collect Efficiency	**3i)** Afterburner Combustion Parameters
001	022	Tank Vent Boiler, Phase I (SV010)	TBD		CO	100%	99%	>1600 deg F
					VOC	100%	99%	> 0.8 sec
					TRS	100%	99%	
002	023	Flare, Phase I (SV011)	TBD		CO	100%	99%	
					VOC	100%	99%	
					TRS	90%	99%	
003	018	Feed Bin Baghouse, Phase I (SV012)	TBD		PM10	100%	99%	
004	022	Tank Vent Boiler, Phase II (SV022)	TBD		CO	100%	99%	>1600 deg F

					VOC	100%	99%	> 0.8 sec
					TRS	100%	99%	
005	023	Flare, Phase II (SV023)	TBD		CO	100%	99%	
					VOC	100%	99%	
					TRS	90%	99%	
006	024	Feed Bin Baghouse, Phase II (SV024)	TBD		PM10	100%	99%	

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-05B**

EMISSION UNIT INFORMATION, PART 1

07/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

TBD = Manufacturer and Model No. to be determined during Front End Engineering and Design period.

3a) Emis Unit ID No.	**3b)** SV ID No(s).	**3c)** Relation Type	**3d)** Control Equip ID No.	**3e)** Emission Unit Operator's Description	**3f)** Manufacturer	**3g)** Model No.
001	001	(M)ain		Combustion Turbine Generator (CTG)/Heat Recovery Steam Generator (HRSG) (Phase I)	CTG - Siemens or similar	SGT6-5000F or similar
002	002	(M)ain		CTG/HRSG (Phase I)	CTG - Siemens or similar	SGT6-5000F or similar
003	003	(M)ain		Auxiliary Boiler (Phase I)	TBD	TBD
004	004	(M)ain		ASU Cooling Tower (Phase I)	TBD	TBD
005	005	(M)ain		Power Block Cooling Tower (Phase I)	TBD	TBD
006	006	(M)ain		Emergency Diesel Generator - Gasification Island (Phase I)	TBD	TBD
007	007	(M)ain		Emergency Diesel Generator - Power Block (Phase I)	TBD	TBD
008	008	(M)ain		Emergency Firewater Pump Engine (Phase I)	TBD	TBD
009	009	(M)ain		Emergency Firewater Pump Engine (Phase I)	TBD	TBD

010	013	(M)ain		CTG/HRSG (Phase II)	CTG - Seimens or similar	SGT6-5000F or similar
011	014	(M)ain		CTG/HRSG (Phase II)	CTG - Seimens or similar	SGT6-5000F or similar
012	015	(M)ain		Auxiliary Boiler (Phase II)	TBD	TBD
013	016	(M)ain		ASU Cooling Tower (Phase II)	TBD	TBD
014	017	(M)ain		Power Block Cooling Tower (Phase II)	TBD	TBD
015	018	(M)ain		Emergency Diesel Generator - Gasification Island (Phase II)	TBD	TBD
016	019	(M)ain		Emergency Diesel Generator - Power Block (Phase II)	TBD	TBD
017	020	(M)ain		Emergency Firewater Pump Engine (Phase II)	TBD	TBD
018	021	(M)ain		Emergency Firewater Pump Engine (Phase II)	TBD	TBD
					TBD	
					TBD	

MINNESOTA POLLUTION CONTROL AGENCY
AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-05B**

EMISSION UNIT INFORMATION, PART 2

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

TBD = To be determined during Front End Engineering and Design period.

3a) Emis Unit ID No.	**3h)** Maximum Design Capacity	**3i)** Maximum Design Capacity Units	**3j)** Maximum Fuel Input (MMBTU)	**3k)** Commence Construction Date (MM/DD/YY)	**3l)** Initial Startup Date (MM/DD/YY)	**3m)** Firing Method (coal-burning units only)	**3n)** % Fuel for Space Heat (boilers only)	**3o)** Bottle-neck? F = facility G = group of sources	**3p)** SIC Code
001	220	MW	2184, HHV (syngas)	Q1 2006	Q4 2011		TBD		
002	220	MW	2184, HHV	Q1 2006	Q4 2011		TBD		
003	100,000	lb/hr steam	130, HHV	Q1 2006	Q4 2011		TBD		
004	46	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
005	116	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
006	2	MW	TBD	Q1 2006	Q4 2011				
007	350	kW	TBD	Q1 2006	Q4 2011				
008	300	HP	TBD	Q1 2006	Q4 2011				
009	300	HP	TBD	Q1 2006	Q4 2011				

010	220	MW	2184, HHV (syngas)	Q1 2006	Q4 2011		TBD		
011	220	MW	2184, HHV	Q1 2006	Q4 2011		TBD		
012	100,000	lb/hr steam	130, HHV	Q1 2006	Q4 2011		TBD		
013	46	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
014	116	million lb/hr cooling water	NA	Q1 2006	Q4 2011				
015	2	MW	TBD	Q1 2006	Q4 2011				
016	350	kW	TBD	Q1 2006	Q4 2011				
017	300	HP	TBD	Q1 2006	Q4 2011				
018	300	HP	TBD	Q1 2006	Q4 2011				

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-05D**

FUGITIVE EMISSION SOURCE INFORMATION

07/25/05

1) AQ Facility ID No.: _____ **2)** Facility Name: Mesaba One and Mesaba Two

3a) Fugitive Source ID No.	**3b)** Pollutant Emitted (particulate matter (PM) or VOC)	**3c)** Control Equip ID No.	**3d)** Description of Fugitive Emission Source
001	PM	003	Coal Handling and Storage, Phase I
002	PM		Coal Slurry Facilities, Phase I
003	PM		Slag Transport and Storage, Phase I
004	VOC/HAP		Fugitive VOC and HAPs, Phase I
005	PM	006	Coal Handling and Storage, Phase II
006	PM		Coal Slurry Facilities, Phase II
007	PM		Slag Transport and Storage, Phase II
008	VOC/HAP		Fugitive VOC and HAPs, Phase II

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-09**

REQUIREMENTS FORM

2/16/05

Federal and State Requirements

This packet of forms, **GI-09 REQUIREMENTS**, will help you to determine the federal and state requirements with which your facility must comply. Be advised that you must include any applicable requirement that may not be addressed in this part of the application.

The first section of this form asks questions to find out if your facility is subject to specific federal and state regulations. To assist you in filling out this form, there are nine attachments, forms **GI-09A** through **GI-09I**. This form will direct you to each of the attachments as necessary, which will help you determine if your facility is subject to these regulations. When you are directed to an attachment, complete it as required, but *always* return to this **GI-09 REQUIREMENTS** form.

1) National Emission Standards for Hazardous Air Pollutants for Source Categories
(NESHAP for Source Categories, 40 C.F.R. pt. 63)

1a) To determine if any requirements for the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Source Categories (40 C.F.R. pt. 63) apply to your facility, you must complete attached form **GI-09A REQUIREMENTS: NESHAP FOR SOURCE CATEGORIES** (40 C.F.R. pt. 63).

1b) After completing form GI-09A, check one of the following boxes:
☐ YES, my facility **is currently** subject to NESHAP for Source Categories requirements.
☒ NO, my facility **is not currently** subject to NESHAP for Source Categories requirements.

1c) After completing form GI-09A, check one of the following boxes:
☐ YES, my facility **is** subject to requirements of case-by-case MACT under Section 112(g)(2)(B).
☒ NO, my facility **is not** subject to requirements of case-by-case MACT under Section 112(g)(2)(B).

2) National Emission Standards for Hazardous Air Pollutants
(NESHAP; 40 C.F.R. pt. 61)

2a) To determine if any of the National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 C.F.R. pt. 61) apply to your facility, you must complete the attached form **GI-09B REQUIREMENTS: NESHAP** (40 C.F.R. pt. 61).

2b) After completing item 2a, check one of the following boxes:
☐ YES, my facility **is** subject to NESHAP requirements.
☒ NO, my facility **is not** subject to NESHAP requirements.

3) **New Source Review** – Nonattainment and Prevention of Significant Deterioration
(NSR, New Source Review, 40 C.F.R. pt. 51 and 52)

3a) Did you construct, make any physical change to (as defined in 40 C.F.R. § 51.165 or 52.21) or change the method of operation of (as defined in 40 C.F.R. § 51.165 or 52.21) your facility since August 7, 1980?

☒ YES. Go to form **GI-09C REQUIREMENTS: NEW SOURCE REVIEW**.
☐ NO. Go to question 3b and answer NO.

3b) After completing the above question (and form GI-09C if necessary) check one of the following boxes:

☒ YES, my facility **is** subject to NSR requirements.
☐ NO, my facility **is not** subject to NSR requirements until I make a qualifying change.
☐ UNKNOWN. You may only check this box if directed to do so from **GI-09C REQUIREMENTS: NEW SOURCE REVIEW**.

4) **Prevention of Significant Deterioration: Increment**
(1990 Clean Air Act, as amended, Sections 109 and 160-169(B))

MPCA staff will advise on the applicability of this requirement after receipt of the application.

5) **Standards of Performance for New Stationary Sources**
(NSPS, New Source Performance Standards, 40 C.F.R. pt. 60)

5a) Is your facility a Sulfuric Acid Plant?

☒ NO.
☐ YES, you may be subject to this regulation; complete the attached form **GI-09D REQUIREMENTS: NSPS** (you may skip question 5b).

5b) Have you constructed, modified (as defined in 40 C.F.R. § 60.14), or reconstructed (as defined in 40 C.F.R. § 60.15) your emission facility, or any portion thereof, after August 17, 1971?

☐ NO.
☒ YES, you may be subject to this regulation. Complete the attached form **GI-09D REQUIREMENTS: NSPS**.

5c) If you answered NO to questions 5a and 5b your facility is not subject to federal NSPS requirements. Answer "NO" to question 5d.

5d) After completing the above questions (and the attachment if necessary) check one of the following boxes:

☒ YES, my facility (or a portion of it) **is** subject to NSPS requirements.
☐ NO, my facility **is not** subject to NSPS requirements.

6) Acid Rain Program under Title IV
(40 C.F.R. pt. 72, 40 C.F.R. pt. 73; and 1990 Clean Air Act, as amended, Sections 401-416)

6a) Is your facility one of the Phase I or Phase II units listed below?

☒ NO. Go to question 6b.
☐ YES. Go to question 6c and answer YES.

Austin Utilities:	Northeast Station		
Interstate Power:	Fox Lake		
Minnesota Power and Light:	Clay Boswell	M.L. Hibbard	Syl Laskin
Northern States Power:	High Bridge Sherburne County Na. 1 -- 7237	Minnesota Valley Allen S. King Future Base	Riverside Black Dog
Otter Tail Power:	Hoot Lake		
Rochester Public Utility:	Silver Lake		

6b) Does your facility combust fossil fuel and generate electricity for wholesale or retail sale, such as a cogeneration facility, a qualifying facility (as defined in the Federal Power Act), independent power producer, or solid waste incinerator?

☐ NO. Go to question 6c and answer NO.
☒ YES. Your facility may be subject to Acid Rain Requirements. Refer to the applicability definitions in 40 C.F.R. § 72.6 to find out if they apply.

6c) After completing question 6a and 6b, are you subject to Acid Rain Requirements?

☐ NO, my facility **is not** subject to Acid Rain Requirements.
☒ YES, my facility **is** subject to Acid Rain Requirements. Refer to Form **GI-09E REQUIREMENTS: ACID RAIN** for more information about applying for an acid rain permit.

7) Stratospheric Ozone Protection
(1990 Clean Air Act, as amended, Sections 601-618)

7a) To determine if this federal regulation applies to your facility, you must complete the attached form **GI-09F REQUIREMENTS: STRATOSPHERIC OZONE**.

7b) After completing form **GI-09F REQUIREMENTS: STRATOSPHERIC OZONE**, check one of the following boxes:

☐ YES, my facility **is** subject to this requirement.
☒ NO, my facility **is not** subject to this requirement.

8) **RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL RELEASE PREVENTION**(40 C.F.R. pt. 68, Section 112(r) of the Clean Air Act Amendments)

8a) Section 112(r) of the Clean Air Act requires facilities that produce, process, store or use any of the substances listed in form **GI-09G: RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL, RELEASE PREVENTION** (40 C.F.R. pt. 68), in amounts greater than the listed thresholds, to develop and implement a risk management plan for accidental releases.

8b) Determine if you produce, process, store or use any of the substances listed in form **GI-09G: RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL, RELEASE PREVENTION**, and check one of the following boxes:

☐ Yes, my facility **does** produce, process, store or use one or more of the substances listed in form **GI-09G**, in amounts exceeding the listed thresholds.

☒ No, my facility **does not** produce, process, store or use any of the substances listed in form **GI-09G**, in amounts exceeding the listed thresholds.

9) **Compliance Assurance Monitoring**
(CAM, 40 C.F.R. pt. 64)

9a) To determine if the CAM regulations apply to your facility, you must complete the attached form **GI-09H REQUIREMENTS: CAM**.

9b) After completing question 9a, above, check one of the following boxes:

☐ YES, my facility **is** subject to CAM requirements.

☒ NO, my facility **is not** subject to CAM requirements.

10) **Federal Ozone Measures for the Control of Emissions from Certain Sources**
(1990 Clean Air Act, as amended, Section 183(e))

10a) Rules have been promulgated under the above section of the Clean Air Act regulating VOCs from consumer or commercial products that emit volatile organic compounds. Does your facility manufacture: (check all that apply)

☐ Household consumer products containing VOCs

☐ Architectural coatings containing VOCs

☐ Autobody refinishing coatings containing VOCs

☒ My facility does not manufacture any of the above. Go to question 11).

10b) If you checked any boxes in question 10a) review the regulations at http://www.epa.gov/ttn/atw/183e/gen/183epg.html to determine whether your facility may be subject to any rules that are adopted under § 183(e) requiring emission reductions. After reviewing the regulations, check one of the following boxes.

☐ Yes, my facility is subject to consumer and commercial products regulation under section 183(e). Go to question 10c).

☐ No, my facility is not subject to consumer and commercial products regulation under section 183(e). Go to question 11).

10c) Check the box that best describes your source's compliance status with regards to applicable 183(e) requirements on the date of application, then go on to question 11).

☐ Compliance.

☐ Non-Compliance. Describe: _____

_____

_____

11) Minnesota State Air Quality Rules

11a) To determine which Minnesota State rules you may be subject to, go to form **GI-09I REQUIREMENTS: STATE RULES**.

11b) Whether permitted or not, **every business** and activity in Minnesota **is subject to the rules listed in the following table**:

Title of the Rule	Minnesota Rules (Chapter or Part)	What the Content of the Rule is:
Air Quality Emission Fees	Part 7002.0025 - 7002.0095	Requires facilities to pay emission fees every year within 60 days of MPCA billing.
Air Emission Permits	Parts 7007.0050 - 7007.1850	Outlines when an air emission permit is required and procedures for obtaining one.
Minnesota and National Ambient Air Quality Standards	Part 7009.0010 - 7009.0080	No one is allowed to emit any of the limited pollutants in such a manner that ambient levels of the pollutant are higher than the maximum level.
Applicability of Standards of Performance	Parts 7011.0010, and 7011.0050	Indicates that facilities must comply with all applicable state air pollution rules.
Circumvention	Part 7011.0020	States that no one may conceal or dilute emissions which would otherwise violate a federal or state air pollution control rule.
Emission Standards for Visible Air Contaminants	Part 7011.0100 - 7011.0120	Outlines restrictions against emitting opaque smoke from facilities.
Preventing Particulate Matter from Becoming Airborne	Part 7011.0150	States that no person shall cause particulate matter to become airborne if it can be avoided with listed preventative measures.
Continuous Monitors	Part 7017.1000	Outlines requirements for continuous monitoring systems.
Performance Tests	Part 7017.2001 - 7017.2060	Outlines procedures and methods for emissions and performance testing if required.
Notifications	Part 7019.1000	Requires facilities to notify the MPCA of shutdowns and breakdowns.
Reports	Part 7019.2000	Requires specific records and reports from facilities with continuous monitoring systems.
Emission Inventory	Part 7019.3000 - 7019.3100	Requires facilities to submit an Emission Inventory Report by April 1 every year.
Motor Vehicles	Part 7023.0100 - 7023.0120	Outlines restrictions against emitting opaque smoke from motor vehicles, trains, boats, construction equipment and stationary internal combustion engines.
Noise Pollution Control	Part 7030.0010 - 7030.0080	Sets noise standards which cannot be exceeded.

12) You have completed the Applicable Requirements form.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-09A**

REQUIREMENTS: NESHAP FOR SOURCE CATEGORIES (40 C.F.R. pt. 63)

02/17/05

National Emission Standards for Hazardous Air Pollutants for source categories
(NESHAP for Source Categories, 40 C.F.R. pt. 63)

1) Read through Table A, the list of Hazardous Air Pollutants (HAP) and check one of the following:

☐ No, my facility **does not currently** emit any pollutants from the list, and therefore is not subject to the requirements for NESHAP for Source Categories. Go to question 7.

☒ Yes, my facility **does** emit one or more pollutants from the list. Go on to question 2a.

2a) Does your source have the potential to emit 10 tons per year or more of any single pollutant listed in Table A?

☐ Yes, my facility is a major source of HAP emissions. Go to question 3.

☒ No. Go to question 2b.

2b) Does your source have the potential to emit 25 tons per year or more of any combination of pollutants listed in Table A?

☐ Yes, my facility is a major source of HAP emissions. Go to question 3.

☒ No. Go to question 6.

3) If you answered yes to question 2a or 2b, it may be possible to avoid the requirements associated with being a major source of HAP emissions. If the **actual emissions** of HAPs from your facility will not exceed 10 tons per year of a single HAP or 25 tons per year of all HAPs combined during each of the next five years, you may propose federally enforceable permit conditions to limit your potential HAP emissions to less than 10 tons per year for each HAP and/or 25 tons per year for all HAPs combined. Do you want to accept permit limitations on HAPs to avoid being a major source of HAPs?

☐ No. Go to question 4.

☐ Yes. Briefly describe the limitations you would be willing to accept and abide by in your permit so that your HAP emissions will not exceed 10 tons per year for each HAP and 25 tons per year for all HAPs combined (use separate sheet if needed). Description must include each of the HAP pollutants. Refer to the Application General Instructions for guidance in establishing these limitations, and include your proposed limit, monitoring, recordkeeping, and reporting on Form CD-01. Your facility may be subject to NESHAP for Source Categories requirements until you receive a federally enforceable permit limiting your facility's HAP emissions to a nonmajor source. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1b. To determine whether your facility is subject to NESHAP for nonmajor sources, go to question 6.

4) The attached Table D is a list of NESHAP for Source Categories and important dates associated with each of them. Does your facility have any equipment that fits any of the source categories listed?

☐ No. Go to question 6.
☐ Yes. List all the source categories applicable to your facility, and the associated dates shown in Table D.

_____

_____

_____

_____

_____

5) If you answered no to question 3 **and** yes to question 4, please read all applicable sections of 40 C.F.R. pt. 63 to determine all applicable requirements in each of the NESHAP for Source Categories. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1b.

6) If your source has any equipment that belongs to the following area source categories, place a check in the box next to that category and read the specified NESHAP for Source Categories to determine all applicable requirements for area sources. The rules for these source categories may apply whether or not your facility is considered a major source for hazardous air pollutants. If you check one or more boxes below, you must answer "YES" to question 1b when you return to form **GI-09 Requirements**. Go on to question 7.

☐ Hard and Decorative Chromium Electroplating (40 C.F.R. pt. 63, subp. N)
☐ Chromium Anodizing Tanks (40 C.F.R. pt. 63, subp. N)
☐ Ethylene Oxide Commercial Sterilization and Fumigation Operations (40 C.F.R. pt. 63, subp. O)
☐ Perchloroethylene Dry Cleaning Facilities (40 C.F.R. pt. 63, subp. M)
☐ Secondary Lead Smelting Facilities (40 C.F.R. pt. 63, subp. X)
☐ Halogenated Solvent Degreasers (40 C.F.R. pt. 63, subp. T)

7) Does this permit application seek authorization to construct or reconstruct a major source of HAP (10 TPY or more of any pollutant listed on Table A, or 25 TPY or more of any combination of pollutants listed in Table A)?

☐ Yes. Go on to question 8.
☒ No. Return to form **GI-09 Requirements** and answer "NO" to question 1c.

8) Is your proposed project subject to any of the promulgated standards as listed in Table D?

☐ Yes, my facility is subject to the preconstruction review requirements under its MACT standard and to the General Provisions of the MACT standard. Return to form **GI-09 Requirements** and answer "YES" to question 1b and "NO" to question 1c.
☐ No, my facility may be subject to preconstruction review requirements under section 112(g)(2)(B). Go to question 9.

9) If you answered "No" to question 8, it may be possible to avoid the section 112(g)(2)(B) requirement of performing a case-by-case MACT determination for your proposed project by proposing a federally enforceable permit conditions to limit your potential HAP emissions to less than 10 tons per year for each HAP and/or 25 tons per year for all HAPs combined from the new proposed project. Do you want to accept permit limitations on HAPs to avoid the section 112(g)(2)(B) requirement?

☐ No. Go to question 10.

☐ Yes. Briefly describe the limitations you would be willing to accept and abide by in your permit so that your HAP emissions will not exceed 10 tons per year for each HAP and 25 tons per year for all HAPs combined (use separate sheet if needed). Description must include all the HAP pollutants. Refer to the Application General Instructions for guidance in establishing these limitations, and include your proposed limit, monitoring, recordkeeping, and reporting on Form CD-01. Your facility may be subject to NESHAP for Source Categories requirements until you receive a federally enforceable permit limiting your facility's HAP emissions from the proposed project to below the major source thresholds. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1c.

_____

_____

_____

_____

_____

_____

_____

10) If you answered "No" to question 8 **and** "No" to question 9, please read 40 C.F.R. § 63.43 to 63.44 to determine all applicable requirements, including application requirements for a case-by-case MACT determination and what is required for your facility when a subsequent MACT standard for your facility is promulgated. When you return to form **GI-09 Requirements**, you must answer "YES" to question 1c.

11) Return to form **GI-09 Requirements**, and answer questions 1b and 1c using the above information.

Minnesota Pollution Control Agency

AIR QUALITY
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PERMIT APPLICATION FORM **GI-09B**

REQUIREMENTS: NESHAP (40 C.F.R. pt. 61)

05/11/98

National Emission Standards for Hazardous Air Pollutants
(NESHAP, 40 C.F.R. pt. 61)

1) Part 61 NESHAPs were the regulations in existence before the 1990 Clean Air Act Amendments. They apply only to air emission sources listed in Table C (attached) that emit the pollutants listed. Table C contains:

- a pollutant;
- a facility description;
- a Minnesota Rules reference;
- a Code of Federal Regulation 40 part 61 (40 C.F.R. pt. 61) subpart reference.

2) Read through Table C. If your facility emits any of the listed pollutants, and your facility type, process or equipment matches those associated with the pollutant, a NESHAP may apply to you. To determine if a standard applies to your facility, refer to the corresponding 40 C.F.R. pt. 61 subpart(s) and Minnesota Rules listed and read the requirements in detail.

3) After reviewing the NESHAP reference list and reading the corresponding 40 C.F.R. pt. 61 subpart(s) check one of the following boxes:

☒ NO, my facility **is not** subject to NESHAP requirements. Return to form **GI-09 Requirements**, and answer "NO" to question 2b.

☐ YES, my facility (or a portion of it) **is** subject to NESHAP requirements. Answer "YES" to question 2b when you return to form **GI-09 Requirements**.

If you have determined that your facility must comply with federal NESHAP requirements, you are also subject to state NESHAP requirements. Minn. R. ch. 7011 lists Minnesota State NESHAP requirements.

4) Check and complete the following questions (4a, 4b, and 4c). Some NESHAPs apply to an entire mine, plant or shop. Others apply to specific units, like a reactor, valve or vessel. If you check 4c, you must complete a group of questions for each emission unit subject to a NESHAP. Attach additional pages as necessary to identify all emission units subject to NESHAP at your facility. Photocopy each 40 C.F.R. pt. 61 subpart you have listed (*except* the Asbestos NESHAP), ***highlight*** the portions of the subpart that directly applies to your facility, and attach the copies to this application form.

4a) ☐ My business is only subject to the NESHAP for the Demolition and Renovation of Asbestos containing structures identified in 40 C.F.R. § 61.145; I do not need an Air Emission Permit. I have contacted the MN Department of Health and the asbestos team at the MN Pollution Control Agency regarding any renovation or demolition projects and have obtained an asbestos abatement permit if necessary. (For more information refer to Minn. Rules 7007.0300, subp. 1.C.)

4b) ☐ My entire facility is subject to NESHAP requirements.

Describe Emission Facility _____
Date of Facility Construction _____
Applicable 40 C.F.R. pt. 61 subparts(s) _____
Applicable Minnesota State Rule Reference _____
Has this Source Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number

4c) ☐ My facility has one or more emission unit(s) subject to NESHAP requirements. Provide the information requested below for each unit that is subject to a NESHAP.

Describe Emission Equipment _____
Emission Unit Number _____
Stack/Vent Number _____
Date of Original Equipment Installation _____ (Month/Date/Year)
Applicable 40 C.F.R. pt. 61 subpart(s) _____
Applicable Minnesota State Rule Reference _____
Has this Unit Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number _____

Describe Emission Equipment _____
Emission Unit Number _____
Stack/Vent Number _____
Date of Original Equipment Installation _____ (Month/Date/Year)
Applicable 40 C.F.R. pt. 61 subpart(s) _____
Applicable Minnesota State Rule Reference _____
Has this Unit Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number _____

Describe Emission Equipment _____
Emission Unit Number _____
Stack/Vent Number _____
Date of Original Equipment Installation _____ (Month/Date/Year)
Applicable 40 C.F.R. pt. 61 subpart(s) _____
Applicable Minnesota State Rule Reference _____
Has this Unit Been Permitted Previously?
☐ NO
☐ YES, list Air Emission Permit Number _____

5) Return to form **GI-09 Requirements**, question 2b.

TABLE C
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

POLLUTANT	FACILITY OR EMISSION UNIT TYPE	MINN RULES	40 C.F.R. 61 SUBPART
RADON	Underground Uranium Mines; Department of Energy Facilities; Phosphorus Fertilizer Plants; and Facilities Processing or Disposing of Uranium Ore and Tailings	7011.9960	B, Q, R, T, W
BERYLLIUM	Beryllium Extraction Plants; Ceramic Plants, Foundries, Incinerators, Propellant Plants, and Machine Shops that Process Beryllium Containing Material; and Rocket Motor Firing Test Sites	7011.9940 - 7011.9945	C, D
MERCURY	Mercury Ore Processing; Manufacturing Processes Using Mercury Chloralkali Cells; and Sludge Incinerators	7011.9950 - 7011.9955	E
VINYL CHLORIDE	Ethylene Dichloride Manufacturing Via Oxygen, HCl and Ethylene; Vinyl Chloride Manufacturing; and Polyvinyl Chloride Manufacturing	7011.9980	F
RADIO-NUCLIDES	Department of Energy; Nuclear Regulatory Commission Licensed Facilities; Other Federal Facilities; and Elemental Phosphorus Plants	7011.9970	H, I, K
BENZENE	Fugitive Process, Storage, and Transfer Equipment Leaks; Coke By-Product Recovery Plants; Benzene Storage Vessels; Benzene Transfer Operations; and Benzene Waste Operations	7011.9930	J, L, Y, BB, FF
ASBESTOS*	Asbestos Mills; Roadway Surfacing with Asbestos Tailings; Manufacture of Products Containing Asbestos; Demolition; Renovation; and Spraying and Disposal of Asbestos Waste	7011.9920 - 7011.9927	M
INORGANIC ARSENIC	Glass Manufacturer; Primary Copper Smelter; Arsenic Trioxide and Metallic Arsenic Production Facilities	7011.9910	N, O, P
VOLATILE HAZARDOUS AIR POLLUTANTS (VHAP)	Pumps, Compressors, Pressure Relief Devices, Connections, Valves, Lines, Flanges, Product Accumulator Vessels, etc. in VHAP Service (As of 11/30/94 only vinyl chloride and benzene are regulated by 40 C.F.R. 61, subp. V)	7011.9990	V

*If you are only subject to 40 C.F.R. §61.145 (subp. M Standard for Demolition and Renovation), because you are doing asbestos abatement, you do not need a Minnesota Air Emission Permit, but you must contact the Minnesota Department of Health at (612) 627-5097 and the asbestos team at the Minnesota Pollution Control Agency at (651) 297-8685 before beginning any abatement activity.

Minnesota Pollution Control Agency

AIR QUALITY
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PERMIT APPLICATION FORM **GI-09C**

REQUIREMENTS:
NEW SOURCE REVIEW (40 C.F.R. pt. 52)

05/11/98

New Source Review
(NSR; 40 C.F.R. pt. 52)

Throughout this form you are asked for the Potential to Emit (PTE) of your facility or of changes to your facility. The PTE values in most cases are defined as the maximum uncontrolled PTE of the emission facility. In some cases, PTE calculations may reflect factors such as control equipment or permit limitations, but **ONLY** if proof is given that such factors were provisions of a federally enforceable permit issued to the facility.

New Source Review (NSR) regulations may apply to modifications to existing facilities or for the construction of a new facility. There are two kinds of review: one for nonattainment areas and one for attainment areas. For a nonattainment pollutant, if the potential to emit is more than 100 tons per year, New Source Review could apply. For attainment areas, the threshold is 100 or 250 tons per year depending on the type of facility.

This form is rather complex, but addresses a complicated regulatory program. Each item is intended to assist you in the process of determining applicability as easily and quickly as possible. Items 1-3 will help you determine the threshold -- a federally established pollutant level -- for your facility. The next two items, 4 and 5, determine if, based on your current PTE, you are considered a major stationary source. If your facility is not a major source now, item 6 asks if it was major in the past. Item 7 determines if you can accept "synthetic minor" limitations, while item 8 requires you to specify what these limitations would be.

It may be possible for sources that were major to become synthetic minor facilities. Items 9-10 are basic criteria questions that need to be answered. Sources who wish to pursue this option will need to work closely with MPCA staff to determine if the facility does qualify for the synthetic minor status. Items 11, 12, and 13 determine if you constructed a major facility. Item 14 requires a description of each change (physical or operational) made at your facility after it actually began emitting pollutants at a rate higher than your threshold. A detailed description is required for each change, including dates and emission levels through today. If necessary and/or allowed, item 14f requires you to specify "synthetic minor" limitations for just the change. Item 14 must be filled out separately for each change made, requiring duplication of those two pages. Item 15 directs specific sources to contact the MPCA for further guidance.

1) Is your facility defined as one of the following, (Some SIC Code(s) applying to specific categories are given in parentheses):

Coal Cleaning Plants-With Thermal Dryers	Kraft Pulp Mills (2611, 2621)
Portland Cement Plants (3241)	Primary Zinc Smelters (3339)
Iron and Steel Mills (332X)	Primary Aluminum Ore Reduction Plants (3334)
Primary Copper Smelters (3331)	Municipal Incinerators Capable of Charging More Than 250 Tons of Refuse per Day
Hydrofluoric Acid Plants (2819, 2899)	Sulfuric Acid Plants (2819)
Nitric Acid Plants (2873)	Petroleum Refineries (2911)
Lime Plants (3274)	Phosphate Rock Processing Plants (1475)
Coke Oven Batteries (3312)	Sulfur Recovery Plants (2819)
Carbon Black Plants (Furnace Process, 2895)	Primary Lead Smelters (3339)
Fuel Conversion Plants	Sintering Plants*
Secondary Metal Production Plants (334X)	Chemical Process Plants (28XX)
Fossil-Fuel Boilers (or combination thereof) totaling more than 250 MMBtu/hr	Petroleum Storage & Transfer Units, Total Storage Capacity over 300,000 Barrels
Taconite Ore Processing Plants (1011)	Glass Fiber Processing Plants
Charcoal Production Plants (2819, 2861)	Fossil Fuel-Fired Steam Electric Plants of more than 250 MMBtu/hr

* Processing of fine grain materials into coarser lumps (performed primarily on ores).

☐ NO, my facility is not classified as one of the 28 sources listed above. Go to item 2.

☒ YES, my facility is classified as one of the 28 sources listed above. An air emission source having PTE (potential to emit) more than 100 TPY (tons per year) of any single regulated pollutant is considered a major stationary source. **For the rest of this form, 100 TPY is the threshold you must use in answering the questions**. Go to item 4.

2) Is your facility located in a nonattainment area (see form **GI-01 Facility Information**, question 14)?

☐ NO. Go to item 3.

☐ YES. Check all of the following pollutants that apply:

☐ PM_{10} ☐ SO_2 ☐ CO

An air emission source having the potential to emit more than 100 TPY of any pollutant(s) checked above, or 250 TPY of any single regulated pollutant not checked above is considered a major stationary source. **For the rest of this form, 100 TPY is the threshold for any pollutant(s) checked above, and 250 TPY is the threshold for the remaining regulated pollutants. You must use these values in answering the remaining questions**. Go to item 4.

3) I answered NO to items 1 and 2; my facility is not one of the 28 sources listed and my facility is not located in a non-attainment area. An air emission source having the potential to emit of more than 250 TPY of any single regulated pollutant is considered a major stationary source. **For the rest of this form, 250 TPY is the threshold you must use in answering the questions.**

4) In the boxes below, enter the current PTE (in tons per year) of your entire facility under each regulated pollutant. ("Current PTE" means the PTE of your facility prior to receiving the permit for which you are now applying.)

PM_{10}	PM (includes PM_{10})	SO_2	NO_X	VOC	CO	Pb	Fluorides

Sulfuric Acid Mist	H_2S	Total reduced sulfur (includes H_2S)	Reduced sulfur compounds (includes H_2S)	MWC organics	MWC metals	MWC acid gases	MSW landfill gases	Ozone-depleting substances

5) Is the current PTE of your facility above the 100/250 TPY threshold for your facility, making your facility a major stationary source?

☐ YES. My facility is currently considered a major stationary source, go to question 7.
☐ NO. Go to question 6.

6) Since August 7, 1980, has the PTE of your facility ever exceeded your 100/250 TPY threshold value?

☐ YES. Go to question 7.
☐ NO. My facility is not subject to NSR until I make a qualifying change. Return to form **GI-09 Requirements** and answer "NO" to question 3b.

[Note: If you do not know what the PTE of your facility has been in the past, it is sufficient for the purposes of **this question only** to use the following formula to ***roughly estimate*** PTE:

(8760 hours/year) x (actual emissions of a pollutant for a given year in tons/year)/(the number of hours of operation for that year).

Again, **this formula cannot be used for any other purpose.** This is only a screening test, it does not represent the required PTE calculation method for air permitting.

7) Since August 7, 1980, have the **actual emissions** from your facility ever exceeded the 100/250 TPY threshold value for your facility?

☐ YES. Go to item 9.
☐ NO. My facility is allowed to accept federally enforceable permit limitations to limit potential emissions to less than a major source (below the threshold). Go to question 8.

8) The **actual emissions** from your facility have never exceeded the 100/250 TPY threshold established for your facility. Would you be willing to accept federally enforceable permit limitations to limit potential emissions from your facility to less than the 100/250 TPY threshold?

☐ NO. Go to item 11.

☐ YES. You are required to specify limitations (called synthetic minor limits) for your facility. These limitations will limit your air emissions. This will be dependent on your emission sources and can have some flexibility. Briefly describe what limitations you would be willing to accept and abide by. Refer to the Application General Instructions for guidance in establishing these limitations. Include the specific limits, monitoring, recordkeeping, and reporting on Form CD-01.

_____

_____

_____

_____

_____

_____

(DUPLICATE THIS FORM OR ADD EXTRA PAGES AS NEEDED)

Return to form **GI-09 Requirements**, question 3b, and check Unknown.

9) Have you removed any equipment from your facility since the **actual emissions** exceeded the 100/250 TPY threshold?

☐ NO. Go to question 11.

☐ YES. Go to question 10.

10) Have the actual emissions from the facility remained under the 100/250 TPY threshold for the last two years?

☐ NO. Go to question 11.

☐ YES. It may be possible to obtain a synthetic minor permit for your facility. **Complete the remaining items in this form and contact the MPCA for further guidance as listed in item 15.**

11) Did you construct your facility after August 7, 1980?

☐ NO. Go to question 14.

☐ YES, construction on my facility began on (date) _____. The PTE of my facility (in tons per year) when constructed was:

PM_{10}	**PM (includes PM_{10})**	**SO_2**	**NO_X**	**VOC**	**CO**	**Pb**	**Fluorides**

Sulfuric Acid Mist	**H_2S**	**Total reduced sulfur (includes H_2S)**	**Reduced sulfur compounds (includes H_2S)**	**MWC organics**	**MWC metals**	**MWC acid gases**	**MSW landfill gases**	**Ozone-depleting substances**

12) Are any of the PTE values entered in question 11 greater than the 100/250 TPY threshold for your facility?

☐ NO. Go to question 14.

☐ YES. Go to question 13**.**

13) Have the actual emissions for the operations installed during the facility's construction ever exceeded the 100/250 TPY threshold for any year after the construction date?

☐ NO. Go to question 14.

☐ YES. My facility was a major source when it was constructed. If a BACT/LAER analysis **was not** done at the time of construction, the facility may be subject to backward looking NSR (if the analysis was not done at the time of construction but has been done since, it may not be necessary to repeat it). Contact the Permit Technical Advisor at (651)282-5844 or (800)646-6247 for additional guidance. Go to question 14**.**

14) NSR groups changes made during the same budget or planning period as a single modification. This means that changes need to be grouped together based on budgeting or planning periods and evaluated as one modification to determine if NSR/PSD applies to the changes that have been made.

Items 14a through 14g need to be completed for each modification made at your facility, through the current date (include any modifications you are proposing in this application, too). Begin with the first modification after the PTE of your facility exceeded the 100/250 TPY threshold or the first modification made after August 7, 1980, whichever is later. DO NOT INCLUDE modifications which were authorized by a permit from the MPCA. Duplicate and add additional pages as necessary. (Note: if your facility was under the 100/250 TPY threshold and the first modification you made was over 100/250 TPY, provide the information listed in items 14a, b, c, d, e, and f on a separate sheet of paper.) If you have not modified your facility since meeting the 100/250 TPY threshold, go to form **GI-09 Requirements**, question 3b, and answer "NO."

14a) Describe the physical change in or change in method of operation to your facility:
Construction of Mesaba One and Mesaba Two is subject of this permit application.

14b) In what year(s) did the modification occur? **Construction of Mesaba One will commence in the 1st quarter of 2008; construction of Mesaba Two will commence in 2010.**

14c) List the potential emissions increase (in tons per year) of each pollutant for this modification.

PM_{10}	PM (includes PM_{10})	SO_2	NO_X	VOC	CO	Pb	Fluorides
493	503	1250	2872	197	2539	0.028	

Sulfuric Acid Mist	H_2S	Total reduced sulfur (includes H_2S)	Reduced sulfur compounds (includes H_2S)	MWC organics	MWC metals	MWC acid gases	MSW landfill gases	Ozone-depleting substances
126	17	20						

NOTE; SO_2 is decreased based on conversion to H_2SO_4. Other tables assume 1390 TPY SO_2. PM_{10} includes sulfuric acid mist. Emissions reflect Mesaba One and Mesaba Two.

14d) Are the values you entered in item 14c for this modification greater than the values listed in item 14e for each regulated pollutant?

☐ NO. This was a minor change, go to question 14g.

☒ YES. Go to question 14e.

14e) Beginning with the year entered in item 14b through the current date, did the actual emissions of regulated pollutants resulting only from this modification ever exceed the values listed in the following table?

Pollutant	Threshold (tons/year)	Effective Date
PM_{10}	15	July 31, 1987
PM	25	August 7, 1980
SO_2	40	August 7, 1980
NO_X	40	August 7, 1980
VOC	40	August 7, 1980
CO	100	August 7, 1990
Pb	0.6	August 7, 1980
Fluorides	3	August 7, 1980
Sulfuric Acid Mist	7	August 7,. 1980
H_2S	10	August 7, 1980
Total reduced sulfur	10	August 7, 1980
Reduced sulfur compounds	10	August 7, 1980
MWC organics	3.5×10^{-6}	August 12, 1991
MWC metals	15	August 12, 1991
MWC acid gases	40	August 12, 1991
MSW landfill gases	50	March 12, 1996
Ozone depleting substances	100	March 19, 1998 (EPA memo)

☐ YES. This modification is subject to backward looking NSR, unless a BACT/LAER analysis was done at the time of modification. (If analysis was not done at the time of modification, but has been done since then, it may not be necessary to repeat it.) Contact the Permit Technical Advisor at (651)282-5844 or (800)646-6247 for additional guidance.

☒ NO. Go to question 14f.

14f) The actual emissions from this modification have never exceeded the levels listed in item 14e. Are you willing to accept federally enforceable permit limitations to limit the potential emissions increase of the modification to less than those levels?

☒ NO. Go to item 14g. **Emissions for Mesaba One and Mesaba Two will not commence until 2010 and 2012/2013, respectively.**

☐ YES. You are required to specify limitations (called "synthetic minor" limits) for this change. These limits will limit your air emissions to below the levels listed in item 14e. This will be dependent on your emissions sources and can have some flexibility. Briefly describe what limitations you would be willing to accept and abide by. Refer to the Application General Instructions for guidance in establishing these limitations. Include the specific limits, monitoring, recordkeeping, and reporting on Form CD-01.

(DUPLICATE THIS FORM OR ADD EXTRA PAGES AS NEEDED)

Go to item 14g.

14g) Repeat item 14 until each non-permitted physical change or change in method of operation to your facility has been identified, duplicating item 14 as necessary.

15) It may be possible to accept synthetic minor permit limitations if your actuals have exceeded the threshold levels, if you have removed equipment and the actual emissions for the last two calendar years of operation have remained under the threshold levels. You should contact the MPCA for more guidance on whether your facility qualifies for synthetic minor limitations.

If you have triggered NSR/PSD levels and cannot or choose not to accept synthetic minor limitations, you need to check YES to question 3b on **Form GI-09 Requirements**. If your facility has received permits for modifications or completed NSR/PSD reviews as requested by the MPCA, you should work with MPCA staff to determine the compliance status of your facility regarding NSR/PSD and establishing limits.

Minnesota Pollution Control Agency

AIR QUALITY
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ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-09D**

REQUIREMENTS: NSPS (40 C.F.R. pt. 60)

05/11/05

Standards of Performance for New Stationary Sources
(NSPS, New Source Performance Standards, 40 C.F.R. pt. 60)

1) NSPS are federal rules that define limits, testing and monitoring for certain specific emission units. These standards are proposed and promulgated in the Federal Register and published in the Code of Federal Regulations, title 40 part 60 (40 C.F.R. pt. 60). Table D lists the standards promulgated through April 1998. Table D may not be complete if a new NSPS has been promulgated since this form was last revised. The table contains:

- a brief emission source description;
- a corresponding 40 C.F.R. pt. 60 subpart reference;
- an effective date for all performance standards promulgated as of April 1998.

[Please note: the best way to keep up-to-date on NSPS regulations is through the EPA's Web page (www.epa.gov) or the Federal Register since there can be a significant time lag between the date when a standard is proposed or promulgated and when it is finally published in the Code of Federal Regulations.]

2) Please read through the emission sources in Table D. If you have modified (as defined in 40 C.F.R. § 60.14), reconstructed (as defined in 40 C.F.R. § 60.15) or constructed the described emission source on or after the effective date listed in the table, your facility may be subject to the requirements of 40 C.F.R. pt. 60. Generally, reconstruction means that the cost of a repair exceeds 50 percent of what it would cost to install a new emission unit. If you have had an extensive and expensive repair, it may count as a reconstruction.

If you know or suspect standards may apply to your facility you must refer to the corresponding 40 C.F.R. pt. 60 subpart and read the requirements in detail to make a final determination. Note: the general provisions found in 40 C.F.R. pt. 60, subp. A, apply to <u>all</u> facilities subject to any other NSPS requirements.

3) After you review the list of sources subject to NSPS and read any applicable 40 C.F.R. pt. 60 subparts, check one of the following boxes:

☐ NO, my facility is not subject to NSPS. Return to Form **GI-09 Requirements**, and answer "NO" to question 5d.

☒ YES, my facility is subject to NSPS.

4) The following page lists information needed to identify your facility's emission sources subject to NSPS. Complete the group of questions for all emission equipment subject to NSPS, attaching additional pages if necessary. Photocopy each 40 C.F.R. pt. 60 subpart you have listed and highlight the portions of each subpart that directly apply to your facility, including the general provisions found in Subpart A. Attach the copies to this application form.

The MPCA has reprinted Subpart A and some additional NSPS regulations from the *Code of Federal Regulations*. The available regulations are starred in Table D. To obtain copies, contact the Permit Document Coordinator at (651)282-5843.

5) Return to Form **GI-09 Requirements**, and answer "YES" to question 5d.

Describe Emission Equipment	Mesaba One and Mesaba Two CTG	
Emission Unit Number	001, 002, 010, 011	
Stack/Vent Number	001, 002, 013, 014	
Date of Equipment Manufacture		(Month/Date/Year)
Date of Equipment Installation	Construction start Q1 2008	(Month/Date/Year)
Date of Reconstruction (if applicable)		(Month/Date/Year)
Date of Modification (if applicable)		(Month/Date/Year)
Applicable 40 C.F.R. pt. 60 subpart or Federal Register Reference	70 FR 9706, 2/28/05 Proposed Revisions to NSPS Subpart Da	

This source is also subject to the general provisions of 40 C.F.R. pt. 60, subp. A.

Has this Unit Been Permitted Previously?

- ☒ NO
- ☐ YES, list Air Emission Permit Number

Have you attached a photocopied, highlighted version of the 40 C.F.R. pt. 60 subpart?

- ☒ YES
- ☐ NO

Describe Emission Equipment	Mesaba One and Mesaba Two Auxiliary Boilers	
Emission Unit Number	003, 012	
Stack/Vent Number	003, 015	
Date of Equipment Manufacture		(Month/Date/Year)
Date of Equipment Installation	Construction start Q1 2008	(Month/Date/Year)
Date of Reconstruction (if applicable)		(Month/Date/Year)
Date of Modification (if applicable)		(Month/Date/Year)
Applicable 40 C.F.R. pt. 60 subpart or Federal Register Reference	Subpart Db	

This source is also subject to the general provisions of 40 C.F.R. pt. 60, subp. A.

Has this Unit Been Permitted Previously?

- ☒ NO
- ☐ YES, list Air Emission Permit Number

Have you attached a photocopied, highlighted version of the 40 C.F.R. pt. 60 subpart?

- ☒ YES
- ☐ NO

Describe Emission Equipment	Mesaba One and Mesaba Two Tank Vent Boiler	
Emission Unit Number	CE-001, CE-004	
Stack/Vent Number	010, 022	
Date of Equipment Manufacture		(Month/Date/Year)
Date of Equipment Installation	Construction start Q1 2008	(Month/Date/Year)
Date of Reconstruction (if applicable)		(Month/Date/Year)
Date of Modification (if applicable)		(Month/Date/Year)
Applicable 40 C.F.R. pt. 60 subpart or Federal Register Reference	Subpart Dc	

This source is also subject to the general provisions of 40 C.F.R. pt. 60, subp. A.

Has this Unit Been Permitted Previously?

- ☒ NO
- ☐ YES, list Air Emission Permit Number

Have you attached a photocopied, highlighted version of the 40 C.F.R. pt. 60 subpart?

- ☒ YES
- ☐ NO

DUPLICATE THIS FORM AS NEEDED

TABLE D
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Performance standards promulgated as of October 20, 2003		
Source categories subject to federal performance standards	**40 C.F.R. 60 Subpart**	**Effective date constructed, modified or reconstructed**
Fossil-Fuel Fired Steam Generators >250 MMBtu	D	After: 08/17/71
Electric Utility Steam Generators >250 MMBtu	Da	After: 09/18/78
Industrial-Commercial-Institutional Steam Generators >100 MMBtu	Db	After: 06/19/84
Small Industrial-Commercial-Institutional Steam Generators >10 MMBtu but <100 MMBtu	Dc	After: 06/09/89
Incinerators	E, CCCC, DDDD	varies
Hospital/Medical/Infectious Waste Incinerators	Ec, Ce	Initial Construction
Municipal Waste Combustors	Cb, Ea, Eb, AAAA, BBBB	varies
Portland Cement Plants	F	After: 08/17/71
Nitric Acid Plants	G	After: 08/17/71
Sulfuric Acid Plants	H, Cd	Initial Construction
Asphalt Concrete Plants	I	After: 06/11/73
Petroleum Refineries	J	After: 06/11/73
Storage Vessels for Petroleum Liquids	K, Ka	After: 06/11/73
Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids)	Kb	After: 07/23/84
Secondary Lead Smelters	L	After: 06/11/73
Secondary Brass and Bronze Production Plants	M	After: 06/11/73
Oxygen Process Furnaces	N	After: 06/11/73
Oxygen Process Steelmaking Facilities	Na	After: 01/20/83
Sewage Treatment Plants	O	After: 06/11/73
Primary Copper Smelters	P	After: 10/16/74
Primary Zinc Smelters	Q	After: 10/16/74
Primary Lead Smelters	R	After: 10/16/74
Primary Aluminum Reduction Plants	S	After: 10/23/74
Phosphate Fertilizer Industry	T,U,V,W,X	After: 10/22/74
Coal Preparation Plants	Y	After: 10/24/74
Ferroalloy Production Facilities	Z	After: 10/24/74
Steel Plants	AA, AAa	After: 10/21/74
Kraft Pulp Mills	BB	After: 09/24/76
Glass Manufacturing Plants	CC	After: 06/15/79
Grain Elevators	DD	After: 08/03/78
Surface Coating of Metal Furniture	EE	After: 11/28/80
Stationary Gas Turbines	GG	After: 10/03/77
Lime Manufacturing Plants	HH	After: 05/03/77
Lead-Acid Battery Manufacturing Plants	KK	After: 01/14/80
Metallic Mineral Processing Plants	LL	After: 08/24/82
Automobile and Light-Duty Truck Surface Coating Operations	MM	After: 10/05/79

Table 1, continued

Source categories subject to federal performance standards	40 C.F.R. 60 Subpart	Effective date constructed, modified or reconstructed
Phosphate Rock Plants	NN	After: 09/21/79
Ammonium Sulfate Manufacture	PP	After: 02/04/80
Graphic Arts Industry: Publication Rotogravure Printing	QQ	After: 08/28/80
Pressure Sensitive Tape and Label Surface Coating Operations	RR	After: 12/30/80
Industrial Surface Coating: Large Appliances	SS	After: 12/24/80
Metal Coil Surface Coating	TT	After: 01/05/81
Asphalt Processing and Asphalt Roofing Manufacture	UU	After: 11/18/80
Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	VV	After: 01/05/81
Beverage Can Surface Coating Industry	WW	After: 11/26/80
Bulk Gasoline Terminals	XX	After: 12/17/80
New Residential Wood Heaters *	AAA	After: 07/01/88
Rubber Tire Manufacturing Industry	BBB	After: 01/20/83
VOC Emissions from the Polymer Manufacturing Industry	DDD	After: 09/30/87
Flexible Vinyl and Urethane Coating and Printing	FFF	After: 01/18/83
Equipment Leaks of VOC in Petroleum Refineries	GGG	After: 01/04/83
Synthetic Fiber Production Facilities	HHH	After: 11/23/82
VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes	III	After: 10/21/83
Petroleum Dry Cleaners	JJJ	After: 12/14/82
Onshore Natural Gas Processing: VOC Equipment Leaks and SO_2 Emissions	KKK, LLL	After: 01/20/84
VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations	NNN	After: 12/30/83
Nonmetallic Mineral Processing Plants (Including Sand and Gravel Processing)	OOO	After: 08/31/83
Wool Fiberglass Insulation Manufacturing Plants	PPP	After: 02/07/84
VOC Emissions from Petroleum Refinery Wastewater Systems	QQQ	After: 05/04/87
VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	RRR	After: 06/29/90
Magnetic Tape Coating Facilities	SSS	After: 01/22/86
Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	TTT	After: 01/08/86
Calciners and Dryers in Mineral Industries	UUU	After: 04/23/86
Polymeric Coating of Supporting Substrates Facilities	VVV	After: 04/30/87
Municipal Solid Waste Landfills	WWW, Cc	Initial Construction

** According to Minn. Rules Pt. 7007.0300, subp. 1(B), "any stationary source that would be required to obtain a permit solely because it is subject to Code of Federal Regulations, title 40, part 60, subp. AAA" is exempt from permitting.

Minnesota Pollution Control Agency

AIR QUALITY
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PERMIT APPLICATION FORM **GI-09G**

REQUIREMENTS: RISK MANAGEMENT PROGRAMS FOR CHEMICAL ACCIDENTAL RELEASE PREVENTION (40 C.F.R. pt. 68)

05/11/98

If you produce, process, store or use any of the substances, in excess of the threshold listed in the following table, you may be subject to the requirements under Section 112(r) of the Clean Air Act. After reviewing Table G, return to form **GI-09 Requirements** and answer question 8b.

TABLE G
LIST OF REGULATED TOXIC SUBSTANCES AND THRESHOLD QUANTITIES FOR ACCIDENTAL RELEASE PREVENTION

Chemical Name	**CAS No.**	**Threshold Quantity (lbs)**
Acetaldehyde	75-07-0	10,000
Acetylene [Ethyne]	74-86-2	10,000
Acrolein [2-Propenal]	107-02-8	5,000
Acrylonitrile [2-Propenenitrile]	107-13-1	20,000
Acrylyl chloride [2-Propenoyl chloride]	814-68-6	5,000
Allyl alcohol [2-Propen-1-ol]	107-18-6	15,000
Allylamine [2-Propen-1-amine]	107-11-9	10,000
Ammonia (anhydrous)	7664-41-7	10,000
Ammonia (conc 20% or greater)	7664-41-7	20,000
Arsenous trichloride	7784-34-1	15,000
Arsine	7784-42-1	1,000
Boron trichloride [Borane, trichloro-]	10294-34-5	5,000
Boron trifluoride [Borane, trifluoro-]	7637-07-2	5,000
Boron trifluoride compound with methyl ether (1:1) [Boron, trifluoro[oxybis[metane]]-, T-4-	353-42-4	15,000
Bromine	7726-95-6	10,000
Bromotrifluorethylene [Ethene, bromotrifluoro-]	598-73-2	10,000
1,3-Butadiene	106-99-0	10,000
Butane	106-97-8	10,000
1-Butene	106-98-9	10,000
2-Butene	107-01-7	10,000
Butene	25167-67-3	10,000
2-Butene-*cis*	590-18-1	10,000
2-Butene-*trans* [2-Butene, (E)]	624-64-6	10,000
Carbon disulfide	75-15-0	20,000
Carbon oxysulfide [Carbon oxide sulfide (COS)]	463-58-1	10,000
Chlorine	7782-50-5	2,500
Chlorine dioxide [Chlorine oxide (ClO_2)]	10049-04-4	1,000
Chlorine monoxide [Chlorine oxide]	7791-21-1	10,000
Chloroform [Methane, trichloro-]	67-66-3	20,000
Chloromethyl ether [Methane, oxybis[chloro-]	542-88-1	1,000
Chloromethyl methyl ether [Methane, chloromethoxy-]	107-30-2	5,000
2-Chloropropylene [1-Propene, 2-chloro-]	557-98-2	10,000
1-Chloropropylene [1-Propene, 1-chloro-]	590-21-6	10,000

TABLE G (Continued)

Chemical Name	CAS No.	Threshold Quantity (lbs)
Crotonaldehyde [2-Butenal]	4170-30-3	20,000
Crotonaldehyde, (E)- [2-Butenal, (E)-]	123-73-9	20,000
Cyanogen [Ethanedinitrile]	460-19-5	10,000
Cyanogen chloride	506-77-4	10,000
Cyclohexylamine [Cyclohexanamine]	108-91-8	15,000
Cyclopropane	75-19-4	10,000
Diborane	19287-45-7	2,500
Dichlorosilane [Silane, dichloro-]	4109-96-0	10,000
Difluoroethane [Ethane, 1,1-difluoro-]	75-37-6	10,000
Dimethyldichlorosilane [Silane, dichlorodimethyl-]	75-78-5	5,000
1,1-Dimethylhydrazine [Hydrazine, 1,1-dimethyl-]	57-14-7	15,000
Dimethylamine [Methanamine, N-methyl-]	124-40-3	10,000
2,2-Dimethylpropane [Propane, 2,2-dimethyl-]	463-82-1	10,000
Epichlorohydrin [Oxirane, (chloromethyl)-]	106-89-8	20,000
Ethane	74-84-0	10,000
Ethyl acetylene [1-Butyne]	107-00-6	10,000
Ethylamine [Ethanamine]	75-04-7	10,000
Ethyl chloride [Ethane, chloro-]	75-00-3	10,000
Ethylene [Ethene]	74-85-1	10,000
Ethylenediamine [1,2-Ethanediamine]	107-15-3	20,000
Ethyleneimine [Aziridine]	151-56-4	10,000
Ethylene oxide [Oxirane]	75-21-8	10,000
Ethyl ether [Ethane, 1,1'-oxybis-]	60-29-7	10,000
Ethyl mercaptan [Ethanethiol]	75-08-1	10,000
Ethyl nitrite [Nitrous acid, ethyl ester]	109-95-5	10,000
Fluorine	7782-41-4	1,000
Formaldehyde (solution)	50-00-0	15,000
Furan	110-00-9	5,000
Hydrazine	302-01-2	15,000
Hydrochloric acid (conc 30% or greater)	7647-01-0	15,000
Hydrocyanic acid	74-90-8	2,500
Hydrogen	1333-74-0	10,000
Hydrogen chloride (anhydrous) [Hydrochloric acid]	7647-01-0	5,000
Hydrogen fluoride/Hydrofluoric acid (conc 50% or greater) [Hydrofluoric acid]	7664-39-3	1,000
Hydrogen selenide	7783-07-5	500
Hydrogen sulfide	7783-06-4	10,000
Iron, pentacarbonyl- [Iron carbonyl (Fe(CO)5), (TB-5-11)-]	13463-40-6	2,500
Isobutane [Propane, 2-methyl]	75-28-5	10,000
Isobutyronitrile [Propanenitrile, 2-methyl-]	78-82-0	20,000
Isopentane [Butane, 2-methyl-]	78-78-4	10,000
Isoprene [1,3-Butadiene, 2-methyl-]	78-79-5	10,000
Isopropylamine [2-Propanamine]	75-31-0	10,000
Isopropyl chloride [Propane, 2-chloro-]	75-29-6	10,000
Isopropyl chloroformate [Carbonochloridic acid, 1-methylethyl ester]	108-23-6	15,000
Methacrylonitrile [2-Propenenitrile, 2-methyl-]	126-98-7	10,000

TABLE G (Continued)

Chemical Name	CAS No.	Threshold Quantity (lbs)
Methane	74-82-8	10,000
Methylamine [Methanamine]	74-89-5	10,000
3-Methyl-1-butene	563-45-1	10,000
2-Methyl-1-butene	563-46-2	10,000
Methyl chloride [Methane, chloro-]	74-87-3	10,000
Methyl chloroformate [Carbonochloridic acid, methylester]	79-22-1	5,000
Methyl ether [Methane, oxybis-]	115-10-6	10,000
Methyl formate [Formic acid, methyl ester]	107-31-3	10,000
Methyl hydrazine [Hydrazine, methyl-]	60-34-4	15,000
Methyl isocyanate [Methane, isocyanato-]	624-83-9	10,000
Methyl mercaptan [Methanethiol]	74-93-1	10,000
2-Methylpropene [1-Propene, 2-methyl-]	115-11-7	10,000
Methyl thiocyanate [Thiocyanic acid, methyl ester]	556-64-9	20,000
Methyltrichlorosilane [Silane, trichloromethyl-]	75-79-6	5,000
Nickel carbonyl	13463-39-3	1,000
Nitric acid (conc 80% or greater)	7697-37-2	15,000
Nitric oxide [Nitrogen oxide (NO)]	10102-43-9	10,000
Oleum (Fuming Sulfuric acid) [Sulfuric acid, mixture with sulfur trioxide]	8014-95-7	10,000
1,3-Pentadiene	504-60-9	10,000
Pentane	109-66-0	10,000
1-Pentene	109-67-1	10,000
2-Pentene, (E)-	646-04-8	10,000
2-Pentene, (Z)-	627-20-3	10,000
Peracetic acid [Ethaneperoxoic acid]	79-21-0	10,000
Perchloromethylmercaptan [Methanesulfenyl chloride, trichloro-]	594-42-3	10,000
Phosgene [Carbonic dichloride]	75-44-5	500
Phosphine	7803-51-2	5,000
Phosphorus oxychloride [Phosphoryl chloride]	10025-87-3	5,000
Phosphorus trichloride [Phosphorous trichloride]	7719-12-2	15,000
Piperidine	110-89-4	15,000
Propadiene [1,2-Propadiene]	463-49-0	10,000
Propane	74-98-6	10,000
Propionitrile [Propanenitrile]	107-12-0	10,000
Propyl chloroformate [Carbonochloridic acid, propylester]	109-61-5	15,000
Propylene [1-Propene]	115-07-1	10,000
Propyleneimine [Aziridine, 2-methyl-]	75-55-8	10,000
Propylene oxide [Oxirane, methyl-]	75-56-9	10,000
Propyne [1-Propyne]	74-99-7	10,000
Silane	7803-62-5	10,000
Sulfur dioxide (anhydrous)	7446-09-5	5,000
Sulfur tetrafluoride [Sulfur fluoride (SF4), (T-4)-]	7783-60-0	2,500
Sulfur trioxide	7446-11-9	10,000
Tetrafluoroethylene [Ethene, tetrafluoro-]	116-14-3	10,000
Tetramethyl lead [Plumbene, tetramethyl-]	75-74-1	10,000
Tetramethylsilane [Silane, tetramethyl-]	75-76-3	10,000
Tetranitromethane [methane, tetranitro-]	509-14-8	10,000

TABLE G (Continued)

Chemical Name	CAS No.	Threshold Quantity (lbs)
Titanium tetrachloride [Titanium chloride ($TiCl_4$) (T-4)-]	7550-45-0	2,500
Toluene 2,4-diisocyanate [Benzene, 2,4-diisocyanato-1-methyl-]	584-84-9	10,000
Toluene 2,6-diisocyanate [Benzene, 1,3-diisocyanato-2-methyl-]	91-08-7	10,000
Toluene diisocyanate (unspecified isomer) [Benzene, 1,3-diisocyanatomethyl-]	26471-62-5	10,000
Trichlorosilane [Silane, trichloro-]	10025-78-2	10,000
Trifluorochloroethylene [Ethene, chlorotrifluoro-]	79-38-9	10,000
Trimethylamine [Methanamine, N,N-dimethyl-]	75-50-3	10,000
Trimethylchlorosilane [Silane, chlorotrimethyl-]	75-77-4	10,000
Vinyl acetate monomer [Acetic acid ethenyl ester]	108-05-4	15,000
Vinyl acetylene [1-Buten-3-yne]	689-97-4	10,000
Vinyl chloride [Ethene, chloro-]	75-01-4	10,000
Vinyl ethyl ether [Ethene, ethoxy-]	109-92-2	10,000
Vinyl flouride [Ethene, fluoro-]	75-02-5	10,000
Vinylidene chloride [Ethene, 1,1-dichloro-]	75-35-4	10,000
Vinylidene flouride [Ethene, 1,1-difluoro-]	75-38-7	10,000
Vinyl methyl ether [Ethene, methoxy-]	107-25-5	10,000

Minnesota Pollution Control Agency
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Compliance Assurance Monitoring (40 C.F.R. pt. 64)

The CAM rule applies to certain emission units at facilities required to obtain a Part 70 permit.

In general, CAM applies to emission units meeting the following criteria:

1. The emission unit is subject to an emission limit or standard (including limits and standards in Minnesota Rules contained in the State Implementation Plan) for an air pollutant regulated by Part 70;

2. Compliance with the applicable limit or standard is achieved through the use of add-on control equipment; and

3. The emission unit has pre-controlled potential emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the Part 70 major source level for that pollutant (in tons per year).

For exemptions, see Table C at the end of this form.

Use of continuous emissions monitoring system (CEMS), continuous opacity monitoring system (COMS), or predictive emission monitoring system (PEMS) does not qualify as an exemption to the CAM rule. However, §64.3(d) states that use of a CEMS, COMS, or PEMS meets the requirements of CAM.

CAM applicability is determined on a pollutant-by-pollutant basis for each "pollutant specific emissions unit," defined at 40 C.F.R. § 64.1 as "an emissions unit considered separately with respect to each regulated air pollutant." For purposes of CAM submittal requirements, a "**large pollutant specific emissions unit**" is an emissions unit with potential controlled emissions equal to or greater than 100% of the major source threshold amount for a given regulated pollutant. ("Major source threshold amount" as it applies to Minnesota, means 100 tons per year of particulate matter smaller than ten microns in aerodynamic diameter (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), volatile organic compounds (VOC), carbon monoxide (CO), or lead; 10 tons per year of any hazardous air pollutant (HAP); or 25 tons per year of any combination of HAPs. The levels may be different in current or future nonattainment areas. Refer to 40 C.F.R. § 70.2 under the definition of "major source" for further detail.) "**Other pollutant specific emissions units**" are those units whose uncontrolled potential emissions may be equal to or greater than 100% of the major source threshold amount, but controlled emissions are less than that threshold.

If you are applying for the first time for a Part 70 permit, after determining the uncontrolled and controlled potential emissions of the emissions units, the following questions must be considered for each **large** pollutant specific emissions unit, as defined above..

If you are applying for a major amendment to an existing Part 70 permit, after determining the uncontrolled and controlled potential emissions of the emissions units, the following questions must be considered for each **large** pollutant specific emissions unit, as defined above, to which the amendment is applicable.

If you are applying for reissuance of an existing Part 70 permit, after determining the uncontrolled and controlled potential emissions of the emissions units, the following questions must be considered for each pollutant specific emissions unit **(large and other)** for which CAM applicability has not already been determined through a Part 70 permitting action.

1) Is the unit subject to an emission limitation or standard, specified in either a rule or permit? For existing emission units, check your current permit to see if there are any emission limits specified for the emission unit.

☐ No, the emission unit is not subject to CAM. Repeat question 1 with next emission unit.
☒ Yes, the emission unit is subject to an emission limitation or standard. Go on to question 2.

2) Is an add-on control device used to achieve compliance with that limitation or standard? (For example, a boiler may have a NO_X limit and an SO_2 limit. If the boiler uses lime injection for SO_2 control but relies on a low-NO_X burner to meet the NO_X limit, then the emission unit would be subject to CAM for SO_2 but not for NO_X.)

☒ No, the emission unit is not subject to CAM. Return to question 1 and repeat with next emission unit.
☐ Yes. Go on to question 3.

3) There are some exemptions allowed by the rule. Review the list of exemptions in Table C, then answer the following question.

☐ No, the emission unit is subject to CAM. List the emission unit in Table A and repeat questions 1 through 3 for the next emissions unit. When each emission unit has been considered, go on to complete the rest of Table A and Table D.

☐ Yes, the emission unit is exempt from CAM. List the emission unit in Table D and repeat questions 1 through 3 for the next emissions unit. When each emission unit has been considered, go on to complete the rest of Table A and Table D.

Table A. Emission Units Subject to CAM

EU #	Emission Unit	CE #	Description of Control Equipment	Pollutant(s) which are subject to CAM

Duplicate this table as needed.

You must prepare a CAM submittal for each unit listed in Table 4, and provide it with the permit or amendment application. The CAM submittal, also referred to as the monitoring approach submittal, should include:

- information on indicators (gauges, meters, or other devices used to monitor operating parameters of control equipment)
- indicator ranges, or the process by which indicators are to be established
- performance criteria
- justification for the proposed monitoring
- control device operating data recorded during a performance test, supplemented by engineering assessments or manufacturer's recommendations to justify the proposed indicator range
- a test plan and schedule for obtaining data if performance test data are not available
- an implementation plan, if monitoring requires installation, testing or other activities prior to implementation

Some of this information will be incorporated into the operating permit. The permit will specify the approved monitoring approach and the indicator range(s), including the averaging periods.

Table D. Emission Units EXEMPT from CAM

EU #	Why exempt (not large enough, uncontrolled, exemption category from Table C, etc.)
CTGs (EU-001, 002, 010,& 011)	NOx, CO, PM, SO2 > 100 TPY, but no add-on control devices
Flares (CE-002 & 005)	CO > 100 TPY, but no add-on control devices
Aux Boiler, Engines, Fire Pumps, Cooling Tower	No other EUs are "large pollutant specific emission units"

For additional information, please refer to the CAM rule at 40 C.F.R. pt. 64.
Additional information, including a Technical Guidance Document that includes example submittals, is available on the Internet at http://www.epa.gov/ttn/emc/cam.html

Table C
CAM RULE EXEMPTIONS

The CAM rule does not apply to:

1. Units subject to emission limitations or standards proposed by EPA after November 15, 1990, pursuant to section 111 or 112 of the Clean Air Act. In situations where some portions of a facility operate control devices in order to comply with emission standards issued prior to November 15, 1990, only those portions of the facility must comply with the requirements of the CAM rule.

2. Situations where continuous compliance monitoring is already specified in an operating permit. The CAM rule exempts the Permittee from additional monitoring requirements and directs the Permittee to use the continuous compliance monitoring data to fulfill the CAM rule monitoring and certification requirements.

3. Stratospheric ozone protection requirements

4. Acid Rain Program requirements

5. Emission limitations or standards that apply solely under an emissions trading program

6. Municipally-owned utility peak-shaving units where
   - ⇒ the unit is exempt from all Acid Rain Program monitoring requirements, and
   - ⇒ the unit operates for the sole purpose of providing electricity during periods of peak electrical demand or emergency situations, and
   - ⇒ the unit will be operated consistent with that purpose throughout the permit term, and
   - ⇒ emissions from the unit are less than 50 percent of the amount required for the source to be classified as a major source, based on an average of the last 3 years, and are expected to remain so.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

Minnesota State Air Quality Rules

Some businesses and activities in Minnesota are subject to the following rules. Read each question to determine if the rule applies to you.

1) Minnesota Air Pollution Episodes
(Minn. R. 7009.1000-7009.1110)

1a) After your facility is permitted, will your facility be allowed to emit more than 250 tons per year of any one of the following pollutants: particulate matter, sulfur dioxide, nitrogen oxides, ozone [volatile organic compounds], carbon monoxide, or non-methane hydrocarbons?

☐ No, my facility is not subject to the Minn. R. 7009.1000-7009.1110.
☒ Yes, my facility is subject to the Minn. R. 7009.1000-7009.1110

2) Minnesota Standards of Performance for Stationary Sources (Minn. R. ch. 7011)

2a) Does your facility have any equipment that meets the following definition?

"A furnace, boiler or other combustion equipment in Minnesota which burns fossil fuel for the purpose of producing steam, hot water, hot air, or other hot liquid, gas, or solid, where the smoke doesn't have direct contact with the heated medium for which another standard of performance has not been promulgated."

☒ No, my facility **is not** subject to Minn. R. 7011.0500-7011.0551. Go to question 2b.
☐ Yes, my facility **is** subject to Minn. R. 7011.0500-7011.0551 Standards of Performance for Indirect Heating Fossil-Fuel Burning Equipment. List the units subject to this rule below. Read the rule to determine the specific requirements that apply to each subject unit ("new" or "existing" as defined in the rule), and use Form CD-01 to list those requirements. Then go on to question 2b)

Note: The indirect heating units at Mesaba Energy are not subject to the state standard because the are subject to the federal NSPS (40 C.F.R. 60 Subparts Da, Db, and Dc)

2b) Is your facility type or process equipment found in Table J on page 7? This table contains only state-specific requirements; it does not include state rules that incorporate federal rules by reference.

☐ No, none of the Minnesota Rules listed in Table J apply to my facility. Go to question 3).
☒ Yes, my facility or process equipment may be subject to the rule associated with it in Table J. Read the associated rule to see if it applies. Then go to item 2c).

2c) After reading through Table J and any rule that may apply to your facility or equipment, list the ones that do apply to your air emission source(s) in Table H on page 2. Again, Table J includes only state-specific requirements; it does not include state rules that incorporate federal rules by reference. You do not need to list state rules that incorporate federal rules by reference. You do not need to list the Standards of Performance for Indirect Heating Fossil-Fuel Burning Equipment again, if it applies (see 2a, above).

Table H: Equipment Subject to Minnesota Standards of Performance

Emission Source ID Number	Minnesota Rule Part that Applies	What the Rule Part Applies to (Whole facility or Specific Piece of Equipment)
FS-001 & FS-005	7011.1100	Coal Handling Facilities
EU-001, 002, 006, 007, 008, 009, 101, 011, 015, 016, 017 & 018	7011.2300	Internal Combustion Engines - Emergency Fire Water Pumps and Emergency Generators

(DUPLICATE THIS TABLE AS NEEDED)

3) Minnesota Acid Deposition Control (Minn. R. 7021.0050)

3a) Does your facility generate electricity?

☐ No. My facility is not subject to Acid Deposition Control Requirements. Go to question 4.
☒ Yes. Go to question 3b.

3b) Does your facility contain indirect heating equipment with a rated heat input of more than 5,000 million BTUs per hour?

☐ No. Go to question 3c.
☒ Yes. My facility is subject to Acid Deposition Control Requirements.

3c) If your facility is an electric utility, is the total generating capacity of all the electric generating facilities in Minnesota which are owned by your facility's parent company more than 1,000 megawatts?

☐ No. My facility is not subject to Acid Deposition Control Requirements.
☒ Yes. My facility is subject to Acid Deposition Control Requirements.

4) Standards of Performance for Industrial Process Equipment (Minn. R. 7011.0700 - 7011.0735)

4a) Do you have any industrial process equipment on-site that is not regulated by any other Standard of Performance (NSPS or MN Rules Standard of Performance)? **If you have any equipment/emission source that is <u>not</u> listed above in item 2a) or Table H, or listed on Form GI-09D, then the answer to this question is YES.**

☐ No, my equipment is not subject to this rule. Go to question 5**).**
☒ Yes. This equipment is subject to the Industrial Process Equipment Rule. List these units in Table I, indicating whether the equipment was or was not in operation before July 9, 1969. Then go to question 4b).

4b) **Opacity Standard**

(Note: Opacity is a measure of visible emissions or how much of the view is obscured by stack emissions. The emissions causing opacity are often smoke or dust.)

For industrial process equipment which was *in operation before July 9, 1969*, the equipment shall not exhibit greater than 20 percent opacity, except that a maximum of 60 percent opacity shall be permissible for four minutes in any 60 minute period and a maximum of 40 percent opacity shall be permissible for four additional minutes in any 60 minute period.

For industrial process equipment which was *not in operation before July 9, 1969*, the equipment shall not exhibit greater than 20 percent opacity.

Go to 4c).

4c) Does any of the industrial process equipment you listed in Table I have particulate control equipment with a collection efficiency of at least 99 percent if it was in operation before July 9, 1969, or 99.7 percent if it was not in operation before July 9, 1969?

☒ No. Go to question 4d).
☐ Yes. These units are considered to be in compliance with the remaining requirements of this rule.

For those units meeting this criterion which were in operation before July 9, 1969, complete Table I by checking the box labeled "Collection Efficiency > 90%."

For those units meeting these criterion which were not in operation before July 9, 1969, complete Table I by checking the box labeled "Collection Efficiency > 99.7%."

Then, if there are units listed in Table I which are not controlled by control equipment with a collection efficiency of 99% or 99.7% (as applicable), go on to question 4d).

4d) Has it been demonstrated that the operation of the entire facility in compliance with all ambient air quality standards? This is typically shown through some level of computer dispersion modeling.

☒ Yes. Go to question 4e).
☐ No. Skip to item 4i).

4e) Is the facility located outside of the seven county Minneapolis-St. Paul metropolitan region?

☒ Yes. Go to question 4f)
☐ No. Skip to item 4i).

4f) Is the facility located outside of the city of Duluth?

☒ Yes. Go to question 4g).
☐ No. Skip to item 4i).

4g) Is the facility located at least 1/4 mile from any residence or public roadway?

☒ Yes. Go to question 4h).
☐ No. Skip to item 4i).

4h) Answer this question individually for each remaining unit listed in Table I (those which were not identified in item 4c) as being controlled by control equipment having a control efficiency of 99% or 99.7% (as applicable)). Does the industrial process equipment have particulate control equipment with a collection efficiency of at least 85 percent?

☒ Yes, the unit is considered to be in compliance with the remaining requirements of this rule. For each unit for which you can answer "yes" to question 4h), complete Table I by checking the box labeled "Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%." Answer question 4h) for each remaining unit on Table I.

☐ No. For each unit for which you answered "No" to question 4h), complete Table I as described in item 4i). Then go to question 5).

4i) Complete Table I for all remaining industrial process equipment listed (those which were not identified in question 4c) as being controlled by control equipment having a control efficiency of 99% or 99.7% (as applicable)). Use Table K to determine the particulate limit in either pounds per hour (lb/hr) or grains per dry standard cubic foot (gr/dscf). Then go to question 5).

TABLE I: EQUIPMENT SUBJECT TO INDUSTRIAL PROCESS EQUIPMENT RULE

Equipment Subject to Industrial Process Equipment Rule (list EU number(s))		Applicable Particulate Limit
FS-002, 005	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☒ Not in operation before July 9, 1969	☒ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr
	☐ In operation before July 9, 1969	☐ Collection Efficiency > 90%
		☐ Collection Efficiency > 99.7%
	☐ Not in operation before July 9, 1969	☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85%
		☐ _____ gr/dscr
		☐ _____ lb/hr

(DUPLICATE THIS TABLE AS NEEDED)

5) Waste Combustors
(Minn. Rules 7011.1201-7011.1290)

Note: Depending on the type of waste combustor you operate, you may be instructed to fill out one or more of the following forms:

WC-01 -- Required if you determine that your waste combustor requires a permit.
WC-02 -- Required if you install/operate a Class IV waste combustor at a hospital.
WC-03 -- Required if you do not met the stack height requirements of Minn. R. 7011.1235.

If after reading through the following section, you determine that you are required to fill out one or more of the WC forms, contact the Air Quality Permit Document Coordinator.

5a) Do you operate a waste combustor?

"Waste Combustor" means any emissions unit or emission facility where mixed municipal solid waste, solid waste, or refuse-derived fuel is combusted, and includes incinerators, energy recovery facilities, or other combustion devices. A metals recovery incinerator is a waste combustor. A combustion device combusting primarily wood, or at least 70 percent fossil fuel and wood in combination with up to 30 percent papermill wastewater treatment plant sludge is not a waste combustor. A soil treatment facility, paint burn-off oven, wood heater, or residential fireplace is not a waste combustor.

"Wood" is defined as: wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including sawdust, sander dust, wood chips, wood scraps, slabs, millings, shavings, and processed pellets made from wood and other forest residues.

A facility that is co-firing RDF or MSW at rates less than 30 percent by weight is not regulated as a waste combustor, but is regulated as a boiler.

☐ Yes, I operate a waste combustor. Answer questions 5b through 5e to determine whether you are allowed to continue to operate, and what type of permit the waste combustor requires. Allowed waste combustors must obtain an air emissions permit.
☒ No, the facility equipment is not subject to this rule. Go to question 6.

5b) Is the waste combustor solely a crematory, pathological or an animal carcass incinerator?

☐ Yes. It is subject to standards of performance in 7011.1215, subp. 3. The waste combustor is an insignificant activity that does not need to be reported. Go to question 6.
☐ No, the facility equipment is not subject to this rule. Go to question 6.

5c) Is the design capacity of the waste combustor equal to or greater than 3 million Btu/hr?

"Design capacity" means: the hourly throughput of the waste combustor unit based on heat input from solid waste to the combustion system as stated by the manufacturer or designer, based on accepted design and engineering practices. For a non-continuous feed system, design capacity means the total heat input from solid waste per cycle.

If you don't have a manufacturer's design capacity in terms of heat input, you may estimate heat input by the following formula:

$$\mathbf{H_{in} = (HHV) \times (R)}$$

Where:

H_{in} = Heat input rate
HHV = heat value of waste
R = waste input rate, in lb/hr, as defined by the manufacturer
Commercial/Retail/Institutional Wastes = 7000 Btu/lb
General Industrial Wastes = 9000 Btu/lb
Medical/Infectious Wastes = 10,000 Btu/lb

☐ Yes, the waste combustor has a design capacity of 3 million Btu/hr or greater. The waste combustor is subject to the standards of performance applicable to waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-01.

☐ No, the heat input rate is below 3 million Btu/hr. Go to question 5d.

5d) Is the waste combustor used as a metal recover incinerator?

"Metals recovery incinerator" means a furnace or incinerator used primarily to recover precious and non-precious metals by burning the combustible fraction from waste. An aluminum sweat furnace is not a metals recovery incinerator.

☐ Yes. The waste combustor is subject to the standards of performance applicable to waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-01.

☐ No. Go to question 5e.

5e) Is the waste combustor located at a hospital?

☐ Yes. The waste combustor is subject to the standards of performance applicable to Class IV waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-02 if the waste combustor will comply with all of the design, operating, and standards of performance in parts 7011.1201 to 7011.1290. Otherwise, an air emissions permit must be issued, and you must complete for WC-01. [**Please Note:** There are federal Standards of Performance that must also be met for new sources (see Form GI-09D), and the state will be adopting more stringent standards for existing incinerators by December of 1998.]

☐ No, the waste combustor is not located at a hospital. The operation of this waste combustor was banned after January 30, 1996. Your compliance plan must contain specific steps to cease operation of this waste combustor.

6) Return to Form **GI-09 REQUIREMENTS**, question 11b.

Table J: Minnesota Standards of Performance for Stationary Sources *

Facility or Equipment Type	Associated Minnesota Rule
Direct Heating Equipment	7011.0600 through 7011.0625
Concrete Manufacturing Plants	7011.0850 through 7011.0860
Stage One Vapor Recovery	7011.0865 through 7011.0870
Hot Mix Asphalt Plants	7011.0900 through 7011 0925
Bulk Agricultural Commodity Facilities (Grain Elevators)	7011.1000 through 7011.1015
Coal Handling Facilities	7011.1100 through 7011.1140
Incinerators (waste combustors)	7011.1201 through 7011.1285
Sewage Sludge Incinerators	7011.1300 through 7011.1325
Petroleum Refineries	7011.1400 through 7011.1430
Liquid Petroleum and VOC Storage Vessels	7011.1500 through 7011.1515
Sulfuric Acid Plants	7011.1600 through 7011.1630
Nitric Acid Plants	7011.1700 through 7011.1725
Brass and Bronze Plants	7011.1900 through 7011.1915
Iron and Steel Plants	7011.2000 through 7011.2015
Inorganic Fibrous Materials	7011.2100 through 7011.2105
Stationary Internal Combustion Engine (Generators)	7011.2300
Municipal Solid Waste Landfills	7011.3500 through 7011.3510
Asbestos	7011.9921 through 701109927

* This table does NOT include Minnesota Rules which incorporate federal NSPS and/or NESHAP by reference.

TABLE K:
INSTRUCTIONS FOR DETERMINING YOUR PARTICULATE LIMIT

Minnesota has a State rule for the concentration of particulate matter that may be in your exhaust stream. The unit of the standard is grains per dry standard cubic foot. You need to convert your actual exhaust flow to dry standard cubic feet per minute to find the emission limit from the rule.

Sources subject to this rule are required to meet the emission limits established at all times. These limits will vary depending on operating conditions. To determine compliance at any point in time (i.e. for a stack test), follow the steps below:

1. Determine the amount of dry material (subtract any water or moisture content) in pounds per hour that is processed by your equipment.

2. Use Table K.1 to determine your allowed emission rate based on process weight rate. If your process weight rate falls between two values on the table, interpolate or extrapolate using the equation:

$$E = 3.59 \times \left(\frac{P}{2000}\right)^{0.62} \qquad \text{for} \quad P \quad 60{,}000 \text{ lbs/hour; and:}$$

$$E = 17.31 \times \left(\frac{P}{2000}\right)^{0.16} \qquad \text{for} \quad P > 60{,}000 \text{ lbs/hour}$$

where:

E = emission rate in lbs/hour; and
P = process weight rate in lbs/hour

3. If your process equipment is vented to the atmosphere, determine the airflow through your stack. Correct to 68 F and 14.7 psi, and correct to remove any moisture in the gas stream to obtain the air flow in dry standard cubic feet per minute (dscfm).

4. Use Table K.2 to determine your allowed concentration in grains per dry standard cubic foot (gr/dscf). Interpolate using the equation:

$$c = 1.7627 \times V^{-0.3241}$$

where:

c = concentration in gr/dscf,
V = gas volume in dscfm

5. Determine which of the two emission rates calculated above is *less stringent*. To convert a concentration (calculated in step 4) to an emission rate (calculated in step 2), use the following equation:

$$E = c \times V \times \left(\frac{60}{7000}\right)$$

where:

E = emission rate in lbs/hour;
c = concentration in gr/dscf,
V = gas volume in dscfm

Table K.1

Process Rate (lbs/hour)	Emission Rate (lbs/hour)
50	0.37
100	0.55
500	1.53
1,000	2.25
5,000	6.34
10,000	9.73
20,000	14.99
60,000	29.60
80,000	31.19
120,000	33.28
160,000	34.85
200,000	36.11
400,000	40.35
1,000,000	46.72

Table K.2

Source Gas Volume (dscfm)	Concentration (gr/dscf)
7,000 or less	0.100
8,000	0.096
9,000	0.092
10,000	0.089
20,000	0.071
30,000	0.062
40,000	0.057
50,000	0.053
60,000	0.050
80,000	0.045
100,000	0.042
120,000	0.040
140,000	0.038
160,000	0.036
180,000	0.035
200,000	0.034
300,000	0.030
400,000	0.027
500,000	0.025
600,000	0.024
800,000	0.021
1,000,000 or more	0.020

Regardless of the allowable emission rates calculated from Tables K.1 and K.2, no process equipment is allowed to emit more than 0.30 grains per standard cubic foot of exhaust gas.

MINNESOTA POLLUTION
CONTROL AGENCY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

HG-2003

ASSESSING THE IMPACTS OF MERCURY RELEASES TO AMBIENT AIR

11/24/03

Purpose: Recognizing that Minnesota's surface waters are impaired by unacceptable levels of mercury, virtually all of which comes from the air, and that sometimes releases to the air are unavoidable, the MPCA's goal is to minimize increases in mercury emissions associated with new facilities or expansions. Of particular focus in this guidance are mercury releases from taconite production, secondary metal processors, the combustion of fuels in electricity generating stations and industrial boilers (except when burning only natural gas), and sewage sludge, municipal or other incineration.

Applications for modifications (as defined in Chapter 7007) or new facilities in these sectors should demonstrate that mercury emissions have been accurately quantified, and that the project's mercury emissions have been minimized through an effort to identify cost-effective emission reduction alternatives. Demonstration of an appropriate level of effort should be achieved through the following steps:

1. Provide estimates of potential, current actual, and future actual emissions, in pounds per year (see attached Table 1).

2. Describe any measures currently in use at the facility to reduce mercury emissions. Reduction measures may include pre-processing methods or technologies, selection of process units that are inherently-low emitting technologies, or downstream/add-on control equipment.

3. Provide a diagram that shows the flow of mercury through the facility. The MPCA has found that opportunities for mercury reduction often become evident from an analysis of mercury inputs, flow through the process, and outputs. Accordingly, the MPCA recommends that proposals include a diagram of mercury flow through the facility to identify significant pathways of mercury associated with the project. Mercury Flow Diagrams are most useful when quantitative estimates are made, but qualitative diagrams are a useful first step. Figure 1 is an example of a Mercury Flow Diagram, as produced by the Western Lake Superior Sanitary District (WLSSD) for their process in 1993. WLSSD has since discontinued incineration, but nevertheless, this flow diagram serves as an excellent example.

4. Provide an evaluation of alternatives that could be used to reduce mercury emissions, including a comparison of reduction potential and cost. This evaluation can be summarized in a table that lists alternatives that could be used to reduce mercury emissions, including a comparison of reduction potential and cost (see, for example, Table 2). The reduction alternatives should not be limited to industry-standard controls for the source category. The alternatives should include methods to avoid introducing mercury into the process, controls applied to similar types of sources, innovative control technologies and strategies, modification of the existing process or process equipment, pollution prevention measures, and combinations of these alternatives. If the alternative selected for implementation is not the lowest in

mercury emissions, then the project proposer is expected to demonstrate that the alternatives lower in mercury emissions are either not technically or economically feasible.

Example: WLSSD Mercury Flow Diagram, for May 1993

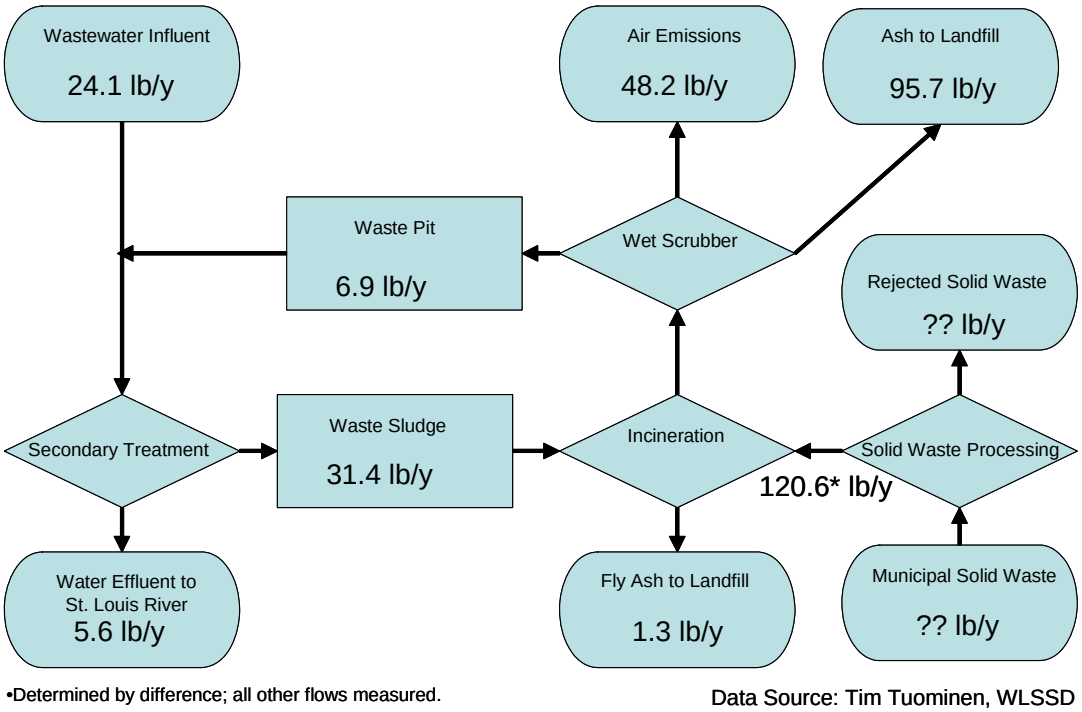


Figure 1. An example of a mercury flow diagram, based on the operation of the incinerator operated by the Western Lake Superior Sanitary District (WLSSD), for May 1993. The incinerator had two mercury inputs, wastewater and municipal solid waste. The wet scrubber caught a portion of the mercury, but put that mercury back into the process. Later, WLSSD exploited the capture of mercury by the wet scrubber by removing the mercury before putting the water back into the secondary treatment. WLSSD also worked to minimize emissions to the air by working aggressively with industry and the public to reduce mercury loading to both wastewater and municipal solid waste (MSW). An example of wastewater minimization was a project with Potlatch that identified a mercury-contaminated chemical feedstock used at their mill- low mercury feedstock was substituted at no additional cost. An example of MSW minimization is Duluth's early ban on the sale of mercury thermometers, which was feasible because cost-effective substitutes were available.

The mass of mercury may not balance between inputs and outputs because the flux rates are largely based on unadjusted concentrations and mass transfer rates. Nevertheless, even in the absence of precise balance, a mercury flow diagram such as this reveals

information that is useful for mercury reduction efforts. When conducting mass balances at existing facilities, multiple measurements should be taken in order to ascribe a sense of confidence to each number, either through a range or standard deviation.

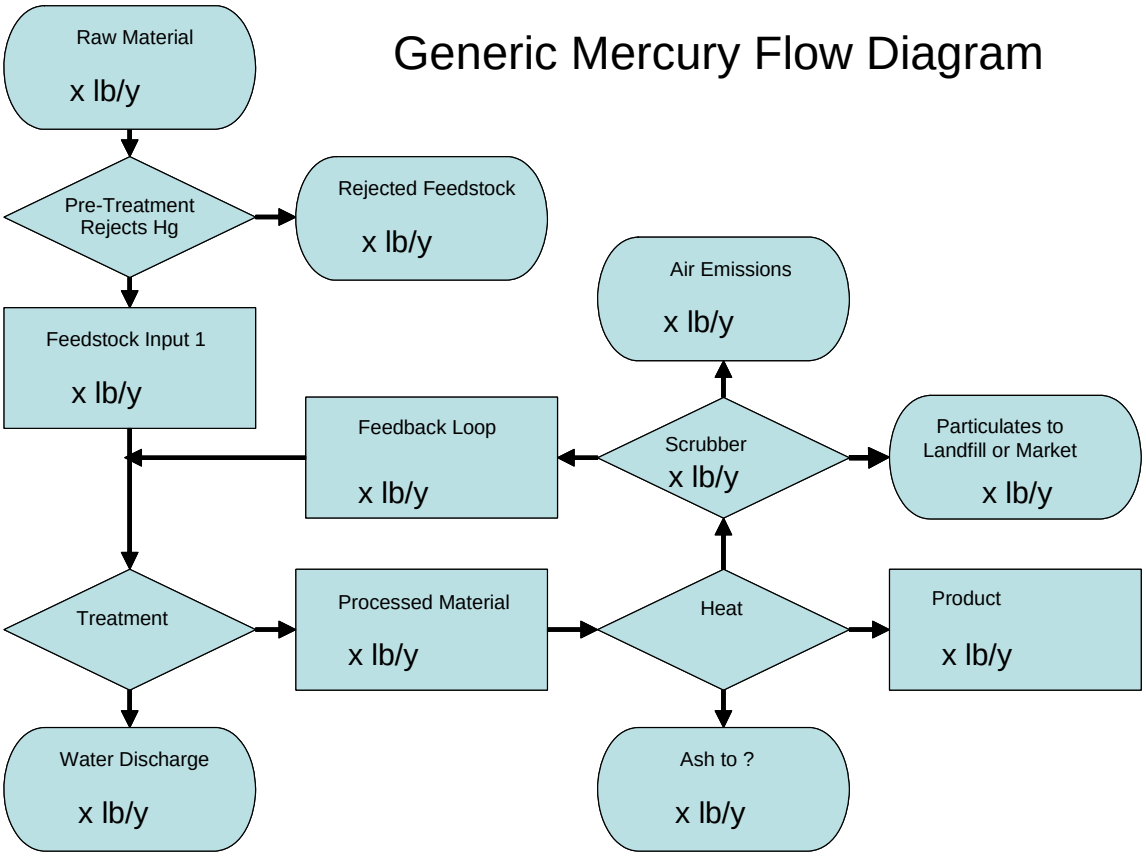
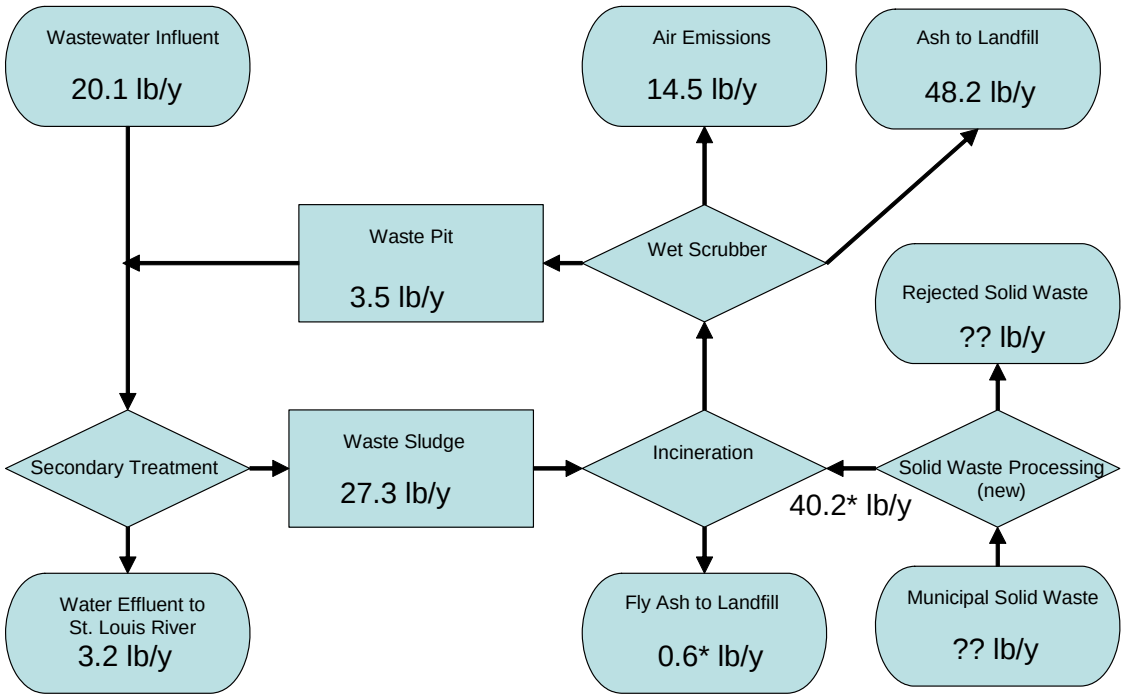


Figure 2. A generic mercury flow diagram that proposers may modify to describe mercury flow at their facility. Different shaped boxes are used as described in the key, Figure 4. The shapes and arrows are available in a variety of software packages, including Microsoft PowerPoint (Flowchart, in AutoShapes).

Example: WLSSD Mercury Flow Diagram, for February 1996

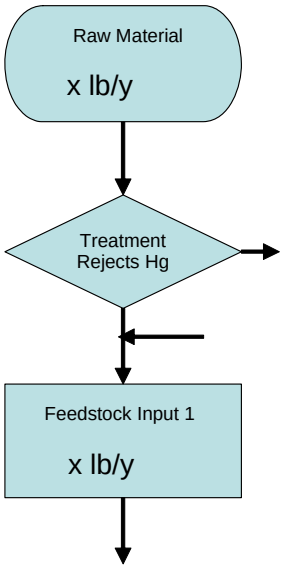


•Determined by difference; all other flows measured.

Data Source: Tim Tuominen, WLSSD

Figure 3. Mercury flow through the WLSSD facility after modifications in waste processing. The difference between this operation and that in 1993 (Figure 1) is described in Table 3. Multiple measurements of a flow stream will help describe the range or variability of a stream.

Key



An rounded rectangle is used to show the materials that are the input or output to the process.

An diamond shows those points in the process where the outflow splits in two or more directions, potentially offering an opportunity to segregate mercury and keep it out of the environment.

A rectangle is used to show a particular stage in the process that doesn't offer any option for segregating mercury. Although multiple arrows may come into each box, usually only one output or arrow leaves each box.

Figure 4. Key for the different shaped boxes used in a mercury flow diagram.

Table 1. Mercury emissions associated with Mesaba One and Mesaba Two (See Block Flow Diagram Provided on the Following Page).

Source Name/Id	potential to emit (pounds per year)				current actual emissions (pounds per year)				future estimated actual emissions (pounds per year)			
	particulate-bound	ionized	elemental	total	particulate-bound	ionized	elemental	total	particulate-bound	ionized	elemental	total
CTGs				51	(NA)							51
TVBs				2								2
Flares				1								1

1. Provide an estimate of mercury emissions for each emissions source expected to release mercury,
2. If the mercury emissions can be speciated into its chemical form, please provide an estimate for each fraction and the total.
3. Provide a description of the data sources relied upon in generating the data for this table.

Notes for mercury estimates:

1) Estimated total mercury emissions based on average expected mercury content of preferred feedstock and assuming between 90% to 95% overall removal by IGCC Power Station systems. PTE based on acceptance of permit limit compliance with which to be verified by continuous monitoring. See Appendix B, Exhibit B-1 for note on mercury content of fuels.

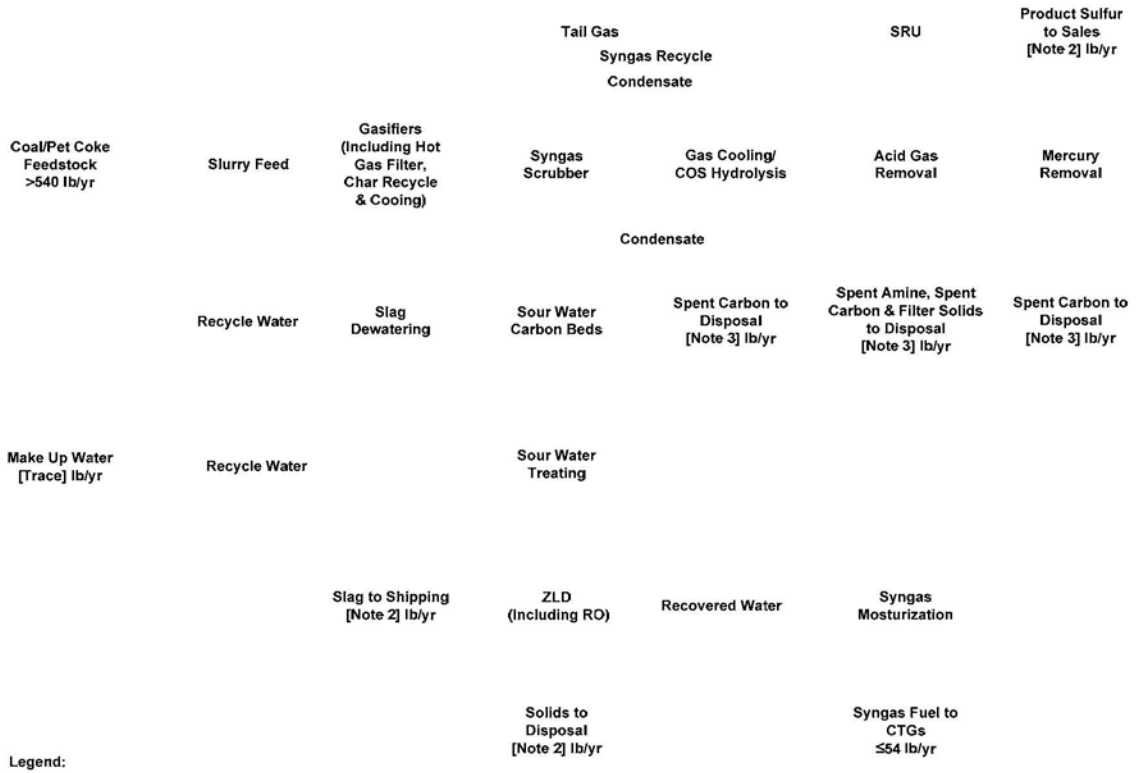
2) Mercury speciation is presumed to be predominantely in elemental form based on reducing atmosphere in gasifier.

3. E-Gas™ Vendor and Wabash River Coal Gasification Repowering Project test results.

Table 2. A table that can be used to summarize alternative methods to reduce mercury emissions from a facility.

Alternative	Total Mercury Emitted (lb/year)	Alternative Description	Reduction Potential (lb/year)	Annualized Cost ($)	Cost Effectiveness ($ per lb Hg)
Worst Case	54	Inherently low-emitting IGCC technology combined with impregnated carbon adsorption systems for treatment of syngas fuel and process water streams. Long term ability to blend low mercury fuels (i.e., petroleum coke) to compensate for higher sulfur fuel use on short term.	>486	TBD	TBD

Mesaba Energy Project – Mercury Flow Diagram (Mesaba One & Two)



Legend:

ZLD = Zero Liquid Discharge
RO = Reverse Osmosis
SRU = Sulfur Recovery Unit
COS = Carbonyl Sulfide
= Major distribution pathway for mercury residual
= Minor distribution pathway for mercury residual
= Major sink for mercury entering process; distribution dependent upon feedstock

Notes:

1. Mercury mass flow rates (lb/yr) are based on expected mercury content of Mesaba One & Two feedstock and minimum 90% removal efficiency on 12-month rolling average.
2. Mercury partitioning to these endpoints is unknown, but expected to be very low based on process conditions and/or upstream treatment capturing mercury species
3. Majority of mercury entering feedstock is expected to be captured by carbon filter beds. Disposal will be to licensed treatment, storage, disposal facility.

Table 3. An example based on modifications to WLSSD's process in 1996 (see 1996 flow diagram in Figure 3). New MSW processing reduced mercury in the combusted solid waste by 67%, to 40.2 lb/year. In addition, influent loading was reduced by 17%, to 20.1 lb/year. Total loading was reduced from about 145 to 60 lb/year, or 58%, and air emissions were reduced by 70%. Emissions were therefore reduced more than loading, probably because the wet scrubber and its operation were improved prior to the testing, capturing 68% of the incinerated mercury in 1993 and 79% in 1996. Cost information is not available.

Alternative	Total Mercury Emitted (lb)	Alternative Description	Reduction Potential (lb)	Annualized Cost ($)	Cost Effectiveness ($ per lb Hg)
A	48.2	WLSSD base operation, as documented in May 1993			
B		Reduction in loading due to change in solid waste processing.	80.4	Unknown	
C		Reduction in loading due to reduced mercury in liquid waste.	4.0	Unknown	
D		Improvement in wet scrubber and its operation	unknown	Unknown	
B + C + D	14.5	The effect of alternatives B, C, and D were evaluated simultaneously, so emissions are known for only the sum.	84.4	Unknown	

Background to "Assessing the Impacts of Mercury Releases to Ambient Air"

Over 80 percent of lakes assessed in Minnesota have been classified as impaired due to mercury contamination, under section 303(d) of the federal Clean Water Act. People and wildlife are at risk of impaired health from eating fish from these waters, and the Minnesota Department of Health must issue very restrictive fish-consumption advisories for these listed waters. As required by the Clean Water Act, the Minnesota Pollution Control Agency must work to reduce mercury in the fish including reducing mercury releases to air, water and land.

Based on the recommendation of a stakeholder advisory council, the 1999 Minnesota Legislature set goals for reducing mercury air emissions and established a voluntary reduction initiative. Minnesota's goals are to reduce mercury emissions 60 percent from 1990 levels by 2000 and 70 percent by 2005 from 1990 levels. Sources emitting mercury can submit agreements to the MPCA by which they voluntarily reduce mercury releases. As long as adequate progress is made using voluntary efforts, MPCA has agreed not to pursue additional regulations for sources participating in the voluntary program. If voluntary efforts are not sufficient, the MPCA will consider pursuing additional regulatory authority. The MPCA will report to the Legislature in 2005 on the Minnesota's mercury reduction efforts, including the voluntary agreements.

Since 1990, emissions of mercury from sources within Minnesota have been reduced by approximately 68% according to MPCA estimates for 2000. Nearly all of this decrease is due to discontinued use of mercury in products such as paint and batteries and improvements in pollution control equipment on garbage incinerators. During this time, emissions from coal-fired power plants and taconite processing facilities have increased, but only slightly. Total mercury emissions from all Minnesota sources in 2000 are estimated to be 3,642 pounds. The MPCA expects emissions to decrease slightly from this level by 2005.

Due to the long-range transport of mercury in the atmosphere, most of the mercury emitted in Minnesota is deposited outside of the state. Similarly, most of the mercury deposited in Minnesota originates from sources outside of the state. MPCA staff estimates that only about 10 percent of deposition within Minnesota is due to emissions within Minnesota. Even though reductions of emissions in Minnesota will have little effect on deposition in Minnesota, it is still important and necessary to reduce our emissions to reduce deposition in other parts of the region and world, just as reductions are need from regional and global sources to reduce mercury contamination of fish in Minnesota. This guidance describes a means of determining whether air releases have been minimized to the greatest extent possible. Besides ensuring that increases in mercury releases are minimized, this guidance recognizes that it is equally important that new or expanding sources of mercury air emissions do not also increase releases to other environmental media through other pathways.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-01**

GENERAL EMISSIONS CALCULATION FORM

03/31/99

- Use this form to calculate actual emissions for processes or units that cannot be accounted for in the process/unit specific emissions calculations forms.
- Duplicate this form as necessary to identify all emission units, or attach sheets with equivalent information..

1) AQ Facility ID No.:

2) Facility Name: Mesaba One (ASU Cooling Tower); Mesaba Two identical

3) Emission Unit Identification Number: 004; 013

4) Stack/Vent Designation Number: 004; 016

5) Pollution Control Equipment Identification Number(s): (high efficiency drift eliminators)

6) Process Type: ☐ Batch Process ☒ Continuous Process

7) Operating Capacity: 46 Units: million lb/hr cooling water

8) Source of Emission Factors used in Table Delow: Supplier data

9) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

9a) Pollutant	**9b)** Emission Factor (lbs/Unit)	**9c)** Emission Rate (lbs/hr)	**9d)** Maximum Uncontrolled Emissions (tons/yr)	**9e)** Actual Uncontrolled Emissions (tons/yr)	**9f)** Pollution Control Efficiency (%)	**9g)** Maximum Controlled Emissions (tons/yr)	**9h)** Actual Controlled Emissions (tons/yr)	**9i)** Limited Controlled Emissions (tons/yr)
PM	0.0272	1.3	5.5			5.5		
PM10	0.0272	1.3	5.5			5.5		
SOx								
NOx								
VOC								
CO								
Lead								

10) Check all of the following that are appropriate:

☐ This process/unit combusts fuel. Include fuel combustion emissions on Form EC-02 (Boilers), EC-03 (Internal Combustion Engines), or EC-08 (Ovens, Dryers, Furnaces), as appropriate.

☐ This process/unit uses clean-up solvents in addition to the process described by the emissions above. Include clean-up solvent emissions on Form EC-12.

☐ This process/unit emits Hazardous Air Pollutants (HAPs). Include HAP emissions on Form EC-13A (VOC HAPs), EC-13B (Particulate HAPs), or EC-13C (Combustion HAPs), as appropriate.

11) Operating Limitations, if applicable:

No operating limits are proposed.

Notes: Units for Item 9b) are lb/million lbs of cirulating cooling water. Emission factor is based on maximum drift of 0.001% of circulating cooling water and maximum 2720 ppm total dissolved solids in cooling water based on eight cycles of concentration.

Minnesota Pollution Control Agency

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ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-01**

GENERAL EMISSIONS CALCULATION FORM

03/31/99

- Use this form to calculate actual emissions for processes or units that cannot be accounted for in the process/unit specific emissions calculations forms.
- Duplicate this form as necessary to identify all emission units, or attach sheets with equivalent information..

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Flare); Mesaba Two identical

3) Emission Unit Identification Number: CE-002; CE-005)

4) Stack/Vent Designation Number: 011; 023

5) Pollution Control Equipment Identification Number(s): CE-002; CE-005

6) Process Type: ☐ Batch Process ☒ Continuous Process

7) Operating Capacity: 2 - 3730 (intermittant) Units: million Btu/hr

8) Source of Emission Factors used in Table Delow: Estimates based on operation of similar equipment

9) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

9a) Pollutant	**9b)** Emission Factor (lbs/Unit)	**9c)** Emission Rate (lbs/hr)	**9d)** Maximum Uncontrolled Emissions (tons/yr)	**9e)** Actual Uncontrolled Emissions (tons/yr)	**9f)** Pollution Control Efficiency (%)	**9g)** Maximum Controlled Emissions (tons/yr)	**9h)** Actual Controlled Emissions (tons/yr)	**9i)** Limited Controlled Emissions (tons/yr)
PM	0.008	30				1.7		1.7
PM10	0.008	30				1.7		1.7
SOx	0.003 - 0.28	1040				12.3		12.3
NOx	0.064	239				13.4		13.4
VOC	0.006	22			(includ'd)	1.3		1.3
CO	0.55 - 1.52	5680			(includ'd)	286		286
Lead	0.89E-06	0.003				0.0015		0.0002

10) Check all of the following that are appropriate:

☐ This process/unit combusts fuel. Include fuel combustion emissions on Form EC-02 (Boilers), EC-03 (Internal Combustion Engines), or EC-08 (Ovens, Dryers, Furnaces), as appropriate.

☐ This process/unit uses clean-up solvents in addition to the process described by the emissions above. Include clean-up solvent emissions on Form EC-12.

☒ This process/unit emits Hazardous Air Pollutants (HAPs). Include HAP emissions on Form EC-13A (VOC HAPs), EC-13B (Particulate HAPs), or EC-13C (Combustion HAPs), as appropriate.

11) Operating Limitations, if applicable:

This equipment is an emergency safety device that is also used to dispose of non-useable gases during gasifier startup and shutdown. The emission estimates shown are based on approximately 1260 annual hours of startup and shutdown operation plus about 200 annual hours of intermittant syngas flaring due to upset events in the IGCC Power Station (see attached permit application Section 4.1.3 and emission calculations in Appendix A, Exhibit A-4.

Notes:

Item 9b) - Units are lb/10^6 Btu of gas flared. SO2 emission factors are calculated from expected worst-case range of flared gas sulfur content. See attached emission calcuation appendix for source of non-SO2 emission factors.

Item 9i) - See attached emission calculation appendix for assumed worst case annual operating scenario.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-01**

GENERAL EMISSIONS CALCULATION FORM

03/31/99

- Use this form to calculate actual emissions for processes or units that cannot be accounted for in the process/unit specific emissions calculations forms.
- Duplicate this form as necessary to identify all emission units, or attach sheets with equivalent information..

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Power Block Cooling Tower); Mesaba Two is identical

3) Emission Unit Identification Number: 005; 012

4) Stack/Vent Designation Number: 005; 015

5) Pollution Control Equipment Identification Number(s): (high efficiency drift eliminators)

6) Process Type: ☐ Batch Process ☒ Continuous Process

7) Operating Capacity: 116 Units: million lb/hr cooling water

8) Source of Emission Factors used in Table Delow: Supplier data

9) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

9a) Pollutant	**9b)** Emission Factor (lbs/Unit)	**9c)** Emission Rate (lbs/hr)	**9d)** Maximum Uncontrolled Emissions (tons/yr)	**9e)** Actual Uncontrolled Emissions (tons/yr)	**9f)** Pollution Control Efficiency (%)	**9g)** Maximum Controlled Emissions (tons/yr)	**9h)** Actual Controlled Emissions (tons/yr)	**9i)** Limited Controlled Emissions (tons/yr)
PM	0.0272	3.1	14			14		
PM10	0.0272	3.1	14			14		
SOx								
NOx								
VOC								
CO								
Lead								

10) Check all of the following that are appropriate:

☐ This process/unit combusts fuel. Include fuel combustion emissions on Form EC-02 (Boilers), EC-03 (Internal Combustion Engines), or EC-08 (Ovens, Dryers, Furnaces), as appropriate.

☐ This process/unit uses clean-up solvents in addition to the process described by the emissions above. Include clean-up solvent emissions on Form EC-12.

☐ This process/unit emits Hazardous Air Pollutants (HAPs). Include HAP emissions on Form EC-13A (VOC HAPs), EC-13B (Particulate HAPs), or EC-13C (Combustion HAPs), as appropriate.

11) Operating Limitations, if applicable:

No operating limits are proposed.

Notes: Units for Item 9b) are lb/million lbs of cirulating cooling water. Emission factor is based on maximum drift of 0.001% of circulating cooling water and maximum 2720 ppm total dissolved solids in cooling water based on eight cycles of concentration.

- Fill out this form for each boiler, or attach sheets with equivalent information.
- Instructions begin on Page 6.
- If the boiler emits Hazardous Air Pollutants (HAPs), fill out and attach Form EC-13C.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Tank Vent Boiler); Mesaba Two is identical.

3) Emission Unit Identification Number: CE-001; CE-004

4) Stack/Vent Designation Number: 010; 022

5) Maximum Rated Boiler Capacity: 65 (HHV) million BTU/hr

6) Control Equipment: 010; 022

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Syngas and tank vent gas	0.005		240 Btu/cf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	270,000 cf/hr (approx)	ton/hr; gal/hr; cf/hr
Natural gas			1000 Btu/cf (approx)	Btu/ton, Btu/gal, Btu/cf	40,000 cf/hr	ton/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		ton/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a Pollutant	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
PM	0.01		0.65	2.8				0.9	
PM_{10}	0.01		0.65	2.8				0.9	
SOx	0.035 - 0.084		5.2 - 8.5	37				15.8	
NOx	0.3		19.5	85.4				26.4	
VOC	0.004		0.3	1.1				0.4	
CO	0.09		5.9	25.6				7.9	
Lead	0.8E-06		0.0003	0.001				7.0E-05	

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a Pollutant	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
PM	0.01		0.4	1.8			0.9		
PM_{10}	0.01		0.4	1.8			0.9		
SOx	0.00286		0.1	0.5			0.3		
NOx	0.3		12	52.6			26.4		
VOC	0.004		0.02	0.7			0.4		
CO	0.09		3.6	15.8			7.9		
Lead	NA								

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e, 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a Pollutant	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
PM									
PM_{10}									
SOx									
NOx									
VOC									
CO									
Lead									

11) Worse-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

Pollutant	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
PM	2.8	0.9
PM_{10}	2.8	0.9
SOx	37	15.8
NOx	85.4	26.4
VOC	1.1	0.4
CO	25.6	7.9
Lead	0.001	0.0003

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

Total sulfur in syngas fuel will be limited to 120 ppmv/1-hr avg, 100 ppmv/3- and 8-hr avg, 75 ppmv/24-hr avg, and 50 ppmv/30-day rolling avg. Annual fuel consumption of syngas plus tank vent gas plus natural gas will not exceed 176,000 x 10^6 Btu/yr - See attached permit application Section 4.1.2 and emission calculation Appendix A, Exhibit A-2 for assumed worst case annual operating scenario and other details.

Notes:

Item 8) - This equipment also oxidizes tank vent gas containing about 1.5 lb/hr equivalent sulfur, which will be converted to 3 lb/hr SO2. Mass emission rates listed include this SO2 from tank vent gas, the emission factors do not include it.

Items 8b) and 9b) - Units are lb/10^6 Btu of gas fired, non-SO2 emission factors are based on supplier data or test results for similar equipment using similar fuels. SO2 emission factors are calculated from expected worst-case range of fuel sulfur content (excluding tank sulfur in tank vent gas - see above).

Item 8i) - See attached permit application for assumed worst case annual operating scenario and other details.

- Fill out this form for each boiler, or attach sheets with equivalent information.
- Instructions begin on Page 6.
- If the boiler emits Hazardous Air Pollutants (HAPs), fill out and attach Form EC-13C.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Aux Boiler); Mesaba Two is identical

3) Emission Unit Identification Number: 003; 012

4) Stack/Vent Designation Number: 003; 015

5) Maximum Rated Boiler Capacity: 130 (HHV) million BTU/hr

6) Control Equipment: Low NOx burner

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Natural gas (only fuel proposed)			1000 Btu/cf (approx)	Btu/ton, Btu/gal, Btu/cf	130,000 cf/hr	ton/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		ton/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		ton/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a Pollutant	**8b** Emission Factor lb/(10^6)Btu	**8c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
PM	0.005		0.65	2.8				0.7	
PM_{10}	0.005		0.65	2.8				0.7	
SOx	0.00286		0.37	1.6				0.4	
NOx	0.036		4.7	20.5				5.1	
VOC	0.004		0.52	2.3				0.6	
CO	0.074		9.6	42.1				10.5	
Lead									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a Pollutant	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
PM									
PM_{10}									
SOx									
NOx									
VOC									
CO									
Lead									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e, 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a Pollutant	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/cf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, cf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
PM									
PM_{10}									
SOx									
NOx									
VOC									
CO									
Lead									

11) Worse-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

Pollutant	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
PM	2.8	0.7
PM_{10}	2.8	0.7
SOx	1.6	0.4
NOx	20.5	5.1
VOC	2.3	0.6
CO	42.1	10.5
Lead		

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

Because the Auxiliary Boiler will normally operate only when there is not steam available from the gasifiers or HRSGs, it is anticipated to operate at less than 25% annual capacity factor - see permit application text Section 4.1.7 and Appendix A, Exhibit A-3.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM

PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG - natural gas); Mesaba Two is identical

3) Emission Unit Identification Number: 001; 010

4) Stack/Vent Designation Number: 001; 013

5) Control Equipment Identification Number: (steam injection for NOx control)

6) Engine Type: ☐ Reciprocating ☒ Turbine ☐ Other: _____

7) Engine is Used For: ☒ Non-Emergency use **(If you check this box, you must complete Part 2 of this form.)** ☐ Emergency use only

8) Rated Heat Input: 2077 (HHV) mmBtu/hr

9) Rated Mechanical Output: 220 MW ~~HP~~ @ 3600 RPM

10) Fuel Type: p/l natural gas (startup/backup fuel) @ _____ % Sulfur

11) Fuel Consumption Rate: 2,080,000 cf/hr (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	0.0087	18	79			4.0	
PM10	0.0087	18	79			4.0	
SO_2	0.00286	5.9	25.8			1.3	
NO_X	0.0953	198	867			43.6	
VOC	0.00318	6.6	28.9			1.5	
CO	0.0347	72	315			15.8	
Lead	NA						

13) Operating Limitations, if applicable:

After first 36 mos. of operation, natural gas use would be limited to 440 hr/yr. Increased natural gas use is requested during first 36 mos - see application text Section 4.1.1 and emission calculation Appendix A, Exhibit A-1 for details.

Note for 12b) - units are lb/10^6 Btu (HHV) gas fired, emission data from equip mfr, except SO2 based on 1 grain sulfur/100 scf nat gas. Nominal heating value of about 1000 Btu/scf (HHV) is assumed.

1) **AQ Facility ID No. --** Fill in your Air Quality Facility ID Number as indicated on Form GI-01 or Form RP-01, item 1a.

2) **Facility Name --** Enter your facility name as indicated on Form GI-01 or Form RP-01, item 2.

3) **Emission Unit Identification Number --** Fill in the identification number of the emission unit. Obtain this number from Form GI-05B, unless you are using this form for Registration Permit Option D. In that case, just provide a description of the emission unit.

4) **Stack/Vent Designation Number --** [Skip this item if using this form for Registration Permit Option D.] Fill in the designation number of the stack(s) or vent(s) through which the engine will exhaust into the atmosphere. Obtain these numbers from Form GI-05B.

5) **Control Equipment Identification Number --** Fill in the identification number of the control equipment. Obtain this number from Form GI-05B, unless you are using this form for Registration Permit Option D. In that case, enter the description from Form RP-D2.

6) **Engine Type --** Indicate the appropriate engine type.

7) **Engine is Used For --** Indicate if the engine is used for routine operation or for emergency use.

8) **Rated Heat Input --** Enter the rated heat input of the engine, in units of million British thermal units (mmBtu) per hour.

9) **Rated Mechanical Output** -- Fill in the rated output of the engine in horsepower at a specified rpm.

10) **Fuel Type --**Fill in the fuel type (e.g., natural gas, diesel). **Fill out this form for each fuel burned.** Fill in the weight percent sulfur content, if applicable.

11) **Rated Fuel Consumption --** Fill in the manufacturer's rated fuel consumption for the engine. This information can be obtained from the manufacturer. If the engine has been derated, attach the supporting documentation. Circle the appropriate units.

12) **Calculations Summary:**

12a) **Pollutant --** For each pollutant listed in the table, calculate the engine's emissions.

12b) **Emission Factor --** Fill in the emission factors from Table EC-03.1 (Columns A - I) or obtain this information from the Compilation of Air Pollutant Emission Factors (AP-42) or EPA document 450/4-90-003. Circle the applicable units. [If you choose not to use Table EC-03.1, remember to use only uncontrolled emission factors.]

12c) **Emission Rate --** Fill in the Emission Rate in lb/hr. Calculate the emission rate by using one of the following methods:

If the emission factor is in units of pounds per quantity of fuel (gallons or cubic feet):

$$\begin{aligned}&\text{Emission Rate [lb / hr]:}\\&\quad = \text{Fuel Consumption Rate [qty / hr]} \times \text{Emission Factor [lb / qty]}\\&\quad = (\text{item 11}) \times (\text{item 12b})\end{aligned}$$

If the emission factor is in units of pounds per hp-hr power output:

$$\begin{aligned}&\text{Emission Rate [lb / hr]:}\\&\quad = \text{Rated Mechanical Output [hp]} \times \text{Emission Factor [lb / hp - hr]}\\&\quad = (\text{item 9}) \times (\text{item 12b})\end{aligned}$$

If the emission factor is in units of pounds per MMBtu heat input:

$$\begin{aligned}&\text{Emission Rate [lb / hr]}\\&\quad = \text{Rated Heat Input [MMBtu / hr]} \times \text{Emission Factor [lb / MMBtu]}\\&\quad = (\text{item 8}) \times (\text{item 12b})\end{aligned}$$

12d) **Maximum Uncontrolled Emissions --** [Skip this item if using this form for Registration Permit Option D.] Fill in the maximum uncontrolled emissions in tons per year. If the engine is an "emergency generator" (a generator whose sole function is to provide back-up power when power from the local utility is interrupted), the U.S. EPA has stated in a memorandum dated September 6, 1995, that maximum uncontrolled emissions may be based on operating the generator 500 hours per year. Use the following equation:

$$\begin{aligned}&\text{Maximum Uncontrolled Emissions [tons / yr]:}\\&\quad = \text{Emission Rate}\left[\frac{\text{lb}}{\text{hr}}\right] \times 0.25\left[\frac{\text{hrs}}{\text{yr}}\cdot\frac{\text{ton}}{\text{lbs}}\right]\\&\quad = (\text{item 12c}) \times 0.25\end{aligned}$$

The September 6, 1995 EPA memo applies only to emergency generators as defined above. It does not apply to peaking units at electric utilities (peak shaving units); generators at industrial facilities that typically operate at low rates but are not confined to emergency use; or any standby generator that is also used during times when power is available from the utility. If your engine is not an emergency generator, you must base maximum uncontrolled emissions on operating the engine 8,760 hours per year. Use the following equation:

$$\begin{aligned}&\text{Maximum Uncontrolled Emissions [tons / yr]:}\\&\quad = \text{Emission Rate}\left[\frac{\text{lb}}{\text{hr}}\right] \times 4.38\left[\frac{\text{hrs}}{\text{yr}}\cdot\frac{\text{ton}}{\text{lbs}}\right]\\&\quad = (\text{item 12c}) \times 4.38\end{aligned}$$

12e) **Pollution Control Efficiency --** The pollution control efficiency is the product of the capture efficiency and the destruction/collection efficiency indicated on Form GI-05A, or, if you are using this form for Registration Permit Option D, the control efficiency is indicated on Form RP-D2. Enter the number here and remember to include on Form CD-01 a plan to demonstrate and maintain the destruction/collection efficiency. [If you are using this form for Registration Permit Option D, you do not need to fill out Form

CD-01.] The efficiency should be expressed for each pollutant. If there is no control equipment for the particular pollutant, then indicate zero.

12f) **Maximum Controlled Emissions --** [Skip this item if you are using this form for Registration Permit Option D.] Fill in the maximum controlled emissions (i.e., after taking into consideration the pollution control equipment) of the process/unit in tons per year. Calculate the maximum controlled emissions (in tons per year) by using the following formula:

Max. Controlled Emissions [tons / yr]:

$$= \text{Max. Uncontrolled Emissions}\left[\frac{\text{tons}}{\text{yr}}\right] \times \left(\frac{100 \text{ - Pollution Control Efficiency}}{100}\right)$$

$$= (\text{item 12d}) \times \left(\frac{100 \text{ - (item 12e)}}{100}\right)$$

12g) **Limited Controlled Emissions** -- [Skip this item if using this form for Registration Permit Option D.] The Limited Controlled Emissions are calculated by taking into account all proposed limitations on operation of the source. These limitations include limits on hours of operation, on the amount of material mined, handled, crushed, screened, etc. The proposed limit should be described in item 13 and on Form CD-01. You start the calculation of Limited Controlled Emissions by repeating the calculation of Emission Rate (item 12c) but taking into account the limits you propose.

If an emission unit is subject to an emission limitation specified in 40 C.F.R. pt. 60, 40 C.F.R. pt. 61, 40 C.F.R. pt. 63 or Minn. Rules ch. 7011, you must show this requirement in the calculation of Limited Controlled Emissions and take this into account in calculating the Limited Controlled Emissions. If you choose to propose to comply with more a stringent limit, you should state this clearly and show the resulting allowed emissions in this calculation.

12h) **Actual Emissions** -- If this is an existing unit and historical records exist, calculate actual emissions using the average of the previous two calendar years of equipment or fuel usage data (last 12 months if using this form for Registration Permit Option D], or average the previous two emission inventory reports if an inventory was submitted. Report actual emissions in tons/year.

Calculate actual emissions using the following method.:

- If the emission factor is in units of pounds per quantity of fuel (gallons or cubic feet):

Actual Emissions [ton / yr]:

$$= \text{Fuel Consumption Rate [qty / yr]} \times \text{Emission Factor [lb / qty]} \times \frac{1}{2000}\left[\frac{\text{ton}}{\text{lb}}\right] \times \left(\frac{100 - \text{Pollution Control Efficiency}}{100}\right)$$

$$= \text{Consumption Rate} \times (\text{item 12b}) \times 0.0005 \times \left(\frac{100 - (\text{item 12e})}{100}\right)$$

- If the emission factor is in units of pounds per hp-hr power output or pounds per MMBtu heat input:

Actual Emissions [ton / year]:

$$= \text{Emission Rate}\left[\text{lb / hr}\right] \times \text{Actual Operating Hours [hr]} \times \frac{1}{2000}\left[\frac{\text{ton}}{\text{lb}}\right] \times \left(\frac{100 - \text{Pollution Control Efficiency}}{100}\right)$$

$$= (\text{item 12c}) \times \text{Actual Operating Hours} \times 0.0005 \times \left(\frac{100 - (\text{item 12e})}{100}\right)$$

If this is a new unit or no records exist, use a reasonable estimate of how many hours the unit will be operated, how much fountain solution will be used, how much cleaning solution, etc.

13) **Operating Limitations --** Describe any permit limits you plan to take to restrict your PTE (fuel type and/or usage, hours of operation, etc.). Attach additional sheets, if necessary. Describe the limiting factors and cite any rules that apply (e.g. Minn. Rules, Best Available Control Technology (BACT)). The associated limits must be used to calculate your PTE. If you used vendor certification or stack test data to limit your PTE, that factor will become a permit limit. Include all proposed limits on Form CD-01.

TABLE EC-03.1: Emission factors[a] for internal combustion engines and fuels

Columns	A	B	C	D	E	F	G	H	I	J	K
	PM[b] (lb/unit)	PM10 (lb/unit)	PM Filterable [c] (lb/unit)	PM Condensable [d] (lb/unit)	SOx (lb/unit)	NOx (lb/unit)	VOC (lb/unit)	CO (lb/unit)	Lead (lb/unit)	Heat Value (BTU/Unit)	UNITS
Industrial Reciprocating Engines :											
Distillate (diesel) oil, <600 hp	0.002 2	0.002 2	- - - -	- - - -	0.002 05	0.031	0.002 514	0.006 68	- - - -	n/a[f]	hp-hr power output
	0.31	0.31	- - - -	- - - -	0.29	4.41	0.36	0.95	- - - -	n/a[f]	MMBtu fuel input
Distillate (diesel) oil, ≥600 hp	0.000 7	0.000 7	- - - -	- - - -	0.008 09 S[e]	0.024	0.000 642	0.005 5	- - - -	n/a[f]	hp-hr power output
	0.069 7	0.057 3	0.062 0	0.007 7	1.01 S[e]	3.2	0.082	0.85	- - - -	n/a[f]	MMBtu fuel input
Gasoline	0.000 721	0.000 721	- - - -	- - - -	0.000 591	0.011	0.021 591	0.439	- - - -	n/a[f]	hp-hr power output
	0.10	0.10	- - - -	- - - -	0.084	1.63	3.030	62.7	- - - -	n/a[f]	MMBtu fuel input
Natural Gas	0.000 010	0.000 010	- - - -	- - - -	0.000 000 6	0.003 40	0.000 082 9	0.000 430	- - - -	1,050	cubic feet burned
Kerosene/Naphtha	0.033 5	0.032 0	- - - -	- - - -	0.006 2	0.469 0	0.032 1	0.102 0	- - - -	135,000	gallons burned
Propane	0.005 0	0.005 0	- - - -	- - - -	0.000 35	0.139 0	0.083 0	0.129 0	- - - -	91,500	gallons burned
Butane	0.005 0	0.005 0	- - - -	- - - -	0.000 35	0.139 0	0.083 0	0.129 0	- - - -	102,600	gallons burned
Natural Gas-Fired Pipeline Compressor Engines:											
2-cycle lean burn											
= 90% Load	0.038 4	0.038 4	- - - -	0.009 91	0.000 588	3.17	0.12	0.386	- - - -	n/a[f]	MMBtu fuel input
< 90% Load	0.038 4	0.038 4	- - - -	0.009 91	0.000 588	1.94	0.12	0.353	- - - -	n/a[f]	MMBtu fuel input
4-cycle lean burn											
= 90% Load	0.000 077 1	0.000 077 1	- - - -	0.009 91	0.000 588	4.08	0.118	0.317	- - - -	n/a[f]	MMBtu fuel input
< 90% Load	0.000 077 1	0.000 077 1	- - - -	0.009 91	0.000 588	0.847	0.118	0.557	- - - -	n/a[f]	MMBtu fuel input
4-cycle rich burn											
= 90% Load	0.009 5	0.009 5	- - - -	0.009 91	0.000 588	2.21	0.029 6	3.72	- - - -	n/a[f]	MMBtu fuel input
< 90% Load	0.009 5	0.009 5	- - - -	0.009 91	0.000 588	2.27	0.029 6	3.51	- - - -	n/a[f]	MMBtu fuel input

Columns	A	B	C	D	E	F	G	H	I	J	K
	PM[b] (lb/unit)	PM10 (lb/unit)	PM Filterable [c] (lb/unit)	PM Condensable [d] (lb/unit)	SOx (lb/unit)	NOx (lb/unit)	VOC (lb/unit)	CO (lb/unit)	Lead (lb/unit)	Heat Value (BTU/Unit)	UNITS
Turbine Engines (Electrical Generation):											
Natural Gas [g]											
Water/steam injection	0.006 6	0.006 6	0.001 9	0.004 7	0.94 S[e]	0.13	0.002 1	0.03	- - - -	n/a[f]	MMBtu fuel input
uncontrolled	- - - -	- - - -	- - - -	- - - -	0.94 S[e]	0.32	0.002 1	0.082	- - - -	n/a[f]	MMBtu fuel input
Distillate Oil (Diesel)[g]											
Water/steam injection	0.012	0.012	0.004 3	0.007 2	1.01 S[e]	0.24	0.000 41	0.076	0.000 014	n/a[f]	MMBtu fuel input
uncontrolled	- - - -	- - - -	- - - -	- - - -	1.01 S[e]	0.88	0.000 41	0.003 3	- - - -	n/a[f]	MMBtu fuel input
Kerosene/Naphtha	0.005 0	0.004 8	- - - -	- - - -	0.006 2	0.067 8	0.004 77	0.015 4	- - - -	135,000	gallons burned
Landfill Gas [g]	0.023	0.023	- - - -	- - - -	0.045	0.14	0.013	0.44	- - - -	n/a[f]	MMBtu fuel input
Digester Gas [g]	0.012	0.012	- - - -	- - - -	0.006 5	0.16	0.005 8	0.017	0.000 0034	n/a[f]	MMBtu fuel input

Notes:

[a] Emission factors adapted from EPA documents AP-42 and 450/4-90-003. An "- - - -" indicates that there is currently no emission factor available.

[b] PM refers to all particulate matter of all sizes, PM_{10} refers only to particulate matter from 0.0 to 10.0 microns in diameter.

[c] Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Condensable PM is that particulate matter collected in the impinger portion of an EPA Method 5 (or equivalent) sampling train.

[e] An "S" denotes a weighted emission factor. To obtain the corrected emission factor, multiply the listed factor by the sulfur content of the fuel (in percent). For the distillate oil/turbine engine combination using 0.5% sulfur fuel, the corrected emission factor for SOx would be determined:

SOx emission factor = 1.01 x 0.5 = 0.525 lb/MMBtu fuel input

[f] n/a = not applicable

[g] Data is for turbine engines operated at high load (>80%). For emissions data at other loads, see the background report for AP-42 Chapter 3, available online at www.epa.gov/ttn/chief.

MINNESOTA POLLUTION CONTROL AGENCY
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PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM

PART 2: AMBIENT AIR IMPACTS

01/03/00

Complete Part 2 (Screen Model for Ambient Air Impacts) for each fuel burned in each engine with a generator to be used for other than emergency purposes, or attach sheets with equivalent information.

NOTE: Applicant has conducted ambient air modeling using AERMOD and provided the results of such modeling in the Application in Section 7. Ambient air impacts are shown to be in compliance with all ambient air quality standards.

Running the Screen Model:

14) Run SCREEN, enter name for this run

15) Source Type: _____

16) Emission Rate: _____ gram/second

17) Stack Height: _____ feet

18) Stack Inside Diameter: _____ feet

19) Stack Velocity:

- ☐ Option 1: the velocity directly in meters/second as a number only (default) _____
- ☐ Option 2: the flowrate in cubic meters/second _____
- ☐ Option 3: the flowrate in cubic feet/minute *for ambient temp= 293K (67.7 deg F) _____

20) Stack Temperature:

- ☐ Option 1 (default) _____
- ☐ Option 2: the manufacturer's estimated typical operating temp (K) _____

21) Ambient Air Temperature (K): _____

22) Receptor Height: _____

23) Urban or Rural? _____

24) Consider Building Downwash? _____

25) Building Height: (meters) _____

26) Building Horizontal Dimensions (meters): minimum: _____ maximum: _____

27) Complex Terrain Option _____

28) Simple Terrain Option _____

29) Select Full Meteorology, Option 1

30) Select Automated Distance Array _____

31) Enter distances _____

32) Record highest ambient air impact: _____

33) Select Discreet Distances

34) Highest predicted 1-hour ambient air impact _____

35) Ambient Air Impact Table

Pollutant and Averaging Time	35a) Maximum Uncontrolled Emissions lb/hour	35b) Pollution Control Efficiency %	35c) Maximum Controlled Emissions lb/hr	35d) Maximum Controlled Emissions grams/sec	35e) 1-hour Ambient Air Impact at 1 gm/sec microgm/m3	35f) Averaging time scaling factor	35g) Ambient Air Impact for stated Averaging Time microgm/m3
PM_{10} 24 hr							
SO_2 3 hr							
SO_2 24 hr							
NO_X 1 hr							
NO_X 24 hr							
CO 1 hr							
CO 8 hr							

36) Compare ambient air impacts for the appropriate averaging time to the following target levels in micrograms/cubic meter:

PM_{10} 24 hour target	= 150	NOx 1 hour target	= 1130
		NOx 24 hour target	= 282
SO_2 3 hour target	= 1300	CO 1 hour target	= 40,000
SO_2 24 hour target	= 365	CO 8 hour target	= 10,000

37) If any target level is exceeded, rerun SCREEN using a different stack height, until no exceedance is predicted. That is the stack height that must be used with the engine.

Running the Screen Model: You can obtain the SCREEN model from U.S. EPA at the following web page: **www.epa.gov/ttn/scram**. Instructions are provided here, but if you find you need additional assistance with obtaining or using SCREEN, you can contact the Air Quality Helpline at (651) 282-5844 or (800) 646-6247. Air Quality staff at those numbers will be able to answer your questions or direct your call to someone who can.

14) Start SCREEN, enter a name for this run.

15) For "Source Type" choose "P" for Point Source.

16) Emission Rate: Enter 1.0 gram/second. At the end of this form, you will adjust the results from the SCREEN model for the calculated maximum grams/second for each pollutant.

17) Stack Height: Enter the stack height above grade level in meters (3.28 feet = 1 meter).

18) Stack Inside Diameter: Enter the stack inside diameter in meters.

19) Stack Velocity: SCREEN provides three ways to enter this data. The default (Option 1) is to enter the exhaust gas velocity directly in meters/second as a number only. As an alternative, you can enter the flowrate in cubic meters/second (Option 2) or cubic feet/minute (Option 3) but you must include the appropriate notation so the program will know which data you are giving it. The diesel engine manufacturer will be able to provide this data for the engine.

20) Stack Temperature: The exhaust gas temperature must be entered in degrees Kelvin (K). Enter the manufacturer's estimated typical operating temperature, converted to K, or use 700 as default.

As an example, a typical temperature might be 800 degrees F. First convert to Celsius (C) using the following equation:

$$\text{degrees C} = \frac{5}{9} \times (\text{degrees F} - 32)$$

$$427 \text{ degrees C} = \frac{5}{9} \times (800 \text{ degrees F} - 32)$$

Next convert to Kelvin (K) by adding 273:

$$\text{degrees K} = \text{degrees C} + 273$$

$$700 \text{ degrees K} = 427 \text{ degrees C} + 273$$

21) Ambient Air Temperature: Enter 293

22) Receptor Height: Enter 0.0

23) Urban or Rural option: Choose "Urban" unless the generator is in a truly rural area. If there are several buildings in the vicinity of the generator, the urban option should be selected.

24) Consider Building Downwash: Enter Yes. **NOTE:** For a generator located far from any buildings, the generator enclosure itself acts as a building and can cause downwash. For buildings that are short in height compared to the length and width, and the generator is located more than 5 building heights from the closest wall, use the generator enclosure dimensions for building downwash. For tall buildings, use 5 times the projected width,

which is the diagonal length across the roof of the building. In general, use 5 times the LESSER of the building height or projected width to determine if a building is close enough to cause downwash.

25) Building Height: Enter the roofline height of the nearby building that dictates the most severe building downwash effect. This may be difficult to predict, and you may need to run SCREEN more than once, using different nearby buildings and the generator enclosure, to determine which one produces the highest ambient air impact.

26) Building Minimum and Maximum Horizontal Dimensions: Enter the horizontal dimensions of the building used in item 25.

27) Complex Terrain Option: Enter NO.

28) Simple Terrain Option: Enter NO.

29) Meteorology: Select the full meteorology option, Option 1.

30) Automated Distance Array: Select by entering YES.

31) Enter Distances: Enter "100,1000". SCREEN will automatically calculate and display the ambient air impact from 100 to 1000 meters in increments of 100 meters.

32) Record highest ambient air impact: Record the highest ambient air impact for 100 to 1000 meters.

33) Select Discrete Distances: Enter distances of 10, 20, 30, 40, 50, 60, 70, 80, and 90. As you enter each one, SCREEN will compute the ambient air impact at that distance and display it.

34) Record the highest predicted 1-hour ambient air impact. Also enter this number in all rows under column 35e in the Ambient Air Impact table on page 9.

35) Ambient Air Impact Table.

35a) Emission Rate in lb/hr: Enter the emission rates calculated in Part 1, item 12c, for PM_{10}, SO_2, NO_X, and CO. Use the same hourly emission rate for each averaging time for SO_2, NO_X , and CO.

35b) Pollution Control Efficiency: Enter the pollution control efficiency from Part 1, item 12e, for each pollutant. Use the same SO_2 efficiency for both SO_2 lines, and the same NO_X efficiency for both NO_X lines.

35c) Maximum Controlled Emissions in lb/hour: For each line, calculate the maximum controlled emissions in lb/hour using the following equation:

$$\text{Maximum ntrolled Emissions}\left[\frac{\text{lb}}{\text{hour}}\right] = \text{Emission Rate}\left[\frac{\text{lb}}{\text{hour}}\right] \times \left(\frac{100 - \text{Pollution Control Efficiency}}{100}\right)$$

$$\text{(Item 35c)} = \text{(item 35a)} \times \left(\frac{100 - \text{(item 35b)}}{100}\right)$$

35d) Maximum Controlled Emissions in grams/second: For each line, calculate the maximum controlled emissions in grams/second by dividing the maximum controlled emissions in lb/hour by 7.94:

$$\text{Maximum} \quad \text{ntrolled Emissions} \left[\frac{\text{grams}}{\text{second}}\right] = \frac{\text{Maximum} \quad \text{ntrolled Emissions} \left[\frac{\text{lb}}{\text{hour}}\right]}{7.94}$$

$$(\text{ item 35d }) = \frac{(\text{ item 35c })}{7.94}$$

35e) **1-hour Ambient Air Impact at 1 gm/second:** This is the number identified in item 34. This should be the same number in each line of the table.

35f) **Averaging Time Scaling Factor:** This has been provided for you.

35g) **Ambient Air Impact for Stated Averaging Time:** This is the number you will compare to the standards shown in item 36. Calculate this number by multiplying the maximum controlled emissions in grams/second by the 1-hour ambient impact at 1 gram/second and then by the averaging time scaling factor, as follows:

$$\text{Ambient Air Impact} \left[\frac{\text{microgram}}{\text{cubic meter}}\right] = \text{Maximum Controlled Emissions} \left[\frac{\text{grams}}{\text{second}}\right] \times 1 - \text{hour Ambient Impact} \left[\frac{\text{microgram}}{\text{cubic meter}}\right] \times \text{scaling factor}$$

$$(\text{ item 32g }) = (\text{ item 32d }) \times (\text{ item 32e }) \times (\text{ item 32f })$$

36) Compare ambient air impact for each pollutant and for the appropriate averaging time to the following target levels:

PM_{10} 24 hour ambient air standard	=	150 micrograms/cubic meter
SO_2 3 hour ambient air standard	=	1300 micrograms/cubic meter
SO_2 24 hour ambient air standard	=	365 micrograms/cubic meter
NO_x 1 hour emergency episode level	=	1130 micrograms/cubic meter
NO_x 24 hour emergency episode level	=	282 micrograms/cubic meter
CO 1 hour ambient air standard	=	40,000 micrograms/cubic meter
CO 8 hour ambient air standard	=	10,000 micrograms/cubic meter

37) If any target level is exceeded, rerun SCREEN using a different stack height, until no exceedance is predicted. That is the stack height that must be installed.

Minnesota Pollution Control Agency

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ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM

PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG - syngas); Mesaba Two is identical

3) Emission Unit Identification Number: 001; 010

4) Stack/Vent Designation Number: 001; 013

5) Control Equipment Identification Number: (desulfurized fuel, N2 injection for NOx control)

6) Engine Type: ☐ Reciprocating ☒ Turbine ☐ Other: _____

7) Engine is Used For: ☒ Non-Emergency use (If you check this box, you must complete Part 2 of this form.) ☐ Emergency use only

8) Rated Heat Input: 2184 (HHV) mmBtu/hr

9) Rated Mechanical Output: 220 MW ~~HP~~ @ 3600 RPM

10) Fuel Type: IGCC syngas @ 0.005 % Sulfur

11) Fuel Consumption Rate: 9,000,000 cf/hr (approx) (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	12b) Emission Factor (lbs/unit)	12c) Emission Rate (lbs/hr)	12d) Maximum Uncontrolled Emissions (tons/yr)	12e) Pollution Control Efficiency (%)	12f) Maximum Controlled Emissions (tons/yr)	12g) Limited Controlled Emissions (tons/yr)	12h) Actual Emissions (tons/yr)
PM	0.0114	25	110		110		
PM10	0.0114	25	110		110		
SO2	0.028 - 0.084	59 - 183	802		333		
NOX	0.0714	156	683		683		
VOC	0.004	8.7	38		38		
CO	0.0435	95	416		416		
Lead	0.8E-06	0.0002	0.007		0.007		

13) Operating Limitations, if applicable:

Total sulfur in syngas fuel will be limited to 120 ppmv/1-hr avg, 100 ppmv/3- and 8-hr avg, 75 ppmv/24-hr avg, and 50 ppmv/30-day rolling avg - see permit application text Section 4.1.1 and Appendix A, Exhibit A-2 for more description.

Notes:

Item 11) - Volumetric fuel flow, dry and excluding dilution nitrogen, based on minimum expected syngas heating value. Syngas heating value will range from about 240 to 305 Btu/dscf, HHV.

Item 12b) - Units are lb/10^6 Btu (HHV) gas fired based on minimum expected heating value, emission data from potential equip mfrs, except lead factor is from available IGCC literature (see applicationj text). Range shown for SO2 is based on 50 to 120 ppmv total fuel sulfur and expected range of syngas HHV.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG - syngas); Mesaba Two is identical

3) Emission Unit Identification Number: 002; 011

4) Stack/Vent Designation Number: 002; 014

5) Control Equipment Identification Number: (desulfurized fuel, N2 injection for NOx control)

6) Engine Type: ☐ Reciprocating ☒ Turbine ☐ Other: _____

7) Engine is Used For: ☒ Non-Emergency use (If you check this box, you must complete Part 2 of this form.) ☐ Emergency use only

8) Rated Heat Input: 2184 (HHV) mmBtu/hr

9) Rated Mechanical Output: 220 MW ~~HP~~ @ 3600 RPM

10) Fuel Type: IGCC syngas @ 0.005 % Sulfur

11) Fuel Consumption Rate: 9,000,000 cf/hr (approx) (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	12b) Emission Factor (lbs/unit)	12c) Emission Rate (lbs/hr)	12d) Maximum Uncontrolled Emissions (tons/yr)	12e) Pollution Control Efficiency (%)	12f) Maximum Controlled Emissions (tons/yr)	12g) Limited Controlled Emissions (tons/yr)	12h) Actual Emissions (tons/yr)
PM	0.0114	25	110		110		
PM10	0.0114	25	110		110		
SO2	0.028 - 0.084	59 - 183	802		333		
NOX	0.0714	156	683		683		
VOC	0.004	8.7	38		38		
CO	0.0435	95	416		416		
Lead	0.8E-06	0.0002	0.007		0.04		

13) Operating Limitations, if applicable:

Total sulfur in syngas fuel will be limited to 120 ppmv/1-hr avg, 100 ppmv/3- and 8-hr avg, 75 ppmv/24-hr avg, and 50 ppmv/30-day rolling avg - see permit application text Section 4.1.1 and Appendix A, Exhibit A-1 for more description.

Notes:

Item 11) - Volumetric fuel flow, dry and excluding dilution nitrogen, based on minimum expected syngas heating value. Syngas heating value will range from about 240 to 305 Btu/dscf, HHV.

Item 12b) - Units are lb/10^6 Btu (HHV) gas fired based on minimum expected heating value, emission data from potential equip mfrs, except lead factor is from available IGCC literature (see applicationj text). Range shown for SO2 is based on 50 to 120 ppmv total fuel sulfur and expected range of syngas HHV.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Emergency Fire Water Pump Engines); Mesaba Two is identical

3) Emission Unit Identification Number: 008/009; 017/018

4) Stack/Vent Designation Number: 008/009; 020/021

5) Control Equipment Identification Number: _____

6) Engine Type: ☒ Reciprocating ☐ Turbine ☐ Other: _____

7) Engine is Used For: ☐ Non-Emergency use ☒ Emergency use only
(If you check this box, you must complete Part 2 of this form.)

8) Rated Heat Input: TBD mmBtu/hr

9) Rated Mechanical Output: 300 HP @ TBD RPM

10) Fuel Type: Low sulfur diesel @ 0.05 % Sulfur

11) Fuel Consumption Rate: TBD (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	0.0022	0.7	0.2			0.03	
PM10	0.0022	0.7	0.2			0.03	
SO_2	0.00205	0.6	0.2			0.03	
NO_X	0.031	9.3	2.3			0.5	
VOC	.0025	0.7	0.2			0.04	
CO	0.0067	2.0	0.5			0.1	
Lead							

13) Operating Limitations, if applicable:

Emergency and engine maintenance operation, only. Maintenance operation limited to 100 hours per year.

Notes:

Information shown is for one of two identical units to be installed with each phase, 1200 hp (four engines) to be installed for Phases I plus II.

Item 12b) - Units are lb/hp-hr based on AP-42, Table 3.3-1.

Items 12d) and 12g) - Maximum uncontrolled emission based on 500 hr/yr operation as defined by U.S. EPA; limited controlled emission based on proposed maximum annual operation of 100 hr/yr.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM

PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Emergency Diesel Generator - Gasification Island); Mesaba Two is identical

3) Emission Unit Identification Number: 006; 015

4) Stack/Vent Designation Number: 006; 018

5) Control Equipment Identification Number: _____

6) Engine Type: ☒ Reciprocating ☐ Turbine ☐ Other: _____

7) Engine is Used For: ☐ Non-Emergency use ☒ Emergency use only
(If you check this box, you must complete Part 2 of this form.)

8) Rated Heat Input: TBD mmBtu/hr

9) Rated Mechanical Output: 2 MW ~~HP~~ @ TBD RPM

10) Fuel Type: Low sulfur diesel @ 0.05 % Sulfur

11) Fuel Consumption Rate: TBD (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	0.94	1.9	0.5			0.09	
PM10	0.94	1.9	0.5			0.09	
SO_2	0.54	1.1	0.3			0.05	
NO_X	32.2	64.4	16			3.2	
VOC	0.95	1.9	0.5			0.09	
CO	7.4	14.8	3.7			0.7	
Lead							

13) Operating Limitations, if applicable:

Emergency and engine maintenance operation, only. Maintenance operation limited to 100 hours per year.

Notes:

Item 12b) - Units are lb/MW-hr based on AP-42, Table 3.4-1 and using 1341 hp/MW to convert units shown in AP-42.

Item 12c) - SO2 emission based on 0.05 wt % sulfur in diesel fuel.

Items 12d) and 12g) - Maximum uncontrolled emission based on 500 hr/yr operation as defined by U.S. EPA; limited controlled emission based on proposed maximum annual operation of 100 hr/yr.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-03**

INTERNAL COMBUSTION ENGINE (SINGLE-FUEL) FORM
PART 1: EMISSION CALCULATIONS

02/17/05

- Fill out Part 1 of this form for each fuel burned in each engine, or attach sheets with equivalent information. If the engine emits Hazardous Air Pollutants (HAPs), fill out and attach form EC-13C.
  Fill out Part 2 of this form only if you are installing a generator to be used for other than emergencies.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Emergency Diesel Generator - Power Block)

3) Emission Unit Identification Number: 007; 016

4) Stack/Vent Designation Number: 007; 019

5) Control Equipment Identification Number: _____

6) Engine Type: ☒ Reciprocating ☐ Turbine ☐ Other: _____

7) Engine is Used For: ☐ Non-Emergency use ☒ Emergency use only
(If you check this box, you must complete Part 2 of this form.)

8) Rated Heat Input: TBD mmBtu/hr

9) Rated Mechanical Output: 350 kW ~~HP~~ @ TBD RPM

10) Fuel Type: Low sulfur diesel @ 0.05 % Sulfur

11) Fuel Consumption Rate: TBD (gal/hr or cf/hr)

12) Calculations Summary: **Shown for Mesaba One; Mesaba Two is identical.**

12a) Pollutant	**12b)** Emission Factor (lbs/unit)	**12c)** Emission Rate (lbs/hr)	**12d)** Maximum Uncontrolled Emissions (tons/yr)	**12e)** Pollution Control Efficiency (%)	**12f)** Maximum Controlled Emissions (tons/yr)	**12g)** Limited Controlled Emissions (tons/yr)	**12h)** Actual Emissions (tons/yr)
PM	3.0	1.0	0.25			0.05	
PM10	3.0	1.0	0.25			0.05	
SO_2	2.7	1.0	0.25			0.05	
NO_X	41.6	14.6	3.6			0.7	
VOC	3.3	1.2	0.3			0.06	
CO	9.0	3.1	0.8			0.2	
Lead							

13) Operating Limitations, if applicable:

+

Notes:

Item 12b) - Units are lb/MW-hr based on AP-42, Table 3.3-1 and using 1341 hp/MW to convert units shown in AP-42.

Items 12d) and 12g) - Maximum uncontrolled emission based on 500 hr/yr operation as defined by U.S. EPA; limited controlled emission based on proposed maximum annual operation of 100 hr/yr.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **EC-13C**

HAZARDOUS AIR POLLUTANTS CALCULATION FORM (FUEL COMBUSTION HAPS)

5/27/98

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Tank Vent Boiler); Mesaba Two is identical

3) Emission Unit Identification Number: _____

4) Stack/Vent Designation Number: 010; 022

5) Maximum Rated Equipment Capacity: 65 (HHV) million BTU/hr

6) Control Equipment Designation Number: CE001; CE-004

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Syngas	0.005		240 Btu/cf (HHV)	Btu/ton, Btu/gal, Btu/cf	270,000 cf/hr	tons/hr; gal/hr; cf/hr
Natural Gas			1000 Btu/cf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	40,000 cf/hr	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
See attached permit application Section 4.2.3 and emissions calculations, Appendix B, Exhibit B-3, for description of HAPs emissions.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
N/A									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

See Form EC-02 and permit application Section 4.1.2.

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG); Mesaba Two is identical

3) Emission Unit Identification Number: 001; 010

4) Stack/Vent Designation Number: 001; 013

5) Maximum Rated Equipment Capacity: 2184 (HHV, syngas), 2077 (HHV, natural gas) for each of two CTGs million BTU/hr

6) Control Equipment Designation Number: (NA)

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
syngas (primary)	0.005 vol %		240-305 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2184 million Btu/hr HHV, each	tons/hr; gal/hr; cf/hr
natural gas (startup, backup)	1 grain /100 scf		1020 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2077 million Btu/hr HHV, each	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:
Shown for Mesaba One; Mesaba Two is identical.

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
See attached permit application text Section 4.2.3 and Appendix B, Exhibit B-2 for HAPs discussion and emission calculations.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
Natural gas (backup fuel) - NA									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
NA									

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
See attached permit application text and appendices.					

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

No operating limits proposed for syngas fuel. Natural gas startup and backup operation will be limited to 440 hours per year after first 36 months of operation (see attached application text Section 4.1.1)..

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (CTG); Mesaba Two is identical

3) Emission Unit Identification Number: 002; 011

4) Stack/Vent Designation Number: 002; 011

5) Maximum Rated Equipment Capacity: 2184 (HHV, syngas), 2077 (HHV, natural gas) million BTU/hr

6) Control Equipment Designation Number: (NA)

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
syngas (primary)	0.005 vol %		240-305 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2184 million Btu/hr HHV	tons/hr; gal/hr; cf/hr
natural gas (startup, backup)	1 grain /100 scf		1020 Btu/scf (approx HHV)	Btu/ton, Btu/gal, Btu/cf	2077 million Btu/hr HHV	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
See attached permit application text Section 4.2.3 and Appendix B, Exhibit B-2 for HAPs discussion and emission calculations.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
Natural gas (backup fuel) - NA									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)
NA									

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)
See attached permit application text and appendices.					

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

No operating limits proposed for syngas fuel. Natural gas startup and backup operation will be limited to 440 hours per year after first 36 months of operation (see attached application text Section 4.1.1)..

PERMIT APPLICATION FORM **EC-13C**

HAZARDOUS AIR POLLUTANTS CALCULATION FORM (FUEL COMBUSTION HAPS)

5/27/98

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 6.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One (Flare) ; Mesaba Two is identical

3) Emission Unit Identification Number: (CE-002); (CE-005)

4) Stack/Vent Designation Number: 011; 023

5) Maximum Rated Equipment Capacity: 2 - 3730 (intermittant) million BTU/hr

6) Control Equipment Designation Number: 002; 005

7) Fuel Parameters

Shown for Mesaba One; Mesaba Two is identical.

7a) Fuel Type	**7b)** % Sulfur	**7c)** % Ash	**7d)** Heat Value	Units	**7e)** Fuel Consumption Rate	Units
Syngas and waste gas (+ nat gas pilot)	0.005 - 0.040		250 Btu/cf (approx)	Btu/ton, Btu/gal, Btu/cf	NA	tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr
				Btu/ton, Btu/gal, Btu/cf		tons/hr; gal/hr; cf/hr

When calculating Potential Emissions, use items 8a, 8b, 8d, 8e, 8g, 8h, and 8i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 8a, 8b, 8c, 8f, 8g, and 8j.

8) Calculations Summary - Primary Fuel:

8a HAP Name (CAS)	**8b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**8c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**8d** Emission Rate (lbs/hr)	**8e** Maximum Uncontrolled Emissions (tons/yr)	**8f** Actual Uncontrolled Emissions (tons/yr)	**8g** Pollution Control Efficiency (%)	**8h** Maximum Controlled Emissions (tons/yr)	**8i** Limited Controlled Emissions (tons/yr)	**8j** Actual Controlled Emissions (tons/yr)
(See attached permit application Section 4.2.3 and emissions calculations, Appendix B, Exhibit B-4, for description of HAPs emissions.									

When calculating Potential Emissions, use items 9a, 9b, 9d, 9e, 9g, 9h, and 9i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 9a, 9b, 9c, 9f, 9g, and 9j.

9) Calculations Summary - Back-up Fuel:

9a HAP Name (CAS)	**9b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**9c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**9d** Emission Rate (lbs/hr)	**9e** Maximum Uncontrolled Emissions (tons/yr)	**9f** Actual Uncontrolled Emissions (tons/yr)	**9g** Pollution Control Efficiency (%)	**9h** Maximum Controlled Emissions (tons/yr)	**9i** Limited Controlled Emissions (tons/yr)	**9j** Actual Controlled Emissions (tons/yr)
NA									

When calculating Potential Emissions, use items 10a, 10b, 10d, 10e , 10g, 10h, and 10i (if a limit is proposed in item 12).
When calculating Actual Emissions, use items 10a, 10b, 10c, 10f, 10g, and 10j.

10) Calculations Summary - Back-up Fuel:

10a HAP Name (CAS)	**10b** Emission Factor (lbs/ton, lbs/gal, lbs/MMcf, etc.)	**10c** Actual Annual Fuel Use (tons, gallons, MMcf, etc.)	**10d** Emission Rate (lbs/hr)	**10e** Maximum Uncontrolled Emissions (tons/yr)	**10f** Actual Uncontrolled Emissions (tons/yr)	**10g** Pollution Control Efficiency (%)	**10h** Maximum Controlled Emissions (tons/yr)	**10i** Limited Controlled Emissions (tons/yr)	**10j** Actual Controlled Emissions (tons/yr)

11) Worst-Case Potential-to-Emit Summary: (Ignore this item if filling out this form for a Registration Permit Option D)

HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)	HAP Name (CAS)	**11a)** ***Before Operating Limits:*** (tons/yr)	**11b)** ***After Operating Limits:*** (tons/yr)

12) Operating Limitations, if applicable: (Ignore this item if filling out this form for a Registration Permit Option D)

See Form EC-01 and permit application Section 4.1.3.

- Duplicate this form as necessary, or attach sheets with equivalent information.
- Instructions begin on Page 4.

1) AQ Facility ID No.: _____

2) Facility Name: Mesaba One and Mesaba Two (fugitive HAP/VOC)

3) Emission Unit Identification Number: FS-004 and FS-008

4) Stack/Vent Designation Number: N/A

5) Control Equipment Designation Number: _____

Complete item 6 or 7, not both.

6) Calculations Summary using Material Content: **Shown for Mesaba One; Mesaba Two is identical.**

Potential Emissions (Do not complete this table if using this form for Registration Permit Option D. Go to Actual Emissions Table in item 6.)

6a) Volatile HAP Name (CAS)	**6b)** Maximum HAP Content (lbs/gal)	**6c)** Maximum Material Usage Rate (gal/hr)	**6d)** Maximum Uncontrolled HAP Emission Rate (lbs/hr)	**6e)** Maximum Uncontrolled HAP Emissions (tons/yr)	**6f)** Pollution Control Efficiency (%)	**6g)** Maximum Controlled HAP Emissions (tons/yr)	**6h)** Limited Controlled HAP Emissions (tons/yr)
See permit application text, Section 4.1.4 and Appendix B, Exhibit B-5 for description of fugitive HAP/VOC emissions and calculations							

Actual Emissions

6a) Volatile HAP Name (CAS)	**6i)** Actual HAP Content (lbs/gal)	**6j)** Actual Material Usage Rate (gal/hr)	**6k)** Actual Uncontrolled HAP Emission Rate (lbs/hr)	**6l)** Actual Uncontrolled HAP Emissions (tons/yr)	**6f)** Pollution Control Efficiency (%)	**6m)** Actual Controlled HAP Emissions (tons/yr)
(N/A)						

7) Calculations Summary using Emission Factors:

Potential Emissions (Do not complete this table if using this form for Registration Permit Option D. Go to the Actual Emission Table in item 7.)

7a) Volatile HAP Name (CAS)	**7b)** Maximum Emission Factor	**7c)** Maximum Hourly Production or Material Use	**7d)** Maximum HAP Emission Rate (lbs/hr)	**7e)** Maximum Uncontrolled HAP Emissions (tons/yr)	**7f)** Pollution Control Efficiency (%)	**7g)** Maximum Controlled HAP Emissions (tons/yr)	**7h)** Limited Controlled HAP Emissions (tons/yr)

Actual Emissions

7a) Volatile HAP Name (CAS)	**7i)** Actual Emission Factor	**7j)** Actual Hourly Production or Material Use	**7k)** Actual Uncontrolled HAP Emission Rate (lbs/hr)	**7l)** Actual Uncontrolled HAP Emissions (tons/yr)	**7f)** Pollution Control Efficiency (%)	**7m)** Actual Controlled HAP Emissions (tons/yr)

8) Operating Limitations, if applicable: (Ignore this item if using the form for Registration Permit Option D).

none proposed

the PTE after limiting factors are taken into account. Attach additional sheets that show calculations and assumptions.

Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **IA-01**

INSIGNIFICANT ACTIVITIES (REQUIRED TO BE LISTED)

06/01/04

1) AQ Facility ID No.: _____

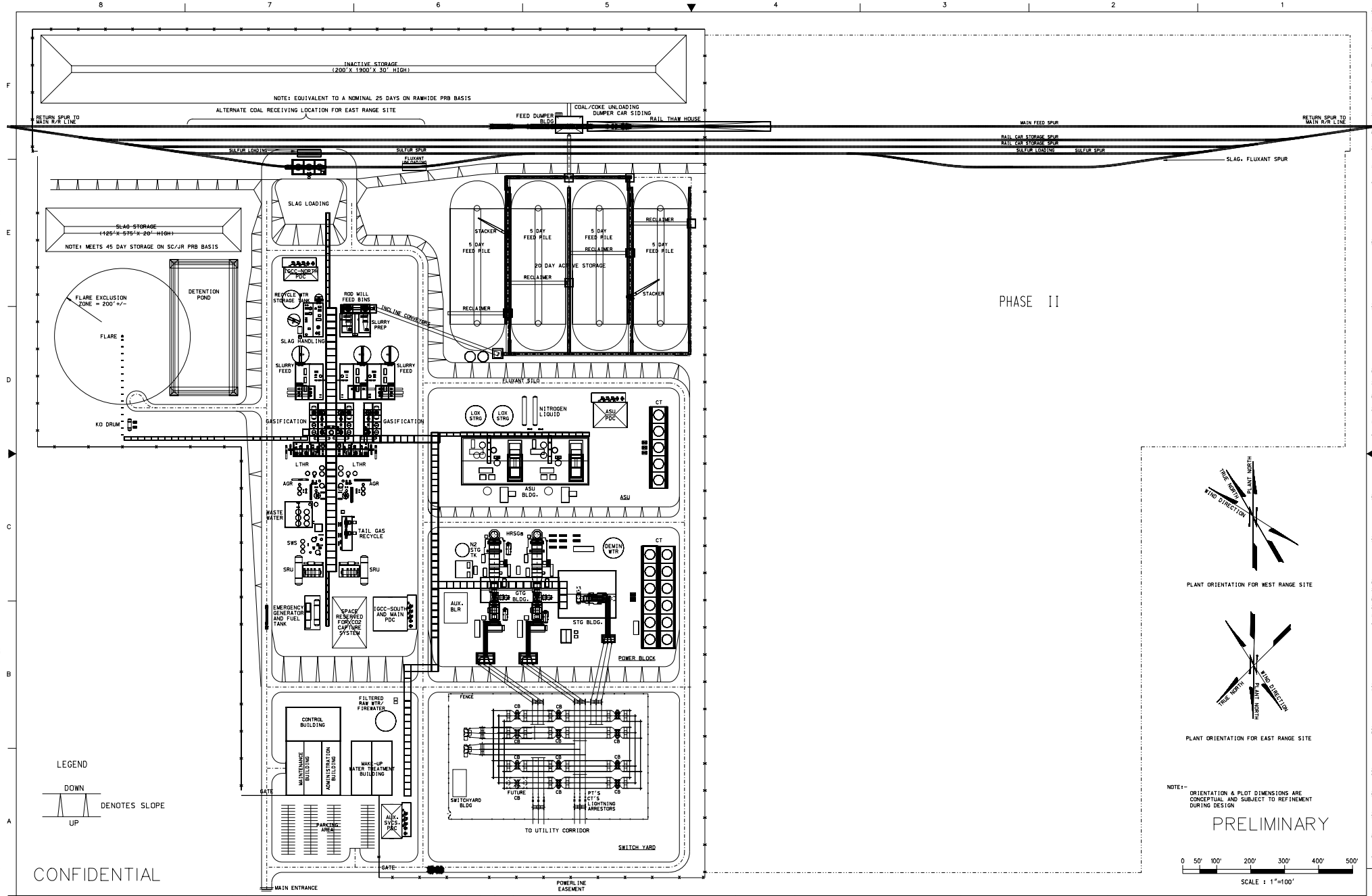
2) Facility Name: Mesaba One and Mesaba Two

3) Description of Activities

3a)	Rule Citation	**3b)** Description of Activities at the Facility
☒	7007.1300, subp. 3(A)	Portable space heaters for miscellaneous winter use during construction and plant operations and maintenance
☒	7007.1300, subp. 3(B)(1)	Infrared heaters used in rail car thaw shed
☐	7007.1300, subp. 3(B)(2)	
☐	7007.1300, subp. 3(C)	
☐	7007.1300, subp. 3(D)	
☐	7007.1300, subp. 3(E)(1)	

☒	7007.1300, subp. 3(E)(2)	Low sulfur diesel fuel storage for stationary emergency egines
☐	7007.1300, subp. 3(F)	
☒	7007.1300, subp. 3(G)	Plant chem lab
☐	7007.1300, subp. 3(H)(1)	
☒	7007.1300, subp. 3(H)(2)	Hydraulic and hydrostatic testing equipment used for construction and plant maintenance
☒	7007.1300, subp. 3(H)(3)	Brazing, soldering and welding equipment used for construction and plant maintenance
☒	7007.1300, subp. 3(H)(4)	Office blueprint machine
☐	7007.1300, subp. 3(H)(5)	
☐	7007.1300, subp. 3(H)(6)	
☒	7007.1300, subp. 3(H)(7)	Various construction and operations maintenance equipment cleaning operations

☐	7007.1300, subp. 3(I)	
☒	7007.1300, subp. 3(J)	Some graveled (unpaved) roads included in permanent plant facilities
☒	7007.1300, subp. 3(K)	Spray paint equipment for plant equipment and facility maintenance work
☐	7007.1300, subp. 4	
☐	7008.4100	
☐	7008.4110	



REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS	REFERENCE DWG NUMBER	REFERENCE DRAWINGS
A	17MAY05	PRELIMINARY CONCEPTUAL LAYOUT FOR PLOT SPACE ALLOCATION	TB	JT	GS										
B	29JUN05	GENERAL UPDATE	TB	JT											
C	11AUG05	ADD 3RD GASIFICATION TRAIN, RECONFIGURE SIZE OF FEED STRG. AREA	CB	JT											
D	21OCT05	GENERAL UPDATE	SR	JT											
E	12DEC05	ADD AUX. BOILER AND EAST RANGE COAL RECEIVING LOCATION	SR	JT											

PLOT DATE:

FLUOR

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CONTRACT A2AS
DESIGNED BY TB
CHECKED BY JT
SUPERVISOR JT — APP DATE
LEAD ENGR/SPEC. — APP DATE
FLUOR GS — APP DATE
CLIENT — APP DATE

EXCELSIOR ENERGY INC.
MESABA ENERGY PROJECT

PHASE I CONCEPTUAL PLOT PLAN

SCALE 1"=100'
DRAWING NUMBER A2AS-PP-SK1
REV E
CAD FILE NAME tb_mesaba_ph1_rev.e.DWG

XREF ATTACHED - YES☐ NO☐ MANUAL CHANGES MADE - YES☐ NO☐ DWG FILE UPDATED - YES☐ NO☐ MODEL UPDATED - YES☐ NO☐

Appendix A

Criteria Air Pollutant Emission Calculations

APPENDIX A – CRITERIA POLLUTANT EMISSION CALCULATIONS

This appendix presents the calculations and assumptions used to estimate criteria[4] pollutant emissions resulting from the Mesaba Energy Project. The criteria pollutants are sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM, or PM less than 10 microns, PM10). Lead is also considered a criteria pollutant, but this for application lead emissions are included with the hazardous air pollutant (HAP) estimates.

Emission estimates are presented in the following sections:

Exhibit A-1 Combustion Turbine Emission Rates

Exhibit A-2 Tank Vent Boiler Emission Rates

Exhibit A-3 Auxiliary Boiler Emission Rates

Exhibit A-4 Flare Emission Rates

Exhibit A-5 Cooling Tower Emission Rates

Exhibit A-6 Emergency Diesel Engines Emission Rates

Exhibit A-7 Fugitive Particulate Emission Calculations

Each section describes how the emission estimates presented in Section 4 of this application were developed and include example calculations, key assumptions, and reference citations. For simplicity, only calculations for Phase I of the project are presented. Phase II emissions will be numerically identical to Phase I.

[4] "Criteria" pollutants are those for which quantitative ambient air quality standards have been established.

Exhibit A-1 Combustion Turbine Generators

Mesaba Energy Project
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Air Permit Application

Exhibit A-1 COMBUSTION TURBINE EMISSION RATES

Basis: Siemens SGT6-5000Fperformance estimates for Mesaba Project or estimated worst case for other suppliers

Short-term Emissions on Syn Gas

Syngas fuel rate per CTG 2110 to 2184 x 10^6 Btu/hr, HHV (from Siemens)

Min Coal conversion efficency	**0.714**	Syngas heating value =	242 Btu/dscf (HHV)	(PRB coal)
Max Coal conversion efficency	**0.793**	Syngas heating value =	303 Btu/dscf (HHV)	(Illinois coal)
Gasifiers coal feed (per CTG)	2955 (max)	2754 (min) x 10^6 Btu/hr (HHV)		

1-, 3-, 8-, 24-hr and 30-day averages*				
	lb/hr (per stack)	lb/10^6 Btu coal min	lb/10^6 Btu coal max	Basis
NOx	156	0.053	0.057	15 ppmvd (@15% O2)
CO	95	0.032	0.034	15 ppmvd (@ 15% O2)
PM10	25	0.008	0.009	filterable (front-half) + condensible (back half)
VOC	8.7	0.003	0.003	2.4 ppmvd (@ 15% O2)

* Mass emission rate from CTG suppliers for basis stated.

Energy Bill Limits	
	lb/10^6 Btu coal
NOx	0.08
CO	NA
PM10	0.01
VOC	NA

Syn Gas SO2 Emission from Combustion Turbine					
Avg time	Syn gas avg sulfur, ppm	SO2, lb/hr (min) (per stack)	SO2, lb/hr (max) (per stack)	lb/10^6 Btu coal min	lb/10^6 Btu coal max
1-hr	120	141	183	0.051	0.062
3-hr	100	117	152	0.043	0.052
8-hr	100	117	152	0.043	0.052
24-hr	75	88	114	0.032	0.039
30-day	50	59	76	0.021	0.026
Energy Bill Limit				0.05	0.05

Example calculations for SO2
(From Ideal Gas Law, 1 lbmol gas = 380 scf, scf defined @ 60 deg F, 1 atm)
Max SO2 for 50 ppmv total sulfur in fuel
= (2184 x10^6 Btu/hr)/(242 Btu/scf) x (50 scf sulfur/10^6 scf) x (64 lb SO2/380 scf) = 76 lb SO2/hr/CTG
Min SO2 for 50 ppmv total sulfur in fuel
= (2110 x10^6 Btu/hr)/(303 Btu/scf) x (50 scf sulfur/10^6 scf) x (64 lb SO2/380 scf) = 59 lb SO2/hr/CTG

Short-term Emissions on Natural Gas

Nat gas fuel rate per CTG= 2077 x 10^6 Btu/hr, HHV (supplier data)

1-, 3-, 8-, 24-hr and 30-day averages*		
	lb/hr (per stack)	Basis
NOx	198	25 ppmvd (@15% O2)
CO	72	15 ppmvd (@ 15% O2)
PM10	18	filterable (front-half) + condensible (back half)
VOC	6.6	2.4 ppmvd (@ 15% O2)
SO2	5.9	1 grain sulfur/100 scf in pipeline nat gas.

* Mass emission rate from CTG suppliers for basis stated.

CTG Startup/shutdown Emissions per CTG (supplier data)

Avg Startup/shutdown Emission, lb/hr				
	Hot Start	Warm Start	Cold Start	Worst Case, lb/hr
NOx	108	116	121	121
CO	2116	2740	2205	2740
PM10	10	11	11	11
VOC	204	263	212	263
Typical duration	52 min	81 min	101 min	(N/A)

Notes: - Only CO and VOC hourly average startup emission rates exceed normal full load operation emission rates.
- CO and VOC shutdown emission rates (not shown) will also exceed normal full load emission rates, but are less than worst-case startup emissions.
- CTG fuel consumption, and therefore also SO2 emissions, are less during startup/shutdown than normal full load operation

Exhibit A-1 CTG Page 1 of 2

Mesaba Energy Project
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Exhibit A-1 COMBUSTION TURBINE EMISSION RATES

Worst Case Estimated Annual Emissions

Worst Case Annual Emissions			
	ton/yr (per stack)	avg lb/hr (per stack)	Basis
NOx*	739	169	1st yr - 2630 hr nat gas full load operation, balance on syn gas at full load
	720	164	2nd yr - 1750 hr nat gas full load operation, balance on syn gas at full load
	702	160	3rd yr - 880 hr nat gas full load operation, balance on syn gas at full load
	693	158	4th yr and later - 440 hr nat gas full load operation, balance on syn gas at full load
CO	482	110	50 hr/yr startup/shutdown, balance of year on syn gas at full load**
PM10	110	25	8760 hr/yr on syn gas at full load
VOC	44	10	50 hr/yr startup/shutdown, balance of year on syn gas at full load**
SO2	333	76	50 ppm ann avg sulfur in fuel, 8760 hr/yr on syn gas at full load

* Maximum natural gas use assumed as 30% during first year (2630 hours during first 12 calendar months after initial commercial operation), 20% during second year, 10% during third year, and 5% during fourth and following years (all excluding startup operations

** Startup/shutdown based on approximately 25 starts per year per CTG and about 2 hours per event.

Actual Annual Emissions for Backup Natural Gas Emissions

Actual Emissions for Natural Gas and Syngas Operating Scenarios					
Year	1	2	3	4	Basis - Idicated hours of natural gas full load operation plus additional operation as stated below
Hr/yr	2630	1750	880	440	
Ton/yr (per stack)					
NOx	739	720	702	693	Balance of year on syn gas at full load
SO2	241	272	302	318	Balance of year on syn gas at full load, 50 ppm ann avg sulfur in fuel
CO	452	462	472	477	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load
PM10	100	103	106	108	Balance of year on syn gas at full load
VOC	42	43	44	44	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load

Phase I plus Phase II, ton/yr				
NOx	2954	2880	2807	2770
SO2	964	1088	1210	1271
CO	1808	1848	1888	1909
PM10	401	414	426	432
VOC	167	171	174	176

Exhibit A-1 CTG Page 2 of 2

Exhibit A-2 Tank Vent Boiler

Mesaba Energy Project
01/20/2006

Air Permit Application

Exhibit A-2 TANK VENT BOILER EMISSION RATES (Phase I)

Basis: ConocoPhillips estimates and supplier data for similar equipment

TVB emission factors (lb/10^6 Btu fired)

	SG	NG	Basis
SO2	*	0.00286	1 grain/100 scf nat gas
NOx	0.3	0.3	supplier data for similar equipment
CO	0.09	0.09	60 ppmvd (12% O2), supplier data for similar equipment
PM10	0.01	0.01	supplier data for similar equipment
VOC	0.004	0.004	CoP estimate

(SG = syngas, NG = natural gas)

* See emission table below

SO2 from sulfur in tank vent gas during normal oper = 3 lb/hr (CoP estimate)

Operating Modes	Capacities, 10^6 Btu/hr SG	NG
Gasifier outage		40
Startup	10	30
Maximum operation, short-term	65	
Normal operation, long-term	15	

syngas HHV = 242 Btu/dscf

Worst Case SO2 Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs							
Startup, hrs							
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs					620	8,360	
SG consumed, 10^6 Btu	65	195	520	1560	15,800	151,400	
NG consumed, 10^6 Btu	0	0	0	0	0	0	
Sulfur in SG, ppmv	120	100	100	75	50	50	
SO2 from SG, lb/10^6 Btu SG*	0.084	0.070	0.070	0.052	0.035	0.035	
SO2 from SG or NG, lbs	5	14	36	82	551	5,275	
SO2 from tank vent gas, lbs	3	9	24	72	2,160	26,280	
Total SO2, lb/hr	8.4	7.5	7.5	6.4	3.8	3.6	15.8

* Example SO2 emission factor calculations.
SO2 (syngas) = (50 scf S/10^6 scf fuel) x (64 lb SO2/380 scf S)/(242 Btu/scf fuel) = 0.035 lb SO2/10^6 Btu
SO2 (natural gas) = 1 grain S/100 scf x 10^3 scf/10^6 Btu x 1 lb/7000 grain x 2 lb SO2/lb SO2 = 0.00286 lb SO2/10^6 Btu

Worst Case Non-Sulfur Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs					620	720	
Startup, hrs						263	
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs						7,377	
SG consumed, 10^6 Btu	65	195	520	1560	6,500	139,285	
NG consumed, 10^6 Btu	0	0	0	0	24,800	36,690	
NOx,lb/hr	19.5	19.5	19.5	19.5	13.0	6.0	26.4
CO, lb/hr	5.9	5.9	5.9	5.9	3.9	1.81	7.9
PM10, lb/hr	0.7	0.7	0.7	0.7	0.4	0.20	0.9
VOC, lb/hr	0.3	0.3	0.3	0.3	0.2	0.1	0.4

Exhibit A-2 TVB Page 1 of 1

Exhibit A-3 Auxiliary Boiler

Mesaba Energy Project
01/20/2006

Air Permit Application

Exhibit A-3 AUXILIARY BOILER EMISSION ESTIMATES (Phase I)

(Mainly used for startups, could be used for other purposes, primarily during power block outages)

Maximum steam generation 100,000 lb/hr
Maximum heat release 130 10^6 Btu/hr, HHV
Natural gas fuel, only

Emission factors

	lb/10^6 Btu, HHV	Basis
SO2	0.00286	1.0 grain total sulfur/100 scf pipeline natural gas
NOx	0.036	Low NOx burner, based on similar equipment from previous project
CO	0.074	Similar equipment from previous project
PM10	0.005	Similar equipment from previous project
VOC	0.004	Similar equipment from previous project

Emission calulations

	Max short-term lb/hr (1)	Annual average ton/yr (2)
SO2	0.37	0.41
NOx	4.7	5.1
CO	9.6	10.5
PM10	0.65	0.71
VOC	0.52	0.57

Notes:
(1) Maximum 1-hr, 3-hr, 8-hr, 24-hr, and 30-day average emission rates.
(2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than 0.25 x 8760 hr/yr x 130 million Btu/hr = 285 billion Btu/yr)

Exhibit A-3 Aux Boiler Page 1 of 1

Exhibit A-4 Flare

Mesaba Energy Project
01/20/2006

Air Permit Application

Exhibit A-4 FLARE EMISSION RATES (Phase I)

Emission Factors

	lb/10^6 Btu fired, HHV		
	SG	NG	Basis
SO2	see table	0.00286	1 grain sulfur/100 scf pipeline natural gas
NOx	0.064	0.064	TRNCC guidance document (1)
CO	1.5	0.55	Assumed 99% destruction of CO in SG (2), TRNCC factor for NG (1)
PM10	0.008	0.008	Very little unoxidized carbon in syngas, therefore very little PM, used AP-42 factor for NG in boiler (a small value) (3)
VOC	0.006	0.006	Virtually no VOC in syngas, used AP-42 factor for NG in boiler (a small value) (3)

Notes:

(1) Texas Natural Resource Conservation Commission (now Texas Commission on Environmental Quality), *Technical Guidance Package for Chemical Sources, Flares and Oxidizers (RG-109)*, May 1997

(2) CO emission factor based on 50 vol % CO in flared gas, assumed 99% destruction efficiency, and 242 Btu/scf HHV,
CO = (0.50 scf/scf) x (1 - 0.99)/(242 Btu/scf) x (28 lb/380 scf) x (10^6/10^6) = 1.52 lb/10^6 Btu, HHV

(3) U.S. EPA, AP-42, Table 1.4-2

	Capacities, 10^6 Btu/hr		
Operating Modes	SG	NG	
Steady state (pilot only)		2	
Heatup/deslag		40	
Flaring syn gas, max 1-hr avg	3730		(85% of max capacity for two gasifiers)
Flaring syn gas, max > 1-hr avg	3510		
Flaring syn gas, max >8-hr avg	1755		

Syngas HHV = 242 Btu/dscf

Worst Case Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Steady state (pilot only) hrs	1	3	8	24	720	8760	
Heatup/deslag hrs					210	1260	
Flaring hrs syn gas, max 1-hr	1						
Flaring hrs syn gas, max >1-hr		3	8				
Flaring hrs gas, max >8-hr				24	100	200	
SG flared, 10^6 Btu	3730	10530	28,080	42,120	175,500	351,000	
NG consumed, 10^6 Btu	2	6	16	48	9840	67920	
Sulfur in SG, ppmv	400	300	200	150	100	100	
SO2 from SG, lb/10^6 Btu SG	0.279	0.209	0.139	0.105	0.070	0.070	
SO2,lb/hr (total SG + NG)	1,040	734	489	183	17.0	2.8	12.3
NOx,lb/hr	238.8	224.8	224.8	112.4	16.5	3.1	13.4
CO, lb/hr	5,680	5,345	5,345	2,673	379	65	285.9
PM10, lb/hr	29.9	28.1	28.1	14.1	2.1	0.38	1.7
VOC, lb/hr	22.4	21.1	21.1	10.5	1.5	0.29	1.3

Exhibit A-4 Flare Page 1 of 1

Exhibit A-5 Cooling Towers

Mesaba Energy Project
01/20/2006

Air Permit Application

Exhibit A-5 COOLING TOWER EMISSION RATE (Phase I)

Basis: Similar equipment from previous project.

Cooling Tower Operating Data and Emission Calculation			
Parameter	**Power Block**	**Gasification/ ASU**	**Basis**
Heat rejected, million Btu/hr	1740	690	Preliminary heat balances
Cooling water (CW) circulation rate, million lb/hr	116	46	Typical cooling tower design
Max CW dissolved solids, ppmw	2700	2700	TDS of water supply plus eight cycles of concentration
Drift, fraction of circulating CW	0.0010%	0.0010%	Typical supplier guarantee
PM10 emission rate, lb/hr	3.1	1.2	Calculated
PM10 emission rate, ton/yr	13.7	5.4	Calculated

Total PM10 cooling tower emission, Phase I = 19.2 ton/yr

Example calculation:
Maximum expected total dissolved solids (TDS) in makeup water = 337 parts per million by weight (ppmw)
Maximum expected TDS in circulating cooling water at eight cycles of concentration = 8 x 337 = 2700 ppmw
Power Block cooling tower PM10 = (116 x 10^6 lb/hr) x (0.00001 lb drift/lb) x (2700 lb PM/10^6 lb drift) = 3.1 lb PM10/hr

Exhibit A-5 Cooling Towers Page 1 of 1

Exhibit A-6 Emergency Generators and Fire Pumps

Exhibit A-6 EMERGENCY DIESEL ENGINES EMISSION RATES (Phase I)

Basis: AP-42, Sections 3.3 and 3.4

Short-term Emission Rates						
		Emission Factor or Emission Rate				
Engines	Total hp	NOx	SO2*	CO	PM102	VOC
Emission Factors						
Large Stationary Diesel And All Stationary Dual-fuel Engines, >600 hp - emission factor from AP-42, Table 3.4-1, lb/hp-hr		0.024	8.09E-03	5.50E-03	0.0007	7.05E-04
Emission factor - Gasoline And Diesel Industrial Engines, <600 hp - emission factor from AP-42, Table 3.3-1, lb/hp-hr		0.031	2.05E-03	6.68E-03	2.20E-03	2.47E-03
Emission Rates						
Emergency Generator, 2 MW - emission, lb/hr	2682	64	1.1	15	1.9	1.9
Emergency Generator, 350 kW - emission, lb/hr	469	15	1.0	3.1	1.0	1.2
2 Emergency Fire Water Pump Engines, 300 hp each - emission, lb/hr	600	19	1.2	4.0	1.3	1.5
Total	**3751**					

* Large engine SO2 emission factor to be multiplied by the wt % sulfur in fuel (small engine factor is not adjusted)

Fuel sulfur = 0.05 wt%
1 MW = 1341 bhp

Annual Emission Rates**					
	Emission Rate, ton/yr				
Engines	NOx	SO2	CO	PM102	VOC
Emergency Generator, 2 MW - emission, ton/yr	3.2	0.05	0.7	0.09	0.09
Emergency Generator, 350 kW - emission, ton/yr	0.7	0.05	0.2	0.05	0.06
2 Emergency Fire Water Pump Engines, 300 hp each - emission, ton/yr	0.9	0.06	0.2	0.07	0.07
Total	**4.9**	**0.2**	**1.1**	**0.2**	**0.2**

** Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.

Example Calculation
2 MW generator SO2:
2 MW x 1341 hp/MW = 2682 hp
SO2 = 2682 hp x 0.00809lb/hp-hr x 0.05 wt% S = 1.08 lb/hr
Annual SO2 = 1.08 lb/hr x 100hr/yr x 1 ton/2000 lb = 0.05 ton/yr

Exhibit A-7 Material Handling System

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Exhibit A-7 FUGITIVE PARTICULATE MATTER EMISSION CALCULATIONS

TABLE OF CONTENTS

1.0 EMISSION FACTORS
2.0 THROUGHPUT RATES
3.0 COAL AND PILE SURFACE AREAS
4.0 COAL PILE WIND EROSION
5.0 SLAG PILE WIND EROSION

1.0 EMISSION FACTORS

1.1 For Rail Car Unloading, E is obtained from EPRI CS-3455 (6/84)

1.2 For Transfer Points 2 through 13, Coal Emission Factors are calculated from the equation given in AP-42, Section 13.2.4

E= k*0.0032*{(U/5)^1.3/(M/2)^1.4} lb/ton

where, k=particle size multiplier (dimensionless). Its value is 0.74 for PM30 and 0.35 for PM10.

U=mean wind speed, miles per hour (mph)

M=material moisture content (%)

For the Mesaba Energy Project Site, wind speed frequency data were obtained from University of Minnesota Technical Bulletin AD-TB1955 for the Hibbing, MN area. (web link http://climate.umn.edu/pdf/climate_of_minnesota/comXIV.pdf), where the mean annual average wind speed is 9.3 miles per hour.

The assumed surface moisture content for PRB coal is 4%*

This gives

For PM30, E= 0.74*0.0032*{(9.3/5)^1.3/(4/2)^1.4} = 0.002011 lb/ton

and

For PM10, E= 0.35*0.0032*{(9.3/5)^1.3/(4/2)^1.4} = 0.000951 lb/ton

1.3 For slag handling, emission factors are given by the same equations on substituting the moisture content of slag = 2%

For PM30, E= 0.74*0.0032*{(9.3/5)^1.3/(2/2)^1.4} = 0.005306 lb/ton

and

For PM10, E= 0.35*0.0032*{(9.3/5)^1.3/(2/2)^1.4} = 0.002509 lb/ton

1.4 For onsite truck traffic (slag transfer) emission factors are obtained from AP-42 Section 13.2.2

For vehicles traveling on unpaved surfaces at industrial sites,

E=k^(s/12)^a * (W/3)^b lb/ Vehicle Miles Travelled (VMT)

where k,a and b are emperical constants and

s= surface material silt content (%)

W= mean vehicle weight (tons)

From Tables in AP-42 Section 13.2.2

	PM30	PM10
k	4.9	1.5
a	0.7	0.9
b	0.45	0.45

Assuming s=6% and W= 30 tons (30 tons represents the mean weight between the estimated loaded (40 tons) and empty (20 ton) truck weights)

For PM30, E=4.9*(6/12)^0.7 * (30/3)^0.45= 8.5

For PM10, E=1.5*(6/12)^0.9 * (30/3)^0.45= 2.3

* PRB coal ranges from 20 to 30% in total moisture, however much of this water is chemically bound to the coal. In the absence of specific data, these calculations assume an average surface moisture for PRB coal of about 4%, somewhat less than the mean reported for a range of coals in AP-42, Table 13.2.4-1, to account for the "dustyness" observed by some users of PRB coal.

2.0 THROUGHPUT RATES

As received maximum feed rate for PRB Coal, tpd, 8550
Slag production rate, tpd, 772

2.1 Coal, for materials handling upstream of coal pile:

2.1.1 Maximum hourly feed rate is based on unloading of 36 cars (119 tons per car) per hour

=119*36= 4284 , say 4,300 tons per hour

Time to Unload 115-car train = 115*119/4300= 3.18 , say 3.2 hours

2.1.2 Maximum annual throughput rate based on 100% capacity factor
=8550*365= 3120750 , say, 3,100,000 tons per year

2.2 For materials handling downstream of coal pile:
Peak rate is based on 120% of the normal average coal rate required for the nominal plant output

= 120% of 8550/24= 427.5 , say 430 tons per hour

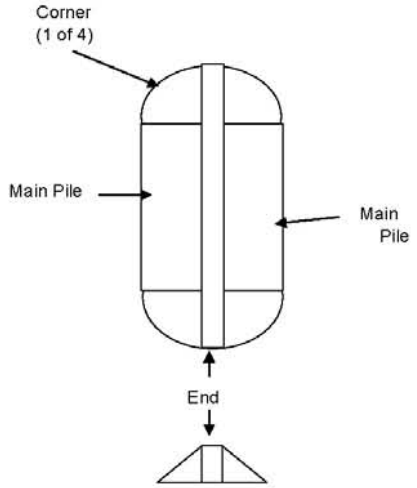
5.3 Slag
2.3.1 Max. hourly throughput based on 120% of the normal average coal rate required for the nominal plant c
= 120% of 772/24= 38.6 , say 39 tons per hour

2.3.2 Maximum annual throughput rate based on 100% capacity factor
=772*365= 281780 tons per year

2.4 For Slag disposal truck traffic, the throughput rate is based on vehicle miles travelled.
Assuming 20 ton trucks, number of trucks required per hour = 772/(24*20)= 1.608 , use 2
Assuming 0.2 miles round trip, VMT/hour= 0.2*2= 0.4 VMT/hour
Maximum annual throughput rate based on 100% capacity factor
=0.4*8760= 3504 , say, 3,500 VMT per year

3.0 COAL AND SLAG PILE SURFACE AREAS

3.1 **Surface Area of Coal Pile**



Givens

Length of pile, ft	500
Width of pile, ft	160
Angle of repose, degrees	35
Height of pile, ft	47

Calculated

Edge width, ft	67.1	
Area of sides= 2*(500-2*67.1)*47/sin 35o =		59,941 ft^2
Area of Top= (500-2*67.1)*(160-2*67.1) =		9,420 ft^2
Area of 4 corners, assuming conical shape= PI*67.1*(67.1^2+47^2)^0.5		17,279 ft^2
Area of 2 ends= 2*67.1*(160-2*67.1)		3,457 ft^2
		90,098 ft^2

3.2 **Surface Area of Slag Pile**

Length of pile, ft	575
Width of pile, ft	125
Angle of repose, degrees	27
Height of pile, ft	20

Calculated

Edge width, ft	39.3	
Area of sides= 2*(500-2*39.3)*20/sin 27o =		43,745 ft^2
Area of Top= (500-2*39.3)*(160-2*39.3) =		40,462 ft^2
Area of 4 corners, assuming conical shape= PI*39.3*(39.3^2+20^2)^0.5		5,432 ft^2
Area of 2 ends= 2*39.3*(160-2*39.3)		3,650 ft^2
		93,290 ft^2

4.0 COAL PILE WIND EROSION:

Windage emissions were calculated based on AP-42 Section 13.2.5

4.1 Source Activity and control application parameters:

		Source
Frequency of disturbance (days/yr):	365	Assumed
Height of pile (ft)	47	Sheet 5
Length of pile (ft)	500	Sheet 5
Width of pile (ft)	160	Sheet 5
Total surface area (ft2)	90,098	Sheet 5
Threshhold friction velocity (m/s)	1.12	From AP-42 Section 13.2.5, Table 13.2.5-2 for uncrusted coal pile
Threshhold wind velocity @ 10 m (m/s)	21	From AP-42 Section 13.2.5, Table 13.2.5-2 for uncrusted coal pile
Number of Active Piles	4	

4.2 Pile surface area within each surface wind speed range:

Based on AP-42 Section 13.2.5, Fig. 13.2.5-2, Pile B3
(Configuration B3 used based on slag pile shape and estimated relative wind direction, per Phase 1 Conceptual Plot Plan)
Contours of normalized surface wind speeds, where us=surface wind speed and ur=approach wind speed

Area ID	us/ur	%	area (ft2)
1.1	1.1	4	3604
0.9	0.9	14	12614
.6b	0.6	26	23425
.6a	0.6	28	25227
.2b	0.2	25	22525
.2a	0.2	3	2703

4.3 Calculate emission factor E=k*sum(P)

where k = 1 for PM
k = 0.5 for PM10

From AP-42 Section 13.2.5, Table 13.2.5-2, Section 13.2.5.3

4.4 Climatic data:

From Climate of Minnesota, University of Minnesota Document AD-TB1955 data (1983) for Hibbing

Mean wind speed: 9.3 mph

Wind speed Distribution

Spd (mph)	Assume	% of year	days/yr
<8	6	38.9	141.985
8-12	10	30.4	110.96
13-18	18	27	98.55
19-24	24	3.3	12.045
25-31	31	0.4	1.46
highest			
		100	365

Percent of year from Climate of Minnesota data (1983) for Hibbing (AD-TB 1955 Table 20)

4.5 Erosion Potential P = 58 (u*-ut*)^2 + 25 (u*-ut*) where u*= friction velocity (m/s) and ut=threshold friction velocity (m/s)

Days Peak wind (u10+) u+s = (us/ur) * u10+

u+ is the fastest mile value
u+ is the fastest mile value

	mph	m/s	us/ur=.2	us/ur=.6	us/ur=.9	us/ur=1.1
142.0	6	2.68	0.54	1.61	2.41	2.95
111.0	10	4.47	0.89	2.68	4.02	4.92
98.6	18	8.05	1.61	4.83	7.24	8.85
12.0	24	10.73	2.15	6.44	9.66	11.80
1.5	31	13.86	2.77	8.31	12.47	15.24
365.0						

Days

	u* = 0.1 u+s				Daily P(g/m2)			
	us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1	us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1
142.0	0.05	0.16	0.24	0.30	0	0	0	0
111.0	0.09	0.27	0.40	0.49	0	0	0	0
98.6	0.16	0.48	0.72	0.89	0	0	0	0
12.0	0.21	0.64	0.97	1.18	0	0	0	1.711357
1.5	0.28	0.83	1.25	1.52	0	0	4.115648	19.58594

4.6 Emission Results

Sum (P*#Days)	0.000	0.000	6.009	49.209		g/m2	
Areas	2343.6	4519.9	1171.8	334.8		m^2	
					TOTAL		
Emission/yr/active pile	0	0	0.008	0.018	**0.026**	ton/yr	PM
	0	0	0.004	0.009	**0.013**	ton/yr	PM10
Total Emissions/yr (active)	0	0	0.031	0.073	**0.104**	ton/yr	PM
	0	0	0.016	0.036	**0.052**	ton/yr	PM10

5.0 SLAG STORAGE PILE WIND EROSION:

5.1 Source Activity and control application parameters:

Frequency of disturbance (days/yr):	365
Height of pile (ft)	20
Length of pile (ft)	575
Width of pile (ft)	125
Total surface area (ft2)	93,290
Threshhold friction velocity (m/s)	1.12
Threshhold wind velocity @ 10 m (m/s)	21
Number of Active Piles	1

5.2 Pile surface area within each surface wind speed range:

Area ID	us/ur	%	area (ft2)
1.1	1.1	4	3732
0.9	0.9	14	13061
.6b	0.6	26	24255
.6a	0.6	28	26121
.2b	0.2	25	23323
.2a	0.2	3	2799

5.3 Calculate emission factor E=k*sum(P)

k = 1 for PM30
k = 0.5 for PM10

P = 58 (u*-u*t)^2 + 25 (u*-u*t)

5.4 Climatic data:

Mean wind speed: 9.3 mph
Wind speed Distribution

speed (mph)		% of year	days/yr
<8	6	38.9	141.985
8-12	10	30	109.5
13-18	18	27	98.55
19-24	24	3.3	12.045
25-31	31	0.4	1.46
		99.6	

Percent of year from Climate of Minnesota data (1983) for Hibbing

5.5 Erosion Potential:

Days Peak wind (u10+) u+s = (us/ur) * u10+

	mph	m/s	us/ur-=.2	us/ur=.6	us/ur=.9	us/ur=1.1
142.0	6	2.68	0.54	1.61	2.41	2.95
109.5	10	4.47	0.89	2.68	4.02	4.92
98.6	18	8.05	1.61	4.83	7.24	8.85
12.0	24	10.73	2.15	6.44	9.66	11.80
1.5	31	13.86	2.77	8.31	12.47	15.24
363.5						

Days

	u* = 0.1 u+s				Daily P(g/m2)			
	us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1	us/ur*.2	us/ur*.6	us/ur*.9	us/ur*1.1
142.0	0.05	0.16	0.24	0.30	0	0	0	0
109.5	0.09	0.27	0.40	0.49	0	0	0	0
98.6	0.16	0.48	0.72	0.89	0	0	0	0
12.0	0.21	0.64	0.97	1.18	0	0	0	1.711357
1.5	0.28	0.83	1.25	1.52	0	0	4.115648	19.58594

5.6 Emission Results

Sum (P*#Days)	0.000	0.000	6.009	49.209		g/m2	
Areas	2426.7	4680.0	1213.3	346.7		m^2	
					TOTAL		
Emission/yr/active pile	0	0	0.008	0.019	**0.027**	ton/yr	PM30
	0	0	0.004	0.009	**0.013**	ton/yr	PM10
Total Emissions/yr (active)	0	0	0.008	0.019	**0.027**	ton/yr	PM30
	0	0	0.004	0.009	**0.013**	ton/yr	PM10

Appendix B

Hazardous Air Pollutant Emission Calculations

This appendix presents the calculations and assumptions used to estimate hazardous air pollutant (HAP) emissions potentially resulting from the Mesaba Energy Project

Emission estimates are presented in the following sections:

Exhibit B-1 HAPs Emission Summary
Exhibit B-2 Combustion Turbine HAPs Emission Summary
Exhibit B-3 Tank Vent Boiler HAPs Emission Summary
Exhibit B-4 Flare HAPs
Exhibit B-5 Fugitive HAPs Emission Summary
Exhibit B-6 HAP Metals Emission Factors
Exhibit B-7 AP-42 and NETL Coal HAP Emission Factors
Exhibit B-8 Wabash River CTG HAPs
Exhibit B-9 Wabash River Syngas HAPs
Exhibit B-10 Wabash River TVB HAPs

In general, the HAPs evaluation includes those CAA § 112(b)(1) chemicals/compounds that either have been measured at the Wabash River or are listed in the *U.S. EPA Compilation of Air Pollutant Emission Factors (AP-42)* for coal combustion. Emission factors for the targeted HAPs were developed from the following sources, listed in order of preference:

1. Process stream analytical results and stack emission test results from the Wabash River Coal Gasification Repowering Demonstration Project.
2. Preliminary material balances and engineering design for the Mesaba Energy Project.
3. Published HAPs emission data for IGCC processes, such as the NETL 2002 report regarding the environmental aspects of coal gasification-based power generation (USDOE/NETL, 2002).
4. Published coal combustion (not gasification) average emission factors from AP-42.

The following sections show how the HAP emission estimates presented in Section 4 of this application were developed and include example calculations, key assumptions, and reference citations. For simplicity, only calculations for Phase I of the IGCC Power Station are presented. Phase II emissions will be numerically identical to Phase II.

To further illustrate the methodologies used, the following step-by-step example calculations are provided.

<u>Total chromium (Cr) emission from CTGs</u>

1. From Exhibit B-9, total Cr concentration in product syngas was not detected at the Wabash River during a test in November 2005. Using one-half the detection limit for the sample size, the assumed Cr concentration in product syngas is less than 0.0024 mg/dscm (milligram per dry standard meter).
2. From Exhibit B-8, assuming an average Wabash coal conversion efficiency (coal energy converted to syngas energy) of 0.77 and a representative heating value for syngas of 280 Btu/dscf HHV, this Cr concentration is equivalent to:

   $Cr = 0.0024\ mg/m^3 \times 1\ lb/454 \times 10^3\ mg \times 1\ m^3/35.3\ ft^3 \times 1\ ft^3/280\ Btu \times 0.77 \times 10^{12}/10^{12}$
   $= 0.41\ lb\ Cr/10^{12}\ Btu\ coal$

3. Exhibit B-6 shows how the Wabash metals emission factors are adjusted for the worst-case Mesaba feed concentrations. Available information indicates that the potential Mesaba solid feedstocks could range from 2.4 to 7 mg/kg CR concentration, while the Wabash feed contains about 5.5 mg/kg Cr. Multiplying the Wasbash emission factor by the ratio of the worst-case Mesaba concentration to the Wabash concentration gives the maximum expected Mesaba emission factor:

   Cr = 0.41 lb Cr/10^{12} Btu x 7/5.5 = 0.52 lb Cr/10^{12} Btu coal.

4. Exhibit B-2 presents the estimated HAPs emission rates for the Phase I CTGs. Based on an average feed rate to the gasifiers of 5775x10^6 Btu/hr, the annual Cr emission rate would be:

   Cr = 0.52 lb Cr/10^{12} Btu x 5595x10^6 Btu/hr x 8760 hrs/yr x 1 ton/2000 lbs = 0.013 ton/yr.

<u>Methyl tertiary butyl ether (MTBE) emission from CTGs</u>

1. Inspection of Exhibit B-8 shows that MTBE was apparently not measured for the Wabash River CTGs. No data for this HAP were found in available IGCC-specific reports. Therefore, AP-42 will be used to estimate this emission rate.

2. Exhibit B-7shows the AP-42 default emission factors for coal combustion-related HAPs. This table shows a factor of 3.5E-05 lb/ton of coal combusted. This factor is converted to units of heat input, based on the lowest as-received heating value expected for Mesaba, as follows:

   MTBE = 0.000035 lb/ton x 1 ton/2000 lbs x 1 lb/8300 Btu/lb x $10^{12}/10^{12}$ = 2.1 lb/10^{12} Btu

3. Exhibit B-2 shows the calculated emission rate of MTBE from the CTGs:

   MTBE = 2.1 lb/10^{12} Btu x 5595x10^6 Btu/hr x 8760 hrs/yr x 1 ton/2000 lbs = 0.1053 ton/yr.

Exhibit B-1 HAPs Emission Summary

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Exhibit B-1 HAPs EMISSION SUMMARY
(Phase I)

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				
		CTGs	TVB	Flare	Fugitive	Total
75-07-0	Acetaldehyde	0.044	1.6E-04	3.9E-04		0.045
98-86-2	Acetophenone	0.022	7.9E-05	2.0E-04		0.022
107-02-8	Acrolein	0.43	1.5E-03	3.8E-03		0.43
7440-36-0	Antimony	0.027	2.8E-04	7.0E-04		0.028
7440-38-2	Arsenic	0.059	1.5E-03	3.7E-03		0.064
71-43-2	Benzene	0.061	0.028	0.071	0.0063	0.167
100-44-7	Benzyl chloride	1.03	3.7E-03	9.2E-03		1.0
7440-41-7	Beryllium	0.0064	7.9E-06	2.0E-05		0.0064
92-52-4	Biphenyl	0.0025	9.0E-06	2.2E-05		0.0025
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	0.11	3.9E-04	9.6E-04		0.109
75-25-2	Bromoform	0.06	2.0E-04	5.0E-04		0.057
7440-43-9	Cadmium	0.24	5.7E-05	1.4E-04		0.24
75-15-0	Carbon disulfide	1.13	4.0E-03	1.0E-02	0.034	1.18
463581	Carbonyl sulfide				0.058	0.058
532-27-4	Chloroacetophenone, 2-	0.0103	3.7E-05	9.2E-05		0.0104
108-90-7	Chlorobenzene	0.032	1.1E-04	2.8E-04		0.032
67-66-3	Chloroform	0.088	3.2E-04	7.9E-04		0.089
0-00-5	Chromium, total (1)	0.013	1.1E-03	2.6E-03		0.016
18540-29-9	Chromium, (hexavalent)	0.0038	3.2E-04	7.9E-04		0.0049
7440-48-4	Cobalt (1)	0.0064	1.2E-03	3.0E-03		0.011
98-82-8	Cumene	0.0078	2.6E-05	6.6E-05		0.0079
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	0.140	4.6E-03	1.2E-02	0.0088	0.16
77-78-1	Dimethyl sulfate	0.071	2.5E-04	6.3E-04		0.072
121-14-2	Dinitrotoluene, 2,4-	4.2E-04	1.5E-06	3.7E-06		4.2E-04
100-41-4	Ethyl benzene	0.14	0.032	0.079	5.4E-06	0.25
75-00-3	Ethyl chloride (Chloroethane)	0.061	2.2E-04	5.5E-04		0.062
106-93-4	Ethylene dibromide (Dibromoethane)	0.0018	6.3E-06	1.6E-05		0.0018
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	0.059	2.1E-04	5.3E-04		0.060
50-00-0	Formaldehyde	0.42	1.5E-03	3.7E-03	1.1E-06	0.42
110-54-3	Hexane	0.10	3.5E-04	8.8E-04	1.5E-06	0.10
7647-01-0	Hydrochloric acid	0.096	3.0E-04	7.4E-04	0.034	0.13
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	1.2	5.3E-05	1.3E-04		1.2
78-59-1	Isophorone	0.86	3.1E-03	7.6E-03		0.87
7439-92-1	Lead	0.014	6.3E-05	1.6E-04		0.014
7439-96-5	Manganese	0.025	2.4E-03	5.9E-03		0.034
7439-97-6	Mercury	0.012	6.6E-04	1.6E-04		0.013
74-83-9	Methyl bromide (Bromomethane)	1.23	0.011	0.029		1.3
74-87-3	Methyl chloride (Chloromethane)	0.78	6.0E-03	1.5E-02		0.80
71-55-6	Methyl chloroform (1,1,1-Trichloroethane) (4)	0.029	1.1E-04	2.6E-04		0.030
78-93-3	Methyl ethyl ketone (2-Butanone)	0.58	2.1E-03	5.1E-03		0.58
60-34-4	Methyl hydrazine	0.25	9.0E-04	2.2E-03		0.25
80-62-6	Methyl methacrylate	0.029	1.1E-04	2.6E-04		0.030
1634-04-4	Methyl tert butyl ether	0.051	1.8E-04	4.6E-04		0.052

Exhibit B-1 Summary 1 of 2

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Exhibit B-1 HAPs EMISSION SUMMARY
(Phase I)

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				
		CTGs	TVB	Flare	Fugitive	Total
75-09-2	Methylene chloride (Dichloromethane)	0.056	5.5E-04	1.4E-03		0.058
91-20-3	Naphthalene	0.064	8.1E-04	2.0E-03	2.6E-05	0.067
7440-02-0	Nickel	0.0096	4.2E-03	1.0E-02		0.024
108-95-2	Phenol	0.95	1.2E-02	3.0E-02	7.8E-08	0.99
123-38-6	Proprionaldehyde	0.561	2.0E-03	5.0E-03		0.568
7784-49-2	Selenium	0.014	2.4E-04	5.9E-04		0.015
100-42-5	Styrene	0.037	1.3E-04	3.3E-04		0.037
127-18-4	Tetrachloroethylene (Perchloroethylene)	0.063	2.3E-04	5.7E-04		0.064
108-88-3	Toluene	0.00081	0.0112	0.0280	6.6E-04	0.041
108-05-4	Vinyl acetate	0.011	4.0E-05	1.0E-04		0.011
1330-20-7	Xylenes	0.055	0.013	0.032	1.0E-05	0.10
	Total federal HAPs	***11.4***	***0.2***	***0.4***	***0.1***	***12.0***
	Other Emissions					
56-55-3	Benz[a]anthracene	5.6E-05	2.0E-07	5.0E-07		5.7E-05
207-08-9	Benzo(k)fluoranthene	1.6E-04	5.8E-07	1.4E-06		1.6E-04
50-32-8	Benzo[a]pyrene	5.6E-05	2.0E-07	5.0E-07		5.7E-05
218-01-9	Chrysene (Benzo(a)phenanthrene)	1.5E-04	5.3E-07	1.3E-06		1.5E-04
193-39-5	Indeno(1,2,3-cd)pyrene	9.1E-05	3.2E-07	8.1E-07		9.2E-05
3697-24-3	Methylchrysene, 5-	3.2E-05	1.1E-07	2.8E-07		3.2E-05
7664-93-9 14808-79-8	Sulfuric acid and sulfates	62.0	0.2	0.6		62.8
	Other VOC				8.3	8.3
	Hydrogen sulfide				8.6	8.6
	Total Volatile Organic Compounds (VOC)	9.6	0.1	0.4	8.4	18.6
	Total Reduced Sulfur (TRS) Compounds	1.1	0.004	0.010	8.7	9.8

Significant HAPs	ton/yr	Basis
Acrolein	0.4	AP-42 coal combustion
Benzyl chloride	1.0	AP-42 coal combustion
Carbon disulfide	1.2	NETL report
Formaldehyde	0.4	NETL report
Hydrogen fluoride (Hydrofluoric acid)	1.2	NETL report
Isophorone	0.9	AP-42 coal combustion
Methyl bromide (Bromomethane)	1.3	Wabash data
Methyl chloride (Chloromethane)	0.8	AP-42 coal combustion
Methyl ethyl ketone (2-Butanone)	0.6	AP-42 coal combustion
Phenol	1.0	Wabash data
Proprionaldehyde	0.6	AP-42 coal combustion
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Exhibit B-2 Combustion Turbine HAPs Emission Summary

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Exhibit B-2 COMBUSTION TURBINE HAPs EMISSION SUMMARY
(Phase I)

Plant Performance

Syngas fuel	2115 x 10^6 Btu/hr/CTG, HHV (SW Case 2)
Min Coal conversion efficency	**0.719** (PRB coal)
Max Coal conversion efficency	**0.793** (Illinois coal)
Gasifiers coal feed, total Phase 1	5883 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
	5595 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor (lb/10^12 Btu coal)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	0.011	0.044	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	0.01	0.02	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	0.10	0.43	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony (1)	1.1	0.0065	0.027	Wabash River test data
7440-38-2	Arsenic (1)	2.4	0.0141	0.059	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	0.000014	0.000056	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	2.5	0.015	0.061	Wabash River test data
207-08-9	Benzo(k)fluoranthene (5)	0.0066	0.000039	0.00016	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene (3)	0.0023	0.000014	0.000056	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	0.25	1.03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium (1)	0.26	0.0015	0.0064	Wabash River test data
92-52-4	Biphenyl	0.10	0.00060	0.0025	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	0.026	0.11	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	0.014	0.056	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium (1)	9.6	0.06	0.24	Wabash River test data
75-15-0	Carbon disulfide	46	0.27	1.13	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	0.0025	0.010	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	0.0076	0.032	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform (4)	3.6	0.021	0.09	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total (1)	0.52	0.0031	0.013	Wabash River test data
18540-29-9	Chromium, (hexavalent)	0.16	0.00092	0.0038	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.0060	0.000035	0.00015	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt (1)	0.26	0.0015	0.0064	Wabash River test data
98-82-8	Cumene	0.32	0.0019	0.0078	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	5.7	0.034	0.14	NETL, Table 2-6 (see Reference 1)
77-78-1	Dimethyl sulfate	2.9	0.017	0.071	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	0.00010	0.00042	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	5.7	0.034	0.14	AP-42, Table 1.1-14 (see Reference 2)
75-00-3	Ethyl chloride (Chloroethane)	2.5	0.015	0.061	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	0.00042	0.0018	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	0.014	0.059	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	0.10	0.42	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	0.024	0.10	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid (1)	3.9	0.023	0.096	Wabash River test data
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (6)	50	0.29	1.23	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	0.000022	0.00009	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	0.21	0.86	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.56	0.0033	0.014	Wabash River test data
7439-96-5	Manganese (1)	1.0	0.0061	0.025	Wabash River test data
7439-97-6	Mercury	0.5	0.0029	0.012	(See Note 2)
74-83-9	Methyl bromide (Bromomethane)	50.2	0.30	1.23	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	31.9	0.19	0.78	AP-42, Table 1.1-14 (see Reference 2)

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Exhibit B-2 COMBUSTION TURBINE HAPs EMISSION SUMMARY
(Phase I)

Plant Performance

Syngas fuel 2115 x 10^6 Btu/hr/CTG, HHV (SW Case 2)
Min Coal conversion efficency **0.719** (PRB coal)
Max Coal conversion efficency **0.793** (Illinois coal)
Gasifiers coal feed, total Phase 1 5883 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
5595 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor (lb/10^6 Btu coal)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	0.011	0.044	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	0.01	0.02	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	0.10	0.43	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony (1)	1.1	0.0065	0.027	Wabash River test data
7440-38-2	Arsenic (1)	2.4	0.0141	0.059	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	0.000014	0.000056	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	2.5	0.015	0.061	Wabash River test data
207-08-9	Benzo(k)fluoranthene (5)	0.0066	0.000039	0.00016	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene (3)	0.0023	0.000014	0.000056	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	0.25	1.03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium (1)	0.26	0.0015	0.0064	Wabash River test data
92-52-4	Biphenyl	0.10	0.00060	0.0025	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	0.026	0.11	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	0.014	0.056	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium (1)	9.6	0.06	0.24	Wabash River test data
75-15-0	Carbon disulfide	46	0.27	1.13	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	0.0025	0.010	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	0.0076	0.032	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform (4)	3.6	0.021	0.09	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total (1)	0.52	0.0031	0.013	Wabash River test data
18540-29-9	Chromium, (hexavalent)	0.16	0.00092	0.0038	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.0060	0.000035	0.00015	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt (1)	0.26	0.0015	0.0064	Wabash River test data
98-82-8	Cumene	0.32	0.0019	0.0078	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	5.7	0.034	0.14	NETL, Table 2-6 (see Reference 1)
77-78-1	Dimethyl sulfate	2.9	0.017	0.071	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	0.00010	0.00042	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	5.7	0.034	0.14	AP-42, Table 1.1-14 (see Reference 2)
75-00-3	Ethyl chloride (Chloroethane)	2.5	0.015	0.061	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	0.00042	0.0018	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	0.014	0.059	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	0.10	0.42	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	0.024	0.10	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid (1)	3.9	0.023	0.096	Wabash River test data
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (6)	50	0.29	1.23	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	0.000022	0.00009	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	0.21	0.86	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.56	0.0033	0.014	Wabash River test data
7439-96-5	Manganese (1)	1.0	0.0061	0.025	Wabash River test data
7439-97-6	Mercury	0.5	0.0029	0.012	(See Note 2)
74-83-9	Methyl bromide (Bromomethane)	50.2	0.30	1.23	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	31.9	0.19	0.78	AP-42, Table 1.1-14 (see Reference 2)

Exhibit B-2 CTGs Page 1 of 2

Exhibit B-3 Tank Vent Boiler HAPs Emission Summary

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Exhibit B-3 TANK VENT BOILER HAPs EMISSION SUMARY
(Phase I)

Syngas fuel consumption rates

65 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
20 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (1)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	1.2E-04	1.6E-04	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	5.9E-05	7.9E-05	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	1.1E-03	1.5E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony	3.2	2.1E-04	2.8E-04	Wabash River test data
7440-38-2	Arsenic	16.9	1.1E-03	1.5E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	1.5E-07	2.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	323	2.1E-02	2.8E-02	Wabash River test data
207-08-9	Benzo(k)fluoranthene (4)	0.0066	4.3E-07	5.8E-07	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene (2)	0.0023	1.5E-07	2.0E-07	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	2.7E-03	3.7E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium	0.09	5.9E-06	7.9E-06	NETL, Table 2-11 (see Reference 1)
92-52-4	Biphenyl	0.10	6.7E-06	9.0E-06	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	2.9E-04	3.9E-04	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	1.5E-04	2.0E-04	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium	0.65	4.2E-05	5.7E-05	Wabash River test data
75-15-0	Carbon disulfide	46	3.0E-03	4.0E-03	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	2.7E-05	3.7E-05	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	8.5E-05	1.1E-04	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform (3)	3.6	2.3E-04	3.2E-04	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total	12	7.8E-04	1.1E-03	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.6	2.3E-04	3.2E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.006	3.9E-07	5.3E-07	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt	13.7	8.9E-04	1.2E-03	Wabash River test data
98-82-8	Cumene	0.30	2.0E-05	2.6E-05	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide) (2)	53	3.4E-03	4.6E-03	Wabash River test data
77-78-1	Dimethyl sulfate	2.9	1.9E-04	2.5E-04	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	1.1E-06	1.5E-06	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	362	2.4E-02	3.2E-02	Wabash River test data
75-00-3	Ethyl chloride (Chloroethane)	2.5	1.6E-04	2.2E-04	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	4.7E-06	6.3E-06	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	1.6E-04	2.1E-04	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	1.1E-03	1.5E-03	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	2.6E-04	3.5E-04	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid	3.4	2.2E-04	3.0E-04	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (5)	0.6	3.9E-05	5.3E-05	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	2.4E-07	3.2E-07	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	2.3E-03	3.1E-03	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.72	4.7E-05	6.3E-05	Wabash River test data (for syngas)
7439-96-5	Manganese	27.1	1.8E-03	2.4E-03	Wabash River test data
7439-97-6	Mercury	7.5	4.9E-04	6.6E-04	Wabash River test data
74-83-9	Methyl bromide (Bromomethane)	131	8.5E-03	1.1E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane) (2)	68	4.4E-03	6.0E-03	Wabash River test data
71-55-6	Methyl chloroform (1,1,1-Trichloroethane) (3)	1.2	7.8E-05	1.1E-04	AP-42, Table 1.1-14 (see Reference 2)

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Air Permit Application

Exhibit B-3 TANK VENT BOILER HAPs EMISSION SUMARY
(Phase I)

Syngas fuel consumption rates

65 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
20 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (1)	Short-term Emission, 1-hr and 30-day avg (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
78-93-3	Methyl ethyl ketone (2-Butanone)	23.5	1.5E-03	2.1E-03	AP-42, Table 1.1-14 (see Reference 2)
60-34-4	Methyl hydrazine	10.2	6.7E-04	9.0E-04	AP-42, Table 1.1-14 (see Reference 2)
80-62-6	Methyl methacrylate	1.2	7.8E-05	1.1E-04	AP-42, Table 1.1-14 (see Reference 2)
1634-04-4	Methyl tert butyl ether	2.1	1.4E-04	1.8E-04	AP-42, Table 1.1-14 (see Reference 2)
3697-24-3	Methylchrysene, 5-	0.0013	8.5E-08	1.1E-07	AP-42, Table 1.1-13 (see Reference 2)
75-09-2	Methylene chloride (Dichloromethane) (2)	6.3	4.1E-04	5.5E-04	Wabash River test data
91-20-3	Naphthalene (2)	9.2	6.0E-04	8.1E-04	Wabash River test data
7440-02-0	Nickel	47.9	3.1E-03	4.2E-03	Wabash River test data
108-95-2	Phenol	135	8.8E-03	1.2E-02	Wabash River test data
123-38-6	Proprionaldehyde	22.9	1.5E-03	2.0E-03	AP-42, Table 1.1-14 (see Reference 2)
7784-49-2	Selenium	2.7	1.8E-04	2.4E-04	Wabash River test data
100-42-5	Styrene	1.51	9.8E-05	1.3E-04	AP-42, Table 1.1-14 (see Reference 2)
7664-93-9 14808-79-8	Sulfuric acid and sulfates	2,530	1.6E-01	2.2E-01	(See Note 6)
127-18-4	Tetrachloroethylene (Perchloroethylene) (3)	2.59	1.7E-04	2.3E-04	AP-42, Table 1.1-14 (see Reference 2)
108-88-3	Toluene (2)	128	8.3E-03	1.1E-02	Wabash River test data
108-05-4	Vinyl acetate	0.46	3.0E-05	4.0E-05	AP-42, Table 1.1-14 (see Reference 2)
1330-20-7	Xylenes (2)	145	9.4E-03	1.3E-02	Wabash River test data

Notes:
(1) Emission factors are based on Wabash River test data where available. Otherwise, the same NETL IGCC or AP-42 coal combustion average emission factors are used as for the CTGs.
(2) Wabash test results show "non-detects" for benzo(a)pyrene, cyanide, methyl chloride, methylene chloride, naphthalene, toluene, and xylenes. The values shown in the table are one-half the values of the reported detection limits, except for benzo(a)pyrene where the AP-42 coal combustion factor is used because the reported detection limits are four orders of magnitude greater than the AP-42 factor.
(3) Wabash test results show only non-detects for chloroform, trichloroethane, and tetra chloro ethane with no detection limits reported. The values shown are the AP-42 coal combustion factors.
(4) AP-42 Section 1.1 gives only a factor for benzo(b,j,k)fluoranthene. This factor shown on table in the cell for the "k" isomer.
(5) Hydrofluoric acid is estimated using the fraction of total feed fluorine measured in the LGTI incinerator stack, as reported in Reference 2, and the highest expected concentrations of fluorine in the Mesaba feed steams. (See AP-24/NETL calculation spreadsheet.)
(6) Sulfuric acid and sulfates calculated using same emission factor as CTGs.

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report*, December 2002.
(2) AP-42 - U.S. EPA, *Compilation of Air Pollutant Emission Factors, Vol 1, Fifth Ed (Publication AP-42)*, January 1995.

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Exhibit B-4 Flare HAPs

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Exhibit B-4 FLARE HAPs EMISSION SUMMARY
(Phase I)

Syngas combustion rates

3730 x 10^6 Btu/hr, HHV (maximum 1-hr avg) (Note 1)
260 x 10^6 Btu/hr, HHV (maximum 30-day avg)
50 x 10^6 Btu/hr, HHV (annual avg)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (2)	Short-term Emission (lb/hr) 1-hr avg	Short-term Emission (lb/hr) 30-day avg	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	6.7E-03	4.7E-04	3.9E-04	NETL, Table 2-17 (see Reference 1)
98-86-2	Acetophenone	0.90	3.4E-03	2.3E-04	2.0E-04	AP-42, Table 1.1-14 (see Reference 2)
107-02-8	Acrolein	17.5	6.5E-02	4.6E-03	3.8E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-36-0	Antimony	3.2	1.2E-02	8.3E-04	7.0E-04	Wabash River test data
7440-38-2	Arsenic	16.9	6.3E-02	4.4E-03	3.7E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	8.6E-06	6.0E-07	5.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	323	1.2E+00	8.4E-02	7.1E-02	Wabash River test data
207-08-9	Benzo(k)fluoranthene	0.0066	2.5E-05	1.7E-06	1.4E-06	AP-42, Table 1.1-13 (see Reference 2)
50-32-8	Benzo[a]pyrene	0.0023	8.6E-06	6.0E-07	5.0E-07	AP-42, Table 1.1-13 (see Reference 2)
100-44-7	Benzyl chloride	42.2	1.6E-01	1.1E-02	9.2E-03	AP-42, Table 1.1-14 (see Reference 2)
7440-41-7	Beryllium	0.09	3.4E-04	2.3E-05	2.0E-05	NETL, Table 2-11 (see Reference 1)
92-52-4	Biphenyl	0.10	3.8E-04	2.7E-05	2.2E-05	AP-42, Table 1.1-13 (see Reference 2)
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	4.4	1.6E-02	1.1E-03	9.6E-04	AP-42, Table 1.1-14 (see Reference 2)
75-25-2	Bromoform	2.3	8.6E-03	6.0E-04	5.0E-04	AP-42, Table 1.1-14 (see Reference 2)
7440-43-9	Cadmium	0.65	2.4E-03	1.7E-04	1.4E-04	Wabash River test data
75-15-0	Carbon disulfide	46	1.7E-01	1.2E-02	1.0E-02	NETL, Table 2-17 (see Reference 1)
532-27-4	Chloroacetophenone, 2-	0.42	1.6E-03	1.1E-04	9.2E-05	AP-42, Table 1.1-14 (see Reference 2)
108-90-7	Chlorobenzene	1.3	4.8E-03	3.4E-04	2.8E-04	AP-42, Table 1.1-14 (see Reference 2)
67-66-3	Chloroform	3.6	1.3E-02	9.4E-04	7.9E-04	AP-42, Table 1.1-14 (see Reference 2)
0-00-5	Chromium, total	12	4.5E-02	3.1E-03	2.6E-03	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.6	1.3E-02	9.4E-04	7.9E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total (see permit application, Section 4.2).
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.006	2.2E-05	1.6E-06	1.3E-06	AP-42, Table 1.1-13 (see Reference 2)
7440-48-4	Cobalt	13.7	5.1E-02	3.6E-03	3.0E-03	Wabash River test data
98-82-8	Cumene	0.30	1.1E-03	7.8E-05	6.6E-05	AP-42, Table 1.1-14 (see Reference 2)
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	53	2.0E-01	1.4E-02	1.2E-02	Wabash River test data
77-78-1	Dimethyl sulfate	2.9	1.1E-02	7.5E-04	6.3E-04	AP-42, Table 1.1-14 (see Reference 2)
121-14-2	Dinitrotoluene, 2,4-	0.017	6.3E-05	4.4E-06	3.7E-06	AP-42, Table 1.1-14 (see Reference 2)
100-41-4	Ethyl benzene	362	1.4E+00	9.4E-02	7.9E-02	Wabash River test data
75-00-3	Ethyl chloride (Chloroethane)	2.5	9.3E-03	6.5E-04	5.5E-04	AP-42, Table 1.1-14 (see Reference 2)
106-93-4	Ethylene dibromide (Dibromoethane)	0.072	2.7E-04	1.9E-05	1.6E-05	AP-42, Table 1.1-14 (see Reference 2)
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	9.0E-03	6.2E-04	5.3E-04	AP-42, Table 1.1-14 (see Reference 2)
50-00-0	Formaldehyde	17	6.3E-02	4.4E-03	3.7E-03	NETL, Table 2-17 (see Reference 1)
110-54-3	Hexane	4.0	1.5E-02	1.0E-03	8.8E-04	AP-42, Table 1.1-14 (see Reference 2)
7647-01-0	Hydrochloric acid	3.4	1.3E-02	8.8E-04	7.4E-04	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	0.6	2.2E-03	1.6E-04	1.3E-04	NETL, Table 2-5 (see Reference 1)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	1.4E-05	9.6E-07	8.1E-07	AP-42, Table 1.1-13 (see Reference 2)
78-59-1	Isophorone	34.9	1.3E-01	9.1E-03	7.6E-03	AP-42, Table 1.1-14 (see Reference 2)
7439-92-1	Lead	0.72	2.7E-03	1.9E-04	1.6E-04	Wabash River test data (for syngas)
7439-96-5	Manganese	27.1	1.0E-01	7.0E-03	5.9E-03	Wabash River test data
7439-97-6	Mercury (3)	0.75	2.8E-03	2.0E-04	1.6E-04	Wabash River test data, reduced by 90%
74-83-9	Methyl bromide (Bromomethane)	131	4.9E-01	3.4E-02	2.9E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	68	2.5E-01	1.8E-02	1.5E-02	AP-42, Table 1.1-14 (see Reference 2)
71-55-6	Methyl chloroform (1,1,1-Trichloroethane)	1.2	4.5E-03	3.1E-04	2.6E-04	AP-42, Table 1.1-14 (see Reference 2)
78-93-3	Methyl ethyl ketone (2-Butanone)	23.5	8.8E-02	6.1E-03	5.1E-03	AP-42, Table 1.1-14 (see Reference 2)
60-34-4	Methyl hydrazine	10.2	3.8E-02	2.7E-03	2.2E-03	AP-42, Table 1.1-14 (see Reference 2)
80-62-6	Methyl methacrylate	1.2	4.5E-03	3.1E-04	2.6E-04	AP-42, Table 1.1-14 (see Reference 2)

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Exhibit B-4 FLARE HAPs EMISSION SUMMARY
(Phase I)

Syngas combustion rates

3730 x 10^6 Btu/hr, HHV (maximum 1-hr avg) (Note 1)
260 x 10^6 Btu/hr, HHV (maximum 30-day avg)
50 x 10^6 Btu/hr, HHV (annual avg)

CAS # or MPCA #	Compound	Emission Factor (lb/10^12 Btu syngas) (2)	Short-term Emission (lb/hr) 1-hr avg	Short-term Emission (lb/hr) 30-day avg	Annual Emission (ton/yr)	Emission Factor Source
1634-04-4	Methyl tert butyl ether	2.1	7.8E-03	5.5E-04	4.6E-04	AP-42, Table 1.1-14 (see Reference 2)
3697-24-3	Methylchrysene, 5-	0.0013	4.8E-06	3.4E-07	2.8E-07	AP-42, Table 1.1-13 (see Reference 2)
75-09-2	Methylene chloride (Dichloromethane)	6.3	2.3E-02	1.6E-03	1.4E-03	Wabash River test data
91-20-3	Naphthalene	9.2	3.4E-02	2.4E-03	2.0E-03	Wabash River test data
7440-02-0	Nickel	47.9	1.8E-01	1.2E-02	1.0E-02	Wabash River test data
108-95-2	Phenol	135	5.0E-01	3.5E-02	3.0E-02	Wabash River test data
123-38-6	Proprionaldehyde	22.9	0.085	0.0060	0.0050	AP-42, Table 1.1-12 (see Reference 2)
7784-49-2	Selenium	2.7	1.0E-02	7.0E-04	5.9E-04	Wabash River test data
100-42-5	Styrene	1.51	5.6E-03	3.9E-04	3.3E-04	AP-42, Table 1.1-14 (see Reference 2)
7664-93-9 14808-79-8	Sulfuric acid and sulfates	2,530	9.4E+00	6.6E-01	5.5E-01	(See Note 4)
127-18-4	Tetrachloroethylene (Perchloroethylene)	2.59	9.7E-03	6.7E-04	5.7E-04	AP-42, Table 1.1-14 (see Reference 2)
108-88-3	Toluene	128	4.8E-01	3.3E-02	2.8E-02	Wabash River test data
108-05-4	Vinyl acetate	0.46	1.7E-03	1.2E-04	1.0E-04	AP-42, Table 1.1-14 (see Reference 2)
1330-20-7	Xylenes	145	5.4E-01	3.8E-02	3.2E-02	Wabash River test data

Notes:
(1) Combustion rates shown are assumed worst-case to allow for planned plant startup and shut down operations as well as an allowance for unplanned operational upsets such as combustion turbine trips and pressure safety valve releases. Only treated syngas will be combusted in the flare during planned flaring events.
(2) No Wabash River emission test data are available for the flare. HAPs emissions are estimated using the same emission factors as the tank vent boiler and the assumed syngas combustion rate in the flare. The notes for the tank vent incinerator HAPs emission summary also apply to the flare.
(3) Mercury emission factor based on the TVB factor reduced by 90 %, since most gas routed to the flare will flow through the normal syngas treating system, including the activated carbon beds for mercury removal.
(4) Sulfuric acid calculated asuming 7% of SOx in combustion products converts to SO3 which reacts with water to form H2SO4.
Assuming 100 ppmvd total sulfur in flared gas and about 275 Btu/ft3 HHV,
Sulfuric acid = 0.07 x 100 ft3/10^6 ft3 x 1 ft3/275 Btu x 98 lb/380 ft3 = 6565 lb/10^12 Btu

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.
(2) AP-42 - U.S. EPA, *Compilation of Air Pollutant Emission Factors, Vol 1, Fifth Ed (Publication AP-42),* January 1995.

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Exhibit B-5 Fugitive HAPs Emission Summary

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Exhibit B-5 FUGITIVE HAPs EMISSION SUMMARY
(Phase I)

Process Stream[1]		Raw Syngas			SourSyngas			Product Syngas			Acid Gas			SRU and Tail Gas			Sour CO2 gas		
Total process fluid leak rate, lb/hr[2]		8.7			6.0			1.5			2.0			13.1			0.7		
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr
	Federal HAPs																		
71-43-2	Benzene	95	A	0.0009	95	A	0.0006	20	A	3.0E-05									
75-15-0	Carbon disulfide	575	A	0.0050	438	A	0.0026	2.7	A	4.1E-06									
463581	Carbonyl sulfide	1,300	B	0.011	83	B	0.00050	4.8	B	0.000007	700	B	0.0014				30.0	B	0.000021
100-41-4	Ethyl benzene	0.076	A	6.63E-07	0.076	A	4.55E-07	0.076	A	1.153E-07									
50-00-0	Formaldehyde	0.016	A	1.4E-07	0.016	A	9.57E-08	0.016	A	2.427E-08									
110-54-3	Hexane	0.021	A	1.8E-07	0.021	A	1.3E-07	0.021	A	3.2E-08									
7647-01-0	Hydrochloric acid	0.017	A	1.5E-07	0.017	A	1.0E-07	0.017	A	2.6E-08									
74-90-8	Hydrogen cyanide	83	B	0.00072	83	B	0.00050	0	B	0							1,000	B	0.0007
91-20-3	Naphthalene	0.4	A	3.5E-06	0.4	A	2.4E-06	0.008	A	1.2E-08									
108-95-2	Phenol	0.0011	A	9.6E-09	0.0011	A	6.6E-09	0.0011	A	1.7E-09									
108-88-3	Toluene	10.3	A	0.00009	10.3	A	6.18E-05	0.066	A	1.0E-07									
1330-20-7	Xylenes	0.14	A	1.22E-06	0.14	A	0.37E-07	0.14	A	2.124E-07									
	Total Federal HAPs			0.018			0.004			4.2E-05			0			0			0.0007
	Other																		
7664-41-7	Ammonia	4,000	B	0.035	6.5	B	3.9E-05	0	B	0							74,000	B	0.051
7783-06-4	Hydrogen sulfide	15,000	B	0.13	18,000	B	0.11	50	B	7.6E-05	460,000	B	0.92	58,000	B	0.76	27,000	B	0.019
	MDEA																		
	VOC[4]			0.018			0.004			0.000			0.001			0.000			0.001
	TRS[5]			0.15			0.11			8.7E-05			0.93			0.76			0.02

Process Stream		Rich MDEA			Lean MDEA			Sour Water			Stripped Sour Water			Recoverd Oil			Total Estimated Gaseous Fugitive Emissions		
Total process fluid leak rate, lb/hr[2]		1.5			1.7			1.3			0.5			0.3					
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr		lb/hr	ton/yr
	Federal HAPs																		
71-43-2	Benzene																	0.0014	0.0063
75-15-0	Carbon disulfide																	0.008	0.034
463581	Carbonyl sulfide	25	B	3.9E-05				2	B	2.7E-06								0.013	0.058
100-41-4	Ethyl benzene																	1.2E-08	5.4E-08
50-00-0	Formaldehyde																	2.8E-07	1.1E-06
110-54-3	Hexane																	3.4E-07	1.5E-06
7647-01-0	Hydrochloric acid							4000	B	0.005	4700	B	0.002					0.008	0.034
74-90-8	Hydrogen cyanide							70	B	0.00009								0.0020	0.0088
91-20-3	Naphthalene																	5.8E-08	2.6E-05
108-95-2	Phenol																	1.8E-08	7.8E-08
108-88-3	Toluene																	0.00015	6.6E-04
1330-20-7	Xylenes																	2.3E-06	1.0E-05
	Total Federal HAPs			0			0			0.005			0.002			0		***0.032***	***0.14***
	Other																		
7664-41-7	Ammonia			0			0	30,000	B	0.04	300	B	0.0002			0		0.1	0.6
7783-06-4	Hydrogen sulfide	20,000	B	0.03	350	B	0.0006	1,500	B	0.0020			0			0		2.0	8.6
	MDEA	500,000	B	0.9	500,000	B	0.8			0			0			0		1.6	7.1
	VOC[4]			0.774			0.849			0.000			0.000	1E+06	B	0.25		1.9	8.3
	TRS[5]			0.03			0			0.0020			0			0		2.0	8.7

[1]Process stream descriptions for fugitive emission estimates:

Stream	Description	Stream	Description
Raw syngas	Gasifier outlet to COS hyrolyses reactor outlet	Rich amine	H2S/CO2-laden MDEA from absorber to acid gas stripper
Sour syngas	Hydrolysis reactor outlet to AGR/AGE absorbers overhead	Lean amine	Regenerated amine from stripper to absorber (incl storage)
Product syngas	AGR/AGE to CTGs	Sour water	Sour water from various sources to sour water stripper
Acid gas	Acid gas stripper overhead to SRU inlet	Stripped SW	Stripper bottoms to slurry recycle and ZLD
SRU and tail gas	SRU inlet through tail gas recycle to gasifier	Recovered oil	Oil recovered from drainage oily water separator
Sour CO2 gas	Sour water degassing column to AGR		

[2]Estimated fugitive emission quantities for the total process stream components based on U.S. EPA average emission factors (see next page). This value is multiplied by each component concentration to determine the individual component emission rates. ***Example:*** Benzene fugitive emission from raw syngas = 8.7 lb/hr x 95 lb/10^6 lb = 0.00083 lb/hr.
[3]Basis for emission factors; "A" denotes test results from the Wabash River gasification facility, "B" denotes calculated from the ConocoPhillips/Fluor material balance.
[4]Volatile organic compounds (VOC) include MDEA, benzene, carbon disulfide, carbonyl sulfide, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, and xylenes.
[5]Total reduced sulfur (TRS) includes carbon disulfide, carbonyl sulfide, and hydrogen sulfide.

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Exhibit B-5 FUGITIVE HAPs EMISSION SUMMARY
(Phase I)

Fugitve Emission Sources Estimates[1]

	Gas		Light Liquid		Heavy Liquid			Sample
Process Stream	Valves	Comp seals	Valves	Pumps	Valves	Pumps	Connectors	Connects
Raw syngas	510						500	1
Sour syngas	230	4					230	1
Product syngas	80						100	2
Acid gas	120						100	1
SRU and tail gas	480	9					560	
Sour CO2 gas	40						40	
Rich MDEA					350		340	
Lean MDEA					330	19	290	
Sour water					240	21	200	
Stripped sour water					120	2	100	
Recovered oil					30	4	40	
Totals	**1460**	**13**	**0**	**0**	**1070**	**46**	**2500**	**5**

Total Fugitive Emission Rates[2]

	Gas		Light Liquid		Heavy Liquid			Sample	
	Valves	Comp seals	Valves	Pumps	Valves	Pumps	Connectors	Connects	
Emission factor lb.hr/source	**0.0131**	**0.502**	**0.00888**	**0.0438**	**0.00051**	**0.019**	**0.00403**	**0.033**	**Total**
Process Stream	**Estimated emission rate, lb/hr**								
Raw syngas	6.68						2.02	0.03	8.73
Sour syngas	3.01	2.01					0.93	0.03	5.98
Product syngas	1.05						0.40	0.07	1.52
Acid gas	1.57						0.40	0.03	2.01
SRU and tail gas	6.29	4.52					2.26		13.06
Sour CO2 gas	0.52						0.16		0.69
Rich MDEA					0.18		1.37		1.55
Lean MDEA					0.17	0.36	1.17		1.70
Sour water					0.12	0.40	0.81		1.33
Stripped sour water					0.06	0.04	0.40		0.50
Recovered oil					0.02	0.08	0.16		0.25
									37.3
									163 tpy

[1]Emission source estimates based on conceptual equipment inventory for the Mesaba IGCC Power Station and an estimate from piping and instrumentation diagrams (P&IDs) for a similar E-Gas IGCC project. An allowance is added to account for valves and other components not shown on the P&IDs.
[2]Estimated emission rates for all components (including non-VOC and non-HAP's) in each process stream, based on *Protocol for Equipment Leak Estimates*, U.S EPA 453-R95-017, November 1995, Table 2-1

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Exhibit B-6 HAP Metals Emission Factors

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Exhibit B-6 HAP METALS EMISSION FACTORS

The following two tables summarize the adjustment of the Wabash HAP emission factors for the worst case Mesaba feed metals content, assuming that the Wabash factors are representative of the Illinois Basin coal and pet coke feed. The first table compares the trace metal data available for the range of Mesaba solid feed streams for the metals that have been measured at Wabash River.and identifies the maximum values for each trace metal. The second table shows the calculation of the Mesaba worst case emission factors by multiplying the Wabash factors by the ratio of the worst case concentrations to the actual Wabash concentrations.

HAPs factors for metals corrected for worst case Mesaba feeds.

	Mean concentration in solid fuel, mg/kg					
Element	Jacobs Ranch[a]	Spring Creek[b]	Rawhide[c]	Illinois or Petcoke [d]	Flint Hills Coke[e]	Mesaba Worst Case
Antimony	0.5		0.86	3.5		3.5
Arsenic	5.1	1.5	1.2	7.6		7.6
Beryllium	0.40	0.21	0.22	1.8		1.8
Cadmium	0.30	0.16	0.18	7.6		7.6
Chromium	7	2.4	3.8	5.55		7.0
Cobalt	4		1.9	7.3		7.3
Lead	3.4	2.6	2.4	17.3		17.3
Manganese	30	16.2		12.33		30
Mercury			0.06			
Nickel	14	1.5		370	257	370
Selenium	2	1.2		3		3.0
Chlorides	147	0	130	100		147

Sources: a) Jacobs Ranch Mine Quality Specifications, Typical Upper Wyodak Product
b) Spring Creek Coal Mine 2005 Quality Specifications
c) Rawhide 2005 - 2007 Typical Analysis and production data base for 1993 - 2005
d) Larger value for Illinois Basin coal or Pine Bend petcoke.sources: Wabash River Coal Gasification Repowering Project Final Technical Report (coal slurry dry compositon data for 1997 and 1998) or Koch Refining data for Pine bend petcoke.
e) Sample Analysis of pertoleum coke for Flint Hill Resources, Commercial testing & Engineering Co., February 19, 2004

Emission Factor Adjustment for Treated Syngas

Element	Mesaba Worst Case Feed Conc, mg/kg	Wabash Actual Feed Conc, mg/kg	Wabash HAP Emission Factor lb/10^12 Btu coal	Calculated Worst Case Mesaba HAP Factor lb/10^12 Btu coal	
Antimony	3.5	3.5	1.1	1.1	
Arsenic	7.6	7.6	2.4	2.4	
Beryllium	1.81	1.81	0.26	0.26	
Cadmium	7.6	7.6	9.6	9.6	
Chromium	7.0	5.55	0.41	0.52	
Cobalt	7.3	7.3	0.26	0.26	
Lead	17.3	17.3	0.56	0.56	
Manganese	30	12.33	0.43	1.04	
Mercury	(see calculation below)			0.50	(90% O/A removal)
Nickel	370	370	0.39	0.39	
Selenium	3.0	3.0	0.56	0.56	
Chlorides	147	100	2.6	3.9	

Mercury based on Rawhide PRB feed, 0.06 ppmwd avg Hg, approx 12,000 Btu/lb HHV
Hg = (0.10) x 0.06 lb/10^6 lb /(12,000 Btu/lb) x 10^6/10^6 = 0.5 lb/10^12 Btu

Ex B-6 Metals Emission Factors Page 1 of 1

Exhibit B-7 AP-42 and NETL Coal HAP Emission Factors

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Exhibit B-7 AP-42 and NETL COAL HAP EMISSION FACTORS

CAS # or MPCA #	Chemical Name	Emission Factor used for HAPs calculation ($lb/10^{12}$ Btu coal)	AP-42, Section 1.1 (lb/ton coal)	NETL IGCC Env Report, data from LGTI ($lb/10^{12}$Btu)	Comments
75-07-0	Acetaldehyde	1.8		1.8	NETL, Table 2-17
98-86-2	Acetophenone	0.90	0.000015		AP-42, Table 1.1-14, see Example Calulation (1)
107-02-8	Acrolein	17.5	0.00029		AP-42, Table 1.1-14
56-55-3	Benz[a]anthracene	0.0023		0.0023	NETL, Table 2-17
207-08-9	Benzo(k)fluoranthene	0.0066	1.10E-07		AP-42, Table 1.1-13
50-32-8	Benzo[a]pyrene	0.0023	3.80E-08		AP-42, Table 1.1-13
100-44-7	Benzyl chloride	42.2	0.0007		AP-42, Table 1.1-14
7440-41-7	Beryllium	0.090		0.09	NETL, Table 2-11
92-52-4	Biphenyl	0.10	1.70E-06		AP-42, Table 1.1-13
117-81-7	Bis(2-ethylhexyl)phthalate	4.40	0.000073		AP-42, Table 1.1-14
75-25-2	Bromoform	2.3	0.000039		AP-42, Table 1.1-14
75-15-0	Carbon disulfide	46		46	NETL, Table 2-17
532-27-4	Chloroacetophenone, 2-	0.42	0.000007		AP-42, Table 1.1-14
108-90-7	Chlorobenzene	1.3	0.000022		AP-42, Table 1.1-14
67-66-3	Chloroform	3.6	0.000059		AP-42, Table 1.1-14
218-01-9	Chrysene (Benzo(a)phenanthrene)	0.0060	1.00E-07		AP-42, Table 1.1-13
98-82-8	Cumene	0.32	0.0000053		AP-42, Table 1.1-14
57-12-5	Cyanide (cyanide ion, Inorganic cyanides, Isocyanide)	5.7		3.2 ug/Nm3 (CTG)	NETL, Table 2-6, see Example Calulation (2)
77-78-1	Dimethyl sulfate	2.9	0.000048		AP-42, Table 1.1-14
121-14-2	Dinitrotoluene, 2,4-	0.017	2.80E-07		AP-42, Table 1.1-14
100-41-4	Ethyl benzene	5.7	0.000094		AP-42, Table 1.1-14
75-00-3	Ethyl chloride (chloroethane)	2.5	0.000042		AP-42, Table 1.1-14
106-93-4	Ethylene dibromide	0.072	0.0000012		AP-42, Table 1.1-14
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	2.4	0.00004		AP-42, Table 1.1-14
50-00-0	Formaldehyde	17		17	NETL, Table 2-17
110-54-3	Hexane	4.0	0.000067		AP-42, Table 1.1-14
7664-39-3	Hydrogen fluoride (hydrofluoric acid)	0.6 or 50		0.012% (TVB) or 1% (CTG) of fluoride in feed	NETL, Table 2-5, see Example Calulation (3)
193-39-5	Indeno(1,2,3-cd)pyrene	0.0037	6.10E-08		AP-42, Table 1.1-13
78-59-1	Isophorone	34.9	0.00058		AP-42, Table 1.1-14
74-87-3	Methyl chloride (chloromethane)	32	0.00053		AP-42, Table 1.1-14
71-55-6	Methyl chloroform (1,1,1-Trichloroethane)	1.20	2.00E-05		AP-42, Table 1.1-14
78-93-3	Methyl ethyl ketone (2-butanone)	23	0.00039		AP-42, Table 1.1-14
60-34-4	Methyl hydrazine	10	0.00017		AP-42, Table 1.1-14
80-62-6	Methyl methacrylate	1.2	0.00002		AP-42, Table 1.1-14
1634-04-4	Methyl tert butyl ether	2.1	0.000035		AP-42, Table 1.1-14
3697-24-3	Methyl chrysene, 5-	0.0013	2.20E-08		AP-42, Table 1.1-13
123-38-6	Proprionaldehyde	23	0.00038		AP-42, Table 1.1-14
100-42-5	Styrene	1.5	0.000025		AP-42, Table 1.1-14
127-18-4	Tetrachloroethylene (perchloroethylene)	2.6	0.000043		AP-42, Table 1.1-14
108-88-3	Toluene	0.033		0.033	NETL, Table 2-17
108-05-4	Vinyl acetate	0.46	0.0000076		AP-42, Table 1.1-14
1330-20-7	Xylenes	2.23	0.000037		AP-42, Table 1.1-14

Example calculations:

1) Worst case coal HHV (as received) to convert AP-42 factors
= 8300 Btu/lb HHV for PRB
Acetophenone = 0.000015 lb/ton x 1 ton/2000 lb x 1 lb/8300 Btu x $10^{12}/10^{12}$ =
= 0.90 $lb/10^{12}$ Btu coal

2) Cynanide = 3.2 ug/m3 in CTG exhaust, assume CTG exhaust gas = 38,000 scf/10^6 Btu (see CTG HAPs calc for Wabash River) and about 0.75 overall coal conversion
= 3.2 g/10^6 m3 x 1 lb/454 g x 1 m3/35.3 ft3 x 38,000 scf/10^6 Btu SG x 0.75 Btu SG/Btu coal
= 5.7 $lb/10^{12}$ Btu coal

3) Fluorides = 1% of fluorine in coal feed for CTGs, worst case PRB, 60 ppm F by wt, dry, 12,000 Btu/lb HHV, dry
= 0.01 x 60 lb F/10^6 lb coal x 1 lb/12,000 Btu x 10^6/10^6
= 50 $lb/10^{12}$ Btu coal;
= 0.012% of fluorine in coal feed for TVB
= 0.6 $lb/10^{12}$ Btu

Ex B-7 AP-42 and NETL factors Page 1 of 1

Exhibit B-8 Wabash River CTG HAPs

Mesaba Energy Project **Air Permit Application**
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Exhibit B-8 WABASH RIVER CTG HAPs

Assumptions
CTG exhaust flow = 40,000 scf(@ 15% O2)/10^6 Btu SG (based on Siemens perf summary)
Coal conversion = 0.77
Syngas HHV = 280 Btu/dscf

WABASH RIVER IGCC TEST DATA

Compound	Units	Nov-97 HRSG (coke)	Jan-98 HRSG (coal)	Use for HAP calc	Lb/10^12 Btu coal	
HAP Metals						
(based on metals per unit vol of syngas, see syngas spreadsheet)						
Antimony	mg/dscm (SG)			0.0065	1.1	
Arsenic	"			0.014	2.4	
Beryllium	"			0.0015	0.3	
Cadmium	"			0.05575	9.6	
Chromium	"			0.0024	0.41	
Cobalt	"			0.0015	0.26	
Lead				0.0033	0.56	
Manganese	"			0.0025	0.43	
Mercury	"	(Use 10% of worst feed)			0.50	
Nickel	"			0.0023	0.39	
Selenium	"			0.00325	0.56	
HAP Organics						
Benzene	ug/m3	2.06	0.539	1.30	2.5	
Bromomethane (methyl bromide)	ug/m3	52	0.255	26.13	50.2	
Chloromethane (methyl chloride)	ug/m3	ND	ND			
Methylene chloride	ug/m3	1.2	ND	1.2	2.31	
Chloroform		ND	ND			
1,1,1-trichloroethane		ND	ND			
Tetrachloroethane		ND	ND			
Benzo(a)pyrene	ug/m3	1.155	1.56	1.36	2.6	(used AP-42, instead)
Naphthalene	ug/m3	1.155	1.56	1.36	2.6	
Phenol	ug/m3	2.8	37.5	20.15	38.7	
Other HAPs						
Hydrogen chloride (MW=36.5)	ppmv	(based on syngas)		0.01	2.6	

	highlight denotes not detected, value shown is one-half reported detection limit
ND	denotes not detected, no detection limit reported

Example calculations

Antimony = 0.0065 mg/m3 x 1 lb/454x10^3 mg x 1 m3/35.3 ft3 x 1 ft3/280 Btu x 0.77 x 10^12 = 1.1 lb/10^12 Btu coal

Mercury (worst-case PRB) = 0.06 ppmw = 0.06 lb/10^6 lb x 1 lb/12,000 Btu x 0.1 x 10^6 = 0.50 lb/10^12 Btu coal (dry, HHV)

Benzene = 1.30 ug/m3 x 1 lb/454x10^6 ug x 1 m3/35.3 ft3 x 40000 ft3/10^6 Btu x 0.77 = 2.5 lb10^12 Btu coal

HCl = 0.01 scf/10^6 scf x 36.5 lb/380 scf x 1 scf/280 Btu x 0.77 x 10^6/10^6 = 2.64 lb/10^12 Btu coal

Exhibit B-8 WR CTG Page 1 of 1

Exhibit B-9 Wabash River Syngas HAPs

Mesaba Energy Project
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Exhibit B-9 WABASH RIVER SYNGAS HAPs

Assumptions
syngas HHV = 280 Btu/dscf
syngas MW = 21 lb/lbmol

1 gmole = 24.0 x 10^-3 m3 @ 293 K

WABASH RIVER IGCC TEST DATA

		May-97		October 1998		September 1999		Mar-03	Nov-05	Use for	Use for Fugitive HAP calc			ppm (wt)			Lb/10^12 Btu syngas
Compound	Units	Raw Syngas	Sour Syngas	Raw Syngas	Sour Syngas	Raw Syngas	Sour Syngas	Product Syngas	Product Syngas	fuel comb HAP calc	Raw Syngas	Sour Syngas	Product Syngas	Raw Syngas	Sour Syngas	Product Syngas	Product Syngas
HAP Metals																	
Antimony	mg/dscm	< 0.03	<0.037	0.006	< .001	0.004	0.0065			0.0065	N/A	N/A	N/A				1.45
Arsenic	"	0.1	0.1133	0.294	0.0305	0.0401	0.0996	0.005	0.0231	0.014	N/A	N/A	N/A				3.13
Beryllium	"								0.0015	0.0015	N/A	N/A	N/A				0.33
Cadmium	"	<0.0017	<0.0019	0.0005	0.0004	0.0006	0.0011	0.11	0.0015	0.056	N/A	N/A	N/A				12.42
Chromium	"	1.33	0.0916	1.191	0.0096	0.1256	0.0527		0.0024	0.0024	N/A	N/A	N/A				0.53
Cobalt	"	0.009	<0.0038	0.014	0.0019	0.002	0.0041		0.0015	0.0015	N/A	N/A	N/A				0.33
Lead								0.005	0.0015	0.003	N/A	N/A	N/A				0.72
Manganese	"	0.805	0.124	0.328	0.0219	0.1249	0.0706		0.0025	0.0025	N/A	N/A	N/A				0.56
Mercury	"	0.016	0.038	0.075	0.0446	< 0.0036	0.011	0.005	0.0015	0.003	N/A	N/A	N/A				0.72
Nickel ( )	"	0.266	0.038	0.796	0.106	0.2378	0.093		0.0023	0.0023	N/A	N/A	N/A				0.51
Selenium	"	0.755	0.033	0.314	0.0026	0.056	0.0095	0.005	0.0015	0.003	N/A	N/A	N/A				0.72
HAP Organics																	
Benzene (MW=78)	ppmv	39		25		13		6.3	4.5	N/A	25.7	25.7	5.4	95	95	20	
Hexane (MW=86)	ppmv							0.005		N/A	0.005	0.005	0.005	0.021	0.021	0.021	
Ethyl-benzene (MW=106)	ppmv							0.005	0.025	N/A	0.015	0.015	0.015	0.076	0.076	0.076	
Formaldehyde (MW=30)	mg/dscm								0.014	N/A			0.0140			0.016	
Toluene (MW=92)	ppmv		0.192		0.055		6.8	0.005	0.025	N/A	2.3	2.3	0.015	10.3	10.3	0.066	
xylenes (MW=106)	ppmv							0.005	0.05	N/A	0.028	0.028	0.028	0.14	0.14	0.14	
Phenol	mg/dscm								0.001	N/A			0.0010			0.0011	
Naphthalene (MW = 128)	mg/dscm		<0.165		0.244		0.454		0.007	N/A	0.349	0.349	0.0070	0.40	0.40	0.0080	
Carbon disulfide (MW = 76)	ppmv	< 333	167	< 333	167	159	31	1.18	0.32	N/A	159	121	0.75	575	439	2.7	
Other HAPs																	
Hydrogen Chloride (MW=36.5)	ppmv							0.010		0.010	0.01	0.01	0.01	0.017	0.017	0.017	3.4

highlight denotes not detected, value shown is one-half reported detection limit

Example calculations
(See also CTG spreadsheet)

Antimony = 0.0065 mg/m3 x 1 lb/454x10^3 mg x 1 m3/35.3 ft3 x 1 ft3/280 Btu x 10^12 = 1.45 lb/10^12 Btu syngas

Benzene = 19 ppmv = 19 lbmol Bz/10^6 lbmol SG x 78 lb/lbmol Bz/21 lb/lbmol SG = 71 ppm(wt)

Naphthalene = 0.349 mg/m3 x (24 x10^-3 m3 SG)/(21 x 10^3 mg) = 0.40 ppm(wt)

Hydrogen chloride = 0.01 ppmv = 0.01 ft3/10^6 ft3 x 36.5 lb/380 ft3 x 1 scf/280 Btu x 10^6/10^6 = 3.4 lb/10^12 Btu

Exhibit B-9 WR Syngas Page 1 of 1

Exhibit B-10 Wabash River TVB HAPs

Mesaba Energy Project
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05/03/2006

Air Permit Application

Exhibit B-10 WABASH RIVER TVB HAPs

Assumptions
TVI flue gas flow = 30,000 dscf/10^6 Btu (@ 13% O2), see below

WABASH RIVER IGCC TEST DATA

Compound	Units	May-97 TGI Stack	Nov-97 TGI Stack (coke)	Jan-98 TGI Stack (coal)	Oct-98 TGI Stack	Sep-99 TGI Stack	Nov-05 TGI Stack	Use for HAP calc	Lb/10^12 Btu gas
HAP Metals									
Antimony	mg/dscm	0.0045			0.00038	0.000195		0.0017	3.2
Arsenic	"	0.0138			0.0129	0.00866	0.0008	0.0090	16.9
Cadmium	"	0.00023			0.00032	0.000134	0.0007	0.00035	0.65
Chromium	"	0.0086			0.00655	0.00872	0.0017	0.0064	12.0
Cobalt	"	0.0006			0.000424	0.0275	0.0007	0.0073	13.7
Manganese	"	0.0358			0.0107	0.0101	0.0014	0.0145	27.1
Mercury	"	0.00375			0.00922	0.00152	0.0015	0.0040	7.5
Nickel	"	0.0037	0.0481	0.0103	0.00792	0.0818	0.0018	0.026	47.9
Selenium	"	0.0045			0.00011	0.000483	0.0007	0.0014	2.7
HAP Organics									
Benzene (MW = 78)	ug/m3	813	25.6	14.8	141.4	17.6	24.1	173	323
Bromomethane (methyl bromide)	ug/m3		137	ND			3.5	70	131
Chloromethane (methyl chloride)	ug/m3		64	8.6				36	68
Methylene chloride	ug/m3		1.7	5.1				3.4	6.3
Chloroform			ND	ND					
1,1,1-trichloroethane			ND	ND					
Tetrachloroethane			ND	ND					
Ethyl-benzene (MW = 94)	ppmv	0.15			0.0435	0.0012	0.00026	0.049	362
Toluene (MW= 92)	ppmv	0.025			0.0435	0.0012	0.0006	0.018	128
xylenes (MW= 107)	ppmv	0.0235			0.0435	0.0012	0.00026	0.017	145
Benzo(a)pyrene	ug/m3		1.4	12.9				7.1	13.4
Naphthalene	ug/m3		1.4	12.9			0.4	4.9	9.2
Phenol	ug/m3	222	3.12	166	4.4	37.2	0.8	72	135
Cyanide	mg/dscm	0.068			0.016		0.0014	0.028	53

	highlight denotes not detected, value shown is one-half reported detection limit
ND	denotes not detected, no detection limit reported

TVB flue gas calc: Based on data from Mesaba CTG supplier, CTG exhaust gas for syngas fuel = approx 40,000 dscf (@ 15% O2)/10^6 Btu, HHV
Based on test data, Wabash TVB typically operates at about 13% O2 (dry).
Convert CTG flue gas to 13% O2 = 40,000 x (0.2095 - 0.15)/(0.2095 - 0.13) = 29937 , so use about 30,000 dscf (@13@ O2)/10^6 Btu,

Example HAP factor: Antimony = 0.00029 mg/m3 x (1 lb/454 x 10^3 mg) x 0.3048^3 m3/ft3 x 30,000 ft3/10^6 Btu x 10^3/10^3 = 3.17 lb/10^12 Btu

Exhibit B-10 WR TVB Page 1 of 1

APPENDIX C

AIR MODELING PROTOCOL

AIR QUALITY MODELING PROTOCOL
CLASS I AREA IMPACT ANALYSES

EXCELSIOR ENERGY
MESABA ENERGY PROJECT

January, 2006
Revised June 2006

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MMA Project Number 1877-05

1.0 INTRODUCTION

Excelsior Energy Inc. ("Excelsior"), an energy development company based in Minnetonka, Minnesota has created two wholly-owned project companies, MEP-I LLC and MEP-II LLC (MEP-I LLC and MEP-II LLC, together, the "Company") to construct, own and operate at a site in Northeastern Minnesota a 1,212 megawatt$_{(net)}$ integrated gasification combined cycle ("IGCC") steam electric power generating station (hereafter, the "IGCC Power Station") fueled by coal and other solid, petroleum-based feedstocks. The IGCC Power Station consists of Phase I and Phase II of the Mesaba Energy Project each phase of which is nominally rated at peak to deliver 606 meagawatts$_{(net)}$ of electricity to the bus bar of the high voltage switchyard located within the IGCC Power Station's fenced boundary. The IGCC Power Station will be located in Itasca County within the city limits of Taconite. Approximate UTM coordinates (NAD83) for the site center are 472,210m E, 5,243,370m N.

The IGCC Power Station will require PSD new source review, including an evaluation of impacts on Class I areas. The present document comprises an Air Quality Modeling Protocol, describing the methodology proposed for analysis of Class I impacts. It is being submitted to the Minnesota Pollution Control Agency (MPCA) and the cognizant Federal Land Managers (FLMs) for review and comment.

The Class I analyses will address impacts to the Boundary Waters Canoe Area (BWCA), Voyageurs National Park (VNP) and the Rainbow Lakes Wilderness (RLW). The distance from the IGCC Power Station to the closest point in each of these Class I areas is approximately 61 miles (98 km) for the BWCA, 75 miles (121 km) for VNP, and 117 miles (188 km) for RLW. The next closest Class I area, Isle Royale National Park, is more than 300 km from the station, beyond the distance where long-range transport modeling has been shown to provide realistic impact predictions.

This Protocol has been developed in accordance with the U.S. EPA Guideline on Air Quality Models (40 CFR Part 51, Appendix W), the IWAQM Phase 2 report (December, 1998), and the Phase I FLAG report (December 2000). Excelsior representatives and their consultants met with the U.S. Forest Service in Duluth on September 20, 2005, and with the National Park Service in Denver on November 9, 2005 to discuss Class I issues and analyses. Information from those meetings has been incorporated in this Protocol. Because of schedule requirements, some Class I analyses have been conducted prior to submittal of this protocol. The methodology that has been applied, as well as potential refinements that will be implemented in an updated analysis, are described herein.

2.0 IGCC POWER STATION AIR POLLUTANT EMISSIONS

Table 2-1 shows estimated annual emissions of criteria pollutants for each phase of the two-phase IGCC Power Station. Based upon these data, the IGCC Power Station will be a major stationary source to be located in a PSD area, and will therefore be subject to PSD new source review permitting requirements for each of the pollutants shown.

The primary emission sources at the IGCC Power Station will be combustion turbines (two turbines and stacks for each phase), tank vent boilers, flares, and auxiliary boilers (one of each per phase). Other sources will include evaporative cooling towers, material handling operations, and emergency diesel generators and fire pumps. The emergency sources will only operate for short time periods, generally when other sources are not in operation.

Emissions of air pollutants will be minimized through the inherently low-emission IGCC technology and application of BACT to the emission units. Controls will include diluent injection and good combustion practices for the combustion turbines, and optimum design and combustion practices for the tank vent boilers, flares, and other combustion sources. Cooling tower emissions will be controlled by high efficiency drift eliminators, and fugitive particulate matter emissions will be controlled by enclosures and dust suppressant spray systems.

During normal operation of the full two-phase IGCC Power Station, the only significant air pollutant emissions will be from the combustion turbines and tank vent boilers. During short periods when flaring of syngas takes place, SO_2 emissions from the flares will exceed total facility SO_2 emissions for normal operation. However, at these times facility NO_x and PM10 emissions will be much less than normal. The combustion turbines may for limited time periods operate on natural gas rather than syngas. During these times NO_x emission rates will be slightly higher than for syngas operation, but SO_2 emissions will be very low. Therefore, the normal operation scenario represents highest combined-source pollutant emissions; only normal operation emissions will be modeled for the Class I analyses.

Pollutant emission rates for long-range transport modeling represent maximum expected emissions for a two-phase plant for the appropriate averaging periods. All maximum emission rates and stack emission parameters are based upon engineering design specifications, as documented in the formal air permit application. Modeling parameters for Class I analyses are given in Table 2-2.

Speciation of particulate matter emissions from the combustion turbines, as shown in Table 2-2, was based on available data for IGCC Power Station sources and Federal Land Manager (FLM) guidance on emissions from natural gas-fired turbines. The total particulate emissions (filterable plus condensable) and total sulfuric acid emissions are from Mesaba design specifications. The partitioning of filterable and condensable fractions, elemental carbon emissions, and organic aerosol emissions were calculated using the FLM consensus methodology. All filterable particulate was assumed to be elemental carbon less than 2.5 microns in diameter. All particulate emissions from the tank vent boilers were assumed to be $PM_{2.5}$. Calculations are shown in Table 2-3.

Table 2-1. Worst-Case Annual Emissions (Tons/year) Excelsior IGCC Power Station (for each Phase)

Source	SO_2	NO_x	CO	VOC	PM10
Combustion Turbines (total for two)	666	1386	964	88	220
Tank Vent Boiler	15.8	26.4	7.9	0.4	0.9
Auxiliary Boiler	0.4	5.1	10.5	0.6	0.7
Flare	12.3	13.4	285.9	1.3	1.7
Cooling Towers					19.7
Coal Handling					2.0
Slag Handling					1.0
Coal Slurry Facility					0.2
Total	694.5	1430.9	1268.3	90.3	246.2

Table 2-2. Modeling Parameters For Mesaba CALPUFF Modeling

Parameter	Combustion Turbines (each of four)	Tank Vent Boilers (each of two)
stack height (m)	45.72	64.01
stack diameter (m)	6.1	1.83
temp (K)	394.3	579.8
velocity (m/s) – short-term	20.1	8.46
annual	20.1	1.95
SO_2 - 3-hr (g/s)	19.15	0.94
24-hr	14.36	0.81
annual	9.58	0.45
NO_x - 3-hr (g/s)	19.66	2.46
24-hr	19.66	2.46
annual	19.91	0.76
Elemental Carbon (g/s) all time periods	0.787	0
Sulfate (g/s) all time periods	0.945	0
Organic aerosol (g/s) all time periods	1.397	0
$PM_{2.5}$ (g/s) all time periods	0	0.088
PM10 (g/s)	0	0

Table 2-3. Estimation of Particulate Matter Speciation for Combustion Turbine Stacks (each)

Total PM Emissions, Filterable plus Condensable, from Plant Design Specifications = 25 lb/hr.

Assume, as per FLM guidance for gas-fired CTs, that 25% of PM10 is filterable, and 75% is condensable.

Then Filterable PM10 = 6.25 lb/hr.

Assume that 100% of Filterable PM10 is elemental carbon.

Then EC = 6.25 lb/hr

Condensable PM10 = 0.75(25) = 18.75 lb/hr.

H_2SO_4 = 7.66 lb/hr per design specifications

Then condensable SO_4 = 7.5 lb/hr

Assume remainder of condensable PM10 is organic (SOA).

Then final speciation is:

EC = 6.25 lb/hr = 0.787 g/s
SO_4 = 7.5 lb/hr = 0.945 g/s
SOA = 11.09 lb/hr = 1.397 g/s

3.0 AIR QUALITY MODEL AND APPLICATION

The CALPUFF air quality model will be used for all Class I area analyses. CALPUFF is the approved EPA long-range transport model as referenced in the Guideline on Air Quality Models. It consists of three components: the CALMET model for processing of meteorological data, CALPUFF for the transport and dispersion calculations, and CALPOST for analysis and post-processing of model results. The CALMET model version will be 5.53a, Level 040716; CALPUFF will be version 5.711a, Level 040716. Input options and data utilized in the models will generally corresponded to default or recommended values; table 3-1 provides a list of input options that are specific to the Mesaba application and differ from standard default values.

For background ozone (O_3) concentration, a constant value of 40 ppb has been used for initial CALPUFF modeling. Some hourly O_3 monitoring data may be available for the analysis region. If appropriate data can be acquired, hourly ozone files will be utilized for future modeling. A constant ammonia background of 1.0 ppb will be assumed.

The CALMET/CALPUFF modeling domain will be a 700km by 500km area approximately centered on the IGCC Power Station footprint, with a four kilometer grid spacing. The coordinate system is Lambert Conformal. Receptor locations within each of the Class I areas were obtained from the National Park Service. Figure 3-1 shows the modeling domain, terrain elevation contours, and the modeling receptors.

Terrain elevations were derived with the TERREL preprocessor; an average elevation was extracted for each cell in the modeling domain. Land use data were obtained from USGS 1:250,000 scale land use and land cover digital data, using CTGCOMP (version 1.0, 961113) and CTGPROC (version 1.2, 010206). The elevation and land use files were combined for CALMET input using MAKEGEO (version 1.1, 010206).

Source input to CALPUFF will consist of four combustion turbines and two tank vent boilers for a two-phase Mesaba facility. Building downwash effects on stack emissions will be included through use of output from the BPIP PRIME wake effects program. Copies of complete CALMET and CALPUFF input files are included with this Protocol (Appendix A).

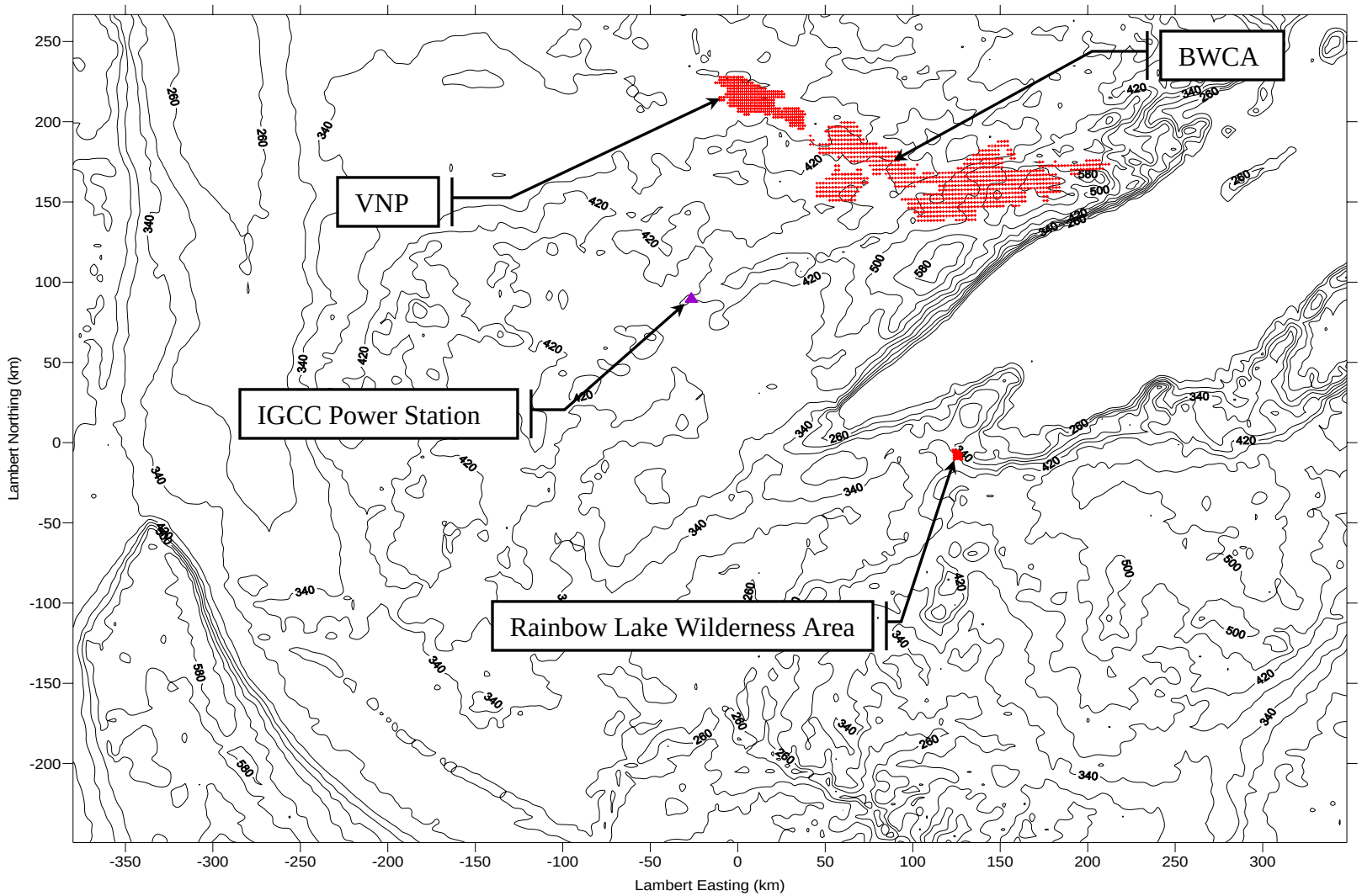
Initial CALPUFF modeling analyses utilized meteorological data for the years 1990, 1992, and 1996. These are the same years used for other recent CALPUFF applications in northern Minnesota and the data were readily available. Gridded meteorological fields used as input to the CALMET processor were MM4 (1990) and MM5 (1992, 1996) prognostic data acquired from the National Park Service (NPS). Additional surface, upper air, and precipitation data were used in CALMET to refine the meteorological fields. Hourly surface data from 13 stations were used along with precipitation data from 28 stations. Upper air data from two stations were used; St. Cloud MN and International Falls MN for 1990 and 1992, and Minneapolis and International Falls for 1996. The surface and precipitation stations are listed in Appendix B.

MM5 data with higher resolution for more recent years are now available from the State of Minnesota. These later MM5 data sets will be used, with surface and upper air data from representative regional stations, for subsequent CALMET/CALPUFF modeling.

Table 3-1. CALMET/CALPUFF Non-Default Input Parameters

Input Group	Parameter	Mesaba Selection	Explanation
	CALMET		
5	IKINE	1	Kinemateic effects option used to better account for terrain effects
5	RMAX 1	30 km	No default values
	RMAX 2	40 km	No default values
	RMAX 3	40 km	No default values
	TERRAD	15 km	No default values
	R1	5	No default values
	R2	15	No default values
	CALPUFF		
3	Species Modeled	SO_2, SO_4, NO_x, EC SOA, $PM_{2.5}$, HNO_3, NO_3	Modeled all species emitted by Mesaba sources, and others (HNO_3, NO_3) involved in plume chemistry
4	LSAMP	F	No gridded receptors (sampling grid) used
8	Part. Size	Mean = 0.48 st. dev. = 2	All particulate species assumed $PM_{2.5}$
11	MOZ	0	Constant ozone background
11	BCK03	40.0 ppb	Representation background ozone concentration
11	BCKNH3	1.0 ppb	Conservative background ammonia concentration (0.5 ppb recommended for forested lands)
12	NSPLIT	3	Puff-splitting used (default)

Figure 3-1 Mesaba Calmet Modeling Domain and Class 1 areas.



4.0 INCREMENT ANALYSES

CALPUFF model results for pollutant concentration at each Class I area receptor will be processed with CALPOST to determine the highest and highest second-high concentration for each pollutant and averaging time in each Class I area. Allowable Class I increments and Significant Impact Levels (SILs) are shown in Table 4-1.

The IGCC Power Station emission rates appropriate to each averaging time, as listed in Table 2-2, will be used in separate CALPUFF model runs to evaluate 3-hour, 24-hour, and annual increment consumption. Each model simulation will be carried out for each year of meteorological data; the highest concentration for any year will be compared to the applicable SIL, and the highest second-high from the three years will be compared to the allowable increment limit.

For calculation of particulate matter (PM10) impacts, the sum of all particle species (EC, SOA, FPM, CPM, and SO_4) will be calculated to represent the total PM10 concentration.

Initial CALPUFF modeling for the IGCC Power Station has indicated that predicted SO_2 concentrations may exceed the SIL in the BWCA and VNP for 3-hour and 24-hour averaging times. It will therefore be appropriate to carry out "cumulative" SO_2 modeling to assess the impact of the IGCC Power Station and all regional increment-consuming emissions.

Excelsior Energy contacted the Minnesota Pollution Control Agency (MPCA) and requested modeling information for regional SO_2 increment sources. MPCA provided detailed emission and stack data for those Minnesota sources with potential for Class I SO_2 impacts. The sources and net increment-consuming emissions are listed in Table 4-2. The MPCA inventory generally lists maximum allowable emissions for post-baseline sources. The allowable emissions will be used in increment modeling for all sources except Minnesota Power-Clay Boswell. Actual emissions data were acquired for the most recent two years for Clay Boswell; the emission rate in Table 4-2 represents the maximum actual hourly rate for that time period.

Some individual sources in the MPCA increment inventory have negative emission rates (i.e., actual SO_2 emissions have decreased since the baseline date, resulting in increment expansion). Since the CALPUFF model does not accept negative emission rates, two model runs will be carried out; one with the positive emissions and one with the negative emission rates. Concentration impacts of the negative sources will be subtracted from those of the positive sources for each hour/receptor to derive total increment impacts of all sources.

Results of the cumulative increment modeling (highest second-high 3-hour and 24-hour concentration for BWCA and VNP) will be compared to the PSD Class I increment limits to demonstrate compliance.

Table 4-1. Class I Area Increment Limits and Significant Impact Levels (SILs)

Pollutant	Averaging Time	Class I Increment (µg/m^3)	Significant Impact Level (µg/m^3)
SO_2	3-hour	25.0	1.0
	24-hour	5.0	0.2
	annual	2.0	0.1
PM10	24-hour	8.0	0.3
	annual	4.0	0.2
NO_2	annual	2.5	0.1

Table 4-2. Modeled Increment Consuming SO_2 Emissions For Cumulative Class I Increment Analysis

Source	Net Increment SO_2 Emissions	
	lb/hr	g/s
IGCC Power Station		
3-hour	622.9	78.48
24-hour	468.7	59.06
Minnesota Power – Hibbard	416.8	52.51
Blandin Paper – Rapids Energy	417.0	52.54
Northshore Mining	-20.8	-2.62
Minnesota Power – Clay Boswell	1686	212.4
Potlatch Paper – Cloquet	-34.5	-4.35
Hibbing Taconite – Hibbing	772.3	97.31
Boise Cascade	141.6	17.84
Mesabi Nugget – Hoyt Lakes	225.6	28.42

5.0 DEPOSITION OF NITROGEN AND SULFUR

The CALPUFF results for each of the Class I areas will be processed with CALPOST to calculate total annual deposition of nitrogen and sulfur at each receptor as a result of IGCC Power Station emissions. Model results for annual impacts (maximum annual average emissions) will be used following the methodology given in the IWAQM Phase I report. Total sulfur deposition is calculated from the wet and dry deposition of SO_2 and sulfate; total nitrogen is represented by the sum of nitrogen from wet and dry fluxes of nitric acid, nitrate, ammonium sulfate and ammonium nitrate, and the dry flux of NOx. For deposition calculations, MNITRATE will be set to a value of 1.0 in POSTUTIL to account for ammonia availability.

Results of deposition calculations for VNP will be compared to the NPS Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr for both sulfur and nitrogen. For the BWCA and RLW, total deposition (IGCC Power Station impact plus background) will be compared to the USFS "green line" values for terrestrial and aquatic ecosystems. The green line values are:

BWCA – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	7.5 – 8 kg/ha-yr
Sulfur + 20% nitrogen	9 – 10

RLW – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	3.5 – 4.5 kg/ha-yr
Sulfur + 20% nitrogen	4.5 – 5.5

6.0 REGIONAL HAZE ANALYSIS

A visibility/regional haze impact analysis will be carried out for BWCA and VNP. Visibility analysis is not required for Rainbow Lakes. The recommended methodology for assessing visibility impacts according to the FLAG guidance involves the use of CALPOST to process the data on concentrations of pollutants from the CALPUFF modeling of 24-hour emissions. In CALPOST a daily value of light extinction is defined by the concentrations of each pollutant that can effect visibility, taking into account the efficiency of each particle type in scattering light, and the relative humidity which influences the size of hygroscopic pollutants (sulfates and nitrates). The 24-hour average light extinction caused by emissions from the modeled source(s) is then compared to the background light extinction, a value based upon "natural" or pristine unpolluted conditions for each Class I area.

The FLMs have established threshold changes in light extinction (as a percentage of natural background) that are believed to represent potential adverse impacts on visibility. These thresholds are 5% (a potentially detectable change) and 10% (a level that may represent an unacceptable degradation).

The standard FLAG visibility analysis will be carried out using the CALPOST processing program and Method 2 for calculating source and background light extinction and the percentage change. Results will be presented in terms of the maximum percentage change and the number of days (24-hour periods) with percent change exceeding five and ten percent for the BWCA and RLW, for each year of meteorological data.

Natural background light extinction will be as given for the BWCA and VNP in the FLAG document. Relative humidity data for calculation of f(RH) in Method 2 is taken from the nearest surface weather station hourly observations. For receptors in the two Class I areas of concern the nearest station is either International Falls, MN or Hibbing MN. A maximum relative humidity cut-off of 95% will be specified.

The CALPOST program calculates f(RH) according to the data tabulated in FLAG. In the US EPA's regional haze modeling guidance [5] they have recommended a slightly different f(RH) function based upon Tang's smoothed data for ammonium sulfate. The EPA data give slightly larger values of f(RH) at intermediate RH, and significantly lower f(RH) at high humidity. The FLAG f(RH) data have been used for initial visibility modeling, but it is proposed to modify CALPOST to use the EPA function for subsequent modeling.

Under 40 CFR 51.301, an adverse impact on visibility is defined as "visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility". This definition indicates that a model-predicted extinction change exceeding a given

[5] U.S. EPA, 2003: Guidance for Tracking Progress Under the Regional Haze Rule. EPA-454/B-03-004, September 2003.

threshold value does not necessarily imply an adverse impact. Some consideration should be given to local conditions at the time and location of the model result, and factors that may have contributed to the predicted impact.

There are several factors inherent in the FLAG Method 2 methodology that are conservative in the sense that they lead to the highest likely impact. These include:

- the extinction change calculated for a Class I area represents the largest change for any receptor within the area.
- the change is calculated relative to natural or pristine background; i.e., the best visibility in the absence of any industrial pollution or abnormal natural events such as forest fires.
- no natural visibility impairment due to fog, precipitation, or clouds is considered
- the calculations assume emissions from the modeled source, at the highest daily rate, for every hour and day of the year

It should also be noted that relative humidity is a critical input to the light extinction calculation; because of the hygroscopic nature of sulfate and nitrate particles, light extinction is greatly magnified under high humidity conditions. The CALPOST visibility calculation uses measured relative humidity at the nearest surface weather station to calculate the humidity effect of given concentrations of sulfate and nitrate particles. The nearest weather station is often some distance from the Class I area of concern, and the observed relative humidity may or may not be representative of the analysis area. Most important, high relative humidity values are frequently associated with fog, precipitation, and low clouds, all of which can create natural visibility impairment. But the possible occurrence of these natural phenomena are not considered in the FLAG method 2 calculation.

Because of these factors, it is planned that additional visibility impact assessments will be carried out to better characterize the potential impacts of the IGCC Power Station on regional haze in Class I areas. These assessments will include application of CALPOST Methods 6 and 7, as well as meteorological analysis of those days on which impacts are projected, analysis of seasonal distribution of impacts, and estimates of average light extinction over extended lines-of-sight within or adjacent to the Class I areas. Based on discussions with the responsible FLMs, no cumulative visibility analyses are proposed at this time.

7.0 IMPACTS ON SOILS, WATERS, AND VEGETATION

Potential impacts to soils, waters, and vegetation in Class I areas will be evaluated on the basis of the model-predicted pollutant concentrations, and the magnitude of predicted annual deposition of sulfur and nitrogen.

Screening criteria for potential air pollution impacts on vegetation have been given by the U.S. Forest Service.[6] The USFS "Green Line" screening values "were set at levels at which it was reasonably certain that no significant change would be observed in ecosystems that contain large numbers of sensitive components." The Green Line screening levels for SO_2 are 5 µg/m^3 maximum annual average and 100 µg/m^3 maximum three-hour average. Though the USFS screening levels were established specifically for Class I areas administered by the Forest Service (BWCA and RLW) it is reasonable to apply the same criteria to VNP, which is administered by the National Park Service (NPS). There are no established screening criteria for NO_2 and PM10; however, Class I area concentrations of NO_2 and PM10 from the IGCC Power Station are indicated to be below significance levels and therefore can be expected to have negligible impacts.

The USFS has also established a green line screening value for ozone concentration. The green line level is a second-highest one-hour concentration during the growing season of 80 ppb. Existing background monitoring data indicate current concentrations near the green line level, but below the red line concentration of 120 ppb. Ozone modeling is not required for the IGCC Power Station, but the modest level of VOC and NO_x emissions indicate that the IGCC Power Station will not cause a significant increase in ozone impacts in the Class I areas.

The USFS has expressed concern about impacts of mercury deposition in the BWCA and RLW. Mercury modeling is not included in the proposed CALPUFF modeling analyses. However, impacts of mercury emissions and possible mercury deposition will be evaluated in separate toxics analyses required by the MPCA as a part of the permitting process.

All results of the Class I area modeling and impact analyses will be included in the formal IGCC Power Station PSD permit application. Moreover, the application will include an Air Modeling Report which will provide details of all analyses, methodology, and results. CALMET, CALPUFF, and CALPOST modeling files in electronic format will be submitted with the application to allow detailed review by the MPCA and FLMs.

[6] Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wildernesses Cited as Class I Air Quality Areas. USFS General Technical Report NE-151, 1991.

APPENDIX A

CALMET
and
CALPUFF

Input Listings

The CALMET and CALPUFF input listings are attached to the Application for a Part 70/New Source Review Construction Authorization Permit as eletronic files named “calmet92mn.xls” and “calpuff_24hr.xls,” respectively.

APPENDIX B

Regional Weather Stations

used for CALMET data processing

Weather Stations Included in CALMET Meteorological Data Processing

C:\Programmer's File Editor\upper.da2
Printed at 12:54 on 29 Nov 2005

Upper Air Stations included in CALMET

WBAN Number	Station Name	State	County	Years
14926	ST CLOUD	Minnesota	Sherburne	90,92
94983	MINNEAPOLIS	Minnesota	Hennepin	96
14918	INTERNATION FALLS	Minnesota	Koochiching	90,92,96

C:\Programmer's File Editor\surface.da2
Printed at 12:50 on 29 Nov 2005

Surface Stations included in CALMET (1990, 1992 and 1996)

WBAN Number	Station Name	CALMET Number	State	County
94902	BROOKINGS	26515	South Dakota	Brookings
14926	ST CLOUD	26550	Minnesota	Sherburne
14954	MANKATO	26585	Minnesota	Blue Earth
14914	FARGO	27530	North Dakota	Cass
14958	BEMIDJI	27550	Minnesota	Beltrami
14916	GRAND FORKS	27576	North Dakota	Grand Forks
14922	MINNEAPOLIS	26580	Minnesota	Hennepin
14913	DULUTH	27450	Minnesota	St. Louis
94931	HIBBING	27455	Minnesota	St. Louis
14918	INTERNATION FALLS	27470	Minnesota	Koochiching
14920	LA CROSSE	26430	Wisconsin	La Crosse
14991	EAU CLAIR	26435	Wisconsin	Chippewa
14897	WAUSAU	26463	Wisconsin	Marathon

C:\Programmer's File Editor\precip.da2
Printed at 13:48 on 29 Nov 2005

Precipitation Stations included in CALMET (1990, 1992 and 1996)

COOP ID	Station Name	State	County
474894	LUCK	Wisconsin	Polk
473511	HAYWARD RS	Wisconsin	Sawyer
478027	SPOONER EXP FARM	Wisconsin	Washburn
474396	LADYSMITH RS	Wisconsin	Rusk
475335	MENOMONIE	Wisconsin	Dunn
478589	TREMPEALEAU DAM 6	Wisconsin	Trempealeau
475352	MERCER RS	Wisconsin	Iron
476854	PRENTICE	Wisconsin	Price
479218	WILLARD	Wisconsin	Clark
476518	PHELPS	Wisconsin	Vilas
477140	RICE RSVR TOMAHAWK	Wisconsin	Lincoln
478963	WAUSAU 7 SSW	Wisconsin	Marathon
218235	THIEF LAKE REFUGE	Minnesota	Marshall
213463	HALSTAD	Minnesota	Norman
216228	ORWELL DAM	Minnesota	Otter Tail
211263	CANBY	Minnesota	Yellow Medicine
211589	CLEMENTSON	Minnesota	Lake of the Woods
218621	WALKER RANGER	Minnesota	Cass
217294	ST. CLOUD/WHITNEY MN.	Minnesota	Sherburne
215435	MINNEAPOLIS WSFO AP, MN	Minnesota	Hennepin
210746	BIG FALLS	Minnesota	Koochiching
214026	INT.FALLS/FALLS INT.MN.	Minnesota	Koochiching
216213	ORR	Minnesota	St. Louis
212248	DULUTH/INT.MN.	Minnesota	St. Louis
213793	HINCKLEY	Minnesota	Pine
218613	WALES 2 ENE	Minnesota	Lake
213296	GRAND PORTAGE R S	Minnesota	Cook
322859	FARGO/HECTOR FIELD ND.	North Dakota	Cass

```
Minnesota/Wisconsin CALMET - 1992 for Excelsior
with MM4 data, 13 surface met stations, 28 precipitation stations
2 Upper Air Stations
---------------- Run title (3 lines) ----------------------------------------

                 CALMET MODEL CONTROL FILE
                 -------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names


Subgroup (a)
------------
Default Name  Type          File Name
------------  ----          ---------
GEO.DAT       input    ! GEODAT= mn4km.geo !
SURF.DAT      input    ! SRFDAT= .\sfc\MNWIsfc92.dat  !
CLOUD.DAT     input    * CLDDAT=            *
PRECIP.DAT    input    ! PRCDAT= pmerge9096.dat !
MM4.DAT       input    ! MM4DAT= mn1992.mm5 !
WT.DAT        input    * WTDAT=             *

CALMET.LST    output   ! METLST= MnWICalmet92.LST     !
CALMET.DAT    output   ! METDAT= \\cluster8\e\project\2005\1877-05\CALMET\1992\MNWICALMET92.DAT!
PACOUT.DAT    output   * PACDAT=            *

All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
        T = lower case      ! LCFILES = T !
        F = UPPER CASE

NUMBER OF UPPER AIR & OVERWATER STATIONS:

   Number of upper air stations (NUSTA)  No default     ! NUSTA =  2  !
   Number of overwater met stations
                           (NOWSTA) No default     * NOWSTA =  0  *

                    !END!
-------------------------------------------------------------------------------
Subgroup (b)
--------------------------------
Upper air files (one per station)
--------------------------------
Default Name  Type       File Name
------------  ----       ---------
UP1.DAT       input     1  ! UPDAT= .\ua\intfls92.dat !  !END!
UP2.DAT       input     2  ! UPDAT= .\ua\stcloud92.dat  !  !END!
-------------------------------------------------------------------------------
Subgroup (c)
----------------------------------------
```

Overwater station files (one per station)

Default Name Type File Name
--- --- ---
SEA1.DAT input 1 * SEADAT= *

Subgroup (d)

Other file names

Default Name Type File Name
--- --- ---
DIAG.DAT input * DIADAT= *
PROG.DAT input * PRGDAT= *

TEST.PRT output * TSTPRT= *
TEST.OUT output * TSTOUT= *
TEST.KIN output * TSTKIN= *
TEST.FRD output * TSTFRD= *
TEST.SLP output * TSTSLP= *

NOTES: (1) File/path names can be up to 70 characters in length
(2) Subgroups (a) and (d) must have ONE 'END' (surround by delimiters) at the end of the group
(3) Subgroups (b) and (c) must have an 'END' (surround by delimiters) at the end of EACH LINE

!END!

INPUT GROUP: 1 -- General run control parameters

Starting date: Year (IBYR) -- No default ! IBYR= 1992 !
Month (IBMO) -- No default ! IBMO= 1 !
Day (IBDY) -- No default ! IBDY= 4 !
Hour (IBHR) -- No default ! IBHR= 1 !

Base time zone (IBTZ) -- No default ! IBTZ= 6 !
PST = 08, MST = 07
CST = 06, EST = 05

Length of run (hours) (IRLG) -- No default ! IRLG= 8616 !

Run type (IRTYPE) -- Default: 1 ! IRTYPE= 1 !

0 = Computes wind fields only
1 = Computes wind fields and micrometeorological variables

```
        (u*, w*, L, zi, etc.)
      (IRTYPE must be 1 to run CALPUFF or CALGRID)

    Compute special data fields required
    by CALGRID (i.e., 3-D fields of W wind
    components and temperature)
    in additional to regular          Default: T    ! LCALGRD = T !
    fields ? (LCALGRD)
    (LCALGRD must be T to run CALGRID)

     Flag to stop run after
     SETUP phase (ITEST)            Default: 2       ! ITEST=  2   !
     (Used to allow checking
     of the model inputs, files, etc.)
     ITEST = 1 - STOPS program after SETUP phase
     ITEST = 2 - Continues with execution of
                 COMPUTATIONAL phase after SETUP

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Map Projection and Grid control parameters
--------------

    Projection for all (X,Y):
    -------------------------

    Map projection
    (PMAP)                    Default: UTM    ! PMAP = LCC  !

       UTM :  Universal Transverse Mercator
       TTM :  Tangential Transverse Mercator
       LCC :  Lambert Conformal Conic
        PS :  Polar Stereographic
        EM :  Equatorial Mercator
      LAZA :  Lambert Azimuthal Equal Area

    False Easting and Northing (km) at the projection origin
    (Used only if PMAP= TTM, LCC, or LAZA)
    (FEAST)                   Default=0.0     ! FEAST  = 0.000  !
    (FNORTH)                    Default=0.0     ! FNORTH = 0.000  !

    UTM zone (1 to 60)
    (Used only if PMAP=UTM)
    (IUTMZN)                   No Default      ! IUTMZN =     !

    Hemisphere for UTM projection?
    (Used only if PMAP=UTM)
    (UTMHEM)                    Default: N      ! UTMHEM = N  !
       N   :  Northern hemisphere projection
       S   :  Southern hemisphere projection
```

Latitude and Longitude (decimal degrees) of projection origin
(Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
(RLAT0) No Default ! RLAT0 = 46.5N !
(RLON0) No Default ! RLON0 = 93.0W !

TTM : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
LCC : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
PS : RLON0 identifies central (grid N/S) meridian of projection
RLAT0 selected for convenience
EM : RLON0 identifies central meridian of projection
RLAT0 is REPLACED by 0.0N (Equator)
LAZA: RLON0 identifies longitude of tangent-point of mapping plane
RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)
(XLAT1) No Default ! XLAT1 = 30N !
(XLAT2) No Default ! XLAT2 = 60N !

LCC : Projection cone slices through Earth's surface at XLAT1 and XLAT2
PS : Projection plane slices through Earth at XLAT1
(XLAT2 is not used)

Note: Latitudes and longitudes should be positive, and include a
letter N,S,E, or W indicating north or south latitude, and
east or west longitude. For example,
35.9 N Latitude = 35.9N
118.7 E Longitude = 118.7E

Datum-region

The Datum-Region for the coordinates is identified by a character
string. Many mapping products currently available use the model of the
Earth known as the World Geodetic System 1984 (WGS-G). Other local
models may be in use, and their selection in CALMET will make its output
consistent with local mapping products. The list of Datum-Regions with
official transformation parameters is provided by the National Imagery and
Mapping Agency (NIMA).

NIMA Datum - Regions(Examples)

WGS-G WGS-84 GRS 80 Spheroid, Global coverage (WGS84)
NAS-C NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
NWS-27 NWS 6370KM Radius, Sphere
NWS-84 NWS 6370KM Radius, Sphere
ESR-S ESRI REFERENCE 6371KM Radius, Sphere

```
    Datum-region for output coordinates
    (DATUM)                  Default: WGS-G     ! DATUM = NAS-C  !


    Horizontal grid definition:
    ---------------------------

    Rectangular grid defined for projection PMAP,
    with X the Easting and Y the Northing coordinate

          No. X grid cells (NX)      No default     ! NX =   183  !
          No. Y grid cells (NY)      No default     ! NY =   130  !

    Grid spacing (DGRIDKM)           No default     ! DGRIDKM = 4. !
                                 Units: km

    Reference grid coordinate of
    SOUTHWEST corner of grid cell (1,1)

       X coordinate (XORIGKM)        No default     ! XORIGKM = -381.90 !
       Y coordinate (YORIGKM)        No default     ! YORIGKM = -251.20 !
                                 Units: km
    Vertical grid definition:
    -------------------------

       No. of vertical layers (NZ)    No default     ! NZ =  9  !

       Cell face heights in arbitrary
       vertical grid (ZFACE(NZ+1))    No defaults
                                 Units: m
      ! ZFACE = 0.,20.,50.,100.,200.,500.,1000.,1500.,2500.,3500. !
!END!


------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output Options
--------------


   DISK OUTPUT OPTION

      Save met. fields in an unformatted
      output file ?             (LSAVE)  Default: T     ! LSAVE = T !
      (F = Do not save, T = Save)

      Type of unformatted output file:
      (IFORMO)                         Default: 1    ! IFORMO =  1  !

          1 = CALPUFF/CALGRID type file (CALMET.DAT)
          2 = MESOPUFF-II type file     (PACOUT.DAT)
```

LINE PRINTER OUTPUT OPTIONS:

Print met. fields ? (LPRINT) Default: F ! LPRINT = F !
(F = Do not print, T = Print)
(NOTE: parameters below control which
met. variables are printed)

Print interval
(IPRINF) in hours Default: 1 ! IPRINF = 1 !
(Meteorological fields are printed
every 1 hours)

Specify which layers of U, V wind component
to print (IUVOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T) Defaults: NZ*0
! IUVOUT = 0 , 0 , 0 , 0 , 0 , 0 , 0 , 0, 0 !

Specify which levels of the W wind component to print
(NOTE: W defined at TOP cell face -- 10 values)
(IWOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T & LCALGRD=T)

Defaults: NZ*0
! IWOUT = 0 , 0 , 0 , 0 , 0 , 0 , 0 , 0, 0 !

Specify which levels of the 3-D temperature field to print
(ITOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T & LCALGRD=T)

Defaults: NZ*0
! ITOUT = 0 , 0 , 0 , 0 , 0 , 0 , 0 , 0, 0 !

Specify which meteorological fields
to print
(used only if LPRINT=T) Defaults: 0 (all variables)

Variable	Print ? (0 = do not print, 1 = print)

```
!  STABILITY  =          0          ! - PGT stability class
!  USTAR      =          0          ! - Friction velocity
!  MONIN      =          0          ! - Monin-Obukhov length
!  MIXHT      =          0          ! - Mixing height
!  WSTAR      =          0          ! - Convective velocity scale
!  PRECIP     =          0          ! - Precipitation rate
!  SENSHEAT   =          0          ! - Sensible heat flux
!  CONVZI     =          0          ! - Convective mixing ht.


 Testing and debug print options for micrometeorological module

   Print input meteorological data and
   internal variables (LDB)        Default: F       ! LDB = F !
   (F = Do not print, T = print)
   (NOTE: this option produces large amounts of output)

   First time step for which debug data
   are printed (NN1)               Default: 1       ! NN1 =  1  !

   Last time step for which debug data
   are printed (NN2)               Default: 1       ! NN2 =  1  !


 Testing and debug print options for wind field module
 (all of the following print options control output to
  wind field module's output files: TEST.PRT, TEST.OUT,
  TEST.KIN, TEST.FRD, and TEST.SLP)

   Control variable for writing the test/debug
   wind fields to disk files (IOUTD)
   (0=Do not write, 1=write)       Default: 0       ! IOUTD =  0  !

   Number of levels, starting at the surface,
   to print (NZPRN2)               Default: 1       ! NZPRN2 =  0  !

   Print the INTERPOLATED wind components ?
   (IPR0) (0=no, 1=yes)            Default: 0       !  IPR0 =  0  !

   Print the TERRAIN ADJUSTED surface wind
   components ?
   (IPR1) (0=no, 1=yes)            Default: 0       !  IPR1 =  0  !

   Print the SMOOTHED wind components and
   the INITIAL DIVERGENCE fields ?
   (IPR2) (0=no, 1=yes)            Default: 0       !  IPR2 =  0  !

   Print the FINAL wind speed and direction
   fields ?
   (IPR3) (0=no, 1=yes)            Default: 0       !  IPR3 =  0  !

   Print the FINAL DIVERGENCE fields ?
```

```
        (IPR4) (0=no, 1=yes)            Default: 0      !  IPR4 =  0  !

        Print the winds after KINEMATIC effects
        are added ?
        (IPR5) (0=no, 1=yes)            Default: 0      !  IPR5 =  0  !

        Print the winds after the FROUDE NUMBER
        adjustment is made ?
        (IPR6) (0=no, 1=yes)            Default: 0      !  IPR6 =  0  !

        Print the winds after SLOPE FLOWS
        are added ?
        (IPR7) (0=no, 1=yes)            Default: 0      !  IPR7 =  0  !

        Print the FINAL wind field components ?
        (IPR8) (0=no, 1=yes)            Default: 0      !  IPR8 =  0  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 4 -- Meteorological data options
--------------

   NO OBSERVATION MODE            (NOOBS)  Default: 0     ! NOOBS =  0   !
        0 = Use surface, overwater, and upper air stations
        1 = Use surface and overwater stations (no upper air observations)
           Use MM5 for upper air data
        2 = No surface, overwater, or upper air observations
           Use MM5 for surface, overwater, and upper air data

   NUMBER OF SURFACE & PRECIP. METEOROLOGICAL STATIONS

      Number of surface stations   (NSSTA)  No default     ! NSSTA =  13 !

      Number of precipitation stations
      (NPSTA=-1: flag for use of MM5 precip data)
                                   (NPSTA)  No default     ! NPSTA =  28  !

   CLOUD DATA OPTIONS
      Gridded cloud fields:
                                 (ICLOUD)  Default: 0     ! ICLOUD =  0  !
      ICLOUD = 0 - Gridded clouds not used
      ICLOUD = 1 - Gridded CLOUD.DAT generated as OUTPUT
      ICLOUD = 2 - Gridded CLOUD.DAT read as INPUT
      ICLOUD = 3 - Gridded cloud cover from Prognostic Rel. Humidity

   FILE FORMATS

      Surface meteorological data file format
                                 (IFORMS)  Default: 2     ! IFORMS =  2  !
```

```
      (1 = unformatted (e.g., SMERGE output))
      (2 = formatted   (free-formatted user input))

      Precipitation data file format
                              (IFORMP)  Default: 2     ! IFORMP =  2  !
      (1 = unformatted (e.g., PMERGE output))
      (2 = formatted   (free-formatted user input))

      Cloud data file format
                              (IFORMC)  Default: 2     ! IFORMC =  2  !
      (1 = unformatted - CALMET unformatted output)
      (2 = formatted   - free-formatted CALMET output or user input)

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 5 -- Wind Field Options and Parameters
--------------


   WIND FIELD MODEL OPTIONS
      Model selection variable (IWFCOD)     Default: 1      ! IWFCOD =  1  !
        0 = Objective analysis only
        1 = Diagnostic wind module

      Compute Froude number adjustment
      effects ? (IFRADJ)                    Default: 1      ! IFRADJ =  1  !
      (0 = NO, 1 = YES)

      Compute kinematic effects ? (IKINE)   Default: 0      ! IKINE  =  1  !
      (0 = NO, 1 = YES)

      Use O'Brien procedure for adjustment
      of the vertical velocity ? (IOBR)     Default: 0      ! IOBR =  0  !
      (0 = NO, 1 = YES)

      Compute slope flow effects ? (ISLOPE) Default: 1      ! ISLOPE  =  1  !
      (0 = NO, 1 = YES)

      Extrapolate surface wind observations
      to upper layers ? (IEXTRP)            Default: -4     ! IEXTRP =  -4 !
      (1 = no extrapolation is done,
       2 = power law extrapolation used,
       3 = user input multiplicative factors
           for layers 2 - NZ used (see FEXTRP array)
       4 = similarity theory used
      -1, -2, -3, -4 = same as above except layer 1 data
           at upper air stations are ignored

      Extrapolate surface winds even
```

```
  if calm? (ICALM)                    Default: 0      ! ICALM  =  0  !
  (0 = NO, 1 = YES)

  Layer-dependent biases modifying the weights of
  surface and upper air stations (BIAS(NZ))
    -1<=BIAS<=1
  Negative BIAS reduces the weight of upper air stations
    (e.g. BIAS=-0.1 reduces the weight of upper air stations
  by 10%; BIAS= -1, reduces their weight by 100 %)
  Positive BIAS reduces the weight of surface stations
    (e.g. BIAS= 0.2 reduces the weight of surface stations
  by 20%; BIAS=1 reduces their weight by 100%)
  Zero BIAS leaves weights unchanged (1/R**2 interpolation)
  Default: NZ*0
                      ! BIAS =  0 ,  0 ,  0 ,  0 ,  0 ,  0,  0 ,  0 ,  0 !

  Minimum distance from nearest upper air station
  to surface station for which extrapolation
  of surface winds at surface station will be allowed
  (RMIN2: Set to -1 for IEXTRP = 4 or other situations
   where all surface stations should be extrapolated)
                                  Default: 4.    ! RMIN2 = -1.0 !

  Use gridded prognostic wind field model
  output fields as input to the diagnostic
  wind field model (IPROG)              Default: 0      ! IPROG =  4  !
  (0 = No, [IWFCOD = 0 or 1]
   1 = Yes, use CSUMM prog. winds as Step 1 field, [IWFCOD = 0]
   2 = Yes, use CSUMM prog. winds as initial guess field [IWFCOD = 1]
   3 = Yes, use winds from MM4.DAT file as Step 1 field [IWFCOD = 0]
   4 = Yes, use winds from MM4.DAT file as initial guess field [IWFCOD = 1]
   5 = Yes, use winds from MM4.DAT file as observations [IWFCOD = 1]
   13 = Yes, use winds from MM5.DAT file as Step 1 field [IWFCOD = 0]
   14 = Yes, use winds from MM5.DAT file as initial guess field [IWFCOD = 1]
   15 = Yes, use winds from MM5.DAT file as observations [IWFCOD = 1]

  Timestep (hours) of the prognostic
  model input data   (ISTEPPG)          Default: 1      ! ISTEPPG =  1   !

RADIUS OF INFLUENCE PARAMETERS

  Use varying radius of influence       Default: F      ! LVARY =  F!
  (if no stations are found within RMAX1,RMAX2,
   or RMAX3, then the closest station will be used)

  Maximum radius of influence over land
  in the surface layer (RMAX1)          No default      ! RMAX1 = 30.0 !
                                  Units: km
  Maximum radius of influence over land
  aloft (RMAX2)                         No default      ! RMAX2 = 40.0 !
                                  Units: km
  Maximum radius of influence over water
```

(RMAX3) No default ! RMAX3 = 40.0 !
Units: km

OTHER WIND FIELD INPUT PARAMETERS

Minimum radius of influence used in
the wind field interpolation (RMIN) Default: 0.1 ! RMIN = 0.1 !
Units: km
Radius of influence of terrain
features (TERRAD) No default ! TERRAD = 15. !

Units: km
Relative weighting of the first
guess field and observations in the
SURFACE layer (R1) No default ! R1 = 5. !
(R1 is the distance from an Units: km
observational station at which the
observation and first guess field are
equally weighted)

Relative weighting of the first
guess field and observations in the
layers ALOFT (R2) No default ! R2 = 15. !
(R2 is applied in the upper layers Units: km
in the same manner as R1 is used in
the surface layer).

Relative weighting parameter of the
prognostic wind field data (RPROG) No default ! RPROG = 0. !
(Used only if IPROG = 1) Units: km

Maximum acceptable divergence in the
divergence minimization procedure
(DIVLIM) Default: 5.E-6 ! DIVLIM= 5.0E-06 !

Maximum number of iterations in the
divergence min. procedure (NITER) Default: 50 ! NITER = 50 !

Number of passes in the smoothing
procedure (NSMTH(NZ))
NOTE: NZ values must be entered
Default: 2,(mxnz-1)*4 ! NSMTH =
2 , 4 , 4 , 4 , 4 , 4 , 4 , 4 , 4 !

Maximum number of stations used in
each layer for the interpolation of
data to a grid point (NINTR2(NZ))
NOTE: NZ values must be entered Default: 99. ! NINTR2 =
99 , 99 , 99 , 99 , 99 , 99 , 99, 99 , 99 !

Critical Froude number (CRITFN) Default: 1.0 ! CRITFN = 1. !

Empirical factor controlling the
influence of kinematic effects
(ALPHA) Default: 0.1 ! ALPHA = 0.1 !

Multiplicative scaling factor for
extrapolation of surface observations
to upper layers (FEXTR2(NZ)) Default: NZ*0.0
! FEXTR2 = 0., 0., 0., 0., 0., 0., 0., 0., 0.!
(Used only if IEXTRP = 3 or -3)

BARRIER INFORMATION

Number of barriers to interpolation
of the wind fields (NBAR) Default: 0 ! NBAR = 0 !

THE FOLLOWING 4 VARIABLES ARE INCLUDED
ONLY IF NBAR > 0
NOTE: NBAR values must be entered No defaults
for each variable Units: km

X coordinate of BEGINNING
of each barrier (XBBAR(NBAR)) ! XBBAR = 0. !
Y coordinate of BEGINNING
of each barrier (YBBAR(NBAR)) ! YBBAR = 0. !

X coordinate of ENDING
of each barrier (XEBAR(NBAR)) ! XEBAR = 0. !
Y coordinate of ENDING
of each barrier (YEBAR(NBAR)) ! YEBAR = 0. !

DIAGNOSTIC MODULE DATA INPUT OPTIONS

Surface temperature (IDIOPT1) Default: 0 ! IDIOPT1 = 0 !
0 = Compute internally from
hourly surface observations
1 = Read preprocessed values from
a data file (DIAG.DAT)

Surface met. station to use for
the surface temperature (ISURFT) No default ! ISURFT = 10 !
(Must be a value from 1 to NSSTA)
(Used only if IDIOPT1 = 0)

Domain-averaged temperature lapse
rate (IDIOPT2) Default: 0 ! IDIOPT2 = 0 !
0 = Compute internally from
twice-daily upper air observations

```
  1 = Read hourly preprocessed values
      from a data file (DIAG.DAT)

  Upper air station to use for
  the domain-scale lapse rate (IUPT) No default     ! IUPT   =  1  !
  (Must be a value from 1 to NUSTA)
  (Used only if IDIOPT2 = 0)
  --------------------------

  Depth through which the domain-scale
  lapse rate is computed (ZUPT)      Default: 200.  ! ZUPT = 200. !
  (Used only if IDIOPT2 = 0)         Units: meters
  --------------------------

Domain-averaged wind components
(IDIOPT3)                            Default: 0     ! IDIOPT3 =  0  !
  0 = Compute internally from
      twice-daily upper air observations
  1 = Read hourly preprocessed values
      a data file (DIAG.DAT)

  Upper air station to use for
  the domain-scale winds (IUPWND)    Default: -1    ! IUPWND = -1  !
  (Must be a value from -1 to NUSTA)
  (Used only if IDIOPT3 = 0)
  --------------------------

  Bottom and top of layer through
  which the domain-scale winds
  are computed
  (ZUPWND(1), ZUPWND(2))        Defaults: 1., 1000. ! ZUPWND= 1., 1000. !
  (Used only if IDIOPT3 = 0)    Units: meters
  --------------------------

Observed surface wind components
for wind field module (IDIOPT4)  Default: 0     ! IDIOPT4 =  0  !
  0 = Read WS, WD from a surface
      data file (SURF.DAT)
  1 = Read hourly preprocessed U, V from
      a data file (DIAG.DAT)

Observed upper air wind components
for wind field module (IDIOPT5)  Default: 0     ! IDIOPT5 =  0  !
  0 = Read WS, WD from an upper
      air data file (UP1.DAT, UP2.DAT, etc.)
  1 = Read hourly preprocessed U, V from
      a data file (DIAG.DAT)

LAKE BREEZE INFORMATION

  Use Lake Breeze Module  (LLBREZE)
                              Default: F      ! LLBREZE = F !
```

```
        Number of lake breeze regions (NBOX)          ! NBOX =  0  !

      X Grid line 1 defining the region of interest
                                          ! XG1 = 0. !
      X Grid line 2 defining the region of interest
                                          ! XG2 = 0. !
      Y Grid line 1 defining the region of interest
                                          ! YG1 = 0. !
      Y Grid line 2 defining the region of interest
                                          ! YG2 = 0. !

       X Point defining the coastline (Straight line)
              (XBCST)  (KM)   Default: none    ! XBCST = 0. !

       Y Point defining the coastline (Straight line)
              (YBCST)  (KM)   Default: none    ! YBCST = 0. !

       X Point defining the coastline (Straight line)
              (XECST)  (KM)   Default: none    ! XECST = 0. !

       Y Point defining the coastline (Straight line)
              (YECST)  (KM)   Default: none    ! YECST = 0. !


     Number of stations in the region     Default: none ! NLB =  0 !
     (Surface stations + upper air stations)

     Station ID's  in the region   (METBXID(NLB))
     (Surface stations first, then upper air stations)
       ! METBXID =  0 !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 6 -- Mixing Height, Temperature and Precipitation Parameters
--------------

   EMPIRICAL MIXING HEIGHT CONSTANTS

     Neutral, mechanical equation
     (CONSTB)                        Default: 1.41   ! CONSTB = 1.41 !
     Convective mixing ht. equation
     (CONSTE)                        Default: 0.15   ! CONSTE = 0.15 !
     Stable mixing ht. equation
     (CONSTN)                        Default: 2400.  ! CONSTN = 2400.!
     Overwater mixing ht. equation
     (CONSTW)                         Default: 0.16   ! CONSTW = 0.16 !
     Absolute value of Coriolis
     parameter (FCORIOL)                 Default: 1.E-4  ! FCORIOL = 1.0E-04!
```

Units: (1/s)

SPATIAL AVERAGING OF MIXING HEIGHTS

Conduct spatial averaging
(IAVEZI) (0=no, 1=yes) Default: 1 ! IAVEZI = 1 !

Max. search radius in averaging
process (MNMDAV) Default: 1 ! MNMDAV = 1 !
Units: Grid
cells
Half-angle of upwind looking cone
for averaging (HAFANG) Default: 30. ! HAFANG = 30. !
Units: deg.
Layer of winds used in upwind
averaging (ILEVZI) Default: 1 ! ILEVZI = 1 !
(must be between 1 and NZ)

OTHER MIXING HEIGHT VARIABLES

Minimum potential temperature lapse
rate in the stable layer above the
current convective mixing ht. Default: 0.001 ! DPTMIN = 0.001 !
(DPTMIN) Units: deg. K/m
Depth of layer above current conv.
mixing height through which lapse Default: 200. ! DZZI = 200. !
rate is computed (DZZI) Units: meters

Minimum overland mixing height Default: 50. ! ZIMIN = 50. !
(ZIMIN) Units: meters
Maximum overland mixing height Default: 3000. ! ZIMAX = 3500. !
(ZIMAX) Units: meters
Minimum overwater mixing height Default: 50. ! ZIMINW = 50. !
(ZIMINW) -- (Not used if observed Units: meters
overwater mixing hts. are used)
Maximum overwater mixing height Default: 3000. ! ZIMAXW = 3500. !
(ZIMAXW) -- (Not used if observed Units: meters
overwater mixing hts. are used)

TEMPERATURE PARAMETERS

3D temperature from observations or
from prognostic data? (ITPROG) Default:0 !ITPROG = 0!

0 = Use Surface and upper air stations
(only if NOOBS = 0)
1 = Use Surface stations (no upper air observations)
Use MM5 for upper air data
(only if NOOBS = 0,1)
2 = No surface or upper air observations
Use MM5 for surface and upper air data

```
        (only if NOOBS = 0,1,2)

    Interpolation type
    (1 = 1/R ; 2 = 1/R**2)              Default:1        ! IRAD =  1  !

    Radius of influence for temperature
    interpolation (TRADKM)              Default: 500.     ! TRADKM =500. !
                                   Units: km

    Maximum Number of stations to include
    in temperature interpolation (NUMTS)  Default: 5        ! NUMTS = 5  !

    Conduct spatial averaging of temp-
    eratures (IAVET)  (0=no, 1=yes)        Default: 1     ! IAVET =  1  !
    (will use mixing ht MNMDAV,HAFANG
     so make sure they are correct)

    Default temperature gradient       Default: -.0098 ! TGDEFB = -0.0098 !
    below the mixing height over
    water (K/m) (TGDEFB)

    Default temperature gradient       Default: -.0045 ! TGDEFA = -0.0045 !
    above the mixing height over
    water (K/m) (TGDEFA)

    Beginning (JWAT1) and ending (JWAT2)
    land use categories for temperature                  ! JWAT1 =  999  !
    interpolation over water -- Make                   ! JWAT2 = 999  !
    bigger than largest land use to disable

  PRECIP INTERPOLATION PARAMETERS

    Method of interpolation (NFLAGP)      Default = 2    ! NFLAGP =  2  !
     (1=1/R,2=1/R**2,3=EXP/R**2)
    Radius of Influence (km) (SIGMAP)     Default = 100.0  ! SIGMAP =100. !
     (0.0 => use half dist. btwn
      nearest stns w & w/out
      precip when NFLAGP = 3)
    Minimum Precip. Rate Cutoff (mm/hr)   Default = 0.01  ! CUTP = 0.01 !
     (values < CUTP = 0.0 mm/hr)
!END!


-------------------------------------------------------------------------------

INPUT GROUP: 7 -- Surface meteorological station parameters
--------------

   SURFACE STATION VARIABLES
   (One record per station -- 13  records in all)
```

```
          1     2
       Name   ID          X coord.   Y coord.   Time   Anem.
                          (km)       (km)       zone   Ht.(m)
     -------------------------------------------------------
! SS1  ='BROOKIN '   26515   -293.2558  -229.2143     6    10.0 !
! SS2  ='STCLOUD '   26550   -78.9386   -101.4754     6    6.10 !
! SS3  ='MANKATO '   26585   -70.5793   -244.7148     6   10.00 !
! SS4  ='FARGO   '   27530  -279.7845     53.1641     6    8.53 !
! SS5  ='BEMIDJI '   27550  -140.2581    109.0812     6   10.00 !
! SS6  ='GRNDFRK '   27576  -300.8847    163.5914     6   10.00 !
! SS7  ='MINSTPL '   26580   -17.7257   -173.5780     6   10.00 !
! SS8  ='DULUTH  '   27450    57.5194     36.0370     6    6.40 !
! SS9  ='HIBBING '   27455    10.9086     94.8316     6   10.00 !
! SS10 ='INTFALL '   27470   -28.4539    222.1096     6    6.10 !
! SS11 ='LACRSSE '   26430   135.5070   -281.2290     6   10.00 !
! SS12 ='EAUCLAIR'   26435   115.4331   -174.2282     6   10.00 !
! SS13 ='WAUSAU  '   26463   255.9194   -164.5718     6   10.00 !


-------------------
                                                                                                                                1

       Four character string for station name
       (MUST START IN COLUMN 9)


                                                                                                                                2

       Five digit integer for station ID

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 8 -- Upper air meteorological station parameters
--------------

    UPPER AIR STATION VARIABLES
    (One record per station --  2  records in all)

          1     2
       Name    ID      X coord.   Y coord.  Time zone
                       (km)       (km)
       ----------------------------------------------
! US1  ='INFL'  14918   -28.24100   222.0010 6    !
! US2  ='STCL'  14926   -79.09602  -102.0104 6    !


-------------------
                                                                                                                                1

       Four character string for station name
       (MUST START IN COLUMN 9)

                                                                                                                                2
```

Five digit integer for station ID

!END!

INPUT GROUP: 9 -- Precipitation station parameters

PRECIPITATION STATION VARIABLES
(One record per station -- 28 records in all)
(NOT INCLUDED IF NPSTA = 0)

```
          1          2
       Name   Station    X coord.  Y coord.
              Code       (km)      (km)
       ------------------------------------
! PS1  ='LUCK' 474894    40.05945   -100.0348    !
! PS2  ='HAYW' 473511   113.1287    -52.60986    !
! PS3  ='SPOO' 478027    83.57548    -72.7456    !
! PS4  ='LADY' 474396   139.2798    -109.2948    !
! PS5  ='MENO' 475335    81.17084   -173.0629    !
! PS6  ='TREM' 478589   121.0592    -267.2398    !
! PS7  ='MERC' 475352   218.033      -31.7587    !
! PS8  ='PREN' 476854   204.2297    -98.52768    !
! PS9  ='WILL' 479218   174.1174   -187.22720    !
! PS10 ='PHEL' 476518   292.8459    -39.29507    !
! PS11 ='RICE' 477140   244.3478    -98.85872    !
! PS12 ='WAUS' 478963   254.8526   -169.9897     !
! PS13 ='THIE' 218235  -210.1333    216.8804     !
! PS14 ='HALS' 213463  -278.8134     97.95155    !
! PS15 ='ORWE' 216228  -236.3947    -25.68501    !
! PS16 ='CANB' 211263  -250.4186   -186.2932     !
! PS17 ='CLEM' 211589  -101.7078    235.4188     !
! PS18 ='WALK' 218621  -114.5457     65.54837    !
! PS19 ='STWH' 217294   -78.93861   -101.4754    !
! PS20 ='MINN' 215435   -16.5085    -173.5814    !
! PS21 ='BIG ' 210746   -57.30112    182.8797    !
! PS22 ='INTF' 214026   -28.45387    222.1096    !
! PS23 ='ORR ' 216213    10.77433    166.4852     !
! PS24 ='DULU' 212248   57.51939    36.03699     !
! PS25 ='HINC' 213793    8.72834   -55.50035     !
! PS26 ='WALE' 218613   94.76866    81.30602     !
! PS27 ='GRAN' 213296   238.5576    162.4988     !
! PS28 ='FARG' 322859  -279.7845    53.16407     !
```

Four character string for station name

(MUST START IN COLUMN 9)

2

Six digit station code composed of state code (first 2 digits) and station ID (last 4 digits)

!END!

Excelsior 1992 - West
183x130 4 km Grid 24-Hour Emission Rates

11/21/2005

```
---------------- Run title (3 lines) ----------------------------------------

                 CALPUFF MODEL CONTROL FILE
                 --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

--------------
Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    ! METDAT = \\cluster8\e\project\2005\1877-05\calmet\1992\mnwicalmet92.dat  !
   or
ISCMET.DAT    input    * ISCDAT =            *
   or
PLMMET.DAT    input    * PLMDAT =            *
   or
PROFILE.DAT   input    * PRFDAT =            *
SURFACE.DAT   input    * SFCDAT =            *
RESTARTB.DAT  input    * RSTARTB=            *
-------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST =excel92puff2w11210524hr.lst  !
CONC.DAT      output   ! CONDAT =excel92puff2w11210524hr.con  !
DFLX.DAT      output   ! DFDAT  =excel92puff2w11210524hr.dry  !
WFLX.DAT      output   ! WFDAT  =excel92puff2w11210524hr.wet  !

VISB.DAT      output   ! VISDAT =excel92puff2w11210524hr.vis  !
RESTARTE.DAT  output   * RSTARTE=            *
-------------------------------------------------------------------------------
Emission Files
--------------
PTEMARB.DAT   input    * PTDAT  =            *
VOLEMARB.DAT  input    * VOLDAT =            *
```

```
BAEMARB.DAT   input    * ARDAT  =           *
LNEMARB.DAT   input    * LNDAT  =           *
-------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    * OZDAT  =           *
VD.DAT        input    * VDDAT  =           *
CHEM.DAT      input    * CHEMDAT=           *
H2O2.DAT      input    * H2O2DAT=           *
HILL.DAT      input    * HILDAT=            *
HILLRCT.DAT   input    * RCTDAT=            *
COASTLN.DAT   input    * CSTDAT=            *
FLUXBDY.DAT   input    * BDYDAT=            *
BCON.DAT      input    * BCNDAT=            *
DEBUG.DAT     output   * DEBUG =            *
MASSFLX.DAT   output   * FLXDAT=            *
MASSBAL.DAT   output   * BALDAT=            *
FOG.DAT       output   * FOGDAT=            *
-------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
        T = lower case      ! LCFILES = F !
        F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length


Provision for multiple input files
----------------------------------

    Number of CALMET.DAT files for run (NMETDAT)
                              Default: 1       ! NMETDAT =   1   !

    Number of PTEMARB.DAT files for run (NPTDAT)
                              Default: 0       ! NPTDAT =  0  !

    Number of BAEMARB.DAT files for run (NARDAT)
                              Default: 0       ! NARDAT =  0  !
```

```
    Number of VOLEMARB.DAT files for run (NVOLDAT)
                                Default: 0       ! NVOLDAT =  0  !

!END!

-------------
Subgroup (0a)
-------------

  The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
 none         input    * METDAT=     *   *END*


-------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

    Option to run all periods found
    in the met. file     (METRUN)   Default: 0       ! METRUN =   1  !

        METRUN = 0 - Run period explicitly defined below
        METRUN = 1 - Run all periods in met. file

     Starting date:   Year (IBYR) -- No default       ! IBYR =   1992 !
     (used only if   Month (IBMO) -- No default       ! IBMO =     !
      METRUN = 0)      Day (IBDY) -- No default       ! IBDY =     !
                    Hour (IBHR) -- No default       ! IBHR =     !

     Base time zone        (XBTZ) -- No default       ! XBTZ = 6    !
        PST = 8., MST = 7.
        CST = 6., EST = 5.
```

```
Length of run (hours) (IRLG) -- No default       ! IRLG =      !

Number of chemical species (NSPEC)
                          Default: 5       ! NSPEC =  9 !

Number of chemical species
to be emitted  (NSE)           Default: 3       ! NSE =  7   !

Flag to stop run after
SETUP phase (ITEST)            Default: 2       ! ITEST =  2   !
(Used to allow checking
of the model inputs, files, etc.)
     ITEST = 1 - STOPS program after SETUP phase
     ITEST = 2 - Continues with execution of program
                 after SETUP

Restart Configuration:

   Control flag (MRESTART)      Default: 0       ! MRESTART =  0   !

      0 = Do not read or write a restart file
      1 = Read a restart file at the beginning of
          the run
      2 = Write a restart file during run
      3 = Read a restart file at beginning of run
          and write a restart file during run

   Number of periods in Restart
   output cycle (NRESPD)        Default: 0       ! NRESPD =  0   !

      0 = File written only at last period
     >0 = File updated every NRESPD periods

Meteorological Data Format (METFM)
                          Default: 1       ! METFM =  1   !

     METFM = 1 - CALMET binary file (CALMET.MET)
```

```
        METFM = 2 - ISC ASCII file (ISCMET.MET)
        METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
        METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                    surface parameters file (SURFACE.DAT)

    PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
    Averaging Time (minutes) (AVET)
                                Default: 60.0    ! AVET = 60. !
    PG Averaging Time (minutes) (PGTIME)
                                Default: 60.0    ! PGTIME = 60. !


!END!


-----------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


    Vertical distribution used in the
    near field (MGAUSS)                 Default: 1     ! MGAUSS =  1   !
      0 = uniform
      1 = Gaussian

    Terrain adjustment method
    (MCTADJ)                            Default: 3     ! MCTADJ =  3   !
      0 = no adjustment
      1 = ISC-type of terrain adjustment
      2 = simple, CALPUFF-type of terrain
          adjustment
      3 = partial plume path adjustment

    Subgrid-scale complex terrain
    flag (MCTSG)                        Default: 0     ! MCTSG =  0   !
      0 = not modeled
```

1 = modeled

Near-field puffs modeled as
elongated 0 (MSLUG) Default: 0 ! MSLUG = 0 !
0 = no
1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS) Default: 1 ! MTRANS = 1 !
0 = no (i.e., final rise only)
1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP) Default: 1 ! MTIP = 1 !
0 = no (i.e., no stack tip downwash)
1 = yes (i.e., use stack tip downwash)

Method used to simulate building
downwash? (MBDW) Default: 1 ! MBDW = 1 !
1 = ISC method
2 = PRIME method

Vertical wind shear modeled above
stack top? (MSHEAR) Default: 0 ! MSHEAR = 0 !
0 = no (i.e., vertical wind shear not modeled)
1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT) Default: 0 ! MSPLIT = 0 !
0 = no (i.e., puffs not split)
1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM) Default: 1 ! MCHEM = 1 !
0 = chemical transformation not
modeled
1 = transformation rates computed
internally (MESOPUFF II scheme)
2 = user-specified transformation
rates used

3 = transformation rates computed
internally (RIVAD/ARM3 scheme)
4 = secondary organic aerosol formation
computed (MESOPUFF II scheme for OH)

Aqueous phase transformation flag (MAQCHEM)
(Used only if MCHEM = 1, or 3) Default: 0 ! MAQCHEM = 0 !
0 = aqueous phase transformation
not modeled
1 = transformation rates adjusted
for aqueous phase reactions

Wet removal modeled ? (MWET) Default: 1 ! MWET = 1 !
0 = no
1 = yes

Dry deposition modeled ? (MDRY) Default: 1 ! MDRY = 1 !
0 = no
1 = yes
(dry deposition method specified
for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP) Default: 3 ! MDISP = 3 !

1 = dispersion coefficients computed from measured values
of turbulence, sigma v, sigma w
2 = dispersion coefficients from internally calculated
sigma v, sigma w using micrometeorological variables
(u*, w*, L, etc.)
3 = PG dispersion coefficients for RURAL areas (computed using
the ISCST multi-segment approximation) and MP coefficients in
urban areas
4 = same as 3 except PG coefficients computed using
the MESOPUFF II eqns.
5 = CTDM sigmas used for stable and neutral conditions.
For unstable conditions, sigmas are computed as in

MDISP = 3, described above. MDISP = 5 assumes that
measured values are read

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5) Default: 3 ! MTURBVW = 3 !
1 = use sigma-v or sigma-theta measurements
from PROFILE.DAT to compute sigma-y
(valid for METFM = 1, 2, 3, 4)
2 = use sigma-w measurements
from PROFILE.DAT to compute sigma-z
(valid for METFM = 1, 2, 3, 4)
3 = use both sigma-(v/theta) and sigma-w
from PROFILE.DAT to compute sigma-y and sigma-z
(valid for METFM = 1, 2, 3, 4)
4 = use sigma-theta measurements
from PLMMET.DAT to compute sigma-y
(valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2) Default: 3 ! MDISP2 = 3 !
(used only if MDISP = 1 or 5)
2 = dispersion coefficients from internally calculated
sigma v, sigma w using micrometeorological variables
(u*, w*, L, etc.)
3 = PG dispersion coefficients for RURAL areas (computed using
the ISCST multi-segment approximation) and MP coefficients in
urban areas
4 = same as 3 except PG coefficients computed using
the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness? Default: 0 ! MROUGH = 0 !
(MROUGH)
0 = no
1 = yes

Partial plume penetration of Default: 1 ! MPARTL = 1 !

elevated inversion?
(MPARTL)
  0 = no
  1 = yes

Strength of temperature inversion Default: 0 ! MTINV = 0 !
provided in PROFILE.DAT extended records?
(MTINV)
  0 = no (computed from measured/default gradients)
  1 = yes

PDF used for dispersion under convective conditions?
                Default: 0 ! MPDF = 0 !
(MPDF)
  0 = no
  1 = yes

Sub-Grid TIBL module used for shore line?
                Default: 0 ! MSGTIBL = 0 !
(MSGTIBL)
  0 = no
  1 = yes

Boundary conditions (concentration) modeled?
                Default: 0 ! MBCON = 0 !
(MBCON)
  0 = no
  1 = yes, using formatted BCON.DAT file
  2 = yes, using unformatted CONC.DAT file

Note: MBCON > 0 requires that the last species modeled
  be 'BCON'. Mass is placed in species BCON when
  generating boundary condition puffs so that clean
  air entering the modeling domain can be simulated
  in the same way as polluted air. Specify zero
  emission of species BCON for all regular sources.

Analyses of fogging and icing impacts due to emissions from arrays of mechanically-forced cooling towers can be performed using CALPUFF in conjunction with a cooling tower emissions processor (CTEMISS) and its associated postprocessors. Hourly emissions of water vapor and temperature from each cooling tower cell are computed for the current cell configuration and ambient conditions by CTEMISS. CALPUFF models the dispersion of these emissions and provides cloud information in a specialized format for further analysis. Output to FOG.DAT is provided in either 'plume mode' or 'receptor mode' format.

Configure for FOG Model output?
Default: 0 ! MFOG = 0 !
(MFOG)
0 = no
1 = yes - report results in PLUME Mode format
2 = yes - report results in RECEPTOR Mode format

Test options specified to see if
they conform to regulatory
values? (MREG) Default: 1 ! MREG = 0 !

0 = NO checks are made
1 = Technical options must conform to USEPA
Long Range Transport (LRT) guidance
METFM 1 or 2
AVET 60. (min)
PGTIME 60. (min)
MGAUSS 1
MCTADJ 3
MTRANS 1
MTIP 1
MCHEM 1 or 3 (if modeling SOx, NOx)
MWET 1
MDRY 1

```
MDISP    2 or 3
MPDF     0 if MDISP=3
         1 if MDISP=2
MROUGH   0
MPARTL   1
SYTDEP   550. (m)
MHFTSZ   0


!END!


--------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

-------------
Subgroup (3a)
-------------

  The following species are modeled:

! CSPEC =        SO2 !        !END!
! CSPEC =        SO4 !        !END!
! CSPEC =        NOX !        !END!
! CSPEC =       HNO3 !        !END!
! CSPEC =        NO3 !        !END!
! CSPEC =       PM10 !        !END!
! CSPEC =         EC !        !END!
! CSPEC =        SOA !        !END!
! CSPEC =       PM25 !        !END!


                                        Dry              OUTPUT GROUP
   SPECIES        MODELED        EMITTED       DEPOSITED              NUMBER
    NAME       (0=NO, 1=YES)   (0=NO, 1=YES)   (0=NO,               (0=NONE,
```

```
  (Limit: 12                          1=COMPUTED-GAS       1=1st CGRUP,
   Characters                           2=COMPUTED-PARTICLE   2=2nd CGRUP,
   in length)                         3=USER-SPECIFIED)     3= etc.)
!        SO2  =       1,          1,        1,          0   !
!        SO4  =       1,          1,        2,          0   !
!        NOX  =       1,          1,        1,          0   !
!       HNO3  =       1,          0,        1,          0   !
!        NO3  =       1,          0,        2,          0   !
!       PM10  =       1,          1,        2,          0   !
!         EC  =       1,          1,        2,          0   !
!        SOA  =       1,          1,        2,          0   !
!       PM25  =       1,          1,        2,          0   !
!END!
```

Note: The last species in (3a) must be 'BCON' when using the boundary condition option (MBCON > 0). Species BCON should typically be modeled as inert (no chem transformation or removal).

Subgroup (3b)

The following names are used for Species-Groups in which results for certain species are combined (added) prior to output. The CGRUP name will be used as the species name in output files. Use this feature to model specific particle-size distributions by treating each size-range as a separate species. Order must be consistent with 3(a) above.

```
INPUT GROUP: 4 -- Map Projection and Grid control parameters
--------------

    Projection for all (X,Y):
    -------------------------

    Map projection
    (PMAP)                    Default: UTM    ! PMAP = LCC  !

       UTM :  Universal Transverse Mercator
       TTM :  Tangential Transverse Mercator
       LCC :  Lambert Conformal Conic
        PS :  Polar Stereographic
        EM :  Equatorial Mercator
      LAZA :  Lambert Azimuthal Equal Area

    False Easting and Northing (km) at the projection origin
    (Used only if PMAP= TTM, LCC, or LAZA)
    (FEAST)                   Default=0.0     ! FEAST  = 0.000  !
    (FNORTH)                  Default=0.0     ! FNORTH = 0.000  !

    UTM zone (1 to 60)
    (Used only if PMAP=UTM)
    (IUTMZN)                  No Default      ! IUTMZN =       !

    Hemisphere for UTM projection?
    (Used only if PMAP=UTM)
    (UTMHEM)                  Default: N      ! UTMHEM = N  !
       N   :  Northern hemisphere projection
       S   :  Southern hemisphere projection

    Latitude and Longitude (decimal degrees) of projection origin
    (Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
    (RLAT0)                   No Default      ! RLAT0 =46.5N !
    (RLON0)                   No Default      ! RLON0 =93.0W !
```

TTM : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
LCC : RLON0 identifies central (true N/S) meridian of projection
RLAT0 selected for convenience
PS : RLON0 identifies central (grid N/S) meridian of projection
RLAT0 selected for convenience
EM : RLON0 identifies central meridian of projection
RLAT0 is REPLACED by 0.0N (Equator)
LAZA: RLON0 identifies longitude of tangent-point of mapping plane
RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)

(XLAT1)	No Default	! XLAT1 = 30N !
(XLAT2)	No Default	! XLAT2 = 60N !

LCC : Projection cone slices through Earth's surface at XLAT1 and XLAT2
PS : Projection plane slices through Earth at XLAT1
(XLAT2 is not used)

Note: Latitudes and longitudes should be positive, and include a
letter N,S,E, or W indicating north or south latitude, and
east or west longitude. For example,
35.9 N Latitude = 35.9N
118.7 E Longitude = 118.7E

Datum-region

The Datum-Region for the coordinates is identified by a character
string. Many mapping products currently available use the model of the
Earth known as the World Geodetic System 1984 (WGS-G). Other local
models may be in use, and their selection in CALMET will make its output
consistent with local mapping products. The list of Datum-Regions with

```
    official transformation parameters is provided by the National Imagery and
    Mapping Agency (NIMA).

    NIMA Datum - Regions(Examples)
    ------------------------------------------------------------------------------
    WGS-G     WGS-84 GRS 80 Spheroid, Global coverage (WGS84)
    NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
    NWS-27    NWS 6370KM Radius, Sphere
    NWS-84    NWS 6370KM Radius, Sphere
    ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

    Datum-region for output coordinates
    (DATUM)                   Default: WGS-G     ! DATUM = NAS-C  !


METEOROLOGICAL Grid:

    Rectangular grid defined for projection PMAP,
    with X the Easting and Y the Northing coordinate

          No. X grid cells (NX)      No default     ! NX =  183  !
          No. Y grid cells (NY)      No default     ! NY =  130  !
       No. vertical layers (NZ)      No default     ! NZ =  9  !

         Grid spacing (DGRIDKM)      No default     ! DGRIDKM =  4. !
                                     Units: km

             Cell face heights
                (ZFACE(nz+1))        No defaults
                                     Units: m
      ! ZFACE = 0.,20.,50.,100.,200.,500.,1000.,1500.,2500.,3500. !

          Reference Coordinates
         of SOUTHWEST corner of
              grid cell(1, 1):

          X coordinate (XORIGKM)     No default     ! XORIGKM =-381.90!
```

Y coordinate (YORIGKM) No default ! YORIGKM =-251.20!
Units: km

COMPUTATIONAL Grid:

The computational grid is identical to or a subset of the MET. grid.
The lower left (LL) corner of the computational grid is at grid point
(IBCOMP, JBCOMP) of the MET. grid. The upper right (UR) corner of the
computational grid is at grid point (IECOMP, JECOMP) of the MET. grid.
The grid spacing of the computational grid is the same as the MET. grid.

X index of LL corner (IBCOMP) No default ! IBCOMP = 1 !
(1 <= IBCOMP <= NX)

Y index of LL corner (JBCOMP) No default ! JBCOMP = 1 !
(1 <= JBCOMP <= NY)

X index of UR corner (IECOMP) No default ! IECOMP = 183 !
(1 <= IECOMP <= NX)

Y index of UR corner (JECOMP) No default ! JECOMP = 130 !
(1 <= JECOMP <= NY)

SAMPLING Grid (GRIDDED RECEPTORS):

The lower left (LL) corner of the sampling grid is at grid point
(IBSAMP, JBSAMP) of the MET. grid. The upper right (UR) corner of the
sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid.
The sampling grid must be identical to or a subset of the computational
grid. It may be a nested grid inside the computational grid.
The grid spacing of the sampling grid is DGRIDKM/MESHDN.

Logical flag indicating if gridded

```
      receptors are used (LSAMP)         Default: T     ! LSAMP = F !
      (T=yes, F=no)

      X index of LL corner (IBSAMP)      No default     ! IBSAMP =      !
       (IBCOMP <= IBSAMP <= IECOMP)

      Y index of LL corner (JBSAMP)      No default     ! JBSAMP =      !
       (JBCOMP <= JBSAMP <= JECOMP)


      X index of UR corner (IESAMP)      No default     ! IESAMP =      !
       (IBCOMP <= IESAMP <= IECOMP)

      Y index of UR corner (JESAMP)      No default     ! JESAMP =      !
       (JBCOMP <= JESAMP <= JECOMP)


     Nesting factor of the sampling
      grid (MESHDN)                      Default: 1     ! MESHDN =     !
      (MESHDN is an integer >= 1)

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 5 -- Output Options
--------------
                                    *                    *
    FILE                    DEFAULT VALUE          VALUE THIS RUN
    ----                   -------------          --------------

   Concentrations (ICON)          1                 !  ICON =  1   !
   Dry Fluxes (IDRY)              1                 !  IDRY =  1   !
   Wet Fluxes (IWET)              1                 !  IWET =  1   !
   Relative Humidity (IVIS)       1                 !  IVIS =  1   !
```

```
 (relative humidity file is
  required for visibility
  analysis)
Use data compression option in output file?
(LCOMPRS)                        Default: T        ! LCOMPRS = T !

*
 0 = Do not create file, 1 = create file


 DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

   Mass flux across specified boundaries
   for selected species reported hourly?
   (IMFLX)                       Default: 0        ! IMFLX =  0  !
     0 = no
     1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
             are specified in Input Group 0)

   Mass balance for each species
   reported hourly?
   (IMBAL)                       Default: 0        ! IMBAL =  0  !
     0 = no
     1 = yes (MASSBAL.DAT filename is
          specified in Input Group 0)


 LINE PRINTER OUTPUT OPTIONS:

   Print concentrations (ICPRT)    Default: 0        ! ICPRT =  1   !
   Print dry fluxes (IDPRT)        Default: 0        ! IDPRT =  1   !
   Print wet fluxes (IWPRT)        Default: 0        ! IWPRT =  1   !
   (0 = Do not print, 1 = Print)

   Concentration print interval
   (ICFRQ) in hours                Default: 1        ! ICFRQ =  24   !
   Dry flux print interval
```

```
(IDFRQ) in hours              Default: 1        ! IDFRQ =  24  !
Wet flux print interval
(IWFRQ) in hours              Default: 1        ! IWFRQ =  24  !

Units for Line Printer Output
(IPRTU)                       Default: 1        ! IPRTU =  3   !
                 for          for
             Concentration    Deposition
   1 =       g/m**3          g/m**2/s
   2 =      mg/m**3          mg/m**2/s
   3 =      ug/m**3          ug/m**2/s
   4 =      ng/m**3          ng/m**2/s
   5 =     Odour Units

Messages tracking progress of run
written to the screen ?
(IMESG)                       Default: 2        ! IMESG =  2   !
  0 = no
  1 = yes (advection step, puff ID)
  2 = yes (YYYYJJJHH, # old puffs, # emitted puffs)


SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

              ---- CONCENTRATIONS ----   ------ DRY FLUXES ------   ------ WET FLUXES ------   -- MASS FLUX --
SPECIES
/GROUP       PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   SAVED ON DISK?
-------      ------------------------   ------------------------   ------------------------   ---------------
!       SO2 =     1,          1,          1,          1,          1,          1,          0   !
!       SO4 =     1,          1,          1,          1,          1,          1,          0   !
!       NOX =     1,          1,          1,          1,          0,          0,          0   !
!      HNO3 =     1,          1,          1,          1,          1,          1,          0   !
!       NO3 =     1,          1,          1,          1,          1,          1,          0   !
!      PM10 =     1,          1,          1,          1,          1,          1,          0   !
!        EC =     1,          1,          1,          1,          1,          1,          0   !
!       SOA =     0,          1,          0,          1,          0,          1,          0   !
!      PM25 =     0,          1,          0,          1,          0,          1,          0   !
```

Note: Species BCON (for MBCON > 0) does not need to be saved on disk.

OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

Logical for debug output
(LDEBUG) Default: F ! LDEBUG = F !

First puff to track
(IPFDEB) Default: 1 ! IPFDEB = 1 !

Number of puffs to track
(NPFDEB) Default: 1 ! NPFDEB = 1 !

Met. period to start output
(NN1) Default: 1 ! NN1 = 1 !

Met. period to end output
(NN2) Default: 10 ! NN2 = 10 !

!END!

INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
---

Subgroup (6a)

Number of terrain features (NHILL) Default: 0 ! NHILL = 0 !

Number of special complex terrain
receptors (NCTREC) Default: 0 ! NCTREC = 0 !

Terrain and CTSG Receptor data for
CTSG hills input in CTDM format ?
(MHILL) No Default ! MHILL = 0 !
1 = Hill and Receptor data created
by CTDM processors & read from
HILL.DAT and HILLRCT.DAT files
2 = Hill data created by OPTHILL &
input below in Subgroup (6b);
Receptor data in Subgroup (6c)

Factor to convert horizontal dimensions Default: 1.0 ! XHILL2M = 0. !
to meters (MHILL=1)

Factor to convert vertical dimensions Default: 1.0 ! ZHILL2M = 0. !
to meters (MHILL=1)

X-origin of CTDM system relative to No Default ! XCTDMKM = 0.0E00 !
CALPUFF coordinate system, in Kilometers (MHILL=1)

Y-origin of CTDM system relative to No Default ! YCTDMKM = 0.0E00 !
CALPUFF coordinate system, in Kilometers (MHILL=1)

! END !

Subgroup (6b)
---

1 **
HILL information

HILL NO.	XC (km)	YC (km)	THETAH (deg.)	ZGRID (m)	RELIEF (m)	EXPO 1 (m)	EXPO 2 (m)	SCALE 1 (m)	SCALE 2 (m)	AMAX1	AMAX2

Subgroup (6c)

COMPLEX TERRAIN RECEPTOR INFORMATION

XRCT (km)	YRCT (km)	ZRCT (m)	XHH

Description of Complex Terrain Variables:

XC, YC = Coordinates of center of hill
THETAH = Orientation of major axis of hill (clockwise from North)
ZGRID = Height of the 0 of the grid above mean sea level
RELIEF = Height of the crest of the hill above the grid elevation
EXPO 1 = Hill-shape exponent for the major axis
EXPO 2 = Hill-shape exponent for the major axis
SCALE 1 = Horizontal length scale along the major axis
SCALE 2 = Horizontal length scale along the minor axis
AMAX = Maximum allowed axis length for the major axis
BMAX = Maximum allowed axis length for the major axis

XRCT, YRCT = Coordinates of the complex terrain receptors
ZRCT = Height of the ground (MSL) at the complex terrain Receptor
XHH = Hill number associated with each complex terrain receptor (NOTE: MUST BE ENTERED AS A REAL NUMBER)

**
NOTE: DATA for each hill and CTSG receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

```
-------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

     SPECIES     DIFFUSIVITY      ALPHA STAR      REACTIVITY    MESOPHYLL RESISTANCE     HENRY'S LAW COEFFICIENT
      NAME       (cm**2/s)                                       (s/cm)                (dimensionless)
     -------     -----------      ----------      ----------    --------------------     -----------------------
!        SO2 =    0.1509,         1000.,          8.,             0.,                 0.04 !
!        NOX =    0.1628,           1.,           8.,             5.,                 3.5 !
!       HNO3 =    0.1628,           1.,          18.,             0.,            0.00000008 !
!END!


-------------------------------------------------------------------------------


INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------
!        SO4 =        0.48,                    2.   !
!        NO3 =        0.48,                    2.   !
!       PM10 =         7.00,                   2.   !
!         EC =        0.48,                   2.   !
!        SOA =        0.48,                    2.   !
!       PM25 =         0.48,                   2.   !

    For SINGLE SPECIES, the mean and standard deviation are used to
    compute a deposition velocity for NINT (see group 9) size-ranges,
    and these are then averaged to obtain a mean deposition velocity.

    For GROUPED SPECIES, the size distribution should be explicitly
    specified (by the 'species' in the group), and the standard deviation
    for each should be entered as 0.  The model will then use the
    deposition velocity for the stated mean diameter.

     SPECIES      GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
```

```
      NAME            DIAMETER                 DEVIATION
                    (microns)                (microns)
     -------      -------------------        ------------------
!END!


-------------------------------------------------------------------------------


INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
--------------

    Reference cuticle resistance (s/cm)
    (RCUTR)                        Default: 30    !  RCUTR = 30.0 !
    Reference ground resistance  (s/cm)
    (RGR)                          Default: 10    !    RGR = 10.0 !
    Reference pollutant reactivity
    (REACTR)                        Default: 8     ! REACTR = 8.0 !

    Number of particle-size intervals used to
    evaluate effective particle deposition velocity
    (NINT)                         Default: 9     !   NINT =  9  !

    Vegetation state in unirrigated areas
    (IVEG)                         Default: 1     !   IVEG =  1   !
      IVEG=1 for active and unstressed vegetation
      IVEG=2 for active and stressed vegetation
      IVEG=3 for inactive vegetation

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 10 -- Wet Deposition Parameters
---------------
```

```
                    Scavenging Coefficient -- Units: (sec)**(-1)

      Pollutant      Liquid Precip.       Frozen Precip.
      ---------      --------------       --------------
!        SO2 =        3.0E-05,             0.0E00 !
!        SO4 =        1.0E-04,            3.0E-05 !
!       HNO3 =         6.0E-05,            1.0E-07 !
!        NO3 =        1.0E-04,            3.0E-05 !
!       PM10 =         1.0E-04,            3.0E-05 !
!         EC =        1.0E-04,            3.0E-05 !
!        SOA =        1.0E-04,            3.0E-05 !
!       PM25 =         1.0E-04,            3.0E-05 !
!END!
-------------------------------------------------------------------------------


INPUT GROUP: 11 -- Chemistry Parameters
---------------

    Ozone data input option (MOZ)     Default: 1           ! MOZ =  0   !
    (Used only if MCHEM = 1, 3, or 4)
      0 = use a monthly background ozone value
      1 = read hourly ozone concentrations from
          the OZONE.DAT data file

    Monthly ozone concentrations
    (Used only if MCHEM = 1, 3, or 4 and
     MOZ = 0 or MOZ = 1 and all hourly O3 data missing)
    (BCKO3) in ppb                  Default: 12*80.
    !  BCKO3 = 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00, 40.00 !

    Monthly ammonia concentrations
    (Used only if MCHEM = 1, or 3)
    (BCKNH3) in ppb                 Default: 12*10.
    !  BCKNH3 =  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0,  1.0 !
```

```
Nighttime SO2 loss rate (RNITE1)
in percent/hour                Default: 0.2        ! RNITE1 = .2 !

Nighttime NOx loss rate (RNITE2)
in percent/hour                Default: 2.0        ! RNITE2 = 2.0 !

Nighttime HNO3 formation rate (RNITE3)
in percent/hour                Default: 2.0        ! RNITE3 = 2.0 !

H2O2 data input option (MH2O2)    Default: 1          ! MH2O2 =  0   !
(Used only if MAQCHEM = 1)
  0 = use a monthly background H2O2 value
  1 = read hourly H2O2 concentrations from
      the H2O2.DAT data file

Monthly H2O2 concentrations
(Used only if MQACHEM = 1 and
 MH2O2 = 0 or MH2O2 = 1 and all hourly H2O2 data missing)
(BCKH2O2) in ppb               Default: 12*1.
*  BCKH2O2 =                                                    *


--- Data for SECONDARY ORGANIC AEROSOL (SOA) Option
(used only if MCHEM = 4)

The SOA module uses monthly values of:
    Fine particulate concentration in ug/m^3 (BCKPMF)
    Organic fraction of fine particulate     (OFRAC)
    VOC / NOX ratio (after reaction)        (VCNX)
to characterize the air mass when computing
the formation of SOA from VOC emissions.
Typical values for several distinct air mass types are:

  Month    1    2    3    4    5    6    7    8    9   10   11   12
         Jan  Feb  Mar  Apr  May  Jun  Jul  Aug  Sep  Oct  Nov  Dec

Clean Continental
```

```
   BCKPMF   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.
   OFRAC  .15  .15  .20  .20  .20  .20  .20  .20  .20  .20  .20  .15
   VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

Clean Marine (surface)
   BCKPMF  .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5
   OFRAC  .25  .25  .30  .30  .30  .30  .30  .30  .30  .30  .30  .25
   VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

Urban - low biogenic (controls present)
   BCKPMF  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.
   OFRAC  .20  .20  .25  .25  .25  .25  .25  .25  .20  .20  .20  .20
   VCNX     4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.

Urban - high biogenic (controls present)
   BCKPMF  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.
   OFRAC  .25  .25  .30  .30  .30  .55  .55  .55  .35  .35  .35  .25
   VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

Regional Plume
   BCKPMF  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.
   OFRAC  .20  .20  .25  .35  .25  .40  .40  .40  .30  .30  .30  .20
   VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

Urban - no controls present
   BCKPMF 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100.
   OFRAC  .30  .30  .35  .35  .35  .55  .55  .55  .35  .35  .35  .30
   VCNX     2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.

Default: Clean Continental
!  BCKPMF = 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00 !
!  OFRAC  = 0.15, 0.15, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.15 !
!  VCNX   = 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00 !


!END!
```

INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---

Horizontal size of puff (m) beyond which
time-dependent dispersion equations (Heffter)
are used to determine sigma-y and
sigma-z (SYTDEP) Default: 550. ! SYTDEP = 5.5E02 !

Switch for using Heffter equation for sigma z
as above (0 = Not use Heffter; 1 = use Heffter
(MHFTSZ) Default: 0 ! MHFTSZ = 0 !

Stability class used to determine plume
growth rates for puffs above the boundary
layer (JSUP) Default: 5 ! JSUP = 5 !

Vertical dispersion constant for stable
conditions (k1 in Eqn. 2.7-3) (CONK1) Default: 0.01 ! CONK1 = .01 !

Vertical dispersion constant for neutral/
unstable conditions (k2 in Eqn. 2.7-4)
(CONK2) Default: 0.1 ! CONK2 = .1 !

Factor for determining Transition-point from
Schulman-Scire to Huber-Snyder Building Downwash
scheme (SS used for Hs < Hb + TBD * HL)
(TBD) Default: 0.5 ! TBD = .5 !
TBD < 0 ==> always use Huber-Snyder
TBD = 1.5 ==> always use Schulman-Scire
TBD = 0.5 ==> ISC Transition-point

Range of land use categories for which
urban dispersion is assumed

```
(IURB1, IURB2)                    Default: 10     ! IURB1 =  10  !
                                 19     ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4)

   Land use category for modeling domain
   (ILANDUIN)                     Default: 20     ! ILANDUIN =  20  !

   Roughness length (m) for modeling domain
   (Z0IN)                        Default: 0.25   ! Z0IN = .25 !

   Leaf area index for modeling domain
   (XLAIIN)                      Default: 3.0    ! XLAIIN = 3.0 !

   Elevation above sea level (m)
   (ELEVIN)                      Default: 0.0    ! ELEVIN = .0 !

   Latitude (degrees) for met location
   (XLATIN)                      Default: -999.  ! XLATIN = -999.0 !

   Longitude (degrees) for met location
   (XLONIN)                      Default: -999.  ! XLONIN = -999.0 !

Specialized information for interpreting single-point Met data files -----

   Anemometer height (m) (Used only if METFM = 2,3)
   (ANEMHT)                      Default: 10.    ! ANEMHT = 10.0 !

   Form of lateral turbulance data in PROFILE.DAT file
   (Used only if METFM = 4 or MTURBVW = 1 or 3)
   (ISIGMAV)                     Default: 1      ! ISIGMAV =  1  !
      0 = read sigma-theta
      1 = read sigma-v

   Choice of mixing heights (Used only if METFM = 4)
   (IMIXCTDM)                    Default: 0      ! IMIXCTDM =  0  !
```

0 = read PREDICTED mixing heights
1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN) Default: 1.0 ! XMXLEN = 1.0 !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN) Default: 1.0 ! XSAMLEN = 1.0 !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW) Default: 99 ! MXNEW = 99 !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM) Default: 99 ! MXSAM = 99 !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
(NCOUNT) Default: 2 ! NCOUNT = 2 !

Minimum sigma y for a new puff/slug (m)
(SYMIN) Default: 1.0 ! SYMIN = 1.0 !

Minimum sigma z for a new puff/slug (m)
(SZMIN) Default: 1.0 ! SZMIN = 1.0 !

Default minimum turbulence velocities
sigma-v and sigma-w for each
stability class (m/s)
(SVMIN(6) and SWMIN(6)) Default SVMIN : .50, .50, .50, .50, .50, .50
Default SWMIN : .20, .12, .08, .06, .03, .016

Stability Class : A B C D E F

```
                    ---   ---   ---   ---   ---   ---
          ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500!
          ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016!

Divergence criterion for dw/dz across puff
used to initiate adjustment for horizontal
convergence (1/s)
Partial adjustment starts at CDIV(1), and
full adjustment is reached at CDIV(2)
(CDIV(2))                    Default: 0.0,0.0  ! CDIV = .00, .00 !

Minimum wind speed (m/s) allowed for
non-calm conditions. Also used as minimum
speed returned when using power-law
extrapolation toward surface
(WSCALM)                      Default: 0.5    ! WSCALM = .5 !

Maximum mixing height (m)
(XMAXZI)                      Default: 3000.  ! XMAXZI = 3500.0 !

Minimum mixing height (m)
(XMINZI)                     Default: 50.    ! XMINZI = 50.0 !

Default wind speed classes --
5 upper bounds (m/s) are entered;
the 6th class has no upper limit
(WSCAT(5))              Default   :
          ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10.8 (10.8+)

     Wind Speed Class :  1     2     3     4     5
                    ---   ---   ---   ---   ---
          ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

Default wind speed profile power-law
exponents for stabilities 1-6
(PLX0(6))               Default   : ISC RURAL values
          ISC RURAL : .07, .07, .10, .15, .35, .55
```

```
                    ISC URBAN : .15, .15, .20, .25, .30, .30

                Stability Class :  A     B     C     D     E     F
                                  ---   ---   ---   ---   ---   ---
                         ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !

Default potential temperature gradient
for stable classes E, F (degK/m)
(PTG0(2))                Default: 0.020, 0.035
                         ! PTG0 = 0.020,   0.035 !

Default plume path coefficients for
each stability class (used when option
for partial plume height terrain adjustment
is selected -- MCTADJ=3)
(PPC(6))             Stability Class :  A     B     C     D     E     F
                   Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
                                  ---   ---   ---   ---   ---   ---
                         !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

Slug-to-puff transition criterion factor
equal to sigma-y/length of slug
(SL2PF)                  Default: 10.       ! SL2PF = 5.0 !

Puff-splitting control variables ------------------------

  VERTICAL SPLIT
  --------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)                 Default:   3       ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
```

24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
0=do not re-split 1=eligible for re-split
(IRESPLIT(24)) Default: Hour 17 = 1
! IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

Split is allowed only if last hour's mixing
height (m) exceeds a minimum value
(ZISPLIT) Default: 100. ! ZISPLIT = 100.0 !

Split is allowed only if ratio of last hour's
mixing ht to the maximum mixing ht experienced
by the puff is less than a maximum value (this
postpones a split until a nocturnal layer develops)
(ROLDMAX) Default: 0.25 ! ROLDMAX = 0.25 !

HORIZONTAL SPLIT

Number of puffs that result every time a puff
is split - nsplith=5 means that 1 puff splits
into 5
(NSPLITH) Default: 5 ! NSPLITH = 5 !

Minimum sigma-y (Grid Cells Units) of puff
before it may be split
(SYSPLITH) Default: 1.0 ! SYSPLITH = 1.0 !

Minimum puff elongation rate (SYSPLITH/hr) due to
wind shear, before it may be split
(SHSPLITH) Default: 2. ! SHSPLITH = 2.0 !

Minimum concentration (g/m^3) of each
species in puff before it may be split
Enter array of NSPEC values; if a single value is
entered, it will be used for ALL species
(CNSPLITH) Default: 1.0E-07 ! CNSPLITH = 1.0E-07 !

Integration control variables ----------

Fractional convergence criterion for numerical SLUG
sampling integration
(EPSSLUG) Default: 1.0e-04 ! EPSSLUG = 1.0E-04 !

Fractional convergence criterion for numerical AREA
source integration
(EPSAREA) Default: 1.0e-06 ! EPSAREA = 1.0E-06 !

Trajectory step-length (m) used for numerical rise
integration
(DSRISE) Default: 1.0 ! DSRISE = 1.0 !

Boundary Condition (BC) Puff control variables ----------

Minimum height (m) to which BC puffs are mixed as they are emitted
(MBCON=2 ONLY). Actual height is reset to the current mixing height
at the release point if greater than this minimum.
(HTMINBC) Default: 500. ! HTMINBC = 500. !

Search radius (km) about a receptor for sampling nearest BC puff.
BC puffs are typically emitted with a spacing of one grid cell
length, so the search radius should be greater than DGRIDKM.
(RSAMPBC) Default: 10. ! RSAMPBC = 10. !

Near-Surface depletion adjustment to concentration profile used when
sampling BC puffs?
(MDEPBC) Default: 1 ! MDEPBC = 1. !
0 = Concentration is NOT adjusted for depletion
1 = Adjust Concentration for depletion

!END!

INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters

Subgroup (13a)

Number of point sources with
parameters provided below (NPT1) No default ! NPT1 = 6 !

Units used for point source
emissions below (IPTU) Default: 1 ! IPTU = 1 !
1 = g/s
2 = kg/hr
3 = lb/hr
4 = tons/yr
5 = Odour Unit * m**3/s (vol. flux of odour compound)
6 = Odour Unit * m**3/min
7 = metric tons/yr

Number of source-species
combinations with variable
emissions scaling factors
provided below in (13d) (NSPT1) Default: 0 ! NSPT1 = 0 !

Number of point sources with
variable emission parameters
provided in external file (NPT2) No default ! NPT2 = 0 !

(If NPT2 > 0, these point
source emissions are read from
the file: PTEMARB.DAT)

!END!

Subgroup (13b)
---

a

POINT SOURCE: CONSTANT DATA

```
                                                                b         c
 Source      X UTM     Y UTM          Stack   Base     Stack      Exit   Exit    Bldg.  Emission
  No.     Coordinate Coordinate        Height Elevation Diameter    Vel.  Temp.   Dwash   Rates
            (km)      (km)             (m)     (m)       (m)     (m/s)  (deg. K)
 ------   ---------- ---------- ------   ------   -------- ----- -------- ----- --------
      1  ! SRCNAM = CT1PI      !
      1  ! X =   -26.60188, 90.47040, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      1  ! FMFAC  =      1.0 !   !END!
      2  ! SRCNAM = CT2PI      !
      2  ! X =   -26.57211, 90.44989, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      2  ! FMFAC  =      1.0 !   !END!
      3  ! SRCNAM = TVIPI      !
      3  ! X =   -26.66799, 90.62411, 64.01,  434.30,    1.83,    8.46,  579.8, 1.0,  0.81,0,2.46,0,0,0,
                 0,           0,     0.088 !
      3  ! FMFAC  =      1.0 !   !END!
      4  ! SRCNAM = CT1PII     !
      4  ! X =   -26.42979, 90.34962, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      4  ! FMFAC  =      1.0 !   !END!
      5  ! SRCNAM = CT2PII     !
      5  ! X =   -26.40002, 90.32912, 45.72,  434.30,    6.10,   20.08,  394.3, 1.0, 14.36,0.945,19.66,0,0,0,
                 0.787,    1.397,      0   !
      5  ! FMFAC  =      1.0 !   !END!
      6  ! SRCNAM = TVIPII     !
      6  ! X =   -26.17563, 90.27560, 64.01,  434.30,    1.83,    8.46,  579.8, 1.0,  0.81,0,2.46,0,0,0,
                 0,           0,     0.088 !
      6  ! FMFAC  =      1.0 !   !END!
```

---

a

Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

SRCNAM is a 12-character name for a source
(No default)
X is an array holding the source data listed by the column headings
(No default)
SIGYZI is an array holding the initial sigma-y and sigma-z (m)
(Default: 0.,0.)
FMFAC is a vertical momentum flux factor (0. or 1.0) used to represent
the effect of rain-caps or other physical configurations that
reduce momentum rise associated with the actual exit velocity.
(Default: 1.0 -- full momentum used)

b
0. = No building downwash modeled, 1. = downwash modeled
NOTE: must be entered as a REAL number (i.e., with decimal point)

c
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IPTU
(e.g. 1 for g/s).

Subgroup (13c)

BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH

Source a
No. Effective building height, width, length and X/Y offset (in meters)
every 10 degrees. LENGTH, XBADJ, and YBADJ are only needed for
MBDW=2 (PRIME downwash option)
------ ---
1 ! SRCNAM = CT1PI !
1 ! HEIGHT = 27.43, 27.43, 22.86, 27.43, 27.43, 27.43,

```
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  45.72,
          45.72,  27.43,  22.86,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
     1  !  WIDTH =   29.14,  60.85,  71.65,  20.00,  61.24,  29.67,
          33.21,  35.75,  37.20,  37.52,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  43.30,
          46.18,  60.85,  71.65,  20.00,  61.24,  29.67,
          33.21,  35.75,  37.20,  37.52,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
     1  !  LENGTH =  37.52,  45.96,  27.58,  35.03,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.12,  35.75,  33.00,
          26.47,  45.96,  27.58,  35.03,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.21,  35.65,  37.20 !
     1  !  XBADJ =  -38.99, -49.06, -64.17, -39.39, -39.51, -38.43,
         -36.19, -32.84, -28.50, -23.29,  18.88,  26.38,
          -7.48,  29.78,  28.84,  27.02,  -1.86,-226.50,
        -222.12,   3.10,  36.60,   4.36,  -7.42,   0.93,
          -0.86,  -2.62,  -4.30,  -5.85, -43.47, -45.68,
         -12.52, -54.92, -58.42, -29.74, -60.03, -37.00 !
     1  !  YBADJ =    8.72, -13.05, -16.33,  -2.52, -24.30,  -9.86,
         -13.13, -16.01, -18.40, -20.23, -30.75, -24.88,
         -21.87, -10.99,  -3.47,   4.16, -15.11,  11.95,
         -24.70,  13.05,  16.33,   2.52,  24.30,   9.86,
          13.13,  16.01,  18.40,  20.23,  30.75,  24.88,
          21.87,  10.99,   3.47,  17.66, -11.66,  12.10 !

!END!
     2  ! SRCNAM = CT2PI      !
     2  !  HEIGHT =  27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  45.72,  45.72,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
```

```
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
     2  !  WIDTH =   29.14,  60.75,  54.90,  83.81,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  39.10,  43.21,
          29.14,  60.75,  54.90,  83.81,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
     2  !  LENGTH =  37.42,  54.25,  46.56,  65.39,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.12,  38.52,  33.00,
          37.42,  54.25,  46.56,  65.39,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          20.00,  25.14,  29.58,  33.12,  35.65,  37.10 !
     2  !  XBADJ =  -38.89, -86.87, -76.94, -69.67, -49.55, -38.38,
         -36.15, -32.82, -28.50, -23.31, -17.41, -10.98,
         -44.78,  -6.32,  -4.97,  -3.47,-250.24,-247.70,
           1.47,  32.62,  30.38,   4.28,   2.62,   0.88,
          -0.89,  -2.64,  -4.30,  -5.83,  -7.19,  -8.32,
          24.78, -18.82, -24.61, -29.65, -33.79, -36.90 !
     2  !  YBADJ =    8.74, -29.83, -39.76, -34.42,  11.80,  -9.82,
         -13.09, -15.96, -18.35, -20.18, -21.40, -21.97,
         -25.49, -21.03, -19.63, -17.63,  21.49, -18.95,
          -8.74,  29.83,  39.76,  34.42, -11.80,   9.82,
          13.09,  15.96,  18.35,  20.18,  21.40,  21.97,
          25.49,  21.03,  19.63,  17.63,  15.09,  12.10 !

!END!
     3  ! SRCNAM = TVIPI      !
     3  !  HEIGHT =   0.00,   0.00,  45.72,  45.72,  45.72,  45.72,
          45.72,  45.72,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,  45.72,  45.72,  45.72,  45.72,
          45.72,  45.72,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  WIDTH =    0.00,   0.00,  47.70,  47.79,  47.58,  45.93,
          42.88,  38.52,   0.00,   0.00,   0.00,   0.00,
           0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
```

```
            0.00,   0.00,  47.70,  47.79,  47.58,  45.93,
           42.88,  38.52,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  LENGTH =   0.00,   0.00,  11.23,  12.21,  20.06,  27.30,
           33.71,  39.10,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,  11.23,  12.21,  20.06,  27.30,
           33.71,  39.10,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  XBADJ =    0.00,   0.00,  78.83,  84.74,  84.46,  81.61,
           76.28,  68.63,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00, -90.06, -96.95,-104.52,-108.91,
         -109.99,-107.73,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
     3  !  YBADJ =    0.00,   0.00, -44.26, -28.92, -12.71,   3.89,
           20.37,  36.24,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,  44.26,  28.92,  12.71,  -3.89,
          -20.37, -36.24,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00 !
!END!
     4  ! SRCNAM = CT1PII     !
     4  !  HEIGHT =  27.43,  27.43,  22.86,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
           27.43,  27.43,  22.86,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
           27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
     4  !  WIDTH =   29.14,  60.85,  71.60,  19.94,  61.24,  29.58,
           33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
           35.03,  36.82,  37.51,  37.05,  35.46,  32.80,
           29.14,  60.85,  71.60,  19.94,  61.24,  29.58,
           33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
           35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
     4  !  LENGTH =  37.52,  45.96,  27.58,  35.03,  46.93,  37.51,
           37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
```

```
          19.94,  25.14,  29.58,  33.21,  35.75,  37.20,
          37.52,  45.96,  27.58,  35.03,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          19.94,  25.14,  29.58,  33.12,  35.75,  37.20 !
    4  !  XBADJ =  -53.91, -48.59, -64.17, -39.07, -39.26, -38.27,
         -36.11, -32.85, -28.60, -23.48, -17.64, -11.27,
          -7.80,  -6.71,  -5.41,  26.45,  23.79,  20.40,
          16.39,   2.63,  36.60,   4.04,  -7.67,   0.76,
          -0.94,  -2.61,  -4.20,  -5.66,  -6.96,  -8.04,
         -12.14, -18.44, -24.17, -29.18, -59.54, -57.60 !
    4  !  YBADJ =  -25.19, -12.78, -16.31,  -2.17, -23.92,  -9.38,
         -12.62, -15.47, -17.85, -19.69, -20.93, -21.53,
         -21.55, -20.85, -19.52,   4.23,  11.64,  18.70,
          25.19,  12.78,  16.31,   2.17,  23.92,   9.38,
          12.62,  15.47,  17.85,  19.69,  20.93,  21.53,
          21.55,  20.85,  19.52,  17.59, -11.64, -18.70 !

!END!
    5  ! SRCNAM = CT2PII     !
    5  !  HEIGHT =  27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43,
          27.43,  27.43,  27.43,  27.43,  27.43,  27.43 !
    5  !  WIDTH =   29.14,  60.81,  54.94,  84.07,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80,
          29.14,  60.81,  54.94,  84.07,  61.24,  29.58,
          33.12,  35.65,  37.10,  37.42,  36.61,  34.68,
          35.03,  36.82,  37.51,  37.05,  35.46,  32.80 !
    5  !  LENGTH =  37.52,  54.12,  46.42,  64.77,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          19.94,  25.14,  29.67,  33.21,  35.75,  37.20,
          37.52,  54.12,  46.42,  64.77,  46.93,  37.51,
          37.05,  35.46,  32.80,  29.14,  24.60,  19.31,
          19.94,  25.14,  29.67,  33.21,  35.75,  37.20 !
```

```
     5  !  XBADJ =  -38.40, -85.82, -75.86, -68.74, -49.31, -54.43,
           -57.90, -59.60, -59.50, -57.59, -53.93, -48.63,
           -45.10, -42.81,  -5.49,  -4.04,  -2.45,  -0.80,
             0.88,  31.70,  29.44,   3.96,   2.37,  16.92,
            20.85,  24.14,  26.70,  28.45,  29.33,  29.32,
            25.16,  17.67, -24.17, -29.18, -33.29, -36.40 !
     5  !  YBADJ =    8.92, -30.06, -39.81, -34.17,  12.19,  24.43,
            17.87,  10.77,   3.35,  -4.18, -11.58, -18.62,
           -25.18, -30.90, -19.47, -17.55, -15.11, -12.20,
            -8.92,  30.06,  39.81,  34.17, -12.19, -24.43,
           -17.87, -10.77,  -3.35,   4.18,  11.58,  18.62,
            25.18,  30.90,  19.47,  17.55,  15.11,  12.20 !

!END!
     6  ! SRCNAM = TVIPII     !
     6  !  HEIGHT =  45.72,  45.72,  45.72,  45.72,  45.72,   0.00,
             0.00,   0.00,   0.00,  21.34,  21.34,  21.34,
             0.00,   0.00,   0.00,   0.00,   0.00,  45.72,
            45.72,  45.72,  45.72,  45.72,  45.72,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,  45.72 !
     6  !  WIDTH =   46.18,  47.67,  47.70,  47.79,  47.58,   0.00,
             0.00,   0.00,   0.00,  86.08,  69.74,  51.28,
             0.00,   0.00,   0.00,   0.00,   0.00,  43.30,
            46.18,  47.67,  47.70,  47.79,  47.58,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,  43.30 !
     6  !  LENGTH =  26.47,  19.14,  11.23,  12.21,  20.06,   0.00,
             0.00,   0.00,   0.00, 121.80, 121.41, 117.32,
             0.00,   0.00,   0.00,   0.00,   0.00,  33.00,
            26.47,  19.14,  11.23,  12.21,  20.06,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
             0.00,   0.00,   0.00,   0.00,   0.00,  33.00 !
     6  !  XBADJ =   71.20,  77.94,  82.30,  79.56,  70.77,   0.00,
             0.00,   0.00,   0.00,-215.27,-220.50,-219.04,
             0.00,   0.00,   0.00,   0.00,   0.00, -95.30,
           -97.67, -97.08, -93.53, -91.76, -90.82,   0.00,
```

```
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,  62.30 !
     6  !  YBADJ =  -25.07, -10.03,   5.32,  20.51,  35.07,   0.00,
            0.00,   0.00,   0.00,  44.77,  17.29, -10.72,
            0.00,   0.00,   0.00,   0.00,   0.00,  39.35,
           25.07,  10.03,  -5.32, -20.51, -35.07,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00,   0.00,
            0.00,   0.00,   0.00,   0.00,   0.00, -39.35 !

!END!
--------
```

a

Building height, width, length, and X/Y offset from the source are treated as a separate input subgroup for each source and therefore must end with an input group terminator.

Subgroup (13d)

---

a

POINT SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission rates given in 13b. Factors entered multiply the rates in 13b. Skip sources here that have constant emissions. For more elaborate variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

IVARY determines the type of variation, and is source-specific:

(IVARY) Default: 0

- 0 = Constant
- 1 = Diurnal cycle (24 scaling factors: hours 1-24)
- 2 = Monthly cycle (12 scaling factors: months 1-12)
- 3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)
- 4 = Speed & Stab. (6 groups of 6 scaling factors, where

first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12

5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

---

a

Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters

Subgroup (14a)

Number of polygon area sources with
parameters specified below (NAR1) No default ! NAR1 = 0 !

Units used for area source
emissions below (IARU) Default: 1 ! IARU = 1 !

1 = g/m**2/s
2 = kg/m**2/hr
3 = lb/m**2/hr
4 = tons/m**2/yr
5 = Odour Unit * m/s (vol. flux/m**2 of odour compound)
6 = Odour Unit * m/min

7 = metric tons/m**2/yr

Number of source-species
combinations with variable
emissions scaling factors
provided below in (14d) (NSAR1) Default: 0 ! NSAR1 = 0 !

Number of buoyant polygon area sources
with variable location and emission
parameters (NAR2) No default ! NAR2 = 0 !
(If NAR2 > 0, ALL parameter data for
these sources are read from the file: BAEMARB.DAT)

!END!

Subgroup (14b)
---

a
AREA SOURCE: CONSTANT DATA
---

b

Source No.	Effect. Height (m)	Base Elevation (m)	Initial Sigma z (m)	Emission Rates
---	---	---	---	---

a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.
b
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IARU
(e.g. 1 for g/m**2/s).

Subgroup (14c)

COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON

Source a
No. Ordered list of X followed by list of Y, grouped by source
--- ---
---
a
Data for each source are treated as a separate input subgroup
and therefore must end with an input group terminator.

Subgroup (14d)
---

a
AREA SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 14b. Factors entered multiply the rates in 14b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0

0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12

5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

---
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters

Subgroup (15a)

Number of buoyant line sources
with variable location and emission
parameters (NLN2) No default ! NLN2 = 0 !

(If NLN2 > 0, ALL parameter data for
these sources are read from the file: LNEMARB.DAT)

Number of buoyant line sources (NLINES) No default ! NLINES = 0 !

Units used for line source
emissions below (ILNU) Default: 1 ! ILNU = 1 !
1 = g/s
2 = kg/hr
3 = lb/hr
4 = tons/yr

```
      5 =    Odour Unit * m**3/s  (vol. flux of odour compound)
      6 =    Odour Unit * m**3/min
      7 =    metric tons/yr

   Number of source-species
   combinations with variable
   emissions scaling factors
   provided below in (15c)       (NSLN1) Default: 0  !  NSLN1 =  0  !

   Maximum number of segments used to model
   each line (MXNSEG)                          Default: 7   ! MXNSEG =  7  !

   The following variables are required only if NLINES > 0.  They are
   used in the buoyant line source plume rise calculations.

     Number of distances at which              Default: 6   ! NLRISE =  6  !
     transitional rise is computed

     Average building length (XL)              No default   ! XL = .0 !
                                    (in meters)

     Average building height (HBL)             No default   ! HBL = .0 !
                                    (in meters)

     Average building width (WBL)              No default   ! WBL = .0 !
                                    (in meters)

     Average line source width (WML)           No default   ! WML = .0 !
                                    (in meters)

     Average separation between buildings (DXL)  No default   ! DXL = .0 !
                                    (in meters)

     Average buoyancy parameter (FPRIMEL)      No default   ! FPRIMEL = .0 !
                                    (in m**4/s**3)

!END!
```

Subgroup (15b)

BUOYANT LINE SOURCE: CONSTANT DATA

Source No.	Beg. X Coordinate (km)	Beg. Y Coordinate (km)	End. X Coordinate (km)	End. Y Coordinate (km)	Release Height[a] (m)	Base Elevation (m)	Emission Rates
---	---	---	---	---	---	---	---

---

[a] Data for each source are treated as a separate input subgroup and therefore must end with an input group terminator.

[b] An emission rate must be entered for every pollutant modeled. Enter emission rate of zero for secondary pollutants that are modeled, but not emitted. Units are specified by ILNTU (e.g. 1 for g/s).

Subgroup (15c)

BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA[a]

Use this subgroup to describe temporal variations in the emission rates given in 15b. Factors entered multiply the rates in 15b. Skip sources here that have constant emissions.

IVARY determines the type of variation, and is source-specific:

(IVARY) Default: 0

0 = Constant

1 = Diurnal cycle (24 scaling factors: hours 1-24)

2 = Monthly cycle (12 scaling factors: months 1-12)

3 = Hour & Season (4 groups of 24 hourly scaling factors, where first group is DEC-JAN-FEB)

4 = Speed & Stab. (6 groups of 6 scaling factors, where first group is Stability Class A, and the speed classes have upper bounds (m/s) defined in Group 12

5 = Temperature (12 scaling factors, where temperature classes have upper bounds (C) of: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 50+)

---

a

Data for each species are treated as a separate input subgroup and therefore must end with an input group terminator.

INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters

Subgroup (16a)

Number of volume sources with parameters provided in 16b,c (NVL1) No default ! NVL1 = 0 !

Units used for volume source

```
    emissions below in 16b       (IVLU)     Default: 1  !  IVLU =   1  !
         1 =        g/s
         2 =       kg/hr
         3 =       lb/hr
         4 =     tons/yr
         5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
         6 =     Odour Unit * m**3/min
         7 =     metric tons/yr

    Number of source-species
    combinations with variable
    emissions scaling factors
    provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

    Number of volume sources with
    variable location and emission
    parameters                   (NVL2)     No default  !  NVL2 =   0   !

    (If NVL2 > 0, ALL parameter data for
     these sources are read from the VOLEMARB.DAT file(s) )

!END!

---------------
Subgroup (16b)
---------------
                                   a
         VOLUME SOURCE: CONSTANT DATA
         ------------------------------
                                                                b
       X UTM      Y UTM      Effect.    Base     Initial    Initial    Emission
    Coordinate  Coordinate   Height   Elevation  Sigma y    Sigma z     Rates
       (km)       (km)         (m)       (m)        (m)       (m)
    ----------  ----------   ------    ------    --------   --------   --------
--------
   a
    Data for each source are treated as a separate input subgroup
```

and therefore must end with an input group terminator.

b
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IVLU
(e.g. 1 for g/s).

Subgroup (16c)
---

a
VOLUME SOURCE: VARIABLE EMISSIONS DATA

Use this subgroup to describe temporal variations in the emission
rates given in 16b. Factors entered multiply the rates in 16b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use VOLEMARB.DAT and NVL2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY) Default: 0

0 = Constant
1 = Diurnal cycle (24 scaling factors: hours 1-24)
2 = Monthly cycle (12 scaling factors: months 1-12)
3 = Hour & Season (4 groups of 24 hourly scaling factors,
where first group is DEC-JAN-FEB)
4 = Speed & Stab. (6 groups of 6 scaling factors, where
first group is Stability Class A,
and the speed classes have upper
bounds (m/s) defined in Group 12
5 = Temperature (12 scaling factors, where temperature
classes have upper bounds (C) of:
0, 5, 10, 15, 20, 25, 30, 35, 40,
45, 50, 50+)

---
a
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
---

Subgroup (17a)

Number of non-gridded receptors (NREC) No default ! NREC = 1272 !

!END!

Subgroup (17b)
---
a
NON-GRIDDED (DISCRETE) RECEPTOR DATA

Receptor No.	X UTM Coordinate (km)	Y UTM Coordinate (km)	Ground Elevation (m)	Height Above Ground (m)	b
1 ! X =	103.1693,	138.2968,	487.0	!!END!	Boundary Waters
2 ! X =	104.9739,	138.3293,	483.0	!!END!	Boundary Waters
3 ! X =	106.7784,	138.3624,	475.0	!!END!	Boundary Waters
4 ! X =	108.5829,	138.3960,	472.0	!!END!	Boundary Waters
5 ! X =	110.3874,	138.4302,	474.0	!!END!	Boundary Waters
6 ! X =	112.1918,	138.4650,	472.0	!!END!	Boundary Waters

7 ! X =	113.9963,	138.5003,	468.0	!!END!	Boundary Waters
8 ! X =	115.8007,	138.5361,	469.0	!!END!	Boundary Waters
9 ! X =	117.6052,	138.5726,	480.0	!!END!	Boundary Waters
10 ! X =	124.8228,	138.7240,	490.0	!!END!	Boundary Waters
11 ! X =	126.6272,	138.7632,	498.0	!!END!	Boundary Waters
12 ! X =	128.4316,	138.8030,	502.0	!!END!	Boundary Waters
13 ! X =	130.2359,	138.8434,	502.0	!!END!	Boundary Waters
14 ! X =	132.0403,	138.8844,	503.0	!!END!	Boundary Waters
15 ! X =	133.8446,	138.9259,	502.0	!!END!	Boundary Waters
16 ! X =	135.6489,	138.9679,	511.0	!!END!	Boundary Waters
17 ! X =	103.1214,	140.9822,	457.0	!!END!	Boundary Waters
18 ! X =	104.9251,	141.0147,	460.0	!!END!	Boundary Waters
19 ! X =	106.7288,	141.0478,	472.0	!!END!	Boundary Waters
20 ! X =	108.5324,	141.0814,	472.0	!!END!	Boundary Waters
21 ! X =	110.3361,	141.1155,	457.0	!!END!	Boundary Waters
22 ! X =	112.1397,	141.1503,	455.0	!!END!	Boundary Waters
23 ! X =	113.9433,	141.1856,	472.0	!!END!	Boundary Waters
24 ! X =	115.7469,	141.2214,	456.0	!!END!	Boundary Waters
25 ! X =	117.5505,	141.2578,	473.0	!!END!	Boundary Waters
26 ! X =	119.3541,	141.2948,	472.0	!!END!	Boundary Waters
27 ! X =	121.1577,	141.3324,	473.0	!!END!	Boundary Waters
28 ! X =	122.9613,	141.3705,	478.0	!!END!	Boundary Waters
29 ! X =	124.7648,	141.4091,	489.0	!!END!	Boundary Waters
30 ! X =	126.5684,	141.4484,	487.0	!!END!	Boundary Waters
31 ! X =	128.3719,	141.4882,	487.0	!!END!	Boundary Waters
32 ! X =	130.1754,	141.5285,	501.0	!!END!	Boundary Waters
33 ! X =	131.9789,	141.5695,	502.0	!!END!	Boundary Waters
34 ! X =	133.7824,	141.6110,	499.0	!!END!	Boundary Waters
35 ! X =	135.5859,	141.6530,	518.0	!!END!	Boundary Waters
36 ! X =	101.2706,	143.6356,	487.0	!!END!	Boundary Waters
37 ! X =	103.0735,	143.6675,	447.0	!!END!	Boundary Waters
38 ! X =	104.8763,	143.7000,	441.0	!!END!	Boundary Waters
39 ! X =	106.6791,	143.7330,	470.0	!!END!	Boundary Waters
40 ! X =	108.4820,	143.7666,	472.0	!!END!	Boundary Waters
41 ! X =	110.2848,	143.8007,	478.0	!!END!	Boundary Waters
42 ! X =	112.0876,	143.8354,	472.0	!!END!	Boundary Waters
43 ! X =	113.8904,	143.8707,	472.0	!!END!	Boundary Waters

44 ! X =	115.6931,	143.9066,	472.0	!!END!	Boundary Waters
45 ! X =	117.4959,	143.9430,	472.0	!!END!	Boundary Waters
46 ! X =	119.2986,	143.9799,	472.0	!!END!	Boundary Waters
47 ! X =	121.1014,	144.0175,	481.0	!!END!	Boundary Waters
48 ! X =	122.9041,	144.0556,	487.0	!!END!	Boundary Waters
49 ! X =	124.7068,	144.0942,	503.0	!!END!	Boundary Waters
50 ! X =	126.5095,	144.1334,	502.0	!!END!	Boundary Waters
51 ! X =	128.3122,	144.1732,	502.0	!!END!	Boundary Waters
52 ! X =	130.1149,	144.2135,	506.0	!!END!	Boundary Waters
53 ! X =	131.9176,	144.2545,	522.0	!!END!	Boundary Waters
54 ! X =	133.7202,	144.2959,	533.0	!!END!	Boundary Waters
55 ! X =	135.5229,	144.3380,	510.0	!!END!	Boundary Waters
56 ! X =	97.6195,	146.2593,	456.0	!!END!	Boundary Waters
57 ! X =	99.4215,	146.2900,	441.0	!!END!	Boundary Waters
58 ! X =	101.2235,	146.3214,	441.0	!!END!	Boundary Waters
59 ! X =	103.0255,	146.3532,	446.0	!!END!	Boundary Waters
60 ! X =	104.8275,	146.3857,	467.0	!!END!	Boundary Waters
61 ! X =	106.6295,	146.4187,	463.0	!!END!	Boundary Waters
62 ! X =	108.4315,	146.4523,	463.0	!!END!	Boundary Waters
63 ! X =	110.2335,	146.4864,	475.0	!!END!	Boundary Waters
64 ! X =	112.0354,	146.5211,	472.0	!!END!	Boundary Waters
65 ! X =	113.8374,	146.5564,	475.0	!!END!	Boundary Waters
66 ! X =	115.6393,	146.5922,	474.0	!!END!	Boundary Waters
67 ! X =	117.4412,	146.6286,	487.0	!!END!	Boundary Waters
68 ! X =	119.2432,	146.6655,	472.0	!!END!	Boundary Waters
69 ! X =	121.0451,	146.7030,	487.0	!!END!	Boundary Waters
70 ! X =	122.8469,	146.7411,	493.0	!!END!	Boundary Waters
71 ! X =	124.6488,	146.7798,	487.0	!!END!	Boundary Waters
72 ! X =	126.4507,	146.8190,	502.0	!!END!	Boundary Waters
73 ! X =	128.2525,	146.8587,	528.0	!!END!	Boundary Waters
74 ! X =	130.0544,	146.8990,	531.0	!!END!	Boundary Waters
75 ! X =	131.8562,	146.9399,	518.0	!!END!	Boundary Waters
76 ! X =	133.6580,	146.9814,	527.0	!!END!	Boundary Waters
77 ! X =	135.4598,	147.0234,	516.0	!!END!	Boundary Waters
78 ! X =	137.2616,	147.0660,	533.0	!!END!	Boundary Waters
79 ! X =	139.0634,	147.1091,	530.0	!!END!	Boundary Waters
80 ! X =	140.8652,	147.1528,	558.0	!!END!	Boundary Waters

81 ! X =	142.6669,	147.1971,	544.0	!!END!	Boundary Waters
82 ! X =	144.4686,	147.2419,	542.0	!!END!	Boundary Waters
83 ! X =	146.2704,	147.2873,	600.0	!!END!	Boundary Waters
84 ! X =	148.0721,	147.3332,	589.0	!!END!	Boundary Waters
85 ! X =	149.8737,	147.3797,	557.0	!!END!	Boundary Waters
86 ! X =	151.6754,	147.4268,	559.0	!!END!	Boundary Waters
87 ! X =	157.0804,	147.5714,	521.0	!!END!	Boundary Waters
88 ! X =	158.8820,	147.6208,	548.0	!!END!	Boundary Waters
89 ! X =	160.6836,	147.6706,	563.0	!!END!	Boundary Waters
90 ! X =	97.5741,	148.9446,	441.0	!!END!	Boundary Waters
91 ! X =	99.3753,	148.9754,	438.0	!!END!	Boundary Waters
92 ! X =	101.1764,	149.0067,	455.0	!!END!	Boundary Waters
93 ! X =	102.9776,	149.0385,	459.0	!!END!	Boundary Waters
94 ! X =	104.7788,	149.0710,	471.0	!!END!	Boundary Waters
95 ! X =	106.5799,	149.1040,	463.0	!!END!	Boundary Waters
96 ! X =	108.3811,	149.1375,	471.0	!!END!	Boundary Waters
97 ! X =	110.1822,	149.1716,	457.0	!!END!	Boundary Waters
98 ! X =	111.9833,	149.2063,	451.0	!!END!	Boundary Waters
99 ! X =	113.7844,	149.2416,	456.0	!!END!	Boundary Waters
100 ! X =	115.5855,	149.2774,	457.0	!!END!	Boundary Waters
101 ! X =	117.3866,	149.3138,	458.0	!!END!	Boundary Waters
102 ! X =	119.1877,	149.3507,	467.0	!!END!	Boundary Waters
103 ! X =	120.9887,	149.3882,	472.0	!!END!	Boundary Waters
104 ! X =	122.7898,	149.4262,	481.0	!!END!	Boundary Waters
105 ! X =	124.5908,	149.4649,	502.0	!!END!	Boundary Waters
106 ! X =	126.3919,	149.5040,	484.0	!!END!	Boundary Waters
107 ! X =	128.1929,	149.5438,	487.0	!!END!	Boundary Waters
108 ! X =	129.9939,	149.5841,	494.0	!!END!	Boundary Waters
109 ! X =	131.7949,	149.6250,	517.0	!!END!	Boundary Waters
110 ! X =	133.5958,	149.6664,	524.0	!!END!	Boundary Waters
111 ! X =	135.3968,	149.7084,	512.0	!!END!	Boundary Waters
112 ! X =	137.1978,	149.7509,	519.0	!!END!	Boundary Waters
113 ! X =	138.9987,	149.7941,	533.0	!!END!	Boundary Waters
114 ! X =	140.7996,	149.8377,	530.0	!!END!	Boundary Waters
115 ! X =	142.6005,	149.8820,	548.0	!!END!	Boundary Waters
116 ! X =	144.4014,	149.9268,	561.0	!!END!	Boundary Waters
117 ! X =	146.2023,	149.9721,	563.0	!!END!	Boundary Waters

118 ! X =	148.0032,	150.0181,	562.0	!!END!	Boundary Waters
119 ! X =	149.8040,	150.0646,	609.0	!!END!	Boundary Waters
120 ! X =	151.6049,	150.1116,	557.0	!!END!	Boundary Waters
121 ! X =	153.4057,	150.1592,	563.0	!!END!	Boundary Waters
122 ! X =	155.2065,	150.2074,	551.0	!!END!	Boundary Waters
123 ! X =	157.0073,	150.2561,	568.0	!!END!	Boundary Waters
124 ! X =	158.8081,	150.3055,	573.0	!!END!	Boundary Waters
125 ! X =	160.6088,	150.3553,	578.0	!!END!	Boundary Waters
126 ! X =	162.4096,	150.4057,	571.0	!!END!	Boundary Waters
127 ! X =	164.2103,	150.4567,	561.0	!!END!	Boundary Waters
128 ! X =	175.0143,	150.7745,	533.0	!!END!	Boundary Waters
129 ! X =	176.8150,	150.8294,	561.0	!!END!	Boundary Waters
130 ! X =	52.5172,	151.0445,	426.0	!!END!	Boundary Waters
131 ! X =	54.3177,	151.0612,	450.0	!!END!	Boundary Waters
132 ! X =	56.1183,	151.0784,	441.0	!!END!	Boundary Waters
133 ! X =	57.9188,	151.0962,	440.0	!!END!	Boundary Waters
134 ! X =	59.7193,	151.1146,	475.0	!!END!	Boundary Waters
135 ! X =	61.5198,	151.1335,	481.0	!!END!	Boundary Waters
136 ! X =	63.3203,	151.1530,	477.0	!!END!	Boundary Waters
137 ! X =	65.1208,	151.1731,	472.0	!!END!	Boundary Waters
138 ! X =	66.9213,	151.1937,	427.0	!!END!	Boundary Waters
139 ! X =	93.9279,	151.5703,	441.0	!!END!	Boundary Waters
140 ! X =	95.7283,	151.5999,	437.0	!!END!	Boundary Waters
141 ! X =	97.5287,	151.6301,	450.0	!!END!	Boundary Waters
142 ! X =	99.3290,	151.6609,	449.0	!!END!	Boundary Waters
143 ! X =	101.1293,	151.6922,	462.0	!!END!	Boundary Waters
144 ! X =	102.9297,	151.7240,	445.0	!!END!	Boundary Waters
145 ! X =	104.7300,	151.7564,	474.0	!!END!	Boundary Waters
146 ! X =	106.5303,	151.7894,	457.0	!!END!	Boundary Waters
147 ! X =	108.3306,	151.8230,	472.0	!!END!	Boundary Waters
148 ! X =	110.1309,	151.8571,	451.0	!!END!	Boundary Waters
149 ! X =	111.9312,	151.8917,	453.0	!!END!	Boundary Waters
150 ! X =	113.7314,	151.9269,	452.0	!!END!	Boundary Waters
151 ! X =	115.5317,	151.9627,	451.0	!!END!	Boundary Waters
152 ! X =	117.3320,	151.9991,	459.0	!!END!	Boundary Waters
153 ! X =	119.1322,	152.0360,	457.0	!!END!	Boundary Waters
154 ! X =	120.9324,	152.0735,	472.0	!!END!	Boundary Waters

155 ! X =	122.7326,	152.1115,	472.0	!!END!	Boundary Waters
156 ! X =	124.5328,	152.1501,	462.0	!!END!	Boundary Waters
157 ! X =	126.3330,	152.1893,	479.0	!!END!	Boundary Waters
158 ! X =	128.1332,	152.2290,	517.0	!!END!	Boundary Waters
159 ! X =	129.9334,	152.2693,	502.0	!!END!	Boundary Waters
160 ! X =	131.7335,	152.3102,	487.0	!!END!	Boundary Waters
161 ! X =	133.5336,	152.3516,	517.0	!!END!	Boundary Waters
162 ! X =	135.3338,	152.3935,	516.0	!!END!	Boundary Waters
163 ! X =	137.1339,	152.4361,	496.0	!!END!	Boundary Waters
164 ! X =	138.9340,	152.4792,	518.0	!!END!	Boundary Waters
165 ! X =	140.7341,	152.5228,	533.0	!!END!	Boundary Waters
166 ! X =	142.5341,	152.5670,	578.0	!!END!	Boundary Waters
167 ! X =	144.3342,	152.6118,	569.0	!!END!	Boundary Waters
168 ! X =	146.1342,	152.6572,	588.0	!!END!	Boundary Waters
169 ! X =	147.9343,	152.7031,	588.0	!!END!	Boundary Waters
170 ! X =	149.7343,	152.7496,	582.0	!!END!	Boundary Waters
171 ! X =	151.5343,	152.7966,	566.0	!!END!	Boundary Waters
172 ! X =	153.3343,	152.8442,	539.0	!!END!	Boundary Waters
173 ! X =	155.1342,	152.8923,	563.0	!!END!	Boundary Waters
174 ! X =	156.9342,	152.9411,	588.0	!!END!	Boundary Waters
175 ! X =	158.7341,	152.9903,	532.0	!!END!	Boundary Waters
176 ! X =	160.5341,	153.0402,	563.0	!!END!	Boundary Waters
177 ! X =	162.3340,	153.0906,	561.0	!!END!	Boundary Waters
178 ! X =	164.1339,	153.1415,	563.0	!!END!	Boundary Waters
179 ! X =	174.9329,	153.4591,	604.0	!!END!	Boundary Waters
180 ! X =	176.7327,	153.5140,	606.0	!!END!	Boundary Waters
181 ! X =	45.2939,	153.6694,	452.0	!!END!	Boundary Waters
182 ! X =	47.0936,	153.6838,	455.0	!!END!	Boundary Waters
183 ! X =	48.8933,	153.6988,	437.0	!!END!	Boundary Waters
184 ! X =	50.6930,	153.7144,	434.0	!!END!	Boundary Waters
185 ! X =	52.4927,	153.7305,	442.0	!!END!	Boundary Waters
186 ! X =	54.2924,	153.7471,	442.0	!!END!	Boundary Waters
187 ! X =	56.0921,	153.7644,	447.0	!!END!	Boundary Waters
188 ! X =	57.8918,	153.7822,	461.0	!!END!	Boundary Waters
189 ! X =	59.6915,	153.8005,	472.0	!!END!	Boundary Waters
190 ! X =	61.4912,	153.8195,	488.0	!!END!	Boundary Waters
191 ! X =	63.2909,	153.8389,	479.0	!!END!	Boundary Waters

192 ! X =	65.0905,	153.8590,	472.0	!!END!	Boundary Waters
193 ! X =	66.8902,	153.8796,	458.0	!!END!	Boundary Waters
194 ! X =	106.4807,	154.4750,	455.0	!!END!	Boundary Waters
195 ! X =	108.2802,	154.5085,	453.0	!!END!	Boundary Waters
196 ! X =	110.0796,	154.5426,	451.0	!!END!	Boundary Waters
197 ! X =	111.8791,	154.5773,	456.0	!!END!	Boundary Waters
198 ! X =	113.6785,	154.6125,	456.0	!!END!	Boundary Waters
199 ! X =	115.4779,	154.6483,	460.0	!!END!	Boundary Waters
200 ! X =	117.2773,	154.6846,	457.0	!!END!	Boundary Waters
201 ! X =	119.0767,	154.7215,	472.0	!!END!	Boundary Waters
202 ! X =	120.8761,	154.7590,	487.0	!!END!	Boundary Waters
203 ! X =	122.6755,	154.7970,	487.0	!!END!	Boundary Waters
204 ! X =	124.4748,	154.8356,	460.0	!!END!	Boundary Waters
205 ! X =	126.2742,	154.8747,	480.0	!!END!	Boundary Waters
206 ! X =	128.0735,	154.9144,	484.0	!!END!	Boundary Waters
207 ! X =	129.8728,	154.9547,	495.0	!!END!	Boundary Waters
208 ! X =	131.6721,	154.9955,	505.0	!!END!	Boundary Waters
209 ! X =	133.4715,	155.0369,	488.0	!!END!	Boundary Waters
210 ! X =	135.2707,	155.0789,	487.0	!!END!	Boundary Waters
211 ! X =	137.0700,	155.1214,	487.0	!!END!	Boundary Waters
212 ! X =	138.8693,	155.1645,	503.0	!!END!	Boundary Waters
213 ! X =	140.6685,	155.2081,	533.0	!!END!	Boundary Waters
214 ! X =	142.4678,	155.2523,	533.0	!!END!	Boundary Waters
215 ! X =	144.2670,	155.2971,	563.0	!!END!	Boundary Waters
216 ! X =	146.0662,	155.3424,	594.0	!!END!	Boundary Waters
217 ! X =	147.8654,	155.3883,	609.0	!!END!	Boundary Waters
218 ! X =	149.6645,	155.4347,	609.0	!!END!	Boundary Waters
219 ! X =	151.4637,	155.4817,	582.0	!!END!	Boundary Waters
220 ! X =	153.2628,	155.5293,	563.0	!!END!	Boundary Waters
221 ! X =	155.0620,	155.5774,	562.0	!!END!	Boundary Waters
222 ! X =	156.8611,	155.6261,	563.0	!!END!	Boundary Waters
223 ! X =	158.6602,	155.6754,	563.0	!!END!	Boundary Waters
224 ! X =	160.4593,	155.7252,	579.0	!!END!	Boundary Waters
225 ! X =	162.2584,	155.7756,	562.0	!!END!	Boundary Waters
226 ! X =	164.0574,	155.8265,	560.0	!!END!	Boundary Waters
227 ! X =	171.2535,	156.0359,	578.0	!!END!	Boundary Waters
228 ! X =	173.0524,	156.0897,	613.0	!!END!	Boundary Waters

229 ! X =	174.8514,	156.1440,	608.0	!!END!	Boundary Waters
230 ! X =	176.6503,	156.1989,	604.0	!!END!	Boundary Waters
231 ! X =	178.4493,	156.2543,	608.0	!!END!	Boundary Waters
232 ! X =	180.2482,	156.3103,	608.0	!!END!	Boundary Waters
233 ! X =	182.0471,	156.3668,	629.0	!!END!	Boundary Waters
234 ! X =	183.8459,	156.4240,	658.0	!!END!	Boundary Waters
235 ! X =	45.2728,	156.3556,	457.0	!!END!	Boundary Waters
236 ! X =	47.0717,	156.3700,	436.0	!!END!	Boundary Waters
237 ! X =	48.8705,	156.3850,	427.0	!!END!	Boundary Waters
238 ! X =	50.6694,	156.4005,	427.0	!!END!	Boundary Waters
239 ! X =	52.4683,	156.4166,	453.0	!!END!	Boundary Waters
240 ! X =	54.2671,	156.4333,	441.0	!!END!	Boundary Waters
241 ! X =	56.0660,	156.4505,	442.0	!!END!	Boundary Waters
242 ! X =	57.8648,	156.4683,	457.0	!!END!	Boundary Waters
243 ! X =	59.6637,	156.4866,	457.0	!!END!	Boundary Waters
244 ! X =	61.4625,	156.5056,	467.0	!!END!	Boundary Waters
245 ! X =	63.2614,	156.5250,	457.0	!!END!	Boundary Waters
246 ! X =	65.0602,	156.5451,	457.0	!!END!	Boundary Waters
247 ! X =	66.8590,	156.5656,	454.0	!!END!	Boundary Waters
248 ! X =	68.6578,	156.5868,	457.0	!!END!	Boundary Waters
249 ! X =	115.4241,	157.3340,	471.0	!!END!	Boundary Waters
250 ! X =	117.2226,	157.3703,	464.0	!!END!	Boundary Waters
251 ! X =	119.0212,	157.4072,	497.0	!!END!	Boundary Waters
252 ! X =	120.8198,	157.4446,	502.0	!!END!	Boundary Waters
253 ! X =	122.6183,	157.4826,	472.0	!!END!	Boundary Waters
254 ! X =	124.4168,	157.5212,	483.0	!!END!	Boundary Waters
255 ! X =	126.2153,	157.5603,	486.0	!!END!	Boundary Waters
256 ! X =	128.0138,	157.6000,	484.0	!!END!	Boundary Waters
257 ! X =	129.8123,	157.6403,	488.0	!!END!	Boundary Waters
258 ! X =	131.6108,	157.6811,	487.0	!!END!	Boundary Waters
259 ! X =	133.4093,	157.7224,	487.0	!!END!	Boundary Waters
260 ! X =	135.2077,	157.7644,	484.0	!!END!	Boundary Waters
261 ! X =	137.0061,	157.8069,	487.0	!!END!	Boundary Waters
262 ! X =	138.8046,	157.8499,	517.0	!!END!	Boundary Waters
263 ! X =	140.6030,	157.8936,	518.0	!!END!	Boundary Waters
264 ! X =	142.4014,	157.9377,	533.0	!!END!	Boundary Waters
265 ! X =	144.1998,	157.9825,	548.0	!!END!	Boundary Waters

266 ! X =	145.9981,	158.0278,	587.0	!!END!	Boundary Waters
267 ! X =	147.7965,	158.0736,	563.0	!!END!	Boundary Waters
268 ! X =	149.5948,	158.1201,	563.0	!!END!	Boundary Waters
269 ! X =	151.3931,	158.1671,	579.0	!!END!	Boundary Waters
270 ! X =	153.1914,	158.2146,	563.0	!!END!	Boundary Waters
271 ! X =	154.9897,	158.2627,	563.0	!!END!	Boundary Waters
272 ! X =	156.7880,	158.3114,	543.0	!!END!	Boundary Waters
273 ! X =	158.5863,	158.3606,	544.0	!!END!	Boundary Waters
274 ! X =	160.3845,	158.4104,	579.0	!!END!	Boundary Waters
275 ! X =	162.1828,	158.4608,	578.0	!!END!	Boundary Waters
276 ! X =	163.9810,	158.5117,	624.0	!!END!	Boundary Waters
277 ! X =	165.7792,	158.5632,	564.0	!!END!	Boundary Waters
278 ! X =	167.5773,	158.6152,	579.0	!!END!	Boundary Waters
279 ! X =	169.3755,	158.6678,	589.0	!!END!	Boundary Waters
280 ! X =	171.1737,	158.7210,	587.0	!!END!	Boundary Waters
281 ! X =	172.9718,	158.7747,	582.0	!!END!	Boundary Waters
282 ! X =	174.7699,	158.8290,	596.0	!!END!	Boundary Waters
283 ! X =	176.5680,	158.8838,	549.0	!!END!	Boundary Waters
284 ! X =	178.3661,	158.9393,	532.0	!!END!	Boundary Waters
285 ! X =	180.1642,	158.9952,	540.0	!!END!	Boundary Waters
286 ! X =	181.9622,	159.0518,	579.0	!!END!	Boundary Waters
287 ! X =	183.7602,	159.1088,	559.0	!!END!	Boundary Waters
288 ! X =	45.2517,	159.0416,	442.0	!!END!	Boundary Waters
289 ! X =	47.0497,	159.0560,	457.0	!!END!	Boundary Waters
290 ! X =	48.8478,	159.0710,	427.0	!!END!	Boundary Waters
291 ! X =	50.6458,	159.0865,	437.0	!!END!	Boundary Waters
292 ! X =	52.4438,	159.1026,	436.0	!!END!	Boundary Waters
293 ! X =	54.2418,	159.1193,	442.0	!!END!	Boundary Waters
294 ! X =	56.0399,	159.1365,	433.0	!!END!	Boundary Waters
295 ! X =	57.8379,	159.1543,	455.0	!!END!	Boundary Waters
296 ! X =	59.6359,	159.1726,	443.0	!!END!	Boundary Waters
297 ! X =	61.4339,	159.1915,	463.0	!!END!	Boundary Waters
298 ! X =	63.2319,	159.2110,	488.0	!!END!	Boundary Waters
299 ! X =	65.0299,	159.2310,	458.0	!!END!	Boundary Waters
300 ! X =	66.8278,	159.2516,	456.0	!!END!	Boundary Waters
301 ! X =	68.6258,	159.2727,	457.0	!!END!	Boundary Waters
302 ! X =	70.4238,	159.2944,	487.0	!!END!	Boundary Waters

303 ! X =	90.2009,	159.5703,	426.0	!!END!	Boundary Waters
304 ! X =	91.9988,	159.5987,	402.0	!!END!	Boundary Waters
305 ! X =	93.7967,	159.6277,	421.0	!!END!	Boundary Waters
306 ! X =	95.5945,	159.6573,	409.0	!!END!	Boundary Waters
307 ! X =	97.3924,	159.6874,	441.0	!!END!	Boundary Waters
308 ! X =	99.1902,	159.7181,	435.0	!!END!	Boundary Waters
309 ! X =	100.9880,	159.7493,	423.0	!!END!	Boundary Waters
310 ! X =	115.3703,	160.0195,	435.0	!!END!	Boundary Waters
311 ! X =	117.1680,	160.0558,	435.0	!!END!	Boundary Waters
312 ! X =	118.9657,	160.0927,	435.0	!!END!	Boundary Waters
313 ! X =	120.7634,	160.1301,	465.0	!!END!	Boundary Waters
314 ! X =	122.5611,	160.1681,	476.0	!!END!	Boundary Waters
315 ! X =	124.3588,	160.2067,	472.0	!!END!	Boundary Waters
316 ! X =	126.1565,	160.2458,	466.0	!!END!	Boundary Waters
317 ! X =	127.9541,	160.2854,	481.0	!!END!	Boundary Waters
318 ! X =	129.7518,	160.3257,	513.0	!!END!	Boundary Waters
319 ! X =	131.5494,	160.3665,	484.0	!!END!	Boundary Waters
320 ! X =	133.3471,	160.4078,	484.0	!!END!	Boundary Waters
321 ! X =	135.1447,	160.4497,	491.0	!!END!	Boundary Waters
322 ! X =	136.9423,	160.4922,	487.0	!!END!	Boundary Waters
323 ! X =	138.7399,	160.5353,	508.0	!!END!	Boundary Waters
324 ! X =	140.5374,	160.5789,	540.0	!!END!	Boundary Waters
325 ! X =	142.3350,	160.6230,	543.0	!!END!	Boundary Waters
326 ! X =	144.1325,	160.6677,	548.0	!!END!	Boundary Waters
327 ! X =	145.9300,	160.7130,	566.0	!!END!	Boundary Waters
328 ! X =	147.7276,	160.7589,	530.0	!!END!	Boundary Waters
329 ! X =	149.5251,	160.8053,	543.0	!!END!	Boundary Waters
330 ! X =	151.3225,	160.8522,	518.0	!!END!	Boundary Waters
331 ! X =	153.1200,	160.8998,	533.0	!!END!	Boundary Waters
332 ! X =	154.9175,	160.9478,	552.0	!!END!	Boundary Waters
333 ! X =	156.7149,	160.9965,	548.0	!!END!	Boundary Waters
334 ! X =	158.5123,	161.0457,	533.0	!!END!	Boundary Waters
335 ! X =	160.3097,	161.0955,	578.0	!!END!	Boundary Waters
336 ! X =	162.1071,	161.1458,	571.0	!!END!	Boundary Waters
337 ! X =	163.9045,	161.1967,	594.0	!!END!	Boundary Waters
338 ! X =	165.7019,	161.2482,	604.0	!!END!	Boundary Waters
339 ! X =	167.4992,	161.3002,	606.0	!!END!	Boundary Waters

340 ! X =	169.2966,	161.3528,	594.0	!!END!	Boundary Waters
341 ! X =	171.0939,	161.4059,	594.0	!!END!	Boundary Waters
342 ! X =	172.8912,	161.4596,	624.0	!!END!	Boundary Waters
343 ! X =	174.6884,	161.5139,	639.0	!!END!	Boundary Waters
344 ! X =	176.4857,	161.5687,	645.0	!!END!	Boundary Waters
345 ! X =	178.2829,	161.6241,	645.0	!!END!	Boundary Waters
346 ! X =	180.0802,	161.6800,	632.0	!!END!	Boundary Waters
347 ! X =	181.8774,	161.7365,	670.0	!!END!	Boundary Waters
348 ! X =	183.6746,	161.7936,	624.0	!!END!	Boundary Waters
349 ! X =	45.2306,	161.7275,	442.0	!!END!	Boundary Waters
350 ! X =	47.0278,	161.7419,	440.0	!!END!	Boundary Waters
351 ! X =	48.8250,	161.7569,	439.0	!!END!	Boundary Waters
352 ! X =	50.6222,	161.7724,	437.0	!!END!	Boundary Waters
353 ! X =	52.4194,	161.7885,	436.0	!!END!	Boundary Waters
354 ! X =	54.2165,	161.8051,	427.0	!!END!	Boundary Waters
355 ! X =	56.0137,	161.8223,	447.0	!!END!	Boundary Waters
356 ! X =	57.8109,	161.8401,	442.0	!!END!	Boundary Waters
357 ! X =	59.6081,	161.8584,	442.0	!!END!	Boundary Waters
358 ! X =	61.4052,	161.8773,	457.0	!!END!	Boundary Waters
359 ! X =	63.2024,	161.8968,	452.0	!!END!	Boundary Waters
360 ! X =	64.9995,	161.9168,	457.0	!!END!	Boundary Waters
361 ! X =	66.7967,	161.9374,	446.0	!!END!	Boundary Waters
362 ! X =	68.5938,	161.9585,	457.0	!!END!	Boundary Waters
363 ! X =	70.3909,	161.9802,	466.0	!!END!	Boundary Waters
364 ! X =	72.1881,	162.0025,	480.0	!!END!	Boundary Waters
365 ! X =	73.9852,	162.0253,	445.0	!!END!	Boundary Waters
366 ! X =	90.1589,	162.2559,	440.0	!!END!	Boundary Waters
367 ! X =	91.9559,	162.2843,	416.0	!!END!	Boundary Waters
368 ! X =	93.7529,	162.3133,	414.0	!!END!	Boundary Waters
369 ! X =	95.5499,	162.3429,	422.0	!!END!	Boundary Waters
370 ! X =	97.3469,	162.3730,	412.0	!!END!	Boundary Waters
371 ! X =	99.1439,	162.4037,	412.0	!!END!	Boundary Waters
372 ! X =	100.9409,	162.4349,	420.0	!!END!	Boundary Waters
373 ! X =	102.7379,	162.4667,	440.0	!!END!	Boundary Waters
374 ! X =	104.5349,	162.4991,	424.0	!!END!	Boundary Waters
375 ! X =	106.3318,	162.5320,	438.0	!!END!	Boundary Waters
376 ! X =	108.1288,	162.5654,	408.0	!!END!	Boundary Waters

377 ! X =	109.9257,	162.5995,	455.0	!!END!	Boundary Waters
378 ! X =	111.7226,	162.6341,	457.0	!!END!	Boundary Waters
379 ! X =	113.5196,	162.6693,	436.0	!!END!	Boundary Waters
380 ! X =	115.3165,	162.7050,	436.0	!!END!	Boundary Waters
381 ! X =	117.1134,	162.7413,	442.0	!!END!	Boundary Waters
382 ! X =	118.9102,	162.7781,	457.0	!!END!	Boundary Waters
383 ! X =	120.7071,	162.8155,	457.0	!!END!	Boundary Waters
384 ! X =	122.5040,	162.8535,	472.0	!!END!	Boundary Waters
385 ! X =	124.3008,	162.8920,	472.0	!!END!	Boundary Waters
386 ! X =	126.0977,	162.9311,	471.0	!!END!	Boundary Waters
387 ! X =	127.8945,	162.9707,	488.0	!!END!	Boundary Waters
388 ! X =	129.6913,	163.0110,	484.0	!!END!	Boundary Waters
389 ! X =	131.4881,	163.0517,	517.0	!!END!	Boundary Waters
390 ! X =	133.2849,	163.0931,	497.0	!!END!	Boundary Waters
391 ! X =	135.0816,	163.1350,	503.0	!!END!	Boundary Waters
392 ! X =	136.8784,	163.1774,	520.0	!!END!	Boundary Waters
393 ! X =	138.6751,	163.2204,	512.0	!!END!	Boundary Waters
394 ! X =	140.4719,	163.2640,	516.0	!!END!	Boundary Waters
395 ! X =	142.2686,	163.3082,	514.0	!!END!	Boundary Waters
396 ! X =	144.0653,	163.3529,	523.0	!!END!	Boundary Waters
397 ! X =	145.8620,	163.3981,	521.0	!!END!	Boundary Waters
398 ! X =	147.6587,	163.4439,	503.0	!!END!	Boundary Waters
399 ! X =	149.4553,	163.4903,	521.0	!!END!	Boundary Waters
400 ! X =	151.2520,	163.5373,	533.0	!!END!	Boundary Waters
401 ! X =	153.0486,	163.5848,	567.0	!!END!	Boundary Waters
402 ! X =	154.8452,	163.6328,	580.0	!!END!	Boundary Waters
403 ! X =	156.6418,	163.6815,	552.0	!!END!	Boundary Waters
404 ! X =	158.4384,	163.7307,	552.0	!!END!	Boundary Waters
405 ! X =	160.2350,	163.7804,	542.0	!!END!	Boundary Waters
406 ! X =	162.0315,	163.8307,	553.0	!!END!	Boundary Waters
407 ! X =	163.8281,	163.8816,	563.0	!!END!	Boundary Waters
408 ! X =	165.6246,	163.9330,	592.0	!!END!	Boundary Waters
409 ! X =	167.4211,	163.9850,	594.0	!!END!	Boundary Waters
410 ! X =	169.2176,	164.0376,	573.0	!!END!	Boundary Waters
411 ! X =	171.0141,	164.0907,	591.0	!!END!	Boundary Waters
412 ! X =	172.8105,	164.1444,	579.0	!!END!	Boundary Waters
413 ! X =	174.6070,	164.1986,	574.0	!!END!	Boundary Waters

414 ! X =	176.4034,	164.2534,	572.0	!!END!	Boundary Waters
415 ! X =	178.1998,	164.3087,	575.0	!!END!	Boundary Waters
416 ! X =	179.9962,	164.3647,	583.0	!!END!	Boundary Waters
417 ! X =	181.7926,	164.4211,	564.0	!!END!	Boundary Waters
418 ! X =	183.5889,	164.4782,	564.0	!!END!	Boundary Waters
419 ! X =	50.5986,	164.4584,	442.0	!!END!	Boundary Waters
420 ! X =	52.3949,	164.4745,	442.0	!!END!	Boundary Waters
421 ! X =	54.1912,	164.4911,	427.0	!!END!	Boundary Waters
422 ! X =	55.9876,	164.5083,	427.0	!!END!	Boundary Waters
423 ! X =	57.7839,	164.5261,	455.0	!!END!	Boundary Waters
424 ! X =	59.5802,	164.5444,	450.0	!!END!	Boundary Waters
425 ! X =	61.3766,	164.5633,	445.0	!!END!	Boundary Waters
426 ! X =	63.1729,	164.5827,	458.0	!!END!	Boundary Waters
427 ! X =	64.9692,	164.6028,	432.0	!!END!	Boundary Waters
428 ! X =	66.7655,	164.6233,	442.0	!!END!	Boundary Waters
429 ! X =	68.5618,	164.6445,	443.0	!!END!	Boundary Waters
430 ! X =	70.3581,	164.6661,	436.0	!!END!	Boundary Waters
431 ! X =	72.1544,	164.6884,	453.0	!!END!	Boundary Waters
432 ! X =	73.9506,	164.7112,	461.0	!!END!	Boundary Waters
433 ! X =	86.5244,	164.8866,	411.0	!!END!	Boundary Waters
434 ! X =	88.3206,	164.9138,	399.0	!!END!	Boundary Waters
435 ! X =	90.1168,	164.9417,	408.0	!!END!	Boundary Waters
436 ! X =	91.9130,	164.9701,	419.0	!!END!	Boundary Waters
437 ! X =	93.7092,	164.9991,	396.0	!!END!	Boundary Waters
438 ! X =	95.5053,	165.0286,	422.0	!!END!	Boundary Waters
439 ! X =	97.3015,	165.0587,	400.0	!!END!	Boundary Waters
440 ! X =	99.0977,	165.0894,	406.0	!!END!	Boundary Waters
441 ! X =	100.8938,	165.1206,	397.0	!!END!	Boundary Waters
442 ! X =	102.6900,	165.1524,	396.0	!!END!	Boundary Waters
443 ! X =	104.4861,	165.1848,	411.0	!!END!	Boundary Waters
444 ! X =	106.2822,	165.2177,	423.0	!!END!	Boundary Waters
445 ! X =	108.0783,	165.2511,	427.0	!!END!	Boundary Waters
446 ! X =	109.8744,	165.2851,	427.0	!!END!	Boundary Waters
447 ! X =	111.6705,	165.3197,	408.0	!!END!	Boundary Waters
448 ! X =	113.4666,	165.3549,	427.0	!!END!	Boundary Waters
449 ! X =	115.2627,	165.3906,	442.0	!!END!	Boundary Waters
450 ! X =	117.0587,	165.4268,	431.0	!!END!	Boundary Waters

451 ! X =	118.8548,	165.4637,	424.0	!!END!	Boundary Waters
452 ! X =	120.6508,	165.5011,	433.0	!!END!	Boundary Waters
453 ! X =	122.4468,	165.5390,	466.0	!!END!	Boundary Waters
454 ! X =	124.2428,	165.5775,	471.0	!!END!	Boundary Waters
455 ! X =	126.0388,	165.6166,	472.0	!!END!	Boundary Waters
456 ! X =	127.8348,	165.6562,	497.0	!!END!	Boundary Waters
457 ! X =	129.6308,	165.6964,	504.0	!!END!	Boundary Waters
458 ! X =	131.4267,	165.7372,	531.0	!!END!	Boundary Waters
459 ! X =	133.2227,	165.7785,	488.0	!!END!	Boundary Waters
460 ! X =	135.0186,	165.8204,	503.0	!!END!	Boundary Waters
461 ! X =	136.8145,	165.8628,	533.0	!!END!	Boundary Waters
462 ! X =	138.6104,	165.9058,	518.0	!!END!	Boundary Waters
463 ! X =	140.4063,	165.9494,	518.0	!!END!	Boundary Waters
464 ! X =	142.2022,	165.9935,	494.0	!!END!	Boundary Waters
465 ! X =	143.9981,	166.0382,	491.0	!!END!	Boundary Waters
466 ! X =	145.7939,	166.0834,	491.0	!!END!	Boundary Waters
467 ! X =	147.5898,	166.1292,	506.0	!!END!	Boundary Waters
468 ! X =	149.3856,	166.1756,	519.0	!!END!	Boundary Waters
469 ! X =	151.1814,	166.2225,	518.0	!!END!	Boundary Waters
470 ! X =	152.9772,	166.2700,	531.0	!!END!	Boundary Waters
471 ! X =	154.7730,	166.3180,	595.0	!!END!	Boundary Waters
472 ! X =	156.5687,	166.3666,	575.0	!!END!	Boundary Waters
473 ! X =	158.3645,	166.4158,	549.0	!!END!	Boundary Waters
474 ! X =	160.1602,	166.4655,	547.0	!!END!	Boundary Waters
475 ! X =	161.9559,	166.5158,	549.0	!!END!	Boundary Waters
476 ! X =	163.7516,	166.5667,	570.0	!!END!	Boundary Waters
477 ! X =	165.5473,	166.6181,	598.0	!!END!	Boundary Waters
478 ! X =	167.3430,	166.6700,	609.0	!!END!	Boundary Waters
479 ! X =	169.1386,	166.7225,	610.0	!!END!	Boundary Waters
480 ! X =	170.9343,	166.7756,	597.0	!!END!	Boundary Waters
481 ! X =	172.7299,	166.8293,	595.0	!!END!	Boundary Waters
482 ! X =	174.5255,	166.8835,	585.0	!!END!	Boundary Waters
483 ! X =	176.3211,	166.9383,	573.0	!!END!	Boundary Waters
484 ! X =	178.1166,	166.9936,	578.0	!!END!	Boundary Waters
485 ! X =	179.9122,	167.0495,	579.0	!!END!	Boundary Waters
486 ! X =	181.7077,	167.1060,	569.0	!!END!	Boundary Waters
487 ! X =	190.6852,	167.3966,	564.0	!!END!	Boundary Waters

488 ! X =	192.4806,	167.4565,	572.0	!!END!	Boundary Waters
489 ! X =	194.2760,	167.5168,	589.0	!!END!	Boundary Waters
490 ! X =	54.1659,	167.1774,	443.0	!!END!	Boundary Waters
491 ! X =	55.9614,	167.1945,	426.0	!!END!	Boundary Waters
492 ! X =	57.7569,	167.2123,	424.0	!!END!	Boundary Waters
493 ! X =	59.5524,	167.2306,	442.0	!!END!	Boundary Waters
494 ! X =	61.3479,	167.2495,	428.0	!!END!	Boundary Waters
495 ! X =	63.1434,	167.2689,	427.0	!!END!	Boundary Waters
496 ! X =	64.9389,	167.2889,	426.0	!!END!	Boundary Waters
497 ! X =	66.7343,	167.3095,	426.0	!!END!	Boundary Waters
498 ! X =	68.5298,	167.3306,	432.0	!!END!	Boundary Waters
499 ! X =	70.3252,	167.3523,	430.0	!!END!	Boundary Waters
500 ! X =	77.5070,	167.4446,	458.0	!!END!	Boundary Waters
501 ! X =	79.3024,	167.4691,	461.0	!!END!	Boundary Waters
502 ! X =	81.0978,	167.4941,	439.0	!!END!	Boundary Waters
503 ! X =	84.6886,	167.5459,	426.0	!!END!	Boundary Waters
504 ! X =	86.4840,	167.5726,	426.0	!!END!	Boundary Waters
505 ! X =	88.2793,	167.5999,	404.0	!!END!	Boundary Waters
506 ! X =	90.0747,	167.6277,	427.0	!!END!	Boundary Waters
507 ! X =	91.8701,	167.6561,	396.0	!!END!	Boundary Waters
508 ! X =	93.6654,	167.6851,	396.0	!!END!	Boundary Waters
509 ! X =	95.4608,	167.7146,	397.0	!!END!	Boundary Waters
510 ! X =	97.2561,	167.7447,	396.0	!!END!	Boundary Waters
511 ! X =	99.0514,	167.7753,	396.0	!!END!	Boundary Waters
512 ! X =	100.8467,	167.8065,	400.0	!!END!	Boundary Waters
513 ! X =	106.2326,	167.9035,	396.0	!!END!	Boundary Waters
514 ! X =	108.0279,	167.9370,	411.0	!!END!	Boundary Waters
515 ! X =	109.8231,	167.9710,	411.0	!!END!	Boundary Waters
516 ! X =	111.6184,	168.0056,	400.0	!!END!	Boundary Waters
517 ! X =	115.2088,	168.0764,	405.0	!!END!	Boundary Waters
518 ! X =	117.0041,	168.1126,	426.0	!!END!	Boundary Waters
519 ! X =	118.7993,	168.1494,	427.0	!!END!	Boundary Waters
520 ! X =	120.5945,	168.1868,	429.0	!!END!	Boundary Waters
521 ! X =	122.3896,	168.2247,	447.0	!!END!	Boundary Waters
522 ! X =	124.1848,	168.2632,	457.0	!!END!	Boundary Waters
523 ! X =	125.9800,	168.3023,	488.0	!!END!	Boundary Waters
524 ! X =	127.7751,	168.3419,	469.0	!!END!	Boundary Waters

525 ! X =	129.5702,	168.3821,	463.0	!!END!	Boundary Waters
526 ! X =	131.3654,	168.4228,	564.0	!!END!	Boundary Waters
527 ! X =	133.1605,	168.4641,	534.0	!!END!	Boundary Waters
528 ! X =	134.9556,	168.5060,	548.0	!!END!	Boundary Waters
529 ! X =	136.7506,	168.5484,	539.0	!!END!	Boundary Waters
530 ! X =	138.5457,	168.5914,	518.0	!!END!	Boundary Waters
531 ! X =	140.3408,	168.6349,	549.0	!!END!	Boundary Waters
532 ! X =	142.1358,	168.6790,	494.0	!!END!	Boundary Waters
533 ! X =	143.9308,	168.7236,	518.0	!!END!	Boundary Waters
534 ! X =	145.7258,	168.7689,	548.0	!!END!	Boundary Waters
535 ! X =	147.5208,	168.8147,	514.0	!!END!	Boundary Waters
536 ! X =	149.3158,	168.8610,	514.0	!!END!	Boundary Waters
537 ! X =	151.1108,	168.9079,	549.0	!!END!	Boundary Waters
538 ! X =	152.9057,	168.9554,	561.0	!!END!	Boundary Waters
539 ! X =	154.7007,	169.0034,	564.0	!!END!	Boundary Waters
540 ! X =	156.4956,	169.0520,	553.0	!!END!	Boundary Waters
541 ! X =	158.2905,	169.1011,	533.0	!!END!	Boundary Waters
542 ! X =	160.0854,	169.1508,	549.0	!!END!	Boundary Waters
543 ! X =	161.8803,	169.2011,	564.0	!!END!	Boundary Waters
544 ! X =	163.6752,	169.2519,	571.0	!!END!	Boundary Waters
545 ! X =	165.4700,	169.3033,	567.0	!!END!	Boundary Waters
546 ! X =	167.2648,	169.3552,	576.0	!!END!	Boundary Waters
547 ! X =	169.0597,	169.4077,	580.0	!!END!	Boundary Waters
548 ! X =	170.8545,	169.4608,	594.0	!!END!	Boundary Waters
549 ! X =	172.6492,	169.5144,	606.0	!!END!	Boundary Waters
550 ! X =	174.4440,	169.5686,	610.0	!!END!	Boundary Waters
551 ! X =	190.5961,	170.0815,	518.0	!!END!	Boundary Waters
552 ! X =	192.3907,	170.1413,	518.0	!!END!	Boundary Waters
553 ! X =	194.1853,	170.2016,	518.0	!!END!	Boundary Waters
554 ! X =	195.9798,	170.2625,	524.0	!!END!	Boundary Waters
555 ! X =	197.7744,	170.3240,	545.0	!!END!	Boundary Waters
556 ! X =	199.5688,	170.3860,	541.0	!!END!	Boundary Waters
557 ! X =	201.3633,	170.4486,	566.0	!!END!	Boundary Waters
558 ! X =	203.1578,	170.5118,	572.0	!!END!	Boundary Waters
559 ! X =	204.9523,	170.5755,	555.0	!!END!	Boundary Waters
560 ! X =	206.7467,	170.6398,	476.0	!!END!	Boundary Waters
561 ! X =	208.5411,	170.7046,	445.0	!!END!	Boundary Waters

562 ! X =	55.9353,	169.8809,	423.0	!!END!	Boundary Waters
563 ! X =	57.7300,	169.8987,	426.0	!!END!	Boundary Waters
564 ! X =	68.4978,	170.0169,	430.0	!!END!	Boundary Waters
565 ! X =	70.2924,	170.0386,	427.0	!!END!	Boundary Waters
566 ! X =	77.4708,	170.1308,	442.0	!!END!	Boundary Waters
567 ! X =	79.2653,	170.1553,	442.0	!!END!	Boundary Waters
568 ! X =	81.0599,	170.1803,	453.0	!!END!	Boundary Waters
569 ! X =	82.8545,	170.2059,	426.0	!!END!	Boundary Waters
570 ! X =	84.6490,	170.2321,	410.0	!!END!	Boundary Waters
571 ! X =	86.4436,	170.2588,	405.0	!!END!	Boundary Waters
572 ! X =	88.2381,	170.2861,	411.0	!!END!	Boundary Waters
573 ! X =	90.0326,	170.3139,	411.0	!!END!	Boundary Waters
574 ! X =	91.8272,	170.3423,	411.0	!!END!	Boundary Waters
575 ! X =	93.6217,	170.3712,	429.0	!!END!	Boundary Waters
576 ! X =	95.4162,	170.4007,	419.0	!!END!	Boundary Waters
577 ! X =	97.2107,	170.4308,	400.0	!!END!	Boundary Waters
578 ! X =	99.0051,	170.4614,	428.0	!!END!	Boundary Waters
579 ! X =	100.7996,	170.4926,	452.0	!!END!	Boundary Waters
580 ! X =	125.9211,	170.9881,	424.0	!!END!	Boundary Waters
581 ! X =	127.7154,	171.0277,	442.0	!!END!	Boundary Waters
582 ! X =	129.5097,	171.0679,	469.0	!!END!	Boundary Waters
583 ! X =	131.3040,	171.1086,	460.0	!!END!	Boundary Waters
584 ! X =	133.0983,	171.1499,	533.0	!!END!	Boundary Waters
585 ! X =	134.8925,	171.1917,	472.0	!!END!	Boundary Waters
586 ! X =	136.6868,	171.2341,	480.0	!!END!	Boundary Waters
587 ! X =	138.4810,	171.2771,	470.0	!!END!	Boundary Waters
588 ! X =	140.2752,	171.3206,	476.0	!!END!	Boundary Waters
589 ! X =	142.0694,	171.3647,	547.0	!!END!	Boundary Waters
590 ! X =	143.8636,	171.4093,	505.0	!!END!	Boundary Waters
591 ! X =	145.6578,	171.4545,	511.0	!!END!	Boundary Waters
592 ! X =	147.4519,	171.5003,	520.0	!!END!	Boundary Waters
593 ! X =	149.2461,	171.5466,	533.0	!!END!	Boundary Waters
594 ! X =	151.0402,	171.5935,	533.0	!!END!	Boundary Waters
595 ! X =	172.5686,	172.1997,	564.0	!!END!	Boundary Waters
596 ! X =	174.3625,	172.2539,	582.0	!!END!	Boundary Waters
597 ! X =	176.1564,	172.3086,	549.0	!!END!	Boundary Waters
598 ! X =	177.9503,	172.3639,	533.0	!!END!	Boundary Waters

599 ! X =	179.7442,	172.4197,	541.0	!!END!	Boundary Waters
600 ! X =	181.5380,	172.4761,	521.0	!!END!	Boundary Waters
601 ! X =	183.3319,	172.5331,	555.0	!!END!	Boundary Waters
602 ! X =	185.1257,	172.5906,	503.0	!!END!	Boundary Waters
603 ! X =	186.9195,	172.6487,	500.0	!!END!	Boundary Waters
604 ! X =	188.7133,	172.7073,	547.0	!!END!	Boundary Waters
605 ! X =	190.5071,	172.7665,	515.0	!!END!	Boundary Waters
606 ! X =	192.3008,	172.8263,	556.0	!!END!	Boundary Waters
607 ! X =	194.0945,	172.8866,	594.0	!!END!	Boundary Waters
608 ! X =	195.8882,	172.9475,	526.0	!!END!	Boundary Waters
609 ! X =	197.6820,	173.0089,	518.0	!!END!	Boundary Waters
610 ! X =	199.4756,	173.0709,	598.0	!!END!	Boundary Waters
611 ! X =	201.2693,	173.1335,	570.0	!!END!	Boundary Waters
612 ! X =	203.0629,	173.1966,	518.0	!!END!	Boundary Waters
613 ! X =	204.8565,	173.2603,	472.0	!!END!	Boundary Waters
614 ! X =	206.6501,	173.3245,	479.0	!!END!	Boundary Waters
615 ! X =	208.4437,	173.3893,	469.0	!!END!	Boundary Waters
616 ! X =	210.2372,	173.4547,	464.0	!!END!	Boundary Waters
617 ! X =	212.0308,	173.5206,	495.0	!!END!	Boundary Waters
618 ! X =	55.9092,	172.5672,	411.0	!!END!	Boundary Waters
619 ! X =	57.7030,	172.5849,	443.0	!!END!	Boundary Waters
620 ! X =	75.6408,	172.7931,	440.0	!!END!	Boundary Waters
621 ! X =	77.4346,	172.8170,	457.0	!!END!	Boundary Waters
622 ! X =	79.2283,	172.8414,	430.0	!!END!	Boundary Waters
623 ! X =	81.0220,	172.8664,	451.0	!!END!	Boundary Waters
624 ! X =	82.8157,	172.8920,	427.0	!!END!	Boundary Waters
625 ! X =	84.6095,	172.9181,	427.0	!!END!	Boundary Waters
626 ! X =	86.4032,	172.9448,	411.0	!!END!	Boundary Waters
627 ! X =	88.1969,	172.9721,	427.0	!!END!	Boundary Waters
628 ! X =	89.9906,	172.9999,	426.0	!!END!	Boundary Waters
629 ! X =	91.7842,	173.0283,	396.0	!!END!	Boundary Waters
630 ! X =	93.5779,	173.0572,	401.0	!!END!	Boundary Waters
631 ! X =	95.3716,	173.0867,	396.0	!!END!	Boundary Waters
632 ! X =	102.5461,	173.2103,	400.0	!!END!	Boundary Waters
633 ! X =	129.4492,	173.7536,	457.0	!!END!	Boundary Waters
634 ! X =	131.2426,	173.7943,	426.0	!!END!	Boundary Waters
635 ! X =	133.0361,	173.8355,	421.0	!!END!	Boundary Waters

636 ! X =	134.8295,	173.8773,	421.0	!!END!	Boundary Waters
637 ! X =	136.6229,	173.9197,	441.0	!!END!	Boundary Waters
638 ! X =	138.4163,	173.9627,	487.0	!!END!	Boundary Waters
639 ! X =	140.2097,	174.0062,	451.0	!!END!	Boundary Waters
640 ! X =	142.0030,	174.0502,	471.0	!!END!	Boundary Waters
641 ! X =	143.7964,	174.0948,	479.0	!!END!	Boundary Waters
642 ! X =	145.5897,	174.1400,	488.0	!!END!	Boundary Waters
643 ! X =	147.3830,	174.1857,	492.0	!!END!	Boundary Waters
644 ! X =	149.1763,	174.2320,	503.0	!!END!	Boundary Waters
645 ! X =	150.9696,	174.2789,	518.0	!!END!	Boundary Waters
646 ! X =	172.4879,	174.8848,	490.0	!!END!	Boundary Waters
647 ! X =	174.2810,	174.9390,	472.0	!!END!	Boundary Waters
648 ! X =	181.4532,	175.1611,	473.0	!!END!	Boundary Waters
649 ! X =	199.3824,	175.7557,	505.0	!!END!	Boundary Waters
650 ! X =	201.1752,	175.8182,	524.0	!!END!	Boundary Waters
651 ! X =	202.9680,	175.8813,	549.0	!!END!	Boundary Waters
652 ! X =	204.7608,	175.9449,	541.0	!!END!	Boundary Waters
653 ! X =	206.5535,	176.0091,	454.0	!!END!	Boundary Waters
654 ! X =	64.8479,	175.3475,	411.0	!!END!	Boundary Waters
655 ! X =	66.6408,	175.3680,	426.0	!!END!	Boundary Waters
656 ! X =	68.4337,	175.3891,	440.0	!!END!	Boundary Waters
657 ! X =	70.2267,	175.4108,	427.0	!!END!	Boundary Waters
658 ! X =	72.0196,	175.4330,	411.0	!!END!	Boundary Waters
659 ! X =	73.8125,	175.4557,	427.0	!!END!	Boundary Waters
660 ! X =	75.6055,	175.4790,	443.0	!!END!	Boundary Waters
661 ! X =	77.3984,	175.5029,	439.0	!!END!	Boundary Waters
662 ! X =	79.1913,	175.5274,	396.0	!!END!	Boundary Waters
663 ! X =	80.9841,	175.5524,	433.0	!!END!	Boundary Waters
664 ! X =	82.7770,	175.5779,	427.0	!!END!	Boundary Waters
665 ! X =	84.5699,	175.6041,	430.0	!!END!	Boundary Waters
666 ! X =	86.3628,	175.6308,	422.0	!!END!	Boundary Waters
667 ! X =	88.1556,	175.6580,	427.0	!!END!	Boundary Waters
668 ! X =	89.9485,	175.6858,	404.0	!!END!	Boundary Waters
669 ! X =	91.7413,	175.7142,	427.0	!!END!	Boundary Waters
670 ! X =	131.1813,	176.4798,	421.0	!!END!	Boundary Waters
671 ! X =	132.9739,	176.5210,	432.0	!!END!	Boundary Waters
672 ! X =	134.7664,	176.5628,	442.0	!!END!	Boundary Waters

673 ! X =	136.5590,	176.6052,	457.0	!!END!	Boundary Waters
674 ! X =	138.3516,	176.6481,	472.0	!!END!	Boundary Waters
675 ! X =	140.1441,	176.6916,	456.0	!!END!	Boundary Waters
676 ! X =	141.9366,	176.7356,	472.0	!!END!	Boundary Waters
677 ! X =	143.7291,	176.7802,	439.0	!!END!	Boundary Waters
678 ! X =	145.5216,	176.8254,	442.0	!!END!	Boundary Waters
679 ! X =	147.3141,	176.8711,	442.0	!!END!	Boundary Waters
680 ! X =	149.1066,	176.9174,	442.0	!!END!	Boundary Waters
681 ! X =	150.8990,	176.9642,	446.0	!!END!	Boundary Waters
682 ! X =	156.2763,	177.1080,	457.0	!!END!	Boundary Waters
683 ! X =	158.0687,	177.1571,	457.0	!!END!	Boundary Waters
684 ! X =	57.6490,	177.9572,	411.0	!!END!	Boundary Waters
685 ! X =	61.2333,	177.9944,	417.0	!!END!	Boundary Waters
686 ! X =	63.0254,	178.0137,	426.0	!!END!	Boundary Waters
687 ! X =	64.8175,	178.0337,	398.0	!!END!	Boundary Waters
688 ! X =	66.6096,	178.0542,	396.0	!!END!	Boundary Waters
689 ! X =	68.4017,	178.0753,	411.0	!!END!	Boundary Waters
690 ! X =	70.1938,	178.0969,	411.0	!!END!	Boundary Waters
691 ! X =	71.9859,	178.1191,	406.0	!!END!	Boundary Waters
692 ! X =	73.7780,	178.1419,	438.0	!!END!	Boundary Waters
693 ! X =	75.5701,	178.1652,	409.0	!!END!	Boundary Waters
694 ! X =	77.3621,	178.1891,	425.0	!!END!	Boundary Waters
695 ! X =	79.1542,	178.2135,	396.0	!!END!	Boundary Waters
696 ! X =	80.9463,	178.2385,	427.0	!!END!	Boundary Waters
697 ! X =	82.7383,	178.2641,	422.0	!!END!	Boundary Waters
698 ! X =	84.5303,	178.2902,	413.0	!!END!	Boundary Waters
699 ! X =	86.3224,	178.3168,	396.0	!!END!	Boundary Waters
700 ! X =	88.1144,	178.3441,	442.0	!!END!	Boundary Waters
701 ! X =	89.9064,	178.3719,	433.0	!!END!	Boundary Waters
702 ! X =	91.6984,	178.4002,	427.0	!!END!	Boundary Waters
703 ! X =	134.7034,	179.2485,	457.0	!!END!	Boundary Waters
704 ! X =	136.4951,	179.2908,	472.0	!!END!	Boundary Waters
705 ! X =	138.2868,	179.3337,	433.0	!!END!	Boundary Waters
706 ! X =	140.0786,	179.3772,	448.0	!!END!	Boundary Waters
707 ! X =	141.8702,	179.4212,	459.0	!!END!	Boundary Waters
708 ! X =	143.6619,	179.4658,	457.0	!!END!	Boundary Waters
709 ! X =	145.4536,	179.5109,	440.0	!!END!	Boundary Waters

710 ! X =	147.2452,	179.5566,	473.0	!!END!	Boundary Waters
711 ! X =	149.0368,	179.6029,	451.0	!!END!	Boundary Waters
712 ! X =	154.4116,	179.7450,	453.0	!!END!	Boundary Waters
713 ! X =	156.2032,	179.7935,	457.0	!!END!	Boundary Waters
714 ! X =	157.9948,	179.8425,	460.0	!!END!	Boundary Waters
715 ! X =	46.8742,	180.5458,	411.0	!!END!	Boundary Waters
716 ! X =	48.6655,	180.5607,	385.0	!!END!	Boundary Waters
717 ! X =	50.4568,	180.5762,	396.0	!!END!	Boundary Waters
718 ! X =	52.2481,	180.5922,	411.0	!!END!	Boundary Waters
719 ! X =	54.0394,	180.6088,	411.0	!!END!	Boundary Waters
720 ! X =	55.8307,	180.6260,	411.0	!!END!	Boundary Waters
721 ! X =	57.6220,	180.6437,	397.0	!!END!	Boundary Waters
722 ! X =	59.4133,	180.6620,	426.0	!!END!	Boundary Waters
723 ! X =	61.2046,	180.6808,	396.0	!!END!	Boundary Waters
724 ! X =	62.9959,	180.7002,	372.0	!!END!	Boundary Waters
725 ! X =	64.7872,	180.7201,	385.0	!!END!	Boundary Waters
726 ! X =	66.5785,	180.7406,	380.0	!!END!	Boundary Waters
727 ! X =	68.3697,	180.7617,	383.0	!!END!	Boundary Waters
728 ! X =	70.1610,	180.7833,	381.0	!!END!	Boundary Waters
729 ! X =	71.9522,	180.8055,	398.0	!!END!	Boundary Waters
730 ! X =	73.7435,	180.8282,	396.0	!!END!	Boundary Waters
731 ! X =	75.5347,	180.8516,	396.0	!!END!	Boundary Waters
732 ! X =	77.3259,	180.8754,	381.0	!!END!	Boundary Waters
733 ! X =	79.1172,	180.8998,	396.0	!!END!	Boundary Waters
734 ! X =	80.9084,	180.9248,	407.0	!!END!	Boundary Waters
735 ! X =	82.6996,	180.9504,	411.0	!!END!	Boundary Waters
736 ! X =	84.4908,	180.9765,	412.0	!!END!	Boundary Waters
737 ! X =	86.2820,	181.0031,	378.0	!!END!	Boundary Waters
738 ! X =	88.0732,	181.0303,	396.0	!!END!	Boundary Waters
739 ! X =	89.8643,	181.0581,	378.0	!!END!	Boundary Waters
740 ! X =	91.6555,	181.0865,	378.0	!!END!	Boundary Waters
741 ! X =	138.2221,	182.0195,	424.0	!!END!	Boundary Waters
742 ! X =	140.0130,	182.0630,	454.0	!!END!	Boundary Waters
743 ! X =	141.8038,	182.1069,	455.0	!!END!	Boundary Waters
744 ! X =	143.5947,	182.1515,	456.0	!!END!	Boundary Waters
745 ! X =	145.3855,	182.1966,	450.0	!!END!	Boundary Waters
746 ! X =	147.1763,	182.2423,	457.0	!!END!	Boundary Waters

747 ! X =	148.9671,	182.2885,	448.0	!!END!	Boundary Waters
748 ! X =	154.3394,	182.4306,	457.0	!!END!	Boundary Waters
749 ! X =	156.1301,	182.4790,	437.0	!!END!	Boundary Waters
750 ! X =	46.8522,	183.2321,	382.0	!!END!	Boundary Waters
751 ! X =	48.6427,	183.2471,	400.0	!!END!	Boundary Waters
752 ! X =	50.4332,	183.2625,	401.0	!!END!	Boundary Waters
753 ! X =	52.2237,	183.2785,	396.0	!!END!	Boundary Waters
754 ! X =	54.0141,	183.2951,	411.0	!!END!	Boundary Waters
755 ! X =	55.8046,	183.3123,	393.0	!!END!	Boundary Waters
756 ! X =	57.5951,	183.3300,	396.0	!!END!	Boundary Waters
757 ! X =	59.3855,	183.3483,	427.0	!!END!	Boundary Waters
758 ! X =	61.1760,	183.3671,	402.0	!!END!	Boundary Waters
759 ! X =	62.9664,	183.3864,	411.0	!!END!	Boundary Waters
760 ! X =	64.7568,	183.4064,	396.0	!!END!	Boundary Waters
761 ! X =	66.5473,	183.4269,	380.0	!!END!	Boundary Waters
762 ! X =	68.3377,	183.4480,	381.0	!!END!	Boundary Waters
763 ! X =	70.1281,	183.4696,	381.0	!!END!	Boundary Waters
764 ! X =	71.9185,	183.4917,	396.0	!!END!	Boundary Waters
765 ! X =	73.7089,	183.5145,	396.0	!!END!	Boundary Waters
766 ! X =	75.4993,	183.5378,	395.0	!!END!	Boundary Waters
767 ! X =	77.2897,	183.5616,	381.0	!!END!	Boundary Waters
768 ! X =	79.0801,	183.5860,	396.0	!!END!	Boundary Waters
769 ! X =	80.8705,	183.6110,	378.0	!!END!	Boundary Waters
770 ! X =	82.6609,	183.6365,	378.0	!!END!	Boundary Waters
771 ! X =	84.4512,	183.6626,	382.0	!!END!	Boundary Waters
772 ! X =	143.5274,	184.8371,	436.0	!!END!	Boundary Waters
773 ! X =	145.3174,	184.8822,	479.0	!!END!	Boundary Waters
774 ! X =	147.1074,	184.9279,	436.0	!!END!	Boundary Waters
775 ! X =	148.8973,	184.9741,	436.0	!!END!	Boundary Waters
776 ! X =	150.6873,	185.0208,	442.0	!!END!	Boundary Waters
777 ! X =	152.4772,	185.0682,	452.0	!!END!	Boundary Waters
778 ! X =	154.2671,	185.1160,	442.0	!!END!	Boundary Waters
779 ! X =	41.4613,	185.8773,	420.0	!!END!	Boundary Waters
780 ! X =	43.2509,	185.8906,	381.0	!!END!	Boundary Waters
781 ! X =	46.8303,	185.9187,	351.0	!!END!	Boundary Waters
782 ! X =	48.6199,	185.9336,	389.0	!!END!	Boundary Waters
783 ! X =	50.4096,	185.9491,	365.0	!!END!	Boundary Waters

784 ! X =	52.1992,	185.9651,	365.0	!!END!	Boundary Waters
785 ! X =	53.9888,	185.9816,	408.0	!!END!	Boundary Waters
786 ! X =	55.7785,	185.9988,	396.0	!!END!	Boundary Waters
787 ! X =	57.5681,	186.0165,	411.0	!!END!	Boundary Waters
788 ! X =	59.3577,	186.0347,	411.0	!!END!	Boundary Waters
789 ! X =	61.1473,	186.0535,	402.0	!!END!	Boundary Waters
790 ! X =	62.9369,	186.0729,	396.0	!!END!	Boundary Waters
791 ! X =	64.7265,	186.0928,	387.0	!!END!	Boundary Waters
792 ! X =	66.5161,	186.1133,	411.0	!!END!	Boundary Waters
793 ! X =	68.3057,	186.1344,	365.0	!!END!	Boundary Waters
794 ! X =	70.0953,	186.1560,	366.0	!!END!	Boundary Waters
795 ! X =	71.8848,	186.1781,	395.0	!!END!	Boundary Waters
796 ! X =	73.6744,	186.2009,	374.0	!!END!	Boundary Waters
797 ! X =	75.4640,	186.2242,	372.0	!!END!	Boundary Waters
798 ! X =	77.2535,	186.2480,	372.0	!!END!	Boundary Waters
799 ! X =	79.0431,	186.2724,	378.0	!!END!	Boundary Waters
800 ! X =	148.8276,	187.6598,	436.0	!!END!	Boundary Waters
801 ! X =	150.6167,	187.7065,	436.0	!!END!	Boundary Waters
802 ! X =	152.4058,	187.7538,	436.0	!!END!	Boundary Waters
803 ! X =	154.1948,	187.8017,	443.0	!!END!	Boundary Waters
804 ! X =	41.4418,	188.5641,	396.0	!!END!	Boundary Waters
805 ! X =	43.2307,	188.5773,	350.0	!!END!	Boundary Waters
806 ! X =	52.1747,	188.6517,	354.0	!!END!	Boundary Waters
807 ! X =	53.9635,	188.6683,	354.0	!!END!	Boundary Waters
808 ! X =	55.7523,	188.6855,	380.0	!!END!	Boundary Waters
809 ! X =	57.5411,	188.7031,	412.0	!!END!	Boundary Waters
810 ! X =	59.3299,	188.7214,	411.0	!!END!	Boundary Waters
811 ! X =	61.1186,	188.7402,	411.0	!!END!	Boundary Waters
812 ! X =	62.9074,	188.7596,	399.0	!!END!	Boundary Waters
813 ! X =	64.6962,	188.7795,	396.0	!!END!	Boundary Waters
814 ! X =	66.4849,	188.7999,	415.0	!!END!	Boundary Waters
815 ! X =	68.2737,	188.8210,	396.0	!!END!	Boundary Waters
816 ! X =	70.0624,	188.8426,	362.0	!!END!	Boundary Waters
817 ! X =	71.8512,	188.8647,	363.0	!!END!	Boundary Waters
818 ! X =	41.4224,	191.2507,	351.0	!!END!	Boundary Waters
819 ! X =	52.1503,	191.3383,	411.0	!!END!	Boundary Waters
820 ! X =	53.9382,	191.3549,	396.0	!!END!	Boundary Waters

821 ! X =	55.7262,	191.3720,	426.0	!!END!	Boundary Waters
822 ! X =	57.5141,	191.3897,	396.0	!!END!	Boundary Waters
823 ! X =	59.3020,	191.4079,	396.0	!!END!	Boundary Waters
824 ! X =	61.0900,	191.4267,	411.0	!!END!	Boundary Waters
825 ! X =	62.8779,	191.4460,	372.0	!!END!	Boundary Waters
826 ! X =	64.6658,	191.4660,	396.0	!!END!	Boundary Waters
827 ! X =	66.4538,	191.4864,	363.0	!!END!	Boundary Waters
828 ! X =	68.2417,	191.5074,	366.0	!!END!	Boundary Waters
829 ! X =	70.0296,	191.5290,	361.0	!!END!	Boundary Waters
830 ! X =	50.3387,	194.0090,	357.0	!!END!	Boundary Waters
831 ! X =	52.1258,	194.0250,	386.0	!!END!	Boundary Waters
832 ! X =	53.9129,	194.0416,	411.0	!!END!	Boundary Waters
833 ! X =	55.7000,	194.0587,	396.0	!!END!	Boundary Waters
834 ! X =	57.4871,	194.0764,	408.0	!!END!	Boundary Waters
835 ! X =	59.2742,	194.0946,	393.0	!!END!	Boundary Waters
836 ! X =	61.0613,	194.1134,	381.0	!!END!	Boundary Waters
837 ! X =	62.8484,	194.1327,	396.0	!!END!	Boundary Waters
838 ! X =	64.6355,	194.1526,	362.0	!!END!	Boundary Waters
839 ! X =	66.4226,	194.1731,	371.0	!!END!	Boundary Waters
840 ! X =	68.2096,	194.1941,	360.0	!!END!	Boundary Waters
841 ! X =	69.9967,	194.2157,	361.0	!!END!	Boundary Waters
842 ! X =	52.1013,	196.7116,	361.0	!!END!	Boundary Waters
843 ! X =	53.8876,	196.7282,	381.0	!!END!	Boundary Waters
844 ! X =	55.6739,	196.7453,	390.0	!!END!	Boundary Waters
845 ! X =	57.4601,	196.7629,	396.0	!!END!	Boundary Waters
846 ! X =	59.2464,	196.7811,	397.0	!!END!	Boundary Waters
847 ! X =	61.0327,	196.7999,	397.0	!!END!	Boundary Waters
848 ! X =	62.8189,	196.8193,	392.0	!!END!	Boundary Waters
849 ! X =	64.6052,	196.8392,	360.0	!!END!	Boundary Waters
850 ! X =	66.3914,	196.8596,	365.0	!!END!	Boundary Waters
851 ! X =	68.1776,	196.8806,	360.0	!!END!	Boundary Waters
852 ! X =	59.2186,	199.4679,	360.0	!!END!	Boundary Waters
853 ! X =	61.0040,	199.4866,	360.0	!!END!	Boundary Waters
854 ! X =	62.7894,	199.5060,	360.0	!!END!	Boundary Waters
855 ! X =	64.5748,	199.5259,	360.0	!!END!	Boundary Waters
856 ! X =	66.3602,	199.5463,	366.0	!!END!	Boundary Waters
857 ! X =	34.8392,	195.6850,	353.0	!!END!	Voyageurs

858	! X =	36.0302,	195.6924,	351.0	!!END!	Voyageurs
859	! X =	37.2213,	195.7000,	353.0	!!END!	Voyageurs
860	! X =	30.0655,	197.4492,	376.0	!!END!	Voyageurs
861	! X =	31.2562,	197.4556,	379.0	!!END!	Voyageurs
862	! X =	32.4469,	197.4622,	351.0	!!END!	Voyageurs
863	! X =	33.6376,	197.4691,	351.0	!!END!	Voyageurs
864	! X =	34.8283,	197.4762,	373.0	!!END!	Voyageurs
865	! X =	36.0190,	197.4836,	347.0	!!END!	Voyageurs
866	! X =	37.2097,	197.4912,	354.0	!!END!	Voyageurs
867	! X =	38.4003,	197.4991,	341.0	!!END!	Voyageurs
868	! X =	30.0561,	199.2402,	381.0	!!END!	Voyageurs
869	! X =	31.2464,	199.2466,	351.0	!!END!	Voyageurs
870	! X =	32.4367,	199.2533,	351.0	!!END!	Voyageurs
871	! X =	33.6270,	199.2601,	351.0	!!END!	Voyageurs
872	! X =	34.8174,	199.2673,	374.0	!!END!	Voyageurs
873	! X =	36.0077,	199.2746,	365.0	!!END!	Voyageurs
874	! X =	37.1980,	199.2822,	347.0	!!END!	Voyageurs
875	! X =	27.6667,	201.0195,	366.0	!!END!	Voyageurs
876	! X =	28.8567,	201.0254,	385.0	!!END!	Voyageurs
877	! X =	30.0467,	201.0315,	373.0	!!END!	Voyageurs
878	! X =	31.2366,	201.0379,	379.0	!!END!	Voyageurs
879	! X =	32.4266,	201.0446,	344.0	!!END!	Voyageurs
880	! X =	33.6165,	201.0514,	373.0	!!END!	Voyageurs
881	! X =	34.8065,	201.0585,	356.0	!!END!	Voyageurs
882	! X =	35.9964,	201.0659,	341.0	!!END!	Voyageurs
883	! X =	37.1864,	201.0735,	341.0	!!END!	Voyageurs
884	! X =	20.5205,	202.7806,	366.0	!!END!	Voyageurs
885	! X =	21.7101,	202.7850,	388.0	!!END!	Voyageurs
886	! X =	22.8997,	202.7897,	351.0	!!END!	Voyageurs
887	! X =	24.0893,	202.7946,	351.0	!!END!	Voyageurs
888	! X =	25.2789,	202.7997,	396.0	!!END!	Voyageurs
889	! X =	26.4685,	202.8051,	381.0	!!END!	Voyageurs
890	! X =	27.6581,	202.8107,	387.0	!!END!	Voyageurs
891	! X =	28.8477,	202.8166,	381.0	!!END!	Voyageurs
892	! X =	30.0372,	202.8227,	381.0	!!END!	Voyageurs
893	! X =	31.2268,	202.8291,	373.0	!!END!	Voyageurs
894	! X =	32.4164,	202.8357,	358.0	!!END!	Voyageurs

895 ! X =	33.6060,	202.8426,	341.0	!!END!	Voyageurs
896 ! X =	34.7956,	202.8497,	369.0	!!END!	Voyageurs
897 ! X =	35.9851,	202.8571,	352.0	!!END!	Voyageurs
898 ! X =	37.1747,	202.8647,	341.0	!!END!	Voyageurs
899 ! X =	3.8650,	204.5366,	350.0	!!END!	Voyageurs
900 ! X =	5.0542,	204.5375,	350.0	!!END!	Voyageurs
901 ! X =	6.2434,	204.5387,	372.0	!!END!	Voyageurs
902 ! X =	15.7572,	204.5570,	402.0	!!END!	Voyageurs
903 ! X =	16.9464,	204.5604,	366.0	!!END!	Voyageurs
904 ! X =	18.1357,	204.5640,	365.0	!!END!	Voyageurs
905 ! X =	20.5141,	204.5721,	366.0	!!END!	Voyageurs
906 ! X =	21.7033,	204.5765,	367.0	!!END!	Voyageurs
907 ! X =	22.8925,	204.5811,	357.0	!!END!	Voyageurs
908 ! X =	24.0818,	204.5860,	366.0	!!END!	Voyageurs
909 ! X =	25.2710,	204.5911,	370.0	!!END!	Voyageurs
910 ! X =	26.4602,	204.5965,	366.0	!!END!	Voyageurs
911 ! X =	27.6494,	204.6022,	364.0	!!END!	Voyageurs
912 ! X =	28.8386,	204.6080,	366.0	!!END!	Voyageurs
913 ! X =	30.0278,	204.6142,	362.0	!!END!	Voyageurs
914 ! X =	31.2170,	204.6205,	360.0	!!END!	Voyageurs
915 ! X =	32.4062,	204.6272,	389.0	!!END!	Voyageurs
916 ! X =	33.5954,	204.6340,	379.0	!!END!	Voyageurs
917 ! X =	34.7846,	204.6411,	362.0	!!END!	Voyageurs
918 ! X =	35.9739,	204.6485,	347.0	!!END!	Voyageurs
919 ! X =	37.1631,	204.6561,	350.0	!!END!	Voyageurs
920 ! X =	38.3523,	204.6640,	341.0	!!END!	Voyageurs
921 ! X =	0.2972,	206.3266,	348.0	!!END!	Voyageurs
922 ! X =	1.4861,	206.3268,	350.0	!!END!	Voyageurs
923 ! X =	2.6749,	206.3272,	353.0	!!END!	Voyageurs
924 ! X =	3.8638,	206.3279,	350.0	!!END!	Voyageurs
925 ! X =	5.0526,	206.3288,	350.0	!!END!	Voyageurs
926 ! X =	6.2415,	206.3300,	373.0	!!END!	Voyageurs
927 ! X =	7.4303,	206.3314,	396.0	!!END!	Voyageurs
928 ! X =	8.6192,	206.3331,	375.0	!!END!	Voyageurs
929 ! X =	9.8080,	206.3350,	362.0	!!END!	Voyageurs
930 ! X =	10.9969,	206.3372,	352.0	!!END!	Voyageurs
931 ! X =	12.1857,	206.3396,	358.0	!!END!	Voyageurs

932 ! X =	13.3746,	206.3423,	352.0	!!END!	Voyageurs
933 ! X =	14.5634,	206.3452,	344.0	!!END!	Voyageurs
934 ! X =	15.7523,	206.3483,	370.0	!!END!	Voyageurs
935 ! X =	16.9411,	206.3517,	363.0	!!END!	Voyageurs
936 ! X =	18.1300,	206.3554,	341.0	!!END!	Voyageurs
937 ! X =	19.3188,	206.3593,	368.0	!!END!	Voyageurs
938 ! X =	20.5077,	206.3634,	351.0	!!END!	Voyageurs
939 ! X =	21.6965,	206.3678,	341.0	!!END!	Voyageurs
940 ! X =	22.8854,	206.3725,	351.0	!!END!	Voyageurs
941 ! X =	24.0742,	206.3773,	356.0	!!END!	Voyageurs
942 ! X =	25.2630,	206.3825,	377.0	!!END!	Voyageurs
943 ! X =	26.4519,	206.3878,	369.0	!!END!	Voyageurs
944 ! X =	27.6407,	206.3935,	353.0	!!END!	Voyageurs
945 ! X =	28.8296,	206.3994,	353.0	!!END!	Voyageurs
946 ! X =	30.0184,	206.4055,	345.0	!!END!	Voyageurs
947 ! X =	31.2072,	206.4118,	351.0	!!END!	Voyageurs
948 ! X =	32.3961,	206.4185,	367.0	!!END!	Voyageurs
949 ! X =	33.5849,	206.4253,	354.0	!!END!	Voyageurs
950 ! X =	34.7737,	206.4325,	346.0	!!END!	Voyageurs
951 ! X =	35.9626,	206.4398,	346.0	!!END!	Voyageurs
952 ! X =	37.1514,	206.4474,	341.0	!!END!	Voyageurs
953 ! X =	0.2971,	208.1182,	341.0	!!END!	Voyageurs
954 ! X =	1.4856,	208.1184,	341.0	!!END!	Voyageurs
955 ! X =	2.6741,	208.1188,	341.0	!!END!	Voyageurs
956 ! X =	3.8626,	208.1195,	341.0	!!END!	Voyageurs
957 ! X =	5.0510,	208.1204,	346.0	!!END!	Voyageurs
958 ! X =	6.2395,	208.1216,	341.0	!!END!	Voyageurs
959 ! X =	7.4280,	208.1230,	346.0	!!END!	Voyageurs
960 ! X =	8.6165,	208.1247,	341.0	!!END!	Voyageurs
961 ! X =	9.8050,	208.1266,	341.0	!!END!	Voyageurs
962 ! X =	10.9934,	208.1288,	341.0	!!END!	Voyageurs
963 ! X =	12.1819,	208.1312,	341.0	!!END!	Voyageurs
964 ! X =	13.3704,	208.1338,	341.0	!!END!	Voyageurs
965 ! X =	14.5589,	208.1367,	351.0	!!END!	Voyageurs
966 ! X =	15.7473,	208.1399,	341.0	!!END!	Voyageurs
967 ! X =	16.9358,	208.1433,	341.0	!!END!	Voyageurs
968 ! X =	18.1243,	208.1469,	344.0	!!END!	Voyageurs

969 ! X =	19.3128,	208.1508,	341.0	!!END!	Voyageurs
970 ! X =	20.5012,	208.1550,	341.0	!!END!	Voyageurs
971 ! X =	21.6897,	208.1594,	341.0	!!END!	Voyageurs
972 ! X =	22.8782,	208.1640,	341.0	!!END!	Voyageurs
973 ! X =	24.0667,	208.1689,	341.0	!!END!	Voyageurs
974 ! X =	26.4436,	208.1794,	341.0	!!END!	Voyageurs
975 ! X =	27.6321,	208.1850,	341.0	!!END!	Voyageurs
976 ! X =	28.8205,	208.1909,	341.0	!!END!	Voyageurs
977 ! X =	30.0090,	208.1970,	341.0	!!END!	Voyageurs
978 ! X =	31.1975,	208.2034,	341.0	!!END!	Voyageurs
979 ! X =	32.3859,	208.2100,	341.0	!!END!	Voyageurs
980 ! X =	33.5744,	208.2169,	341.0	!!END!	Voyageurs
981 ! X =	34.7628,	208.2240,	344.0	!!END!	Voyageurs
982 ! X =	-4.4554,	209.9111,	347.0	!!END!	Voyageurs
983 ! X =	-3.2673,	209.9103,	341.0	!!END!	Voyageurs
984 ! X =	-2.0792,	209.9097,	341.0	!!END!	Voyageurs
985 ! X =	-0.8911,	209.9094,	341.0	!!END!	Voyageurs
986 ! X =	0.2970,	209.9093,	341.0	!!END!	Voyageurs
987 ! X =	1.4851,	209.9095,	347.0	!!END!	Voyageurs
988 ! X =	2.6732,	209.9099,	341.0	!!END!	Voyageurs
989 ! X =	3.8613,	209.9106,	341.0	!!END!	Voyageurs
990 ! X =	5.0495,	209.9116,	341.0	!!END!	Voyageurs
991 ! X =	6.2376,	209.9127,	341.0	!!END!	Voyageurs
992 ! X =	7.4257,	209.9142,	341.0	!!END!	Voyageurs
993 ! X =	8.6138,	209.9158,	343.0	!!END!	Voyageurs
994 ! X =	9.8019,	209.9177,	341.0	!!END!	Voyageurs
995 ! X =	10.9900,	209.9199,	381.0	!!END!	Voyageurs
996 ! X =	12.1781,	209.9223,	365.0	!!END!	Voyageurs
997 ! X =	13.3662,	209.9250,	365.0	!!END!	Voyageurs
998 ! X =	14.5543,	209.9279,	365.0	!!END!	Voyageurs
999 ! X =	15.7424,	209.9310,	349.0	!!END!	Voyageurs
1000 ! X =	16.9305,	209.9344,	346.0	!!END!	Voyageurs
1001 ! X =	18.1186,	209.9381,	341.0	!!END!	Voyageurs
1002 ! X =	19.3067,	209.9420,	341.0	!!END!	Voyageurs
1003 ! X =	20.4948,	209.9461,	341.0	!!END!	Voyageurs
1004 ! X =	-5.6417,	211.7038,	351.0	!!END!	Voyageurs
1005 ! X =	-4.4540,	211.7028,	341.0	!!END!	Voyageurs

1006 ! X =	-3.2663,	211.7020,	341.0	!!END!	Voyageurs
1007 ! X =	-2.0785,	211.7014,	341.0	!!END!	Voyageurs
1008 ! X =	-0.8908,	211.7011,	341.0	!!END!	Voyageurs
1009 ! X =	0.2969,	211.7010,	341.0	!!END!	Voyageurs
1010 ! X =	1.4847,	211.7012,	353.0	!!END!	Voyageurs
1011 ! X =	2.6724,	211.7016,	349.0	!!END!	Voyageurs
1012 ! X =	3.8601,	211.7023,	361.0	!!END!	Voyageurs
1013 ! X =	5.0479,	211.7032,	365.0	!!END!	Voyageurs
1014 ! X =	6.2356,	211.7044,	366.0	!!END!	Voyageurs
1015 ! X =	7.4233,	211.7058,	365.0	!!END!	Voyageurs
1016 ! X =	8.6111,	211.7075,	381.0	!!END!	Voyageurs
1017 ! X =	9.7988,	211.7094,	381.0	!!END!	Voyageurs
1018 ! X =	10.9865,	211.7116,	353.0	!!END!	Voyageurs
1019 ! X =	12.1743,	211.7140,	350.0	!!END!	Voyageurs
1020 ! X =	13.3620,	211.7167,	356.0	!!END!	Voyageurs
1021 ! X =	14.5497,	211.7196,	365.0	!!END!	Voyageurs
1022 ! X =	15.7375,	211.7227,	370.0	!!END!	Voyageurs
1023 ! X =	16.9252,	211.7261,	364.0	!!END!	Voyageurs
1024 ! X =	18.1129,	211.7298,	351.0	!!END!	Voyageurs
1025 ! X =	19.3007,	211.7337,	341.0	!!END!	Voyageurs
1026 ! X =	20.4884,	211.7378,	341.0	!!END!	Voyageurs
1027 ! X =	-10.3894,	213.5018,	347.0	!!END!	Voyageurs
1028 ! X =	-9.2020,	213.4997,	347.0	!!END!	Voyageurs
1029 ! X =	-8.0147,	213.4979,	341.0	!!END!	Voyageurs
1030 ! X =	-4.4526,	213.4940,	341.0	!!END!	Voyageurs
1031 ! X =	-3.2652,	213.4932,	341.0	!!END!	Voyageurs
1032 ! X =	-2.0779,	213.4927,	341.0	!!END!	Voyageurs
1033 ! X =	-0.8905,	213.4924,	341.0	!!END!	Voyageurs
1034 ! X =	0.2968,	213.4923,	341.0	!!END!	Voyageurs
1035 ! X =	1.4842,	213.4925,	341.0	!!END!	Voyageurs
1036 ! X =	2.6716,	213.4929,	377.0	!!END!	Voyageurs
1037 ! X =	3.8589,	213.4936,	381.0	!!END!	Voyageurs
1038 ! X =	5.0463,	213.4945,	393.0	!!END!	Voyageurs
1039 ! X =	6.2336,	213.4957,	381.0	!!END!	Voyageurs
1040 ! X =	7.4210,	213.4971,	396.0	!!END!	Voyageurs
1041 ! X =	8.6084,	213.4988,	366.0	!!END!	Voyageurs
1042 ! X =	9.7957,	213.5007,	378.0	!!END!	Voyageurs

1043 ! X =	10.9831,	213.5029,	380.0	!!END!	Voyageurs
1044 ! X =	12.1705,	213.5053,	390.0	!!END!	Voyageurs
1045 ! X =	13.3578,	213.5079,	398.0	!!END!	Voyageurs
1046 ! X =	14.5452,	213.5108,	396.0	!!END!	Voyageurs
1047 ! X =	15.7325,	213.5140,	396.0	!!END!	Voyageurs
1048 ! X =	16.9199,	213.5174,	377.0	!!END!	Voyageurs
1049 ! X =	18.1072,	213.5210,	374.0	!!END!	Voyageurs
1050 ! X =	19.2946,	213.5249,	366.0	!!END!	Voyageurs
1051 ! X =	20.4819,	213.5291,	361.0	!!END!	Voyageurs
1052 ! X =	-10.3861,	215.2933,	350.0	!!END!	Voyageurs
1053 ! X =	-9.1992,	215.2912,	349.0	!!END!	Voyageurs
1054 ! X =	-8.0122,	215.2894,	344.0	!!END!	Voyageurs
1055 ! X =	-6.8252,	215.2879,	341.0	!!END!	Voyageurs
1056 ! X =	-5.6382,	215.2866,	341.0	!!END!	Voyageurs
1057 ! X =	-4.4512,	215.2855,	341.0	!!END!	Voyageurs
1058 ! X =	-3.2642,	215.2847,	341.0	!!END!	Voyageurs
1059 ! X =	-2.0772,	215.2842,	341.0	!!END!	Voyageurs
1060 ! X =	-0.8902,	215.2839,	341.0	!!END!	Voyageurs
1061 ! X =	0.2967,	215.2838,	361.0	!!END!	Voyageurs
1062 ! X =	1.4837,	215.2840,	381.0	!!END!	Voyageurs
1063 ! X =	2.6707,	215.2844,	366.0	!!END!	Voyageurs
1064 ! X =	3.8577,	215.2851,	365.0	!!END!	Voyageurs
1065 ! X =	5.0447,	215.2860,	366.0	!!END!	Voyageurs
1066 ! X =	6.2317,	215.2872,	366.0	!!END!	Voyageurs
1067 ! X =	7.4187,	215.2886,	360.0	!!END!	Voyageurs
1068 ! X =	8.6057,	215.2903,	360.0	!!END!	Voyageurs
1069 ! X =	9.7927,	215.2922,	359.0	!!END!	Voyageurs
1070 ! X =	10.9796,	215.2944,	365.0	!!END!	Voyageurs
1071 ! X =	12.1666,	215.2968,	381.0	!!END!	Voyageurs
1072 ! X =	13.3536,	215.2994,	381.0	!!END!	Voyageurs
1073 ! X =	14.5406,	215.3023,	387.0	!!END!	Voyageurs
1074 ! X =	15.7276,	215.3055,	394.0	!!END!	Voyageurs
1075 ! X =	16.9146,	215.3089,	381.0	!!END!	Voyageurs
1076 ! X =	18.1016,	215.3125,	381.0	!!END!	Voyageurs
1077 ! X =	19.2885,	215.3164,	347.0	!!END!	Voyageurs
1078 ! X =	20.4755,	215.3206,	356.0	!!END!	Voyageurs
1079 ! X =	21.6625,	215.3250,	366.0	!!END!	Voyageurs

1080 ! X =	22.8495,	215.3296,	369.0	!!END!	Voyageurs
1081 ! X =	24.0365,	215.3345,	366.0	!!END!	Voyageurs
1082 ! X =	25.2234,	215.3396,	338.0	!!END!	Voyageurs
1083 ! X =	26.4104,	215.3450,	338.0	!!END!	Voyageurs
1084 ! X =	-6.8230,	217.0793,	350.0	!!END!	Voyageurs
1085 ! X =	-5.6364,	217.0780,	342.0	!!END!	Voyageurs
1086 ! X =	-4.4498,	217.0769,	341.0	!!END!	Voyageurs
1087 ! X =	-3.2632,	217.0761,	341.0	!!END!	Voyageurs
1088 ! X =	-2.0766,	217.0756,	350.0	!!END!	Voyageurs
1089 ! X =	-0.8900,	217.0753,	369.0	!!END!	Voyageurs
1090 ! X =	0.2967,	217.0752,	364.0	!!END!	Voyageurs
1091 ! X =	1.4833,	217.0754,	366.0	!!END!	Voyageurs
1092 ! X =	2.6699,	217.0758,	395.0	!!END!	Voyageurs
1093 ! X =	3.8565,	217.0765,	407.0	!!END!	Voyageurs
1094 ! X =	5.0431,	217.0774,	396.0	!!END!	Voyageurs
1095 ! X =	6.2297,	217.0786,	366.0	!!END!	Voyageurs
1096 ! X =	7.4163,	217.0800,	391.0	!!END!	Voyageurs
1097 ! X =	8.6030,	217.0817,	354.0	!!END!	Voyageurs
1098 ! X =	9.7896,	217.0836,	358.0	!!END!	Voyageurs
1099 ! X =	10.9762,	217.0858,	351.0	!!END!	Voyageurs
1100 ! X =	12.1628,	217.0882,	367.0	!!END!	Voyageurs
1101 ! X =	13.3494,	217.0908,	354.0	!!END!	Voyageurs
1102 ! X =	14.5360,	217.0937,	364.0	!!END!	Voyageurs
1103 ! X =	15.7226,	217.0969,	351.0	!!END!	Voyageurs
1104 ! X =	16.9093,	217.1003,	365.0	!!END!	Voyageurs
1105 ! X =	18.0959,	217.1039,	381.0	!!END!	Voyageurs
1106 ! X =	19.2825,	217.1078,	371.0	!!END!	Voyageurs
1107 ! X =	20.4691,	217.1120,	367.0	!!END!	Voyageurs
1108 ! X =	21.6557,	217.1163,	381.0	!!END!	Voyageurs
1109 ! X =	22.8423,	217.1210,	366.0	!!END!	Voyageurs
1110 ! X =	24.0289,	217.1258,	351.0	!!END!	Voyageurs
1111 ! X =	25.2155,	217.1310,	338.0	!!END!	Voyageurs
1112 ! X =	26.4021,	217.1363,	338.0	!!END!	Voyageurs
1113 ! X =	-5.6347,	218.8696,	350.0	!!END!	Voyageurs
1114 ! X =	-4.4484,	218.8686,	350.0	!!END!	Voyageurs
1115 ! X =	-3.2622,	218.8678,	365.0	!!END!	Voyageurs
1116 ! X =	-2.0759,	218.8672,	366.0	!!END!	Voyageurs

1117 ! X =	-0.8897,	218.8669,	366.0	!!END!	Voyageurs
1118 ! X =	0.2966,	218.8668,	365.0	!!END!	Voyageurs
1119 ! X =	1.4828,	218.8670,	366.0	!!END!	Voyageurs
1120 ! X =	2.6690,	218.8675,	368.0	!!END!	Voyageurs
1121 ! X =	3.8553,	218.8681,	381.0	!!END!	Voyageurs
1122 ! X =	5.0415,	218.8691,	366.0	!!END!	Voyageurs
1123 ! X =	6.2278,	218.8702,	368.0	!!END!	Voyageurs
1124 ! X =	7.4140,	218.8717,	380.0	!!END!	Voyageurs
1125 ! X =	8.6003,	218.8733,	349.0	!!END!	Voyageurs
1126 ! X =	9.7865,	218.8752,	348.0	!!END!	Voyageurs
1127 ! X =	10.9727,	218.8774,	341.0	!!END!	Voyageurs
1128 ! X =	12.1590,	218.8798,	338.0	!!END!	Voyageurs
1129 ! X =	13.3452,	218.8825,	338.0	!!END!	Voyageurs
1130 ! X =	14.5315,	218.8854,	338.0	!!END!	Voyageurs
1131 ! X =	15.7177,	218.8885,	338.0	!!END!	Voyageurs
1132 ! X =	16.9039,	218.8919,	338.0	!!END!	Voyageurs
1133 ! X =	18.0902,	218.8955,	338.0	!!END!	Voyageurs
1134 ! X =	19.2764,	218.8994,	338.0	!!END!	Voyageurs
1135 ! X =	20.4626,	218.9036,	338.0	!!END!	Voyageurs
1136 ! X =	21.6489,	218.9080,	338.0	!!END!	Voyageurs
1137 ! X =	22.8351,	218.9126,	338.0	!!END!	Voyageurs
1138 ! X =	24.0213,	218.9175,	338.0	!!END!	Voyageurs
1139 ! X =	25.2076,	218.9226,	338.0	!!END!	Voyageurs
1140 ! X =	-5.6329,	220.6611,	343.0	!!END!	Voyageurs
1141 ! X =	-4.4470,	220.6601,	347.0	!!END!	Voyageurs
1142 ! X =	-3.2611,	220.6593,	366.0	!!END!	Voyageurs
1143 ! X =	-2.0753,	220.6587,	381.0	!!END!	Voyageurs
1144 ! X =	-0.8894,	220.6584,	351.0	!!END!	Voyageurs
1145 ! X =	0.2965,	220.6584,	373.0	!!END!	Voyageurs
1146 ! X =	1.4823,	220.6586,	367.0	!!END!	Voyageurs
1147 ! X =	2.6682,	220.6590,	358.0	!!END!	Voyageurs
1148 ! X =	3.8541,	220.6597,	351.0	!!END!	Voyageurs
1149 ! X =	5.0399,	220.6606,	365.0	!!END!	Voyageurs
1150 ! X =	6.2258,	220.6618,	345.0	!!END!	Voyageurs
1151 ! X =	7.4117,	220.6632,	338.0	!!END!	Voyageurs
1152 ! X =	8.5976,	220.6649,	338.0	!!END!	Voyageurs
1153 ! X =	9.7834,	220.6668,	338.0	!!END!	Voyageurs

1154 ! X =	10.9693,	220.6689,	338.0	!!END!	Voyageurs
1155 ! X =	12.1552,	220.6713,	338.0	!!END!	Voyageurs
1156 ! X =	13.3410,	220.6740,	338.0	!!END!	Voyageurs
1157 ! X =	14.5269,	220.6769,	338.0	!!END!	Voyageurs
1158 ! X =	15.7128,	220.6800,	338.0	!!END!	Voyageurs
1159 ! X =	-9.1876,	222.4575,	339.0	!!END!	Voyageurs
1160 ! X =	-8.0021,	222.4557,	350.0	!!END!	Voyageurs
1161 ! X =	-6.8166,	222.4542,	338.0	!!END!	Voyageurs
1162 ! X =	-5.6311,	222.4529,	345.0	!!END!	Voyageurs
1163 ! X =	-4.4456,	222.4519,	338.0	!!END!	Voyageurs
1164 ! X =	-3.2601,	222.4510,	350.0	!!END!	Voyageurs
1165 ! X =	-2.0746,	222.4505,	365.0	!!END!	Voyageurs
1166 ! X =	-0.8891,	222.4502,	379.0	!!END!	Voyageurs
1167 ! X =	0.2964,	222.4501,	365.0	!!END!	Voyageurs
1168 ! X =	1.4819,	222.4503,	348.0	!!END!	Voyageurs
1169 ! X =	2.6674,	222.4507,	338.0	!!END!	Voyageurs
1170 ! X =	3.8529,	222.4514,	338.0	!!END!	Voyageurs
1171 ! X =	5.0384,	222.4523,	338.0	!!END!	Voyageurs
1172 ! X =	6.2239,	222.4535,	338.0	!!END!	Voyageurs
1173 ! X =	7.4094,	222.4549,	338.0	!!END!	Voyageurs
1174 ! X =	8.5948,	222.4566,	338.0	!!END!	Voyageurs
1175 ! X =	9.7803,	222.4585,	338.0	!!END!	Voyageurs
1176 ! X =	10.9658,	222.4607,	338.0	!!END!	Voyageurs
1177 ! X =	12.1513,	222.4631,	338.0	!!END!	Voyageurs
1178 ! X =	-12.7401,	224.2560,	356.0	!!END!	Voyageurs
1179 ! X =	-11.5550,	224.2535,	338.0	!!END!	Voyageurs
1180 ! X =	-10.3698,	224.2512,	351.0	!!END!	Voyageurs
1181 ! X =	-9.1847,	224.2492,	352.0	!!END!	Voyageurs
1182 ! X =	-7.9996,	224.2474,	352.0	!!END!	Voyageurs
1183 ! X =	-6.8145,	224.2458,	352.0	!!END!	Voyageurs
1184 ! X =	-5.6293,	224.2446,	351.0	!!END!	Voyageurs
1185 ! X =	-4.4442,	224.2435,	339.0	!!END!	Voyageurs
1186 ! X =	-3.2591,	224.2427,	339.0	!!END!	Voyageurs
1187 ! X =	-2.0740,	224.2422,	341.0	!!END!	Voyageurs
1188 ! X =	-0.8888,	224.2419,	340.0	!!END!	Voyageurs
1189 ! X =	0.2963,	224.2418,	351.0	!!END!	Voyageurs
1190 ! X =	1.4814,	224.2420,	348.0	!!END!	Voyageurs

1191 ! X =	2.6665,	224.2424,	347.0	!!END!	Voyageurs
1192 ! X =	3.8517,	224.2431,	340.0	!!END!	Voyageurs
1193 ! X =	5.0368,	224.2440,	338.0	!!END!	Voyageurs
1194 ! X =	6.2219,	224.2452,	338.0	!!END!	Voyageurs
1195 ! X =	7.4070,	224.2466,	338.0	!!END!	Voyageurs
1196 ! X =	8.5921,	224.2483,	338.0	!!END!	Voyageurs
1197 ! X =	-10.3666,	226.0428,	338.0	!!END!	Voyageurs
1198 ! X =	-9.1818,	226.0407,	338.0	!!END!	Voyageurs
1199 ! X =	-7.9971,	226.0390,	338.0	!!END!	Voyageurs
1200 ! X =	-6.8123,	226.0374,	338.0	!!END!	Voyageurs
1201 ! X =	-5.6276,	226.0361,	338.0	!!END!	Voyageurs
1202 ! X =	-4.4428,	226.0351,	338.0	!!END!	Voyageurs
1203 ! X =	-3.2581,	226.0343,	338.0	!!END!	Voyageurs
1204 ! X =	-2.0733,	226.0337,	338.0	!!END!	Voyageurs
1205 ! X =	-0.8886,	226.0334,	338.0	!!END!	Voyageurs
1206 ! X =	0.2962,	226.0333,	338.0	!!END!	Voyageurs
1207 ! X =	1.4809,	226.0335,	338.0	!!END!	Voyageurs
1208 ! X =	2.6657,	226.0340,	339.0	!!END!	Voyageurs
1209 ! X =	3.8504,	226.0346,	338.0	!!END!	Voyageurs
1210 ! X =	5.0352,	226.0356,	338.0	!!END!	Voyageurs
1211 ! X =	-10.3633,	227.8346,	338.0	!!END!	Voyageurs
1212 ! X =	-9.1789,	227.8325,	338.0	!!END!	Voyageurs
1213 ! X =	-7.9946,	227.8307,	338.0	!!END!	Voyageurs
1214 ! X =	-6.8102,	227.8292,	338.0	!!END!	Voyageurs
1215 ! X =	-5.6258,	227.8279,	338.0	!!END!	Voyageurs
1216 ! X =	-4.4414,	227.8269,	338.0	!!END!	Voyageurs
1217 ! X =	-3.2570,	227.8260,	338.0	!!END!	Voyageurs
1218 ! X =	-2.0727,	227.8255,	338.0	!!END!	Voyageurs
1219 ! X =	-0.8883,	227.8252,	338.0	!!END!	Voyageurs
1220 ! X =	0.2961,	227.8251,	338.0	!!END!	Voyageurs
1221 ! X =	1.4805,	227.8253,	338.0	!!END!	Voyageurs
1222 ! X =	2.6649,	227.8257,	338.0	!!END!	Voyageurs
1223 ! X =	123.7310,	-10.78810,	388.0	!!END!	Rainbow Lakes
1224 ! X =	127.4331,	-10.70968,	395.0	!!END!	Rainbow Lakes
1225 ! X =	128.0501,	-10.69639,	389.0	!!END!	Rainbow Lakes
1226 ! X =	123.7123,	-9.893789,	382.0	!!END!	Rainbow Lakes
1227 ! X =	124.3293,	-9.880882,	395.0	!!END!	Rainbow Lakes

1228 ! X =	124.9462,	-9.867910,	396.0	!!END!	Rainbow Lakes
1229 ! X =	125.5631,	-9.854875,	393.0	!!END!	Rainbow Lakes
1230 ! X =	126.1801,	-9.841774,	394.0	!!END!	Rainbow Lakes
1231 ! X =	126.7970,	-9.828610,	385.0	!!END!	Rainbow Lakes
1232 ! X =	127.4139,	-9.815382,	380.0	!!END!	Rainbow Lakes
1233 ! X =	128.0308,	-9.802089,	380.0	!!END!	Rainbow Lakes
1234 ! X =	123.6937,	-8.999110,	396.0	!!END!	Rainbow Lakes
1235 ! X =	124.3105,	-8.986204,	396.0	!!END!	Rainbow Lakes
1236 ! X =	124.9273,	-8.973234,	386.0	!!END!	Rainbow Lakes
1237 ! X =	125.5442,	-8.960200,	378.0	!!END!	Rainbow Lakes
1238 ! X =	126.1610,	-8.947103,	381.0	!!END!	Rainbow Lakes
1239 ! X =	126.7778,	-8.933940,	380.0	!!END!	Rainbow Lakes
1240 ! X =	127.3947,	-8.920713,	374.0	!!END!	Rainbow Lakes
1241 ! X =	123.6750,	-8.104692,	387.0	!!END!	Rainbow Lakes
1242 ! X =	124.2917,	-8.091788,	393.0	!!END!	Rainbow Lakes
1243 ! X =	124.9085,	-8.078821,	395.0	!!END!	Rainbow Lakes
1244 ! X =	125.5252,	-8.065789,	392.0	!!END!	Rainbow Lakes
1245 ! X =	126.1420,	-8.052692,	375.0	!!END!	Rainbow Lakes
1246 ! X =	126.7587,	-8.039533,	366.0	!!END!	Rainbow Lakes
1247 ! X =	127.3754,	-8.026308,	365.0	!!END!	Rainbow Lakes
1248 ! X =	127.9922,	-8.013020,	364.0	!!END!	Rainbow Lakes
1249 ! X =	123.6563,	-7.209905,	395.0	!!END!	Rainbow Lakes
1250 ! X =	124.2730,	-7.197003,	395.0	!!END!	Rainbow Lakes
1251 ! X =	124.8896,	-7.184038,	395.0	!!END!	Rainbow Lakes
1252 ! X =	125.5063,	-7.171008,	403.0	!!END!	Rainbow Lakes
1253 ! X =	126.1229,	-7.157913,	384.0	!!END!	Rainbow Lakes
1254 ! X =	126.7396,	-7.144755,	372.0	!!END!	Rainbow Lakes
1255 ! X =	127.3562,	-7.131533,	365.0	!!END!	Rainbow Lakes
1256 ! X =	127.9729,	-7.118246,	365.0	!!END!	Rainbow Lakes
1257 ! X =	123.6377,	-6.315380,	411.0	!!END!	Rainbow Lakes
1258 ! X =	124.2542,	-6.302481,	386.0	!!END!	Rainbow Lakes
1259 ! X =	124.8708,	-6.289516,	381.0	!!END!	Rainbow Lakes
1260 ! X =	125.4873,	-6.276489,	381.0	!!END!	Rainbow Lakes
1261 ! X =	126.1039,	-6.263396,	359.0	!!END!	Rainbow Lakes
1262 ! X =	126.7204,	-6.250240,	335.0	!!END!	Rainbow Lakes
1263 ! X =	127.3370,	-6.237020,	365.0	!!END!	Rainbow Lakes
1264 ! X =	123.0025,	-5.433951,	393.0	!!END!	Rainbow Lakes

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1265 ! X =     123.6190,   -5.421118,   381.0 !!END!   Rainbow Lakes
1266 ! X =     124.2355,   -5.408220,   380.0 !!END!   Rainbow Lakes
1267 ! X =     124.8519,   -5.395258,   380.0 !!END!   Rainbow Lakes
1268 ! X =     125.4684,   -5.382232,   348.0 !!END!   Rainbow Lakes
1269 ! X =     126.0849,   -5.369142,   350.0 !!END!   Rainbow Lakes
1270 ! X =     126.7013,   -5.355988,   329.0 !!END!   Rainbow Lakes
1271 ! X =     122.9840,   -4.539317,   365.0 !!END!   Rainbow Lakes
1272 ! X =     124.2167,   -4.513590,   335.0 !!END!   Rainbow Lakes
-------------
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a

Data for each receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

b

Receptor height above ground is optional. If no value is entered, the receptor is placed on the ground.

APPENDIX D

AIR DISPERSION MODELING ANALYSIS

MESABA ONE AND MESABA TWO

McVehil-Monnett Associates, Inc.
44 Inverness Dr. E., Bldg. C
Englewood, CO 80112

1.0 MODELING METHODOLOGY D-1
1.1 Model and Options D-1
1.2 Building Downwash D-1
1.3 Meteorological Data D-1
1.4 Receptor Grid D-1
1.5 Mesaba Emissions for Modeling D-4
1.6 Modeling of Storage Pile Wind Erosion D-10
2.0 SIGNIFICANT IMPACT MODELING D-18
3.0 PSD INCREMENT ANALYSIS D-20
4.0 NAAQS COMPLIANCE ANALYSIS D-23
5.0 MESABA ONE AND MESABA TWO PROJECT EMISSIONS FOR CALPUFF D-28
6.0 AIR QUALITY MODEL AND APPLICATION D-31
7.0 INCREMENT ANALYSES D-35
8.0 DEPOSITION OF NITROGEN AND SULFUR D-39
9.0 REGIONAL HAZE ANALYSIS D-41

FIGURES

Figure D-1. Significant Building and Stack Locations D-2
Figure D-2. Modeling Receptor Grid and Terrain Elevations (m) D-3
Figure D-3. Mesaba CALMET Modeling Domain and Class I Areas D-33

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PART I: NEAR-FIELD MODELING ANALYSIS

1.0 MODELING METHODOLOGY

1.1 Model and Options

All near-field modeling was conducted with the AERMOD PRIME air quality model (version 04300). The application used all regulatory default options, including stack tip downwash, elevated terrain effects, calms processing, missing data processing, "upper bound" values for supersquat buildings, and no decay of pollutant concentrations due to chemical transformation, deposition, or wet depletion. Rural dispersion coefficients were used in accord with the prevailing land use at the Mesaba site.

1.2 Building Downwash

Building downwash effects on dispersion from Mesaba One and Mesaba Two stacks were accounted for by use of the EPA PRIME downwash algorithm. The locations of all IGCC Power Station buildings and stacks were digitized based on the two-phase plant layout drawings. These locations and the dimensions of all significant plant structures were entered in the EPA BPIP PRIME model to calculate direction-specific building dimensions and other parameters required as input to the AERMOD model. The layout of the IGCC Power Station buildings and stacks as entered into BPIP PRIME is shown in Figure D-1. Input and output files for BPIP PRIME are included with the permit application on compact disk.

1.3 Meteorological Data

Five years of meteorological data were used for all AERMOD dispersion calculations. The data were prepared and processed using the AERMET program by the Minnesota Pollution Control Agency (MPCA). The meteorological data are based upon Hibbing, Minnesota hourly surface weather observations for the years 1972 through 1976, and were developed specifically for the local area of the IGCC Power Station. The data file (HI475935.ZIP) was provided by Mr. Dennis Becker of the MPCA on July 12, 2005 and is included on the application Modeling Files CD.

1.4 Receptor Grid

The near-field receptor grid was developed following MPCA guidance to provide detailed coverage of the area within which Mesaba One and Mesaba Two will have significant impacts. Receptors consist of nested Cartesian grids covering a 21 km x 21 km area centered on the plant site. Receptors were placed at 10 meter spacing along the proposed plant fence line (which will preclude public access). Successive grids beyond the fence line have receptor spacing of 25 meters, 50, 100, 200, 500 and 1000 meters at increasing distances. The receptor grid, with terrain elevation contours, is shown in Figure D-2.

Figure D-1. Significant Building and Stack Locations

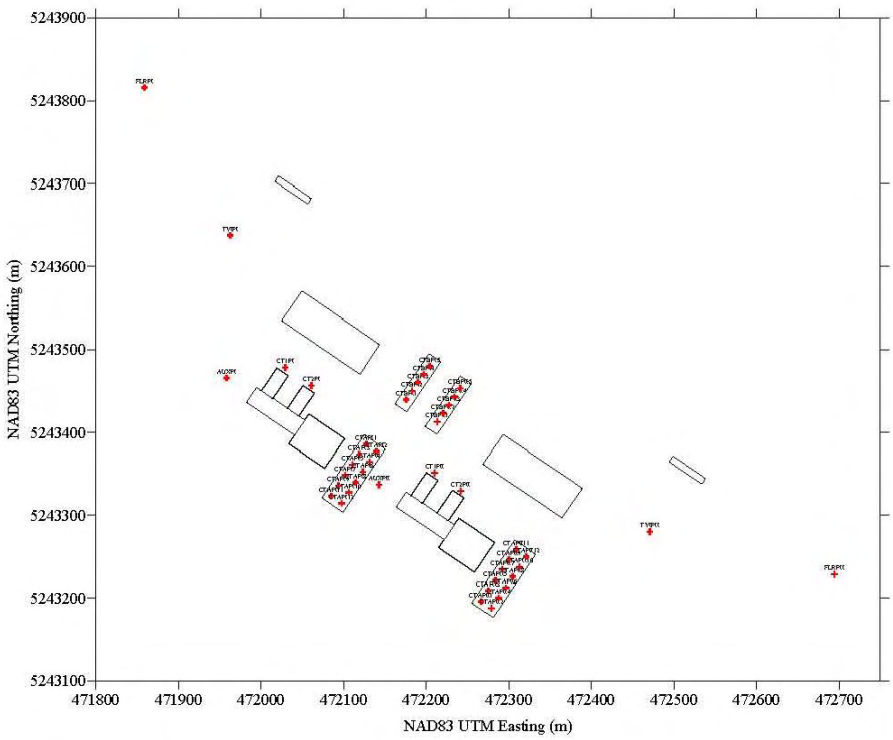
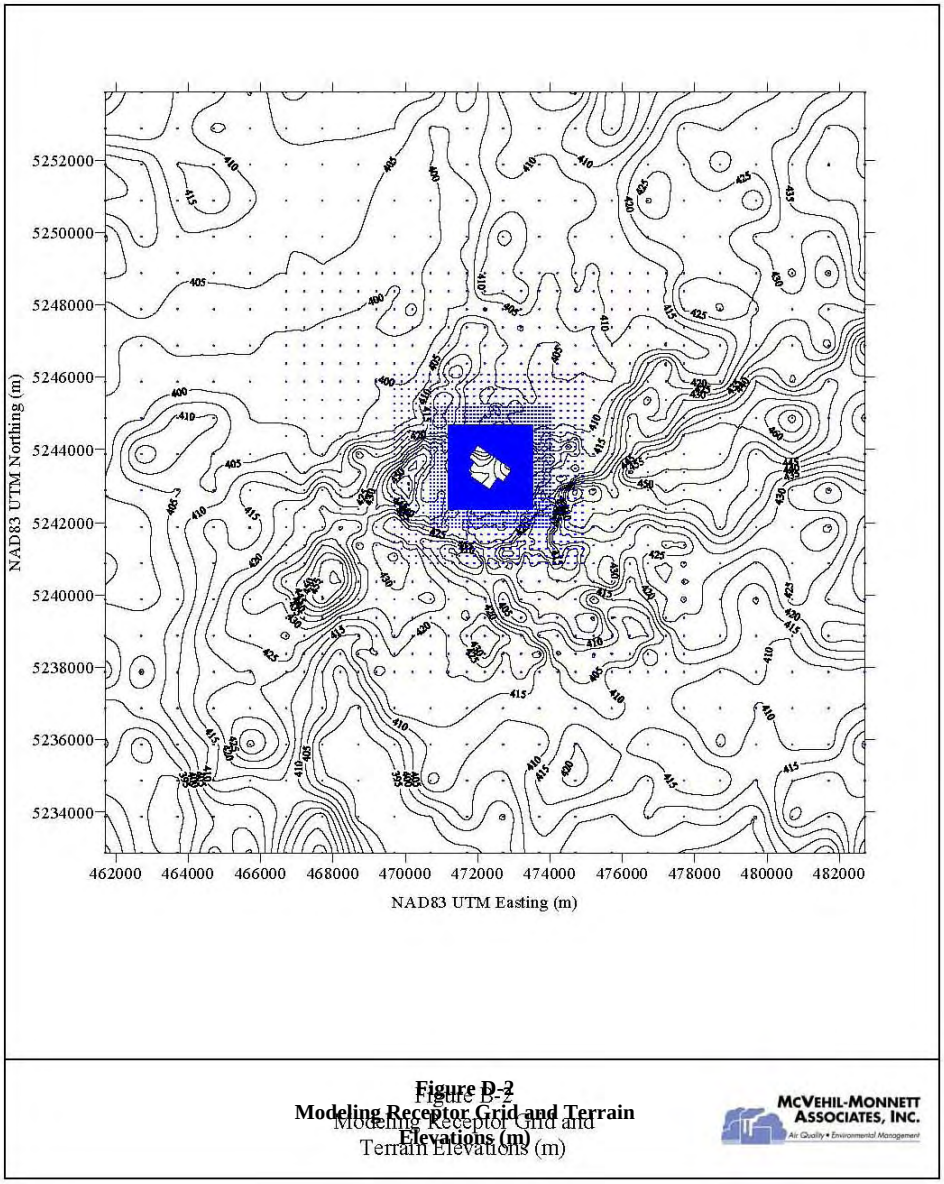


Figure D-1
Significant Building and Stack Locations
For Mesaba Project Phase I and II

Figure D-2. Modeling Receptor Grid and Terrain Elevations (m)



Terrain elevations for all IGCC Power Station sources and buildings were taken from the engineering design plan for the site. Receptor terrain elevations were determined from USGS 7.5 minute DEM data and processed by AERMAP.

Modeling results demonstrated that all maximum impacts of Mesaba One and Mesaba Two occur within approximately one kilometer of the site. Thus all high impacts occur within a dense receptor grid (50 meter or less receptor spacing) and the grid resolution is adequate to define maximum IGCC Power Station impacts.

1.5 Mesaba Emissions for Modeling

Tables B-1 through B-3 present maximum expected emission rates for Mesaba One and Mesaba Two's major point sources for different averaging times and operating scenarios. All emission rates are taken directly from data provided by Excelsior Energy Inc. ("Excelsior"). The emission rates shown, along with the design stack parameters in Table D-4, were used as model input for the air modeling analyses.

The data presented in Table D-1 represent emissions during normal operation of the Mesaba plant. These emission rates were modeled as the "Normal" case to define the expected air quality impacts of the IGCC Power Station.

Emission rates and stack gas conditions for short-term averaging times can be different from those shown in Table D-1 during non-steady-state operating scenarios such as startup and flaring of syngas. To address these short-term conditions, air modeling was also carried out for applicable averaging times (24 hours and less) using the emission rates given in Tables B-2 and B-3. The emission rates represent worst-case maximum emissions for each scenario. The applicable stack parameters for alternate operating scenarios are also shown in Table D-4.

Other sources at Mesaba One and Mesaba Two will consist of two emergency fire pumps (each phase) and two emergency diesel generators (each phase). Since these sources will operate for short time periods, when the primary emission sources will not be in operation, they were not included in the air modeling analyses. Hours of operation will be limited by permit conditions. Their emissions are negligible in comparison to the sources shown in Tables B-1 through B-3.

Cooling towers at Mesaba One and Mesaba Two will emit PM10 as dissolved solids in drift droplets. Each phase of the IGCC Power Station will have one 12-cell and one five-cell cooling tower. Each cell of each tower was included in PM10 modeling as a point source. Stack characteristics were taken directly from engineering design parameters: height = 14.63 m, diameter = 10.06m, exit velocity = 8.14 m/s, and temperature = 313 deg K. Emission rate for PM10 was set equal to 0.0336 g/s for each cell of the 12-cell towers, and 0.0328 g/s per cell for 5-cell towers. These rates correspond to the design drift rate of 0.001 percent and dissolved solids of 2,740 ppm by weight. All cooling towers were assumed to operate for 8,760 hours per year. The cooling towers and emission points are shown on Figure D-1.

Table D-1
Modeling Emission Rates for Normal Operation[1] – One Phase

Source/Averaging Time	SO_2		CO		PM10[2]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour	183	23.06	95	11.97				
Three-Hour	152	19.15						
Eight-Hour			95	11.97				
24-Hour	114	14.36			25	3.15		
Annual	76	9.58			25	3.15	158	19.91
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Annual	3.6	0.45			0.2	0.03	6.0	0.76
Auxiliary Boiler								
One-Hour	0.37	0.05	9.6	1.21				
Three-Hour	0.37	0.05						
Eight-Hour			9.6	1.21				
24-Hour	0.37	0.05			0.65	0.08		
Annual	0.09	0.01			0.16	0.02	1.16	0.15

Table D-1
Modeling Emission Rates for Normal Operation[1] – One Phase Continued

Source/Averaging Time	SO_2		CO		PM10[2]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Flare								
One-Hour	0.01	0.001	1.10	0.14				
Three-Hour	0.01	0.001						
Eight-Hour			1.10	0.14				
24-Hour	0.01	0.001			0.02	0.002		
Annual	2.8	0.35			0.38	0.05	3.1	0.39

[1]Short-term emissions represent normal plant operation on syngas fuel; annual emissions are worst-case annual operation including flaring, gasifier outages, etc.
[2]PM10 emissions include filterable and condensable portions.

Table D-2
Modeling Emission Rates for Worst-Case Flaring Scenario-One Phase

Source/Averaging Time	SO_2		CO		PM10[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Tank Vent Boiler								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Auxiliary Boiler								
Flare								
One-Hour	1040	131.04	5680	715.67				
Three-Hour	734	92.48						
Eight-Hour			5345	637.46				
24-Hour	183	23.06			14.1	1.78		

[1]PM10 emissions include filterable and condensable portions

Table D-3
Modeling Emission Rates for Worst-Case Start-up Operating Scenario – One Phase

Source/Averaging Time	SO_2		CO		PM10[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour	183	23.06	2740	345.23				
Three-Hour	152	19.15						
Eight-Hour			541	68.21				
24-Hour	114	14.36			25	3.15		
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Auxiliary Boiler	0.37	0.05	9.6	1.21	0.65	0.08		
Flare								
One-Hour	0.11	0.01	22	2.77				
Three-Hour	0.11	0.01						
Eight-Hour			22	2.77				
24-Hour	0.11	0.01			0.32	0.04		

[1]PM10 emissions include filterable and condensable portions

Table D-4
Modeling Stack Parameters

Source/Scenario Averaging Time	Stack Ht. (m)	Stack Dia. (m)	Gas Temp (K)	Velocity (m/s)
Combustion Turbines (each)				
Normal Operation	45.72	6.10	394.3	20.08
Startup	45.72	6.10	366.5	11.64
Tank Vent Boiler				
Short-term	64.01	1.83	579.8	8.46
Annual	64.01	1.83	579.8	1.95
Startup	64.01	1.83	579.8	5.21
Auxiliary Boiler	12.19	1.52	422.1	9.70
Flare[(1)]				
Normal Operation	56.39	0.25	1273.0	20.0
Startup	56.39	1.11	1273.0	20.0
Flaring: One-Hour	56.39	10.72	1273.0	20.0
Three-Hour	56.39	10.40	1273.0	20.0
Eight-Hour	56.39	10.40	1273.0	20.0
24-Hour	56.39	7.36	1273.0	20.0
Annual	56.39	0.25	1273.0	20.0

(1) Flare parameters determined by SCREEN 3 methodology based on total heat release

There will also be PM10 emissions from fugitive sources related to coal and material handling. Modeling emission rates for fugitive PM10 are shown in Table D-5. The fugitive sources were represented in the AERMOD model input as area sources. Area sources were defined to occupy the plant areas from which fugitive emissions will be generated, as identified on the plant layout drawing. Modeling specifications for the area sources are given in Table D-6. Emission heights are based on the actual heights of emissions sources and storage piles.

All fugitive emission rates were calculated from applicable emission factors, material throughput rates, and control efficiencies as shown in Section 4.1.5 of the permit application. Maximum hourly emission rates shown in Section 4.1.5 are not appropriate in all cases for modeling of 24-hour average PM10 concentration. The 24-hour emission rates shown in Table D-5 assume a maximum of three unit coal trains unloaded in a 24-hour period; i.e., 41,005 tons per day of coal unloaded and conveyed to active storage. All other 24-hour emission rates are maximum hourly rates as given in Section 4.1.5.

1.6 Modeling of Storage Pile Wind Erosion

Fugitive PM10 emissions from storage piles were calculated according to the methodology of AP-42, Section 13.2.5, and represented in the air quality model as a function of wind speed. Wind speed (STAR) scalers were utilized in AERMOD to simulate the emissions of PM10 during hours of high wind speed.

The calculation of annual wind erosion emissions is shown in Tables B-7. The calculation was made for the active coal storage area for one phase of Mesaba One and Mesaba Two; this same annual emission rate was applied to both phase active coal storage piles and the two slag piles. The inactive coal storage area will be stabilized with surface crusting agents and no wind erosion was included.

The calculations in Tables B-7 are based on Hibbing wind frequency statistics (University of Minnesota Document AD-TB1955 (1983)); Table D-7 (a) shows the wind speed distribution for hourly wind measurements at 10 m height. It was conservatively assumed that the "fastest mile" wind speed (U_{10}^{+}) is given by 1.5 times the hourly speed $\left(U_{10}\right)$.

Other assumptions for the wind erosion calculations are:

Threshold friction velocity (U_t^*) = 1.12 m/s
Roughness length (Z_o) = 0.5 cm

both from AP-42 Table 13.2.5-2 for an uncrusted coal pile. The coal storage pile for a single phase was assumed to occupy a horizontal area of 7432 m^2, with an actual surface area exposed to the wind of 8370 m^2. The pile will be 152 m in length, 49 m in width, and 14.3 m in height.

Table D-5
Fugitive PM10 Emission Rates for Modeling – Mesaba One and Mesaba Two

Source	24-Hour Max		Annual Max	
	lb/hr	g/s	ton/yr	g/s
1 Railcar Unloading	0.372	0.0469	0.674	0.0194
2 Transfer to Conveyor	0.086	0.0108	0.155	0.0045
3 Coal Conveyor Transfers (3)	0.257	0.0324	0.465	0.0134
4 Coal Stacking	0.855	0.1077	1.550	0.0446
5 Coal Reclaim	0.215	0.0271	0.775	0.0223
6 Reclaim Conveyor Transfers (3)	0.129	0.0163	0.465	0.0134
7 Transfer to Feed Bin	0.009	0.0011	0.031	0.0009
8 Coal Slurry Facility Transfers (2)	0.086	0.0108	0.310	0.0089
9 Slag Storage Load-out	0.195	0.0246	0.705	0.0203
10 Slag Disposal Truck Traffic	0.304	0.0383	1.330	0.0383

Table D-6
Area source Modeling Parameters For Fugitive PM10 Emissions – Mesaba One and Mesaba Two

Source ID	Sources Included (Table D-5)	UTM Coordinates		Area Dimensions		Area Orientation	Release Height	Initial σ_z
		E(m)	N(m)	x(m)	y(m)	(deg)	(m)	(m)
COALHNDL	3, 4, 5, 6, 7	472,066.4	5,243,640.0	470	160	34.4	10	3
SLURPI	8 (Phase I)	471,992.5	5,243,673.5	49	14	34.4	3	2
SLAGPI	9, 10 (Phase I)	471,867.0	5,243,903.5	240	35	34.4	5	2
RAILUNLD	1, 2	472,273.5	5,243,740.5	26	16	34.4	3	2
SLURPII	8 (Phase II)	472,465.6	5,243,337.5	49	14	34.4	3	2
SLAGPII	9, 10 (Phase II)	472,532.7	5,243,431.5	300	35	34.4	5	2
COALHDWE	Wind Erosion	472,066.4	5,243,640.0	470	160	34.4	10	3
SLGPIWE	Wind Erosion	471,867.0	5,243,903.5	140	35	34.4	5	2
SLGPIIWE	Wind Erosion	472,664.7	5,243,341.0	140	35	34.4	5	2

Table D-7 (b) lists the surface wind speeds (U_s^+), friction velocities, and erosion potential (P) for each pile sub-area and wind speed class per AP-42 equations and data.

The calculation of annual average wind erosion is shown in Table D-7 (c), where the contributions from each wind speed event where winds exceed the erosion threshold are summed to obtain the total annual PM emission for the storage pile. It was assumed that the pile is disturbed daily, so that each day with a high fastest mile wind speed produces emissions. The annual average emission rate of 0.22 tons per acre per year was assumed to apply to all active storage piles.

For simulation of wind erosion impacts in AERMOD, wind speed scalers are defined to multiply by the average annual emission rate. The scalers are zero for wind speeds below the erosion threshold, and increase with wind speed for hours with speeds exceeding the threshold. Derivation of the wind speed scalers is given in Table D-8. The calculation method assures that total annual wind erosion emissions will equal the value determined in Table D-7, given the wind speed distribution for Hibbing. Table D-8 shows the wind speed classes (U_{10}) used in AERMOD modeling for PM10, and the scalers for each of the six speed classes.

Table D-7
(a).Hibbing MN Wind Frequencies and Assumed Fastest Mile Wind Speed for Each Speed Category

U_{10} (mph)	U_{10} (m/s)	Frequency (%)	U_{10}^{+} (m/s)	Assumed U_{10}^{+} (m/s)
< 8	< 3.58	38.9	< 5.36	5.0
8 – 12	3.58 – 5.58	30.4	5.36 – 8.38	8.0
13 – 18	5.59 – 8.27	27.0	8.39 – 12.41	12.0
19 – 24	8.28 – 10.95	3.3	12.42 – 16.43	16.0
> 24	> 10.95	0.4	> 16.43	20.0

Table D-7
(b) Erosion Potential for Wind Speed Classes and Pile Sub-Areas

U_{10}^{+}	$U_s/U_r = 0.2$			$U_s/U_r = 0.6$			$U_s/U_r = 0.9$			$U_s/U_r = 1.1$		
	U_s^{+}	U^*	P	U_s^{+}	U^*	P	U_s^{+}	U^*	P	U_s^{+}	U^*	P
5	1.0	0.10	0	3.0	0.30	0	4.5	0.45	0	5.5	0.55	0
8	1.6	0.16	0	4.8	0.48	0	7.2	0.72	0	8.8	0.88	0
12	2.4	0.24	0	7.2	0.72	0	10.8	1.08	0	13.2	1.32	7.320
16	3.2	0.32	0	9.6	0.96	0	14.4	1.44	13.939	17.6	1.76	39.757
20	4.0	0.40	0	12.0	1.20	2.371	18.0	1.80	43.819	22.0	2.20	94.651

Data from AP-42 Table 13.2.5-3 and Figure 13.2.5-2 (Pile B3).

$$P = 58(U^* - U_t^*)^2 + 25(U^* - U_t^*)$$

Table D-7
(c). Calculation of Annual Wind Erosion

U_{10}^{+} (m/s)	P (g/m^2)	Days per Year	Fraction of Pile Area (%)	Area (m^2)	Emissions (kg/yr)
12	7.320	98.550	4	335	241.664
16	13.939	12.045	14	1172	196.773
16	39.757	12.045	4	335	160.422
20	2.371	1.460	54	4520	15.647
20	43.819	1.460	14	1172	74.980
20	94.651	1.460	4	335	46.294
				Total	735.780

Annual Average Emission Rate:
735.78 x 10^3 grams x 1/7432m^2 x 1/31.536 x 10^6 sec/yr

= 3.1393 x 10^{-6} g/m^2-s (PM)

or 1.5696 x 10^{-6} g/m^2-s (PM10) = 0.22 ton/acre-year

Table D-8
Calculation of Wind Speed Scalers for AERMOD

Wind Speed Class	Wind Speed Range (U_{10}) (m/s)	U_{10}^{+} (m/s)	Fraction of Area	P (g/m^2)	$\overline{P}$ (g/m^2)	Wind Speed Frequency F	$\overline{P}$ x F
1	< 2.0	3.0	0	0	0		0
2	2.0 – 3.6	5.0	0	0	0		0
3	3.6 – 5.8	8.0	0	0	0		0
4	5.8 – 8.5	12.0	.04	7.320	0.293	.270	.0791
5	8.5 – 10.7	16.0	.14 .04	13.939 39.757	3.542	.033	.1169
6	> 10.7	20.0	.54 .14 .04	2.371 43.819 94.651	11.201	.004	.0448
						Sum of $\overline{P}$ x F = .2408	

$\overline{P}$ = area weighted average of P based on total pile area

Wind Speed Scalers:

a_1 = 0/.2408 = 0.0
a_2 = 0/.2408 = 0.0
a_3 = 0/.2408 = 0.0
a_4 = .293/.2408 = 1.2168
a_5 = 3.542/.2408 = 14.7093
a_6 = 11.201/.2408 = 46.5158

2.0 SIGNIFICANT IMPACT MODELING

Initial air quality modeling was carried out to define maximum impacts of Mesaba One and Mesaba Two alone, for each pollutant and averaging time. Modeling included both phases of the project, with emission rates and stack parameters given in Section 1.0. All relevant operating scenarios were modeled in order to determine highest concentrations for any operating condition.

Results of significant impact area (SIA) modeling are given in Table D-9. All concentrations shown are the highest predicted concentration for any receptor or year of meteorological data.

Minnesota significant impact levels (SILs) are also shown in Table D-9. The data indicate that most predicted impacts are significant; i.e., exceed the applicable SIL. CO impacts are significant only for the worst-case startup scenario (both phases in startup). Thus, startup is the worst-case for CO. For SO_2, PM10, and NO_x, normal operation produces the highest concentrations.

Based upon the results in Table D-9, full increment and NAAQS compliance analyses are necessary for SO_2, PM10, and NO_x. The normal operation scenario only need be modeled, since impacts are less for flaring and startup. A NAAQS compliance demonstration is necessary for CO in the startup mode (one-hour only). Since no regional CO inventory is available, the CO compliance demonstration has utilized the Mesaba-only CO SIA model run.

The SIA is defined as the area over which concentrations exceeding the SIL are predicted. SIA maps are shown in Section 7.0 of the permit application for each pollutant. Maximum radii for the SIA are:

SO_2	4.4 km
PM10	1.6 km
NO_x	3.0 km
CO	0.9 km

All SIAs are limited to an area within less than 5 km from the center of the Mesaba plant site.

Table D-9
Results of Significant Impact Modeling

Operating Scenario	Pollutant	Averaging Time	Max ($\mu g/m^3$)	Time (yr/mo/dy/hr)	UTM Coordinates of Max (m) Easting	Northing	SIL ($\mu g/m^3$)
Normal Operation	SO_2	1-hour	130.2	75042724	471,675	5,243,675	25
		3-hour	77.6	75042724	471,500	5,243,750	25
		24-hour	31.2	75042824	471,475	5,243,650	5
		annual	1.29	76	472,700	5,242,725	1
	PM10	24-hour	27.9	74010224	472,304	5,243,924	5
		annual	1.68	76	472,810	5,243,228	1
	CO	1-hour	172.2	76072301	472,543	5,243,171	2000
		8-hour	59.8	72011408	472,561	5,243,189	500
	NO_x	annual	2.60	76	472,700	5,242,725	1
Flaring	SO_2	1-hour	75.8	74082007	472,454	5,243,819	25
		3-hour	22.8	75032721	470,300	5,244,075	25
		24-hour	5.4	75042824	470,800	5,244,175	5
	CO	1-hour	414.1	74082007	472,454	5,243,819	2000
		8-hour	122.7	72092116	473,450	5,242,775	500
Startup	CO	1-hour	3167.5	75083122	471,750	5,243,600	2000
		8-hour	379.0	75060608	472,500	5,242,925	500

3.0 PSD INCREMENT ANALYSIS

Increment consumption modeling included all IGCC Power Station sources exactly as they were represented in the SIA modeling described in the preceding section (normal operation scenario). In addition, all increment-consuming and increment-expanding sources were included as provided by the MPCA. Regional sources and increment emissions are summarized in Table D-10. No editing or modification of MPCA source files was done, except for deletion of duplicate sources where indicated by an updated source file.

All current/future emission rates in the MPCA files are understood to be potential (allowable) emissions. They were used directly for increment modeling. The "two entry" method of increment modeling was applied; i.e., increment-consuming sources were modeled with positive emission rates and increment-expanding sources were entered in the input file with negative emission rates.

Results of the increment analysis are presented in Table D-11. The results demonstrate that all maximum modeled increment consumption is far below applicable PSD increment limits. Much more than one SIL remains between the highest concentration and the allowable increment as a margin for future growth.

It can be noted that the highest combined-source impacts are nearly equal to the highest concentrations from Mesaba One and Mesaba Two alone. Thus, there is minimal impact of regional increment sources within the Mesaba SIA. Similarly, Mesaba impacts are insignificant in areas most affected by regional sources. On a region-wide basis, Mesaba One and Mesaba Two will have negligible effect on PSD increment consumption.

The geographical distribution of Mesaba increment impacts is the same as the distribution of total Mesaba concentrations; isopleth maps are shown in Section 7.0 of the permit application.

Table D-10
Regional Increment Sources Included in Increment Analyses [1]

Source	File Name	Source Type	Number Of Sources	Increment Emissions					
				SO_2		PM10		NO_x	
				lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Minnesota Power	MPCB77S	Point	1	6130.89[2]	772.48[2]				
Clay Boswell #4	MPC77P	Point	1			510.90	64.373		
Potlatch	PGR0900.PM1	Point	12			62.77	7.91		
Grand Rapids		Volume	96			0.62	.079		
		Area	2			0.0005	.00007		
	PGR0900.NOX	Point	4					95.50	12.03
		Volume	102					0.17	0.02
Blandin Paper Co.	BPCDEC04.NOX	Point	6					-116.91	-14.73
		Point	20					117.72	14.83
	BMPIS072	Point	11	-178.68	-22.51				
		Point	40	595.64	75.05				
		Volume	5	0.02	.002				
	BPC89P	Point	5			-0.13	-.016		
		Point	7			53.44	6.73		
		Volume	4			0.40	0.05		

[1]Source: Christopher Nelson, MPCA; 8/17/05
[2]Annual SO_2 emission limit for Clay Boswell Boiler 4 is 1686 lb/hr = 212.43 g/s; short-term limit shown here.

Table D-11
Results of Mesaba One and Mesaba Two PSD Increment Modeling[1]

Pollutant	Averaging Time	Mesaba [2] ($\mu g/m^3$)	Regional [2] ($\mu g/m^3$)	All [2] ($\mu g/m^3$)	Time yr/mo/day/hr	UTM Coordinates (m)		Allowable ($\mu g/m^3$)
						Easting	Northing	
SO_2	1-hour	122.4	113.0	122.4	75032718	471,650	5,243,650	512
	3-hour	73.4	38.2	73.4	75042821	471,500	5,243,600	512
	24-hour	21.1	10.6	21.1	75042724	471,475	5,243,850	91
	annual	1.29	0.45	1.40	76	472,700	5,242,725	20
PM10	24-hour	23.4	1.2	23.5	74010124	472,329	5,243,906	30
	annual	1.68	0.15	1.72	76	472,810	5,243,228	17
NO_x	annual	2.60	0.13	2.62	76	472,700	5,242,725	25

[1]For 1-hour, 3-hour, and 24-hour periods, the listed concentration is the highest second-high from five years. Annual concentration is the highest for any year.

[2]Mesaba and regional concentrations are highest from each source group for the year of highest total concentration. They usually do not occur at the same time or receptor. The "All" column lists the high or high second-high for all increment sources combined.

4.0 NAAQS COMPLIANCE ANALYSIS

The NAAQS modeling demonstration consisted of calculating the maximum impact of Mesaba One and Mesaba Two sources and all other regional sources, and comparing the highest total impacts, plus background concentrations, to the applicable Minnesota and National Ambient Air Quality Standards (NAAQS). For Mesaba One and Mesaba Two, maximum emission rates in normal operation were modeled for all sources and pollutants, except in the case of CO for which the startup scenario has maximum impacts.

For inclusion of other regional sources, a two step procedure was utilized following the recommendations of MPCA modeling staff. In the first step, Mesaba One and Mesaba Two were modeled along with nearby sources for which emission parameters were provided by the MPCA. The location and time of high and highest second-high concentrations were defined by these model results. These specific high impact events were then remodeled, through use of the AERMOD EVENT option, including a much larger inventory of all regional sources. The full regional inventory, referred to as First Approximation Run (FAR) data, was provided by the MPCA. FAR data files were generated specifically for the Mesaba site location; separate files were provided for each pollutant and averaging time.

The regional sources that were included explicitly in the full five-year NAAQS model runs are detailed in Table D-12. All data were provided by MPCA modeling staff and represent maximum allowable emissions.

Background concentrations, representing natural and remote sources, were estimated on the basis of data from pristine areas and general knowledge of North American background levels. The assumed background levels, shown in Table D-13, are believed to be generally conservative.

Table D-13 lists maximum model-predicted concentrations for Mesaba One and Mesaba Two alone, Mesaba One and Mesaba Two plus nearby sources, and Mesaba One and Mesaba Two plus all regional and FAR sources. Table D-14 shows a comparison of highest modeled impacts from all sources, plus background and one SIL, to the applicable NAAQS. Table D-14 demonstrates that Mesaba One and Mesaba Two emissions will not cause or contribute to an exceedance of any NAAQS.

Isopleth maps, showing the distribution of Mesaba One and Mesaba Two highest impacts near and within the SIA for each pollutant, are presented in Section 7.0 of the air permit application.

Table D-12
Nearby Source Data for Sources Included in Initial NAAQS Modeling (Before Addition of Regional FAR Sources)

Source	Elev. (m)	St. Ht. (m)	St. Dia (m)	Temp. (K)	Vel. (m/s)	Emission Rate					
						SO_2		PM10		NO_x	
						lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Keewatin Taconite	469	45.11	3.87	394.3	16.44	449	56.57	2182	274.93	3188	401.68
MN Pwr-Boswell 1, 2, 3	395	213.36	8.84	352.6	15.59	19420	2446.88	2163	272.53	4664	587.66
MN Pwr-Boswell 4	395	182.88	6.10	343.2	35.85	6131	772.48	511	64.39	3576	450.57
(annual)						1686	212.44				

Source UTM Coordinates

Keewatin Taconite	495,361.0 E, 5,251,235.0 N
Boswell 1, 2, 3	450,543.2 E, 5,234,354.5 N
Boswell 4	450,653.8 E, 5,234,624.3 N

Elevations determined from DEM data

Table D-13
Model-Predicted Concentrations [1, 2] for Mesaba One and Mesaba Two NAAQS Analysis (µg/m^3).

Pollutant & Averaging Time	Mesaba	Mesaba & Nearby	All Sources	Time	Location – UTM (m)	
					Easting	Northing
SO_2						
one-hour	122.4	322.2	327.4	75012612	461,700	5,232,875
three-hour	73.4	134.4	136.5	75111315	461,700	5,234,875
24-hour	22.1	30.6	41.4	75030824	463,700	5,232,875
annual	1.29	1.99	2.67	76	472,700	5,242,725
PM10						
24-hour	13.3	13.7	15.8	73011224	472,329	5,243,906
annual	1.59	1.95	3.14	76	472,810	5,243,228
NO_2						
annual	2.60	3.18	5.09	74	472,625	5,242,700
CO						
one-hour	2669.8	N/A	N/A	75042723	471,650	5,243,675

(1) Short-term gaseous pollutant concentrations are highest second-high; short-term PM10 is the highest 6th high from 5 years; all annual concentrations are highest for any year.
(2) "Mesaba and "Mesaba & Nearby" columns are for the respective worst-case year; the "Time" and "Location" data refer specifically to the "All Sources" maximum.

Table D-14
Comparison of Maximum Model-Predicted Concentrations (μg/m^3) to Ambient Air Quality Standards.

Pollutant & Averaging Time	Modeled[(1)] Concentration	Background	SIL	Total	NAAQS
SO_2					
one-hour	327.4	10.0	25.0	362.4	1300
three-hour	136.5	10.0	25.0	171.5	915
24-hour	41.4	10.0	5.0	56.4	365
annual	2.67	2.0	1.0	5.67	60
PM10					
24-hour	15.8	20.0	5.0	40.8	150
annual	3.14	10.0	1.0	14.14	50
NO_2					
annual	5.09	5.0	1.0	11.09	100
CO					
one-hour	2669.8	7000[(2)]	2000	11,669.8	40,000

[(1)] Modeled concentration is highest second-high for short-term periods, except for PM10 (highest 6th high), and highest for annual average; includes Mesaba and all regional sources.
[(2)] CO background is conservative estimate from urban monitors in Minneapolis/St. Paul. No background data are available for northern Minnesota.

PART II: LONG RANGE TRANSPORT (CALPUFF) MODELING

The Class I CALPUFF analyses addressed impacts to the Boundary Waters Canoe Area (BWCA), Voyageurs National Park (VNP) and the Rainbow Lake Wilderness (RLW). The distance from the IGCC Power Station to the closest point in each of these Class I areas is approximately 61 miles (98 km) for the BWCA, 75 miles (121 km) for VNP, and 117 miles (188 km) for RLW. The next closest Class I area, Isle Royale National Park, is more than 300 km from the station, beyond the distance where long-range transport modeling has been shown to provide realistic impact predictions.

Modeling was carried out in accordance with the U.S. EPA Guideline on Air Quality Models (40 C.F.R. Part 51, Appendix W), the IWAQM Phase 2 report (December, 1998), and the Phase I FLAG report (December 2000). Excelsior representatives and their consultants met with the U.S. Forest Service in Duluth on September 20, 2005, and with the National Park Service in Denver on November 9, 2005 to discuss Class I issues and analyses. Information from those meetings was incorporated in the modeling

5.0 MESABA ONE AND MESABA TWO EMISSIONS FOR CALPUFF

During normal operation of Mesaba One and Mesaba Two, the only significant air pollutant emissions will be from the combustion turbines and tank vent boilers. During short-term, upset conditions when untreated syngas could be flared, SO_2 emissions from the flares may exceed the combined SO_2 emissions from the CTGs during normal operations (see Appendix A, Exhibit A-2). This situation represents a low probability event because Excelsior is designing the gasification island such that only treated syngas would be flared during start-ups. Further, during such abnormal upset conditions, flow of syngas to the CTGs would be interrupted and operation of the gasifier(s) would be reduced or shutdown if the upset condition appeared significant (that is, threatened compliance) and/or persistent, thus limiting the need to flare large quantities of untreated syngas. Notwithstanding the increased short term emissions of SO_2 relative to normal baseload operations of the CTGs, NO_X and PM_{10} emissions from the total facility during such short term upsets will be reduced to levels below normal NO_X and PM_{10} emissions from the CTGs given the rapid turn down capability of the CTGs and gasifiers. A second scenario of interest concerns times when the combustion turbines would operate on natural gas rather than syngas. During such events, NO_X emission rates will be slightly higher than under syngas operation, but SO_2 emissions will be very low. Therefore, the normal operating scenario for Mesaba One and Mesaba Two represents the highest combined-source pollutant emission profile. This justifies limiting Class I modeling analyses to emissions released during normal operations.

Pollutant emission rates for long-range transport modeling represent maximum expected emissions for a two-phase plant for the appropriate averaging periods. All maximum emission rates and stack emission parameters are based upon engineering design specifications, as documented in the air permit application. Modeling parameters for Class I analyses are given in Table D-15.

Speciation of particulate matter emissions from the combustion turbines, as shown in Table D-15, was based on available data for Mesaba One and Mesaba Two sources and Federal Land Manager (FLM) guidance on emissions from natural gas-fired turbines. The total particulate emissions (filterable plus condensable) and total sulfuric acid emissions are from Mesaba design specifications. The partitioning of filterable and condensable fractions, elemental carbon emissions, and organic aerosol emissions were calculated using the FLM consensus methodology. All filterable particulate was assumed to be elemental carbon less than 2.5 microns in diameter. All particulate emissions from the tank vent boilers were assumed to be $PM_{2.5}$. Calculations are shown in Table D-16.

Table D-15
Modeling Parameters For Mesaba CALPUFF Modeling

Parameter	Combustion Turbines (each of four)	Tank Vent Boilers (each of two)
stack height (m)	45.72	64.01
stack diameter (m)	6.1	1.83
temp (K)	394.3	579.8
velocity (m/s) – short-term	20.1	8.46
annual	20.1	1.95
SO_2 - 3-hr (g/s)	19.15	0.94
24-hr	14.36	0.81
annual	9.58	0.45
NO_x - 3-hr (g/s)	19.66	2.46
24-hr	19.66	2.46
annual	19.91	0.76
Elemental Carbon (g/s) all time periods	0.787	0
Sulfate (g/s) all time periods	0.945	0
Organic aerosol (g/s) all time periods	1.397	0
$PM_{2.5}$ (g/s) all time periods	0	0.088
PM_{10} (g/s)	0	0

Table D-16
Estimation of Particulate Matter Speciation for Combustion Turbine Stacks (each)

Total PM Emissions, Filterable plus Condensable, from Plant Design Specifications = 25 lb/hr.

Assume, as per FLM guidance for gas-fired CTs, that 25% of PM_{10} is filterable, and 75% is condensable.

Then Filterable PM_{10} = 6.25 lb/hr.

Assume that 100% of Filterable PM_{10} is elemental carbon.

Then EC = 6.25 lb/hr

Condensable PM_{10} = 0.75(25) = 18.75 lb/hr.

H_2SO_4 = 7.66 lb/hr per design specifications

Then condensable SO_4 = 7.5 lb/hr

Assume remainder of condensable PM_{10} is organic (SOA).

Then final speciation is:

EC = 6.25 lb/hr = 0.787 g/s
SO_4 = 7.5 lb/hr = 0.945 g/s
SOA = 11.09 lb/hr = 1.397 g/s

6.0 AIR QUALITY MODEL AND APPLICATION

The CALPUFF air quality model was used for all Class I area analyses. CALPUFF is the approved EPA long-range transport model as referenced in the Guideline on Air Quality Models. It consists of three components: the CALMET model for processing of meteorological data, CALPUFF for the transport and dispersion calculations, and CALPOST for analysis and post-processing of model results. The CALMET model version is 5.53a, Level 040716; CALPUFF is version 5.711a, Level 040716. Input options and data utilized in the models generally corresponded to default or recommended values; Table D-17 provides a list of input options that are specific to the Mesaba One and Mesaba Two application and differ from standard default values.

For background ozone (O_3) concentration, a constant value of 40 ppb was used for CALPUFF modeling. A constant ammonia background of 1.0 ppb was assumed.

The CALMET/CALPUFF modeling domain is a 700km by 500km area approximately centered on the IGCC Power Station, with a four kilometer grid spacing. The coordinate system is Lambert Conformal. Receptor locations within each of the Class I areas were obtained from the National Park Service. Figure D-3 shows the modeling domain, terrain elevation contours, and the modeling receptors.

Terrain elevations were derived with the TERREL preprocessor; an average elevation was extracted for each cell in the modeling domain. Land use data were obtained from USGS 1:250,000 scale land use and land cover digital data, using CTGCOMP (version 1.0, 961113) and CTGPROC (version 1.2, 010206). The elevation and land use files were combined for CALMET input using MAKEGEO (version 1.1, 010206).

Source input to CALPUFF consisted of four combustion turbines and two tank vent boilers for a two-phase Mesaba facility. Building downwash effects on stack emissions were included through use of output from the BPIP PRIME wake effects program. Complete CALMET and CALPUFF input files are included with the application modeling files.

CALPUFF modeling analyses utilized meteorological data for the years 1990, 1992, and 1996. These are the same years used for other recent CALPUFF applications in northern Minnesota and the data were readily available. Gridded meteorological fields used as input to the CALMET processor were MM4 (1990) and MM5 (1992, 1996) prognostic data acquired from the National Park Service (NPS). Additional surface, upper air, and precipitation data were used in CALMET to refine the meteorological fields. Hourly surface data from 13 stations were used along with precipitation data from 28 stations. Upper air data from two stations were used; St. Cloud MN and International Falls MN for 1990 and 1992, and Minneapolis and International Falls for 1996. The surface and precipitation stations are listed in Table D-18.

Table D-17
CALMET/CALPUFF Non-Default Input Parameters

Input Group	Parameter	Mesaba Selection	Explanation
	CALMET		
5	IKINE	1	Kinemateic effects option used to better account for terrain effects
5	RMAX 1	30 km	No default values
	RMAX 2	40 km	No default values
	RMAX 3	40 km	No default values
	TERRAD	15 km	No default values
	R1	5	No default values
	R2	15	No default values
	CALPUFF		
3	Species Modeled	SO_2, SO_4, NO_x, EC SOA, $PM_{2.5}$, HNO_3, NO_3	Modeled all species emitted by Mesaba sources, and others (HNO_3, NO_3) involved in plume chemistry
4	LSAMP	F	No gridded receptors (sampling grid) used
8	Part. Size	Mean = 0.48 st. dev. = 2	All particulate species assumed $PM_{2.5}$
11	MOZ	0	Constant ozone background
11	BCK03	40.0 ppb	Representation background ozone concentration
11	BCKNH3	1.0 ppb	Conservative background ammonia concentration (0.5 ppb recommended for forested lands)
12	NSPLIT	3	Puff-splitting used (default)

Figure D-3. Mesaba CALMET Modeling Domain and Class I Areas

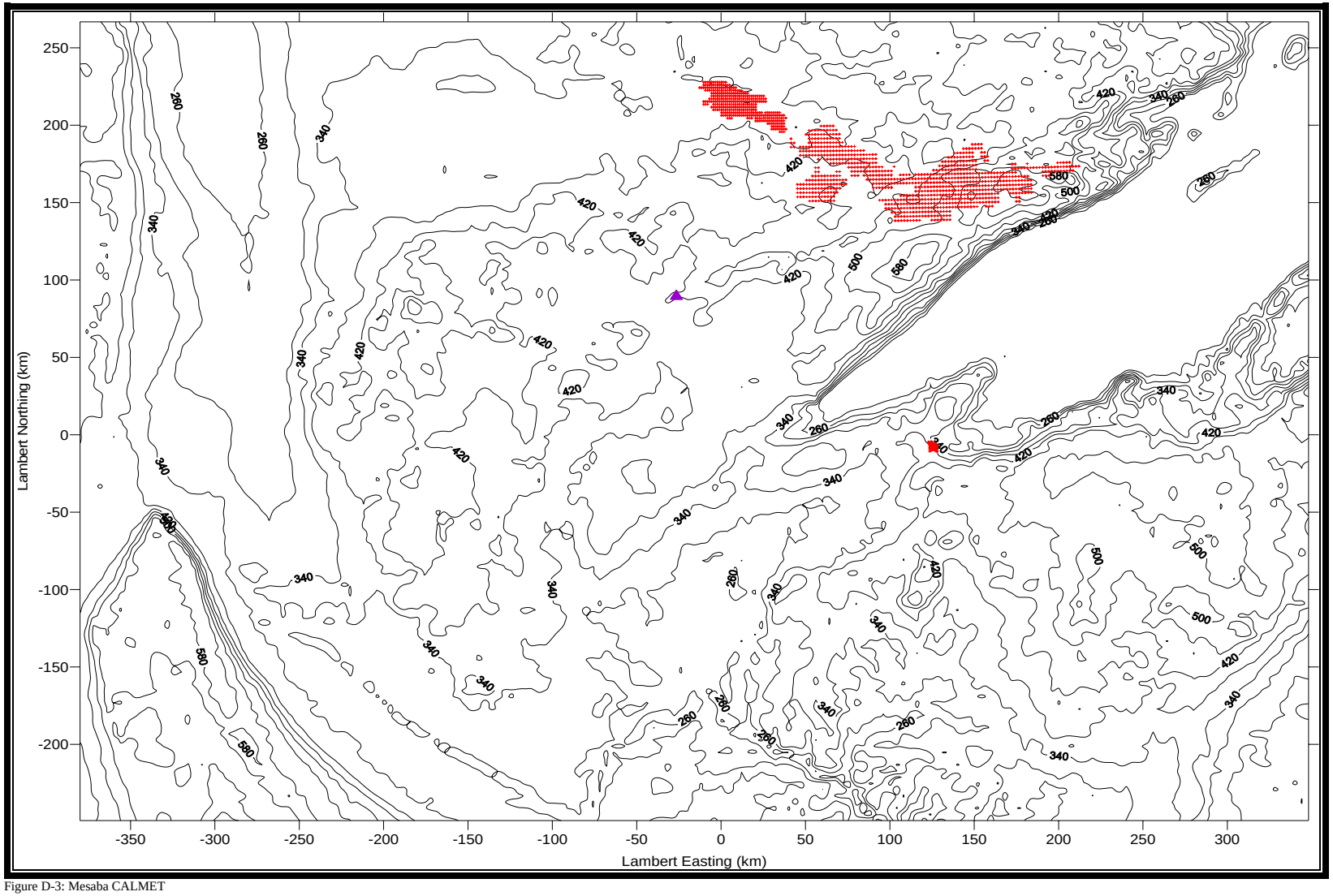


Figure D-3: Mesaba CALMET
Modeling Domain and Class I Areas

Table D-18
Weather Stations Included in CALMET Meteorological Data Processing

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Upper Air Stations included in CALMET

WBAN Number	Station Name	State	County	Years
14926	ST CLOUD	Minnesota	Sherburne	90,92
94983	MINNEAPOLIS	Minnesota	Hennepin	96
14918	INTERNATION FALLS	Minnesota	Koochiching	90,92,96

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Surface Stations included in CALMET (1990, 1992 and 1996)

WBAN Number	Station Name	CALMET Number	State	County
94902	BROOKINGS	26515	South Dakota	Brookings
14926	ST CLOUD	26550	Minnesota	Sherburne
14954	MANKATO	26585	Minnesota	Blue Earth
14914	FARGO	27530	North Dakota	Cass
14050	BEMIDJI	27550	Minnesota	Beltrami
14916	GRAND FORKS	27576	North Dakota	Grand Forks
14922	MINNEAPOLIS	26580	Minnesota	Hennepin
14913	DULUTH	27450	Minnesota	St. Louis
94931	HIBBING	27455	Minnesota	St. Louis
14918	INTERNATION FALLS	27470	Minnesota	Koochiching
14920	LA CROSSE	26430	Wisconsin	La Crosse
14991	EAU CLAIR	26435	Wisconsin	Chippewa
14897	WAUSAU	26463	Wisconsin	Marathon

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Precipitation Stations included in CALMET (1990, 1992 and 1996)

COOP ID	Station Name	State	County
474894	LUCK	Wisconsin	Polk
473511	HAYWARD RS	Wisconsin	Sawyer
478027	SPOONER EXP FARM	Wisconsin	Washburn
474396	LADYSMITH RS	Wisconsin	Rusk
472722	MENOMONIE	Wisconsin	Dunn
478589	TREMPEALEAU DAM 6	Wisconsin	Trempealeau
475352	MERCER RS	Wisconsin	Iron
476854	PRENTICE	Wisconsin	Price
479218	WILLARD	Wisconsin	Clark
476518	PHELPS	Wisconsin	Vilas
477140	RICE RSVR TOMAHAWK	Wisconsin	Lincoln
478963	WAUSAU 7 SSW	Wisconsin	Marathon
218235	THIEF LAKE REFUGE	Minnesota	Marshall
213463	HALSTAD	Minnesota	Norman
216228	ORWELL DAM	Minnesota	Otter Tail
211263	CANBY	Minnesota	Yellow Medicine
211589	CLEMENTSON	Minnesota	Lake of the Woods
218621	WALKER RANGER	Minnesota	Cass
217294	ST. CLOUD/WHITNEY MN.	Minnesota	Sherburne
215435	MINNEAPOLIS WSFO AP, MN	Minnesota	Hennepin
210746	BIG FALLS	Minnesota	Koochiching
214026	INT.FALLS/FALLS INT.MN.	Minnesota	Koochiching
216213	ORR	Minnesota	St. Louis
212248	DULUTH/INT.MN.	Minnesota	St. Louis
213793	HINCKLEY	Minnesota	Pine
218613	WALES 2 ENE	Minnesota	Lake
213296	GRAND PORTAGE R S	Minnesota	Cook
322859	FARGO/HECTOR FIELD ND.	North Dakota	Cass

7.0 INCREMENT ANALYSES

CALPUFF model results for pollutant concentration at each Class I area receptor were processed with CALPOST to determine the highest and highest second-high concentration for each pollutant and averaging time in each Class I area. Allowable Class I increments and Significant Impact Levels (SILs) are shown in Table D-19.

Mesaba One and Mesaba Two emission rates appropriate to each averaging time, as listed in Table D-15, were used in separate CALPUFF model runs to evaluate 3-hour, 24-hour, and annual increment consumption. Each model simulation was carried out for each year of meteorological data; the highest concentration for any year was compared to the applicable SIL, and the highest second-high from the three years was compared to the allowable increment limit. For calculation of particulate matter (PM_{10}) impacts, the sum of all particle species (EC, SOA, FPM, CPM, and SO_4) was calculated to represent the total PM_{10} concentration.

The CALPUFF-generated concentration output was processed with CALPOST to tabulate the highest predicted concentration for each Class I area, pollutant/averaging time, and year of meteorological data. Results are shown in Table D-20. Predicted impacts are less than the applicable SIL, except for short-term SO_2 at the BWCA and VNP. Following FLM guidance, cumulative increment analyses were therefore carried out for short-term SO_2.

Excelsior contacted the MPCA and requested modeling information for regional SO_2 increment sources. MPCA provided detailed emission and stack data for those Minnesota sources with potential for Class I SO_2 impacts. The sources and net increment-consuming emissions are listed in Table D-21. The MPCA inventory generally lists maximum allowable emissions for post-baseline sources. The allowable emissions were used in increment modeling for all sources except Minnesota Power-Clay Boswell. Actual emissions data were acquired for the most recent two years for Clay Boswell; the emission rate in Table D-21 represents the maximum actual hourly rate for that time period.

Table D-19
Class I Area Increment Limits and Significant Impact Levels (SILs)

Pollutant	Averaging Time	Class I Increment ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	3-hour	25.0	1.0
	24-hour	5.0	0.2
	annual	2.0	0.1
PM_{10}	24-hour	8.0	0.3
	annual	4.0	0.2
NO_2	annual	2.5	0.1

Table D-20
PSD Increment Modeling Results for Mesaba Energy Project

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.3804	1.4547	1.5505	25.0	1.00	1.5505
SO_2 24-Hour	0.4554	0.3382	0.3589	5.0	0.20	0.4554
SO_2 Annual	0.0147	0.0127	0.0095	2.0	0.10	0.0147
NOx Annual	0.0174	0.0152	0.0109	2.5	0.10	0.0174
PM_{10} 24-Hour	0.0866	0.0617	0.0586	8.0	0.30	0.0866
PM_{10} Annual	0.0041	0.0037	0.0026	4.0	0.20	0.0041

Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	1.5911	1.0477	1.4836	25.0	1.00	1.5911
SO_2 24-Hour	0.2506	0.2943	0.4492	5.0	0.20	0.4492
SO_2 Annual	0.0128	0.0110	0.0113	2.0	0.10	0.0128
NOx Annual	0.0151	0.0125	0.0142	2.5	0.10	0.0151
PM_{10} 24-Hour	0.0537	0.0500	0.0745	8.0	0.30	0.0745
PM_{10} Annual	0.0037	0.0032	0.0031	4.0	0.20	0.0037

Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Class I SIL (ug/m3)	Max (ug/m3)
SO_2 3-Hour	0.7088	0.7567	0.7012	25.0	1.00	0.7567
SO_2 24-Hour	0.1806	0.1917	0.1711	5.0	0.20	0.1917
SO_2 Annual	0.0075	0.0083	0.0065	2.0	0.10	0.0083
NOx Annual	0.0081	0.0071	0.0068	2.5	0.10	0.0081
PM_{10} 24-Hour	0.0369	0.0462	0.0316	8.0	0.30	0.0462
PM_{10} Annual	0.0022	0.0028	0.0019	4.0	0.20	0.0028

Table D-21
Modeled Increment Consuming SO_2 Emissions For Cumulative Class I Increment Analysis

Source	Net Increment SO_2 Emissions lb/hr	g/s
IGCC Power Station		
3-hour	622.9	78.48
24-hour	468.7	59.06
Minnesota Power – Hibbard	416.8	52.51
Blandin Paper – Rapids Energy	417.0	52.54
Northshore Mining	-20.8	-2.62
Minnesota Power – Clay Boswell	1686	212.4
Potlatch Paper – Cloquet	-34.5	-4.35
Hibbing Taconite – Hibbing	772.3	97.31
Boise Cascade	141.6	17.84
Mesabi Nugget – Hoyt Lakes	225.6	28.42

Some individual sources in the MPCA increment inventory have negative emission rates (i.e., actual SO_2 emissions have decreased since the baseline date, resulting in increment expansion). Since the CALPUFF model does not accept negative emission rates, two model runs were carried out; one with the positive emissions and one with the negative emission rates. Concentration impacts of the negative sources were subtracted from those of the positive sources for each hour/receptor to derive total increment impacts of all sources. To minimize computation time, some sources were combined in the model input. All combined emissions used the stack parameters appropriate to the source with highest emission rate; separate and applicable stack parameters were used for the positive and negative model runs.

Results of the cumulative increment modeling (highest second-high 3-hour and 24-hour concentration for BWCA and VNP) were compared to the PSD Class I increment limits to demonstrate compliance. Results are given in Table D-22. Maximum predicted increment consumption in each of the Class I areas is well below allowable Class I increment limits.

Table D-22
Mesaba Cumulative SO_2 Increment Results (ug/m3)*

Boundary Waters/Pollutant Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Max (ug/m3)	Violation? (Y/N)
SO_2 3-Hour	6.1	7.0	5.8	25.0	7.0	NO
SO_2 24-Hour	2.6	2.1	2.2	5.0	2.6	NO

Voyageurs Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Max (ug/m3)	Violation? (Y/N)
SO_2 3-Hour	5.2	4.6	5.5	25.0	5.5	NO
SO_2 24-Hour	1.6	1.5	1.6	5.0	1.6	NO

Rainbow Lakes Pollutant/ Averaging Period	1990	1992	1996	Class I Inc (ug/m3)	Max (ug/m3)	Violation? (Y/N)
SO_2 3-Hour	4.5	4.3	4.7	25.0	4.7	NO
SO_2 24-Hour	1.4	1.2	1.3	5.0	1.4	NO

* High-second highs

8.0 DEPOSITION OF NITROGEN AND SULFUR

The CALPUFF results for each of the Class I areas were processed with CALPOST to calculate total annual deposition of nitrogen and sulfur at each receptor as a result of Mesaba One and Mesaba Two emissions. Model results for annual impacts (maximum annual average emissions) were used following the methodology given in the IWAQM Phase I report. Total sulfur deposition is calculated from the wet and dry deposition of SO_2 and sulfate; total nitrogen is represented by the sum of nitrogen from wet and dry fluxes of nitric acid, nitrate, ammonium sulfate and ammonium nitrate, and the dry flux of NOx. For deposition calculations, MNITRATE was set to a value of 1.0 in POSTUTIL to account for ammonia availability. Results are presented in Table D-23.

Results of deposition calculations for VNP were compared to the NPS Deposition Analysis Threshold (DAT) of 0.01 kg/ha-yr for both sulfur and nitrogen. For the BWCA and RLW, total deposition (IGCC Power Station impact plus background) was compared to the USFS "green line" values for terrestrial and aquatic ecosystems. The green line values are:

BWCA – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	7.5 – 8 kg/ha-yr
Sulfur + 20% nitrogen	9 – 10

RLW – Terrestrial

Total sulfur	5 - 7 kg/ha-yr
Total nitrogen	5 - 8

- Aquatic

Total sulfur	3.5 – 4.5 kg/ha-yr
Sulfur + 20% nitrogen	4.5 – 5.5

The comparison of Mesaba One and Mesaba Two deposition to NPS and USFS impact thresholds and a discussion of results is presented in Section 8.0 of the permit application. All model-predicted impacts are within or below the acceptable ranges for impacts on sensitive ecosystems.

Table D-23
Maximum Annual Deposition of S and N from IGCC Power Station in Class I Areas (kg/ha-yr)

Class I Area/Year	Sulfur	Nitrogen
Boundary Waters Canoe Area		
1990	1.217×10^{-2}	9.549×10^{-3}
1992	9.797×10^{-3}	7.085×10^{-3}
1996	8.400×10^{-3}	6.217×10^{-3}
Voyageurs National Park		
1990	1.016×10^{-2}	7.864×10^{-3}
1992	1.110×10^{-2}	8.562×10^{-3}
1996	9.780×10^{-3}	7.835×10^{-3}
Rainbow Lakes Wilderness		
1990	5.188×10^{-3}	4.225×10^{-3}
1992	6.336×10^{-3}	4.617×10^{-3}
1996	5.936×10^{-3}	4.749×10^{-3}

9.0 REGIONAL HAZE ANALYSIS

A visibility/regional haze impact analysis was carried out for BWCA and VNP. Visibility analysis is not required for Rainbow Lakes. The recommended methodology for assessing visibility impacts according to the FLAG guidance involves the use of CALPOST to process the data on concentrations of pollutants from the CALPUFF modeling of 24-hour emissions. In CALPOST a daily value of light extinction is defined by the concentrations of each pollutant that can effect visibility, taking into account the efficiency of each particle type in scattering light, and the relative humidity which influences the size of hygroscopic pollutants (sulfates and nitrates). The 24-hour average light extinction caused by emissions from the modeled source(s) is then compared to the background light extinction, a value based upon "natural" or pristine unpolluted conditions for each Class I area.

The standard FLAG visibility analysis was carried out using the CALPOST processing program and Method 2 for calculating source and background light extinction and the percentage change. Results are presented in terms of the maximum percentage change and the number of days (24-hour periods) with percent change exceeding five and ten percent for the BWCA and RLW, for each year of meteorological data.

Natural background light extinction for the BWCA and VNP was calculated from data in the FLAG document. Relative humidity data for calculation of f(RH) in Method 2 is taken from the nearest surface weather station hourly observations. For receptors in the two Class I areas of concern the nearest station is either International Falls, MN or Hibbing MN. A maximum relative humidity cut-off of 95% was specified.

The CALPOST program calculates f(RH) according to the data tabulated in FLAG. In the U.S. EPA's regional haze modeling guidance (U.S. EPA, 2003), they have recommended a slightly different f(RH) function based upon Tang's smoothed data for ammonium sulfate. The EPA data give slightly larger values of f(RH) at intermediate RH, and significantly lower f(RH) at high humidity. The FLAG f(RH) data have been used for visibility modeling, but it would be appropriate to modify CALPOST to use the EPA function for future modeling.

Table D-24 presents results of the CALPUFF visibility analysis following the FLAG methodology, and using "Method 2" of CALPOST for calculation of visibility impacts. The data in Table D-24 indicate that calculated visibility impacts greater than 5 or 10% could occur at some point within the BWCA and VNP on a small number of days each year. Because these data suggest a potential for detectable visibility degradation due to Mesaba One and Mesaba Two emissions, additional analyses were carried out to better quantify and evaluate the possibility of visibility impacts.

There are several factors inherent in the FLAG Method 2 methodology that are conservative in the sense that they lead to the highest likely impact. These include:

- the extinction change calculated for a Class I area represents the largest change for any receptor within the area.
- the change is calculated relative to natural or pristine background; i.e., the best visibility in the absence of any industrial pollution or abnormal natural events such as forest fires.

- no natural visibility impairment due to fog, precipitation, or clouds is considered
- the calculations assume emissions from the modeled source, at the highest daily rate, for every hour and day of the year

There are currently no practical and acceptable ways to include these factors in making a rigorous and more realistic assessment of the probability of actual visibility impairment. However, some procedures have been suggested to account, in part, for potential errors or omissions in the FLAG calculations.

The CALPOST post-processing software contains several alternative algorithms for calculating the change in light extinction due to the modeled source. Method 6 substitutes monthly average relative humidity values (specific to each Class I area) for the hourly relative humidity data at nearby weather stations. This substitution mitigates, to some extent, the high extinction values calculated when very high humidity values are reported throughout the day at the nearest observation site. It is intended to account for the facts that the observed humidity may be unrepresentative of the Class I area, and that very high relative humidities are frequently associated with natural impairment by fog, clouds, and precipitation. The Method 6 calculation is recommended by the U.S. EPA for state regional haze BART analyses.

Method 7 is another modification of the standard Method 2; it attempts to account for natural visibility reduction due to fog or precipitation. In Method 7, the actual measured visibility at the nearest weather station is used as background (instead of natural pristine background) on those hours when fog or precipitation are reported. Method 7 represents another attempt to account for natural visibility reduction in assessing the impact of man-made pollution.

Table D-25 shows the results of Method 6 and Method 7 visibility calculations for Mesaba One and Mesaba Two, with comparison to the Method 2 data. Both alternative analyses indicate lower frequency and magnitude of impacts relative to Method 2. For Method 7, there are only two days of predicted impacts from three years of data exceeding 10% change in light extinction at the BWCA, and none at VNP.

In EPA's BART guidance for regional haze, the 98th percentile of light extinction predictions is recommended as a threshold for significant impact. This means that an average of seven days per year or more of impacts exceeding 5% indicates a significant impact. Under this criterion, the Method 7 results show no significant visibility impact of Mesaba One and Mesaba Two at either Boundary Waters or Voyageurs.

Table D-24
Visibility Results for Mesaba One and Mesaba Two (FLAG Method 2 Analysis)

Year and Parameter	Boundary Waters Canoe Area	Voyageurs National Park
1990 Meteorological Data		
Days > 5%	39	16
Days > 10%	10	1
Maximum Change in light extinction	16.4%	11.8%
1992 Meteorological Data		
Days > 5%	36	25
Days > 10%	15	4
Maximum Change in light extinction	24.1%	19.0%
1996 Meteorological Data		
Days > 5%	17	18
Days > 10%	6	4
Maximum Change in light extinction	15.0%	22.5%

The definition of visibility impairment in 40 C.F.R. 51.301 refers to "any humanly perceptible change in visibility". It has generally been considered that a change in light extinction of 5 to 10% constitutes a just noticeable change in viewing a scene through the atmosphere. But it has been pointed out by Richards (Richards, 1999) that this threshold is only appropriate over a line-of-sight equal to the natural visual range (for the Class I areas in this analysis, a distance on the order of 175 km). For shorter sight lines, a 5 to 10% change in light extinction may not be perceptible. Or, a 5 to 10% local increase in light extinction is not likely to be perceptible over a long sight path for which the average extinction is less. Calculations were made of the average change in light extinction over several 150 km sight lines for the day of highest predicted impact in the BWCA. Using Method 2, the highest Mesaba One and Mesaba Two impact was 24.1% on February 3, 1992 at a receptor near the southern BWCA boundary northeast of the IGCC Power Station. Three sight lines were evaluated: one from the highest receptor directly southwest to the IGCC Power Station, one in the opposite direction from the highest receptor away from the IGCC Power Station, and one extending across the BWCA in an approximate east-west orientation. A separate CALPUFF model run was made for receptors along the three sight lines, and average changes in light extinction were calculated, by Method 2, along each of the three lines. The results showed average extinction changes of 13% (toward Mesaba One and Mesaba Two). 9% (away from Mesaba One and Mesaba Two), and 13.6% (across the BWCA). Though still significant, these calculated average changes are 50% or less of those at the maximum receptor.

Table D-25
Mesaba CALPUFF Visibility Results

Speciated PM	1990	1990	1990	1992	1992	1992	1996	1996	1996
12/5/2005	**Method 2**	**Method 2**	**Method 2**	**Method 2**	**Method 2**	**Method 2**	**Method 2**	**Method 2**	**Method 2**
	> 5 %	> 10 %	Max %	> 5 %	> 10 %	Max %	> 5 %	> 10 %	Max %
Boundary Waters Wilderness	39	10	16.43	36	15	24.11	17	6	14.98
Voyageurs National Park	16	1	11.82	25	4	18.97	18	4	22.47

Speciated PM	1990	1990	1990	1992	1992	1992	1996	1996	1996
12/5/2005	**Method 6**	**Method 6**	**Method 6**	**Method 6**	**Method 6**	**Method 6**	**Method 6**	**Method 6**	**Method 6**
	> 5 %	> 10 %	Max %	> 5 %	> 10 %	Max %	> 5 %	> 10 %	Max %
Boundary Waters Wilderness	24	1	12.12	19	2	11.54	9	0	8.13
Voyageurs National Park	13	0	8.43	14	1	10.22	8	1	12.49

Speciated PM	1990	1990	1990	1992	1992	1992	1996	1996	1996
12/5/2005	**Method 7***	**Method 7**	**Method 7**	**Method 7**	**Method 7**	**Method 7**	**Method 7**	**Method 7**	**Method 7**
	> 5 %	> 10 %	Max %	> 5 %	> 10 %	Max %	> 5 %	> 10 %	Max %
Boundary Waters Wilderness	11	1	10.43	7	1	19.22	2	0	7.63
Voyageurs National Park	3	0	7.93	2	0	6.13	3	0	8.13

* - Hibbing MN used as primary weather station for Boundary Waters Wilderness, International Falls used for Voyageurs NP.

Examination of the meteorology for this single "worst day" shows that temperatures in the BWCA were approximately 22 to 30 deg F, there were a few snow flurries, and a cloud cover of 100% existed at approximately 500 feet above the ground for much of the day. Fog was reported at Hibbing from midnight until 8 PM, with visibility between ½ and 5 miles; at International Falls, fog existed from midnight until 3 PM with visibility less than 1.2 miles until mid-afternoon. Under these conditions, natural conditions would have precluded access to extended scenic views for Park visitors.

An analysis was carried out to characterize the times and meteorological conditions for those days on which CALPUFF, with Method 2, indicated light extinction changes exceeding five percent in either the BWCA or VNP. Hourly meteorological data from Hibbing were assumed to represent the BWCA, and data from International Falls were used for days of impacts at VNP. Days on which fog, precipitation, or low ceiling (less than 3000 feet) occurred were tabulated, along with relative humidity measurements at 6 AM and 12 noon. These times typically represent near highest and lowest humidity values for the day. Also listed for each day was the value of f(RH) used in the CALPOST light extinction calculation. f(RH) represents the daily mean value of the relative humidity parameter that accounts for growth of sulfate and nitrate particles; high values of f(RH) indicate high humidity conditions under which light scattering by these particles is dramatically increased. The value of f(RH) in CALPOST varies from 1.0 for humidity less than 37%, to 9.8 at the maximum CALPOST humidity of 95%.

Results of the meteorological analysis are presented in Table D-26. The main conclusions evident from the Table are:

- Predicted impacts occur predominantly during the winter part of the year; 47 to 61% of all occurrences are indicated between November and March.

- A very high percentage of occurrences coincide with days of natural visibility degradation due to fog, precipitation or low clouds. From 82 to 100% of the days had some occurrence of these weather elements.

- All occurrences of predicted visibility impact were on days of very high relative humidity.

The occurrence of natural visibility degradation on some hours of the day does not necessarily imply that visual impacts of Mesaba One and Mesaba Two emissions could not exist during other periods of the day. There is no practical means of evaluating impacts on an hour-by-hour basis. But since the visibility calculation is made on a daily average basis, it is reasonable to consider natural impacts also in terms of some spatial and time-averaged indicators. At the least, the data in Table D-26 indicate that there were some natural visibility impacts within the Class I areas on nearly all days of predicted Mesaba One and Mesaba Two effects. The analysis shows that modeled impacts overwhelmingly occur on days of inclement weather.

Table D-26
Characteristics of Days with Predicted Visibility Impacts.

Meteorological Characteristic	Boundary Waters Canoe Area		Voyageurs National Park	
	Days > 5% Total 92 Days	Days > 10% Total 31 days	Days > 5% Total 59 days	Days > 10% Total 9 days
Percentage of days November through March	57%	61%	47%	56%
Percentage of days with precipitation	60%	68%	78%	100%
fog	54%	77%	64%	89%
ceiling < 3000 ft	68%	81%	69%	78%
Percentage of days with some natural visibility impairment	82%	94%	88%	100%
Average morning (0600) relative humidity	95%	97%	92%	94%
Average mid-day (1200) relative humidity	76%	85%	75%	83%
Mean daily f((RH)	5.34	6.45	4.73	5.91
equivalent relative humidity	91%	92.5%	90%	92%

Statistics for BWCA from hourly surface weather data at Hibbing MN; statistics for VNP from hourly surface data at International Falls, MN.

To summarize, CALPUFF modeling suggests some days of potential impact at both the BWCA and VNP. However, a number of very conservative elements exist in the FLAG evaluation methodology, and the CALPUFF model chemistry has been shown to significantly overestimate hygroscopic particle concentrations. In consideration of these facts and the meteorological analysis of impact days, it is concluded that Mesaba One and Mesaba Two will have detectable visibility effects on few if any days, and that impacts are highly unlikely to interfere with the visual experience of park visitors.

Results of the Class I area modeling and a more detailed discussion of the impact analyses are presented in Section 8.0 of the permit application. All CALMET, CALPUFF, and CALPOST modeling files in electronic format are included with the application to facilitate review by regulatory agency and FLM modeling staff.

Appendix E

Air Emission Risk Analysis

The Air Emission Risk Analysis and its appendices are attached as electronic files contained in the directory "AERA."

Appendix B

Air Quality

B-1 BACT Analysis
B-2 Cooling Tower Analysis
B-3 Emission Calculations

Appendix B-1

BACT Analysis

APPENDIX B-1
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

In Washington, Best Available Control Technology BACT is required for criteria and toxic air pollutant (TAP) emissions from new and modified industrial sources. This Appendix presents a BACT analysis for emission units associated with the PMEC. The basis for the emissions-related analyses is annual average operation at a design capacity of nominally 600 gross megawatts (MW). The proposed PMEC as currently configured will involve the following major processes and emission units:

- Two Syngas-Fired Combustion Turbines;
- Two Heat Recovery Steam Generators (HRSG) and two Steam Turbine-generator;
- Two 6-cell, Recirculating, Mechanical-draft Cooling Towers for the combined cycle plants;
- One 7-cell Recirculating, Mechanical-draft Cooling Tower for the Air Separation Unit;
- One Auxiliary Boiler
- Solid Feedstock Receiving and Handling (railcar and ship facilities, feeding two storage domes)
- Gasification Plant, including Enclosed Flare
- Slag Handling System
- Syngas Cleanup Processes
- Tank Vent Oxidizer System
- Emergency, Diesel Engine-Driven Generator and Fire Water Pump

B-1.1 BACT ANALYSIS OVERVIEW AND RESULTS SUMMARY

The proposed BACT controls and associated emission rates for each emission unit are summarized in Table B-1-1. Project sources addressed in this table include:

- Combustion turbines
- Railcar solid feedstock unloading to storage bins
- Ship solid feedstock unloading to storage bins
- Feedstock preparation plant (handling systems, rod mill)
- Sulfur recovery unit
- Gasification island flare
- Tank vent collection and boiler system
- Auxiliary boiler

- Cooling towers
- Emergency diesel engines

The IGCC process converts fossil fuel feedstock (petroleum coke, coal, or a combination) into a synthesis gas (syngas), which then can be used to fuel combustion turbines to generate electricity. Figure 2.3-1 of this Application provides an illustration of the proposed PMEC complex indicating the layout of the major plant components within the site.

In this application Energy Northwest is proposing the installation of Selective Catalytic Reduction (SCR) as an (Innovative Control Technology) ICT (defined in 40 CFR 52.21(b)(19)), which surpasses EPA established BACT NO_x control at IGCC facilities. This will be the first proposed installation in the western United States of post-combustion add-on emission controls on syngas-fired combustion turbines. While SCR is commonly used to limit NO_x emissions from natural gas-fired combustion turbines, no prior New Source Review (NSR) permits for IGCC facilities have specified this or any other post-combustion control technology as BACT for NO_x. The explanation for this history is the potential for adverse effects of syngas combustion products on the SCR catalyst and other technical barriers to SCR implementation at IGCC power plants. SCR may only be considered as technically feasible at a cost level much higher than is acceptable for BACT-based emission limits, and as noted above, its performance has never been demonstrated for turbines at an IGCC plant. Petroleum coke (petcoke) or coal-derived syngas is sufficiently different in composition compared to natural gas that SCR cannot be assumed to provide reliable NO_x emissions control without very high additional expenditures to remove sulfur and other contaminants from the syngas fuel. PMEC plans to accomplish this through the addition of a Selexol ® or equivalent system

TABLE B-1-1
PROPOSED BACT FOR THE PMEC

Pollutant	Control	Emissions Limits
IGCC Combustion Turbines (Emissions shown per combustion turbine excluding Start up / Shutdown conditions). All values in lb/MMBtu are based on fuel energy input of feedstock to the gasifiers.		
NO_x	Diluent Injection (BACT Limit)	15 ppm NOx @ 15% O_2 on syngas gas fuel, 3-hour average
		25 ppm NOx @ 15% O_2 on natural gas fuel, 3-hour average
	Selective Catalytic Reduction (ICT Limit)	3 ppm NOx @ 15% O_2 on syngas gas fuel, 3-hour average
		5 ppm NOx @ 15% O_2 on natural gas fuel, 3-hour average
CO	Good Combustion Practices (GCP)	15 ppm @ 15% O_2 (above 50% load) 3-hour average
PM/PM_{10}	GCP, gas cleanup, Gaseous Fuels only	0.009 lb/MMBtu heat input to gasifier

Table B-1-1 (Continued)
Proposed BACT for the PMEC

Pollutant	Control	Emissions Limits
SO_2	Gas cleanup (BACT Limit)	50 ppmvd H_2S in undiluted, unsaturated syngas, rolling 30-day average
	Selexol® Gas Cleanup (ICT limit)	10 ppmvd H_2S in undiluted, unsaturated syngas, rolling 30-day average,
VOC	GCP	0.003 lb/MMBtu heat input to gasifier
NH_3	Molar ratio control on Injection Sys.	5 ppmvd @ 15% O_2 (ammonia slip), 20 lb/hr (ICT-based Limit)
H_2SO_4	Gas cleanup/ Limit on reduced sulfur in syngas	3.2 lb/hr, 13.83 tpy (10 ppm S)
Mercury	Syngas Cleanup Process	0.0033 lb/hr
Railcar Unloading Building and Transfer to Storage Domes (3,186 tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.171 lb/hr
Ship Unloading Facility and Transfer to Storage Domes (1,900 tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.436 lb/hr
Storage Domes Ventilation (3,186 maximum tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.085 lb/hr
Gasification Island Enclosed Flare (capacity of 3,730 MMBtu/hr as syngas) - Assumes worst-case upset (85% of max syngas capacity for gasifiers).		
NO_x	GCP	Exit velocity > 60 meters/second
CO	GCP	
PM/PM_{10}	GCP, gaseous fuel only	
SO_2	GCP, Gas cleanup/Limit on reduced sulfur in syngas	Natural gas purge Steam or air assisted flare design
VOC	GCP	
Tank Vent Collection System and Vapor Processing Unit		
NO_x	GCP, low-NOx burner	0.3 lb/MMBtu fired, 3-hr average
CO	GCP	0.09 lb/MMBtu fired, 3-hr average
PM/PM_{10}	GCP, gaseous material only	0.01 lb/MMBtu fired, 3-hr average
SO_2	Gas cleanup/Limit on reduced sulfur in syngas	5.8 lb/hr SO_2 (1-hour average) 4.2 llb/hour SO_2 (24-hour average)
VOC	GCP	0.004 lb/MMBtu fired, 3-hr average
Auxiliary Boiler (Natural Gas-Fired, 130 MMBtu/hr heat input)		
NO_x	GCP, low-NOx burner	0.036 lb/MMBtu fired, HHV, 3-hr average
CO	GCP	0.074 lb/MMBtu fired, HHV, 3-hr average
PM/PM_{10}	GCP, natural gas fuel only	0.005 lb/MMBtu fired, HHV, 3-hr average
SO_2	GCP, natural gas fuel only	0.00286 lb/MMBtu fired, HHV 3-hr average
VOC	GCP, natural gas fuel only	0.004 lb/MMBtu fired, HHV, 3-hr average

Table B-1-1 (Continued)
Proposed BACT for the PMEC

Pollutant	Control	Emissions Limits
Cooling Towers (2, 6-cell, Mechanical Draft Type)		
PM/PM_{10}	High Efficiency Mist Eliminators, TDS limit in circulating water	0.0010% draft as percent of circulating water
Emergency Diesel Engines (1, 300 hp firewater pump; 1, 2-MW, 2682 hp generator) - assumes 100 hours per year normal maintenance operation per engine.		
NO_x	Combustion controls, restricted operating hours	Operatons limited to < 100 hours/year Use of low-sulfur (0.05 weight percent) diesel fuel.
CO	Combustion controls, restricted operating hours	
PM/PM_{10}	Combustion controls, restricted operating hours, low-sulfur diesel fuel	
SO_2	Low-sulfur diesel fuel, restricted operating hours	
VOC	Combustion controls, low-sulfur diesel fuel, restricted operating hours	

The following sections describe the BACT demonstration process, the unique characteristics of IGCC and syngas that affect facility emissions, and the individual control technology evaluations for each emission unit and pollutant subject to BACT-based limits. Important information is provided comparing the BACT-based limits proposed for NO_x and the alternative limits that are based on adoption of an ICT for the PMEC.

This BACT analysis accounts for combustion turbine unit and syngas clean-up startup cycles, as well as normal operations of this equipment. There will be higher transient emission rates for NO_x, CO and VOC during each turbine start-up event than during normal turbine operations. This is explained by decreased fuel combustion efficiency during the early stages of a startup event and exhaust temperatures that will initially be below the lower end of the SCR operating range. Accordingly, the total annual emissions have been calculated throughout this Application with a conservative assumption of 50 hours of startup operating mode per turbine per year, with normal turbine operations at 100% of capacity for the remaining hours of the year. In practice, a more realistic capacity factor of 90% or less is more likely to occur.

To evaluate BACT for the emission units at an IGCC plant, it is important to understand the IGCC process. Detailed process descriptions for the proposed facilities are given in the main body of this Application. In addition, Section B-1.3 gives a general overview of the regulatory mechanism and requirements for adopting an ICT as part of a New Source Review permit. Sections B-1.4 and B-1.5 provide background on existing or proposed IGCC facilities in the United States, their expected emission levels, and the unique characteristics of this process that must be considered in a BACT evaluation.

B-1.2 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)]*

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below (from the EPA's Draft New Source Review Workshop Manual, 1990)[1]:

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction."

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[1] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams’ physical and chemical characteristics.

For this BACT analysis, the available control options were identified by querying the EPA RBLC and by consulting available literature on control options for IGCC. The analysis also involves review of currently permitted and operating IGCC facilities.

B-1.3 INNOVATIVE CONTROL TECHNOLOGY PROVISIONS

The Washington Department of Ecology (Ecology) air quality regulations have incorporated by reference the federal definition of ICT, as it relates to emission controls adopted as part of a PSD

permit. EFSEC, in turn, has adopted by reference virtually all the provisions of WAC 173-400, including the section related to ICT. To utilize these provisions, a new major source may request that EFSEC approve the implementation of an air pollution control system as an ICT, including special conditions regarding a demonstration phase to achieve effective control. The definition of ICT, as referenced by Washington Administrative Code (WAC) 173-400-720 (4)(a)(v), is provided in Title 40, Part 52 of the Code of Federal Regulations:

> *"...any system of air pollution control that has not been adequately demonstrated in practice but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice, or of achieving at least comparable reductions at lower cost in terms of energy, economics, or non-air quality environmental impacts." [40 CFR 52.21(b)(19)]*

Adoption of an ICT as part of a project includes conditional permit limits that are typically more stringent than BACT-based limits. However, the ICT limits do not completely replace the role of BACT in the new source's permit. The BACT-based limits for the source are still included in the new source's permit in the event that the more stringent levels anticipated for the ICT are not achieved in practice. The ICT-based limits also do not, by their inclusion in the permit, represent a more stringent BACT determination for the affected source category.

In a practical sense, several conditions must be met before the Department can approve the installation of an ICT in conjunction with issuing or revising an air quality permit. These conditions are:

1. The source demonstrates that the proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function.

2. fThe source agrees to a level of continuous emissions reduction equivalent to that which would have been required as a BACT limit by a date specified in the permit or permit revision.

3. Before the date specified in the permit or permit revision, the new source must be able to demonstrate that the achieved emissions (with or without ICT) would not:

    a. Cause or contribute to any violation of an applicable state ambient air quality standard; or

    b. Impact any area where an applicable increment is known to be violated.

4. All other applicable requirements for adoption of the PSD permit conditions, including those for public participation and regional EPA approval, have been met.

A recent precedent in which Ecology included ICT-based limits and related provisions is the PSD permit issued on August 2004, Permit Number PSD-04-01, to the Kennewick Fertilizer Operations (KFO) of Agrium U.S. Inc. for modification of emissions controls on nitric acid plants at their facility in Kennewick, Washington. This permit included a schedule of ICT-based emission rate milestones to be demonstrated for KFO Plant 9. In effect, a sequence of decreasing

daily NO_x emission rate milestones (in units of lb/day) was established for the initial 48 months of source operation after the modification.

The PMEC proposes to implement SCR in concert with enhanced syngas cleanup with the Selexol® or equivalent® process as ICT. In the case of other proposed and permitted IGCC plants, SCR has not been deemed feasible as BACT. Only by making a sizeable investment in more complete syngas desulfurization, beyond that normally deemed BACT for SO2 emission limits, can the PMEC reasonably attempt to utilize SCR for NO_x control, thus potentially reducing NOx emissions of that pollutant by a further 80%.

There is no commercial operating experience with SCR on ICGC plants utilizing coal-derived syngas. However, there is a "substantial likelihood" that the proposed control technology package can achieve reduced NO_x emissions from combustion of syngas. The primary uncertainties, which are substantial, relate to several factors, including system reliability, performance at all operating conditions, reduced catalyst service life, and elevated operating costs. The proposed final ICT NO_x emission limits are shown in Table B-1-1 for the IGCC combustion turbines. Further, as shown below, the proposed PMEC using Selexol® or equivalent with SCR meets each of the previously stated criteria for treatment as an ICT:

1) Both the Selexol® systems and SCR processes are well-established at refineries, utility generating plants, and for larger gas preparation / combustion sources in other industries. Handling and bulk storage of an ammonia solution is necessary to provide a reagent to facilitate the SCR reactions that convert NO_x to elemental nitrogen, but this can be accomplished safely with suitable equipment and work practice safeguards, as evidenced by the routine use of this technology on combustion turbines utilizing natural gas. When properly designed, installed and operated the Selexol®/SCR processes do not "cause or contribute to an unreasonable risk to public health, welfare, or safety."

2) Energy Northwest will agree to include in the requested permit a requirement to achieve by a date-certain a continuous level of NO_x emission control that is at least as stringent as that corresponding to BACT limits for the IGCC combustion turbines.

3) Energy Northwest has supplied with this Application a suitable ambient air impact analysis that demonstrates, based on accepted dispersion models, that the new PMEC combustion turbine emissions, based on ICT limits or the alternative BACT-based limits, will not cause or contribute to violations of an ambient air standard or PSD increment.

4) Lastly, all of the prescribed PSD permit processing requirements for adoption of the ICT and BACT based limits will be met, including public participation and EPA Region 10 review.

The analysis to establish the alternate NO_x emission limits from the PMEC combustion turbines has been included in Section B-1.7.1, in order to support the BACT-based limits that must also be included in the requested PSD permit. In developing the requested permit, Energy Northwest

intends to work with EFSEC to establish a reasonable set of demonstration milestones and a timetable for ICT implementation. It is anticipated that the ICT criteria in the permit could also be based on observed system reliability. To illustrate, if there is evidence after a sufficient test period that the use of Selexol® or equivalent and SCR will not be capable of reliably achieving the ICT limits described above, then some relaxation of these limits will be warranted. Dispersion modeling presented in this application demonstrates that compliance with applicable Washington and National Ambient Air Quality Standards and PSD increments would continue to be achieved, even in the extremely unlikely event that the proposed ICT NO_x control package provided no emission reduction beyond BACT-level controls.

B-1.4 PROJECT SOURCES SUBJECT TO BACT ANALYSIS

To evaluate possible emission control technologies, it is first important to understand the unique IGCC process and the supporting ancillary plant processes. The process descriptions for the various processes that make up the PMEC are included in Chapter 2 of this Application. The PMEC will consist of several facilities/systems representing sources of regulated air pollutants that are addressed in this BACT analysis:

- Combined Cycle Combustion Turbine Generators (Two Units)
- Railcar Solid Feed Stock Unloading and Transfer Points
- Ship Solid Feed Stock Unloading and Transfer Points
- Solid Feed Stock Storage Dome Vents
- Gasification Island Flare
- Tank Vent Collection and Boiler System
- Auxiliary Boiler (One Unit)
- Cooling Towers (two 6 and one 7 cell units)
- Emergency Diesel Engines (Generator and Fire Water Pump)

B-1.5 CONSIDERATION OF ALTERNATIVE GENERATING TECHNOLOGIES

This section addresses recent guidance relating to the need for consideration of alternative electrical generating technologies for the proposed project, as part of the BACT analysis. Compared to Pulverized Coal (PC)-fired Boilers and Circulating Fluidized Bed (CFB) Boilers, the proposed IGCC process is indeed the very lowest emitting solid fuel-based electricity generating technology available, and selection of a completely different solid fuel-based generating technology would not result in lower emissions. Later portions of this BACT analysis address the specific controls that are proposed to minimize the emissions from the proposed IGCC process.

As introduced in Section B-1.2, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures and inherent process characteristics that minimize generation of pollutants. Additionally, it is sometimes possible to modify the production process

or work practices to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, are properly considered in a BACT analysis. In contrast, consideration of alternatives that would involve completely "redefining the design" of the proposed process are not required to be considered (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative generating processes, such as natural gas-fired combined-cycle plants, represent a completely different family of power generation plant designs from IGCC. While there are certain types of components in common, such as cooling towers and steam-driven turbine generators, the technical basis for a gas-fired plant differs markedly from that of the IGCC facility.

Since CFB or PC boilers or a natural gas-fired electrical generating plant would be completely different processes, and represent "redefining the design" compared to IGCC, it is reasonable to conclude that EPA would not require that the BACT analysis for PMEC compare these different technologies. This point was recently reinforced in a December 13, 2005 letter from Stephen Page, Director of EPA's OAQPS, to E3 Consulting, LLC regarding BACT requirements for proposed coal-fired power plant projects. In that letter, EPA clarified that a BACT analysis need not consider an alternative "which would wholly replace the proposed facility with a different type of facility."

The remainder of this BACT analysis describes the various emission control options for specific IGCC facility processes, and demonstrates that the proposed PMEC would achieve the lowest emissions rate technically and economically feasible for such a facility.

B-1.6 EXISTING AND PERMITTED IGCC FACILITIES

For this BACT analysis, the available control options were identified by querying the RBLC database and by consulting available literature on control options for IGCC. Applications and/or permits from a number of other IGCC facilities that have completed the New Source Review process were also reviewed to provide additional reference material for this BACT analysis. A brief summary of the other permitted IGCC plants in the United States and their emissions limits is presented in this section.

Other existing or permitted IGCC facilities include the following examples:

- SG Solutions, Wabash River Generating Station, West Terre Haute, Indiana (operating);
- Tampa Electric Company, Polk Power Station, Mulberry, Florida (operating);
- Global Energy, Inc.'s Kentucky Pioneer Energy LLC, Trapp, Kentucky (permitted/not constructed);
- We Energies, Elm Road Generating Station, Wisconsin (permitted/not constructed);
- Global Energy, Inc.'s Lima Energy Company, Lima, Ohio (permitted/not constructed);
- Steelhead Energy Center, Southern Illinois Clean Energy Center
- ERORA Group, Taylorville Energy Center

The air permits, BACT analyses and additional literature for each of these existing or proposed facilities and several other proposed IGCC plants that have yet to complete permitting were reviewed. Each facility is discussed briefly below and Table B-1-3 summarizes the criteria pollutant emission levels permitted for the combustion turbines units at each facility. The facilities that were subject to BACT determinations are listed as such.

Wabash River Generating Station and PSI Combined Cycle Power Station: The DOE and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI) initiated the Wabash River Coal Gasification Repowering Project. The gasification island includes an E-Gas (originally developed by Dow Chemical and known earlier as Destec Technology, and now operated by SG Solutions) two-stage, oxygen blown gasifier with full heat recovery that is integrated with the power block. This facility has been operated since 1995.

Tampa Electric Company - Polk Power Station: The DOE partly funded the Polk Power Station IGCC project. The facility includes a Texaco (now GE Energy) oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996.

Global Energy - Kentucky Pioneer Power Station: Global Energy USA (Global), owner of Kentucky Pioneer Energy, LLC, negotiated with the DOE and Clean Energy Partners, LP to acquire a conditionally approved IGCC Demonstration Project. The British Gas/Lurgi (BG/L) slagging fixed-bed gasification technology has been proposed in a new 540 MW (net) IGCC facility using both coal and refuse derived fuel as a feedstock. The gasification system would be coupled with Fuel Cell Energy, Inc.'s molten carbonate fuel cell. The air permit for this facility was originally issued in June 2001, and has been extended conditioned on revision of the BACT Analysis; this project is not expected to go forward.

Global Energy - Lima Energy Power Station: Lima Energy Company, a Global Energy company, obtained a final Ohio EPA Permit to Install an IGCC facility in Lima, Ohio. The 540 MW (net) IGCC is expected to use ConocoPhillip's E-Gas entrained flow gasification technology to convert high sulfur coal or petroleum coke into syngas. The air permit was issued in 2002. Construction of the feedstock storage building has begun in order to keep the PSD permit in place while Global decides on whether or not to continue the project.

We Energies - Elm Road Generating Station: We Energies recently proposed a new 600 MW net nominal base-load IGCC generating unit at the Elm Road Generating Station. The facility includes a gasification plant, sulfuric acid plant, two combustion turbine generators and HRSGs, and a steam turbine generator. The permit for this facility was received in January 2004. However, commencement of construction was linked to a determination of need and further acceptance by the Public Utility Commission, which ultimately rejected We Energies' proposal to advance the project.

ERORA Group - Taylorville Energy Center: The ERORA Group is developing the Taylorville Energy Center, a 630 MW (net) IGCC facility to be located in Southern Illinois, and the similar Cash Creek Generation IGCC facility, to be located near Owensboro, Kentucky. They are proposing to use GE Energy gasification technology at both facilities, using local coals

(Kentucky coal for Cash Creek and Illinois coal for Taylorville) as the feedstocks. Both will use Selexol AGR systems, as well as SCR. Neither site is in an ozone non-attainment area, so SCR is not required for BACT purposes. ERORA is using SCR to minimize NO_x emissions from the plant, but not as BACT. This will allow them to minimize the cost to acquire NO_x allowances from the market. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal, by using Selexol instead of MDEA, will be required. Both the Taylorville and Cash Creek applications are under agency review.

Steelhead Energy: Southern Illinois Clean Energy Center This proposed facility will incorporate IGCC with co-production of synthetic natural gas (SNG). The 544 MW (net) facility is proposed to consist of an IGCC plant that will provide syngas to two combustion turbines, with additional syngas being processed in a methanation facility to produce SNG. The primary feedstock for the facility will be Illinois #6 bituminous coal from an adjacent mine. The IGCC facility will consist of two ConocoPhillips gasifiers with syngas cleanup, sulfur or sulfuric acid plant and mercury removal systems. The primary fuel for the combustion turbines will be syngas from the IGCC unit. Natural gas from the SNG unit will be available for startups and as a backup fuel. According to discussions with State of Illinois EPA staff, this project may be re-located to another site, and may only include SNG production, without IGCC power production.

TABLEB-1-3
PERMITTED EMISSION RATES FOR IGCC UNITS

In lbs/MMBtu gasifier fuel energy input (approximate) Location	MMBtu/hr as coal to gasifier or Plant MW (estimated)	CO	NOx	SO_2	PM	VOC
Wabash River (operating)	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station (operating)	2,191	0.045	0.101	0.170	0.008	0.001
Kentucky Pioneer	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy	4,413	0.035	0.067	0.022	0.008	0.007
We Energies	5,424	0.024	0.059	0.023	0.008	0.003
Steelhead Energy Center	544 MW	0.04	0.059	0.033	0.0092	0.0029
Taylorville Energy Center	677 MW	0.036	0.058	0.045	0.007	0.008
PMEC Proposed IGCC	600	0.036	0.012 (3- hr, ICT)	0.016 (3-hr, ICT)	0.0010	0.003

The emission rates listed in Table B-1-3 have been estimated based on permit documents or other published information on the respective facilities and converted to the units of lbs per million Btu of gasifier feedstock, for the purposes of general comparison. The actual permitted levels and/or BACT determination in many cases are expressed in units different than lbs/MMBtu, and may be expressed on the basis of MMBtu input of syngas fuel to the combustion turbines rather than MMBtu to the gasifier (the correct basis). The conclusion to be drawn from this comparative review is that proposed BACT limits for the PMEC are similar to, or more stringent than, those that have been accepted in other recent IGCC permits throughout the United States.

In addition to the units listed in the table above, OUC and Southern Power Company have proposed a nominal 285 Megawatt (net) IGCC Unit (Stanton Unit B) and auxiliary equipment. Unit B will consist of: an air-blown coal gasification system that produces syntesis gas (syngas); one syngas and natural gas-fired General Electric 7FA+e combustion turbine-electrical generator (CT); a duct burner within a supplementary-fired heat recovery steam generator (HRSG); a steam turbine electrical generator (STG); an exhaust stack and a multi-point ground flare. The project was selected by the Department of Energy for funding under Round 2 of the Clean Coal Power Initiative. A Preliminary Determination and draft construction permit for this project were issued by the Florida Department of Environmental Protection Division of Air Resource Management in the summer of 2006.

The IGCC process represents a unique generating technology with promises of increased efficiency, fuel flexibility, low emissions, and opportunities for carbon sequestration. However, it is relevant to note that while there has been significant interest in IGCC facilities, few projects permitted in the past several years have moved substantially forward. The lack of progress toward widespread commercialization of this promising technology is due largely to the fact that the first generation of IGCC plants has incurred significant financial and operational risks. This burden is significant and should be considered in the determination of required emissions controls, particularly if the use of higher levels of controls or unproven methods might add significantly to the costs, reliability or other operational risks of the PMEC.

B-1.7 COMBUSTION TURBINE BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the combustion turbines of the proposed PMEC to determine appropriate BACT emission limits. This BACT analysis is based on the current state of IGCC technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

B-1.7.1 NITROGEN OXIDES BACT ANALYSIS

The criteria pollutant nitrogen oxides (NO_x) is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Syngas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the PMEC combustion turbines will originate as thermal NO_x.

As noted in Section B-1.4 of this Appendix, an IGCC combustion turbine is an inherently low-emitting process. The proposed PMEC combustion turbines can nominally achieve 0.06 lb/MMBtu using diluent injection (i.e., without SCR). The remainder of this analysis considers the use of this lower-emitting IGCC process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbines.

The rate of formation of thermal NO_x in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_x control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent

injection (steam, water, or nitrogen) and dry low-NO_x burners. These technologies are considered to be commercially available pollution prevention techniques. It is necessary to recognize the fundamental differences between natural-gas fired and syngas-fired combustion turbines in evaluating these techniques. Compared to natural gas, syngas has a much higher hydrogen content (natural gas is often over 90% methane), and a much lower heating value (about 250 Btu/scf for syngas vs. 1,000 Btu/scf for natural gas). Also, the pretreatment of the syngas includes a moisturization step which increases the content of water vapor in the gas. Taken together, these differences alter the combustion kinetics of the burner flame in a manner that prevents the use of lean-premix combustion techniques, which are the defining feature of effective Low-NO_x burner design [2].

B-1.7.1.1 Identify Control Technologies

Possible control technologies for the proposed turbines were identified by examination of previous IGCC permits and through RBLC queries for natural gas-fired combined cycle (NGCC) combustion turbines. All previous BACT and LAER determinations for IGCC facilities have resulted in the finding that diluent injection represents the best available control for NO_x. However, for this top-down analysis, all of the following technologies were considered to be potentially available for the PMEC combustion turbines:

<u>Combustion Process Controls</u>

- Dry Low NO_x burners
- Diluent injection (nitrogen or steam)

<u>Post-Combustion Controls</u>

- $SCONO_x$™
- SCR
- Selective non-catalytic reduction (SNCR)

B-1.7.1.2 Evaluate Technical Feasibility

Each identified technology is first examined to determine if it is technically feasible for IGCC combustion turbines burning coal-derived syngas. First, controls potentially achieved by modifications to the combustion process itself are considered. Next, potential control methods utilizing add-on control equipment, such as SCR, to remove NO_x from the exhaust gas stream after its formation during combustion are examined.

Dry Low NO_x Burners

Dry Low-NO_x (DLN) burners control NO_x formation in conventional Natural Gas Combined Cycle (NGCC) combustion turbines by staged combustion of the natural gas. This is done by

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[2] "Major Environmental Aspects of Gasification-Based Power Generation Technologies", U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory, December 2002.

designing the burners to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Syngas differs from natural gas in heating value, gas composition, and flammability characteristics. Existing DLN burner technologies available for combustion turbines were designed for natural gas (methane-based) fuels and will not operate on the syngas (H_2/CO-based) fuels utilized by IGCC combustion turbines. DLN combustors are not technically feasible for this application due to the potential for explosive mixtures in the combustion section due primarily to the high hydrogen content of the syngas. No manufacturer currently makes DLN burners that can be used for a combustion turbine burning petroleum coke or coal-derived syngas. Combustion turbine vendors are currently researching DLN for syngas-fueled combustion turbines, but such combustors are not yet commercially available. Therefore, DLN burners are not a technically feasible control option for this unit.

Diluent Injection

The addition of an inert diluent such as atomized water or nitrogen into the syngas before combustion, and/or steam or nitrogen injection into the high temperature region of a combustor flame serves to inhibit NO_x formation by reducing the peak flame temperature. For the PMEC, the syngas will be diluted with nitrogen and moisturized to condition it for use in the combustion turbine. This effectively lowers the fuel heat content and, consequently, the combustion temperature, and therefore reduces NO_x emissions. Another level of this control option is steam injection directly into the combustion zone to cool temperatures and reduce NO formation. Diluent injection can achieve emission levels of 15 ppmvd NO_x (at 15 % oxygen) when firing 100% syngas. A secondary benefit of diluent injection is that it will increase the mass flow of the exhaust and, thus, the power output per unit of fuel input also increases. It is important to note that the best performance achievable for combustion turbines that are optimized for syngas is 25 ppm NOx when they are firing natural gas.

Diluent injection represents an inherently lower-emitting process for IGCC units, and is a technically feasible control technology. Diluent injection (water vapor and nitrogen) during the conditioning of the syngas is proposed as the BACT limit basis for the PMEC combustion turbines. This option will achieve NO_x levels of 15 ppmvd (at 15% O_2) over a 3-hour average (excluding start up, shutdown and upset periods), and is proposed as the baseline case for the IGCC combustion turbine NO_x BACT analysis. This NO_x control technology and emission level have also been determined as BACT for all other recent IGCC permits.

SCR

SCR is a technology that achieves post-combustion reduction of NO_x from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a specialized catalyst module, promoting conversion of NO_x to molecular nitrogen. The hardware of an SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), the structured, fixed-bed catalyst module, and electronic controls. This is an increasingly common control technology for use on NGCC combustion turbines. However, the design conditions and performance concerns are different for each technology, and a single SCR design is not generally transferable from one generating technology to another.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are:

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

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In natural gas turbine, NO_x removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Certain compounds such as sulfur and certain metals, if present in the exhaust gas stream, can "poison" the catalyst, reducing its performance and useful life, impact catalyst activity, or inhibit conversion efficiency.

The typical effective temperature range for base-metal SCR catalysts is 600 to 800˚F. If the exhaust gas temperature drops below 600˚F, the reaction efficiency becomes too low and increased amounts of NO_x and NH_3 will be released out the stack to the atmosphere. The exhaust temperature after the heat recovery steam generator (HRSG) in a combined cycle unit will be only about 250˚F. Since this temperature is too low for the SCR reactions to occur, SCR catalyst would need to be located upstream of the HRSG where the exhaust gas temperature conditions are favorable.

The most significant SCR feasibility issue for this project is the fact that the syngas contains reduced sulfur compounds, even after the high-efficiency sulfur recovery proposed for the PMEC plant. These drawbacks are reduced, but not eliminated, by the utilization of Selexol® technology for additional sulfur removal to the extent practical. After combustion, some of the oxidized sulfur will form ammonium-sulfur salts in the presence of the ammonia reagent that can impact the SCR catalyst and equipment downstream.

This path of fuel sulfur through the process starts with oxidation of syngas sulfur during combustion, primarily to SO_2 and also a small fraction to SO_3. If SCR were installed, the vanadium in the SCR catalyst would oxidize additional amounts of the SO_2 in the flue gas to SO_3. Adsorption of these sulfur oxides can deactivate the catalyst reaction sites, tending to shorten the effective catalyst service life. In addition, some of the NH_3 reagent injected upstream

of the catalyst will react with the available vapor phase SO_3 to form ammonium sulfate and ammonium bisulfate salts. These salts will largely remain in the vapor phase at the elevated temperature of the SCR system. However, as the exhaust gas cools in the HRSG and further downstream, the gas will drop below the sublimation temperature of these compounds and they will begin to precipitate out, forming corrosive, sticky particles. Accumulation of these salts can cause serious corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer efficiency, even at the relatively low levels of sulfur present in the syngas.

As deposits of ammonium salts increase, they would need to be cleaned periodically from the surface of the HRSG heat transfer fins in order to restore heat transfer efficiency and pressure within the HRSG. The PMEC is incorporating specific design features in the HRSG to facilitate such cleaning, as necessary, downstream of the SCR module. Absent costly design features, adequate cleaning of the heat transfer fins is difficult in a conventional HRSG because of the following:

- Access to interior tube banks is restricted in a compact HRSG module;
- Excessive capital cost and potential for leakage would be encountered if the HRSG heat exchange elements were designed for removal/replacement; and
- The HRSG is in close proximity to upstream catalyst modules; power washing of the HRSG would increase the possibility of inadvertently flooding the fixed-bed catalyst, which would damage it.

The other main feasibility issue with SCR on IGCC units is the potential presence of trace metals and other trace compounds in syngas, which are known to deactivate the sensitive SCR catalyst. For example, arsenic is known to deactivate certain types of catalyst, and the deactivation rate can vary in the presence of other compounds, such as calcium. Research is ongoing to understand how individual and various combinations of flue gas constituents may impact catalyst deactivation rates and performance. Because no full-scale IGCC unit has been tested or operated with SCR in a coal-derived syngas environment, many unknowns remain regarding the potential impacts of trace constituents such as arsenic, nickel, lead, and cadmium. Consequently it is difficult to predict SCR system performance, control efficiency, or catalyst life for this unique application. These uncertainties reinforce the need for SCR to be considered an ICT, as described previously.

There is a growing experience base of SCR use on conventional PC units that seem to suggest that SCR should work in the seemingly less extreme exhaust conditions of an IGCC combustion turbine. However, many key process parameters are different in an IGCC versus a PC unit, and these differences may significantly impact SCR's feasibility, cost, design, and performance in this unique service environment. Key differences for an IGCC compared to a PC plant SCR system application include the following:

- SCR performance expectation in conventional PC unit service is significantly lower (i.e., higher outlet NO_x) than would be needed in this case. PC-based SCR systems typically achieve about 0.07-0.10 lb NO_x/MMBtu with SCR, which is greater than the PMEC proposed level (nominally 0.06 lb/MMBtu for a 3-hour average) without any add-on controls.

- Ammonium bisulfate salts may form in a PC unit air preheater, which is of a very different design from a HRSG. Air preheaters can be designed to accommodate more frequent cleaning, and are thus better-suited to handling precipitation/deposits/corrosion. Air preheater heat transfer baskets are not impacted as much by corrosion as the heat transfer fins in a HRSG.
- Ammonia preferentially adsorbs onto the fly ash produced from a PC unit, so that sulfates and bisulfate can be captured in downstream particulate matter control equipment.

Recent papers by EPA[3] and DOE[4] recognize the challenges associated with the application of SCR to IGCC. These concerns are well-known and validated in the technical literature, and raise legitimate questions regarding the practicality of SCR for this (or any other) IGCC project. However, Energy Northwest proposes to adopt this aggressive control technique along with additional syngas sulfur cleaning as an ICT. This option must be viewed as an enhanced level of emission control that is more stringent than BACT. As explained at the end of Section B-1.2 of this Appendix, EPA does not consider a technology "available" until it has reached commercial availability for the intended service. While SCR is clearly an "available" technology that is commercially demonstrated for many applications, SCR is only at the "concept stage" for IGCC. EPA's New Source Review Workshop Manual[5] specifically states that "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

The question of SCR feasibility in IGCC service has been addressed recently by several other proposed projects and their state and regional environmental agencies. Polk Power Station in Florida, Kentucky Pioneer LLC in Kentucky, Lima Energy LLC in Ohio, and We Energies in Wisconsin have all finalized or updated BACT determinations for their IGCC projects. The state environmental agencies in Florida, Kentucky, Ohio, and Wisconsin, along with US EPA Regions IV and V, have determined BACT for those IGCC projects to be 15 ppm NO_x @15% O_2 using diluent injection (when firing syngas). In each case, SCR was rejected as BACT. This finding is consistent with recent previous BACT determinations for IGCC units using solid feedstocks such as petroleum coke and/or coal.

In summary, SCR has never been employed at an IGCC facility using a solid feedstock such as coal or petroleum coke. No previous BACT determination has found SCR to be technically feasible and economically feasible on an IGCC. On this basis, PMEC is requesting that the adoption of SCR in conjunction with an enhanced level of Selexol® or equivalent-based syngas sulfur removal, be treated as an ICT for purposes of incorporating permit conditions that allow a sufficient incremental timeframe for technology demonstration and final determination of NO_x

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[3] "Environmental Impact Comparisons IGCC vs. PC Plants", Kahn, Wayland, and Schmidt of US EPA, presented at Pittsburgh Coal Conference, September 2005.

[4] "Major Environmental Aspects of Gasification-Based Power Generation Technologies", U.S. DOE/NETL, December 2002

[5] Pg. B-12, "New Source Review Workshop Manual" Draft 1990, EPA Office of Air Quality Planning and Standards.

emissions. Generally accepted BACT for IGCC combustion turbines is diluent injection, and this should be identified as the basis for BACT emission limits in the PMEC permit as well.

SCONOx

The $SCONO_x$™ system is an add-on control device that reduces emissions of multiple pollutants. $SCONO_x$™ control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). $SCONO_x$™ utilizes a single catalyst for the reduction of CO, VOC and NO_x, which are converted to CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of $SCONO_x$™ requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several $SCONO_x$™ units in commercial installations worldwide, although all are on much smaller facilities than the proposed PMEC. The original installation is at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation is on a GE LM2500, an approximately 25 MW combined cycle system, which has had an operating $SCONO_x$™ system since December 1996. That system has undergone many changes over the years. The second commissioning of a $SCONO_x$™ system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NO_x levels of 2.5 ppm, and subsequently received a permit modification extending the $SCONO_x$™ demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

There is no current working experience of $SCONO_x$™ on large combustion turbine units such as those proposed for the PMEC. Similarly, there are no applications of this technology with the fuel sulfur levels associated with IGCC combustion turbines. $SCONO_x$™ was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and now plan to do so. In evaluating technical feasibility for large IGCC power stations, the additional concerns are:

- $SCONO_x$™ uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed PMEC is significantly larger than the much smaller facilities where $SCONO_x$ has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the PMEC combustion turbines.
- The catalyst is very susceptible to poisoning by sulfur compounds. Because of the sulfur content of the syngas, a separate catalyst to absorb SO_2 would be required. The vendor offers a $SCOSO_x$™ catalyst; however, its operation is not proven, and upon regeneration this process would create an H_2S stream that would require treatment.

- SCONOx™ would not be expected to achieve lower guaranteed NO_x levels than SCR, and, for reasons described above, it has even greater feasibility concerns with respect to application on IGCC turbines than those for SCR

For the above reasons, SCONOx™ is considered technically infeasible for application to the PMEC combustion turbines.

SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (NH_3 or urea) is injected into the exhaust gases to react chemically with NO_x, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the NH_3 slip concentrations (NH_3 discharge from the stack) will be very high.

This technology is occasionally used in conventional fired heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been applied in IGCC service, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Because of the incompatibility of the exhaust temperature with the SNCR operating regime, this technology is considered to be technically infeasible.

B-1.7.1.3 Rank Control Technologies

Among the control technologies considered in the previous subsection, only one was determined to be both technically feasible and commercially demonstrated at a cost level acceptable as a BACT option. Specifically, the feasible option is diluent injection upstream of the combustion zone to achieve a controlled level of 15 ppmvd NO_x at 15% O_2 while firing syngas, and 25 ppmvd NO_x at 15% O_2 while firing natural gas. Table B-1-4 shows the typical NO_x control levels for the different options, in comparison with the NSPS Subpart Da limit of approximately 100 ppmv for stationary gas turbines burning syngas that are considered the BACT "floor" for this source category. In addition, a comparison with the proposed installation of SCR as an ICT is included in Table B-1-4.

During periods of firing natural gas as the start-up or back-up fuel, the combustion turbine will achieve 25 ppmvd NO_x, without the benefit of proposed ICT add-on control. This is due to the higher heating value and difference in diffusion flame speed for natural gas versus syngas. The applicant proposes to use natural gas for less than 50 hours/year for turbine startups plus up to 440 hours per year of full-load operation during transition to syngas firing. The annual emissions estimates for the combustion turbine assume this higher NO_x emissions rate for 490 hours per year (total of start up periods and full-load natural gas firing).

TABLE B-1-4
RANKING OF NO_X BACT EMISSION LIMIT OPTIONS FOR COMBUSTION TURBINES

Control Technology Option	Emissions per IGCC CT without Option1 (Tons/yr)	Emissions Reduction per IGCC CT1 (Tons/yr)	Emission Performance	Emissions per IGCC CT1 (Tons/yr)
Selective Catalytic Reduction (SCR) – ICT	725	580	3 ppmv @ 15% O2, 3-hour average (Syngas) 5 ppmv @ 15% O2, 3-hour average (Nat Gas)	145
Diluent (Nitrogen/Moisture) Injection – Proposed BACT	~ 1,520	795	15 ppmv @ 15% O2, 3-hour average (Syngas) 25 ppmv @ 15% O2, 3-hour average (Nat Gas)	725
NSPS BACT [2,]	Baseline Option	N/A	100 ppm @ 15% O_2 (Syngas)[3]	~4,800 tons

Notes:
1. Annual emissions are based on one combustion turbine firing ~490 hours per year on natural gas, and the balance on syngas at full load. (PMEC includes 2 combustion turbines)
2. Most stringent potentially applicable emission limit for the IGCC combustion turbines, from NSPS Subparts Da Syngas units without duct burners

B-1.7.1.4 Evaluate Control Options

The next step in a BACT analysis is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the evaluation in the previous step, the only technically feasible and commercially proven technology suitable for establishment of BACT limits is diluent injection. The most notable environmental impact associated with this NO_x control technology is water usage. Depending on the diluent selected, this option could entail additional water usage. Approximately 25,000 gallons per hour would be used in the moisturization process for NO_x control and power augmentation. Moisturization of the syngas is expected to comprise of approximately 8-9% of total PMEC make-up water usage. The emission rate shown for this option in Table B-1-4 is based on the PMEC combustion turbines operating with nitrogen and water vapor injection into the syngas stream. Since SCR with enhanced syngas desulfurization is proposed as an ICT measure, this evaluation also addresses the energy and environmental effects of SCR.

The principal environmental consideration with respect to implementation of SCR is that, while it will reduce NO_x emissions, it will add NH_3 emissions associated with use of ammonia (NH_3) as the reagent chemical. A portion of the unreacted NH_3 passes through the catalyst and is emitted from the stack. This is called ammonia slip and the magnitude of these emissions depends on the catalyst activity and the degree of NO_x control desired. While reduction in NO_x emissions offers benefits with respect to NO_2 PSD increment consumption and conformance with the NO_2 ambient air quality standard, ammonia is listed as a Class B toxic air pollutant in Ecology regulations (WAC 173-460-160). Also, ammonia emissions contribute to the generation of aerosol species that are regional haze precursors.

As described in Section B-1.7.1.2, there are potential technical barriers to cost-effective implementation of SCR. Injection of ammonia results in formation of ammonium sulfate salts that deposit on the SCR catalyst module, and on duct and heat transfer surfaces downstream of the SCR module. Accumulation of these precipitated ammonium sulfate salts can cause corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer, even at the relatively low levels of sulfur present in the PMEC syngas (see the discussion on the nature of these problems in Section B-1.7.1.2).

The accumulation of a layer of ammonium salts on the heat transfer fins located inside the HRSG gradually decreases the heat transfer efficiency as they become increasingly fouled with deposits. Power output from the combustion turbine can also be significantly affected due to an increase in pressure drop within the HRSG resulting from the partial blockage of gas flow by these deposits. This pressure rise can also impact HRSG casing design requirements. In addition, ammonium bisulfate is corrosive and corrodes the heat transfer fins or tubes, potentially impacting the reliability of the HRSG.

B-1.7.1.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this application of syngas-fired combustion turbines within an IGCC facility, diluent injection in the combustion turbine is the appropriate control technique for setting BACT-based emission limits. The proposed BACT limits based on this technology are 15 ppmvd NOx at 15% O_2 for syngas firing, and 25 ppmvd NOx at 15% O_2 for natural gas firing.

The BACT selection of diluent injection to the NO_x levels described above is strongly supported by recent precedents for similar IGCC projects. Diluent injection was designated as LAER for an IGCC combustion turbine project in Delaware (Motiva/Star Enterprises), as BACT for three new IGCC projects in Wisconsin (We Energies), Kentucky and Ohio (Global Energy) and as BACT in a BACT re-evaluation of an existing IGCC facility in Florida (Tampa Electric).

Implementation of add-on controls such as SCR and SCONOx™ is subject to significant technical feasibility issues with regard to their application to IGCC units, and are not commercially demonstrated for such an application. The PMEC facility has proposed installation of SCR as an ICT, and will accept alternate NO_x emission limits based on this technology target of 3 ppmv NO_x at 15% O_2 for syngas firing, and 5 ppmv NO_x at 15% O_2 for natural gas firing. The demonstration period for these alternate ICT limits should be tied to a schedule for achieving specific emission rate performance and reliability milestones, starting from the initial date of SCR system operation (first day exhaust is treated). If there is evidence after a sufficient test period that the use of Selexol® or equivalent and SCR will not be capable of reliably achieving the ICT limits described above, then some relaxation of these limits will be warranted. Energy Northwest will work closely with EFSEC to establish the ICT timetable and interim target emission rates.

B-1.7.2 SULFUR DIOXIDE AND SULFURIC ACID MIST BACT ANALYSIS

B-1.7.2.1 Identify Control Technologies

Sulfur dioxide emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of syngas in the combustion turbines creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Potentially available control technologies include:

<u>Pre-Combustion Process Controls</u>

- Chemical Absorption Acid Gas Removal (AGR), e.g., MDEA
- Physical Absorption, e.g., Selexol®, Rectisol®

<u>Post-Combustion Controls</u>

- Flue Gas Desulfurization (FGD)

Acid Gas Removal (AGR)

In the gasification process sulfur in the petroleum coke or coal feedstock converts primarily to hydrogen sulfide (H_2S) and, to a lesser extent, to other sulfur species such as carbonyl sulfide (COS). A COS hydrolysis unit is provided in IGCC plants to achieve a higher level of sulfur removal. In the hydrolysis unit, the COS is converted to H_2S, which is more efficiently removed in an AGR system. Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment units, where H_2S in the process gas is removed before use as a fuel or release to the atmosphere. The removed H_2S is recovered either as elemental sulfur in a Sulfur Recovery Unit (e.g., using a Claus process) or converted to H_2SO_4 in a sulfuric acid plant.

Chemical absorption occurs in amine-based systems that use solvents such as methyldiethanolamine (MDEA). Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. This is the technology that has been used in all existing and recently-permitted IGCC facilities, and is considered the baseline BACT level of control for this application.

The operating IGCC facilities at Polk Power Station and Wabash River (SG Solutions) both use amine systems to treat the syngas to total sulfur levels of 100 to 400 ppm. A few IGCC permits were issued between 2001 and 2004 with amine systems designed to treat syngas down to 40 ppm sulfur – however, none of these projects has yet been constructed. While some recent IGCC permit applications (permits pending) have proposed as BACT MDEA systems scrubbing to syngas sulfur levels of 50-75 ppm levels, others (including PMEC) have proposed more aggressive controls such as Selexol®.

Similar or lower levels of sulfur removal are possible using physical absorption AGR systems. The AGR system proposed for the PMEC is an enhanced level of physical absorption employing the Selexol® or equivalent technology that uses mixtures of dimethyl ethers of polyethylene glycol. This process, which will achieve a long-term average of 10 ppmv reduced sulfur in the syngas, is an integral part of the ICT options proposed for inclusion in the PMEC permit. As described in the previous turbine NO_x BACT section, low sulfur levels in the syngas fuel are essential to the viability of SCR for control of reduced turbine NO_x emissions.

Another comparable AGR technology, Rectisol®, utilizes refrigerated methanol as the physical solvent. In these types of AGR processes the H_2S is dissolved under pressure into the solvent. Dissolved acid gases are removed by depressurization to regenerate the solvent for reuse. Physical absorption methods have been used for many years to purify gas streams in the chemical processing and natural gas industries. For example, Selexol® was used with high-sulfur coals in the Cool Water IGCC Project, which was a demonstration facility operated from 1984 – 1988.

The various physical and chemical absorption systems for acid gas removal can be operated at varying levels of efficiency, with capital and operating costs increasing for increasing sulfur removal. In general, the Selexol® and Rectisol® systems can achieve lower sulfur levels than conventional MDEA absorption, or other amine-based chemical absorption systems. There are also operating conditions where the removal efficiencies overlap. For example, MDEA systems are generally the most cost-effective for lower levels of sulfur removal, but the costs increase significantly if deeper sulfur removal is required. In contrast, a Selexol® system would have higher initial capital costs, but would be able to achieve deeper removal levels at a lower incremental cost.

Flue Gas Desulfurization

Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional PC plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95% sulfur removal.

B-1.7.2.2 Evaluate Technical Feasibility

Both chemical and physical absorption methods for AGR are considered feasible for an IGCC, and can achieve control of the sulfur in syngas up to 99% or better. Both of these systems are further considered in this analysis.

FGD cannot provide as high a level of control as the pre-combustion AGR systems. In addition, FGD has the environmental drawbacks of substantial water usage and the need to dispose of a solid byproduct (the scrubber sludge). Given these disadvantages, even though FGD is not technically infeasible, it is not considered to be a reasonable technical option for IGCC. The sulfur would be removed more efficiently and economically from syngas prior to combustion in the combustion turbines; therefore FGD will not be considered further in this BACT analysis.

B-1.7.2.3 Rank Control Technologies

The technically feasible technologies for controlling syngas sulfur levels, and thus turbine SO_x emissions, are summarized in Table B-1-5 in descending order of control efficiency. Emissions in pounds per million Btu of coal feedstock and annual emissions for two combustion turbines are also shown along with uncontrolled and NSPS emissions limits for comparison.

TABLE B-1-5
RANKING OF SO_2 BACT EMISSION LIMIT OPTIONS

Control Technology Option	Sulfur in Syngas (ppm)	Control Efficiency	SO2 Emission Limit (lb/MMBtu input as coal) 2	Annual SO2 Emissions – Per Turbine (tons/yr) 3	Emissions Reduction (tons/yr)
AGR to 1 ppm (requires Rectisol)	1	99.99%	0.0005	6.5	318.5
AGR to 10 ppm (using Selexol®)	10	99.90 %	0.0050	65	260
AGR to 50 ppm[1] BACT Baseline Control Option	50	99.50%	0.0251	325	325
AGR to 100 ppm[1]	100	99.25%	0.05	650	-

1 -- Treatment of syngas to 50-100 ppm sulfur levels could be achieved with either an MDEA or Selexol® AGR system.
2 – Each emission limit must be combined with an averaging time that is suitable for the technology, and the reasonable expectations of process variability. For AGR, the presumed rolling average time is 30 days.
3 – Annual emissions for purposes of this BACT comparison does not include gasifier or turbine startup emissions.

B-1.7.2.4 Evaluate Technical Feasibility

Depending on the feedstock used, the syngas initially produced could contain more than 10,000 ppm sulfur for the worst-case feedstock, primarily in the form of H_2S. In an IGCC process, chemical absorption processes such as AGR with MDEA have been used for existing and permitted IGCC facilities. The normal level of removal for this type of technology is therefore considered the baseline level of control for purposes of this BACT assessment.

The most effective SO_2 control system that is considered to be technically feasible is the physical absorption AGR system using Rectisol to 1 ppm sulfur in syngas, as shown in the table above. The next levels of control can be achieved with either a Selexol®/equivalent or an MDEA system. Table B-1-6 shows incremental emissions reduction that can be achieved and the associated costs for a range of sulfur removal efficiencies compared to the IGCC baseline syngas sulfur level of 50 ppm.

B-17.2.5 Environmental and Economic Impacts

Table B-1-6 shows the average and incremental costs for varying levels of sulfur removal at the proposed PMEC. For this analysis, removal to 50 ppm was chosen as the base, or minimum BACT level of control for IGCC syngas. Significant sulfur removal (versus "uncontrolled" levels) is required at an IGCC facility. It would not be feasible to combust uncontrolled "raw" syngas in the combustion turbines.

TABLE B-1-6
ANNUALIZED COST EVALUATION FOR CANDIDATE BACT SO_2 CONTROL TECHNOLOGIES

Control Technology	Capital Investment (10^6 \$)	Annual Operating Costs (10^6 \$/yr)	Total Annualized Costs (10^6 \$/yr)	Baseline Emissions or Reduction (tons/yr)[1]	Cost Effectiveness (\$/ton)
AGR to 1 ppm (Rectisol)	39.961	4.106	8.494	319	\$26,662
AGR to 10 ppm (Selexol®)	20.980	2.891	5.195	260	\$19,975
AGR to 50 ppm[1] **BACT Baseline Control Option**	-	-	-	**325**	-

1 - Treatment of syngas to 50-100 ppm sulfur levels could be achieved with either an MDEA or Selexol® AGR system. Tons of SO_2 reduced are based on comparison with MDEA system at 50 ppm level.
2 – Each emission limit must be combined with an averaging time that is suitable for the technology, and the reasonable expectations of process variability. For AGR, the presumed rolling average time is 30 days.
3 – Annual emissions for purposes of this BACT comparison does not include gasifier or turbine startup emissions.
Note: *Basis for these cost estimates is provided in Attachment B-1-2.*

Although all the AGR systems require chemical handling and will generate a sour water stream, there are no unique collateral environmental issues that would preclude any of the systems from consideration as BACT. Both physical and chemical absorption-based AGR systems involve chemical processing systems that use solvents to remove H_2S from the syngas. The solvent in each system can be regenerated and reused. Acid gases removed from the syngas in each type of process will be processed to generate elemental sulfur in a separate sulfur recovery system. Each acid gas removal system will generate a sour water stream that must be processed prior to discharge. The potential for fugitive emissions of reduced sulfur compounds from these processes increases as the processes become more complex. Consequently, the capital costs of the AGR systems must assume that fittings and valves are specified to meet low-emission criteria.

B-1.7.2.6 Select Control Technology

The applicant proposes that BACT for control of SO_2 combustion turbine emissions from the IGCC facility (and concurrently for acid mist emissions) be defined as treatment of the syngas by acid gas removal to achieve a syngas sulfur concentration of 50 ppm.

However, the applicant intends to install the Selexol® or equivalent physical absorption system, which will remove more than 99% of the sulfur contained in the syngas used to fuel the combustion turbines and/or achieve a long-term average syngas reduced sulfur species content equal to or less than 10 ppmvd. Syngas at this reduced level of sulfur will result in annual average turbine SO_2 emissions of 0.0053 lb/MMBtu, based on gasifier heat input. Typical BACT determinations for prior IGCC projects utilizing physical absorption processes have operated with approximately 50 ppmv of sulfur remaining in the undiluted, unsaturated syngas (i.e., upstream of final conditioning). The enhanced level of sulfur treatment proposed by PMEC is a necessary prerequisite for effective SCR operation, and is therefore an integral component of the ICT proposed for the combustion turbines.

Use of Selexol® or equivalent to a 10 ppm sulfur level compared to chemical absorption at a 50 ppm level has an incremental cost effectiveness of almost $20,000 per ton of avoided SO_x emissions. Treatment to an even lower level of sulfur, while technically feasible, would be prohibitively more expensive. Achieving a level of 1 ppm sulfur in the syngas fuel using Rectisol® is estimated to require approximately $19 million additional capital investment for the AGR system and $1.2 million dollars per year of additional operating costs. Based on the total emission reduction from the MDEA baseline option, the cost-effectiveness to achieve this most-stringent level of emission equates to approximately $26,660 per ton of SO_2 controlled. Consequently, the annualized cost for an additional reduction of 58 tons per year is economically prohibitive. Therefore, PMEC proposes to implement a Selexol® system or equivalent to remove sulfur (H_2S + COS) down to 10 ppmvd (30-day rolling average) in the undiluted, unsaturated syngas prior to combustion in the combustion turbines.

The proposed turbine SO_2 emission rate of 0.0053 lb/MMBtu (as coal input to the gasifiers) compares very favorably with the new NSPS for Electric Utility Steam Generators (including IGCC) in 40 CFR 60 Subpart Da, which sets a standard of 2.0 lb/MWh, or approximately 0.2 lb/MMBtu. The desulfurization of the combusted fuel that is achieved with IGCC, and the resultant reduction in SO_2 emissions is one of the major environmental advantages of IGCC technology compared with other coal-based power generation systems.

B-1.7.3 VOLATILE ORGANIC COMPOUND BACT ANALYSIS

VOCs are a product of incomplete combustion of the organic syngas fuel. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. The primary technologies identified for reducing VOC emissions from the IGCC combustion turbines are oxidation catalysts and good combustion practices (GCP). A survey of the RBLC database indicated that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. An inherent advantage of IGCC technology is the fact that the combustion turbines use

syngas, a fuel which contains a very low organic content and, when burned, yields very low levels of uncombusted VOC emissions.

B-1.7.3.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the IGCC combustion turbines for control of VOC emissions:

Combustion Process Controls

- IGCC technology (use of low VOC syngas)
- Good Combustion Practices (GCP)

Post Combustion Controls

- Oxidation Catalysts

B-1.7.3.2 Evaluate Technical Feasibility

Low-VOC Syngas Fuel

Combustion of any hydrocarbon material can produce trace levels of uncombusted VOCs. However, combustion of fuels with very low hydrocarbon content can obviously further lower these VOC emissions. The very nature of the IGCC process leads to unusually low levels of any organic emissions from syngas combustion.

The gasification process involves feeding a slurry of carbon-containing materials into a heated and pressurized chamber (the gasifier) along with a controlled and limited amount of oxygen. At the extremely high operating temperature and pressure created by conditions in the gasifier, chemical bonds are broken by oxidation and steam reforming at temperatures sufficiently high to promote very rapid reactions. The various constituents in the feedstock are largely broken down into their fundamental elements in the gasifier, and are reformed in the syngas primarily in the form of diatomic hydrogen (H_2) and CO gas.

Good Combustion Practices (GCP)

GCPs applied to the proposed sources can achieve VOC emission levels below 3 ppmvd (at 15 percent O_2) based on data provided by Fluor. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. This is the technology used as BACT for all other recent IGCC permits.

Oxidation Catalyst

The option that has greatest uncertainty with respect to cost, long-term performance and reliability for application to IGCC turbines is the use of oxidation catalysts. Catalytic oxidation is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC. The catalyst beds that reduce CO can also be effective in reducing VOC emissions. Such

systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing upwards of 90% control for CO.

It is also worth noting that a typical additional incentive to using an oxidation catalyst, when feasible, is the incidental control of organic hazardous air pollutants (HAPs). For example, uncontrolled formaldehyde (CHOH) emissions can be fairly significant from conventional combustion of natural gas. However, since syngas contains primarily elemental hydrogen (H_2) and CO, uncontrolled turbine emissions of formaldehyde and other organic HAP emissions, are significantly less. The reaction path to create formaldehyde is not present for hydrogen and CO fuel constituents. For this reason, oxidation catalyst, even if feasible, would provide less benefit for a syngas-fired combustion turbine versus a natural gas-fired combustion turbine.

Oxidation catalysts are anticipated to experience performance problems due to the presence of low-levels of sulfur and trace metals in the syngas combustion exhaust, as further described in the CO BACT evaluation. The presence of sulfur compounds in the combustion turbine exhaust gases, even with the proposed BACT limit of 10 ppmv in the syngas, will cause poisoning of the metal-catalyst active sites in the catalyst pores. This will result in a more rapid decay in catalytic oxidizer module performance, and increased cost for more frequent catalyst replacement. Further, oxidation catalysts have seldom been applied, and are not viewed as commercially proven on coal-based combustion systems. For all these reasons, catalytic oxidation is not considered a practical or feasible technology for VOC removal for this IGCC application.

B-1.7.2.3 Select Control Technology

The recommended control of VOC emissions from each of the proposed combustion turbines is use of the low VOC fuel and GCPs at the IGCC combustion turbine. These practices will meet a VOC emission limit of 0.003 lb/MMBtu input to the gasifier, or 10 lb/hr/combustion turbine while operating under steady state conditions. This equates to approximately 2.4 ppmv at 15% O_2 in the stack gases. During start up cycles, the proposed BACT limitation on VOC emission is 263 lb/hr, which represents the worst case emission rate during syngas system start up.

B-1.7.4 CARBON MONOXIDE BACT ANALYSIS

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) may result in higher levels of CO emissions. Thus, a compromise must be established, whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation.

B-1.7.4.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the PMEC combustion turbines for control of CO emissions:

Combustion Process Controls

- Good Combustion Practices (GCPs)

Post Combustion Controls

- SCONOx™
- Oxidation Catalyst

B-1.7.4.2 Evaluate Technical Feasibility

Each identified technology was evaluated in terms of its technical feasibility for application to IGCC combustion turbines burning syngas. In general, post-combustion controls either had substantial feasibility issues, or did not offer a level of control that was practically better than GCP.

SCONOx™

The $SCONO_x$™ system was described in the BACT analysis for control of turbine NO_x emissions. It is commercially available for small-frame combustion turbines for controlling CO and can reduce emissions by up to 95 percent. However, it is not commercially available for large frame combustion turbines (like those to be used for PMEC) as discussed in the NO_x BACT discussion. Therefore, SCONOx™ is considered to be technically infeasible for PMEC.

Oxidation Catalysts

Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions. They have been permitted as required CO control equipment for a fairly large number of natural gas combustion turbine applications. The oxidation of CO to CO_2 utilizes excess air present in the combustion turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The introduction of a catalyst bed in the combustion turbine exhaust stream will create a pressure drop, resulting in back pressure to the combustion turbine. This has the effect of reducing the efficiency of the combustion turbine and the power generating capabilities.

As previously mentioned, a common incentive to use a CO oxidation catalyst, if feasible, would be the incidental control of VOC and organic HAPs that would be realized in conjunction with reduced CO emissions. However, as discussed in the VOC BACT section, such benefits are less significant for gas turbines using syngas fuel, which has a very low VOC content, than for units burning natural gas.

A CO catalyst oxidizes CO to CO_2 and VOC and unburned hydrocarbons to CO_2 and H_2O, but also can promote other oxidation reactions such as NH_3 to NO_x and SO_2 to SO_3. Consequently, the presence of a CO catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

CO catalyst typically operate at temperatures between 750 to 1100ºF (400 to 600ºC), and typically the catalyst is more effective at promoting the oxidation reactions as the operating temperature increases. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90%, and typical VOC conversion efficiencies are 40 to 50%.[[6]]

At 750ºF (400ºC), a CO oxidation catalyst will also promote conversion of up to 35% of the SO_2 to SO_3, according to the Electric Power Research Institute (EPRI). At 1000 to 1100ºF (538 to 600ºC), the catalyst will promote an even higher rate of conversion of SO_2 to SO_3. Significant concentrations of SO_3 can promote the formation of visible sulfuric acid mist (also known as a "blue plume") when the exhaust gas cools below the sulfuric acid dewpoint.

If a high temperature (>1000ºF or 538ºC) CO catalyst is used, in order to avoid producing excessive SO_3, the sulfur content of the syngas must be low enough to yield no more than 2 ppmv SOx in the combustion turbine exhaust in order to avoid the blue plume. However, even if a lower temperature CO catalyst is used, the resulting SO_3 concentration would cause unacceptably high rates of ammonium bisulfide formation if an SCR is also present in the HRSG. Therefore, a CO catalyst is <u>not</u> recommended by EPRI for use in IGCC systems which incorporate an SCR. [[7]]

By placing the catalyst at the correct position within the HRSG, the temperature can fall within the range appropriate for CO catalytic oxidation. However, the same catalyst fouling issues mentioned in regard to SCR catalysts for NO_x control will be of concern with CO oxidation catalysts. Compounds in the syngas exhaust, such as sulfur, can cause plugging or deactivation of the CO catalyst, greatly shortening its service life and increasing periodic replacement costs. Even the relatively low concentrations of heavy metals predicted for the IGCC combustion turbine exhaust may adversely affect the performance and longevity of a catalytic oxidation system. Therefore, oxidation catalysts are considered to be technically infeasible for this project.

The Florida Department of Environmental Protection recently established a precedent for the use of an oxidation catalyst as BACT for CO at an IGCC facility in Florida. Specifically, Florida published its Technical Evaluation and Preliminary Determination document on June 16, 2006 for the Curtis H. Stanton Energy Center Unit B proposed by OUC & Southern Power Company – Orlando Gasification LLC. This document includes the Department's BACT analysis for the Stanton project, which found that use of a CO oxidation catalyst is cost effective for that application. However that finding pertained to an unsteablished demonstration IGCC technology that cannot be considered in PMEC (the KBR "Transport Gasfier" in a subbituminous coal-fueled IGCC process) and did not refute the concerns expressed above regarding the serious technical feasibility issues with regard to power plant reliability.

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[6] "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production", California Air Resources Board, http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

[7] ERPI CoalFleet IGCC Permitting Guidelines Manual, Electric Power Research Institute, March 2006.

The Department obtained costs from a CO catalyst vendor, but apparently no written guarantee that the control system would perform at the level to meet the levels of 4.1 ppmvd CO and 2.4 ppmvd VOC, which were included in the facility's permit. The agency proposes that the oxidation catalyst be installed during the second year of the IGCC unit's operation to allow time for stabilization of the gasifier system and implement additional changes, such as better syngas cleaning, if necessary. This use of oxidation catalyst is not an instance of the oxidation catalyst technology having been proven in practice. In addition, as a demonstration project selected for funding assistance by the Department of Energy, the Stanton Project will receive $235 million of the total cost of $557 million from DOE, an advantage not shared by PMEC.

Good Combustion Practices

Good combustion practices (GCPs) include operational and combustor design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. Such control practices applied to the proposed PMEC combustion turbines can achieve CO emission levels of 15 ppm during steady state, full load operation. At lower combustion turbine loads (50-70%), the combustion efficiency drops off notably, and CO emissions would be higher. However, the PMEC combustion turbines are expected to operate for only 50 hours or less per year in startup mode, and this profile (15 ppmvd at 15% O_2) was used as the basis of the BACT analysis.

GCPs are a technically feasible method of controlling CO emissions from the proposed IGCC combustion turbines.

B-1.7.4.3 Rank Control Technologies

The only CO control technology found to be technically feasible for the PMEC combustion turbines burning syngas fuel is presented in Table B-1-7

TABLE B-1-7
RANKING OF FEASIBLE CO CONTROL TECHNOLOGIES FOR GAS TURBINES

Control Technology	Removal Efficiency Range (%)	Controlled Emission Level
GCPs	Not Applicable (baseline)	15 ppmv @ 15% O_2 2,740 lb/hr (startup)

B-1.7.4.4 Select Control Technologies

GCP is considered the baseline and only feasible and commercially demonstrated CO control technology for IGCC combustion turbines. The conditions that led to the recent finding in favor of CO catalyst technology a BACT for Curtis H. Stanton Energy Center Unit B project do not exist for the PMEC. Additionally, GCP has been selected as BACT for all other recent IGCC permits. PMEC proposes that the CO BACT-based limit should be 15 ppmvd @ 15 percent O_2 on a 3-hour average during non-startup operation, using Good Combustion Practices (GCPs). Similarly, for the maximum CO emission limit during turbine startup with GCP is proposed to be 2,740 lb/hr, with an assumed level of 50 hours per year of startup operation for each turbine for purposes of estimating annual emissions.

B-1.7.5 PARTICULATE MATTER BACT ANALYSIS

Particulate matter emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions. Clean gaseous fuel, such as syngas, will also be low emitting. In the PMEC process, as in other IGCC systems, the hot syngas exiting the gasifier is cooled and sent to a water scrubbing system for particulate matter removal prior to other gas treatment processes such as AGR.

The EPA has indicated that particulate matter control devices are not typically installed on combustion turbines and that the cost of installing a particulate matter control device is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the recently revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at a federal level.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible, and does not represent feasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low ash fuel, such as natural gas or syngas. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas or syngas) is the predominant control method listed.

The use of clean syngas fuel and good combustion control is proposed as BACT for PM/PM_{10} control in the proposed PMEC combustion turbines. These operational controls will limit filterable plus condensable PM/PM_{10} emissions to 24 lb/hr, based on 0.01 lb/MMBtu input to the gasifier when operating on syngas.

PMEC is proposing to build enclosed solid fuel storage to improve storage management and minimize particulate emissions.

B-1.7.6 MERCURY BACT ANALYSIS

Since mercury occurs naturally in PBR coals, the PMEC syngas cleanup processes include a system to control mercury that may remain in the syngas. Downstream of the AGR system, the syngas passes through fixed beds of activated carbon that are specially impregnated to remove mercury. Multiple beds in series are used to obtain optimized adsorption. The lower temperature and lower moisture content of the syngas after the Selexol® or equivalent step allows the carbon beds to operate at higher efficiencies. The activated carbon capacity for mercury ranges up to 20% by weight of the carbon. The mercury removal system will remove enough mercury from the syngas so that the mercury content of the syngas fuel is no more than 10% of

the mercury contained in the solid IGCC feed stock. After mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen for control of nitrogen oxides (NO_x) before being used as fuel for power generation in the CTGs.

PMEC's mercury emission calculations assume that the mercury remaining in the syngas after carbon adsorption is emitted in the exhaust of the combustion turbines and other combustion units,. On this basis, the mercury emissions for both combustion turbines are estimated to be 58 lbs per year. Much smaller amounts would be released from the flare, tank vent oxidizer, auxiliary boiler and cooling tower. However, these smaller sources account for less than 2 lbs per year.

B-1.7.6.1 Identify Control Options

Among IGCC facilities that have achieved operating status, only one was found to have permitted emission limits that directly address mercury emissions. Based on engineering development in support of later IGCC permit applications, the use of carbon adsorption is the only technology that has been proposed as a technically feasible method of control specifically for mercury. The following list summarizes the nature of mercury emission limits or proposed control technologies for several IGCC facilities:

- SG Solutions, Wabash River Generating Station, Indiana (Operating)
  - No mercury limits in NSR permit.
- Tampa Electric Company, Polk Power Station, Florida (Operating)
  - Maximum allowable mercury limits in NSR permit for "demonstration period" of 0.025 lb/hr and 0.11 tons per year, and for "post-demonstration" period of 0.0034 lb/hr and 0.017 tons per year.
  - Testing requirement to prove compliance with limits
- Global Energy Inc., Kentucky Pioneer Energy, LLC, Kentucky (Permitted)
  - Stack emission limits of 0.080 milligrams per dry standard cubic foot
  - Testing requirement to prove initial compliance with limit
- Mesaba Energy Project, Minnesota – 1,200 MW(Proposed)
  - Carbon adsorption proposed as control technology
  - Proposed mercury emissions in NSR application based on not less than 90% removal of mercury present in the fuel feedstock, which corresponds to maximum annual emissions of 54 lbs/year[8].
  - Project will comply with NSPS for Coal-Fired Electric Steam Generating Units (40 CFR 60, Subpart Da(b)) standard for IGCC units of 0.000020 lb/MWh (0.0025 ng/J) based on gross electric output.

[8] Mercury emissions presented in the Mesaba air permit application were estimated based on an emission factor of 0.5 lb/10^{12} Btu of feedstock for PRB coal. PMEC has conservatively estimated its mercury emissions using an emission factor of 1.2 lb/10^{12} Btu, which is at the high end of measured Hg levels for PRB coal. This explains the comparable annual emissions estimates for the two facilities, despite the fact that the Mesaba calculations pertain to a 1200 MW IGCC facility while the PMEC will generate only 600 MW.

- Curtis H. Stanton Energy Center, Orlando, Florida – 285 MW (Proposed)
  - Carbon adsorption proposed as control technology
  - Annual emissions are less than BACT significance level for mercury, which is 200 lb/yr
  - Proposed mercury emissions in NSR application were based on average of 90% removal of mercury in present in the fuel feedstock.
  - Agency-proposed permit limit is 0.000010 lb/MWh, which is half of the limit in NSPS (40 CFR 60, Subpart Da(b)) for IGCC units, and corresponds to approximately 22 lb/yr.

B-1.7.6.2 Evaluate Control Options

Operating experience with IGCC processes is relatively limited, so the long-term reliability and performance of specific emission controls for mercury is not well-demonstrated at the commercial scale. At very least, the volume of activated carbon needed for high efficiency adsorption of mercury must be adjusted to account for the potential loss of capacity due to adsorption of sulfur compounds, or other species in the syngas. There is no reported experience to judge the required frequency of replacement for activated carbon in syngas cleanup service.

Consideration of the physical process of adsorption in a carbon bed suggests that higher removal levels would not be achieved by simply increasing the volume of carbon. When a fresh or regenerated bed of carbon is brought into service, the material nearest the gas entrance will capture the contaminant until its surface is essentially "saturated", or it approaches its equilibrium capacity for that prevailing inlet concentration. As unabsorbed molecules travel further into the bed, additional carbon surface becomes saturated. In this manner, an "adsorbing zone" travels through the bed in the direction of gas travel. The exit gas concentration of the contaminant is established by gas-solid equilibrium factors (i.e., surface activity, temperature, pressure, and concentration), rather than mass transfer limits. Enlarging the carbon bed will extend the time before "breakthrough", the point when the entire bed is saturated, but will not appreciably reduce the exit concentration of the contaminant.

In the mercury material balance used to estimate emissions, the primary process specification is that sufficient adsorption capacity will be provided to capture 90% of the mercury in the fuel feedstock. Conservatively, it has been assumed in this application that all of the feedstock mercury will be converted to a gaseous mercury species in the gasifier. In actuality, the feedstock mercury will partition between the gasifier slag and the product gas, in a proportion that is variable and not accurately calculable without measurements for a specific fuel blend.

B-1.7.6.3 Proposed BACT Limit

Given the uncertainty inherent in the mercury balance calculations, and the lack of commercial demonstration of the single feasible control technology, there is no justification to identify BACT control options that are more stringent than the applicable NSPS. For these sources, the BACT "floor" is the recently-revised and relatively stringent limit of a 12-month rolling average of 0.000020 lb/MWh (0.0025 ng/J) based on gross electric output (40 CFR 60.45 Da(b)). With the exception of the most recent proposed permit for the IGCC in Orlando, Florida, all of the prior permits for IGCC have contained limits equivalent to or less stringent than the NSPS. It

remains to be seen whether the Florida permit limit of 0.00001 lb/MWh can be achieved, given the chemical equilibrium limitations on carbon adsorption of mercury.

For mercury emissions from the IGCC combustion turbines, the carbon adsorption design will deliver at least 90% removal of the mercury contained in the feedstock fuel. For PRB coal, this results in a maximum emission rate of 0.0033 lb/hr per turbine (0.000011 lb/MWh) Based on information recently presented in the Mesaba IGCC New Source Review permit application, the mercury content in PRB coal is higher than in petroleum coke. Thus, the emissions estimate based on this coal mercury content represent a worst-case for the PMEC facility. This limit is proposed as the BACT limit for the PMEC project. The estimated maximum annual emission rate of 29 pounds of mercury per year from each of the PMEC combustion turbines is compliant with the NSPS standard.

B-1.8 BACT DETERMINATION - PRECEDENTS FOR SOLID FUEL HANDLING FACILITIES

Various types of industrial facilities include solid fossil fuel handling operations. To review recent BACT precedents for these operations, the RBLC database was surveyed for utility plants and other coal handling operations. These precedents are summarized in Table B-1-8. The control technologies and BACT limits identified in these recent precedents offer guidance for evaluation of BACT options for the PMEC solid fuel unloading, handling and storage operations. The control technologies that may practically establish a BACT emission limit for particulate emission sources in this case are fabric filter baghouses, ESPs, wet scrubbers, and mechanical cyclones. The following general analysis of particulate control technology options feeds into the discussions on BACT for specific IGCC processes involving bulk fuel handling in Sections B-1.9, B-1.10 and B-1.11.

Fabric Filter Baghouse – A fabric filter baghouse collects particulate matter by passing the exhaust gas stream through a series of filters that are constructed of a porous fabric. As the gas passes through the fabric, the dust particles gather on the surface to form a “cake”, which further assists in collecting particulate matter. The method with which the cake is removed is critical to the overall success of the control device. If too much of the cake is removed, there will be additional particulate matter emissions, as the baghouse works to reform the cake. If not enough of the cake is removed, the pressure drop across the baghouse will continue to increase, putting a strain on the system itself.

Two common methods for removing the particulate matter dust cake include reversing the air flow periodically (reverse-air baghouse) or using a pulsed jet of compressed air periodically (pulse-jet baghouse). The selection of the fabric material used is also critical to the overall performance of the baghouse. The material must be able to withstand the maximum temperature and flow-rate of the exhaust gas stream, as well as be chemically compatible with both the exhaust gas and the dust that is being collected.

Electrostatic Precipitator – An ESP uses electrical forces to collect particulate matter from the exhaust gas stream. The particles are first passed through a corona where they acquire an electrical charge before being collected on plates, which are oppositely charged. The particulate matter is knocked loose from the plates in such a manner that it is not re-entrained in the exhaust

gas stream, and is then transferred to a hopper for disposal. However, the low moisture and high solids loading that characterize the exhaust gas make an ESP less efficient than a fabric filter baghouse.

Wet Scrubber – Wet scrubbers reduce emissions by entraining particulate matter in the exhaust gas stream in water droplets. These droplets are then separated from the remaining gas stream. There are three methods in which the particulate matter is entrained in a water droplet:

- Impaction – the particle collides directly with the water droplet;
- Interception – the particle is captured as it moves close to the water droplet; and
- Diffusion – the particle is circulated through the exhaust gas until it can be captured by the water droplet.

In order to be successful at removing particulate matter, the scrubber must be able to create and effectively control water droplet dispersion.

Mechanical Cyclones – A mechanical cyclone can be used to collect particulate matter from exhaust gases by working in a manner similar to a centrifuge. As the exhaust gas flows through the cyclone, the particulate matter is forced to the sides of the cyclone where it is trapped along the wall. Gravity then pulls the particulate matter down the cyclone where it is collected in a hopper.

In addition to a control device, it is important to note that in order for such "end-of-pipe" devices to be effective, the particulate matter emissions need to be captured. Additional measures are usually included with the control device to constitute a complete capture and control system. These control options are discussed in more detail below.

Full and Partial Enclosures – Particulate matter emissions can be effectively limited by covering equipment or emission points with either full or partial enclosures. The types of

TABLE B-1-8
REVIEW OF RECENT BACT DETERMINATIONS FOR SOLID FEED STOCK OPERATIONS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
CO-0055	02-03-06	Powers County, CO	Lamar Utilities Board DBA Lamar Light & Power	Coal Handling and Preparation	150 ton/hr	PM_{10} – 0.02 lb/ton	High Efficiency Fabric Filter Baghouses (99.50% Efficiency)	BACT-PSD
AR-0082	08-30-05	Independence County, AR	Arkansas Lime Company	Coal/Coke Bin Vent	NA	PM_{10} – 0.0150 gr/dscf 5% opacity	Dust Collector (99% efficiency)	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Coal Handling and Storage	NA	PM – 0.01 gr/dscf PM_{10} – 0.01 gr/dscf	Controls include use of water sprays, lowering well, dust suppressants, enclosures and baghouses where feasible.	BACT-PSD
MN-0061	06-26-05	St. Louis, MN	Mesabi Nugget LLC	Coal Pulverizer	36 MMBtu/hr	CO – 3 lb/hr NO_X – 1.8 lb/hr PM – 0.01 gr/dscf PM_{10} – 0.0150 gr/dscf VOC – 0.19 lb/hr 10% opacity	Fabric Filter	BACT-PSD
ND-0021	06-03-05	Bowman County, ND	Montana Dakota Utilities / Westmoreland Power	Coal Handling	400 ton/hr	PM – 0.0050 gr/dscf 5% opacity	Baghouses (99.9% Efficiency)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IN	Auburn Nugget	Coal Car Unloading	165 ton/hr	PM – 0.0052 gr/dscf 3% opacity	Baghouse	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Coal Handling Operations	NA	PM_{10} – 0.01 gr/dscf	Baghouse	BACT-PSD
VA-0292	11-02-04	Buchanan County, VA	Island Creek Coal	Coal Handling and Transfer Operations	3.5 MMton/yr	PM – 16.95 ton/yr PM_{10} – 3.35 ton/yr	Wet Suppression	BACT-PSD
ND-0020	08-04-04	Stark County, ND	Red Trail Energy LLC	Coal Handling	27 ton/hr	PM_{10} – 0.0040 gr/dscf 0% opacity	Baghouse (99.8% Efficiency)	BACT-PSD
SC-0104	02-05-04	Berkeley County, SC	Santee Cooper	Coal Handling	26.28 MMton/yr	PM – 1.4 lb/hr	Baghouse (99.50% Efficiency)	Other Case-by-Case

B-1.9 BACT ANALYSIS FOR RAILCAR UNLOADING AND TRANSFER POINTS

B-1.9.1 PROCESS DESCRIPTION

Energy Northwest expects that fuel selection throughout the lifetime of the PMEC will respond to market conditions and economic considerations. The primary feed stocks will be petroleum coke and coal; natural gas will be the backup fuel. Either petroleum coke or coal feedstocks may be received by rail in dedicated unit trains. However, most petroleum coke is expected to be delivered by barge, and emission control options for the PMEC barge unloading facilities are assessed in Section B-1.10. The following BACT analysis for the rail car unloading facility is based on the solid fuel selection with the highest pollutant emission rates among the anticipated range of fuels.

The proposed unloading building will house supporting facilities for railcar unloading operations and facilitates control of dust emissions, noise abatement, and visual shielding. The railcar coal receiving system will incorporate the use of high-capacity aluminum-steel railcar bottoms dumping to an under-rail pit-hopper system. During unloading of a unit train, the railcars will move at a slow speed (approximately 0.3 mph) through the unloading building. The end doors of the building will be covered with plastic slat covers to reduce transport of emissions to the outside air. The load will be dumped from the bottom of each car into a dump hopper under the track. Multiple collecting conveyors will move the dumped fuel from the hopper to an inclined take-away conveyor that moves the solid fuel from the building to the storage domes.
Nominal design capacity for the railcar unloading facility is 4,300 tons of coal per hour, which forms the basis for the emission estimates used in this BACT analysis. Significant emissions from the railcar unloading facility consist only of particulate matter (PM) and particulates less than 10 microns diameter (PM_{10}). Two separate emission units associated with this facility are included in this BACT analysis:

- Railcar unloading pit-hopper; and
- Conveyor and transfer point.

The proposed BACT for both emission points is enclosure in the unloading building, with the entire building maintained at negative pressure for effective capture of generated dust. The under-track conveyor and transfer point will be enclosed. The exhaust air stream from the unloading building will be treated by a high-efficiency fabric-filter baghouse before being vented to atmosphere.

B-1.9.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Based on current practices for solid material handling systems, several types of commercially available control technologies can be identified for the railcar fuel unloading process at the proposed PMEC facility. An RBLC Database survey indicates that commercially available controls include:

- Unloading building with restricted end door openings and operated at negative pressure with vent stream routed to high-efficiency fabric filter;

- Enclosed batch drop and transfer points with high-efficiency fabric filter;
- Transfer point and batch drop point water sprays,
- Transfer point enclosures only

Based on review of BACT precedents, the emission control option of enclosures with baghouse filters for railcar unloading, handling and storage of petroleum coke and coal had control efficiencies that varied from 99.0% to 99.9%. In addition, water sprays and enclosures are also considered to be available control options for PM_{10} emissions. The ranges of coal handling emission limits for recently permitted sources are as follows:

- PM = 0.0050 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- PM10 = 0.0040 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- Opacity = 0% to 10%

B-1.9.3 INFEASIBLE CONTROL MEASURES

None of the identified emission control options for this source would be viewed as technically infeasible.

B-1.9.4 RANKING OF AVAILABLE CONTROL MEASURES

In approximate order of decreasing stringency these control technology options are:

- Complete enclosure for railcar unloading building and below-grade conveyor and building vented through high-efficiency fabric filter units;
- Railcar unloading pit-hopper enclosure and transfer point enclosures with water or suppressant sprays;
- Enclosed below-grade pit and conveyor only
- Water suppression on railcar unloading bin-hopper and transfer point

B-1.9.5 PROPOSED BACT LIMITS AND CONTROL OPTION

PMEC proposes to adopt the most stringent control option among those identified for this type of particulate emission source. As noted in the discussion of the top-down BACT procedure in the beginning of Section B-1.2, an evaluation of any potential environmental and energy impacts resulting from the implementation of the selected control option must be provided, even when the top-ranked control option is chosen. . The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. This is a relatively minor potential environmental impact, such that use of a fabric filter baghouse is reasonably considered to be the top-ranked control option.
PMEC will adopt a fabric filter performance specification of 99% particulate removal from the airstreams sent to the baghouse. In combination with an estimated particulate collection efficiency of 80% for the entire railroad unloading system, this results in 89.2% removal of all particulate emissions associated with this process.

B-1.10 BACT ANALYSIS FOR SHIP/BARGE UNLOADING FACILITY AND TRANSFER TO STORAGE

As an alternative to receipt of fuel by railcar, PMEC will be furnished with dock and ship unloading equipment for receipt and unloading of petroleum coke and coal feedstocks from ships. The existing Port of Kalama wharf will be extended by the Port to accommodate vessels delivering feed stock for PMEC. Unloading of the oceangoing vessels will be accomplished by means of a rail-mounted, continuous bucket crane (vertical leg type) ship unloader. The ship unloader will be configured to transfer feedstocks onto the dock conveyor at any point along the working limits of the machine. The crane unloader and dock conveyor will be totally or partially enclosed (depending on final design), with the vent stream containing captured particulate routed to a high-efficiency fabric filter baghouse.

The dock conveyor will be approximately 660 feet in length, with a height of about 27 feet above the top of the dock. A reclaim conveyor reaches into the hold of the ship, and gathers the solid fuel material. This conveyor is partially enclosed to reduce entrainment of dust, and accommodate the entry of material to the conveyor. The reclaim conveyor transfers material onto the dock conveyor. As part of the proposed BACT option, the dock conveyor is to be completely enclosed beyond the load point, and partially enclosed (open-topped with windscreens) for receipt of feed stocks from the ship unloader. The conveyor will terminate in a fully enclosed transfer structure, and the transfer point from the conveyor will be provided with a second fabric filter baghouse for control of captured dusts.

Nominal design capacity for this facility is 4,300 tons per hour (set equivalent to the railcar system for purpose of emission estimates). Significant emissions from the ship unloading facility consist only of particulate matter (PM) and particulates less than 10 microns diameter (PM_{10}). There are two emission units for the ship unloading facility that are included in this BACT analysis:

- Continuous bucket unloader unit; and
- Transfer point to the dock conveyor.
- B-1.10.1 Commercially Available Control Technologies

Based on current practices for solid material handling systems, several types of commercially available control technologies can be identified for the fuel unloading and storage systems at the proposed PMEC facility. An RBLC Database survey indicates that high efficiency fabric filter baghouses, water sprayers, dust suppressants, and enclosures are potential BACT options for ship unloading facilities and the associated transfer of petroleum coke and coal to storage facilities. Baghouse efficiencies varied from 99.0% to 99.9%. In addition, water sprays and various levels of facility and/or conveyor enclosures are also considered to be available control options for PM_{10} emissions. The ranges of fuel handling emission limits for recently permitted sources are as follows:

- PM = 0.0050 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- PM_{10} = 0.0040 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- Opacity = 0% to 10%

B-1.10.2 INFEASIBLE CONTROL MEASURES

Of the identified emission control options for this source, only the complete enclosure of the ship unloading facility would be viewed as technically infeasible. The large size of the entire dock operation, and the need for ship access over water would suggest a very complex and very costly structure, unlike anything currently used in commercial ship unloading.

B-1.10.3 RANKING OF AVAILABLE CONTROL MEASURES

In approximate order of decreasing stringency the feasible control technology options are:

- Effective enclosure of collecting and dock conveyors to the extent practical, with air drawn from enclosures and routed to high-efficiency fabric filters;
- Enclosure of dock conveyor and transfer points, with water or suppressant sprays for dust control;
- Water suppression on collecting conveyor and dock conveyor transfer points.

B-1.10.4 PROPOSED BACT LIMITS AND CONTROL OPTION

PMEC proposes to adopt the most stringent control option among those identified as feasible for this type of particulate emission source. As noted in the discussion of the top-down BACT procedure in the beginning of Section B-1.2, a review of any potential environmental and energy impacts resulting from the implementation of the control option must be addressed, even if the top-ranked control option is chosen. The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. This is a relatively minor potential environmental impact, such that use of a fabric filter baghouse is reasonably considered to be the top-ranked control option.

PMEC will adopt a fabric filter performance specification of 99% particulate removal from the airstreams sent to the baghouse. In combination with an estimated particulate collection efficiency of 80% for the entire ship unloading system, this results in 89.2% removal of all particulate emissions associated with this process.

B-1.11 BACT ANALYSIS FOR FEEDSTOCK STORAGE DOME VENT

Both the railcar and ship unloading facilities will supply feedstock via enclosed conveyors to two aluminum dome structures to provide control of fugitive dusts and noise emissions, and an enhanced visual appearance. The fuel storage basis will be a minimum of 30 days of feedstock storage. The upper dome areas will be furnished with low-speed fan powered ventilator units for control and exhaust of heat buildup. The ventilation units will be equipped with power-operated shut-off dampers and will be operated only after the airborne dusts generated within the domes during stockout operations have settled out following each loading period. This limited loading cycle operation was applied to develop a realistic estimate of the maximum potential to emit for this equipment. The unloading equipment for both railcars and ships have higher hourly capacities than that of the gasifier. Thus, the potential to emit for these solids handling sources can be considered to be limited by the capacity of the downstream gasifier system.

Each of the domes will be fed from, and will feed back to, a central transfer tower structure, which will be the receiving point of independent inclined conveyor systems running from the railcar and ship unloading facilities. Reclaiming from each dome will be by means of an underground conveyor feeding to a common surge hopper area in the base of the transfer tower. This hopper will transfer feedstock to one or two inclined conveyors forwarding feedstock to downstream processing facilities. As part of the proposed BACT measures, the transfer tower structure will be fully enclosed for dust capture and furnished with fabric filter baghouse systems for control of captured dusts.

B-1.11.1 COMMERCIALLY AVAILABLE CONTROL OPTIONS

Commercially available PM/PM_{10} control options were identified from review of the EPA's RBLC database. A list of recent PM_{10} BACT determinations for storage facilities at petroleum coke and coal facilities is included in Table B-1-8. The add-on control technologies that may practically be considered to establish a BACT emission limit for the storage dome vent emission point include:

- Fabric Filter Baghouse
- Electrostatic Precipitator (ESP)
- Wet Scrubber; and
- Mechanical Cyclone.

All of the control options identified above are considered technically feasible for controlling PM_{10} emissions from the proposed PMEC storage dome vents.

B-1.11.2 RANKING OF AVAILABLE CONTROL MEASURES

The following is a list of the available control options ranked by control effectiveness:

- Fabric Filter Baghouse – control efficiency greater than 99.9 percent for PM_{10} (typical specification of 0.01 grains per dry standard cubic foot);
- Electrostatic Precipitator – control efficiency approximately 95 percent for PM_{10};
- Wet Scrubber – control efficiency approximately 90 percent for PM_{10}; and
- Mechanical Cyclones – control efficiency up to 80 percent for PM_{10}.

B-1.11.3 CONSIDERATION OF ENERGY, ENVIRONMENTAL AND COST FACTORS

PMEC has elected to use the top-ranked control option to reduce PM_{10} emissions from the storage dome vents. As noted in the top-down BACT procedure discussed in the beginning of Section B-1.2, any potential environmental and energy impacts resulting from the implementation of the selected control option must be addressed even if the top control option is chosen.. The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. However, even considering this potential environmental impact, use of a fabric filter baghouse is still considered to be the top-ranked control option.

B-1.11.4 PROPOSED BACT LIMITS AND CONTROL OPTION

Based on the foregoing discussion, the proposed option to establish BACT emission limits for PM/PM_{10} emissions from the storage domes is the use of fabric filter baghouses. The emission control efficiency proposed for the baghouse is 99.9%, which is equivalent to the more stringent prior BACT determinations, based on those identified in Table B-1-8

B-1.12 GASIFICATION FLARE BACT ANALYSIS

B-1.12.1 PROCESS DESCRIPTION

The coal/petcoke gasification process includes an elevated enclosed flare to burn partially combusted natural gas and scrubbed/desulfurized off-specification syngas during unit startups, or on-specification syngas during short-term combustion turbine outages. Syngas sent to the flare during normal planned flaring events will be filtered, water-scrubbed and further treated in the Selexol® or equivalent and mercury removal systems to remove regulated contaminants prior to flaring. Flaring of untreated syngas or other streams within the plant would only occur as an emergency safety measure during unplanned plant upsets or equipment failures. The flame will be enclosed in a refractory-lined combustion chamber, effectively eliminating any visible flame and significantly reducing noise levels.

The gasification process flare will emit criteria pollutants that are products of combustion. However, the chemical compositions of the predominant gaseous fuels that would be flared, i.e., syngas and natural gas, results in very low emissions of PM_{10}, SO_x and VOC. For the syngas case, there is very little unoxidized carbon in the fuel, which limits the formation of particulate matter during combustion even below the rate for natural gas. Formation of SO_x is limited by the pre-treatment of the syngas flare stream using Selexol® or equivalent, and the inherently low sulfur content of pipeline natural gas. The rate of VOC emission can be conservatively represented by the EPA Document AP-42 factor for external combustion of natural gas. This factor is expected to overestimate VOC emission rates during flaring of syngas, because that fuel is relatively higher in hydrogen and lower in total carbon.

B-1.12.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Review of the federal RBLC database and selected state permit information indicates that low emission design/low NOx burners and regulation of the chemical composition of the flared gases are currently (since 2004) the prevalent BACT options for flares. Table B-1-9 lists recent examples of BACT determinations for flare add-on devices for destruction of emissions to provide guidance in the selection and ranking of commercially proven technology options. For purposes of identifying available control technology options, this portion of the PMEC process can be viewed as substantially similar to hydrocarbon flares in petroleum refineries. Control technologies that may be considered potentially available for the gasification process flare include:

TABLE B-1-9
REVIEW OF RECENT BACT DETERMINATIONS FOR INDUSTRIAL FLARES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels	Refinery Emergency Flares	N/A	No visible emissions. Exit velocity > 60 fps. Max H_2S 0.10 gr/dscf	Flare and burner design. Natural gas purge and steam assisted pilot	PSD-BACT
VT-0019	12-16-04	Orleans County, VT	New England Waste Services Inc	Landfill gas Flare	5000 scfm	CO – 0.37 lb/MMBtu NO_x – 0.0680 lb/MMBtu	Low Emission Design	Other Case-by-Case
IA-0074	08-16-04	Linn County, IA	Archer Daniels Midland Corn Processing	Flare (Natural Gas)	27 MMBtu/hr	SO_2 - 0.02 lb/hr NO_X – 4.05 lb/hr	Natural gas only and low NO_x burner on flare	BACT-PSD
AR-0077	07-22-04	Mississippi County, AR	Steelcorr Inc	Degasser Hotwell Flare (Natural gas)	N/A	PM_{10} – 7.32 lb/hr SO_2 – 0.09 lb/hr VOC – 1.06 lb/hr CO – 1.06 lb/hr NO_x – 0.01 lb/hr	Hotwell and only natural gas combustion	BACT-PSD

Good Combustion Practices - A certain level of flame temperature control can be exercised for the enclosed flare by implementing fuel/air ratio control. In its most sophisticated form, this control utilizes feedback control from oxygen monitors to modulate fuel and air rates in order to maintain the load demand, while reducing pollutant formation. Flare BACT options that have been achieved in practice in California and Texas (e.g., California Air Pollution Control Officers Association [CAPCOA] BACT Clearinghouse) indicate the incorporation of "proper burner management and monitoring" are used to control the emissions of CO, VOCs and NO_x.

Air-Assisted or Steam-Assisted Pilot Burner - Particulate emissions from flares are controlled by using steam injection or air assist to promote proper mixing and complete combustion. This measure provides a reduction in visible emissions that could result from incomplete combustion. In addition, the BACT guidance for flare sources issued by the TNRCC requires monitoring of flame integrity and smokeless design by using air-assist or water- or steam-injection.

Add-On Controls - The gasification system flare is not a candidate for add-on abatement systems. It is generally recognized in the chemical process industries that adoption of add-on control can impede the ability of a flare to respond to unexpected upset conditions. For plant safety, the flare must provide a "fail-safe" that is available regardless of the functioning of pollution control devices.

Chemical Composition of the Flared Gases – This option generally addresses the emissions of PM_{10}, SO_2 and VOC from the flare. As described above, the flaring of either syngas or natural gas results in relatively low emissions of these pollutants, in part because of the relatively low carbon to hydrogen ratio in syngas. It is accepted practice in the chemical process and utility industries that control of SO_2 is achieved by using natural gas-fired pilots or limiting the sulfur content of the flared gases. Prior BACT determinations for flares at refineries have also imposed limits on the hydrogen sulfide (H_2S) content of the flared gases. In keeping with these precedents, the PMEC will use Selexol® or equivalent cleaning of syngas streams sent to the flare.

B-1.12.3 TECHNICALLY INFEASIBLE OPTIONS

Low-NO_x burners (LNB) and ultralow NO_x burners (ULNB) technology is not available for enclosed, ground-level flares, which do not have a confined combustion zone that would allow staged introduction of fuel and air streams. Such designs alter air to fuel ratio in the combustion zone by staging the introduction of the air to promote a "lean-premixed" flame. This results in lower combustion temperatures and reduced NOx formation.

In industrial practice, add-on controls are not considered feasible, or even advisable from a plant safety standpoint. The elevated operating temperature regime of the exhaust gas eliminates from consideration most add-on controls. It is generally recognized in the chemical process industries that adoption of add-on control can impede the ability of a flare to respond to unexpected upset conditions. For plant safety, the flare must provide a "fail-safe" that is available regardless of the functioning of pollution control devices. A flare system is intended to be an inherently simple and reliable system with as few failure modes as possible. Should an add-on control device not

be operational on an occasion when flaring was necessary, it would likely be damaging to both the flare and the control if the hot gases were released with the control device off-line.

B-1.12.4 PROPOSED BACT LIMITS AND CONTROL OPTION

The flare for the PMEC facility will be designed to meet the BACT achieved-in-practice conditions achieved in California (SCAQMD) and Texas (TCEQ). For example, the flares have been designed to maintain an exit velocity above 60 feet per second under all conditions. In addition, the flare will have a natural gas purge and steam or air-assisted mixing at the pilot flame to achieve negligible particulate emissions. These design features are included in the emission calculations for the flare during upset conditions, as presented in this Application.

B-1.13 BACT ANALYSIS TANK VENT COLLECTION AND VAPOR DESTRUCTION SYSTEN

B-1.13.1 PROCESS DESCRIPTION

A tank vent collection and vapor destruction system is proposed to convert off-gas components in various process tank vents to oxidized forms (SO_x, NO_x, H_2O, and CO_2) before venting them to the atmosphere. For the gasification and syngas cleanup processes, the tank vent streams are composed primarily of air purged through various in-process storage tanks. Heat recovery will be accomplished by steam generation in a heat exchanger contacting the hot exhaust gas from the tank vent incinerator before it is directed to a stack. Treated streams may include:

- Air purged through various in-process storage tanks and the slag handling dewatering system off-gas. This tank purge gas may contain very small amounts of sulfur-bearing components.
- In the blending of gasifier feed (that can include treated recycled water and slag fines recycled from other areas of the gasification plant), tanks, drums and other areas of potential fuel exposure to the atmosphere will be covered and vented into the tank vent collection system for emission control.
- Sweep nitrogen introduced into the sulfur pit (to prevent the accumulation of an otherwise potentially explosive mixture of H_2S and air) is collected and fed to the tank vent gas incinerator.

The combined vent streams will generally contain components similar to those in syngas, creating a unique fuel stream that is unlike any found for permitted combustors in the RBLC database (see Table B-1-10). For this reason, pollutant emissions are addressed on an individual basis in this analysis, and compared to existing facilities where appropriate. The combustor emissions are largely dependent on burner specifications for this unique fuel.

TABLE B-1-10
REVIEW OF RECENT BACT DETERMINATIONS TANK VENT COLLECTION / DESTRUCTION SYSTEM

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels	Group B Storage Tanks	47 Tanks from 378,000 to 7,560,000 gal	VOC – 99% destruction, or VOC < 20 ppm at 3% O2	Internal floating roofs with thermal oxidizer	BACT-PSD
NC-0111	07-29-04	Bertie County, NC	Avoca Inc	Rotocel operation Solvent Recycle Tanks	NA	VOC - 0.94 lb/hr	Chilled water-cooled condenser and packed tower scrubber.	BACT-PSD
	7-15-04	Minnesota	Fairbault Energy Park	IGCC Tank Vent oxidizer	40 MMBtu/hr	VOC: Oil-fired – 0.003 lb/MMBtu; Gas fired – 0.006 lb/MMBtu	Good combustion practices	BACT-PSD
	9-29-04	Minnesota	Mankato Energy Center	IGCC Tank Vent oxidizer	70 MMBtu/hr	VOC: Gas fired – 0.007 lb/MMBtu	Good combustion practices	BACT-PSD
OH-0288	06-14-04	Medina County, OH	Owens Corning	Oxidized Asphalt fixed Roof Storage Tanks	60,000 gal tank	PM – 0.01 lb/hr SO_2 – 0.21 lb/hr VOC – 0.05 lb/hr CO – 0.02 lb/hr H_2S – 0.0060 lb/hr 0% opacity	Fixed roof tank and thermal incinerator	BACT-PSD
TX-0375	03-14-02	Harris County, TX	Lyondell	Sour Water Tanks	NA	H_2S – 0.04 lb/hr	Emissions will be collected by a vapor collection system and routed to a control device with a destruction efficiency of 98%.	NSPS
TX-0375	03-14-02	Harris County, TX	Lyondell	Molten Sulfur Storage Tanks	NA	H_2S – 0.0010 lh/hr		

B-1.13.2 NITROGEN OXIDES BACT ANALYSIS

Identification of Available Control Options

For a tank vent collection and thermal destruction system, a number of measures may be considered potentially available for NO_x control:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Low NO_x Burners (LNB)
- Flue Gas Recirculation (FGR)
- Efficient Burner Design /GCP

B-1.13.2.2 Infeasible Control Measures

In order to achieve adequate destruction efficiencies, the tank vent vapor destruction device requires a relatively high combustion flame temperature and extended residence time, both of which are fundamentally incompatible with low NO_x burner technology and flue gas recirculation (FGR). These two technologies are based on reducing the flame temperature to inhibit NO_x formation. In the case of LNB, flame temperature is reduced by staged mixing of fuel and air. The FGR system introduces cooler stack gases with reduced oxygen content into the combustion chamber. Both mechanisms reduce flame temperature in a manner that would have an adverse affect on thermal destruction efficiency. Consequently, dry low-NO_x burners and flue gas recirculation are considered technically infeasible for incineration of tank vent streams.

SCR is not considered a technically feasible control option based on all of the same disadvantages described for SCR application to IGCC turbines in Section B-1.7.1.2. The in-process tank and slag dewatering vent streams will have substantially higher sulfur content than the syngas. Even at the reduced sulfur content levels of the syngas, use of catalyst-based destruction and ammonia injection would result in heavy fouling of the catalyst module material and the downstream heat recovery device on the tank vent thermal oxidizer.

There are two related reasons why SNCR is viewed as technically infeasible for the tank vent gas destruction device. Primarily, there are anticipated to be unacceptable levels of fouling of heat transfer surfaces in the heat recovery section if ammonia is injected upstream. If instead the ammonia is injected downstream of the heat recovery section, the gas temperature will be too low for effective conversion of NO_x . Therefore, this technology is not feasible for the tank vent thermal incinerator.

B-1.13.2.3 Proposed BACT Control Option and Emission Limits

Efficient burner design and good combustion practices are proposed as the BACT option for the tank vent oxidizer unit. The burner for the proposed thermal oxidizer unit would be specified by the vendor to minimize NO_x formation, while accommodating the variable composition of the

unique process gas stream. No add-on combustion controls are technically feasible for this application. The proposed BACT-based limit for this source is 0.3 lb NO_x/MMBtu, based on anticipated performance specifications from the vendor.

B-1.13.3 SULFUR DIOXIDE AND PM_{10} BACT ANALYSIS

Tank purge gases may contain very low levels of sulfur-bearing compounds, which will contribute to SO_2 and PM_{10} emissions during thermal destruction of these gases. The proposed vapor destruction incinerator will offer oxidizing conditions to convert any H_2S present in the tank vents to SO_2.

B-1.13.3.1 Identification of Available Control Options

Sulfur dioxide emissions from any combustion process are directly related to the sulfur content of the fuel, which is also a key factor determining the magnitude of PM_{10} emissions. Potentially available controls for the tank vent oxidizer include pre-combustion controls to limit the sulfur content of the treated streams, combustion controls, or scrubbing the SO_2 from the exhaust gas (post-combustion control):

<u>Pre-Combustion Process Controls (fuel specification)</u>

- Chemical Absorption Acid Gas Removal (AGR), e.g., MDEA
- Physical Absorption, e.g., Selexol®, Rectisol®
- Use of low-sulfur pipeline natural gas

<u>Combustion Controls</u>

- Good combustion practices (GCP)

<u>Post-Combustion Controls</u>

- Flue Gas Desulfurization (FGD)

B-1.13.3.2 Evaluation of Potentially Available Control Options

A discussion of the pre-combustion controls related to syngas production was provided in Section B-1.7.2. Combustion controls consist of good combustion practices, which as shown in Table B-1-11, is currently the prevalent control option for thermal destruction devices. FGD, which is the sole post-combustion control that is considered potentially available for this oxidizer, has not been demonstrated in practice for such sources or for the gas streams that will be incinerated, and is viewed as infeasible.

B-1.13.3 3 Proposed BACT Limits and Control Option

Emissions of SO_2 (and indirectly PM_{10}) can be effectively controlled by limiting the sulfur content of streams routed to the vent gas collection system. Therefore, the control of chemical composition of the treated streams, combined with good combustion practices are the options

proposed as the BACT option to limit SO_2 emissions from this process. The numerical emission limits are dependent upon the averaging time selected, as discussed below.

The anticipated compositions of the syngas, natural gas supply, and other treated streams routed to the tank vent oxidizer were evaluated to estimate the suitable BACT-based emission limits for oxidizer SO_2 emissions. For the PMEC combustion turbines, the syngas sulfur level representing short-term maximum concentration is estimated at 50 ppmvd (expressed as H_2S) in the undiluted syngas, on a 1-hour average basis. Substantially lower sulfur content would be achieved over longer averaging times; for example, 15 ppmvd is foreseen as the maximum concentration on a 24-hour average basis. The treated stream from the sulfur pit would be at comparable worst-case concentrations, but its contribution would be limited by its relatively small flow rate. These worst-case sulfur content levels can be used as the basis for BACT emission limits of 5.8 lb/hr SO_2 on a 1-hour average, and 4.2 lb/hr on a 24-hour average.

Good combustion practices represent the primary control that affects PM_{10} emissions. For the tank vent oxidizer the proposed BACT limit based on this technology, for combustion of either natural gas or syngas, is 0.01 lb/MMBtu PM_{10}.

B-1.13.4 VOLATILE ORGANIC COMPOUND BACT ANALYSIS

B-1.13.4.1 Identification of Available Control Options

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations for destruction of VOC-containing off-gases from storage or process vessels. For identification of commercially available control technologies, this portion of the PMEC process can also be viewed as analogous to tank farms or process tanks in conventional petroleum refineries, chemical process plants, and loading terminals. However, because the use of a thermal oxidizer is included as part of the process, only VOC controls related to external combustion devices were considered.

Recent BACT determinations for refineries, chemical facilities, and IGCC facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas-fired boilers were subject to the requirements listed in Table B-1-10. The commercially available VOC controls for the tank vent oxidizer are limited to good combustion practices.

The waste syngas and natural gas streams that will be the predominant gas streams routed to the vent gas collection system both have a relatively low potential to generate VOC in the combustion process. The syngas is relatively high in hydrogen and CO, with very small amounts of hydrocarbons. So the negligible level of uncombusted VOC emissions in the gas streams to the incinerator do not warrant extensive add-on controls.

B-1.13.4.2 Proposed BACT Limits and Control Option

VOC emissions from the tank vent thermal oxidizer would generally be products of incomplete combustion. Good combustion practices represent the primary control that affects VOC emissions. For the tank vent oxidizer the proposed BACT limit based on this technology, for combustion of either natural gas or syngas, is 0.004 lb VOC/MMBtu.

B-1.13.5 CARBON MONOXIDE BACT ANALYSIS

B-113.5.1 Identification of Available Control Options

Review of the federal RBLC database and selected state permit information indicates that BACT determinations for CO emissions from thermal destruction of organic gas streams consistently specify good combustion practices as the sole control measure required. Several recent BACT determinations for refineries, chemical facilities, and IGCC facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas-fired boilers are listed in Table B-1-11.

B-113.5.2 Proposed BACT Limits and Control Option

Emissions of CO from the tank vent thermal oxidizer would generally be products of incomplete combustion. As the proposed BACT option, CO emissions from this external combustion device will be controlled by good combustion practices. For the tank vent oxidizer the proposed BACT limit based on this technology, for combustion of either natural gas or syngas, is 0.09 lb/MMBtu.

B-1.14 AUXILIARY BOILER BACT ANALYSIS

B-1.14.1 PROCESS DESCRIPTION

One auxiliary boiler will serve the two PMEC generating trains, will provide steam for pre-startup equipment warmup and for other miscellaneous purposes when steam from the gasifiers or HRSGs is not available. This boiler will provide steam in addition to, or in lieu of, the steam that can be generated from the HRSG units provided on the tank vent incinerators. The auxiliary boiler will produce a maximum of about 100,000 lb/hr of steam and will be fueled only by pipeline quality natural gas.

Pollutant emissions from natural gas boiler units include NO_x, PM_{10}, CO, SO_2, and VOCs. Annual operation of the boiler will be equivalent to or less than 25% of the year at maximum capacity.

B-1.14.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations. This portion of the PMEC process can be viewed as substantially similar to auxiliary boilers that are often included in combined cycle power generation units fired on natural gas. Table B-1-11 lists a number of typical BACT determinations in recent years for auxiliary and industrial boiler equipment. The RBLC database survey results indicate that available BACT options for the pollutants emitted from auxiliary boilers include:

- Good Combustion Practices (GCP)
- Staged Air/Fuel Combustion or Overfire Air Injection (OFA)
- Low NOx burners (LNB)
- CO Oxidation Catalysts

- Flue Gas Recirculation (FGR)
- Selective Catalytic Reduction (SCR)
- Low sulfur fuels

B-1.14.3 NO_X BACT ANALYSIS

Several combustion and post-combustion controls are commercially available for the auxiliary boiler. These controls include staged air/fuel combustion, Low-NO_x burners, flue gas recirculation, and SCR. The range of BACT NO_x emission limits for recently permitted auxiliary boilers (since 2004) is from 0.011 lb/MMBtu to 0.7 lb/MMBtu.

B-1.14.3.1 Ranking of Available Control Technologies

The identified control technologies are considered technically feasible for gaseous fuel fired boilers. Consequently, these controls will be ranked and evaluated for each pollutant for which BACT is required. In top-down order of decreasing stringency, the feasible NO_x controls are listed with the approximate level of emission reduction afforded by each technology:

- Low NO_X Burners with SCR 0.011 lb/MMBtu
- Low NO_X Burners with FGR 0.020 lb/MMBtu
- Low NO_X Burners with GCP 0.036 lb/MMBtu
- FGR Alone 0.20 lb/MMBtu
- Staged air/fuel or OFA 0.25 lb/MMBtu
- GCP, Conventional Burners 0.30 lb/MMBtu (BACT Baseline)

B-1.14.3.2 Consideration of Energy, Environmental And Cost Factors

Alternative add-on emission control techniques are available and technically feasible for reduction in NO_X emissions from auxiliary boilers. These are in addition to combustion controls, namely GCP in combination with Low-NO_X burners.

With respect to energy factors, add-on post-combustion controls on an auxiliary boiler of this capacity range will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water, depending upon design. In addition, there are thermal losses associated with the heat-up of the catalyst modules of an SCR.

TABLE B-1-11
REVIEW OF RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0062	12-22-05	Sibley County, MN	Heartland Corn Products	Boiler	198 MMBtu/hr	NO_X – 0.04 lb/MMBtu CO – 0.04 lb/MMBtu	Not Described	BACT-PSD
NC-0101	09-25-05	Forsyth County, NC	Forsyth Energy Projects, LLC	Auxiliary Boiler	110.2 MMBtu/hr	NO_X – 15.13 lb/hr (0.14 lb/MMBtu) SO_X – 0.61 lb/hr (0.0055 lb/MMBtu) CO – 9.08 lb/hr (0.082 lb/MMBtu) VOC – 0.59 lb/hr PM_{10} – 0.82 lb/hr	Low NO_X burners, Good Combustion Control, Clean Burning, and Low-Sulfur Fuel	BACT-PSD
OR-0046	01-06-05	Marion County, OR	Calpine	Auxiliary Boiler	417,904 MMBtu/yr	CO – 0.0380 lb/MMBtu NO_X – 0.0110 lb/MMBtu VOC – 0.0044 lb/MMBtu	SCR	BACT-PSD
WI-0228	10-19-04	Marathon County, WI	Wisconsin Public Service	Auxiliary Boiler	229.8 MMBtu/hr	PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.0006 lb/MMBtu NO_X – 0.10 lb/MMBtu CO – 0.08 lb/MMBtu VOC – 0.0054 lb/MMBtu Hg - 0.0001 lb/hr	Low NOx burners, Good Combustion Practices, and only natural gas.	BACT-PSD
MI-0368	09-08-04	Calhoun County ,MI	Michigan Paperboard Company	Boiler	185 MMBtu/hr	SO_2 – 280 lb/hr (1.51 lb/MMBtu)	Not Described	BACT-PSD
NE-0024	06-22-04	Washington County, NE	Cargill, Inc.	Boiler	198 MMBtu/hr	NO_X – 0.07 lb/MMBtu 20% Opacity	Low NO_X burners and Induced Draft Flue Gas Recirculation	Other Case-by-Case

TABLE B-1-11 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MS-0069	06-08-04	Harrison County, MS	E.I. Dupont De Nemours	Boiler	231 MMBtu/hr	PM_{10} – 1.76 lb/hr NO_X – 0.09 lb/MMBtu	Low NO_X burners with FGR	BACT-PSD
OH-0241	05-27-04	Butler County, OH	Miller Brewing Company	Boiler	238 MMBtu/hr	PM_{10} – 0.01 gr/acf NO_X – 0.70 lb/MMBtu VOC – 2.6 lb/hr CO – 20 lb/hr SO_2 – 1.6 lb/MMBtu	Baghouse, Over fire and side fire air	BACT-PSD
ID-0015	04-05-04	Power County, ID	JR Simplot Company	Boiler	175 MMBtu/hr	NO_X – 7 lb/hr (0.0400 lb/MMBtu)	Low NO_X Burners	RACT
WV-0023	03-02-04	Monongahela County, WV	Longview Power, LLC	Auxiliary Boiler	225 MMBtu/hr	CO – 0.04 lb/MMBtu NO_X – 0.0980 lb/MMBtu PM & PM_{10} – 0.0022 lb/MMBtu SO_2 – 0.0040 lb/hr VOC – 0.0054 lb/MMBtu 10% opacity	Good Combustion Practices, use of low sulfur natural gas, and Low NOX burners	BACT-PSD

Environmental factors associated with post-combustion catalytic systems have affected many recent boiler installations. Generally, these involve the need for ammonia reagent, in the case of SCR, and the effects of spent catalyst module. Both of these factors remain disadvantages of catalyst-based add-on controls. Ammonia slip, the amount of unreacted ammonia that is released from boilers equipped with SCR remains an additional environmental impact. This is usually mitigated by using predictive feed rate control, based on the real-time firing rate or percentage of full-load. Initial performance testing usually includes ammonia slip tests to verify that the control logic is maintaining ammonia emissions within permitted limits.

Differential cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. As these boilers are not continuously operated, but rather are used during relatively infrequent start-up cycles, the emissions abated can be shown not to warrant the investment in capital and operating costs associated with such controls. An annualized cost analysis for the proposed PMEC auxiliary boiler has been conducted to demonstrate this cost barrier. This cost analysis separately considered the two more stringent levels of control above that proposed by PMEC, namely, the use of FGR and SCR as additional control for NO_x emissions. The findings of these cost analyses are summarized in Table B-1-12 (refer to Attachment X2 for further details).

TABLE B-1-12
ECONOMIC ANALYSIS OF POST-COMBUSTION NO_X CONTROLS FOR PMEC AUXILIARY BOILER

Additional Control Option	Controlled Emissions Basis	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Baseline Emissions or Reduction (tons/yr)	Cost Effectiveness ($ / ton)
SCR	0.011 lb/MMBtu, 70% reduction	$813,700	$182,997	4.34	$42,214
FGR	0.2 lb/MMBtu, 45% reduction	$115,500	$34,191	3.06	$11,174
Baseline Option (GCP, Low-NO_X Burner)	4.7 lb/hr	---	---	5.1 (Controlled Emissions)	---

Both the SCR and FGR add-on control technologies for the auxiliary boiler would be cost prohibitively expensive in terms of cost per ton of NO_x abated. The implementation of FGR has an estimated annualized cost of over $34,000, and provides a reduction of 3.06 tons per year compared with the baseline option of GCP. Similarly, the addition of an SCR system on this unit has an estimated annualized cost of $182,987 and would provide a reduction of 4.34 tons per year. From these results, the cost effectiveness of FGR and SCR options are conservatively estimated to be not less than $11,000 and $42,000 per ton, respectively.

B-1.14.3.3 Proposed BACT Limits and Control Option

As illustrated in Table B-1-12, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for technically feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks of such controls, leads to the proposed NO_x BACT option of GCP with Low-NO_x burners. Boiler vendor information indicates that the hourly emissions for this unit with these technologies will be about 0.036 lb/MMBtu NO_x. This rate, or a corresponding lb/hour emission rate, is proposed as the BACT NO_x limit for emissions from the auxiliary boiler emission unit.

B-1.14.4 CO BACT ANALYSIS

Only one post-combustion control is commercially available for the auxiliary boiler. This control is the implementation of an oxidation catalyst module. Based on the RBLC review presented in Table B-1-11, the range of BACT CO emission limits for recently permitted auxiliary boilers (since 2004) is from 0.038 lb/MMBtu to 0.08 lb/MMBtu. BACT for CO on most units is GCP.

B-1.14.4.1 Ranking of Available Control Technologies

The identified control technologies, GCP and oxidation catalyst, are considered technically feasible for gaseous fuel fired boilers. In top-down order of decreasing stringency, the feasible CO controls are listed with the approximate level of control that could be achieved:

- Oxidation Catalyst and GCP 90% control
- GCP 0.74 lb/MMBtu (BACT baseline)

B-1.14.4.2 Consideration of Energy, Environmental and Cost Factors

The use of oxidation catalyst modules as add-on emission control is available and technically feasible for reduction in CO emissions from auxiliary boilers. These are in addition to combustion controls, namely GCP in combination with Low-NO_x burners.

With respect to energy factors, add-on post-combustion controls on an auxiliary boiler of this capacity range will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water, depending upon design. Environmental factors associated with post-combustion catalytic systems have affected many recent boiler installations. Generally, these involve the effects of spent catalyst module disposal.

Prohibitively high annualized cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. Since the boiler is not continuously operated, but rather used during relatively infrequent start-up cycles, the emissions abated can be shown to not warrant the investment in capital and operating costs. An annualized cost analysis for the proposed PMEC auxiliary boiler is provided to demonstrate this cost barrier. The findings of these cost analyses are summarized in Table B-1-13. (refer to Attachment _X2 for additional details)

TABLE B-1-13
ECONOMIC ANALYSIS OF POST-COMBUSTION CO CONTROLS FOR PMEC AUXILIARY BOILER

Additional Control Option	Controlled Emissions Basis	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Baseline Emissions or Reduction (tons/yr)	Cost Effectiveness($ / ton)
Catalytic Oxidizer	0.0074 lb/MMBtu, 90% reduction	$625,382	$153,346	9.45	$16,227
Baseline Option (GCP)	9.6 lb/hr	---	---	10.5	---

The add-on CO control technology for the auxiliary boiler would be cost prohibitive in terms of cost per ton abated. The implementation of a catalytic oxidizer module has an estimated annualized cost of over $153,000, and provides a reduction of 9.45 tons per year, compared with the baseline option of GCP. From these results, the cost effectiveness of the catalytic oxidizer option is conservatively estimated to be not less than $16,000 per ton.

B-1.14.4.3 Proposed BACT Limits and Control Option

As illustrated in Table B-1-12, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks, leads to the proposed BACT option of GCP for CO emissions. Boiler vendor information indicates that the worst case hourly emissions for this unit with these technologies will be 0.074 lb CO/MMBtu. This rate, or a corresponding lb/hour emission rate, is proposed as the BACT limit for CO emissions from the auxiliary boiler emission unit.

B-1.14.5 SO_2, VOC, PM_{10} BACT ANALYSIS

B-1.14.5.1 Ranking of Available Control Technologies

For these pollutants, the commercially available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas, and GCP. Based on review of the RBLC database in Table B-1-11, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- SO_x = 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- VOC = 0.0044 lb/MMBtu to 0.0054 lb/MMBtu
- PM_{10} = 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the PMEC auxiliary boiler, so further evaluation is unnecessary.

B-1.14.5.2 Proposed BACT Limits and Control Option

The limited operating period for the auxiliary boiler results in relatively low emissions of SO_2, VOC and PM_{10}, meaning that an investment in complex add-on controls is not warranted. Therefore, the use of pipeline natural gas and GCP are proposed as the BACT options for this source. Boiler vendor information indicates that the worst case hourly emissions for this unit with these technologies will be 0.005 lb SO_2/MMBtu, 0.004 lb VOC /MMBtu and 0.005 lb PM_{10}/MMBtu.These rates, or corresponding lb/hour emission rates, are proposed as BACT limits for the auxiliary boiler emission unit

B-1.15 COOLING TOWER BACT ANALYSIS

B-1.15.1 PROCESS DESCRIPTION

The proposed cooling system at the PMEC consists of a circulating water system that will utilize a larger (12-cell) mechanical draft cooling tower to support operations of the steam turbine generators. Each of the two generating plants will have independent cooling tower sections, with 6 cells per plant in a combined structure approximately 400 feet long, 120 feet wide, and 40 feet high. A second, smaller tower is also included in the design to support the cooling needs of the remainder of the PMEC, including syngas production and cleanup.

Wet (evaporative) cooling towers emit aqueous aerosol “drift” particles that evaporate to leave crystallized solid particles that are considered PM_{10} emissions. The proposed control technology for PM_{10} is high-efficiency drift eliminators to capture drift aerosols upstream of the release point to the atmosphere.

B-1.15.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Utility generation facilities, refineries, and other large chemical processing plants utilize wet mechanical draft cooling towers for heat rejection. This portion of the PMEC plant can be viewed as substantially similar to such processes.

Review of the federal RBLC database and recent Washington state permits for utility-scale cooling towers indicates that high efficiency drift eliminators and limits on total dissolved solids (TDS) concentration in the circulating water are the techniques which set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, to attempt to optimize droplet impingement at minimal pressure drop.

Table B-1-14 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM_{10} releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce PM_{10} emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the PM_{10} emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, to addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed PMEC tower will be based on 12 cycles of concentration, that is, the circulating water will be on average 12 times the dissolved solids concentration of the make-up water that is introduced. The proposed cooling tower is to be operated at a design level of total dissolved solids (TDS) concentration of 2,400 ppmw in the cooling water, based on 200 ppmw in the make up water.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted (usually because of concerns other than air emissions) by utility-scale combined cycle plants in arid climates. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

B-1.15.3 INFEASIBLE CONTROL MEASURES

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for PM_{10} emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature. The plants for which this measure has been used are, with few exceptions, smaller capacity combined-cycle plants (smaller than the PMEC facility).

TABLE B-1-14
REVIEW OF RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
IA-0082	04-19-06	Cerro Gordo County, IA	Golden Grain Energy	Cooling Tower	NA	PM_{10} – 1.33 lb/hr	Mist Eliminators	BACT-PSD
NC-0101	09-29-05	Forsyth County, NC	Forsyth Energy Projects LLC	Cooling Tower	3834 gal/min	PM – 0.0070 lb/hr PM_{10} – 0.0020 lb/hr	NA	BACT-PSD
OR-0041	08-08-05	Umatilla County, OR	Diamond Wanapa I LP	Cooling Tower	6.2 ft^3/sec	PM – 3532 ppmw	Installation of high efficiency 0.0005% drift eliminators. Limit TDS to less than 3,532 PPMW.	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Cooling tower	140,650 gal/min	PM – NA PM_{10} - NA	RACT is drift eliminators to achieve 0.0005 % drift or less.	BACT-PSD
LA-0192	06-06-05	Orleans County, LA	Cresent City Power LLC	Cooling Tower	290,200 gal.min	PM_{10} – 2.61 lb/hr	TDS = 30,000 PPM 0.0001% drift annual average (Marley Excel Drift Eliminators)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IA	Auburn Nugget	Cooling Tower	23,450 gal/min	PM – 0.0050% of Throughput 20% opacity	NA	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Cooling Tower	NA	PM_{10} – 0.0005% drift	Drift Eliminators	BACT-PSD

TABLE B-1-14 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels LLC	Cooling Tower	NA	PM – 1.6 lb/hr	High Efficiency Drift Eliminators	BACT-PSD
NY-0093	03-31-05	Nassau County, NY	Igen-Nassau Energy Corporation	Cooling Tower	NA	PM_{10} – 0.0005% drift	NA	BACT-PSD
NE-0031	03-09-05	Otoe County, NE	Omaha Public Power District OPPD	Cooling Tower	NA	PM_{10} – 0.0010 lb/hr	Cooling tower shall be equipped with high efficiency mist eliminators with a max total liquid drift not exceed 0.0005% of circulating water flow.	BACT-PSD
WA		Cherry Point	BP Refinery	Cogeneration Cooling Tower	NA	7.2 tpy	0.001% drift	BACT-PSD
WA		Hanging Rock Energy Facility	Duke Energy	Combined Cycle Unit Cooling Tower	NA	3.6 lb/hr	Drift Eliminators	BACT-PSD
WA		Mint Farm Generation		Combined Cycle Unit Cooling Tower	NA	1.08 tpy	Drift Eliminators	BACT-PSD
WA		Wallula Power Project		Combined Cycle Unit Cooling Tower	NA	3.7 lb/hr	Water pre-treatment and 0.0005% drift rate	LAER

A dry cooling tower is at best marginally feasible for PMEC duty, especially in light of the small emissions benefit that would be obtained. Because of the high capital cost and process design changes involved in the use of a dry cooling tower, this measure is viewed as infeasible for the PMEC project.

B-1.15.4 RANKING OF AVAILABLE CONTROL MEASURES

Because all of the commercially available options that could form the basis for a BACT emission limit for PM_{10} from the cooling tower are also technically feasible, this section will rank these options. The technically feasible option of high-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option. There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option.

In "top down" order from most to less stringent, the potentially available candidate control techniques are:

- Combinations of high-efficiency drift eliminators and TDS limit
- High-Efficiency drift eliminators to control drift to as low as 0.0005% of circulating flow
- High-efficiency drift eliminators, as low as 0.001% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Installation of Drift Eliminators (no efficiency specified)

B-1.15.5 CONSIDERATION OF ENERGY, ENVIRONMENTAL AND COST FACTORS

Development of increasingly effective de-entrainment structures has resulted in equipment vendors claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT-basis for emission limits in current permits, but it has not been verified by actual testing, according to process engineers for PMEC and others. Consequently, it is reasonable to identify this very-high efficiency drift eliminator to have not been demonstrated in practice.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to "conventional" specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 12-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved

droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM_{10} abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

B-1.15.6 PROPOSED BACT LIMITS AND CONTROL OPTION

Based on the information from the RBLC database survey, and the energy and cost factors described above, the proposed BACT option for the PMEC cooling towers is use of drift eliminators achieving a maximum drift of 0.001% of the circulating water. This measure, along with a limit on the circulating water TDS to an average of 2,400 ppmw is considered to be the best available control option for particulate emissions from the cooling towers. Taken together, implementation of these two measures represents the most stringent control option that is technically feasible without being cost prohibitive.

B-1.16 INTERNAL COMBUSTION ENGINE BACT ANALYSIS

B-1.16.1 PROCESS DESCRIPTION

One 2 MW emergency diesel generator will be used for the gasification island. Additionally, one nominal 300 hp diesel-driven firewater pump will be provided for each plant (one diesel, one electric). These engines will burn very low sulfur distillate oil. Other than plant emergency situations, the engines will be operated less than five hours per month per engine for routine testing, maintenance, and inspection purposes.

This equipment will emit criteria pollutants associated with diesel-fired engines. As the specific equipment has not yet been specified, the generic emission factors provided by AP-42, Section 3.4 for large stationary diesel engines were used to estimate criteria pollutant emissions. These emission calculations are presented in Appendix URS-1 [This is the URS Excel file with the criteria pollutant emissions inventory.]of this Application.

B-1.16.2 NO_X BACT ANALYSIS

B-1.16.2.1 Available Control Technologies and Technical Feasibility

There are a limited number of technically-feasible NO_x control technologies that are commercially available for internal combustion engines. In practice, the high temperature and relatively low volumetric flow of the engine exhaust eliminates most post-combustion controls. Based on the RBLC database review presented in Table B-1-15, two general types of control options have emerged as technically feasible:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new

engines include these features as standard equipment; accordingly this measure is deemed the baseline case for purposes of the BACT analysis.

Selective Catalytic Reduction (SCR) - In this technology, nitrogen oxides are reduced to gaseous nitrogen by reaction with ammonia in the presence of a supported precious metal catalyst. The SCR system includes a catalyst module downstream of the engine exhaust. Just upstream of the catalyst, a reagent liquid (typically ammonia or urea solution) is injected directly into the exhaust stream.
Another potentially available technology that has been eliminated from consideration on the grounds that it is technically infeasible is:

Non-Selective Catalytic Reduction (NSCR) – Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than 4% oxygen in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.

B-1.16.2.2 Energy and Environmental Considerations

There are several distinguishing factors between the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Absent an emergency situation, the IC engines for the PMEC facility will only operate infrequently and for brief testing/maintenance checks. These short, transient operating periods significantly reduce the effectiveness of the post-combustion controls.

Further, it should be assumed that ammonia emissions will occur under some or all operating conditions. This represents an additional air pollutant that is not emitted when SCR is not used for these engines. Also, the handling and storage of substantial volumes of the required ammonia or urea reagent solutions can pose an additional safety risk to facility personnel, and the risk of environmental harm in the event of an accidental release.

The SCR catalyst requires periodic cleaning due to fouling of the surfaces due to the presence of trace contaminants, such as sulfur compounds, particulate, and organic species. This requirement generates a secondary waste stream of contaminated cleaning solutions that must be disposed as hazardous waste.

TABLE B-1-15
REVIEW OF RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
EMERGENCY ENGINES (>500 HP diesel fuel)								
CO-0055	02-03-06	Powers County, CO	Lamar Utilities Board DBA Lamar Light & Power	Diesel Engine	1500 HP	CO – 0.61 lb/MMBtu SO_2 – 0.06 lb/MMBtu PM_{10} – 0.0160 lb/MMBtu	GCP and low sulfur fuel (< 0.05 by weight)	BACT-PSD
MN-0061	06-26-05	St. Louis, MN	Mesabi Nugget LLC	Back-up Generator	549 HP	20% opacity	Fuel limited to No. 2 fuel oil with 0.05 weight percent sulfur and limited to 100 hr/yr	BACT-PSD
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fules Yuma LLC	Emergency Generator	10.90 MMBtu/hr	NO_X – 6.4 g/kW-hr CO – 3.5 g/kW-hr PM – 0.02 g/kW-hr	"Tier 3" or "Tier 2" emission controls must be certified by manufacturer	BACT-PSD
WA-0329	02-11-05	Snohomish County, WA	Darrington Energy LLC	Standby Generator	1 MW	NO_X –Follow 40 CFR 89	Engine must be new and satisfy federal standards @ 40 CFR 89	BACT-PSD
WA-0328	01-11-05	Whatcom County, WA	BP West Coast Products LLC	Emergency Generator	1.5 MW	NO_X – Follow 40 CFR 89 SO_2 – Federal low sulfur diesel	Engine must be new and satisfy federal standards @ 40 CFR 89 & Fuel must satisfy requirements of on-road diesel at time of fuel purchase	BACT-PSD
LA-0194	11-24-04	Cameron County, LA	Sabine Pass LNG, LP	Emergency Generator	2168 HP	PM_{10} – 0.91 lb/hr NO_X – 37.96 lb/hr CO – 12.22 lb/hr VOC – 1.67 lb/hr	GCP	BACT-PSD

TABLE B-1-15 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
AK-0061	11-05-04	Nome Census Area, AK	Nome Joint Utilities System	Electric Generator	5211 kW	NO_X – 134 lb/hr CO – 10.50 lb/hr PM – 206 lb/hr SO_2 – 0.50% Sulfur by weight	GCP	BACT-PSD
OH-0275	08-24-04	Butler County, OH	PSI Energy-Madison Station	Emergency Generator	17.21 Mmbtu/hr	SO_2 – 8.61 lb/hr NO_X – 55.07 lb/hr CO – 14.63 lb/hr VOC – 1.55 lb/hr PM_{10} – 0.27 ton/yr 20% opacity	Sulfur limited to 0.05 % by weight and limited to 499 hr/yr.	BACT-PSD
WV-0023	03-02-04	Monongahela County, WV	Longview Power LLC	Emergency Generator	1801 HP	CO – 8.85 lb/hr NO_X – 20.90 lb/hr PM_{10} – 1.13 lb/hr SO_2 – 6.5 lb/hr VOC – 1.21 lb/hr	GCP and < 500 hr/yr	BACT-PSD
WI-0207	01-21-04	Chippewa County, WI	Ace Ethanol LLC	Generator	1850 HP	PM – 0.07 g/HP-hr NO_X – 13 g/HP-hr CO – 1 g/HP-hr VOC – 0.12 g/HP-hr	Sulfur limited to 0.05 % by weight and limited to 16.7 hr/month.	BACT-PSD
EMERGENCY ENGINES (<500 HP diesel fuel)								
OK-0110	10-21-05	Muskogee County, OK	Dalitalia LLC	Emergency Generator	NA	CO – 0.0067 lb/HP-hr VOC – 0.0025 lb/HP-hr PM_{10} – 0.0022 lb/HP-hr	GCP	NA
NC-0101	09-29-05	Forsyth County, NC	Forsyth Energy Projects LLC	Emergency Generator and Firewater Pump	11.40 MMBtu/hr	NO_X – 36.48 lb/hr SO_2 – 0.58 lb/hr VOC – 1.04 lb/hr CO – 9.69 lb/hr PM_{10} – 1.14 lb/hr	Emergency use only	BACT-PSD

TABLE B-1-15 (Continued)
REVIEW OF RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
LA-0192	06-06-05	Orleans County, LA	Cresent City Power LLC	Firewater Pump	425 HP	PM_{10} – 0.14 lb/hr SO_2 – 0.61 lb/hr NO_X – 8.9 lb/hr CO – 1.88 lb/hr VOC – 0.05 lb/hr	Good engine design and proper operating practices	BACT-PSD
OH-0252	12-28-04	Lawrence County, OH	Duke Energy Hanging Rock LLC	Backup Generator	500 kW each (670 HP each)	NO_X – 10.20 lb/hr CO – 12.60lb/hr VOC – 1.1 lb/hr SO_2 – 0.27 lb/hr PM_{10} – 0.59 lb/hr	500 hr/yr and Low Sulfur fuel	BACT-PSD
OH-0252	12-28-04	Lawrence County, OH	Duke Energy Hanging Rock LLC	Firewater Pump	265 HP	NOX – 8.2 lb/hr CO – 1.8 lb/hr VOC – 0.66 lb/hr SO_2 – 0.10 lb/hr PM – 0.66 lb/hr	500 hr/yr	BACT-PSD

When SCR or any add-on emission control technology is used, additional auxiliary equipment such as pumps and motors must be added. Also, the presence of the catalyst module adds an increment of pressure drop to the exhaust train. To avoid a substantial drop-off in engine performance, the SCR modules must be designed to minimize the increase in back-pressure. However, the energy requirements of auxiliary equipment and even minor back-pressure increases do reduce the net energy efficiency of the plant. In contrast, the implementation of combustion process controls does not require an add-on system with increased energy use by auxiliary equipment, or use of catalyst and ammonia materials. There is some additional complexity in the engine controls for this option. Proper engine tuning and fuel/air ratio is needed across the full load range to achieve reduced emissions while avoiding a reduction in engine efficiency. The automatic fuel/air ratio controller helps accomplish this objective.

B-1.16.2.3 Ranking of Control Options

With regard to NO_x emission abatement, the ranking of the technically-feasible options is straightforward. The use of SCR offers the highest potential level of control for the proposed diesel-fired emergency engines. Up to 90% reduction in NO_x mass emission at all load levels is claimed for typical internal combustion engines.

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

B-1.16.2.4 Economic Analysis for NOx Controls

Since advanced NO_x controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Addition of SCR is then analyzed as the next incremental control technology, in terms of both control level and cost. Table B-1-16 provides the results of the cost effectiveness analysis for the emergency generator and firewater pump engines.

As shown in Table B-1-16, the annualized operating costs for addition of SCR to the two PMEC IC engines range from about $79,000 to $156,000 per year. The estimated total capital investment is over $230,000 for the smaller unit, and over $500,000 for the 2 MW emergency generator, based on purchased equipment cost estimates. Capital recovery is the single largest annual expense, based on 7% prevailing interest rate, and 10-year service period. Additional maintenance charges are also encountered for operation of the systems and annual catalyst cleaning. This investment would provide 1.8 tons of NO_x reduction per year for the 2 engines combined, assuming 90% emission control efficiency. Cost effectiveness is over $96,000 per ton for the larger generator, and more than $438,000/ton for the smaller firewater pump engine, which in either case represents a prohibitively high cost for this BACT option.

TABLE B-1-16
ECONOMIC ANALYSIS OF POST-COMBUSTION SCR CONTROLS FOR PMEC IC ENGINES

Emergency Engine	Controlled Emissions Basis (90% reduction)	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Emissions or Reduction (tons/yr)	Cost Effectiveness ($ / ton)
2 MW Generator	0.18 tons/yr	$506,086	$155,670	1.62	$96,092
300 hp Fire Water Pump	0.02 tons/yr	$243,844	$78,900	0.18	$438,333

B-1.16.2.5 Proposed BACT for NOx

A cost effectiveness analysis for application has shown that use of SCR is cost prohibitive as a more-stringent control for the IC engines planned for the PMEC facility. The proposed BACT for these engines is the combustion modifications supplied as standard equipment with the candidate types of engines. For an annual emission limitation, it is acceptable that non-emergency hours of operation be limited to 100 hours per year.

B-1.16.3 CO BACT Analysis

Emission estimates for the engine-driven emergency generator and fire water pump using EPA Document AP-42 emission factors indicate "uncontrolled" emissions of about 0.9 tons per year. The engines that would be selected for this project will be equipped with combustion modifications that emphasize reduction in NO_x emissions, at the expense of CO. However, the engines have a relatively small number of anticipated annual operating hours.

B-1.16.3.1 Technically-Feasible Controls

For CO emissions, the commercially available control means for IC engines are:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio control and ignition retard, turbocharging, intercoolers, and lean-burn fuel mix. Currently available engines include these features as standard equipment, so these measures are used as the base case for the BACT cost-effectiveness analysis.

Catalytic Oxidation – This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engine. In the catalyst module, CO diffuses through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst particles. Oxidation reaction on the catalyst surface forms carbon dioxide. Typical vendor indications are that 95% reduction in CO emissions should be achieved.

B-1.16.3.2 Cost Effectiveness Analysis

Given the low number of routine operating hours per year, the cost for catalytic oxidation for CO control will be prohibitive. The estimated annualized cost for addition of catalytic oxidation ranges from approximately $30,300 to $44,300 per unit. This investment would provide 0.24

tons of CO reduction per year for the two PMEC internal combustion engines, assuming a 95% reduction in emissions, and 100 hr/yr operating time for all units. Cost effectiveness for this equipment is well above $100,000 per ton of CO abated for these engines, which represents a prohibitively high cost for this BACT option.

B-1.16.3.3 Proposed BACT for CO

Based on the cost effectiveness analysis for application of catalytic oxidation as a more-stringent increment of control, the proposed BACT for the IC engines is the combustion modifications supplied as standard equipment with the proposed internal combustion engines. For an annual emission limitation, it is acceptable that non-emergency hours of operation be limited to 100 hours per year.

B-1.16.4 BACT ANALYSIS FOR VOLATILE ORGANIC COMPOUNDS (VOC), SO_2, AND PM_{10}

The two internal combustion engines planned for the PMEC facility would have combined annual emissions of 0.09 tons per year for VOC, and 0.05 tons per year each for SO_2 and PM_{10}. Given these low emissions, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost effective emission control. Use of low-sulfur No. 2 diesel, at 0.05 weight percent sulfur, limitation of each engine's operation to no more than 100 hours per year and operation of the engines using advanced combustion controls at proper air/fuel ratios will provide relatively low emissions of VOC and PM_{10}, and are proposed as BACT measures for these pollutants.

Appendix B-1-1

BACT Cost Comparison

PMEC Project SO_2 BACT Cost Analysis Summary

Per Combustion Turbine:

Syngas fuel rate	2100 x 10^6 Btu/hr, HHV		2000 lb/ton		
Min Coal conversion efficenc	**0.719**	Syngas heating value =	242 Btu/dscf (HHV)		(Case 15E, Rawhide PSQ)
Max Coal conversion efficenc	**0.793**	Syngas heating value =	303 Btu/dscf (HHV)		(Case 15C, Illinois No. 6)
Gasifiers coal feed	2921 (max) x 10^6 Btu/hr (HHV)				
Hours of operation	8,760 hrs/yr				

	SO_2 Emissions				**SO_2 Reduction**		
Control Technology	**ppm S in syngas**	**lb/MMBtu (coal)**	**lb/hr**	**tons/yr**	**Total tons/yr**	**Incremental tons/yr**	**Control Efficiency**
Uncontrolled	10,000	5.0105	14,634	64,098	-		0%
NSPS Da (95% control option)		0.2505	732	3,205	60,893	-	95.00%
MDEA (Base IGCC Level)	50	0.0251	73	320	63,778	2,884	99.50%
Selexol	10	0.0050	15	64	64,034	256	99.90%
Rectisol	1	0.0005	1	6	64,092	58	99.99%

Control Technology	**Total Capital Investment**	**Annual Capital Recovery Cost**	**Total Annual Operating Expenses**	**Total Annual Costs**	**SO_2 Reduction (tons/yr)**	**Average Cost Effectiveness ($/ton)**	**Incremental SO_2 Reduction (tons/yr)**	**Incremental Cost Effectiveness ($/ton)**
MDEA (Base IGCC Level)					-		2,884	
Selexol	$20,979,560	$2,303,556	$2,891,022	$5,194,577	256	$20,260	256	$20,260
Rectisol	$39,961,066	$4,387,725	$4,105,838	$8,493,563	314	$27,043	58	$57,186

PMEC Project, Selexol AGR for IGCC Combustion Turbines
Total Capital Investment

SCR System for sulfur removal to 10 ppm

Preliminary

Item	Basis	Cost
Direct Costs		
(1) Purchased Equipment		
Selexol System	Incremental over MDEA Costs based on review of other IGCC permit applications and presentations.	$9,450,000
(a) Total Equipment		$9,450,000
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	$472,500
(c) Sales Tax (0.06 x [1a])	OAQPS, Sect. 1, Table 2.5	$567,000
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.6	$945,000
Total Purchased Equipment Cost, PEC [1a thru 1d]		$11,434,500
(2) Direct Installation (0.083 x PEC)	Peters & Timmerhaus, 1991	$949,064
(3) Instrumentation Controls (installed) (0.02 x PEC)	P & T, 1991	$228,690
(4) Piping (installed) (0.073 x PEC)	P & T, 1991	$834,719
(5) Electrical (installed) (0.046 x PEC)	P & T, 1991	$525,987
TOTAL DIRECT COST (TDC) (1thru 5)		$13,972,959
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$698,648
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	$1,397,296
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$698,648
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	$1,117,837
TOTAL INDIRECT COST (TIC) (6+7)		$3,912,429
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	$2,682,808
Total Plant Cost (TIC + TDC + Cont.)		**$20,568,196**
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	$411,364
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		**$20,979,560**

PMEC Project - BACT Cost Effectiveness Analysis for Selexol

Sulfur in syngas reduction to 10 ppm

Preliminary

Unit Characteristics

TMW	= turbine output in MW	=	300
H	= annual operating hours	=	8,760

Costs

A. Total capital investment, $	See Separate TCI Spreadsheet	=	$20,979,560
B. Direct Annual Costs, $/yr			
1. Operating labor	= (1.0/8 hr shift) x ($25/hr) x (H)	=	$27,375
2. Suervisory labor	= (0.15) x (operating labor)	=	$4,106
3. Maintenance labor and materials	= (0.015 * TCI)	=	$314,693
8. Electricity	= N/A	=	-
9. Performance loss (assume 1% penalty in net output)	= (0.010) x (TMW) x ($0.057/ KWH) x (1000 KW/ MW) x (H)	=	$1,497,960
11. Production Loss	= None	=	-
TOTAL DIRECT COSTS			**$1,844,135**
C. Indirect Annual Costs, $/yr			
1. Overhead	= (0.6) x (all labor and maintenance material costs)	=	$207,705
2. Property Taxes, insurance, admin.	= (0.04) x (total capital investment)	=	$839,182
TOTAL INDIRECT COSTS			**$1,046,887**
TOTAL ANNUAL OPERATING COSTS	= (Direct Annual Costs) + (Indirect Annual Costs)		**$2,891,022**
CAPITAL RECOVERY*	= (0.1098)CRF* x total capital investment	=	**$2,303,556**
Total Annual Cost	**= (Annual Operating Costs) + (Captial Recovery)**	**=**	**$5,194,577**

* The capital recovery factors assumes a 15 year equipment life and 7% interest.

Cells highlighted in green need further review and confirmation for final cost estimates.

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PMEC Project, Rectisol AGR for IGCC Combustion Turbines
Total Capital Investment

SCR System for sulfur removal to 1 ppm

Preliminary

Item	Basis	Cost
Direct Costs		
(1) Purchased Equipment		
Rectisol System	Inremental over Selexol; Costs based on review of other IGCC permit applications and presentations.	$18,000,000
(a) Total Equipment		$18,000,000
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	$900,000
(c) Sales Tax (0.06 x [1a])	OAQPS, Sect. 1, Table 2.5	$1,080,000
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.6	$1,800,000
Total Purchased Equipment Cost, PEC [1a thru 1d]		$21,780,000
(2) Direct Installation (0.083 x PEC)	Peters & Timmerhaus, 1991	$1,807,740
(3) Instrumentation Controls (installed) (0.02 x PEC)	P & T, 1991	$435,600
(4) Piping (installed) (0.073 x PEC)	P & T, 1991	$1,589,940
(5) Electrical (installed) (0.046 x PEC)	P & T, 1991	$1,001,880
TOTAL DIRECT COST (TDC) (1thru 5)		$26,615,160
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$1,330,758
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	$2,661,516
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$1,330,758
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	$2,129,213
TOTAL INDIRECT COST (TIC) (6+7)		$7,452,245
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	$5,110,111
Total Plant Cost (TIC + TDC + Cont.)		**$39,177,516**
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	$783,550
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		**$39,961,066**

Cells highlighted in green need further review and confirmation for final cost estimates.

PMEC Project, Rectisol AGR for IGCC Combustion Turbines

Sulfur in syngas reduction to 1 ppm

Preliminary

Unit Characteristics

TMW	= turbine output in MW	=	300
H	= annual operating hours	=	8,760

Costs

A. Total capital investment, $	See Separate TCI Spreadsheet	=	$39,961,066
B. Direct Annual Costs, $/yr			
1. Operating labor	= (1.0/8 hr shift) x ($25/hr) x (H)	=	$27,375
2. Suervisory labor	= (0.15) x (operating labor)	=	$4,106
3. Maintenance labor and materials	= (0.015 * TCI)	=	$599,416
8. Electricity	= N/A	=	-
9. Performance loss (assume 1% penalty in net output)	= (0.010) x (TMW) x ($0.057/ KWH) x (1000 KW/ MW) x (H)	=	$1,497,960
11. Production Loss	= None	=	-
TOTAL DIRECT COSTS			**$2,128,857**
C. Indirect Annual Costs, $/yr			
1. Overhead	= (0.6) x (all labor and maintenance material costs)	=	$378,538
2. Property Taxes, insurance, admin.	= (0.04) x (total capital investment)	=	$1,598,443
TOTAL INDIRECT COSTS			**$1,976,981**
TOTAL ANNUAL OPERATING COSTS	= (Direct Annual Costs) + (Indirect Annual Costs)		**$4,105,838**
CAPITAL RECOVERY*	= (0.1098)CRF* x total capital investment	=	**$4,387,725**
Total Annual Cost	**= (Annual Operating Costs) + (Captial Recovery)**	**=**	**$8,493,563**

*The capital recovery factors assumes a 15 year equipment life and 7% interest.

Cells highlighted in green need further review and confirmation for final cost estimates.

Appendix B-1-2

IC and Auxiliary Boiler Cost Comparison

TOTAL CAPITAL INVESTMENT AND ANNUAL COST CALCULATIONS
SELECTIVE CATALYST REDUCTION
Natural Gas Fired Auxiliary Boiler 130 MMBtu/hr

Cost Item	Factor	Cost
TOTAL CAPITAL INVESTMENT[1,2] = DC + IC		**813,657**
Direct Annual Costs		
Operating Labor[3]		
Operator	-----	-----
Supervisor	-----	-----
Total Operating Labor		0
Maintenance[4]		
Labor	-----	-----
Materials	-----	-----
Total Maintenance	0.015TCI	12,205
Reagent Cost[4]		
29% Ammonia Solution	6.87 ton/yr @ $0.114/lb	1,566
Utilities[4]		
Electricity	51.7 kWh load @ $0.08/kWh	9,058
Total Utilities		9,058
Catalyst Cost[5]		
Catalyst Replacement	Catalyst life > SCR Service Life	Negligible
Total Catalyst Cost	-----	-----
Miscellaneous[6]		
Performance Tests	-----	5,000
Record Keeping & Reporting	-----	1,000
Total Miscellaneous Costs		6,000
Total Direct Annual Costs (DAC)		**27,263**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	7,323
Administrative Charges[1]	0.02TCI	16,273
Property Taxes[1]	0.01TCI	8,137
Insurance[1]	0.01TCI	8,137
Capital Recovery Factor[7]	-----	0.1424
Capital Recovery[1]	(CRF)(TCI)	115,865
Total Indirect Annual Costs (IAC)		**155,734**
TOTAL ANNUAL COST = DAC + IAC		**182,997**

[1] Costs were assumed using Table 6-5 of Alternative Control Techniques Document - NOx Emissions from Industrial/Commercial/Institutional (IC) Boilers - EPA March 1994. The costs used were based on estimates for a regenerative thermal oxidizer that is limited to a maximum of 85 percent total NOx destruction.

[2] The costs were also adjusted for inflation using an inflation rate of 34.6 percent (1992 to 2004), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the National Aeronautics and Space Administration (www.jsc.nasa.gov/bu2/inflateCPI.html).

[3] Operating and Supervisory Labor is estimated to be minimal since the SCR is a stationary device with few pieces of rotating equioment and can be operated from an exisiting control room.

[4] These factors were taken from Section 4 - NOx Controls EPA Air Pollution Control Cost Manual - 6th Edition dated 3-3-2003 (EPA-452/B-02-001)

[5] Because of the limited operation schedule for the auxiliary boilers, the initial catalyst charge would last for the projected service life of the unit.

[6] These miscellaneous costs are comparable to costs for similar functions for comparable control equipment.

[7] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

Reagent Cost Estimate

Mass Flow Flow Rate of the reagent

$m_{reagent} = (NOx_{in} * Q_B * ASR * M_{reagent}) / (M_{NOx})$ Eq. 2.32

Where:

$m_{reagent}$ (lb/hr) = mass flow rate of reagent	**1.818853**
NOx_{in} (lb/MMBtu) = inlet NOx	0.036
Q_B (MMBtu/hr) = heat input rate	130
ASR = 1.05	1.05
$M_{reagent}$ (MW of ammonia) =	17.03
M_{NOx} (MW of NO2) =	46.01

Mass flow rate of X% aqueous ammonia solution

m_{sol} = mreagent / X% Eq. 2.33

Where:

m_{sol} (lb/hr) = mass flow rate aqueous ammonia solution	**6.271906**
$m_{reagent}$ (lb/hr) = mass flow rate of reagent	1.818853
X% = percent aqueous solution	0.29

Solution Volume Flow Rate

$q_{sol} = (m_{sol} / p_{sol}) * v_{sol}$ Eq. 2.34

Where:

q_{sol} (gph) = solution volume flow rate	**0.837859**	
m_{sol} (lb/hr) = mass flow rate aqueous ammonia solution	6.271906	
p_{sol} (lb/ft^3) = density of 29% aqueous reagent solution	56	
v_{sol} (gal/ft^3) = specific volume of 29% reagent solution	7.481	
Total Solution Needed Per Year (ton/yr)	**6.867738**	**$1,565.84**
Hours of Operation per Year (hr/yr)	2190	
29% Ammonia Solution Cost ($/lb)	0.114	

Power Consumption Estimate

Power = $0.105Q_B [NOx_{in} * n_{NOx} + 0.5 (P_{duct} + n_{total} * P_{catalyst})]$

Where:

Power (kWh) = Electrical Power Usage	51.7345263	
Q_B (MMBtu/hr) = Boiler heat input	130	
NOx_{in} (lb/MMBtu) = inlet NOx	0.036	
n_{NOx} = NOx removal efficiency	85%	
P_{duct} (inch water) = pressure drop of duct	2.5	
n_{total} = number of catalyst layers	4	
$P_{catalyst}$ (inch water) = pressure drop per catyst layer	1	
Total Electricity Needed Per Year (kWh)	**113298.613**	**$9,063.89**
Hours of Operation per Year (hr/yr)	2190	
Electrical Power Cost ($/kWh)	0.08	

Catalyst Replacement Cost Estimate

Catalyst Volume

$vol_{catalyst} = 2.81 * Q_B * n_{adj} * slip_{adj} * NOx_{adj} * S_{adj} * (T_{adj} / N_{SCR})$

Where:

$vol_{catalyst}$ (ft^3) = volume of catalyst	**438.044848**	**$127,033.01**
Q_B (MMBtu/hr) = Heat input rate	130	
n_{adj} = NOx efficiency adjustment factor	1.1862	
$slip_{adj}$ = NH_3 slip adj. factor for slips btw 2 to 5 ppm	1.1701	
NOx_{adj} = NOx_{inlet} adjustment factor	0.8639488	
S_{adj} = sulfur in fuel adjustment factor		0.05%
T_{adj} = Temp. adj. Factor for temps other than 700 F		
Catalyst life (hr)	24,000	
Hours of Operation per Year (hr/yr)	2190	
Catalyst Cost Replacement ($/ft^3)	290	
Catalyst Replacement in years (yr)	10.9589041	
Ammonia Slip (ppm)	2	

TOTAL CAPITAL INVESTMENT AND ANNUAL COST CALCULATIONS
Catalytic Oxidizer
Natural Gas Fired Auxiliary Boiler 130 MMBtu/hr

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Catalytic Oxidizer[1,2]	A	372,157
Catalyst Repalacement Allowance[3]	-----	10,000
Sales Tax[1]	0.03A	11,165
Purchased Equipment Cost (PEC)	B	393,322
Direct Installation Costs[1]		
Foundations & Supports	0.08B	31,466
Handling & Erection	0.14B	55,065
Electrical	0.04B	15,733
Piping	0.02B	7,866
Insulation for Ductwork	0.01B	3,933
Painting	0.01B	3,933
Direct Installation Cost		117,997
Total Direct Costs (DC)		511,318
Indirect Costs		
Installation[1]		
Engineering	0.10B	39,332
Construction & Field Expenses	0.05B	19,666
Contractor Fees	0.10B	39,332
Start-Up	0.02B	7,866
Performance Test	0.01B	3,933
Contingencies	0.03B	3,933
Indirect Installation		114,063
Total Indirect Costs (IC)		114,063
TOTAL CAPITAL INVESTMENT = DC + IC		**625,382**
Direct Annual Costs		
Operating Labor[1,4]		
Operator	0.5 hours/shift	4,835
Supervisor	15% of operator	725
Total Operating Labor		5,560
Maintenance[1,4]		
Labor	0.5 hours/shift	4,835
Materials	100% of maintenance labor	4,835
Total Maintenance		9,669
Utilities[5]		
Electricity	85.1 kWh @ $0.08/kWh	14,910
Total Utilities		14,910
Total Direct Annual Costs (DAC)		**30,139**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	9,138
Administrative Charges[1]	0.02TCI	12,508
Property Taxes[1]	0.01TCI	6,254
Insurance[1]	0.01TCI	6,254
Capital Recovery Factor[6]	-----	0.1424
Capital Recovery1	(CRF)(TCI)	89,054
Total Indirect Annual Costs (IAC)		**123,207**
TOTAL ANNUAL COST = DAC + IAC		**153,346**

[1] Costs were assumed using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001). The costs used were based on estimates for a Fixed-Bed Catalytic Oxidizer assuming a 50% Energy Recovery that is limited to a maximum of 90 percent total CO destruction.

[2] The costs were also adjusted for inflation using an inflation rate of 13.4 percent (1999 to 2004), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the National Aeronautics and Space Administration (www.jsc.nasa.gov/bu2/inflateCPI.html).

[3] Calalyst Replacement Allowance was assumed to be $10,000.

[4] Calculations assume 2,190 hours of operation per year, 8 hours per shift, assuming 0.5 hours per shift related to catalytic oxidizer with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[5] The total utilities cost was caclulated assuming 85.1 kWh electricity usage at a cost of $0.08/kWh to operate the fan motor.

[6] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TOTAL CAPITAL INVESTMENT AND ANNUAL COST CALCULATIONS
Low NOx Burners and Flue Gas Recirculation
Natural Gas Fired Auxiliary Boiler 130 MMBtu/hr

Cost Item	Factor	Cost
TOTAL CAPITAL INVESTMENT[1,2] = DC + IC		**115,487**
Direct Annual Costs		
Operating Labor[3]		
Operator	-----	-----
Supervisor	-----	-----
Total Operating Labor		0
Maintenance[4]		
Labor	-----	-----
Materials	-----	-----
Total Maintenance	0.015TCI	1,732
Utilities[5]		
Electricity	30 hp FGR fan/boiler, $0.08/kwh	4,355
Total Utilities		4,355
Miscellaneous[6]		
Performance Tests	-----	5,000
Record Keeping & Reporting	-----	1,000
Total Miscellaneous Costs		6,000
Total Direct Annual Costs (DAC)		**12,087**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	1,039
Administrative Charges[1]	0.02TCI	2,310
Property Taxes[1]	0.01TCI	1,155
Insurance[1]	0.01TCI	1,155
Capital Recovery Factor[7]	-----	0.1424
Capital Recovery[1]	(CRF)(TCI)	16,445
Total Indirect Annual Costs (IAC)		**22,104**
TOTAL ANNUAL COST = DAC + IAC		**34,191**

[1] Costs were assumed using Table 6-5 of Alternative Control Techniques Document - NOx Emissions from Industrial/Commercial/Institutional (IC) Boilers - EPA March 1994. The costs used were based on estimates for a boiler equiped with Low NOx burners and FGR that is limited to a maximum of 60 percent total NOx destruction.

[2] The costs were also adjusted for inflation using an inflation rate of 34.6 percent (1992 to 2004), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the National Aeronautics and Space Administration (www.jsc.nasa.gov/bu2/inflateCPI.html).

[3] Operating and Supervisory Labor is estimated to be minimal since the Low NOx Burners and FGR are a stationary device with few pieces of rotating equipment and can be operated from an exisiting control room.

[4] These factors were taken from Section 4 - NOx Controls EPA Air Pollution Control Cost Manual - 6th Edition dated 3-3-2003 (EPA-452/B-02-001)

[5] Electricity cost was calculated assuming 30 hp electric fan was needed at a cost of $0.08/kWh.

[6] These miscellaneous costs are comparable to costs for similar functions for comparable control equipment.

[7] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

CONTROL COST EFFECTIVENESS

	SELECTIVE CATALYST REDUCTION	LNB + FGR	Catalytic Oxidizer
	(Controlling NOx Only)		(Controlling CO Only)
	Auxiliary Boiler		
Total Annual Cost ($)	182,997	34,191	153,346
Uncontrolled Pollutant Emissions (tons/year)	5.10	5.10	10.50
Capture Efficiency (%)	100%	100%	100%
Control Efficiency (%)	85%	60%	90%
Expected Emissions after Control (tons/year)	0.77	2.04	1.05
Expected Emission Reduction after Control (tons/year)	4.34	3.06	9.45
Control Cost per Ton of Pollutant Removed ($/ton)	**42,214**	**11,174**	**16,227**

Appendix B-2

Cooling Tower Analysis

APPENDIX B-2
PACIFIC MOUNTAIN ENERGY CENTER, COOLING TOWER MODELING

An analysis was performed of potential cooling tower impacts from the proposed Pacific Mountain Energy Center (PMEC) at the Port of Kalama, Washington. The conclusions of the modeling analysis are as follows:

- It is unlikely plume induced ground-level fogging/icing will occur significantly on nearby roads from either cooling tower
- Due to the moist climate of the region, long condensed plumes may result during periods of elevated relative humidity. However, our analysis indicates such condensed plumes usually occur during conditions of already poor or obscured visibility. During daytime hours when local weather does not obscure the plume, typical condensed plume lengths are less than 40 m and heights less than 30 m for both cooling towers.

Below is a description is included of the modeling techniques applied, the preparation of necessary input data, and the results of the analysis.

B-2.1 MODELING TECHNIQUES

The Seasonal/Annual Cooling Tower Impact (SACTI, Version 11-01-90) model was applied to assess potential impacts from the two proposed PMEC cooling towers. SACTI was developed by Argonne National Laboratory[1] for the Electric Power Research Institute (EPRI) to address the following potential adverse impacts of cooling towers:

- plume visibility
- deposition of cooling tower drift
- ground-level fogging and icing
- shadowing by the plume & reduction of solar energy

SACTI contains algorithms for both natural and mechanical draft cooling towers arranged singly or in clusters. Plume merging and associated enhanced plume rise are treated by the routines contained in the model. While any official regulatory endorsement of SACTI is unknown, this model has been applied for a number of projects where cooling tower impact assessments were required for EFSEC and the California Energy Commission. The characteristics of the tower and the preparation of the meteorological data set are discussed below.

Based on preliminary design information, the characteristics of the proposed PMEC cooling towers are listed in Table B-2-1. In addition to the parameters in Table B-2-1, assumptions

[1]Argonne National Laboratory, 1984. Users Manual: Cooling-Tower-Plume Prediction Code. Prepared for Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94303, EPRI CS-3403-CCM, April 1984.

included a salt density of 2.17 g/cm^3 and the drift droplet size distribution listed in the SACTI Users Manual for mechanical draft cooling towers. Note, unlike conventional dispersion models, the density of the exit air is a variable calculated by the model based on ambient conditions, the design parameters in Table B-2-1, and saturation conditions at the outlet.

A meteorological data set was constructed using hourly wind, solar radiation and differential temperature observations from a nearby station at the Port of Kalama (Noveon Chemical) during 1995. These local data were also used in the air quality dispersion modeling assessment for the facility. The surface data were combined with seasonal mixing heights for Salem[2] using the EPA's regulatory preprocessor program MPRM.

Relative humidity data are necessary for cooling tower assessments and hourly data are not available for the Port of Kalama site. The local meteorological data was supplemented with relative humidity data and "weather-type" observations from the National Weather Service station at Portland Airport.[3] The weather-type observations were used to interpret the results of the cooling tower modeling. Using the Portland weather observations, a flag was added to the data set to indicate periods of potential obscured visibility due to fog, ceiling heights less than 500 hundred feet, precipitation, runway visibilities less than one mile, or relative humidity greater than 98 percent. During periods of obscured visibility a condensed plume from the PMEC cooling towers might not be as noticeable as during ambient conditions conducive to good visibility.

Figure B-2-1 displays a wind rose constructed from the 1995 Port of Kalama data set. Winds exhibit a bi-modal regime, oriented with the north to south alignment of this portion of the Columbia River valley. The average wind speed is 2.7 m/s and high winds greater than 10 m/s are infrequent (4 hours in 1995). Wind speeds coded as calm in the data set also occur relatively infrequently (16 hours in 1995).

B-2.2 MODELING RESULTS

SACTI was applied to simulate plumes from each of the two proposed cooling towers using the 1995 meteorological data set and tower design characteristics described previously. Rural conditions and default options were assumed for the other input variables controlling model operation. The SACTI results were summarized to obtain annual frequency distributions for condensed plume length, condensed plume height, condensed plume radius, ground-level fogging, and icing. The simulations were performed for all hours of the year, and as a subset, daytime hours of the year without weather obscuring events.

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2 Holzworth, G.C., 1972. *Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States.* EPA, Office of Air Programs Publication No. AP101, Rayleigh, NC 27607.

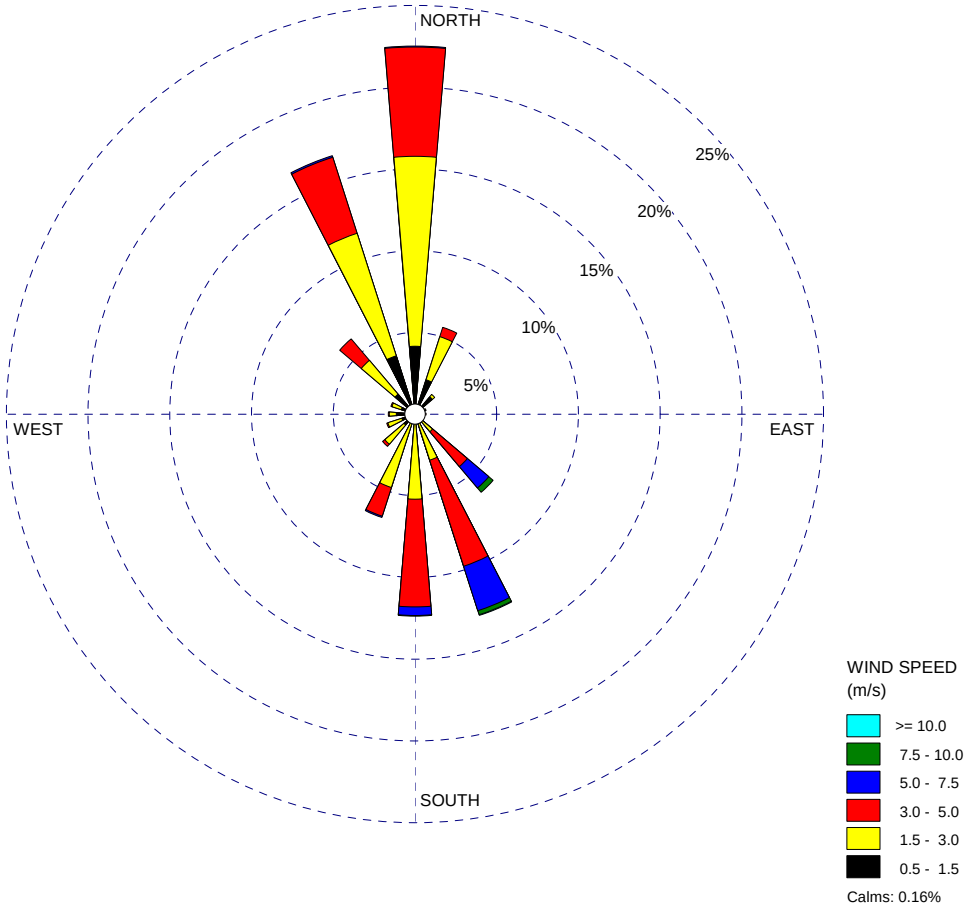
3 Relative humidity data are also available at the Kelso-Longview Airport, but the overall data recovery is not as good as the Portland Airport data set. The Kelso-Longview Airport data also do not include observations of fog and other weather variables that can be used to characterize background visual conditions.

WIND ROSE PLOT:

Port of Kalama Surface Winds for 1995

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
From Noveon	**1995** **Jan 1 - Dec 31** **00:00 - 23:00**	**Geomatrix**	
		MODELER: **kjr**	
	CALM WINDS: **0.16%**	TOTAL COUNT: **8760 hrs.**	
	AVG. WIND SPEED: **2.74 m/s**	DATE: **8/3/2006**	PROJECT NO.: **12096**

WRPLOT View - Lakes Environmental Software

GEOMATRIX

WIND ROSE FOR PORT OF KALAMA 1995
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.000.0

Figure
B-2-1

B-2.3 CONDENSED PLUME LENGTHS

The results of the cooling tower visible plume analysis are summarized in Tables B-2-2 through B-2-7. Frequency distributions of the plume length, height and radius are listed according to downwind sector and radial distance from the center of the cooling tower array. Condensed plume lengths predicted for the Power Block cooling tower in Table B-2-2 are greater than 50 m, 100 m, 500 m and 1000 m, for 31%, 19%, 18%, and 18% of the annual hours, respectively. For the ASU Cooling Tower (Table B-2-5), predicted condensed plume lengths are greater than 50 m, 100 m, 500 m and 1000 m, for 38%, 20%, and 18% of the annual hours, respectively.

Condensed plumes might be visible during daytime hours or when illuminated during the night. The relatively longer condensed plumes occur during conditions of high relative humidity when the ambient air is near saturation. The model does not account for low overcast conditions or fog that would tend to obscure the plume during such conditions. In addition to high relative humidity, stable atmospheric stratification and cool temperatures also foster a long condensed plume. These conditions may produce long visible plumes during the hours near sunrise and sunset, but generally occur during the night when the condensed plume would not be visible.

Figure B-2-2 and Figure B-2-3 display contour plots constructed from the condensed plume length frequencies in Table B-2-2 and Table B-2-5, respectively. As distance increases from the site, condensed plumes more frequently occur along the north-to-south axis of the annual prevailing winds. Although annual winds from the north occur more frequently, more frequent long condensed plumes are predicted for southerly winds. Such winds are more often associated with cool moist conditions that foster long condensed plume lengths. More frequent short to moderate length condensed plumes are predicted for the smaller ASU cooling tower that is oriented normal to the prevailing wind directions. However, longer condensed plumes extending to the north and north-northwest are predicted relatively more frequently from the Power Block cooling tower aligned with the prevailing winds. Westerly winds at the site are infrequent and prolonged condensed plumes traveling directly toward Interstate 5 are rare.

B-2.4 DAYTIME CONDENSED PLUMES EXCLUDING PERIODS OF WEATHER OBSCURING EVENTS

Additional SACTI simulations were conducted to further investigate condensed plume lengths during periods when the plume might be visible. Nighttime periods and observations during natural weather obscuring events were excluded from the data set an, a condensed plume from the cooling tower would probably be obscured by fog, low clouds or would not be visible unless illuminated during the night. For the 1995 Port of Kalama data set, these conditions account for 59% of the total observations.

Table B-2-8 and Table B-2-9 summarize the results of daytime SACTI simulations after periods of weather obscuring visual conditions have been removed from the meteorological data set. Figure B-2-4 and Figure B-2-5 display contour plots constructed from these tables. Figure B-2-6 compares these results with the SACTI simulations discussed previously. The average number of hours of a condensed plume is reduced significantly when fog and nighttime conditions are

removed from consideration. Condensed plume lengths are also shorter due to the less humid, warmer conditions that occur during the day. At a radial distance of 1000 m from the cooling towers, SACTI predicts a condensed plume for about 500 hours per year when summed across all wind directions.

Condensed plumes longer than 1000 m are predicted for about 6 percent of the daytime hours. Long condensed plumes are sometimes predicted when meteorological conditions promote large plume rise even when ground level conditions are well below saturation. During such conditions, the predicted condensed plumes may be indistinguishable from clouds also present above the condensation level.

B-2.5 GROUND-LEVEL FOGGING

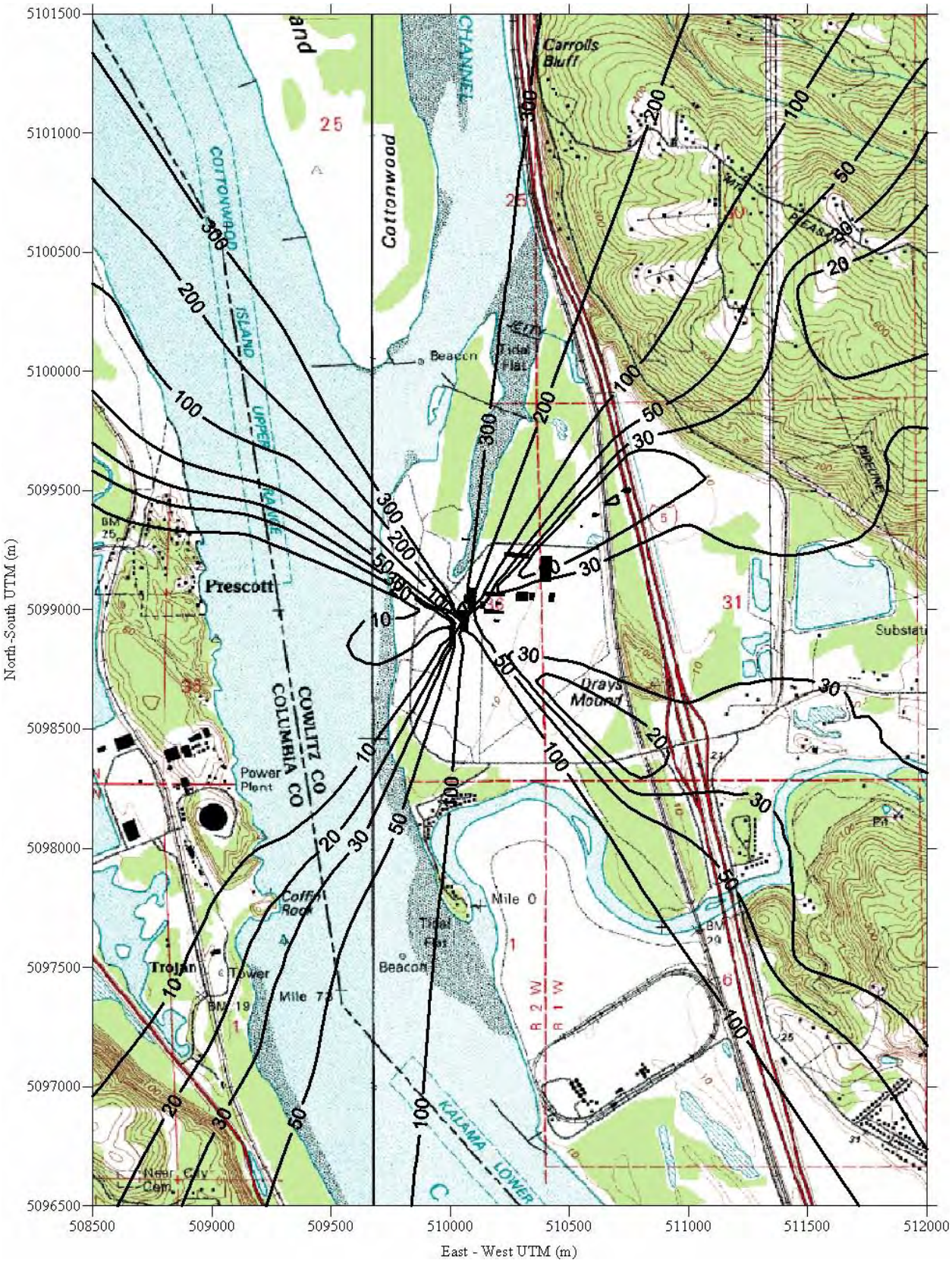
The potential for ground-level fogging and icing on local roadways was also evaluated. In order for these effects to occur, cooling tower plumes must touchdown on the roadway, be condensed, and for icing, the temperature must be below freezing. This requires high winds (low plume rise), the right wind direction, low dew-point depression, and low temperatures (for icing).

The annual average numbers of hours of predicted fogging are shown in Table B-2-10 and Table B-2-11, for the Power Block and ASU Cooling Towers, respectively. According to the SACTI simulations, these effects are rare for the PMEC cooling towers and meteorological conditions at the site. Plume induced ground-level fog is very infrequent, occurring only a few hours a year. Ground level fogging was predicted for a few hours at a distance of 100 m north-northwest of each of the towers, well away from major roads in the study area. During the 1995 simulation period, no hours of ground-level icing were predicted by SACTI.

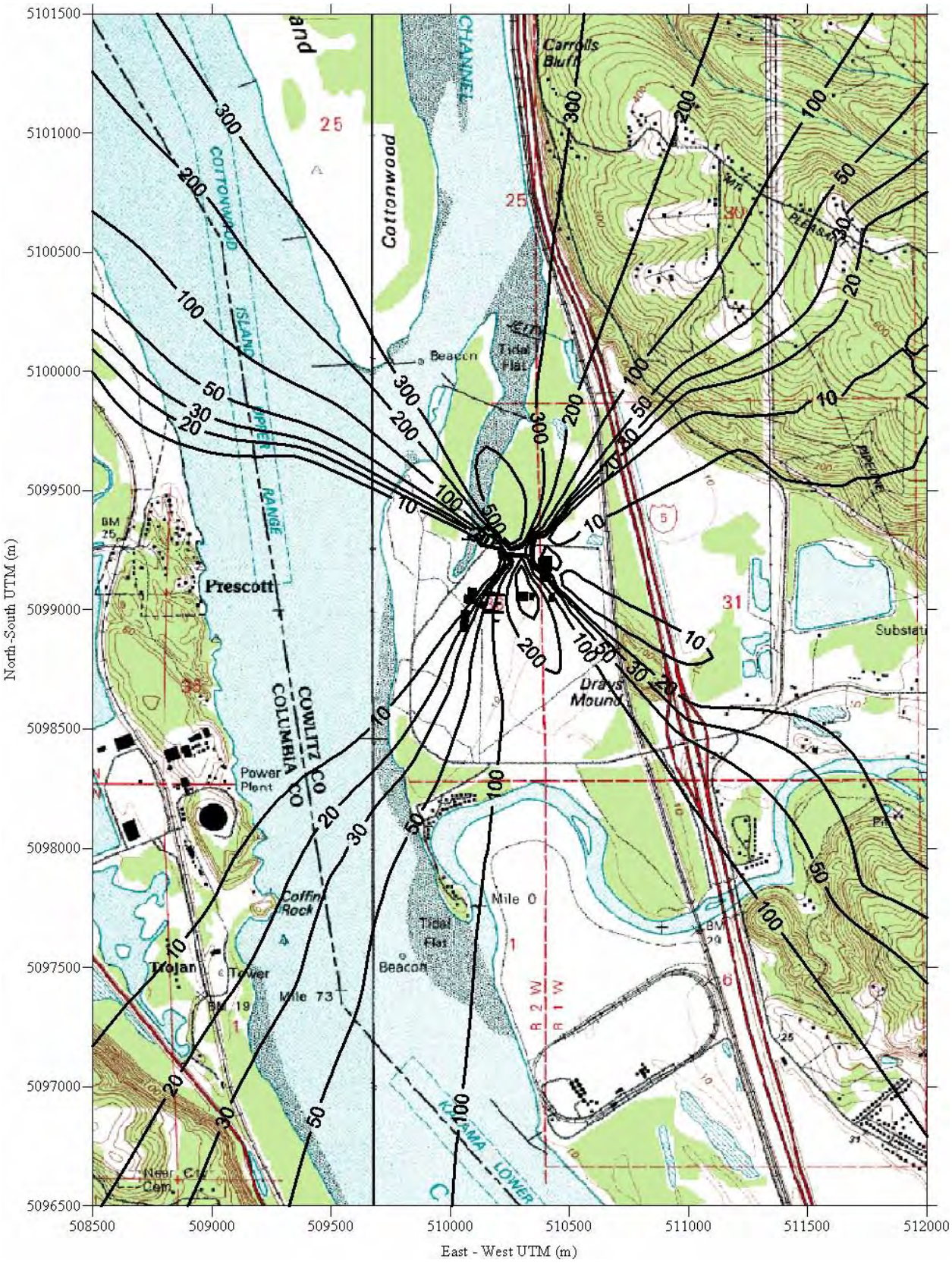
B-2.6 SUMMARY

A cooling tower modeling analysis was conducted using SACTI and year of Port of Kalama meteorological data supplemented with relative humidity and weather-type data from Portland Airport. The simulations indicate condensed plumes would typically not touchdown and cause ground-level fogging or icing. Fogging conditions occur for only about one to four hours per year close to the towers and no periods of icing are predicted based on the 1995 meteorological data.

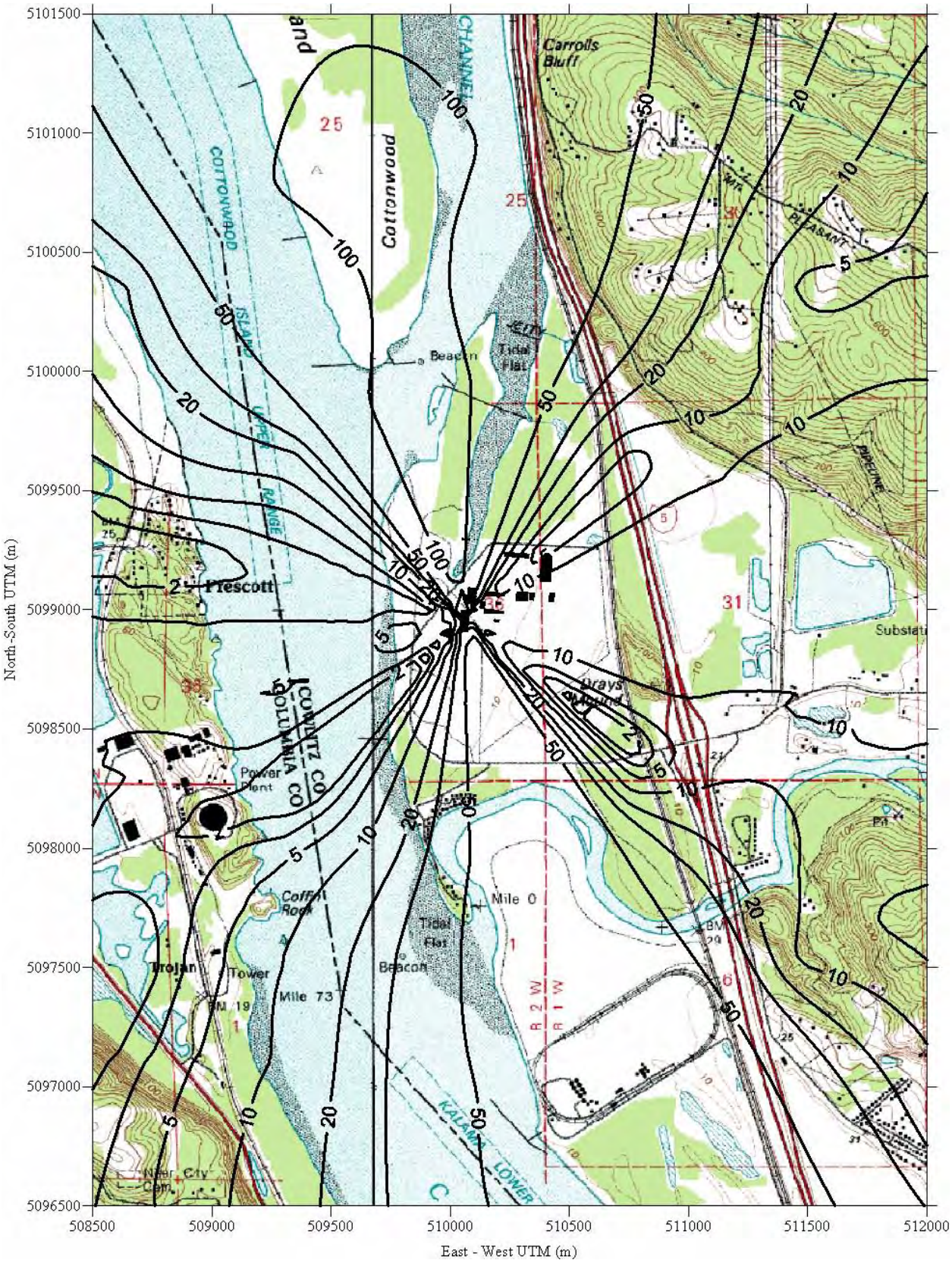
High relative humidity at the site contributed to predictions of long condensed plumes. In many instances, the longer plumes occur at night or during weather conditions that obscure the plume. During conditions when the cooling tower plume would most likely be visible, typical condensed plume lengths are less than 40 m and heights less than 30 m. Condensed plumes longer than 1000 m occur for about 6% of the daytime hours. During such conditions, the predicted condensed plumes may be indistinguishable from clouds also present above the condensation level.



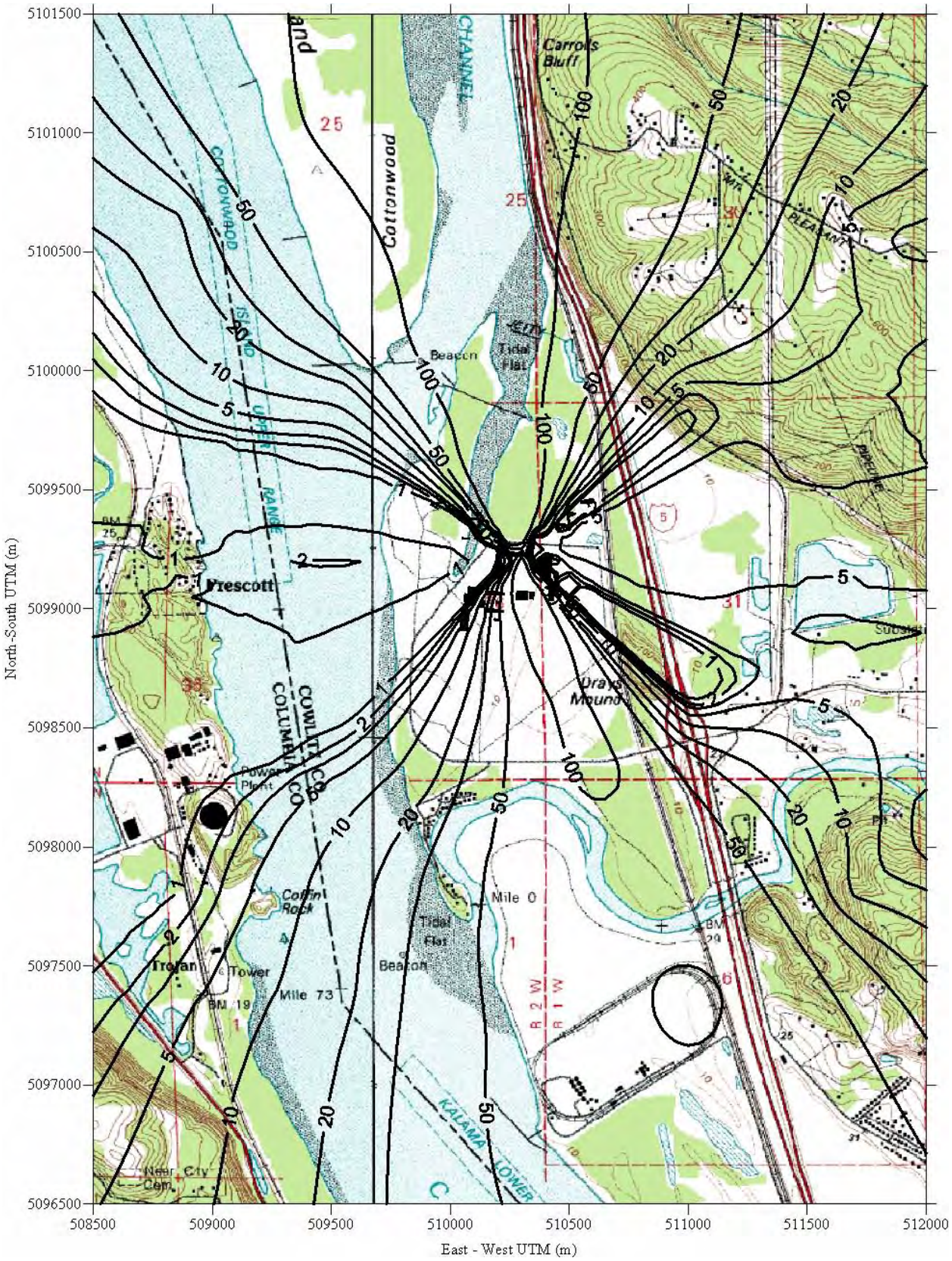
GEOMATRIX	PMEC POWER BLOCK COOLING TOWER CONDENSED PLUME LENGTHS CONTOURS OF HOURS PER YEAR WITH PLUME OVERHEAD Pacific Mountain Energy Center, Kalama, Washington	Project No. 12096.000.0 Figure **B-2-2**



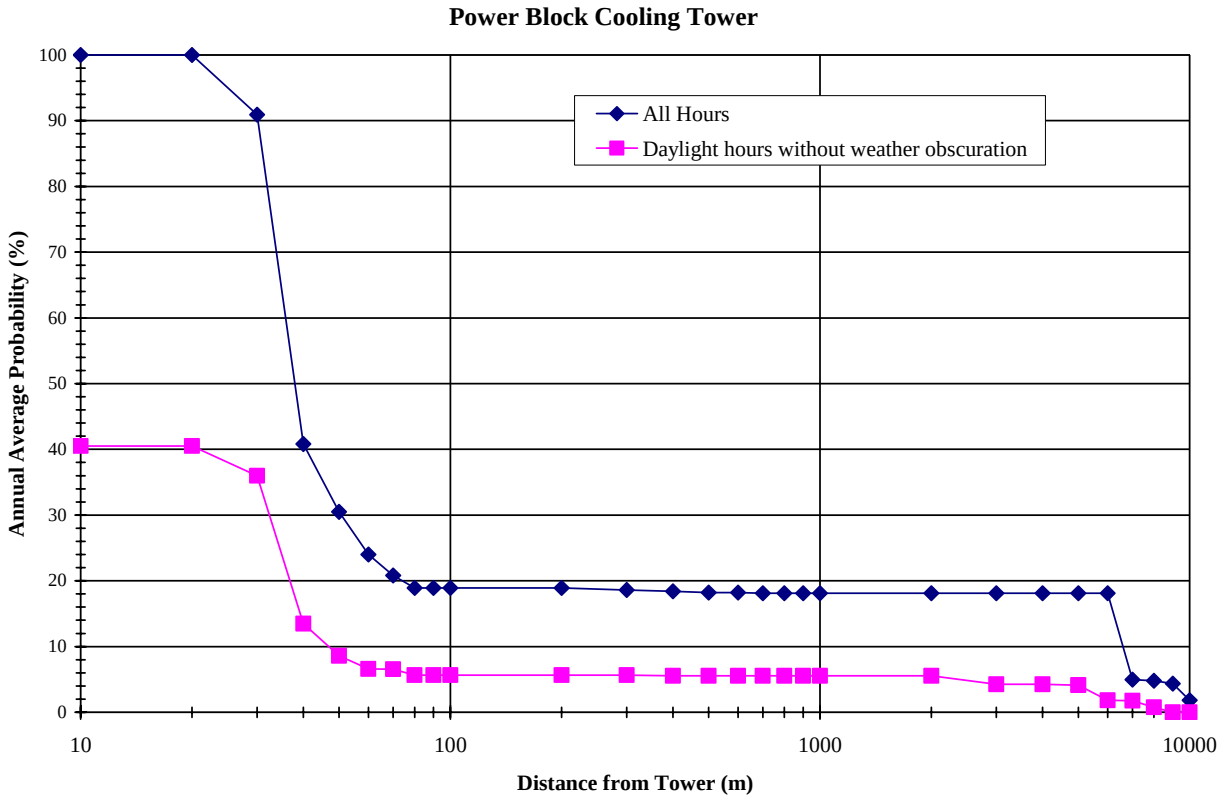
GEOMATRIX	PMEC ASU COOLING TOWER CONDENSED PLUME LENGTHS CONTOURS OF HOURS PER YEAR WITH PLUME OVERHEAD Pacific Mountain Energy Center, Kalama, Washington	Project No. 12096.000.0 Figure **B-2-3**

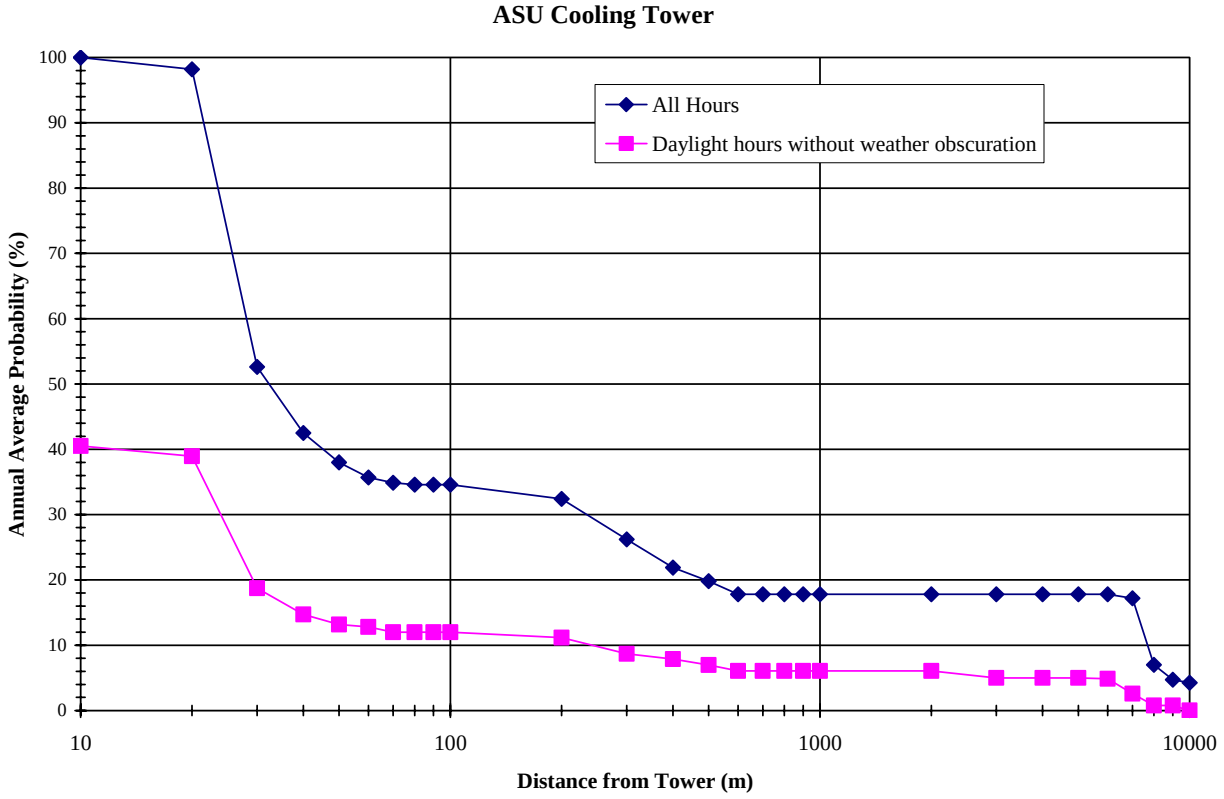


GEOMATRIX	PMEC POWER BLOCK COOLING TOWER CONDENSED PLUME LENGTHS DAYTIME HOURS PER YEAR WITHOUT WEATHER OBSCURATION Pacific Mountain Energy Center, Kalama, Washington	Project No. 12096.000.0 Figure **B-2-4**



GEOMATRIX	PMEC ASU COOLING TOWER CONDENSED PLUME LENGTHS DAYTIME HOURS PER YEAR WITHOUT WEATHER OBSCURATION Pacific Mountain Energy Center, Kalama, Washington	Project No. 12096.000.0 Figure **B-2-5**





GEOMATRIX	ANNUAL AVERAGE PROBABILITY OF CONDENSED PLUME LENGTHS Pacific Mountain Energy Center Kalama, Washington	Project No. 12096.000.0 Figure **B-2-6**

TABLE B-2-1
\PMEC COOLING TOWER CHARACTERISTICS

Parameter	ASU Cooling Tower	Power Block Cooling Tower
Type	linear mechanical draft 1 tower, 7 cells	linear mechanical draft 2 towers, 12 cells (2 rows of 6)
Heat Dissipation Rate (MW)	297	510
Water Circulation Rate (lb/hr)	67,670,000	116,000,000
Total Air Flow (acfm) @ density of 0.070 lb/ft^3	9,590,000	16,440,000
Max Drift Rate (%)	0.001	0.001
Salt Content in Drift (ppmw)	2,400	2,400
Orientation	aligned 86 degrees, clockwise from a north-to-south axis	aligned 4.5 degrees, clockwise from a north-to-south axis
Overall Dimensions (ft)	55 by 330	110 by 290
Height (ft)	48	48
Cell Diameter (ft)	33	33
Exit Velocity & Temperature	variable, calculated by the model assuming saturation conditions	variable, calculated by the model assuming saturation conditions

TABLE B-2-2
PMEC POWER BLOCK COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.20	5.68	1.57	0.73	0.69	0.55	6.00	13.30	12.00	6.81	2.49	1.86	1.61	1.66	5.80	17.00	100.0
20	22.20	5.68	1.57	0.73	0.69	0.55	6.00	13.30	12.00	6.81	2.49	1.86	1.61	1.66	5.80	17.00	100.0
30	21.40	5.23	0.57	0.73	0.69	0.55	4.83	13.20	12.00	6.77	1.34	1.86	1.61	1.66	2.05	16.40	90.90
40	4.46	1.49	0.26	0.16	0.17	0.18	3.36	10.10	8.03	4.62	0.64	0.62	0.52	0.49	0.84	4.94	40.80
50	2.74	0.99	0.07	0.16	0.17	0.18	2.04	8.17	6.45	3.67	0.30	0.62	0.52	0.49	0.44	3.47	30.50
60	1.84	0.65	0.07	0.16	0.17	0.18	2.04	6.32	4.97	2.71	0.30	0.62	0.52	0.49	0.44	2.54	24.00
70	1.53	0.53	0.03	0.16	0.17	0.18	1.32	5.81	4.44	2.33	0.20	0.62	0.52	0.49	0.29	2.18	20.80
80	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
90	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
100	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
200	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.10	3.96	2.10	0.20	0.62	0.52	0.49	0.29	1.97	18.90
300	1.34	0.41	0.03	0.16	0.14	0.14	1.32	5.10	3.96	2.10	0.20	0.55	0.50	0.42	0.29	1.97	18.60
400	1.34	0.41	0.03	0.15	0.13	0.14	1.32	5.10	3.96	2.10	0.20	0.44	0.47	0.37	0.29	1.97	18.40
500	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.10	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.20
600	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.10	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.20
700	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
800	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
900	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
1000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
2000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
3000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
4000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
5000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
6000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.20	0.37	0.42	0.33	0.29	1.97	18.10
7000	0.25	0.03	0.00	0.01	0.02	0.03	0.64	1.10	1.11	0.49	0.13	0.09	0.16	0.12	0.13	0.65	4.97
8000	0.25	0.03	0.00	0.01	0.02	0.03	0.64	1.10	1.11	0.49	0.13	0.05	0.10	0.06	0.13	0.65	4.81
9000	0.25	0.03	0.00	0.01	0.02	0.03	0.25	1.10	1.11	0.49	0.08	0.05	0.10	0.06	0.10	0.65	4.35
10000	0.09	0.00	0.00	0.01	0.01	0.01	0.25	0.34	0.42	0.15	0.08	0.02	0.05	0.02	0.10	0.28	1.84

TABLE B-2-3
PMEC POWER BLOCK COOLING TOWER PLUME HEIGHT FREQUENCY DISTRIBUTION

Height From Tower (m)	Condensed Plume Height Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
30	13.13	3.92	0.82	0.44	0.40	0.39	4.83	12.29	10.96	6.24	1.51	1.16	1.14	1.15	1.98	11.49	71.86
40	2.53	0.88	0.07	0.16	0.21	0.18	2.04	7.50	5.96	3.34	0.30	0.65	0.61	0.56	0.44	3.22	28.65
50	1.53	0.53	0.03	0.16	0.17	0.18	1.32	5.80	4.44	2.33	0.19	0.62	0.52	0.49	0.29	2.18	20.78
60	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
70	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
80	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
90	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
100	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
200	1.34	0.41	0.03	0.16	0.17	0.18	1.32	5.09	3.96	2.10	0.19	0.62	0.52	0.49	0.29	1.97	18.84
300	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
400	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
500	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
600	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
700	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
800	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
900	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
1000	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14

TABLE B-2-4
PMEC POWER BLOCK COOLING TOWER PLUME RADIUS FREQUENCY DISTRIBUTION

Radius (m)	Condensed Plume Radius Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	15.05	3.79	0.77	0.73	0.69	0.55	5.06	12.93	11.82	6.64	1.59	1.86	1.61	1.66	2.25	14.23	81.23
30	2.75	0.96	0.30	0.16	0.17	0.18	3.55	8.10	6.40	3.67	0.74	0.62	0.52	0.49	1.05	3.53	33.20
40	1.34	0.41	0.07	0.16	0.17	0.18	2.04	5.09	3.96	2.10	0.30	0.62	0.52	0.49	0.44	1.97	19.85
50	1.34	0.41	0.03	0.15	0.13	0.14	1.32	5.09	3.96	2.10	0.19	0.44	0.47	0.37	0.29	1.97	18.38
60	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
70	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
80	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
90	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
100	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
200	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
300	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
400	1.34	0.41	0.03	0.10	0.09	0.13	1.32	5.09	3.96	2.10	0.19	0.37	0.42	0.33	0.29	1.97	18.14
500	1.09	0.38	0.03	0.09	0.07	0.09	0.68	3.99	2.85	1.60	0.07	0.32	0.32	0.27	0.16	1.32	13.33
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE B-2-5
PMEC ASU COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.20	5.68	1.57	0.73	0.69	0.55	6.00	13.30	12.00	6.81	2.49	1.86	1.61	1.66	5.80	17.00	100.0
20	21.40	5.33	1.57	0.73	0.69	0.55	6.00	13.20	11.90	6.79	2.49	1.86	1.61	1.66	5.80	16.60	98.20
30	6.13	1.78	0.63	0.71	0.53	0.50	4.82	10.50	8.48	4.95	1.40	1.67	1.37	1.47	1.99	5.67	52.60
40	4.85	1.55	0.39	0.32	0.24	0.23	3.72	9.75	7.70	4.47	0.91	1.03	0.66	0.76	1.21	4.73	42.50
50	4.85	1.55	0.10	0.14	0.13	0.14	2.27	9.75	7.70	4.47	0.38	0.46	0.50	0.37	0.49	4.73	38.00
60	4.04	1.40	0.09	0.07	0.07	0.10	1.98	9.60	7.66	4.47	0.32	0.24	0.24	0.22	0.44	4.72	35.70
70	3.96	1.40	0.07	0.07	0.07	0.10	1.64	9.55	7.64	4.47	0.26	0.24	0.24	0.22	0.37	4.63	34.90
80	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.55	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.60
90	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.55	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.60
100	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.55	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.60
200	3.48	1.29	0.07	0.03	0.05	0.03	1.64	9.00	7.23	4.18	0.26	0.14	0.22	0.13	0.37	4.25	32.40
300	2.43	0.86	0.07	0.03	0.05	0.03	1.64	7.40	5.91	3.39	0.26	0.14	0.22	0.13	0.37	3.25	26.20
400	1.88	0.69	0.07	0.03	0.05	0.03	1.64	6.19	4.96	2.75	0.26	0.14	0.22	0.13	0.37	2.55	21.90
500	1.62	0.57	0.07	0.03	0.05	0.03	1.64	5.50	4.43	2.42	0.26	0.14	0.22	0.13	0.37	2.36	19.80
600	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
700	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
800	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
900	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
1000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
2000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
3000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
4000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
5000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
6000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.80
7000	1.37	0.45	0.03	0.03	0.03	0.01	1.34	4.90	3.96	2.11	0.22	0.13	0.17	0.09	0.29	2.05	17.20
8000	0.41	0.10	0.00	0.01	0.01	0.01	0.63	1.91	1.79	0.85	0.13	0.03	0.07	0.02	0.13	0.88	6.99
9000	0.26	0.05	0.00	0.01	0.01	0.01	0.63	1.09	1.13	0.50	0.13	0.03	0.07	0.02	0.13	0.66	4.74
10000	0.26	0.05	0.00	0.01	0.01	0.01	0.24	1.09	1.13	0.50	0.08	0.02	0.05	0.02	0.10	0.66	4.25

TABLE B-2-6
PMEC ASU COOLING TOWER PLUME HEIGHT FREQUENCY DISTRIBUTION

Height From Tower (m)	Condensed Plume Height Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	22.24	5.68	1.57	0.73	0.69	0.55	5.93	13.27	11.99	6.81	2.48	1.86	1.61	1.66	5.78	17.04	99.89
30	6.10	2.06	0.76	0.33	0.30	0.24	4.40	10.36	8.41	4.97	1.25	1.11	0.82	0.84	1.78	6.34	50.06
40	3.96	1.40	0.09	0.14	0.13	0.14	1.98	9.54	7.64	4.47	0.32	0.46	0.50	0.37	0.44	4.63	36.20
50	3.96	1.40	0.07	0.05	0.06	0.07	1.64	9.54	7.64	4.47	0.26	0.19	0.23	0.16	0.37	4.63	34.73
60	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.54	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.57
70	3.96	1.40	0.07	0.03	0.05	0.03	1.64	9.54	7.64	4.47	0.26	0.14	0.22	0.13	0.37	4.63	34.57
80	3.48	1.29	0.07	0.03	0.05	0.03	1.64	8.99	7.23	4.18	0.26	0.14	0.22	0.13	0.37	4.25	32.36
90	3.00	1.16	0.07	0.03	0.05	0.03	1.64	8.49	6.76	3.89	0.26	0.14	0.22	0.13	0.37	3.83	30.06
100	2.75	1.02	0.07	0.03	0.05	0.03	1.64	7.94	6.40	3.64	0.26	0.14	0.22	0.13	0.37	3.52	28.20
200	2.75	1.02	0.07	0.03	0.05	0.03	1.64	7.94	6.40	3.64	0.26	0.14	0.22	0.13	0.37	3.52	28.20
300	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
400	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
500	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
600	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
700	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
800	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
900	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
1000	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78

TABLE B-2-7
PMEC ASU COOLING TOWER PLUME RADIUS FREQUENCY DISTRIBUTION

Radius (m)	Condensed Plume Radius Annual Frequency (%) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	22.24	5.68	1.57	0.73	0.69	0.55	6.00	13.28	11.99	6.81	2.49	1.86	1.61	1.66	5.80	17.04	100.0
20	12.73	3.29	0.63	0.66	0.46	0.45	4.82	12.85	11.35	6.45	1.40	1.59	1.26	1.33	1.99	10.96	72.22
30	4.49	1.50	0.32	0.07	0.07	0.10	3.44	9.87	8.02	4.66	0.78	0.24	0.24	0.22	1.05	4.96	40.03
40	2.75	1.02	0.07	0.03	0.05	0.03	1.64	7.94	6.40	3.64	0.26	0.14	0.22	0.13	0.37	3.52	28.20
50	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
60	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
70	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
80	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
90	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
100	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
200	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
300	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
400	1.37	0.45	0.07	0.03	0.05	0.03	1.64	4.90	3.96	2.11	0.26	0.14	0.22	0.13	0.37	2.05	17.78
500	1.11	0.40	0.07	0.01	0.02	0.02	1.01	3.81	2.83	1.60	0.14	0.05	0.08	0.06	0.24	1.39	12.84
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE B-2-8
PMEC POWER BLOCK COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION
During Daytime Hours Excluding Periods of Visibility Obscuring Weather

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (Hours per Year)) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	749	114	32	19	29	22	143	359	462	223	78	76	54	63	322	806	3550
20	749	114	32	19	29	22	143	359	462	223	78	76	54	63	322	806	3550
30	721	110	14	19	29	22	107	350	447	219	38	76	54	63	94	785	3153
40	159	42	6	6	5	3	47	241	257	121	11	19	17	12	23	211	1182
50	76	21	2	6	5	3	26	160	169	73	8	19	17	12	13	142	753
60	55	16	1	6	5	3	20	120	124	53	4	19	17	12	8	113	579
70	54	16	1	6	5	3	20	120	124	53	4	19	17	12	8	113	575
80	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
90	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
100	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
200	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
300	46	11	1	6	5	3	20	104	103	44	4	19	17	12	8	93	497
400	46	11	1	5	3	3	20	104	103	44	4	15	15	9	8	93	486
500	46	11	1	5	3	3	20	104	103	44	4	15	15	9	8	93	486
600	46	11	1	5	3	3	20	104	103	44	4	15	15	9	8	93	486
700	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
800	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
900	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
1000	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
2000	46	11	1	5	3	3	20	103	103	44	4	15	15	9	8	93	486
3000	37	7	1	2	1	0	20	84	82	34	4	6	6	4	8	75	373
4000	37	7	1	2	1	0	20	84	82	34	4	6	6	4	8	75	373
5000	37	7	0	2	1	0	17	84	82	34	1	6	6	4	6	75	362
6000	16	4	0	1	1	0	6	32	47	8	1	5	3	2	0	35	162
7000	16	4	0	0	1	0	6	32	47	8	1	1	1	2	0	35	154
8000	8	1	0	0	0	0	6	11	20	3	1	0	0	0	0	16	66
9000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE B-2-9
PMEC ASU COOLING TOWER PLUME LENGTH FREQUENCY DISTRIBUTION

During Daytime Hours Excluding Periods of Visibility Obscuring Weather

Dist. From Tower (m)	Condensed Plume Length Annual Frequency (Hours per Year) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
10	749	114	32	19	29	22	143	359	462	223	78	76	54	63	322	806	3550
20	689	105	32	19	29	22	143	352	458	221	78	76	54	63	322	742	3412
30	211	45	14	16	18	17	102	259	289	133	42	61	40	47	95	251	1640
40	168	42	8	8	9	9	62	245	256	120	20	33	20	24	50	214	1289
50	168	42	5	3	3	3	36	245	256	120	9	14	12	8	17	214	1154
60	168	42	4	1	2	2	24	245	256	120	9	11	6	6	13	214	1122
70	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
80	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
90	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
100	142	42	1	1	2	1	19	235	253	120	4	7	6	4	8	205	1051
200	121	40	1	1	2	1	19	221	239	113	4	7	6	4	8	191	976
300	84	26	1	1	2	1	19	167	189	86	4	7	6	4	8	154	760
400	75	21	1	1	2	1	19	155	169	74	4	7	6	4	8	142	689
500	67	17	1	1	2	1	19	133	147	66	4	7	6	4	8	125	611
600	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
700	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
800	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
900	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
1000	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
2000	57	16	1	1	2	1	19	115	125	54	4	7	6	4	8	110	533
3000	48	12	1	1	1	0	19	94	109	40	4	5	3	2	8	89	437
4000	48	12	1	1	1	0	19	94	109	40	4	5	3	2	8	89	437
5000	48	12	1	1	1	0	19	94	109	40	4	5	3	2	8	89	437
6000	48	12	0	1	0	0	17	94	109	40	1	4	2	0	6	89	426
7000	28	8	0	0	0	0	6	47	65	18	1	0	0	0	0	51	225
8000	8	2	0	0	0	0	6	11	20	3	1	0	0	0	0	15	66
9000	8	2	0	0	0	0	6	11	20	3	1	0	0	0	0	15	66
10000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

TABLE B-2-10
PMEC POWER BLOCK COOLING TOWER FOGGING FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Ground Level Fogging Annual Frequency (Hours per Year) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19
200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19
300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00
500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

TABLE B-2-11
PMEC ASU COOLING TOWER FOGGING FREQUENCY DISTRIBUTION

Dist. From Tower (m)	Ground Level Fogging Annual Frequency (Hours per Year) by Downwind Sector																Sum
	S	SSW	SW	WSW	W	WNW	NW	NNW	N	NNE	NE	ENE	E	ESE	SE	SSE	
100	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.88	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.88
200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38
300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
800	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
900	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1200	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1300	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1400	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Appendix B-3

Emission Calculations

Appendix B-3-1

Criteria Pollutant Emission Calculations

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COMBUSTION TURBINE EMISSION ESTIMATES

Basis: Typical Siemens SGT6-5000F emission estimates or estimated worst case for other suppliers

Short-term Emissions on Syn Gas

Syngas fuel rate per CTG 2100 x 10^6 Btu/hr, HHV (calculated)
1960 x 10^6 Btu/hr, LHV (from Siemens)
Assumed coal conversion efficency **0.76** Undiluted syngas heating value= 240 to 280 Btu/dscf (HHV)
Assumed gasifiers coal feed (per CTG) 2760 x 10^6 Btu/hr (HHV)

Syngas Short-term Emission Rates			
	lb/hr (per stack)	**lb/10^6 Btu coal**	**Basis***
NOx	32	0.012	3 ppmvd (@15% O2), based on 80% removal SCR system and 15 ppm inlet NOx**
NOx (uncontrolled)	160	0.058	15 ppmvd (@ 15% O2)
CO	98	0.036	15 ppmvd (@ 15% O2)
PM10***	24	0.009	filterable (front-half) + condensible (back half)
VOC	9.0	0.003	2.4 ppmvd (@ 15% O2)
NH3	20	0.007	5 ppmvd (@ 15% O2) ammonia slip

* Typical mass emission rates from Siemens for basis stated except CO and PM10, which are allowances for expected guarantees from other suppliers. Siemens currently quotes lower CO and PM10 emission rates than shown.
** The ecomonic tradeoff between CTG combustor NOx emission and SCR size (i.e., diluition nitrogen versus NOx removal efficiency) may be optimized during later engineering.
*** Includes 3 lb/hr ammonium sulfate formed from SO3 and SCR ammonia slip.

Syngas Short-term SO2 Emission Rates			
Avg time	**Syn gas avg sulfur, ppm**	**SO2, lb/hr (per stack)**	**lb/10^6 Btu coal**
1-hr	50	74	0.027
3-hr	30	44	0.016
8-hr	20	29	0.011
24-hr	15	22	0.0080
30-day	10	15	0.0053

Example calculations for SO2
(From Ideal Gas Law, 1 lbmol gas = 380 scf, scf defined @ 60 deg F, 1 atm)
Max SO2 for 10 ppmv total sulfur in fuel
= (2100 x10^6 Btu/hr)/(240 Btu/scf) x (10 scf sulfur/10^6 scf) x (64 lb SO2/380 scf) = 15 lb SO2/hr/CTG

Short-term Emissions on Natural Gas (backup fuel)

Nat gas fuel rate per CTG= 2254 x 10^6 Btu/hr, HHV (supplier data)

Short-term Emission Rates		
	lb/hr (per stack)	**Basis***
NOx	43	5 ppmvd (@15% O2), based on 80% removal SCR system and 25 ppm inlet NOx
NOx (uncontrolled)	215	25 ppmvd (@ 15% O2)
CO	78	15 ppmvd (@ 15% O2)
PM10**	20	filterable (front-half) + condensible (back half)
VOC	9.0	2.4 ppmvd (@ 15% O2)
SO2	6.4	1 grain sulfur/100 scf in pipeline nat gas.
NH3	16	5 ppmvd (@ 15% O2) ammonia slip

* Typical mass emission rates from Siemens for basis stated except CO and PM10, which are allowances for expected guarantees from other suppliers. Siemens currently quotes lower CO and PM10 emission rates than shown.
** Includeds 2 lb/hr ammonium sulfate formed from SO3 and SCR ammonia slip.

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COMBUSTION TURBINE EMISSION ESTIMATES

CTG Startup/shutdown Emissions per CTG (supplier data)

	Avg Startup/shutdown Emission, lb/hr			
	Hot Start	**Warm Start**	**Cold Start**	**Worst Case, lb/hr**
NOx	108	116	121	121
CO	2116	2740	2205	2740
PM10	10	11	11	11
VOC	204	263	212	263
Typical duration	52 min	81 min	101 min	(N/A)

Notes: - NOx, CO and VOC hourly average startup emission rates exceed normal full load operation emission rates.
- NOx, CO and VOC shutdown emission rates (not shown) will also exceed normal full load emission rates, but are less than worst-case startup emissions.
- CTG fuel consumption and, therefore, also SO2 emissions are less during startup/shutdown than normal full load operation

Worst Case Estimated Annual Emissions

Worst Case Annual Emissions			
	ton/yr (per stack)	**avg lb/hr (per stack)**	**Basis**
NOx*	147	34	100 hr/yr startup/shutdown w/o SCR, plus 440 hr nat gas full load operation, balance on syn gas at full load*
CO	561	128	100 hr/yr startup/shutdown, balance of year on syn gas at full load*
PM10	105	24	8760 hr/yr on syn gas at full load
VOC	52	12	100 hr/yr startup/shutdown, balance of year on syn gas at full load*
SO2	65	15	10 ppm ann avg sulfur in fuel, 8760 hr/yr on syn gas at full load
NH3	86	20	8760 hr/yr on syn gas at full load
NOx (uncontrolled)	711	162	100 hr/yr startup/shutdown w/o SCR, plus 440 hr nat gas full load operation, balance on syn gas at full load* No SCR

* Startup/shutdown based on approximately 25 starts per year per CTG and about 4 hours per event.

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TANK VENT OXIDIZER EMISSION RATES

Basis: ConocoPhillips estimates and supplier data for similar equipment

TVO emission factors (lb/10^6 Btu fired)

	SG	NG	Basis
SO2	*	0.00286	1 grain S/100 scf nat gas
NOx	0.3	0.3	supplier data for similar equipment
CO	0.09	0.09	60 ppmvd (12% O2), supplier data for similar equipment
PM10	0.01	0.01	supplier data for similar equipment
VOC	0.004	0.004	CoP estimate

(SG = syngas, NG = natural gas)

* See emission table below

SO2 from sulfur in tank vent gas during normal oper = 3.5 lb/hr (CoP estimate)

	Capacities, 10^6 Btu/hr	
Operating Modes	SG	NG
Gasifier outage		40
Startup	10	30
Maximum operation, short-term	65	
Normal operation, long-term	15	

assumed syngas HHV = 240 Btu/dscf

Worst Case SO2 Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs							
Startup, hrs							
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs					620	8,360	
SG consumed, 10^6 Btu	65	195	520	1560	15,800	151,400	
NG consumed, 10^6 Btu	0	0	0	0	0	0	
Sulfur in SG, ppmv	50	30	20	15	10	10	
SO2 from SG, lb/10^6 Btu SG*	0.035	0.021	0.014	0.011	0.007	0.007	
SO2 from SG or NG, lbs	2	4	7	16	111	1,064	
SO2 from tank vent gas, lbs	3.5	10.5	28	84	2,520	30,660	
Total SO2, lb/hr	5.8	4.9	4.4	4.2	3.7	3.6	15.9

* Example SO2 emission factor calculations,

SO2 (syngas) = (10 scf S/10^6 scf fuel) x (64 lb SO2/380 scf S)/(240 Btu/scf fuel) = 0.0070 lb SO2/10^6 Btu

SO2 (natural gas) = 1 grain S/100 scf x 10^3 scf/10^6 Btu x 1 lb/7000 grain x 2 lb SO2/lb S = 0.00286 lb SO2/10^6 Btu

Worst Case Non-Sulfur Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	30-day	12-mo avg	Ton/yr
Gasifier outage, hrs					620	720	
Startup, hrs						263	
Max operation, short-term hrs	1	3	8	24	100	400	
Normal operation, long-term hrs						7,377	
SG consumed, 10^6 Btu	65	195	520	1560	6,500	139,285	
NG consumed, 10^6 Btu	0	0	0	0	24,800	36,690	
NOx,lb/hr	19.5	19.5	19.5	19.5	13.0	6.0	26.4
CO, lb/hr	5.9	5.9	5.9	5.9	3.9	1.81	7.9
PM10, lb/hr	0.7	0.7	0.7	0.7	0.4	0.20	0.9
VOC, lb/hr	0.3	0.3	0.3	0.3	0.2	0.1	0.4

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AUXILIARY BOILER EMISSION ESTIMATES

(Mainly used for startups, could be used for other purposes, primarily during power block outages)

Maximum steam generation 100,000 lb/hr
Maximum heat release 130 10^6 Btu/hr, HHV
Natural gas fuel, only

Emission factors

	lb/10^6 Btu, HHV	Basis
SO2	0.00286	1.0 grain total sulfur/100 scf pipeline natural gas
NOx	0.036	Low NOx burner, based on similar equipment from previous project
CO	0.074	Similar equipment from previous project
PM10	0.005	Similar equipment from previous project
VOC	0.004	Similar equipment from previous project

Emission calulations

	Max short-term lb/hr (1)	Annual average ton/yr (2)
SO2	0.37	0.41
NOx	4.7	5.1
CO	9.6	10.5
PM10	0.65	0.71
VOC	0.52	0.57

Notes:
(1) Maximum 1-hr, 3-hr, 8-hr, 24-hr, and 30-day average emission rates.
(2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than 0.25 x 8760 hr/yr x 130 million Btu/hr = 285 billion Btu/yr)

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ENCLOSED GROUND FLARE EMISSION RATES

Emission Factors

	lb/10^6 Btu fired, HHV		
	SG	**NG**	**Basis**
SO2	see table	0.00286	1 grain sulfur/100 scf pipeline natural gas
NOx	0.07	0.07	Equipment supplier estimate
CO	1.54	0.55	Assumed 99% destruction of CO in SG (1), TRNCC factor for NG (2)
PM10	0.008	0.008	Very little unoxidized carbon in syngas, therefore very little PM, used AP-42 factor for NG in boiler (a small value) (3)
VOC	0.006	0.006	Virtually no VOC in syngas, used AP-42 factor for NG in boiler (a small value) (3)

Notes:

(1) CO emission factor based on 50 vol % CO in flared gas, assumed 99% destruction efficiency, and 240 Btu/scf HHV,
CO = (0.50 scf/scf) x (1 - 0.99)/(240 Btu/scf) x (28 lb/380 scf) x (10^6/10^6) = 1.54 lb/10^6 Btu, HHV

(2) Texas Natural Resource Conservation Commission (now Texas Commission on Environmental Quality),
Technical Guidance Package for Chemical Sources, Flares and Oxidizers (RG-109), May 1997

(3) U.S. EPA, AP-42, Table 1.4-2

		Capacities, 10^6 Btu/hr		
Operating Modes		SG	NG	
Steady state (pilot only)			2	
Gasifier Startup	1 Hour	270		(flared gas is partially oxidized natural gas, similar to syngas,
	3 Hour	260		or incompletely oxidized syngas)
	8 Hour	190		
	24 Hour	100		
	50 Hours	75		Heatup/startup - average entire time frame per gasifer
Gasifier shutdown	8 hour	50		Gasifier deslag - average time per shutdown
Flaring syn gas, max 1-hr avg		3730		(85% of max capacity for two gasifiers)
Flaring syn gas, max > 1-hr avg		3510		
Flaring syn gas, max >8-hr avg		1755		

Syngas HHV = 240 Btu/dscf

Operating Mode	SO2	NOx	CO	PM10	VOC
Pilot only emissions, lb/hr	0.0057	0.14	1.10	0.016	0.012
stack exit flow (ft3/s)	1200				
stack exit velocity (m/s)	0.186				

Normal Worst-Case Emissions							
	Emission Averaging Time						
Operating Modes	1-hr	3-hr	8-hr	24-hr	12-mo avg	Ton/yr	Notes
Steady state (pilot only) hrs	1	3	8	24	8760		Includes one gasifier starting up and shutting down 12 times per year
Startup flaring hrs syngas	1	3	8	24	600		
Shutdown deslag flaring hrs SG					96		
Normal flaring hrs syngas					200		
Syngas flared, 10^6 Btu	270	780	1,520	2,400	400,800		
NG consumed, 10^6 Btu	2	6	16	48	17520		
Sulfur in SG, ppmv	50	30	20	15	10		
SO2 from SG, lb/10^6 Btu SG	0.035	0.021	0.014	0.011	0.007		
SO2,lb/hr (total SG + NG)	9.49	5.49	2.68	1.06	0.3	1.4	
NOx,lb/hr	19.04	18.34	13.44	7.14	3.3	14.6	
CO, lb/hr	415.57	400.22	292.77	154.61	71	312	
PM10, lb/hr	2.18	2.10	1.54	0.82	0.38	1.7	
VOC, lb/hr	1.63	1.57	1.15	0.61	0.29	1.3	
stack exit flow (ft3/s)	8,021	7,727	5,662	3,008	1,408		Scaled from the maximum 1 hour upset flow
stack exit velocity (m/s)	1.245	1.199	0.879	0.467	0.219		

Worst Case Emergency Upset Emissions					
	Emission Averaging Time				
Operating Modes	1-hr	3-hr	8-hr	24-hr	Notes
Steady state (pilot only) hrs	1	3	8	24	Facility Upset assumes 85% of maximum syngas capacity for two gasifiers
Flaring hrs syn gas, max 1-hr	1				
Flaring hrs syn gas, max >1-hr		3	8		
Flaring hrs gas, max >8-hr				24	
SG flared, 10^6 Btu	3730	10530	28080	42120	
NG consumed, 10^6 Btu	2	6	16	48	
Sulfur in SG, ppmv	400	300	100	50	
SO2 from SG, lb/10^6 Btu SG	0.281	0.211	0.070	0.035	
SO2,lb/hr (total SG + NG)	1,048	740	247	62	
NOx,lb/hr	261	246	246	123	
CO, lb/hr	5,727	5,389	5,389	2,695	
PM10, lb/hr	29.9	28.1	28.1	14.1	
VOC, lb/hr	22.4	21.1	21.1	10.5	
stack exit flow (ft3/s)	110,000	103,512	103,512	51,756	Scaled from the maximum 1 hour upset flow
stack exit velocity (m/s)	17.076	16.069	16.069	8.034	

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COOLING TOWER EMISSION RATE

Basis: Similar equipment from previous project.

Cooling Tower Operating Data and Emission Calculation			
Parameter	**Power Block**	**Gasification/ ASU**	**Basis**
Heat rejected, million Btu/hr	1740	1015	Typical plant performance
Cooling water (CW) circulation rate, million lb/hr	116	68	Typical cooling tower design
Max CW dissolved solids, ppmw	2400	2400	TDS of water supply and 12 cycles of concentration
Drift, fraction of circulating CW	0.0010%	0.0010%	Typical supplier guarantee
PM10 emission rate, lb/hr	2.8	1.6	Calculated
PM10 emission rate, ton/yr	12.2	7.1	Calculated

Total PM10 cooling tower emission 19.3 ton/yr

Example calculation: (TO BE CONFIRMED)
Maximum expected total dissolved solids (TDS) in makeup water = 200 parts per million by weight (ppmw)
Maximum expected TDS in circulating cooling water at twelve cycles of concentration = 12 x 200 = 2400 ppmw
Power Block cooling tower PM10 = (116 x 10^6 lb/hr) x (0.00001 lb drift/lb) x (2400 lb PM/10^6 lb drift)
= 2.8 lb PM10/hr

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EMERGENCY DIESEL ENGINES EMISSION RATES

Short-term Emission Rates						
	Total	Emission Factor or Emission Rate				
Engines	**hp**	**SO2**	**NOx**	**CO**	**PM10**	**VOC**
Emission Factors						
NONROAD Tier 1 Light Commercial Generator Sets >1200hp		0.0004	0.0137	0.0018	0.0004	0.0006
NONROAD Tier 1 Light Commercial Pumps 300-600hp		0.0004	0.0134	0.0030	0.0004	0.0005
Emission Rates						
Emergency Generator, 2 MW - emission, lb/hr	2682	1.0	37	5	1.0	1.7
1 Emergency Fire Water Pump Engine, 300 hp - emission, lb/hr*	300	0.1	4	0.9	0.1	0.1

* Two pumps will be provided, one will be electric engine-driven. Emissions for one engine shown for worst case permitting.

Note: the EPA NONROAD emissions will meet the BACT requirement

Fuel sulfur = 0.05 wt%
1 MW = 1341 bhp

Annual Emission Rates**						
		Emission Rate, ton/yr				
Engines		**SO2**	**NOx**	**CO**	**PM10**	**VOC**
Emergency Generator, 2 MW - emission, ton/yr		0.05	1.8	0.2	0.05	0.09
1 Emergency Fire Water Pump Engine, 300 hp - emission, ton/yr		0.01	0.2	0.0	0.01	0.01
Total		**0.05**	**2.04**	**0.28**	**0.05**	**0.09**

** Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.

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FUGITIVE PARTICULATE MATTER

Annual Coal/Coke Requirement

	15930	Amount of coal/coke delivered per train (tons/train)
	150	Number of deliveries per year (trains/year)
	2,389,500	Annual amount of coal/coke delivered (tons/year)

For modeling purposes the total annual coal/coke requirement is assumed to arrive by either train or ship.

Emission Factor

AP-42 Section 13.2.4 Aggregate Handling

E = uncontrolled PM_{10} emissions (lb/ton) = k * (0.0032) * $(U/5)^{1.3}$ / $(M/2)^{1.4}$

k	0.35	particle size multiplier (dimensionless)
U	2.27	mean wind speed (miles per hour [mph]) = 200 ft/min from negative pressurization of train unloading building
M	4.5	material moisture content (%) - Table 13.2.4-1 Coal-fired power plant for coal as received
E =	0.000129	lb/ton PM10 uncontrolled
assume	79.2	% control efficiency (80% capture and 99% control = 79% reduction)
E =	0.000027	lb/ton PM10 controlled

Train Unloading

Dumps to underground hopper and the train is inside a building with plastic flaps across the ends
The unloading building is under negative pressure and dust is collected and sent to a baghouse

	5	hours per train to unload
	3186	Maximum hourly unloading rate (ton/hr)
	15930	Maximum daily unloading rate (ton/day)
Emissions	0.085	Maximum hourly PM_{10} emission rate (lb/hr)
	0.018	Maximum daily PM_{10} emission rate (lb/hr)
	0.0320	Maximum annual PM_{10} emission rate (ton/yr)

Storage Dome Transfer Point

All coal/coke tranfered from the train unloading station and/or the ship unloading station into the storage domes passes through this point and the PM emissions are controlled with a baghouse.

	3186	Maximum hourly unloading rate (ton/hr) either trains or ships
	45600	Maximum daily unloading rate (ton/day) either trains or ships
	2,389,500	Maximum annual unloading rate (ton/yr) either trains or ships
Emissions	0.085	Maximum hourly PM_{10} emission rate (lb/hr)
	0.051	Maximum daily PM_{10} emission rate (lb/hr)
	0.0320	Maximum annual PM_{10} emission rate (ton/yr)

Ship Unloading

Alternative to train unloading. Assume same amount of coal/coke delivered as on trains.
Ship unloads by bucket crane to a conveyor belt, particulate is suctioned to a baghouse
The mean wind speed for this source is the mean outdoor wind speed, since the drop from the bucket crane to the conveyor belt occurs outside.

Emission Factor

AP-42 Section 13.2.4 Aggregate Handling

E = uncontrolled PM_{10} emissions (lb/ton) = k * (0.0032) * $(U/5)^{1.3}$ / $(M/2)^{1.4}$

k	0.35	particle size multiplier (dimensionless)
U	10	mean wind speed (miles per hour [mph])
M	4.5	material moisture content (%) - Table 13.2.4-1 Coal-fired power plant for coal as received
E =	0.000886	lb/ton PM10 uncontrolled
assume	79.2	% control efficiency (80% capture and 99% control = 79% reduction)
E =	0.000184	lb/ton PM10 controlled
	2,389,500	Annual amount of coal/coke delivered (tons/year)
	70000	Maximum ship capacity (tons)
	34	ships/year
	1900	Maximum hourly unloading rate (ton/hr)
	37	hours per ship to unload
	45600	Maximum daily unloading rate (ton/day)
Emissions	0.350	Maximum hourly PM_{10} emission rate (lb/hr)
	0.350	Maximum daily PM_{10} emission rate (lb/hr)
	0.2202	Maximum annual PM_{10} emission rate (ton/yr)

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FUGITIVE PARTICULATE MATTER

Storage Dome Ventilation

Storage Dome Ventilation will not occur during loading of the domes or until most of the particulate has settled although fine particules will still hang in the air in the domes.
Calculate emissions based on total coal/coke stacked in dome.

	3186	Maximum hourly unloading rate (ton/hr) either trains or ships
	45600	Maximum daily unloading rate (ton/day) either trains or ships
	2,389,500	Maximum annual unloading rate (ton/yr) either trains or ships
Emissions	0.085	Maximum hourly PM_{10} emission rate (lb/hr)
	0.051	Maximum daily PM_{10} emission rate (lb/hr)
	0.032	Maximum annual PM_{10} emission rate (ton/yr)

Note: Emissions will occur from either the train unloading area or the ship unloading area but not both, as the total annual coal/coke
Note: Short-term emissions from the storage dome ventilation system will not occur at the same time as emissions from the train and

Summary PM10 Emissions

		Maximum Hourly		Maximum Daily		Annual Emissions	
Scenario		lb/hr	g/s	lb/hr	g/s	ton/yr	g/s
1 - Train Unloading	Train Unloading	0.085	0.011	0.018	0.002	0.032	0.001
	Storage Domes	0.085	0.011	0.051	0.006	0.032	0.001
	Total	**0.171**	**0.022**	**0.069**	**0.009**	**0.064**	**0.002**
2 -Ship Unloading	Storage Domes	0.085	0.011	0.051	0.006	0.032	0.001
	Ship Unloading	0.350	0.044	0.350	0.044	0.220	0.006
	Total	**0.436**	**0.055**	**0.401**	**0.051**	**0.252**	**0.007**
3 - Dome Ventilation	Ventilation	0.085	0.011	0.051	0.006	0.032	0.001
Maximum Short-term Emissions		**0.436**	**0.055**	**0.401**	**0.051**		
unloading emissions plus the dome ventilation						**0.284**	**0.008**

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Stack Parameters

Source	Combustion Turbines(ea)	Tank Vent Oxidizer	Auxiliary Boiler	Flare	Cooling Towers (per cell)(1)
Stack height, ft above grade(2)	150	210	40	100	48
Stack diameter, ft	20	6	5	50	33
Stack outlet temp, deg F	250	584	300	1600	104
Stack exit flow, act ft3/sec	21,200(3)	785(4)	625	1200 to 110,000(5)	22,833

Notes:

(1) Twelve cells estimated for power block cooling tower, seven cells estimated for ASU/gasification cooling tower.

(2) Minimum stack height assumed for worst-case dispersion.

(3) Value shown in table is based on full load syn gas combustion (relatively constant for varying ambient temperatures). Corresponding full load stack flow for natural gas combustion will vary from about 19,000 act ft3/sec during warm summer ambient temperatures to about 22,400 act ft3/sec at cold winter ambient temperatures.

(4) Based on 65 million Btu/hr syn gas or natural gas combustion. Assumed 12% O_2. Stack exit flows for other heat input rates may be assumed proportional to the heat input rate for each fuel.

(5) Estimated flare exhaust gas rates for stated range of heat input from 40 to 3730 million Btu/hr.

Appendix B-3-2

Hazardous Air Pollutant Emission Calculations

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PACIFIC MOUNTAIN ENERGY CENTER
HAPs EMISSION SUMMARY

CAS # or MPCA #	Compound	Federally Listed Compound HAP	Washington State TAP	Daily HAP Emission (lb/hr) CTGs	TVO	Flare	Fugitive	Auxiliary Boiler	Power Cooling Tower	Gas/ASU Cooling Tower	Emergency Fire Pump	Emergency Generator	Total	Washington State ASIL (ug/m3) Class A	Class B	Small Quantity Emission Rate Exemption Level Class A lb/yr	Class B lb/yr	Class B lb/hr	Washington State Class B 24-hour Modeling Required
106-99-0	1,3-Butadiene	Yes	Yes								8.21E-05		8.21E-05	0.0036	-	0.5	-	-	No
75-07-0	Acetaldehyde	Yes	Yes	9.94E-03	1.17E-04	9.00E-05					1.61E-03	4.73E-04	1.22E-02	0.45	-	50	-	-	No
107-02-8	Acrolein	Yes	Yes								1.94E-04	1.48E-04	3.42E-04	-	0.02	-	175	0.02	No
7664-41-7	Ammonia	No	Yes	3.94E+01			2.88E-02						3.94E+01	-	100	-	17500	2	Yes
7440-36-0	Antimony	Yes	Yes	6.07E-03	1.95E-04	1.50E-04							6.42E-03	-	1.7	-	175	0.02	No
7440-38-2	Arsenic	Yes	Yes	1.32E-02	1.03E-03	7.90E-04		2.48E-05	5.80E-06	3.38E-06			1.51E-02	0.00023	-	**	-	-	No
7440-39-3	Barium	No	Yes					5.45E-04					5.45E-04	-	1.7	-	175	0.02	No
71-43-2	Benzene	Yes	Yes	1.32E-02	1.96E-02	1.51E-02	1.78E-04	2.60E-04			1.96E-03	1.46E-02	6.49E-02	0.12	-	20	-	-	No
7440-41-7	Beryllium	Yes	Yes	1.44E-03	5.85E-06	4.50E-06		1.49E-06					1.45E-03	0.00042	-	**	-	-	No
106-97-8	Butane	No	Yes					2.60E-01					2.60E-01	-	6300	-	43748	5	No
7440-43-9	Cadmium	Yes	Yes	5.30E-02	3.90E-05	3.00E-05		1.36E-04					5.32E-02	0.00056	-	**	-	-	No
75-15-0	Carbon disulfide	Yes	Yes	2.54E-01	2.99E-03	2.30E-03	9.50E-04						2.60E-01	-	100	-	17500	2	No
463581	Carbonyl sulfide	Yes	Yes				1.70E-03						1.70E-03	-	***	-	-	-	No
7782-50-5	Chlorine (Cl)	Yes	Yes						2.90E-03	1.69E-03			4.59E-03	-	5	-	175	0.02	No
18540-29-9	Chromium, (hexavalent)	Yes	Yes	8.45E-04	2.18E-04	1.68E-04		1.73E-04					1.40E-03	0.000083	-	**	-	-	No
7440-48-4	Cobalt	Yes	Yes	1.44E-03	8.32E-04	6.40E-04		1.04E-05					2.92E-03	-	0.17	-	175	0.02	No
7440-50-8	Copper	No	Yes					1.05E-04					1.05E-04	-	0.67	-	175	0.02	No
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	Yes	Yes	3.15E-02	3.25E-03	2.50E-03	2.78E-04						3.75E-02	-	17	-	1750	0.2	No
100-41-4	Ethyl benzene	Yes	Yes		2.20E-02	1.69E-02	1.57E-07						3.89E-02	-	160	-	22750	2.6	No
7782-41-4	Fluorine (F)	No	Yes						3.48E-04	2.03E-04			5.51E-04	-	5.3	-	175	0.02	No
50-00-0	Formaldehyde	Yes	Yes	9.38E-02	1.11E-03	8.50E-04	3.30E-08	9.29E-03			2.48E-03	1.48E-03	1.09E-01	0.077	-	20	-	-	No
110-54-3	Hexane	Yes	Yes				4.33E-08	2.23E-01					2.23E-01	-	200	-	22750	2.6	No
7647-01-0	Hydrochloric acid	Yes	Yes	7.18E-02	6.42E-04	4.94E-04	3.06E-03						7.60E-02	-	7	-	175	0.02	Yes
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	Yes	Yes	2.76E-01	3.90E-05	3.00E-05							2.76E-01	-	8.7	-	175	0.02	Yes
6/4/7783	Hydrogen sulfide	Yes	Yes				1.17E-01						1.17E-01	-	0.9	-	175	0.02	Yes
7439-92-1	Lead	Yes	Yes	3.09E-03	2.77E-05	2.13E-05			1.16E-06	6.77E-07			3.14E-03	0.5*	-	50	-	-	No
7439-96-5	Manganese	Yes	Yes	5.74E-03	1.64E-03	1.27E-03		4.70E-05	2.32E-03	1.35E-03			1.24E-02	-	0.4	-	175	0.02	No
7439-97-6	Mercury	Yes	Yes	6.62E-03	4.55E-04	3.50E-05		3.22E-05	5.80E-07	3.38E-07			7.15E-03	-	0.33	-	175	0.02	No
74-83-9	Methyl bromide (Bromomethane)	Yes	Yes	2.63E-01	8.00E-03	6.15E-03							2.77E-01	-	5	-	175	0.02	Yes
74-87-3	Methyl chloride (chloromethane)	Yes	Yes		4.10E-03	3.15E-03							7.25E-03	-	340	-	43748	5	No
75-09-2	Methylene chloride (Dichloromethane)	Yes	Yes	1.21E-02	3.84E-04	2.95E-04							1.28E-02	0.56	-	50	-	-	No
7439-98-7	Molybdenum	No	Yes					1.36E-04					1.36E-04	-	33	-	5250	0.6	No
91-20-3	Naphthalene	Yes	Yes	1.38E-02	5.59E-04	4.30E-04	7.30E-07	7.55E-05			1.78E-04	2.44E-03	1.75E-02	-	170	-	22750	2.6	No
7440-02-0	Nickel	Yes	Yes	2.15E-03	2.91E-03	2.24E-03		2.60E-04					7.55E-03	0.0021	-	0.5	-	-	No
109-66-0	Pentane	No	Yes					3.22E-01					3.22E-01	-	6000	-	43748	5	No
108-95-2	Phenol	Yes	Yes	2.03E-01	8.19E-03	6.30E-03	2.27E-09						2.18E-01	-	63	-	10500	1.2	No
115-07-1	Propylene	Yes	No								5.42E-04	5.24E-02	5.29E-02	-	-	-	-	-	No
7784-49-2	Selenium	Yes	Yes	3.09E-03	1.63E-04	1.25E-04		2.97E-06	1.16E-05	6.77E-06			3.40E-03	-	0.67	-	175	0.02	No
7440-22-4	Silver	No	Yes						1.16E-06	6.77E-07			1.84E-06	-	0.33	-	175	0.02	No
7664-93-9 14808-79-8	Sulfuric acid and sulfates	No	Yes	3.16E+00	3.72E-02	1.88E-01							3.38E+00	-	3.3	-	175	0.02	Yes
108-88-3	Toluene	Yes	Yes	1.82E-04	7.74E-03	5.95E-03	1.88E-05	4.21E-04			8.59E-04	5.28E-03	2.04E-02	-	400	-	43748	5	No
7440-62-2	Vanadium	No	Yes					2.85E-04					2.85E-04	-	0.17	-	175	0.02	No
1330-20-7	Xylenes	Yes	Yes		8.78E-03	6.75E-03	2.89E-07				5.99E-04	3.62E-03	1.97E-02	-	1500	-	43748	5	No
Polyaromatic Hydrocarbon (PAH)		Yes	Yes											0.00048	-	**	-	-	No
PAH	Benzo(a)pyrene	No	Yes					1.49E-07			3.95E-07	4.82E-06	5.37E-06						
PAH	Benz(a)anthracene	No	Yes	1.27E-05	1.50E-07	1.15E-07		2.23E-07			3.53E-06	1.17E-05	2.84E-05						
PAH	Benzo(b)fluoranthene	No	Yes					2.23E-07			2.08E-07	2.08E-05	2.13E-05						
PAH	Chrysene	No	Yes					2.23E-07			7.41E-07	2.87E-05	2.97E-05						
PAH	Dibenzo(a,h)anthracene	No	Yes					1.49E-07			1.22E-06	6.50E-06	7.87E-06						
PAH	Indeno(1,2,3-cd)pyrene	No	Yes					2.23E-07			7.88E-07	7.77E-06	8.78E-06						
PAH	2-Methylnaphthalene	No	No					2.97E-06					2.97E-06						
PAH	3-Methylchloranthrene	No	No					2.23E-07					2.23E-07						
PAH	7,12-Dimethylbenz(a)anthracene	No	No					1.98E-06					1.98E-06						
PAH	Acenaphthene	No	No					2.23E-07			2.98E-06	8.79E-05	9.11E-05						
PAH	Acenaphthylene	No	No					2.23E-07			1.06E-05	1.73E-04	1.84E-04						
PAH	Anthracene	No	No					2.97E-07			3.93E-06	2.31E-05	2.73E-05						
PAH	Benzo(g,h,i)perylene	No	No					1.49E-07			1.03E-06	1.04E-05	1.16E-05						
PAH	Benzo(k)fluoranthene	No	No					2.23E-07			3.26E-07	4.09E-06	4.64E-06						
PAH	Fluoranthene	No	No					3.71E-07			1.60E-05	7.57E-05	9.20E-05						
PAH	Fluorene	No	No					3.47E-07			6.13E-05	2.40E-04	3.02E-04						
PAH	Phenanathrene	No	No					2.10E-06			6.17E-05	7.66E-04	8.30E-04						
PAH	Pyrene	No	No					6.19E-07			1.00E-05	6.97E-05	8.03E-05						
	Total federal HAPs			1.34E+00	9.50E-02	7.28E-02	1.23E-01	2.34E-01	5.24E-03	3.06E-03	8.68E-03	8.19E-02	1.96						
	Total Washington State TAPs			4.39E+01	1.32E-01	2.61E-01	1.52E-01	8.17E-01	5.59E-03	3.26E-03	7.97E-03	2.81E-02	45.32						

Notes:
(1) See following spreadsheets for more detailed emission calculations per source
(2) For the CAA112 requirements the combination of all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM), each individual PAH is not a HAP. For the Washington State requirements, the combination of the first 6 PAHs in the table is compared with the ASIL.
* Lead Class A ASIL 24-hour averaging time
** the ASIL is less than the threshold for use with the Small Quantity Emission Rate Exemption Levels
*** Listed as a Class B pollutant, but there is no Small Quantity Emission Rate Exemption Level

Energy Northwest
Fluor & URS Calculations
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PACIFIC MOUNTAIN ENERGY CENTER
HAPs EMISSION SUMMARY

CAS # or		Federally Listed Compound	Washington State	Annual Average HAP Emission (ton/yr)										Washington State ASIL (ug/m3)		Small Quantity Emission Rate Exemption Level			Washington State Class A Annual Modeling Required	Washington State Class B 24-Hour Modeling Required
MPCA #	Compound	HAP	TAP	CTGs	TVO	Flare	Fugitive	Auxiliary Boiler	Power Cooling Tower	Gas/ASU Cooling Tower	Emergency Fire Pump	Emergency Generator	Total	Class A	Class B	Class A lb/yr	Class B lb/yr	Class B lb/hr		
106-99-0	1,3-Butadiene	Yes	Yes								4.11E-06		4.11E-06	0.0036	-	0.5	-	-	No	No
75-07-0	Acetaldehyde	Yes	Yes	4.35E-02	1.58E-04	3.94E-04					8.05E-05	2.37E-05	4.42E-02	0.45	-	50	-	-	Yes	No
107-02-8	Acrolein	Yes	Yes								9.71E-06	7.40E-06	1.71E-05	-	0.02	-	175	0.02	No	No
7664-41-7	Ammonia	No	Yes	1.73E+02			1.26E-01						1.73E+02	-	100	-	17500	2	No	Yes
7440-36-0	Antimony	Yes	Yes	2.66E-02	2.63E-04	6.57E-04							2.75E-02	-	1.7	-	175	0.02	No	No
7440-38-2	Arsenic	Yes	Yes	5.80E-02	1.38E-03	3.46E-03		2.71E-05	2.54E-05	1.48E-05			6.29E-02	0.00023	-	**	-	-	Yes	No
7440-39-3	Barium	No	Yes					5.97E-04					5.97E-04	-	1.7	-	175	0.02	No	No
71-43-2	Benzene	Yes	Yes	5.80E-02	2.65E-02	6.61E-02	7.79E-04	2.85E-04			9.80E-05	7.28E-04	1.53E-01	0.12	-	20	-	-	Yes	No
7440-41-7	Beryllium	Yes	Yes	6.29E-03	7.88E-06	1.97E-05		1.63E-06					6.32E-03	0.00042	-	**	-	-	Yes	No
106-97-8	Butane	No	Yes					2.85E-01					2.85E-01	-	6300	-	43748	5	No	No
7440-43-9	Cadmium	Yes	Yes	2.32E-01	5.26E-05	1.31E-04		1.49E-04					2.32E-01	0.00056	-	**	-	-	Yes	No
75-15-0	Carbon disulfide	Yes	Yes	1.11E+00	4.03E-03	1.01E-02	4.16E-03						1.13E+00	-	100	-	17500	2	No	No
463581	Carbonyl sulfide	Yes	Yes				7.45E-03						7.45E-03	-	***	-	-	-	No	No
7782-50-5	Chlorine (Cl)	Yes	Yes						1.27E-02	7.41E-03			2.01E-02	-	5	-	175	0.02	No	No
18540-29-9	Chromium, (hexavalent)	Yes	Yes	3.70E-03	2.94E-04	7.36E-04		1.90E-04					4.92E-03	0.000083	-	**	-	-	Yes	No
7440-48-4	Cobalt	Yes	Yes	6.29E-03	1.12E-03	2.80E-03		1.14E-05					1.02E-02	-	0.17	-	175	0.02	No	No
7440-50-8	Copper	No	Yes					1.15E-04					1.15E-04	-	0.67	-	175	0.02	No	No
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	Yes	Yes	1.38E-01	4.38E-03	1.10E-02	1.22E-03						1.54E-01	-	17	-	1750	0.2	No	No
100-41-4	Ethyl benzene	Yes	Yes		2.96E-02	7.40E-02	6.87E-07						1.04E-01	-	160	-	22750	2.6	No	No
7782-41-4	Fluorine (F)	No	Yes						1.52E-03	8.89E-04			2.41E-03	-	5.3	-	175	0.02	No	No
50-00-0	Formaldehyde	Yes	Yes	4.11E-01	1.49E-03	3.72E-03	1.45E-07	1.02E-02			1.24E-04	7.41E-05	4.27E-01	0.077	-	20	-	-	Yes	No
110-54-3	Hexane	Yes	Yes				1.90E-07	2.44E-01					2.44E-01	-	200	-	22750	2.6	No	No
7647-01-0	Hydrochloric acid	Yes	Yes	3.14E-01	8.65E-04	2.16E-03	1.34E-02						3.31E-01	-	7	-	175	0.02	No	Yes
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	Yes	Yes	1.21E+00	5.26E-05	1.31E-04							1.21E+00	-	8.7	-	175	0.02	No	Yes
6/4/7783	Hydrogen sulfide	Yes	Yes				5.11E-01						5.11E-01	-	0.9	-	175	0.02	No	Yes
7439-92-1	Lead	Yes	Yes	1.35E-02	3.73E-05	9.32E-05			5.08E-06	2.96E-06			1.37E-02	0.5*	-	50	-	-	Yes	No
7439-96-5	Manganese	Yes	Yes	2.51E-02	2.22E-03	5.54E-03		5.15E-05	1.02E-02	5.93E-03			4.90E-02	-	0.4	-	175	0.02	No	No
7439-97-6	Mercury	Yes	Yes	2.90E-02	6.13E-04	1.53E-04		3.52E-05	2.54E-06	1.48E-06			2.98E-02	-	0.33	-	175	0.02	No	No
74-83-9	Methyl bromide (Bromomethane)	Yes	Yes	1.15E+00	1.08E-02	2.69E-02							1.19E+00	-	5	-	175	0.02	No	Yes
74-87-3	Methyl chloride (chloromethane)	Yes	Yes		5.52E-03	1.38E-02							1.93E-02	-	340	-	43748	5	No	No
75-09-2	Methylene chloride (Dichloromethane)	Yes	Yes	5.32E-02	5.17E-04	1.29E-03							5.50E-02	0.56	-	50	-	-	Yes	No
7439-98-7	Molybdenum	No	Yes					1.49E-04					1.49E-04	-	33	-	5250	0.6	No	No
91-20-3	Naphthalene	Yes	Yes	6.04E-02	7.53E-04	1.88E-03	3.20E-06	8.27E-05			8.90E-06	1.22E-04	6.33E-02	-	170	-	22750	2.6	No	No
7440-02-0	Nickel	Yes	Yes	9.43E-03	3.92E-03	9.79E-03		2.85E-04					2.34E-02	0.0021	-	0.5	-	-	Yes	No
109-66-0	Pentane	No	Yes					3.52E-01					3.52E-01	-	6000	-	43748	5	No	No
108-95-2	Phenol	Yes	Yes	8.90E-01	1.10E-02	2.76E-02	9.94E-09						9.28E-01	-	63	-	10500	1.2	No	No
115-07-1	Propylene	Yes	No								2.71E-05	2.62E-03	2.65E-03	-	-	-	-	-	No	No
7784-49-2	Selenium	Yes	Yes	1.35E-02	2.19E-04	5.48E-04		3.25E-06	5.08E-05	2.96E-05			1.44E-02	-	0.67	-	175	0.02	No	No
7440-22-4	Silver	No	Yes						5.08E-06	2.96E-06			8.04E-06	-	0.33	-	175	0.02	No	No
7664-93-9 14808-79-8	Sulfuric acid and sulfates	No	Yes	1.38E+01	5.01E-02	8.24E-01							1.47E+01	-	3.3	-	175	0.02	No	Yes
108-88-3	Toluene	Yes	Yes	7.98E-04	1.04E-02	2.61E-02	8.22E-05	4.61E-04			4.29E-05	2.64E-04	3.81E-02	-	400	-	43748	5	No	No
7440-62-2	Vanadium	No	Yes					3.12E-04					3.12E-04	-	0.17	-	175	0.02	No	No
1330-20-7	Xylenes	Yes	Yes		1.18E-02	2.96E-02	1.27E-06				2.99E-05	1.81E-04	4.16E-02	-	1500	-	43748	5	No	No
Polyaromatic Hydrocarbon (PAH)		Yes	Yes											0.00048	-	**	-	-	Yes	No
PAH	Benzo(a)pyrene	No	Yes					1.63E-07			1.97E-08	2.41E-07	4.24E-07							
PAH	Benz(a)anthracene	No	Yes	5.56E-05	2.01E-07	5.04E-07		2.44E-07			1.76E-07	5.84E-07	5.73E-05							
PAH	Benzo(b)fluoranthene	No	Yes					2.44E-07			1.04E-08	1.04E-06	1.30E-06							
PAH	Chrysene	No	Yes					2.44E-07			3.71E-08	1.44E-06	1.72E-06							
PAH	Dibenzo(a,h)anthracene	No	Yes					1.63E-07			6.12E-08	3.25E-07	5.49E-07							
PAH	Indeno(1,2,3-cd)pyrene	No	Yes					2.44E-07			3.94E-08	3.89E-07	6.72E-07							
PAH	2-Methylnaphthalene	No	No					3.25E-06					3.25E-06							
PAH	3-Methylchloranthrene	No	No					2.44E-07					2.44E-07							
PAH	7,12-Dimethylbenz(a)anthracene	No	No					2.17E-06					2.17E-06							
PAH	Acenaphthene	No	No					2.44E-07			1.49E-07	4.39E-06	4.79E-06							
PAH	Acenaphthylene	No	No					2.44E-07			5.31E-07	8.66E-06	9.44E-06							
PAH	Anthracene	No	No					3.25E-07			1.96E-07	1.15E-06	1.68E-06							
PAH	Benzo(g,h,i)perylene	No	No					1.63E-07			5.13E-08	5.22E-07	7.36E-07							
PAH	Benzo(k)fluoranthene	No	No					2.44E-07			1.63E-08	2.05E-07	4.65E-07							
PAH	Fluoranthene	No	No					4.07E-07			7.99E-07	3.78E-06	4.99E-06							
PAH	Fluorene	No	No					3.80E-07			3.07E-06	1.20E-05	1.55E-05							
PAH	Phenanathrene	No	No					2.30E-06			3.09E-06	3.83E-05	4.37E-05							
PAH	Pyrene	No	No					6.78E-07			5.02E-07	3.48E-06	4.66E-06							
	Total federal HAPs			5.87E+00	1.28E-01	3.19E-01	5.38E-01	2.56E-01	2.29E-02	1.34E-02	4.34E-04	4.10E-03	7.15							
	Total Washington State TAPs			1.92E+02	1.78E-01	1.14E+00	6.64E-01	8.94E-01	2.45E-02	1.43E-02	3.98E-04	1.40E-03	195.28							

Notes:
(1) See following spreadsheets for more detailed emission calculations per source
(2) For the CAA112 requirements the combination of all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM), each individual PAH is not a HAP. For the Washington State requirements, the combination of the first 6 PAHs in the table is compared with the ASIL.
* Lead Class A ASIL 24-hour averaging time
** the ASIL is less than the threshold for use with the Small Quantity Emission Rate Exemption Levels
*** Listed as a Class B pollutant, but there is no Small Quantity Emission Rate Exemption Level

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COMBUSTION TURBINE HAPs EMISSION SUMMARY

Plant Performance

Syngas fuel 2100 x 10^6 Btu/hr/CTG, HHV
Assumed Coal conversion efficency **0.76** (PRB coal)
Gasifiers coal feed, total both CTGs 5520 x 10^6 Btu/hr, HHV (total for two gasifiers)

CAS # or MPCA #	Compound	Emission Factor (lb/10^{12} Btu coal)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	0.010	0.044	NETL, Table 2-17 (see Reference 1)
7440-36-0	Antimony (1)	1.1	0.0061	0.027	Wabash River test data
7440-38-2	Arsenic (1)	2.4	0.0132	0.058	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	0.000013	5.6E-05	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	2.4	0.013	0.058	Wabash River test data
7440-41-7	Beryllium (1)	0.26	0.0014	0.006	Wabash River test data
7440-43-9	Cadmium (1)	9.6	0.05	0.232	Wabash River test data
75-15-0	Carbon disulfide	46	0.25	1.112	NETL, Table 2-17 (see Reference 1)
0-00-5	Chromium, total (1)	0.51	0.0028	0.012	Wabash River test data
18540-29-9	Chromium, (hexavalent)	0.15	0.00084	0.004	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total
7440-48-4	Cobalt (1)	0.26	0.0014	0.006	Wabash River test data
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	5.7	0.031	0.138	NETL, Table 2-6 (see Reference 1)
50-00-0	Formaldehyde	17	0.09	0.411	NETL, Table 2-17 (see Reference 1)
7647-01-0	Hydrochloric acid	13	0.072	0.314	Wabash River test data
7664-39-3	Hydrogen fluoride (Hydrofluoric acid) (3)	50	0.28	1.209	NETL, Table 2-5 (see Reference 1)
7439-92-1	Lead (1)	0.56	0.0031	0.014	Wabash River test data
7439-96-5	Manganese (1)	1.0	0.0057	0.025	Wabash River test data
7439-97-6	Mercury (1)	1.2	0.0066	0.029	(See Note 2)
74-83-9	Methyl bromide (Bromomethane)	47.7	0.26	1.153	Wabash River test data
75-09-2	Methylene chloride (Dichloromethane)	2.2	0.012	0.053	Wabash River test data
91-20-3	Naphthalene	2.5	0.014	0.060	Wabash River test data
7440-02-0	Nickel (1)	0.39	0.0022	0.009	Wabash River test data
108-95-2	Phenol	36.8	0.20	0.890	Wabash River test data
7784-49-2	Selenium (1)	0.56	0.0031	0.014	Wabash River test data
7664-93-9 14808-79-8	Sulfuric acid and sulfates	572	3.2	13.830	(See Note 4)
108-88-3	Toluene	0.033	0.00018	0.001	NETL, Table 2-17 (see Reference 1)
7664-41-7	Ammonia (5)	7141	39.42	172.66	5 ppmv ammonia slip from the SCR

Notes:
(1) Wabash factors for HAP metals and HCl are adjusted assumed worst-case PMEC feed composition.
(2) Mercury factor based on 90% overall removal for PRB coal feed.
Worst case mercury feed (PRB) = 0.14 ppmwd Hg and approx 12,000 Btu/lb HHV, dry: Hg = 0.14 lb/10^6 lb x 1 lb/12,000 Btu x 0.1 x 10^{12}
= 1.2 lb Hg/10^12 Btu coal
(3) Hydrofluoric acid is estimated using fraction of total feed fluorine measured in the LGTI combustion turbine stacks, as reported in Reference 1, and the highest expected concentration of fluorine in the PMEC feed steams.
(4) Sulfuric acid calculated asuming 7% of SOx in HRSG exhaust converts to SO3 which reacts with water to form H2SO4.
Assuming 10 ppmvd total sulfur in fuel, 240 Btu/ft3 HHV, and 0.76 coal energy conversion to syngas,
Sulfuric acid = 0.07 x 10/10^6 x 1 ft3/240 Btu x 98 lb/380 ft3 x 0.76 x 10^{12} = 572 lb/10^12 Btu coal
(5) Ammonia slip from the SCR (5 ppmvd (@ 15% O2) - provided by Fluor - see Criteria Pollutant emission spreadsheet for details

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy,*Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.

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TANK VENT OXIDIZER HAPs EMISSION SUMMARY

Syngas fuel consumption rates 65 x 10^6 Btu/hr, HHV (max, use for short-term emission calculation)
20 x 10^6 Btu/hr, HHV (avg, use for annual emission calculation)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (1)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	1.2E-04	1.6E-04	NETL, Table 2-17 (see Reference 1)
7440-36-0	Antimony	3.0	2.0E-04	2.6E-04	Wabash River test data
7440-38-2	Arsenic	15.8	1.0E-03	1.4E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	1.5E-07	2.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	302	2.0E-02	2.6E-02	Wabash River test data
7440-41-7	Beryllium	0.09	5.9E-06	7.9E-06	NETL, Table 2-11 (see Reference 1)
7440-43-9	Cadmium	0.60	3.9E-05	5.3E-05	Wabash River test data
75-15-0	Carbon disulfide	46	3.0E-03	4.0E-03	NETL, Table 2-17 (see Reference 1)
0-00-5	Chromium, total	11.2	7.3E-04	9.8E-04	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.4	2.2E-04	2.9E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total
7440-48-4	Cobalt	12.8	8.3E-04	1.1E-03	Wabash River test data
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	50	3.3E-03	4.4E-03	Wabash River test data
100-41-4	Ethyl benzene	338	2.2E-02	3.0E-02	Wabash River test data
50-00-0	Formaldehyde	17	1.1E-03	1.5E-03	NETL, Table 2-17 (see Reference 1)
7647-01-0	Hydrochloric acid	9.9	6.4E-04	8.7E-04	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	0.6	3.9E-05	5.3E-05	NETL, Table 2-5 (see Reference 1)
7439-92-1	Lead	0.43	2.8E-05	3.7E-05	Wabash River test data (for syngas)
7439-96-5	Manganese	25.3	1.6E-03	2.2E-03	Wabash River test data
7439-97-6	Mercury	7.0	4.6E-04	6.1E-04	Wabash River test data
74-83-9	Methyl bromide (Bromomethane)	123	8.0E-03	1.1E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	63	4.1E-03	5.5E-03	Wabash River test data
75-09-2	Methylene chloride (Dichloromethane)	5.9	3.8E-04	5.2E-04	Wabash River test data
91-20-3	Naphthalene	8.6	5.6E-04	7.5E-04	Wabash River test data
7440-02-0	Nickel	44.7	2.9E-03	3.9E-03	Wabash River test data
108-95-2	Phenol	126	8.2E-03	1.1E-02	Wabash River test data
7784-49-2	Selenium	2.5	1.6E-04	2.2E-04	Wabash River test data
7664-93-9 14808-79-8	Sulfuric acid and sulfates	572	3.7E-02	5.0E-02	(See Note 2)
108-88-3	Toluene	119	7.7E-03	1.0E-02	Wabash River test data
1330-20-7	Xylenes	135	8.8E-03	1.2E-02	Wabash River test data

Notes:
(1) Hydrofluoric acid is estimated using the fraction of total feed fluorine measured in the LGTI incinerator stack, as reported in Reference 2, and the highest expected concentrations of fluorine in the Mesaba feed steams.
(2) Sulfuric acid and sulfates calculated using same emission factor as CTGs.

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.

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FLARE HAPs EMISSION SUMMARY

Syngas combustion rates 50 x 10^6 Btu/hr, HHV (annual average) (1)

CAS # or MPCA #	Compound	Emission Factor ($lb/10^{12}$ Btu syngas) (2)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)	Emission Factor Source
75-07-0	Acetaldehyde	1.8	9.0E-05	3.9E-04	NETL, Table 2-17 (see Reference 1)
7440-36-0	Antimony	3.0	1.5E-04	6.6E-04	Wabash River test data
7440-38-2	Arsenic	15.8	7.9E-04	3.5E-03	Wabash River test data
56-55-3	Benz[a]anthracene	0.0023	1.2E-07	5.0E-07	NETL, Table 2-17 (see Reference 1)
71-43-2	Benzene	302	1.5E-02	6.6E-02	Wabash River test data
7440-41-7	Beryllium	0.09	4.5E-06	2.0E-05	NETL, Table 2-11 (see Reference 1)
7440-43-9	Cadmium	0.60	3.0E-05	1.3E-04	Wabash River test data
75-15-0	Carbon disulfide	46	2.3E-03	1.0E-02	NETL, Table 2-17 (see Reference 1)
0-00-5	Chromium, total	11.2	5.6E-04	2.5E-03	Wabash River test data
18540-29-9	Chromium, (hexavalent)	3.4	1.7E-04	7.4E-04	Portion of total chromium emitted in +6 valenece state, assumed to be 30% of total
7440-48-4	Cobalt	12.8	6.4E-04	2.8E-03	Wabash River test data
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	50	2.5E-03	1.1E-02	Wabash River test data
100-41-4	Ethyl benzene	338	1.7E-02	7.4E-02	Wabash River test data
50-00-0	Formaldehyde	17	8.5E-04	3.7E-03	NETL, Table 2-17 (see Reference 1)
7647-01-0	Hydrochloric acid	9.9	4.9E-04	2.2E-03	Wabash River test data (for syngas)
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	0.6	3.0E-05	1.3E-04	NETL, Table 2-5 (see Reference 1)
7439-92-1	Lead	0.43	2.1E-05	9.3E-05	Wabash River test data (for syngas)
7439-96-5	Manganese	25.3	1.3E-03	5.5E-03	Wabash River test data
7439-97-6	Mercury (3)	0.7	3.5E-05	1.5E-04	Wabash River test data, reduced by 90%
74-83-9	Methyl bromide (Bromomethane)	123	6.2E-03	2.7E-02	Wabash River test data
74-87-3	Methyl chloride (Chloromethane)	63	3.2E-03	1.4E-02	Wabash River test data
75-09-2	Methylene chloride (Dichloromethane)	5.9	3.0E-04	1.3E-03	Wabash River test data
91-20-3	Naphthalene	8.6	4.3E-04	1.9E-03	Wabash River test data
7440-02-0	Nickel	44.7	2.2E-03	9.8E-03	Wabash River test data
108-95-2	Phenol	126	6.3E-03	2.8E-02	Wabash River test data
7784-49-2	Selenium	2.5	1.3E-04	5.5E-04	Wabash River test data
7664-93-9 14808-79-8	Sulfuric acid and sulfates	3,761	1.9E-01	8.2E-01	(See Note 4)
108-88-3	Toluene	119	6.0E-03	2.6E-02	Wabash River test data
1330-20-7	Xylenes	135	6.8E-03	3.0E-02	Wabash River test data

Notes:
(1) Combustion rates shown are for normal operations, which includes plant startups
(2) No Wabash River emission test data are available for the flare. HAPs emissions are estimated using the same emission factors as the tank vent oxid and the assumed syngas combustion rate in the flare. The notes for the tank vent oxidizer HAPs emission summary also apply to the flare.
(3) Mercury emission factor based on the TVO factor reduced by 90 %, since most gas routed to the flare will flow through the normal syngas treating sy including the activated carbon beds for mercury removal.
(4) Sulfuric acid calculated asuming 7% of SOx in combustion products converts to SO3 which reacts with water to form H2SO4.
Assuming 50 ppmvd total sulfur in flared gas and about 240 Btu/ft3 HHV,
Sulfuric acid = 0.07 x $50/10^6$ x 1 ft3/240 Btu x 98 lb/380 ft3 x 10^{12} = 3761 lb/10^12 Btu

References:
(1) NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002.

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HAPs Metals Emission Factor Adjustment for Treated Syngas

Element	Wabash Actual Feed Conc, mg/kg (1)	Wabash HAP Actual Feed Conc lb/10^12 Btu coal	Wabash Measured Syngas HAP Emission Factor lb/10^12 Btu coal (2)	Fraction of Feed HAP in Wabash Product Syngas (3)	PMEC Worst Case Feed Conc, mg/kg (4)	PMEC Worst Case Feed Conc, Conc lb/10^12 Btu coal	PMEC Worst Case HAP Emission Factor for Syngas lb/10^12 Btu coal (5)
Antimony	3.5	292	1.1	0.0038	3.5	292	1.1
Arsenic	7.6	633	2.4	0.0038	7.6	633	2.4
Beryllium	1.8	150	0.26	0.0017	1.8	150	0.26
Cadmium	0.3	25	9.6	0.3840	0.3	25	9.6
Chromium	5.6	467	0.41	0.00088	7.0	583	0.51
Cobalt	7.3	608	0.26	0.00043	7.3	608	0.26
Lead	17.3	1442	0.56	0.00039	17.3	1442	0.56
Manganese	12.3	1025	0.43	0.00042	30	2500	1.0
Mercury	**(90% O/A removal, see calc below)**				0.14	11.7	1.2
Nickel	370	30833	0.39	0.000013	370	30833	0.39
Selenium	3.0	250	0.56	0.0022	3.0	250	0.56
Chlorides	100	8333	2.6	0.00031	500	41667	13.0

Notes:
(1) Estimated composition of Wabash River feed based on the larger of either feed coal composition data reported to U.S. DOE or petcoke data provided by CoP.
(2) Calculated from reported HAPs concentration measurements in Wabash River product syngas during various test programs from 1997 to 2005.
(3) Ratio of syngas concentration to feed concentration.
(4) Highest expected PMEC feed concentration based on Fluor data for PRB coal and limited data for U.S petcoke *(to be confirmed)*.
(5) Predicted emission factor for PMEC product syngas using HAPs fraction in syngas from Wabash River test program.

Assumption: Solid feed nominal heating value = 12,000 Btu/lb, dry HHV

Example calcs:
<u>HAPs in feed</u>
Cr = 5.6 mg/kg = 5.6 x 10^{-3} g Cr/10^{3} g dry feed x 1 lb/12,000 Btu x 10^{12} = 467 lb/10^12 Btu
<u>Fractrion in syngas</u>
Fraction Cr in syngas = 0.41 lb/10^{12} Btu/(467 lb/10^{12} Btu) = 0.00088
<u>PMEC HAPs emission factor</u>
Predicted Cr emission factor for PMEC syngas = 0.00088 x 583 lb/10^{12} Btu = 0.51 lb/10^12 Btu
<u>Mercury</u>
Mercury based on PRB feed, 0.14 ppmwd avg Hg
Hg = (0.10) x 0.14 lb/10^{6} lb /(12,000 Btu/lb) x 10^{12} = 1.2 lb/10^12 Btu

FUGITVE HAPs EMISSION SUMMARY

(Typical Two-train 600 MW E-Gas IGCC)

Process Stream [1]		Raw Syngas			SourSyngas			Product Syngas			Acid Gas			SRU and Tail Gas			Sour CO2 gas		
Total process fluid leak rate, lb/hr[2]		1.1			0.72			0.24			0.28			1.5			0.084		
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr
	Federal HAPs																		
71-43-2	Benzene	95	A	0.0001	95	A	0.0001	20	A	4.9E-06									
75-15-0	Carbon disulfide	575	A	0.0006	439	A	0.0003	2.7	A	6.5E-07									
463581	Carbonyl sulfide	1,300	B	0.001	83	B	0.00006	4.8	B	0.000001	700	B	1.9E-04				30.0	B	0.000003
100-41-4	Ethyl benzene	0.076	A	8.38E-08	0.076	A	5.46E-08	0.076	A	1.843E-08									
50-00-0	Formaldehyde	0.016	A	1.76E-08	0.016	A	1.15E-08	0.016	A	3.881E-09									
110-54-3	Hexane	0.021	A	2.3E-08	0.021	A	1.5E-08	0.021	A	5.1E-09									
7647-01-0	Hydrochloric acid	0.017	A	1.9E-08	0.017	A	1.2E-08	0.017	A	4.1E-09									
74-90-8	Hydrogen cyanide	83	B	0.00009	83	B	0.00006	0	B	0							1,000	B	0.0001
91-20-3	Naphthalene	0.4	A	4.4E-07	0.4	A	2.9E-07	0.008	A	1.9E-09									
108-95-2	Phenol	0.0011	A	1.2E-09	0.0011	A	7.9E-10	0.0011	A	2.7E-10									
108-88-3	Toluene	10.3	A	0.00001	10.3	A	7.4E-06	0.066	A	1.6E-08									
1330-20-7	Xylenes	0.14	A	1.54E-07	0.14	A	1.01E-07	0.14	A	3.396E-08									
	Total Federal HAPs			0.002			0.001			6.8E-06			0			0			0.0001
	Other																		
7664-41-7	Ammonia	4,000	B	0.004	6.5	B	4.7E-06	0	B	0.0E+00							74,000	B	0.006
7783-06-4	Hydrogen sulfide[6]	15,000	B	0.01	18,000	B	0.01	50	B	5.6E-06	460,000	B	0.06	58,000	B	0.04	27,000	B	0.001
	AGR solvent																		
	VOC[4]			0.002			0.001			6.7E-06			1.9E-04			0.000			0.000
	TRS[5]			0.01			0.01			7.4E-06			0.06			0.04			0.00

Process Stream		Rich AGR solvent			Lean AGR solvent			Sour Water			Stripped Sour Water			Recoverd Oil			Total Estimated Gaseous Fugitive Emissions		
Total process fluid leak rate, lb/hr[2]		0.32			0.65			0.60			0.14			0.11					
CAS # or MPCA #	Compound	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr	Emission factor ppm(wt)	Basis[3]	Emission lb/hr		lb/hr	ton/yr
	Federal HAPs																		
71-43-2	Benzene																	0.00018	0.00078
75-15-0	Carbon disulfide																	0.0010	0.0042
463581	Carbonyl sulfide	25	B	7.9E-06				2	B	1.2E-06								0.0017	0.0074
100-41-4	Ethyl benzene																	1.6E-07	6.9E-07
50-00-0	Formaldehyde																	3.3E-08	1.4E-07
110-54-3	Hexane																	4.3E-08	1.9E-07
7647-01-0	Hydrochloric acid							4000	B	0.002	4700	B	0.001					0.0031	0.013
74-90-8	Hydrogen cyanide							70	B	0.00004								0.00028	0.0012
91-20-3	Naphthalene																	7.3E-07	3.2E-06
108-95-2	Phenol																	2.3E-09	9.9E-09
108-88-3	Toluene																	1.9E-05	8.2E-05
1330-20-7	Xylenes																	2.9E-07	1.3E-06
	Total Federal HAPs			0			0			0.002			0.001			0		***0.0062***	***0.027***
	Other																		
7664-41-7	Ammonia			0			0	30,000	B	0.02	300	B	0.0000			0		0.029	0.13
7783-06-4	Hydrogen sulfide[6]	20,000	B	0.00	350	B	0.0001	1,500	B	0.0004			0			0		0.12	0.5
	AGR solvent	500,000	B	0.2	500,000	B	0.3			0			0			0		0.48	2.1
	VOC[4]			0.158			0.323			0.000			0.000	1E+06	B	0.11		0.59	2.6
	TRS[5]			0.00			0			0.0004			0			0		0.12	0.5

[1]Process stream descriptions for fugitive emission estimates:

Stream	Description	Stream	Description
Raw syngas	Gasifier outlet to COS hyrolysis reactor outlet	Rich AGR solvent	H2S/CO2-laden solvent from absorber to acid gas stripper
Sour syngas	Hydrolysis reactor outlet to AGR/AGE absorbers overhead	Lean AGR solvent	Regenerated solvent from stripper to absorber (incl storage)
Product syngas	AGR/AGE to CTGs	Sour water	Sour water from various sources to sour water stripper
Acid gas	Acid gas stripper overhead to SRU inlet	Stripped SW	Stripper bottoms to slurry recycle and ZLD
SRU and tail gas	SRU inlet through tail gas recycle to gasifier	Recovered oil	Oil recovered from drainage oily water separator
Sour CO2 gas	Sour water degassing column to AGR		

[2]Estimated fugitive emission quantities for the total process stream components based on U.S. EPA average emission factors (see next page). This value is multiplied by each component concentration. to determine the individual component emission rates. ***Example:*** Benzene fugitive emission from raw syngas = 1.1 lb/hr x 95 lb/10^6 lb = 0.00010 lb/hr.

[3]Basis for emission factors; "A" denotes test results from the Wabash River gasification facility, "B" denotes calculated from the ConocoPhillips/Fluor material balance.

[4]Volatile organic compounds (VOC) include AGR solvent, benzene, carbon disulfide, carbonyl sulfide, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, and xylenes.

[5]Total reduced sulfur (TRS) includes carbon disulfide, carbonyl sulfide, and hydrogen sulfide.

FUGITVE HAPs EMISSION SUMMARY

(Typical Two-train 600 MW E-Gas IGCC)

[6]Hydrogen sulfide emissions estimated to be 46% of component count emission estimate, good engineering will ensure this emission level is met.

Fugitve Emission Sources Estimates[1]

	Gas		Light Liquid		Heavy Liquid			Sample
Process Stream	**Valves**	**Comp seals**	**Valves**	**Pumps**	**Valves**	**Pumps**	**Connectors**	**Connects**
Raw syngas	510						500	1
Sour syngas	230	4					230	1
Product syngas	80						100	2
Acid gas	120						100	1
SRU and tail gas	480	9					560	
Sour CO2 gas	40						40	
Rich AGR solvent					350		340	
Lean AGR solvent					330	19	290	
Sour water					240	21	200	
Stripped sour water					120	2	100	
Recovered oil					30	4	40	
Totals	**1460**	**13**	**0**	**0**	**1070**	**46**	**2500**	**5**

Total Fugitive Emission Rates[2]

	Gas		Light Liquid		Heavy Liquid			Sample	
	Valves	**Comp seals**	**Valves**	**Pumps**	**Valves**	**Pumps**	**Connectors**	**Connects**	
Emission factor lb.hr/source	**0.0017**	**0.0502**	**0.00142**	**0.00438**	**0.00051**	**0.019**	**0.000403**	**0.033**	**Total**
Process Stream	**Estimated emission rate, lb/hr**								
Raw syngas	0.87						0.20	0.03	1.10
Sour syngas	0.39	0.20					0.09	0.03	0.72
Product syngas	0.14						0.04	0.07	0.24
Acid gas	0.20						0.04	0.03	0.28
SRU and tail gas	0.82	0.45					0.23		1.49
Sour CO2 gas	0.07						0.02		0.08
Rich MDEA					0.18		0.14		0.32
Lean MDEA					0.17	0.36	0.12		0.65
Sour water					0.12	0.40	0.08		0.60
Stripped sour water					0.06	0.04	0.04		0.14
Recovered oil					0.02	0.08	0.02		0.11

[1]Emission source estimates based on conceptual equipment inventory and an estimate from piping and instrumentation diagrams (P&IDs) for a typical 600 MW E-Gas IGCC project. An allowance is added to account for valves and other components not shown on the P&IDs.
[2]Estimated emission rates for all components (including non-VOC and non-HAPs) in each process stream, based on *Protocol for Equipment Leak Estimates,* U.S EPA 453-R95-017, November 1995, Table 2-1. These factors are adjusted by the 90% emission control for light liquid pumps and compressors shown on Table 5-1 plus the control efficiencies shown on Table 5-2 for monthly monitoring of gas and light liquid valves and connectors.

Energy Northwest
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AUXILIARY BOILER HAPs EMISSION SUMMARY

Natural gas fuel consumption rates 130 10^6 Btu/hr, HHV
1050 Btu/scf
0.124 10^6 scf/hr

CAS #	Compound	Federally Listed Compound HAP	Washington State TAP	PAH	Emission Factor (lb/10° scf)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
7440-38-2	Arsenic	Yes	Yes	No	2.00E-04	2.48E-05	2.7E-05
7440-39-3	Barium	No	Yes	No	4.40E-03	5.45E-04	6.0E-04
71-43-2	Benzene	Yes	Yes	No	2.10E-03	2.60E-04	2.8E-04
7440-41-7	Beryllium	Yes	Yes	No	1.20E-05	1.49E-06	1.6E-06
106-97-8	Butane	No	Yes	No	2.10E+00	2.60E-01	2.8E-01
7440-43-9	Cadmium	Yes	Yes	No	1.10E-03	1.36E-04	1.5E-04
7440-47-3	Chromium	Yes	Yes	No	1.40E-03	1.73E-04	1.9E-04
7440-48-4	Cobalt	Yes	Yes	No	8.40E-05	1.04E-05	1.1E-05
7440-50-8	Copper	No	Yes	No	8.50E-04	1.05E-04	1.2E-04
50-00-0	Formaldehyde	Yes	Yes	No	7.50E-02	9.29E-03	1.0E-02
110-54-3	Hexane	Yes	Yes	No	1.80E+00	2.23E-01	2.4E-01
7439-96-5	Manganese	Yes	Yes	No	3.80E-04	4.70E-05	5.2E-05
7439-97-6	Mercury	Yes	Yes	No	2.60E-04	3.22E-05	3.5E-05
7439-98-7	Molybdenum	No	Yes	No	1.10E-03	1.36E-04	1.5E-04
91-20-3	Naphthalene	Yes	Yes	No	6.10E-04	7.55E-05	8.3E-05
7440-02-0	Nickel	Yes	Yes	No	2.10E-03	2.60E-04	2.8E-04
109-66-0	Pentane	No	Yes	No	2.60E+00	3.22E-01	3.5E-01
7782-49-2	Selenium	Yes	Yes	No	2.40E-05	2.97E-06	3.3E-06
108-88-3	Toluene	Yes	Yes	No	3.40E-03	4.21E-04	4.6E-04
7440-62-2	Vanadium	No	Yes	No	2.30E-03	2.85E-04	3.1E-04
PAH	Benzo(a)pyrene	No	Yes	Yes	1.20E-06	1.49E-07	1.6E-07
PAH	Benz(a)anthracene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Benzo(b)fluoranthene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Chrysene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Dibenzo(a,h)anthracene	No	Yes	Yes	1.20E-06	1.49E-07	1.6E-07
PAH	Indeno(1,2,3-cd)pyrene	No	Yes	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	2-Methylnaphthalene	No	No	Yes	2.40E-05	2.97E-06	3.3E-06
PAH	3-Methylchloranthrene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	7,12-Dimethylbenz(a)anthracene	No	No	Yes	1.60E-05	1.98E-06	2.2E-06
PAH	Acenaphthene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Acenaphthylene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Anthracene	No	No	Yes	2.40E-06	2.97E-07	3.3E-07
PAH	Benzo(g,h,i)perylene	No	No	Yes	1.20E-06	1.49E-07	1.6E-07
PAH	Benzo(k)fluoranthene	No	No	Yes	1.80E-06	2.23E-07	2.4E-07
PAH	Fluoranthene	No	No	Yes	3.00E-06	3.71E-07	4.1E-07
PAH	Fluorene	No	No	Yes	2.80E-06	3.47E-07	3.8E-07
PAH	Phenanathrene	No	No	Yes	1.70E-05	2.10E-06	2.3E-06
PAH	Pyrene	No	No	Yes	5.00E-06	6.19E-07	6.8E-07

Notes:
1) Emission factor source EPA AP-42 Section 1.4
2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than
0.25 x 8760 hr/yr x 130 million Btu/hr = 285 billion Btu/yr)
3) Washington State PAHs determined by WAC 173-460-50
4) For the CAA112 requirements all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)

Energy Northwest
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COOLING TOWER HAPs EMISSION RATE

Basis: Similar equipment from previous project.

Cooling Tower Operating Data and Emission Calculation					
Parameter			**Power Block**	**Gasification/ ASU**	**Basis**
Heat rejected, million Btu/hr			1740	1015	Typical plant performance
Cooling water (CW) circulation rate, million lb/hr			116	68	Typical cooling tower design
Max CW dissolved solids, ppmw			2400	2400	TDS of water supply and 12 cycles of concentration
Drift, fraction of circulating CW			0.0010%	0.0010%	Typical supplier guarantee

Example calculation:
Maximum expected total dissolved solids (TDS) in makeup water = 200 parts per million by weight (ppmw)
Maximum expected TDS in circulating cooling water at twelve cycles of concentration = 12 x 200 = 2400 ppmw
TAP emission rate (Power block) = (116 x 10^6 lb/hr) x (0.00001 drift) x (ppmw/10^6)

Power Block Cooling Tower

CAS #	Compound	Federal	Washington State	Emission Factor	Short-term Emission	Annual Emission	Notes
		HAP	TAP	ppmw	(lb/hr)	(ton/yr)	
7440-38-2	Arsenic	Yes	Yes	0.005	5.80E-06	2.54E-05	
7782-50-5	Chlorine (Cl)	Yes	Yes	2.5	2.90E-03	1.27E-02	ppmw value shown is one-half stated detection limit
7782-41-4	Fluorine (F)	No	Yes	0.3	3.48E-04	1.52E-03	ppmw value shown is one-half stated detection limit
7439-92-1	Lead	Yes	Yes	0.001	1.16E-06	5.08E-06	ppmw value shown is one-half stated detection limit
7439-96-5	Manganese (Mn)	Yes	Yes	2	2.32E-03	1.02E-02	
7439-97-6	Mercury	Yes	Yes	0.0005	5.80E-07	2.54E-06	ppmw value shown is one-half stated detection limit
7784-49-2	Selenium	Yes	Yes	0.01	1.16E-05	5.08E-05	ppmw value shown is one-half stated detection limit
7440-22-4	Silver	No	Yes	0.001	1.16E-06	5.08E-06	ppmw value shown is one-half stated detection limit

Gasification/ASU Cooling Tower

CAS #	Compound	Federal	Washington State	Emission Factor	Short-term Emission	Annual Emission	Notes
		HAP	TAP	ppmw	(lb/hr)	(ton/yr)	
7440-38-2	Arsenic	Yes	Yes	0.005	3.38E-06	1.48E-05	
7782-50-5	Chlorine (Cl)	Yes	Yes	2.5	1.69E-03	7.41E-03	ppmw value shown is one-half stated detection limit
7782-41-4	Fluorine (F)	No	Yes	0.3	2.03E-04	8.89E-04	ppmw value shown is one-half stated detection limit
7439-92-1	Lead	Yes	Yes	0.001	6.77E-07	2.96E-06	ppmw value shown is one-half stated detection limit
7439-96-5	Manganese (Mn)	Yes	Yes	2	1.35E-03	5.93E-03	
7439-97-6	Mercury	Yes	Yes	0.0005	3.38E-07	1.48E-06	ppmw value shown is one-half stated detection limit
7784-49-2	Selenium	Yes	Yes	0.01	6.77E-06	2.96E-05	ppmw value shown is one-half stated detection limit
7440-22-4	Silver	No	Yes	0.001	6.77E-07	2.96E-06	ppmw value shown is one-half stated detection limit

Notes:
1) Raw Water Analysis: Primary data from Kalama well water samples taken between 01/19/06 and 01/25/06 (3 samples) and analyzed between 1/23/06 and 02/07/06.

Energy Northwest
URS Calculations
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EMERGENCY DIESEL ENGINES HAPs EMISSION RATES

1 Emergency Fire Water Pump Engine

300 hp
7000 Btu/hp-hr

CAS #	Compound	Federally Listed Compound HAP	Washington State TAP	PAH	Emission Factor (lb/10^6 Btu)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
106-99-0	1,3-Butadiene	Yes	Yes	No	3.91E-05	8.21E-05	4.11E-06
75-07-0	Acetaldehyde	Yes	Yes	No	7.67E-04	1.61E-03	8.05E-05
107-02-8	Acrolein	Yes	Yes	No	9.25E-05	1.94E-04	9.71E-06
71-43-2	Benzene	Yes	Yes	No	9.33E-04	1.96E-03	9.80E-05
50-00-0	Formaldehyde	Yes	Yes	No	1.18E-03	2.48E-03	1.24E-04
91-20-3	Naphthalene	Yes	Yes	No	8.48E-05	1.78E-04	8.90E-06
115-07-1	Propylene	Yes	No	No	2.58E-04	5.42E-04	2.71E-05
108-88-3	Toluene	Yes	Yes	No	4.09E-04	8.59E-04	4.29E-05
1330-20-7	Xylenes	Yes	Yes	No	2.85E-04	5.99E-04	2.99E-05
PAH	Benzo(a)pyrene	No	Yes	Yes	1.88E-07	3.95E-07	1.97E-08
PAH	Benzo(a)anthracene	No	Yes	Yes	1.68E-06	3.53E-06	1.76E-07
PAH	Benzo(b)fluoranthene	No	Yes	Yes	9.91E-08	2.08E-07	1.04E-08
PAH	Chrysene	No	Yes	Yes	3.53E-07	7.41E-07	3.71E-08
PAH	Dibenz(a,h)anthracene	No	Yes	Yes	5.83E-07	1.22E-06	6.12E-08
PAH	Indeno(1,2,3-cd)pyrene	No	Yes	Yes	3.75E-07	7.88E-07	3.94E-08
PAH	Acenaphthene	No	No	Yes	1.42E-06	2.98E-06	1.49E-07
PAH	Acenaphthylene	No	No	Yes	5.06E-06	1.06E-05	5.31E-07
PAH	Anthracene	No	No	Yes	1.87E-06	3.93E-06	1.96E-07
PAH	Benzo(g,h,i)perylene	No	No	Yes	4.89E-07	1.03E-06	5.13E-08
PAH	Benzo(k)fluoranthene	No	No	Yes	1.55E-07	3.26E-07	1.63E-08
PAH	Fluoranthene	No	No	Yes	7.61E-06	1.60E-05	7.99E-07
PAH	Fluorene	No	No	Yes	2.92E-05	6.13E-05	3.07E-06
PAH	Phenanthrene	No	No	Yes	2.94E-05	6.17E-05	3.09E-06
PAH	Pyrene	No	No	Yes	4.78E-06	1.00E-05	5.02E-07

1) Two pumps will be provided, one will be electric engine-driven. Emissions for one engine shown for worst case permitting.
2) Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.
3) Emission factors from EPA AP-42 Section 3.3 Small Diesel Engines (<600hp)
4) Washington State PAHs determined by WAC 173-460-50
5) For the CAA112 requirements all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)

Emergency Generator, 2 MW

2682 hp
7000 Btu/hp-hr

CAS #	Compound	Federally Listed Compound HAP	Washington State TAP	PAH	Emission Factor (lb/10^6 Btu)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
75-07-0	Acetaldehyde	Yes	Yes	No	2.52E-05	4.73E-04	2.37E-05
107-02-8	Acrolein	Yes	Yes	No	7.88E-06	1.48E-04	7.40E-06
71-43-2	Benzene	Yes	Yes	No	7.76E-04	1.46E-02	7.28E-04
50-00-0	Formaldehyde	Yes	Yes	No	7.89E-05	1.48E-03	7.41E-05
91-20-3	Naphthalene	Yes	Yes	No	1.30E-04	2.44E-03	1.22E-04
115-07-1	Propylene	Yes	No	No	2.79E-03	5.24E-02	2.62E-03
108-88-3	Toluene	Yes	Yes	No	2.81E-04	5.28E-03	2.64E-04
1330-20-7	Xylenes	Yes	Yes	No	1.93E-04	3.62E-03	1.81E-04
PAH	Benzo(a)pyrene	No	Yes	Yes	2.57E-07	4.82E-06	2.41E-07
PAH	Benz(a)anthracene	No	Yes	Yes	6.22E-07	1.17E-05	5.84E-07
PAH	Benzo(b)fluoranthene	No	Yes	Yes	1.11E-06	2.08E-05	1.04E-06
PAH	Chrysene	No	Yes	Yes	1.53E-06	2.87E-05	1.44E-06
PAH	Dibenz(a,h)anthracene	No	Yes	Yes	3.46E-07	6.50E-06	3.25E-07
PAH	Indeno(1,2,3-cd)pyrene	No	Yes	Yes	4.14E-07	7.77E-06	3.89E-07
PAH	Acenaphthene	No	No	Yes	4.68E-06	8.79E-05	4.39E-06
PAH	Acenaphthylene	No	No	Yes	9.23E-06	1.73E-04	8.66E-06
PAH	Anthracene	No	No	Yes	1.23E-06	2.31E-05	1.15E-06
PAH	Benzo(g,h,i)perylene	No	No	Yes	5.56E-07	1.04E-05	5.22E-07
PAH	Benzo(k)fluoranthene	No	No	Yes	2.18E-07	4.09E-06	2.05E-07
PAH	Fluoranthene	No	No	Yes	4.03E-06	7.57E-05	3.78E-06
PAH	Fluorene	No	No	Yes	1.28E-05	2.40E-04	1.20E-05
PAH	Phenanthrene	No	No	Yes	4.08E-05	7.66E-04	3.83E-05
PAH	Pyrene	No	No	Yes	3.71E-06	6.97E-05	3.48E-06

1) Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.
2) Emission factors from EPA AP-42 Section 3.4 Large Diesel Engines (>600hp)
3) Washington State PAHs determined by WAC 173-460-50
4) For the CAA112 requirements all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)

TO: Interested Parties / Applicant

RE: PSI Energy / 167-19843-00021

FROM: George M. Needham
Director
Vigo County Air Pollution Control

Notice of Decision: Approval – Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-17-3-4 and 326 IAC 2, this permit modification is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-7-3 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office Environmental Adjudication, 100 North Senate Avenue, Government Center North, Room 1049, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

Pursuant to 326 IAC 2-7-18(d), any person may petition the U.S. EPA to object to the issuance of a Title V operating permit or modification within sixty (60) days of the end of the forty-five (45) day EPA review period. Such an objection must be based only on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impractible to raise such issues, or if the grounds for such objection arose after the comment period.

To petition the U.S. EPA to object to the issuance of a Title V operating permit, contact:

U.S. Environmental Protection Agency
401 M Street
Washington, D.C. 20406

If you have technical questions regarding the enclosed documents, please contact our office at (812) 462-3433.

Via Certified Mail

August 11, 2005

Mr. Steven L. Pearl
PSI Energy, Inc.
1000 East Main Street
Plainfield, Indiana 46168

Re: 167-19843-00021
First Significant Permit Modification to
Part 70 No.: T 167-7176-00021

Dear Mr. Pearl:

PSI Energy, Inc. was issued a permit on September 2, 2004 for a stationary electric generating station. A letter requesting changes to this permit was received on November 12, 2004. Pursuant to the provisions of 326 IAC 2-7-12 a significant permit modification to this permit is hereby approved as described in the attached Technical Support Document.

The modification consists of of the following: Incorporation of revisions to New Source Performance Standard (NSPS) for Turbines, 40 CFR 60, Subpart GG. These revisions include: the use of a continuous emission monitoring system (CEMS) to replace steam-to-fuel ratios for NOx control; the elimination of fuel bound nitrogen determinations when the Permittee is not claiming any credit for fuel bound nitrogen; and, the removal of certain fuel sulfur analysis requirements when the gaseous fuel being combusted meets the definition of natural gas.

All other conditions of the permit shall remain unchanged and in effect. Please attach a copy of this modification and the following revised permit pages to the front of the original permit.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5. If you have any questions on this matter, please contact Mr. Rob Harmon, VCAPC, 103 South 3rd Street, Terre Haute, Indiana 47807, or call at (812) 462-3433.

Sincerely,

ORIGINAL SIGNED BY
George M. Needham
Director
Vigo County Air Pollution Control

Attachments
rkh
cc: File – Vigo County
U.S. EPA, Region V
Mindy Hahn – IDEM, OAQ Permit Branch
Winter Bottom – IDEM, OAQ

PART 70 OPERATING PERMIT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT - OFFICE OF AIR QUALITY
and
VIGO COUNTY AIR POLLUTION CONTROL

PSI Energy, Inc. - Wabash River Generating Station
450 Bolton Road
West Terre Haute, Indiana 47885
and
PSI Energy, Inc. - Wabash River Repowering
445 Bolton Road
West Terre Haute, Indiana 47885

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17. This permit also addresses certain new source review requirements for existing equipment and is intended to fulfill the new source review procedures pursuant to 326 IAC 2-7-10.5, applicable to those conditions.

Operation Permit No.: T167-7176-00021	
Original Signed by: Janet G. McCabe, Assistant Commissioner Office of Air Quality	Issuance Date: September 2, 2004 Expiration Date: September 2, 2009

First Significant Permit Modification No.: 165-19843-00021	
Issued by: ORIGINAL SIGNED BY: George M. Needham, Director Vigo County Air Pollution Control	Issuance Date: August 11, 2005

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) and Vigo County Air Pollution Control (VCAPC). The information describing the source contained in conditions A.1, A.3, and A.4, is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Responsible Official:	Manager of the Wabash River Station / Manager of the Wabash River Repowering
Source Address:	Wabash River Station - 450 Bolton Road, West Terre Haute, Indiana 47885 Wabash River Repowering - 445 Bolton Road, West Terre Haute, Indiana 47885
Mailing Address:	c/o Steven L. Pearl, 1000 East Main Street, Plainfield, Indiana 46168
Source Telephone:	(812) 535-2329
SIC Code:	4911
County Location:	Vigo County
Source Location Status:	Maintenance Attainment for Sulfur Dioxide Attainment for PM2.5 Nonattainment for ozone under the 8-hour standard Attainment for all other criteria pollutants
Source Status:	Part 70 Permit Program Major Source, under PSD Rules; Major Source, under Nonattainment NSR Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

This source consists of an electric utility generating station with an on-site contractor that produces and supplies synthetic gas (“syngas”) derived from petroleum products :

(a) PSI Energy, Inc. - Wabash River Generating Station (167-00021), the primary operation, is located at 450 Bolton Road, West Terre Haute, Indiana 47885;

(b) PSI Energy, Inc. – Wabash River Repowering (167-00021), a co-located but independent operation, is located at 445 Bolton Road, West Terre Haute, Indiana 47885, and

(c) Wabash River Energy, LLC (167-00091), the supporting operation to Wabash River Repowering, is located at 444 West Sandford Ave., West Terre Haute, Indiana 47885.

IDEM and VCAPC have determined that PSI Energy, Inc. - Wabash River Generating Station and Wabash River Energy, LLC are under the common control of PSI Energy, Inc. These two plants are considered one source due to contractual control. Therefore, the term “source” in the Part 70 documents refers to both PSI Energy, Inc. and Wabash River Energy as one source.

Separate Part 70 permits will be issued to PSI Energy, Inc. with Permit No.: 167-7176-00021 and Wabash River Energy with Permit No.: 167-7353-00091 (issued on December 31, 1998) solely for administrative purposes.

A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(15)]

This stationary source consists of the following emission units and pollution control devices:

1. Combustion Turbine, identified as Unit 1A, constructed in 1995, with a nominal rated capacity of 1709.1 million BTU per hour (192 megawatt), utilizing syngas or natural gas in combined cycle

mode and natural gas in simple cycle mode, utilizing steam injection for NO_x control, and exhausting to stack 1A (combined cycle mode) or 1D (simple cycle mode). Stack 1A (combined cycle) has continuous emission monitors for SO_2, NOx, CO_2, and volumetric flow rate as well as a continuous opacity monitor (COM). Stack 1D (bypass) has continuous emission monitors for NOx and CO_2.

2. Repowering Auxiliary Boiler fired on natural gas only, identified as Unit 1B, constructed in 1995, with a nominal rated capacity of 144 million BTU per hour, using low NOx burners as NOx control, and exhausting to Stack 1B with continuous emission monitors for NOx and CO_2.

3. Natural gas fired boiler, identified as Unit 1C, constructed in 2001, with a nominal rated capacity of 397.8 million BTU per hour, using low NOx burners with flue gas recirculation as NOx control, and exhausting to stack 1C with continuous emission monitors for NOx, CO_2, and CO.

4. Fuel preheater, identified as Unit 1E, constructed in 2001, with a nominal rated capacity of 7.13 million BTU per hour, utilizing natural gas for fuel, using a low emission rate burner for NO_x control, and exhausting to stack 1E.

5. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 2, constructed in 1953, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 913.8 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

6. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 3, constructed in 1954, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

7. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 4, constructed in 1955, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

8. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 5, constructed in 1956, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 1096.2 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

9. Tangential fired coal electric utility boiler (pulverized - dry bottom, tangential), identified as Unit 6, constructed in 1968, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 2999.0 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

10. Coal pile maintenance, identified as F-1.

11. Coal handling, identified as F-2.

12. Plant roads, identified as F-4.

13. Diesel Generator, identified as 7A, constructed in 1967, combusting #2 fuel oil, with a nominal rated capacity of 28.6 million BTU per hour, used for intermittent and emergency duty, using no control, and exhausting to stack 7A.

14. Diesel Generator, identified as 7B, constructed in 1967, combusting #2 fuel oil, with a nominal rated capacity of 28.6 million BTU per hour, used for intermittent and emergency duty, using no control, and exhausting to stack 7B.

15. Diesel Generator, identified as 7C, constructed in 1967, combusting #2 fuel oil, with a nominal rated capacity of 28.6 million BTU per hour, used for intermittent and emergency duty, using no control, and exhausting to stack 7C.

A.4 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)][326 IAC 2-7-5(15)]

This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

1. Thaw pit Fuel oil tank: 20,000 gallon (constructed 1990) [326 IAC 12][40 CFR 60, Subpart Kb]
2. Coal pile wind erosion [326 IAC 6-1-2][326 IAC 6-4]
3. Lime silo: 1388 cubic feet [326 IAC 6-1-2]
4. Lime day bin: 87 cubic feet [326 IAC 6-1-2]
5. Unit 6 hydroveyor [326 IAC 6-1-2]
6. Degreaser (maintenance shop): 30 gallon (constructed about 1980) [326 IAC 8-3]
7. Ash hydroveyor separator Units 1&2 [326 IAC 6-1-2]
8. Ash hydroveyor separator Units 3&4 [326 IAC 6-1-2]
9. Ash hydroveyor separator Unit 5 [326 IAC 6-1-2]
10. Parts cleaner (electric shop): 30 gallon (constructed about 1980) [326 IAC 8-3]
11. Parts cleaner (main floor storage area): 30 gallon (constructed about 1980) [326 IAC 8-3]
12. Ash pond: 216 acres [326 IAC 6-1-2][326 IAC 6-4]
13. Ash pond management and maintenance [326 IAC 6-1-2]
14. Two (2) Repowering fuel oil storage tank: 99,500 gallon each (constructed in 1993) [326 IAC 12][40 CFR 60, Subpart Kb]
15. Fuel oil tank: 50,000 gallons (constructed in 1986) [326 IAC 12][40 CFR 60, Subpart Kb]

A.5 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability); and

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3).

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

B.2 Permit Term [326 IAC 2-7-5(2)] [326 IAC 2-1.1-9.5]

This permit is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

B.3 Enforceability [326 IAC 2-7-7]

(a) Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, VCAPC, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

(b) Unless otherwise stated, all terms and conditions in this permit that are local requirements, including any provisions designed to limit the source's potential to emit, are enforceable by Vigo County Air Pollution Control.

B.4 Termination of Right to Operate [326 IAC 2-7-10] [326 IAC 2-7-4(a)]

The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

This permit does not convey any property rights of any sort, or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ and VCAPC, within a reasonable time, any information that IDEM, OAQ and VCAPC, may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34). Upon request, the Permittee shall also furnish to IDEM, OAQ and VCAPC, copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ or VCAPC, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)] [326 IAC 2-7-6(1)] [326 IAC 2-7-5(3)(C)]

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted under this permit or 326 IAC 2-7 shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form or its equivalent, with each submittal requiring certification. One (1) certification can cover multiple forms in one (1) submittal.

(c) A responsible official is defined at 326 IAC 2-7-1(34).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. The initial certification shall cover the time period from the date of final permit issuance through December 31 of the same year. All subsequent certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted in letter form no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ and VCAPC, on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent; and

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3).

The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, including the following information on each facility:

(1) Identification of the individual(s), by title or classification, responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

The PMP extension notification does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall implement the PMPs, including any required record keeping, as necessary to ensure that failure to implement a PMP does not cause or contribute to an exceedance of any limitation on emissions.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ and VCAPC, upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ and VCAPC. IDEM, OAQ and VCAPC, may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions.

The submittal of the PMP and the PMP extension notification does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) To the extent the Permittee is required by 40 CFR Part 63 to have an Operation, Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation except as provided in 326 IAC 2-7-16 or this condition.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ and VCAPC within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

IDEM
Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-5674 (ask for Compliance Section)
Facsimile Number: 317-233-5967.

VCAPC
Telephone Number: 812-462-3433
Facsimile Number: 812-462-3447

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) IDEM, OAQ and VCAPC, may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4-(c)(9) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ and VCAPC, by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report. Any emergencies that have been previously reported pursuant to Paragraph (b)(5) of this condition and certified by the Responsible Official need only be referenced by the date of the original report.

B.12 Permit Shield [326 IAC 2-7-15] [326 IAC 2-7-20] [326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ and VCAPC, shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ or VCAPC, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ or VCAPC, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5]

(a) All terms and conditions of previous permits issued pursuant to permitting programs approved into the state implementation plan have been either

(1) incorporated as originally stated,

(2) revised, or

(3) deleted

by this permit.

(b) All previous registrations and permits are superseded by this permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

B.14 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]

(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. A deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report.

The Quarterly Deviation and Compliance Monitoring Report does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)]

[326 IAC 2-7-8(a)] [326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)].

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ or VCAPC, determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ or VCAPC, to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ or VCAPC at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ or VCAPC, may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and VCAPC, and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

(b) Timely Submittal of Permit Renewal [326 IAC 2-7-4(a)(1)(D)]

(1) A timely renewal application is one that is:

(A) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(B) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ and VCAPC, on or before the date it is due.

(2) If IDEM, OAQ and VCAPC, upon receiving a timely and complete permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

(c) Right to Operate After Application for Renewal [326 IAC 2-7-3] [326 IAC 2-7-4]
If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ and VCAPC, take final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by a reasonable deadline specified in writing by IDEM, OAQ and VCAPC, any additional information identified as being needed to process the application. [326 IAC 2-7-4(a)(2)(D) and (E)]

(d) United States Environmental Protection Agency Authority [326 IAC 2-7-8(e)]
If IDEM, OAQ and VCAPC, fail to act in a timely way on a Part 70 permit renewal, the U.S. EPA may invoke its authority under Section 505(e) of the Clean Air Act to terminate or revoke and reissue a Part 70 permit.

B.17 Source Modification [326 IAC 1-2-42] [326 IAC 2-7-10.5]

(a) The Permittee shall obtain approval as required by 326 IAC 2-7-10.5 from the IDEM, OAQ prior to making any modification to the source. Pursuant to 326 IAC 1-2-42, "Modification" means one (1) or more of the following activities at an existing source:

(1) A physical change or change in the method of operation of any existing emissions unit that increases the potential to emit any regulated pollutant that could be emitted from the emissions unit, or that results in emissions of any regulated pollutant not previously emitted.

(2) Construction of one (1) or more new emissions units that have the potential to emit regulated air pollutants.

(3) Reconstruction of one (1) or more existing emission units that increases the potential to emit of any regulated air pollutant.

(b) Any application requesting a source modification shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The Permittee shall also comply with the applicable provisions of 326 IAC 2-7-11 (Administrative Permit Amendments) or 326 IAC 2-7-12 (Permit Modification) prior to operating the approved modification.

B.18 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12] [40 CFR 72]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

Any such application shall be certified by the “responsible official” as defined by 326 IAC 2-7-1(34).

(d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

(e) No permit amendment or modification is required for the addition, operation or removal of a nonroad engine, as defined in 40 CFR 89.2.

B.19 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12 (b)(2)]

(a) No Part 70 permit revision shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

B.20 Operational Flexibility [326 IAC 2-7-20] [326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b), (c), or (e), without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the emissions allowable under this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records accessible on-site which document, on a rolling five (5) year basis, all such changes and emissions trading that are subject to 326 IAC 2-7-20(b), (c), or (e) and makes such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ and VCAPC, in the notices specified in 326 IAC 2-7-20(b)(1), (c)(1), and (e)(2).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;
(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade increases and decreases in emissions in the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c). The notification requirement per (a)(4) of this condition does not apply to emission trades of SO_2 or NO_x under 326 IAC 21 or 326 IAC 10-4.

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, VCAPC, or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the requirements of part (a) of this condition do not apply.

B.21 Inspection and Entry [326 IAC 2-7-6] [IC 13-14-2-2] [IC 13-17-3-2] [IC 13-30-3-1]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, VCAPC, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records are physically present or electronically accessible under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a permit modification that allows for a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

The application which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ and VCAPC, within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ or VCAPC, the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing**,** Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314][326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-7-5(1)]

C.1 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.2 Open Burning [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1. 326 IAC 4-1-3 (a)(2)(A) and (B) are not federally enforceable.

C.3 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator or incinerate any waste or refuse except as provided in 326 IAC 4-2 and 326 IAC 9-1-2. 326 IAC 9-1-2 is not federally enforceable.

C.4 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.5 Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]

Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the plan submitted on November 14, 1996. The plan is included as Attachment A.

C.6 Motor Vehicle Fugitive Dust Sources [326 IAC 6-4-4]

Pursuant to 326 IAC 6-4-4, no vehicle shall be driven or moved on any public street, road, alley, highway, or other thoroughfare, unless such vehicle is so constructed as to prevent its contents from dripping, sifting, leaking, or otherwise escaping therefrom so as to create conditions which result in fugitive dust. This section applies only to the cargo any vehicle may be conveying and mud tracked by the vehicle.

C.7 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140.

Testing Requirements [326 IAC 2-7-6(1)]

C.9 Performance Testing [326 IAC 3-6]

(a) All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ and VCAPC.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ and VCAPC of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ and VCAPC not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ and VCAPC, if the Permittee submits to IDEM, OAQ and VCAPC, a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period. The test report requires certification by the responsible official.

Compliance Requirements [326 IAC 2-1.1-11]

C.10 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]

C.11 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality

100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

and

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

C.12 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]

(a) The Permittee shall calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COM shall be in operation at all times that the induced draft fan is in operation.

(b) All continuous opacity monitoring systems shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(c) In the event that a breakdown of a continuous opacity monitoring system occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(d) Whenever a continuous opacity monitor (COM) is malfunctioning or will be down for calibration, maintenance, or repairs for a period of one (1) hour or more, compliance with the applicable opacity limits shall be demonstrated by the following:

(1) Visible emission (VE) notations shall be performed once per hour during daylight operations following the shutdown or malfunction of the primary COM. A trained employee shall record whether emissions are normal or abnormal for the state of operation of the emission unit at the time of the reading.

(A) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(B) If abnormal emissions are noted during two consecutive emission notations, the Permittee shall begin Method 9 opacity observations within four hours of the second abnormal notation.

(C) VE notations may be discontinued once a COM is online or formal Method 9 readings have been implemented.

(2) If a COM is not online within twenty-four (24) hours of shutdown or malfunction of the primary COM, the Permittee shall provide certified opacity reader(s), who may be employees of the Permittee or independent contractors, to self-monitor the emissions from the emission unit stack.

(A) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(B) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least once every four (4) hours during daylight operations, until such time that a COM is in operation.

(C) Method 9 readings may be discontinued once a COM is online.

(D) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(3) If abnormal emissions are observed, the Permittee shall take reasonable response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a deviation from this permit.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5 and 40 CFR 60.

C.13 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]
Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60 Appendix A, 40 CFR 60 Appendix B, 40 CFR 63, 40 CFR 75, or other approved methods as specified in this permit.

C.14 Pressure Gauge and Other Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) Whenever a condition in this permit requires the measurement of a voltage, current, temperature or flow rate, the instrument employed shall have a scale such that the expected normal reading shall be no less than twenty percent (20%) of full scale and be accurate within plus or minus two percent ("2%) of full scale reading.

(b) The Permittee may request the IDEM, OAQ approve the use of an other instrument that does not meet the above specifications provided the Permittee can demonstrate an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of operating parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]

C.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee prepared and submitted written emergency reduction plans (ERPs) consistent with safe operating procedures on June 30, 1980.

(b) Upon direct notification by IDEM, OAQ and VCAPC, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.16 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

If a regulated substance as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.17 Compliance Response Plan - Preparation, Implementation, Records, and Reports [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) The Permittee is required to prepare a Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. If a Permittee is required to have an Operation, Maintenance and Monitoring (OMM) Plan or Parametric Monitoring Plan and Start-up, Shutdown, and Malfunction (SSM) Plan under 40 CFR 63, such plans shall be deemed to satisfy the requirements for a CRP for those compliance monitoring conditions. A CRP shall be submitted to IDEM, OAQ and VCAPC upon request. The CRP shall be prepared within ninety (90) days after issuance of this permit by the Permittee, supplemented from time to time by the Permittee, maintained on site, and comprised of:

(1) Reasonable response steps that may be implemented in the event that a response step is needed pursuant to the requirements of Section D of this permit; and an expected timeframe for taking reasonable response steps.

(2) If, at any time, the Permittee takes reasonable response steps that are not set forth in the Permittee's current Compliance Response Plan or Operation, Maintenance and Monitoring (OMM) Plan or Parametric Monitoring Plan and Start-up, Shutdown, and Malfunction (SSM) Plan and the Permittee documents such response in accordance with subsection (e) below, the Permittee shall amend its Compliance Response Plan or Operation, Maintenance and Monitoring (OMM) Plan or Parametric Monitoring Plan and Start-up, Shutdown, and Malfunction (SSM) Plan to include such response steps taken.

The OMM Plan or Parametric Monitoring and SSM Plan shall be submitted within the time frames specified by the applicable 40 CFR 63 requirement.

(b) For each compliance monitoring condition of this permit, reasonable response steps shall be taken when indicated by the provisions of that compliance monitoring condition as follows:

(1) Reasonable response steps shall be taken as set forth in the Permittee's current Compliance Response Plan or Operation, Maintenance and Monitoring (OMM) Plan or Parametric Monitoring Plan and Start-up, Shutdown, and Malfunction (SSM) Plan; or

(2) If none of the reasonable response steps listed in the Compliance Response Plan or Operation, Maintenance and Monitoring (OMM) Plan or Parametric Monitoring Plan and Start-up, Shutdown, and Malfunction (SSM) Plan is applicable or responsive to the excursion, the Permittee shall devise and implement additional response steps as expeditiously as practical. Taking such additional response steps shall not be considered a deviation from this permit so long as the Permittee documents such response steps in accordance with this condition.

(3) If the Permittee determines that additional response steps would necessitate that the emissions unit or control device be shut down, and it will be ten (10) days or more until the unit or device will be shut down, then the Permittee shall promptly notify the IDEM, OAQ and VCAPC of the expected date of the shut down. The notification shall also include the status of the applicable compliance monitoring parameter with respect to normal, and the results of the response actions taken up to the time of notification.

(4) Failure to take reasonable response steps shall be considered a deviation from the permit.

(c) The Permittee is not required to take any further response steps for any of the following reasons:

(1) A false reading occurs due to the malfunction of the monitoring equipment and prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for a minor permit modification to the permit, and such request has not been denied.

(3) An automatic measurement was taken when the process was not operating.

(4) The process has already returned or is returning to operating within “normal” parameters and no response steps are required.

(d) When implementing reasonable steps in response to a compliance monitoring condition, if the Permittee determines that an exceedance of an emission limitation has occurred, the Permittee shall report such deviations pursuant to Section B-Deviations from Permit Requirements and Conditions.

(e) The Permittee shall record all instances when, in accordance with Section D, response steps are taken. In the event of an emergency, the provisions of 326 IAC 2-7-16 (Emergency Provisions) requiring prompt corrective action to mitigate emissions shall prevail.

(f) Except as otherwise provided by a rule or provided specifically in Section D, all monitoring as required in Section D shall be performed when the emission unit is operating, except for time necessary to perform quality assurance and maintenance activities.

C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ and VCAPC that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAQ and VCAPC may extend the retesting deadline.

(c) IDEM, OAQ and VCAPC reserve the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

(a) The Permittee shall submit an annual emission statement certified pursuant to the requirements of 326 IAC 2-6, that must be received by July 1 of each year and must comply with the minimum requirements specified in 326 IAC 2-6-4. The annual emission statement shall meet the following requirements:

(1) Indicate estimated actual emissions of criteria pollutants from the source, in compliance with 326 IAC 2-6 (Emission Reporting);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) (“Regulated pollutant which is used only for purposes of Section 19 of this rule”) from the source, for purposes of Part 70 fee assessment.

(b) The annual emission statement covers the twelve (12) consecutive month time period starting January 1 and ending December 31. The annual emission statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

The emission statement does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The annual emission statement required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ and VCAPC, on or before the date it is due.

C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner or Vigo County Air Pollution Control makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner or Vigo County Air Pollution Control within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

C.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street

Terre Haute, Indiana 47807

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ and VCAPC, on or before the date it is due.

(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(e) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period. Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

Stratospheric Ozone Protection

C.22 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with the standards for recycling and emissions reduction:

(a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

(b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

(c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

(d) Pursuant to 40 CFR 82, Subpart E (The Labeling of Products Using Ozone-Depleting Substances), all containers in which a Class I or Class II substance is stored or transported and all products containing a Class I substance shall be labeled as required under 40 CFR Part 82.

Ambient Monitoring Requirements [326 IAC 7-3]

C.23 Ambient Monitoring [326 IAC 7-3]

(a) The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).

(b) The Permittee and other operators subject to the requirements of this rule, located in the same county, may submit a joint monitoring plan to satisfy the requirements of this rule. [326 IAC 7-3-2(c)]

(c) The Permittee may petition the commissioner for an administrative waiver of all or some of the requirements of 326 IAC 7-3 if such owner or operator can demonstrate that ambient monitoring is unnecessary to determine continued maintenance of the sulfur dioxide ambient air quality standards in the vicinity of the source. [326 IAC 7-3-2(d)]

Part 2 MACT Application Submittal Requirement

C.24 Application Requirements for Section 112(j) of the Clean Air Act [40 CFR 63.52(e)][40 CFR 63.56(a)] [40 CFR 63.9(b)] [326 IAC 2-7-12]

(a) The Permittee shall submit a Part 2 Maximum Achievable Control Technology (MACT) Application in accordance with 40 CFR 63.52(e)(1). The Part 2 MACT Application shall meet the requirements of 40 CFR 63.53(b).

(b) Notwithstanding paragraph (a), the Permittee is not required to submit a Part 2 MACT Application if the Permittee no longer meets the applicability criteria of 40 CFR 63.50 by the application deadline in 40 CFR 63.52(e)(1). For example, the Permittee would not have to submit a Part 2 MACT Application if, by the application deadline:

(1) The source is no longer a major source of hazardous air pollutants, as defined in 40 CFR 63.2;

(2) The source no longer includes one or more units in an affected source category for which the U.S. EPA failed to promulgate an emission standard by May 15, 2002; or

(3) The MACT standard or standards for the affected source categories included at the source are promulgated.

(c) Notwithstanding paragraph (a), pursuant to 40 CFR 63.56(a), the Permittee shall comply with an applicable promulgated MACT standard in accordance with the schedule provided in the MACT standard if the MACT standard is promulgated prior to the Part 2 MACT Application deadline or prior to the issuance of permit with a case-by-case Section 112(j) MACT determination. The MACT requirements include the applicable General Provisions requirements of 40 CFR 63, Subpart A. Pursuant to 40 CFR 63.9(b), the Permittee shall submit an initial notification not later than 120 days after the effective date of the MACT, unless the MACT specifies otherwise. The initial notification shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

and

United States Environmental Protection Agency, Region V
Director, Air and Radiation Division
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

Combustion Turbine, identified as Unit 1A, constructed in 1995, with a nominal rated capacity of 1709.1 million BTU per hour (192 megawatt), utilizing syngas or natural gas in combined cycle mode and natural gas in simple cycle mode, utilizing steam injection for NO_x control, and exhausting to stack 1A (combined cycle mode) or 1D (simple cycle mode). Stack 1A (combined cycle) has continuous emission monitors for SO_2, NOx, CO_2, and volumetric flow rate as well as a continuous opacity monitor (COM). Stack 1D (bypass) has continuous emission monitors for NOx and CO_2.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.1.1 General Provisions Relating to NSPS [326 IAC 12][40 CFR 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated under 326 IAC 12, apply to the combustion turbine (Unit 1A) except when otherwise specified in 40 CFR Part 60, Subpart GG.

D.1.2 NSPS Nitrogen Oxide Standard [326 IAC 12][40 CFR 60.332]

Pursuant to 40 CFR 60.332(a)(1) and 40 CFR 60.332(b) the Permittee shall not allow to be discharged into the atmosphere, any gases which contain nitrogen oxides in excess of 0.0075 percent (%) (75 ppm @ 15% oxygen, dry basis). This is based on the following equation:

$$STD = 0.0075*(14.4/Y)+F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis);
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at peak load for the facility; and
F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

Exemptions:

(a) Pursuant to 40 CFR 60.332(f), stationary gas turbines using water or steam injection for control of NOx emissions are exempt from the nitrogen oxide standard when ice fog is deemed a traffic hazard by the Permittee.

(b) Pursuant to 40 CFR 60.332(i), exemptions from the nitrogen oxide standard may be granted on a case-by-case basis in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

D.1.3 Nitrogen Oxide Emission Limitation [326 IAC 2-2]

Pursuant to CP 167-2610-00021 (Issued May 27, 1993), the nitrogen oxides (NO_x) emissions from the gas turbine shall not exceed 25 ppmdv at 15 percent oxygen for syngas or natural gas combustion.

D.1.4 NSPS Standard for Sulfur Dioxide [326 IAC 12][40 CFR 60.333]

Pursuant to 40 CFR 60.333, the Permittee shall comply with one of the two following requirements:

(a) The Permittee shall not discharge into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15% oxygen and on a dry basis; OR

(b) The Permittee shall not burn any fuel which contains sulfur in excess of 0.8 percent by weight.

D.1.5 Carbon Monoxide BACT [326 IAC 2-2-3][40 CFR 52.21]

Pursuant to CP 167-2610-00021 (Issued May 27, 1993, as amended in 2001), 326 IAC 2-2, and 40 CFR 52.21, the best available control technology (BACT) for carbon monoxide shall be good combustion practices. CO emissions shall not exceed 15 ppm when burning syngas or natural gas corrected to 15% oxygen at 75% or greater load. The practice and instrumentation plan shall be submitted to the VCAPC along with the methods and parameters which are based on test results to ensure continued compliance.

D.1.6 Sulfuric Acid Mist BACT [326 IAC 2-2-3][40 CFR 52.21]

Pursuant to CP 167-2610-00021 (Issued May 27, 1993), 326 IAC 2-2, and 40 CFR 52.21, the best available control technology (BACT) for sulfuric acid mist shall be: a) 0.01 lb of sulfuric acid (H_2SO_4) mist per million BTU by limiting the sulfur content of the syngas to 360 ppm or less as measured by a gas chromatograph, and b) design exit gas temperature from the Heat Recovery Steam Generator (HRSG) to be at least 264 EF.

D.1.7 Opacity Limitations

Pursuant to CP 167-2610-00021 (Issued May 27, 1993), the opacity from Unit 1A (exhausting to stack 1A) shall be limited to 20 percent. PSI Energy may request a special exemption pursuant to 326 IAC 5-1-3(d) if proper operation of the turbine justifies such a request. Compliance shall be determined by continuous opacity monitoring in accordance with 40 CFR 75.14. Per 40 CFR 75.14(c), opacity monitoring is not required for when the turbine is operated in simple cycle mode using natural gas only and exhausting through stack 1D.

D.1.8 Particulate Matter [326 IAC 6-1-2]

Pursuant to 326 IAC 6-1-2(a), the PM emissions from the combustion turbine stack shall not exceed 0.03 grains per dry standard cubic foot.

D.1.9 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP), in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this emissions unit and its control device.

D.1.10 Unit 1 Removal [326 IAC 2-2]

Pursuant to CP 167-2610-00021 (Issued May 27, 1993), coal-fired boiler No. 1 (Unit 1) at the Wabash Generating Station shall remain permanently inoperable. (This boiler was removed from service on December 31, 1994.)

Compliance Determination Requirements

D.1.11 NSPS Test Methods and Procedures [326 IAC 12][40 CFR 60.335]

(a) Pursuant to 40 CFR 60.335(a), the Permittee shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the IDEM, OAQ and VCAPC to determine the nitrogen content of the fuel being fired. Pursuant to 40 CFR Part 60.334(h)(2), the Permittee is not required to monitor the nitrogen content of the fuel combusted in the turbine if the Permittee does not claim any allowance for fuel bound nitrogen.

(b) Pursuant to 40 CFR 60.335(b), the Permittee, in conducting the performance tests required in 40 CFR 60.8, shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this Condition.

(c) Pursuant to 40 CFR 60.335(c), the Permittee shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Condition D.1.2 and Condition D.1.4 as follows:

(1) The nitrogen oxides emission rate (NO_x) shall be computed for each run using the following equation:

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5}\, e^{19(Ho-0.00633)}(288K/T_a)1.53$$

where: NO_x= emission rate of NO_x at 15 percent O_2 and ISO standard conditions, volume percent;
NO_{xo}= observed NO_x concentration, ppm by volume;
P_r= reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg;
P_o= observed combustor inlet absolute pressure at test, mm Hg;
H_o= observed humidity of ambient air, g H_2O/g air;
e= transcendental constant, 2.718; and
T_a= ambient temperature, EK.

(2) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this Condition.

(d) Pursuant to 40 CFR 60.335(d), the owner or operator shall determine compliance with the sulfur content standard in Condition D.1.4 as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference - see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the IDEM, OAQ and VCAPC. Notwithstanding the provisions of 40 CFR 60.334(h)(3), the Permittee is not required to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Section 60.331(u), regardless of whether an existing custom schedule approved by IDEM, OAQ and VCAPC for Subpart GG requires such monitoring. The Permittee shall use one of the sources of information described in 40 CFR 60.334(h)(3)(i) and (ii).

(e) Pursuant to 40 CFR 60.335(e), to meet the requirements of Condition D.1.13, the Permittee shall use the methods specified in paragraphs (a) and (d) of this Condition to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the Permittee, a service contractor retained by the Permittee, the fuel vendor, or any other qualified agency. Pursuant to 40 CFR 60.334(h)(2) and (3), the Permittee is not required to analyze the fuel nitrogen content when the Permittee claims a zero allowance for fuel bound nitrogen. The Permittee also does not have to analyze the fuel for sulfur content if it qualifies as natural gas.

(f) Pursuant to 40 CFR 60.335(f) the Permittee may use the following alternatives to the reference methods and procedures specified in this condition: Instead of using the equation in paragraph (c)(1) of this Condition, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in 40 CFR 60.8 to ISO standard day conditions. These factors are developed for each gas turbine model they manufacturer in terms of combustion inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. They shall be substantiated with data and must be approved for use by the IDEM, OAQ and VCAPC before the initial performance test required by 40 CFR 60.8. Notices of approval of custom ambient condition correction factors will be published in the Federal Register.

D.1.12 Nitrogen Oxide Controls

(a) Pursuant to CP 167-2610-00021 (Issued May 27, 1993) and SSM 167-11328-00021 (issued January 27, 2000), the steam injection shall be used to control nitrogen oxide emissions to the levels required in Condition D.1.2 and D.1.3.

(b) The steam injection system shall be in service and operating at the appropriate rate, as determined by the continuous emission monitoring system (CEMS) which consists of NO_x and O_2 or CO_2 monitors, whenever the turbine is in operation, except for the time specified for start-up and shutdown period.

D.1.13 NSPS Monitoring of Emissions [326 IAC 12][40 CFR 60.334]

(a) Pursuant to 40 CFR 60.334(b), the Permittee shall install, certify, maintain, operate, and quality assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 or CO2 monitors. The CEMS shall be installed, certified, maintained and operated as specified in 40 CFR 60.334(b)(1) through (b)(3).

(b) The Permittee shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The custom schedule for the combustion turbine shall be as follows:
  (1) Pursuant to 40 CFR Part 60.334(h)(2), the Permittee is not required to monitor the nitrogen content of the fuel combusted in the turbine if the Permittee does not claim any allowance for fuel bound nitrogen.
  (2) Notwithstanding the provisions of 40 CFR 60.334(h)(3), the Permittee is not required to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Section 60.331(u), regardless of whether an existing custom schedule approved by IDEM, OAQ and VCAPC for Subpart GG requires such monitoring. The Permittee shall use one of the sources of information described in 40 CFR 60.334(h)(3)(i) and (ii).

(c) Periods of excess emissions and monitor downtime that shall be reported are defined as follows:
  (1) Nitrogen oxides.
    (i) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a “4-hour rolling average NO_X concentration" is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.
    (ii) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).
    (iii) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the Permittee has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. The Permittee does not have to report ambient conditions if the Permittee opts to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if the Permittee is not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).
  (2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.
  (3) Ice fog. Each period during which an exemption provided in Condition D.1.2 is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.14 Record Keeping Requirements

(a) To document compliance with Conditions D.1.2, D.1.3, and D.1.4 the Permittee shall maintain all records generated in accordance with Conditions D.1.11 and D.1.12.

(b) To document compliance with Conditions D.1.5 and D.1.6 the Permittee shall maintain records containing the information necessary. The information shall, as a minimum, contain the following information.

(1) The date, fuel, and times for all periods of turbine operation;
(2) The fuel type and consumption during all periods of the turbine operation;
(3) The sulfur content of the fuel, unless the fuel is demonstrated to meet the definition of natural gas in which case it is not required to be monitored; and
(4) Records of NOx and SO2 CEM data.

(c) To document compliance with Section C - Opacity and Condition D.1.7, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and Condition D.1.7.

(1) Data and results from the most recent stack test.
(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5 and 40 CFR 75.14.
(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(d) To document compliance with Condition D.1.9, the Permittee shall maintain records of any additional inspections prescribed by the Preventive Maintenance Plan.

(e) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.1.15 Reporting Requirements

(a) The Permittee shall submit the following information on a quarterly basis:

(1) Records of excess NOx emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements of this permit.
(2) A quarterly excess emissions report shall be submitted, based on any continuous opacity monitor (COM) required by this section, pursuant to 326 IAC 3-5-7. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements, of this permit.

The reports submitted by the Permittee do require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall submit the following information pursuant to 40 CFR 60.334 and 40 CFR 60.7:

To document compliance with Conditions D.1.2 and D.1.4, pursuant to 40 CFR 60.334, excess emissions and monitoring system performance (MSP) reports shall be submitted to the in accordance with Section C – General Reporting Requirements semi-annually for each six month period in the calendar year. All semi-annual reports shall be postmarked by the 30th day following the end of each six-month period. For the purpose of reports under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) For nitrogen oxides: Any unit operating hour in which the 4-hour rolling average NOx concentration exceeds the applicable emission limit.

(2) For sulfur dioxide: Any daily period which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

SECTION D.2 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

Repowering Auxiliary Boiler fired on natural gas only, identified as Unit 1B, constructed in 1995, with a nominal rated capacity of 144 million BTU per hour, using low NOx burners as NOx control, and exhausting to Stack 1B with continuous emission monitors for NOx and CO_2.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.2.1 General Provisions Relating to NSPS [326 IAC 12][40 CFR 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated under 326 IAC 12, apply to the boiler (Unit 1B) except when otherwise specified in 40 CFR Part 60, Subpart Db.

D.2.2 New Source Performance Standard (NSPS) [326 IAC 12][40 CFR 60, Subpart Db]

Pursuant to 326 IAC 12 and 40 CFR 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) and Construction Permit CP 167-2610-00021, issued on May 27, 1993, the nitrogen content of the fuel shall not exceed 0.30 weight percent.

D.2.3 Particulate Matter [326 IAC 6-1-2]

Pursuant to 326 IAC 6-1-2(b)(3) all gaseous fuel-fired steam generators (Unit 1B) shall not emit a particulate matter content greater than 0.01 grain per dry standard cubic foot.

D.2.4 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this facility and its emission control devices.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.2.5 Record Keeping Requirements

(a) To document compliance with Condition D.2.2, the Permittee shall maintain records in accordance with 40 CFR 60.49b.

(b) To document compliance with Condition D.2.4, the Permittee shall maintain records of any additional inspections prescribed by the Preventive Maintenance Plan.

(c) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.3 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

1. Natural gas fired boiler, identified as Unit 1C, constructed in 2001, with a nominal rated capacity of 397.8 million BTU per hour, using low NOx burners with flue gas recirculation as NOx control, and exhausting to stack 1C with continuous emission monitors for NOx, CO_2, and CO.

2. Fuel preheater, identified as Unit 1E, constructed in 2001, with a nominal rated capacity of 7.13 million BTU per hour, utilizing natural gas for fuel, using a low emission rate burner for NO_x control, and exhausting to stack 1E.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1 General Provisions Relating to NSPS [326 IAC 12][40 CFR 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated under 326 IAC 12, apply to the boiler (Unit 1C) except when otherwise specified in 40 CFR Part 60, Subpart Da.

D.3.2 New Source Performance Standard (NSPS) [326 IAC 12] [40 CFR 60, Subpart Da]

Pursuant to 326 IAC 12 and 40 CFR 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978), emissions from Unit 1C shall not exceed the following:

(a) for particulate matter:

(1) Three-hundredths (0.03) pound PM per million Btu (MMBtu) heat input when combusting gaseous fuel. [40 CFR 60.42a(a)(1)]

(2) Twenty percent (20%) opacity (six-minute average), except for one six-minute period per hour of not more than twenty-seven percent (27%) opacity. [40 CFR 60.42a(b)]

(b) for sulfur dioxide: (While combusting liquid or gaseous fuels:)

(1) Eight-tenths (0.80) pound SO_2 per million Btu (MMBtu) heat input and ninety percent (90%) reduction, or

(2) Less than two-tenths (0.20) pound SO_2 per million Btu (MMBtu) heat input and zero percent (0%) reduction (while combusting gaseous fuels). [40 CFR 60.43a(b)(1) and (2)]

(c) for nitrogen oxides:

(1) Two-tenths (0.20) pound NO_X per million Btu (MMBtu) heat input and twenty-five (25%) reduction while combusting gaseous fuels. [40 CFR 60.44a(a)(1) and (2)]

D.3.3 CO Emission Limitations [326 IAC 2-2]

Pursuant to SSM 167-11328-00021 issued on January 27, 2000, the combined emissions of CO from the boiler (Unit 1C) and the fuel preheater (Unit 1E) shall be less than one hundred (100) tons per 12 consecutive month period with compliance demonstrated at the end of each month. Compliance with this limit makes 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable.

D.3.4 Particulate Matter [326 IAC 6-1-2]

Pursuant to 326 IAC 6-1-2(b)(3) the gaseous fuel-fired steam generators (Unit 1E) must not emit a particulate matter content greater than 0.01 grain per dry standard cubic foot.

D.3.5 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP), in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for these facilities and any emission control devices.

Compliance Determination Requirements

D.3.6 NSPS Compliance Provisions [326 IAC 12][40 CFR 60, Subpart Da]

(a) Compliance with the pound per million Btu (MMBtu) PM emission limitation in Condition D.3.2 constitutes compliance with the percent reduction requirements for PM in Condition D.3.2. [40 CFR 60.46a(a)]

(b) Compliance with the pound per million Btu (MMBtu) NO_X emission limitations in Condition D.3.2 constitutes compliance with the percent reduction requirements for NO_X in Condition D.3.2. [40 CFR 60.46a(b)]

(c) The PM and NO_X emission limitations in Condition D.3.2 apply at all times except during periods of startup, shutdown, or malfunction. [40 CFR 60.46a(c)]

(d) The SO_2 emission limitations in Condition D.3.2 apply at all times except during periods of startup, shutdown, or when emergency conditions exist and the procedures under 40 CFR 40.46a(d) are implemented. [40 CFR 60.46a(c)]

(e) Compliance with the SO_2 and NO_X emission limitations and SO_2 percent reductions requirements in Condition D.3.2 shall be based on a thirty (30) day rolling average. Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2 only).

(f) Compliance with the visible emission limitation in Condition D.3.2 shall be determined by 40 CFR 60, Appendix A, Method 9 and 40 CFR 60.11.

(g) If the Permittee has not obtained the minimum quantity of emission data (specified under 40 CFR 60.47a), compliance may be determined by following the procedures in section 7 of 40 CFR 60, Appendix A, Method 19.

D.3.7 NSPS Compliance Determination Procedures and Methods [326 IAC 12][40 CFR 60.48a]

Pursuant to 40 CFR 60.48a, the Permittee shall use methods and procedures in Appendix A of 40 CFR 60 in order to properly conduct the performance tests required under 40 CFR 60.8. (Section 60.8(f) does not apply for SO_2 and NO_x in this case). The procedures, along with acceptable alternative methods are as follows:

(a) The Permittee shall determine compliance with the particulate matter standards under Condition D.3.2 and the opacity standards under Condition D.3.2 as follows:
  (1) The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.
  (2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.
    (i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160"14 EC (320"25 EF).
    (ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the

O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 concentrations at each traverse point.

(3) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

(b) The Permittee shall determine compliance with the sulfur dioxide standard in Condition D.3.2 as follows:

(1) The appropriate procedures from Method 19 shall be used to determine the emission rate.

(c) The Permittee shall determine compliance with the nitrogen oxides standard in Condition D.3.2 as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO_x.

(2) The continuous monitoring system in § 60.47a (c) and (d) shall be used to determine the concentrations of NO_x and CO_2 or O_2.

(d) The Permittee may use the following alternative methods and procedures, as applicable:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 EC (320 EF). The procedures of §§ 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The Fc factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of § 60.46(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

D.3.8 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 12] [40 CFR 60, Subpart Da]

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and CFR 60, Subpart Da, continuous emission monitoring systems for Unit 1C shall be calibrated, maintained, and operated for measuring NOx, O_2 or CO_2 and CO, which meet the performance specifications of 326 IAC 3-5-2 and 40 CFR 60.47a.

D.3.9 NSPS Emission Monitoring [326 IAC 12][40 CFR 60.47a]

(a) Pursuant to 40 CFR 60.47a(c), the Permittee shall calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxide emissions discharged to the atmosphere. The output of this monitoring system shall be recorded.

(b) Pursuant to 40 CFR 60.47a(d), the Permittee shall, at the location where the nitrogen oxide monitor is, calibrate, maintain, and operate a continuous oxygen or carbon dioxide continuous monitoring system. The output of this monitoring system shall be recorded.

(c) Pursuant to 40 CFR 60.47a(e), the monitoring systems specified above shall be operated (and data recorded) at all times, including periods of startup, shutdown, malfunction, or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(d) Pursuant to 40 CFR 60.47a(f), the Permittee shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirements is not met with a continuous emission monitoring system, the Permittee shall supplement emission data with other monitoring systems approved by IDEM, OAQ and VCAPC or the reference methods below.

(1) Pursuant to 40 CFR 60.47a(h), when it become necessary to supplement continuous monitoring system data to meet the minimum data requirements, the Permittee shall use the following reference methods:

(A) Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(B) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(C) The procedure in Method 19 shall be used to compute each 1-hour average concentration in ng/J (lb/million BTU) heat input.

(2) Pursuant to 40 CFR 60.47a(j), the following alternatives to the reference methods and procedures may be used:

(A) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1-hour.

(B) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(C) For Method 3B, Method 3A may be used.

(e) Pursuant to 40 CFR 60.47a(g), the 1-hour averages are used to calculate average emission rates under the Compliance Provisions section above. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(f) Pursuant to 40 CFR 60.47a(i) the Permittee shall use the following methods and procedures to conduct monitoring system performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d). Acceptable alternative methods and procedures are given in paragraph (d)(2) of this Condition.

(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O_2, SO_2, and NO_x concentrations.

(2) SO_2 or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under Performance Specification 2 of Appendix B of this part.

(3) The span value for a continuous monitoring system measuring nitrogen oxides is 500 ppm.

D.3.10 Continuous Emission Monitoring System (CEMS) [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-1(d)(1), the Permittee with an emission limitation or permit requirement established under 326 IAC 2-1-3(i)(8) shall be required to calibrate, certify, operate and maintain a continuous monitoring system for measuring emissions rates (for CO in this case) in pounds per hour from stack 1C in accordance with 326 IAC 3-5-2 and 326 IAC 3-5-3.

(b) The emissions from the fuel preheater (Unit 1E) shall be estimated by utilizing the potential emissions (determined using the manufacturer's maximum emission rate)

(c) The Permittee shall submit to IDEM, OAQ and VCAPC, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4. This SOP was submitted on April 16, 2001.

(d) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(e) In instances of downtime, the Permittee shall use the manufacturer's specification of maximum emission rate to demonstrate compliance with the limits established in Condition D.3.3 if the emission unit (1C) is in operation at the time.

(f) After twelve (12) consecutive months of operation, the Permittee may submit to IDEM, OAQ and VCAPC alternative emission factors and their corresponding operating parameters to use in lieu of the manufacturer's emission rates in instances of downtime. The alternative emissions factors must be approved by IDEM, OAQ and VCAPC prior to use in calculating emissions for the limitations established in this permit. The alternative emission factors shall be based upon

collected monitoring and/or approved performance tests. In the event that the information submitted does not contain sufficient data to establish appropriate emission factors, the Permittee shall continue to collect data until appropriate emission factors can be established. During this period of time, the Permittee shall continue to use the manufacturer's maximum emission rates in periods of downtime.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.3.11 Record Keeping Requirements

(a) To document compliance with Condition D.3.3 and D.3.10, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits established in Condition D.3.3 and D.3.10.
   (1) All continuous CO monitoring data, pursuant to 326 IAC 3-5.
   (2) Records of the type and amount of fuel used in each unit (Unit 1C and Unit 1E).
   (3) Measured and calculated emission summaries.

(b) To document compliance with Conditions D.3.2, D.3.6, and D.3.7, the Permittee shall maintain records to comply with the NSPS Reporting Requirements outlined in Condition D.3.12 of this section. Records shall be complete and sufficient to establish compliance with the limit established in Condition D.3.2, D.3.6, and D.3.7.

(c) To document compliance with Condition D.3.5, the Permittee shall maintain records of any additional inspections prescribed by the Preventive Maintenance Plan.

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.3.12 NSPS Reporting Requirements [326 IAC 12][40 CFR 60.49a]

Pursuant to 40 CFR 60.49a, the Permittee shall report the following quarterly:

(a) For sulfur dioxide and nitrogen oxides the following information is reported to the IDEM, OAQ and VCAPC for each 24-hour period.
   (1) Calendar Date;
   (2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million BTU) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken;
   (3) Identification of the boiler operating days for which pollutant or diluent data have not been obtained for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken;
   (4) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions;
   (5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;
   (6) Identification of times when hourly averages have been obtained based on manual sampling methods;
   (7) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and
   (8) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(b) If the minimum quantity of emission data as required by Condition D.3.9(d) is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of D.3.9(e) is reported to the IDEM, OAQ and VCAPC for that 30-day period:
   (1) The number of hourly averages available for outlet emission rates (n_o);
   (2) The standard deviation of hourly averages for outlet emission rates (s_o);
   (3) The applicable potential combustion concentration; and
   (4) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(c) For any periods for which nitrogen oxides emissions data is not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(d) The Permittee shall submit a signed statement indicating whether:
   (1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.
   (2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.
   (3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
   (4) Compliance with the standards has or has not been achieved during the reporting period.

(e) The Permittee shall submit the written reports required under this section and 40 CFR 60, subpart A to the IDEM, OAQ and VCAPC for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

D.3.13 Reporting Requirements

(a) The Permittee shall submit a quarterly excess emissions report, if applicable, based on the continuous emissions monitor (CEM) data for CO, pursuant to 326 IAC 3-5-7. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements of this permit. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(b) A quarterly summary of the information to document compliance with the emission limitation in Condition D.3.3 shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting. This report shall include the following information: monthly CO emissions from Unit 1C (tons); monthly CO emissions from Unit 1E (tons); combined monthly CO emissions from the two (2) Units (Unit 1C and 1E) (tons); total prior eleven (11) consecutive months CO emissions (tons) from the two (2) Units combined; and the total twelve (12) consecutive month CO emissions (tons) from the two (2) Units combined. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

SECTION D.4 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

1. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 2, constructed in 1953, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 913.8 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

2. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 3, constructed in 1954, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

3. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 4, constructed in 1955, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

4. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 5, constructed in 1956, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 1096.2 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

5. Tangential fired coal electric utility boiler (pulverized - dry bottom, tangential), identified as Unit 6, constructed in 1968, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 2999.0 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.4.1 Particulate Matter (PM) [326 IAC 6-1-13]

Pursuant to 326 IAC 6-1-13 (Particulate limits - Vigo County) the particulate emissions from boilers (Units 2, 3, 4, 5, and 6) shall not exceed 0.1338 pounds of particulate matter per million BTU.

D.4.2 Sulfur Dioxide (SO2) [326 IAC 7-4-3]

Pursuant to 326 IAC 7-4-3 (Vigo County Sulfur Dioxide emission limitations) the sulfur dioxide emissions from boilers (Units 2, 3, 4, 5, and 6) shall not exceed 4.04 pounds of sulfur dioxide per MM BTU.

D.4.3 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(1) During boiler startups, an exemption from the forty percent (40%) opacity limit is allowed for up to two (2) hours (twenty (20) six (6) minute averaging periods) or until the flue gas temperature reaches two hundred forty (240) degrees Fahrenheit, whichever occurs first. In addition, an exemption of up to five (5) hours (fifty (50) six (6)minute averaged periods) is allowed for one (1) unit startup each calendar year.

(2) During boiler shutdowns, an exemption from the forty percent (40%) opacity limit is allowed for up to two (2) hours (twenty (20) six (6) minute averaged periods).

(3) Operation of the electrostatic precipitator is not required during these times.

(b) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging periods in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period. [326 IAC 5-1-3(b)]

(c) If a facility cannot meet the opacity limitations in (b) of this condition, the Permittee may submit a written request to IDEM, OAQ and VCAPC, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

D.4.4 Operation Standards [326 IAC 2-1.1-5(a)(4)] [40 CFR 261] [40 CFR 279] [329 IAC 13]

(a) All coal burned, including coal treated with any additive, shall meet the ASTM definition of coal.

(b) The burning of hazardous waste, as defined by 40 CFR 261, is prohibited in these facilities (Units 2, 3, 4, 5, and 6). Any boiler or condenser tube chemical cleaning waste liquids evaporated in the boiler, and any, binding agent or used oil combusted shall meet the toxicity characteristic requirements for non-hazardous waste.

(c) Any boiler or condenser tube chemical cleaning waste liquids evaporated in the boiler shall only contain the cleaning solution and two full volume boiler or condenser rinses.

D.4.5 Hourly Particulate Matter and SO_2 Emission Limitations [326 IAC 7-4-3][326 IAC 6-1-13]

In accordance with the modeling analysis required for the approval of 326 IAC 7-4-3 and 326 IAC 6-1-13, as well as 40 CFR 52.770(c)(66)(i)(A), the hourly particulate matter and sulfur dioxide emissions shall not exceed the following:

(a) The combined particulate matter emissions from Units 2, 3, 4, 5, and 6 shall not exceed a total of 848.4 pounds per hour (lbs/hr), with compliance demonstrated using a 3-hour average.

(b) The combined sulfur dioxide (SO_2) emissions from Units 2, 3, 4, 5, and 6 shall not exceed a total of 25,618 pounds per hour (lbs/hr), with compliance demonstrated using a three hour block average (three hour block periods ending at 03:00, 06:00, 09:00, 12:00, 15:00, 18:00, 21:00, and 24:00).

D.4.6 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

(a) A Preventive Maintenance Plan (PMP), in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for these facilities and their emission control devices.

(b) The PMP for an electrostatic precipitator shall include the following inspections, performed according to the indicated schedules:

(1) Plate and electrode alignment, every major maintenance outage, but no less than every two (2) years;

(2) ESP TR set components, performed whenever there is an outage of any nature lasting more than three (3) days, unless such inspections have been performed within the last six (6) months. At a minimum the following inspections shall be performed:
- (A) Internal inspection of shell for corrosion (including but not limited to doors, hatches, insulator housings, and roof area).
- (B) Effectiveness of rapping (including but not limited to buildup of dust on discharge electrodes and plates).
- (C) Gas distribution (including but not limited to buildup of dust on distribution plates and turning vanes).
- (D) Dust accumulation (including but not limited to buildup of dust on shell and support members that could result in grounds or promote advanced corrosion).
- (E) Major misalignment of plates (including but not limited to a visual check of plate alignment).
- (F) Rapper, vibrator and TR set control cabinents (including but not limited to motors and lubrication).
- (G) Rapper assembly (including but not limited to loose bolts, ground wires, water in air lines, and solenoids).
- (H) Vibrator and rapper seals (including but not limited to air in-leakage, wear, and deterioration).
- (I) TR set controllers (including but not limited to low voltage trip point, over current trip point, and spark rate).
- (J) Vibrator air pressure settings.

(3) Air and water infiltration, once per month. The recommended method for this inspection is for audible checks around ash hoppers/hatches, duct expansion joints, and areas of corrosion.

(4) Flue gas conditioning system (FGCS) components, performed whenever there is an outage of any nature lasting more than three days, unless such inspections have been performed within the last six months.

Compliance Determination Requirements

D.4.7 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

(a) Within the two (2) calendar years following the most recent stack test, compliance with the PM limitation in Condition D.4.1 for each Unit (Units 2, 3, 4, 5, and 6) shall be determined by a performance stack test conducted utilizing methods as approved by the Commissioner. This test shall be repeated at least once every two (2) calendar years following this valid compliance demonstration. Tests may be conducted individually in the unit duct work, or in Stack A in any combination of units, so long as all units are included in at least one test every two (2) calendar years. Testing shall be conducted in accordance with Section C- Performance Testing.

(b) The most recent test from (a) above shall be used to establish a correlation between heat input and pounds of particulate matter emission per million BTU of heat input (for each individual unit) to determine compliance with the hourly particulate limitation in Condition D.4.5.

D.4.8 Operation of Electrostatic Precipitator [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitators (ESPs) shall be in operation at all times that the boilers vented to the ESPs are in operation and combusting coal, except during periods of startup, shutdown, or emergency as described in Condition D.4.3 and Section B - Emergency Provisions.

D.4.9 Continuous Emissions Monitoring [326 IAC 3-5]

Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), continuous emission monitoring systems for the combined Unit 2, Unit 3, Unit 4, Unit 5, and Unit 6 stack (Stack A) shall be calibrated, maintained,

and operated for measuring opacity, which meet the performance specifications of 326 IAC 3-5-2. Continuous monitoring of opacity is not required during periods in which the boilers are not operating and combusting fuel.

D.4.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-2] [326 IAC 7-4-3]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of 4.04 pounds per million BTU using a thirty (30) day rolling weighted average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d) and (e); or

(2) Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-3 or of continuous emissions monitoring.

(c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7 shall not apply. [326 IAC 7-2-1(g)]

D.4.11 Cleaning Waste Characterization [326 IAC 2-1.1-5(a)(4)] [40 CFR 261]

The Permittee shall use appropriate methodology as identified in 40 CFR Part 261 to characterize all boiler or condenser chemical cleaning wastes that will be evaporated, to determine compliance with the Operation Standards condition in this D section.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.4.12 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) The ability of the ESP to control particulate emissions shall be monitored once per shift, when the unit is in operation, by measuring and recording the number of T-R sets in service and the primary and secondary voltages and the currents of the transformer-rectifier (T-R) sets.

(b) Reasonable response steps shall be taken in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports whenever the percentage of T-R sets in service falls below 90 percent (90%). T-R set failure resulting in less than 90 percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a violation of this permit.

D.4.13 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) In the event of opacity exceeding thirty percent (30%) average opacity for three (3) consecutive six (6) minute averaging periods, appropriate response steps shall be taken in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below thirty percent. Examples of expected response steps include, but are not limited to, boiler loads being reduced, adjustment of flue gas conditioning rate, and ESP T-R sets being returned to service.

(b) Opacity readings in excess of thirty percent (30%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a violation of this permit.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.4.14 Record Keeping Requirements

(a) To document compliance with Section C - Opacity and Conditions D.4.1, D.4.3, and D.4.5, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.4.1 and D.4.3.

(1) Data and results from the most recent stack test;
(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5;
(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime; and
(4) All ESP parametric monitoring readings.

(b) To document compliance with Conditions D.4.2 and D.4.5, the Permittee shall maintain records in accordance with (1) through (2) below during coal combustion. Records maintained for (1) through (2) shall be sufficient to demonstrate compliance using a thirty (30) day rolling weighted average and shall be complete and sufficient to establish compliance with the SO_2 limit established in Condition D.4.2.

(1) All fuel sampling and analysis data, pursuant to 326 IAC 7-2; and
(2) Actual fuel usage since last compliance period.

(c) To document compliance with Condition D.4.5, the Permittee shall maintain records of the 3-hour block average SO_2 and 3-hour average Particulate Matter emissions from Stack A (Units 2, 3, 4, 5, and 6 combined). The particulate matter emission rate shall be developed using actual heat input rate for each unit in conjunction with the respective correlation between heat input and pounds of particulate matter emissions per million BTU heat input from the latest stack test. The SO_2 rate shall be developed using the current coal sulfur analysis and the heat input rates.

(d) To document compliance with Condition D.4.6, the Permittee shall maintain records of the results of all boiler and emission control equipment inspections, including any additional inspections prescribed by the Preventive Maintenance Plan.

(e) To document compliance with Condition D.4.12, the Permittee shall maintain records of boiler operation, and the operational status of each T-R set.

(f) To document compliance with the provisions of 40 CFR 75, the Permittee shall maintain records of all SO_2 and NO_x CEM data.

(g) Pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of the information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4. In addition, any revision to the SOP shall be submitted to IDEM, OAQ and VCAPC.

(h) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.4.15 Reporting Requirements

(a) A quarterly summary of opacity exceedances shall be submitted to the addresses listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the

quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) A quarterly report of the thirty (30) day rolling weighted average sulfur dioxide emission rate in pounds per million Btus, and records of the daily average coal sulfur content, coal heat content, weighing factor, and daily average sulfur dioxide emission rate in pounds per million Btus shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. [326 IAC 7-2-1(c)(1)]

The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) A quarterly summary of hourly SO_2 or Particulate Matter exceedances shall be submitted to the addresses listed in Section C - General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) Pursuant to 326 IAC 3-5-7(5), reporting of continuous monitoring system instrument downtime, except for zero (0) and span chacks, which shall be reports separately, shall include the following:

(1) Date of downtime
(2) Time of commencement.
(3) Duration of each downtime.
(4) Reasons for each downtime.
(5) Nature of system repairs and adjustments.

The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

1. Coal pile maintenance, identified as F-1.
2. Coal handling, identified as F-2.
3. Coal pile wind erosion [326 IAC 6-1-2][326 IAC 6-4]
4. Lime silo: 1388 cubic feet [326 IAC 6-1-2]
5. Lime day bin: 87 cubic feet [326 IAC 6-1-2]
6. Unit 6 hydroveyor [326 IAC 6-1-2]
7. Ash hydroveyor separator Units 1&2 [326 IAC 6-1-2]
8. Ash hydroveyor separator Units 3&4 [326 IAC 6-1-2]
9. Ash hydroveyor separator Unit 5 [326 IAC 6-1-2]
10. Ash pond: 216 acres [326 IAC 6-1-2][326 IAC 6-4]
11. Ash pond management and maintenance [326 IAC 6-1-2]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.5.1 Particulate Matter (PM) Emissions [326 IAC 6-1-2(a)]

Pursuant to 326 IAC 6-1-2(a), each of these emission units shall not emit greater than 0.03 grain per dry standard cubic foot.

D.5.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP), in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for these facilities and their emission control devices.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.5.3 Visible Emissions Notations [326 2-7-6(1)][326 IAC 2-7-5(1)]

(a) Visible emission notations of any coal handling unloading and transfer points shall be performed once per shift during normal daylight operations when handling coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of any ash handling exhaust point shall be performed once per shift during normal daylight operations when handling ash. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the ash storage pond shall be performed once per shift during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

(d) If visible emissions are observed crossing the property line or boundries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a violation of this permit.

(e) If abnormal emissions are observed at an unloading or transfer point, the Permittee shall take reasonable response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports. Observation of abnormal emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a violation of this permit.

(f) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(g) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(h) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.5.4 Record Keeping Requirements

(a) To document compliance with Section C - Opacity and Condition D.5.3, the Permittee shall maintain records of the visible emission notations and all response steps taken and the outcome for each.

(b) To document compliance with Condition D.5.2, the Permittee shall maintain records of any additional inspections prescribed by the Preventive Maintenance Plan.

(c) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

SECTION D.6 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

1. Diesel Generator, identified as 7A, constructed in 1967, combusting #2 fuel oil, with a nominal rated capacity of 28.6 million BTU per hour, used for intermittent and emergency duty, using no control, and exhausting to stack 7A.

2. Diesel Generator, identified as 7B, constructed in 1967, combusting #2 fuel oil, with a nominal rated capacity of 28.6 million BTU per hour, used for intermittent and emergency duty, using no control, and exhausting to stack 7B.

3. Diesel Generator, identified as 7C, constructed in 1967, combusting #2 fuel oil, with a nominal rated capacity of 28.6 million BTU per hour, used for intermittent and emergency duty, using no control, and exhausting to stack 7C.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.6.1 Sulfur Dioxide (SO2) [326 IAC 7-1.1-2]

Pursuant to 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations), the SO2 emissions from Units 7A, 7B, and 7C shall not exceed 0.5 pounds per million BTU.

D.6.2 Particulate Matter Emission Limitations [326 IAC 6-1-2]

Pursuant to 326 IAC 6-1-2(a), particulate matter emissions from the diesel fired generators (7A, 7B, and 7C) shall not exceed 0.03 grain per dry standard cubic foot.

D.6.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section B -Preventive Maintenance Plan, of this permit, is required for these facilities.

Compliance Determination Requirements

D.6.4 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-1.1-2][326 IAC 7-2]

Pursuant to 326 IAC 3-7-4, 326 IAC 7-1.1-2, and 326 IAC 7-2, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed 0.5 pounds per million BTU, demonstrated on a calendar month average, by:

(a) Providing vendor analysis of fuel delivered, accompanied by a vendor certification; or

(b) Providing analysis of fuel oil samples collected and analyzed using the ASTM methods cited in 326 IAC 3-7-4(a).

(1) Oil samples shall be collected from the tanker truck load prior to transferring fuel to the storage tank; or

(2) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)][326 IAC 2-7-5(1)]

D.6.5 Visible Emissions Notations

(a) Visible emission (VE) notations of the generators' stack exhausts shall be performed once per shift during normal daylight operations while combusting fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) If abnormal emissions are observed at any generators' exhaust, the Permittee shall take reasonable response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps in accordance with Section C - Compliance Response Plan - Preparation, Implementation, Records, and Reports, shall be considered a deviation from this permit.

(c) "Normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(d) A trained employee is an employee who has worked at the plant at least (1) month and has been trained in the appearance and characteristics of normal visible emissions for the generators.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.6.6 Record Keeping Requirements

(a) To document compliance with Conditions D.6.1 and D.6.4, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained shall be complete and sufficient to establish compliance with the SO2 limit as required in Conditions D.6.1 and D.6.4.

(1) Calendar dates covered in the compliance period.

(2) Monthly weighted average sulfur content.

(3) Fuel heat content.

(4) Fuel consumption.

(5) Monthly weighted average sulfur dioxide emission rate in pounds per million BTU.

(b) To document compliance with Condition D.6.5, the Permittee shall maintain records of visible emission notations of the generators' stack exhausts.

(c) To document compliance with Condition D.6.3, the Permittee shall maintain records of any additional inspections prescribed by the Preventive Maintenance Plan.

(d) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.6.7 Reporting Requirements

A summary of the information to document compliance with Condition D.6.1 shall be submitted to the addresses listed in Section C - General Reporting Requirements upon request.

The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

SECTION D.7 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]:

1. Thaw pit fuel oil tank: 20,000 gallon (constructed 1990)[326 IAC 12][40 CFR 60, Subpart Kb]
2. Degreaser (maintenance shop): 30 gallon (constructed about 1980) [326 IAC 8-3]
3. Parts cleaner (electric shop): 30 gallon (constructed about 1980) [326 IAC 8-3]
4. Parts cleaner (main floor storage area): 30 gallon (constructed about 1980) [326 IAC 8-3]
5. Two (2) Repowering fuel oil storage tank: 99,500 gallon each (constructed in 1993) [326 IAC 12][40 CFR 60, Subpart Kb]
6. Fuel oil tank: 50,000 gallons (constructed in 1986) [326 IAC 12][40 CFR 60, Subpart Kb]

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.7.1 General Provisions Relating to NSPS [326 IAC 12][60 CFR 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated under 326 IAC 12, apply to the fuel oil storage tanks (Thaw pit, two (2) Repowering, and Fuel oil tank) except when otherwise specified in 40 CFR Part 60, Subpart Kb.

D.7.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations), for cold cleaning operations constructed after January 1, 1980 (Maintenance shop, electric shop, and main floor storage area), the Permittee shall:

(a) Equip the cleaner with a cover;
(b) Equip the cleaner with a facility for draining cleaned parts;
(c) Close the degreaser cover whenever parts are not being handled in the cleaner;
(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;
(e) Provide a permanent, conspicuous label summarizing the operation requirements;
(f) Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, in such a manner that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.7.3 NSPS Recordkeeping Requirements [40 CFR 60, Subpart Kb]

All records of each storage vessel (Thaw pit. two (2) Repowering, and Fuel oil tank), as specified in 60.110b(a), shall be kept and made readily accessible for the life of the source. The records shall include the dimension and an analysis showing the capacity of the storage vessel.

SECTION E **TITLE IV CONDITIONS**

Facility Description [326 IAC 2-7-5(15)]

1. Combustion Turbine, identified as Unit 1A, constructed in 1995, with a nominal rated capacity of 1709.1 million BTU per hour (192 megawatt), utilizing syngas or natural gas in combined cycle mode and natural gas in simple cycle mode, utilizing steam injection for NO_x control, and exhausting to stack 1A (combined cycle mode) or 1D (simple cycle mode). Stack 1A (combined cycle) has continuous emission monitors for SO_2, NOx, CO_2, and volumetric flow rate as well as a continuous opacity monitor (COM). Stack 1D (bypass) has continuous emission monitors for NOx and CO_2.

2. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 2, constructed in 1953, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 913.8 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

3. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 3, constructed in 1954, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

4. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 4, constructed in 1955, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

5. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 5, constructed in 1956, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 1096.2 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

6. Tangential fired coal electric utility boiler (pulverized - dry bottom, tangential), identified as Unit 6, constructed in 1968, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 2999.0 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Acid Rain Program

E.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21] [40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72

through 40 CFR 78. The Acid Rain permit for this source is attached to this permit as Appendix A, and is incorporated by reference.

E.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION F Nitrogen Oxides Budget Trading Program - NO_X Budget Permit for NO_X Budget Units Under 326 IAC 10-4-1(a)

ORIS Code: 1010

NO_X Budget Source [326 IAC 2-7-5(15)]

1. Combustion Turbine, identified as Unit 1A, constructed in 1995, with a nominal rated capacity of 1709.1 million BTU per hour (192 megawatt), utilizing syngas or natural gas in combined cycle mode and natural gas in simple cycle mode, utilizing steam injection for NO_x control, and exhausting to stack 1A (combined cycle mode) or 1D (simple cycle mode). Stack 1A (combined cycle) has continuous emission monitors for SO_2, NOx, CO_2, and volumetric flow rate as well as a continuous opacity monitor (COM). Stack 1D (bypass) has continuous emission monitors for NOx and CO_2.

2. Natural gas fired boiler, identified as Unit 1C, constructed in 2001, with a nominal rated capacity of 397.8 million BTU per hour, using low NOx burners with flue gas recirculation as NOx control, and exhausting to stack 1C with continuous emission monitors for NOx, CO_2, and CO.

3. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 2, constructed in 1953, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 913.8 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

4. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 3, constructed in 1954, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

5. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 4, constructed in 1955, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 922.9 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

6. Wall fired coal electric utility boiler (pulverized - dry bottom), identified as Unit 5, constructed in 1956, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 1096.2 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

7. Tangential fired coal electric utility boiler (pulverized - dry bottom, tangential), identified as Unit 6, constructed in 1968, using #2 fuel oil as ignition fuel, with a nominal rated heat input capacity of 2999.0 million BTU per hour, using modified burner design (low NOx) for NOx control and electrostatic precipitator (ESP) for particulate control, exhausting to Stack A. Stack A is equipped with a continuous opacity monitor (COM) to monitor opacity as well as continuous emission monitors for NOx, CO_2, SO_2, and volumetric flow rate.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

F.1 Automatic Incorporation of Definitions [326 IAC 10-4-7(e)]

This NO_X budget permit is deemed to incorporate automatically the definitions of terms under 326 IAC 10-4-2.

F.2 Standard Permit Requirements [326 IAC 10-4-4(a)]

(a) The owners and operators of the NO_X budget source and each NO_X budget unit shall operate each unit in compliance with this NO_X budget permit.

(b) The NO_X budget units subject to this NO_X budget permit are Unit 1A, Unit 1C, Unit 2, Unit 3, Unit 4, Unit 5, and Unit 6.

F.3 Monitoring Requirements [326 IAC 10-4-4(b)]

(a) The owners and operators and, to the extent applicable, the NO_X authorized account representative of the NO_X budget source and each NO_X budget unit at the source shall comply with the monitoring requirements of 40 CFR 75 and 326 IAC 10-4-12.

(b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 326 IAC 10-4-12 shall be used to determine compliance by each unit with the NO_X budget emissions limitation under 326 IAC 10-4-4(c) and Condition F.4, Nitrogen Oxides Requirements.

F.4 Nitrogen Oxides Requirements [326 IAC 10-4-4(c)]

(a) The owners and operators of the NO_X budget source and each NO_X budget unit at the source shall hold NO_X allowances available for compliance deductions under 326 IAC 10-4-10(j), as of the NO_X allowance transfer deadline, in each unit's compliance account and the source's overdraft account in an amount:

(1) Not less than the total NO_X emissions for the ozone control period from the unit, as determined in accordance with 40 CFR 75 and 326 IAC 10-4-12;

(2) To account for excess emissions for a prior ozone control period under 326 IAC 10-4-10(k)(5); or

(3) To account for withdrawal from the NO_X budget trading program, or a change in regulatory status of a NO_X budget opt-in unit.

(b) Each ton of NO_X emitted in excess of the NO_X budget emissions limitation shall constitute a separate violation of the Clean Air Act (CAA) and 326 IAC 10-4.

(c) Each NO_X budget unit shall be subject to the requirements under (a) above and 326 IAC 10-4-4(c)(1) starting on May 31, 2004.

(d) NO_X allowances shall be held in, deducted from, or transferred among NO_X allowance tracking system accounts in accordance with 326 IAC 10-4-9 through 11, 326 IAC 10-4-13, and 326 IAC 10-4-14.

(e) A NO_X allowance shall not be deducted, in order to comply with the requirements under (a) above and 326 IAC 10-4-4(c)(1), for an ozone control period in a year prior to the year for which the NO_X allowance was allocated.

(f) A NO_X allowance allocated under the NO_X budget trading program is a limited authorization to emit one (1) ton of NO_X in accordance with the NO_X budget trading program. No provision of the NO_X budget trading program, the NO_X budget permit application, the NO_X budget permit, or an exemption under 326 IAC 10-4-3 and no provision of law shall be construed to limit the authority of the U.S. EPA or IDEM, OAQ to terminate or limit the authorization.

(g) A NO_X allowance allocated under the NO_X budget trading program does not constitute a property right.

(h) Upon recordation by the U.S. EPA under 326 IAC 10-4-10, 326 IAC 10-4-11, or 326 IAC 10-4-13, every allocation, transfer, or deduction of a NO_X allowance to or from each NO_X budget unit's compliance account or the overdraft account of the source where the unit is located is deemed to amend automatically, and become a part of, this NO_X budget permit of the NO_X budget unit by operation of law without any further review.

F.5 Excess Emissions Requirements [326 IAC 10-4-4(d)]

The owners and operators of each NO_X budget unit that has excess emissions in any ozone control period shall do the following:

(a) Surrender the NO_X allowances required for deduction under 326 IAC 10-4-10(k)(5).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed under 326 IAC 10-4-10(k)(7).

F.6 Record Keeping Requirements [326 IAC 10-4-4(e)] [326 IAC 2-7-5(3)]

Unless otherwise provided, the owners and operators of the NO_X budget source and each NO_X budget unit at the source shall keep, either on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years:

(a) The account certificate of representation for the NO_X authorized account representative for the source and each NO_X budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 326 IAC 10-4-6(h). The certificate and documents shall be retained either on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond the five (5) year period until the documents are superseded because of the submission of a new account certificate of representation changing the NO_X authorized account representative.

(b) All emissions monitoring information, in accordance with 40 CFR 75 and 326 IAC 10-4-12, provided that to the extent that 40 CFR 75 and 326 IAC 10-4-12 provide for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_X budget trading program.

(d) Copies of all documents used to complete a NO_X budget permit application and any other submission under the NO_X budget trading program or to demonstrate compliance with the requirements of the NO_X budget trading program.

This period may be extended for cause, at any time prior to the end of five (5) years, in writing by IDEM, OAQ, Vigo County Air Pollution Control (VCAPC) or the U.S. EPA. Records retained at a central location within Indiana shall be available immediately at the location and submitted to IDEM, OAQ, VCAPC, or U.S. EPA within three (3) business days following receipt of a written request. Nothing in 326 IAC 10-4-4(e) shall alter the record retention requirements for a source under 40 CFR 75. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

F.7 Reporting Requirements [326 IAC 10-4-4(e)]

(a) The NO_X authorized account representative of the NO_X budget source and each NO_X budget unit at the source shall submit the reports and compliance certifications required under the NO_X budget trading program, including those under 326 IAC 10-4-8, 326 IAC 10-4-12, or 326 IAC 10-4-13.

(b) Pursuant to 326 IAC 10-4-4(e) and 326 IAC 10-4-6(e)(1), each submission shall include the following certification statement by the NO_X authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the NO_X budget sources or NO_X budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 10-4 requires a submission to IDEM, OAQ, the NO_X authorized account representative shall submit required information to:

Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South 3rd Street
Terre Haute, Indiana 47807

(d) Where 326 IAC 10-4 requires a submission to U.S. EPA, the NO_X authorized account representative shall submit required information to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

F.8 Liability [326 IAC 10-4-4(f)]

The owners and operators of each NO_X budget source shall be liable as follows:

(a) Any person who knowingly violates any requirement or prohibition of the NO_X budget trading program, a NO_X budget permit, or an exemption under 326 IAC 10-4-3 shall be subject to enforcement pursuant to applicable state or federal law.

(b) Any person who knowingly makes a false material statement in any record, submission, or report under the NO_X budget trading program shall be subject to criminal enforcement pursuant to the applicable state or federal law.

(c) No permit revision shall excuse any violation of the requirements of the NO_X budget trading program that occurs prior to the date that the revision takes effect.

(d) Each NO_X budget source and each NO_X budget unit shall meet the requirements of the NO_X budget trading program.

(e) Any provision of the NO_X budget trading program that applies to a NO_X budget source, including a provision applicable to the NO_X authorized account representative of a NO_X budget source, shall also apply to the owners and operators of the source and of the NO_X budget units at the source.

(f) Any provision of the NO_X budget trading program that applies to a NO_X budget unit, including a provision applicable to the NO_X authorized account representative of a NO_X budget unit, shall also apply to the owners and operators of the unit. Except with regard to the requirements applicable

to units with a common stack under 40 CFR 75 and 326 IAC 10-4-12, the owners and operators and the NO_X authorized account representative of one (1) NO_X budget unit shall not be liable for any violation by any other NO_X budget unit of which they are not owners or operators or the NO_X authorized account representative and that is located at a source of which they are not owners or operators or the NO_X authorized account representative.

F.9 Effect on Other Authorities [326 IAC 10-4-4(g)]

No provision of the NO_X budget trading program, a NO_X budget permit application, a NO_X budget permit, or an exemption under 326 IAC 10-4-3 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NO_X authorized account representative of a NO_X budget source or NO_X budget unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the CAA.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
and
VIGO COUNTY AIR POLLUTION CONTROL

PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: PSI Energy Inc. - Wabash River Generating Station
Source Address: 450 Bolton Road, West Terre Haute, Indiana 47885
Source Name: PSI Energy Inc. - Wabash River Repowering
Source Address: 445 Bolton Road, West Terre Haute, Indiana 47885
Mailing Address: c/o Steven L. Pearl, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: 167-7176-00021

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

Annual Compliance Certification Letter

Test Result (specify)

Report (specify)

Notification (specify)

Affidavit (specify)

Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Telephone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE BRANCH
100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
Phone: 317-233-5674
Fax: 317-233-5967
and

VIGO COUNTY AIR POLLUTION CONTROL
103 South 3rd Street
Terre Haute, Indiana 47807
Phone: 812-462-3433
Fax: 812-462-3447

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name:	PSI Energy Inc. - Wabash River Generating Station
Source Address:	450 Bolton Road, West Terre Haute, Indiana 47885
Source Name:	PSI Energy Inc. - Wabash River Repowering
Source Address:	445 Bolton Road, West Terre Haute, Indiana 47885
Mailing Address:	c/o Steven L. Pearl, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.:	167-7176-00021

This form consists of 2 pages **Page 1 of 2**

9 This is an emergency as defined in 326 IAC 2-7-1(12)
- C The Permittee must notify the Office of Air Quality (OAQ) and Vigo County Air Pollution Control (VCAPC), within four (4) daytime business hours (OAQ: 1-800-451-6027 or 317-233-5674, ask for Compliance Section and VCAPC: 812-462-3433); and
- C The Permittee must submit notice in writing or by facsimile within two (**2**) working days (IDEM Facsimile Number: 317-233-5967 and VCAPC Facsimile Number: 812-462-3447), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N Describe: Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by:

Title / Position:

Date:

Telephone:

A certification is not required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
and
VIGO COUNTY AIR POLLUTION CONTROL

PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: PSI Energy Inc. - Wabash River Generating Station
Source Address: 450 Bolton Road, West Terre Haute, Indiana 47885
Source Name: PSI Energy Inc. - Wabash River Repowering
Source Address: 445 Bolton Road, West Terre Haute, Indiana 47885
Mailing Address: c/o Steven L. Pearl, 1000 East Main Street, Plainfield, Indiana 46168
Part 70 Permit No.: 167-7176-00021

Months:_____to_____Year: _____

This report shall be submitted quarterly based on a calendar year. For the purpose of this permit, "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. Deviations that are required to be reported by an applicable requirement shall be reported according to the schedule stated in the applicable requirement and do not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement (specify permit condition #)

Date of Deviation: **Duration of Deviation:**

Number of Deviations:

Probable Cause of Deviation:

Response Steps Taken:

Permit Requirement (specify permit condition #)

Date of Deviation: **Duration of Deviation:**

Number of Deviations:

Probable Cause of Deviation:

Response Steps Taken:

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed By:

Title/Position:

Date:

Telephone:

Attach a signed certification to complete this report.

Indiana Department of Environmental Management
Office of Air Quality
And
Vigo County Air Pollution Control

Technical Support Document (TSD) for a Significant Permit Modification

Source Background and Description

Source Name:	PSI Energy, Inc. – Wabash River Generating Station
Source Location:	450 Bolton Road, West Terre Haute, Indiana 47885
County:	Vigo
SIC Code:	4911
Operation Permit No.:	T167-7176-00021
Operation Permit Issuance Date:	September 2, 2004
Permit Modification No.:	167-19843-00021
Permit Reviewer:	Rob Harmon

The Office of Air Quality (OAQ) and Vigo County Air Pollution Control have reviewed a modification application from PSI Energy, Inc. – Wabash River Generating Station, relating to the operation of a stationary electric power generating station.

Source Definition

This power plant with gasification operations consists of a source with an on-site contractor:

(1) Cinergy (PSI Energy) - Wabash River, the primary operation, consists of two (2) plants
   (a) PSI Energy, Inc. – Wabash River Generating Station, located at 450 Bolton Road, West Terre Haute, Indiana, 47885; and
   (b) PSI Energy, Inc. – Wabash River Repowering, located at 445 Bolton Road, West Terre Haute, Indiana, 47885.

(2) SG Solutions, LLC, the supporting operation, is located at 444 West Sandford Road, West Terre Haute, Indiana.

IDEM and VCAPC have determined that Cinergy - Wabash River (both plants), and SG Solutions, LLC are under the common control of Cinergy - Wabash River. These three plants are considered one source due to contractural control. Therefore, the term "source" in the Part 70 documents refers to Cinergy - Wabash River (both plants) and SG Solutions, LLC as one source.

Separate Part 70 permits will be issued to Cinergy - Wabash River (both plants) and SG Solutions, LLC solely for administrative purposes. The initial Part 70 Permit for Cinergy (PSI Energy) – Wabash River (both plants) was issued on September 2, 2004.

History

On November 12, 2004, PSI Energy, Inc. submitted an application to the OAQ and VCAPC requesting a permit modification to revise the 40 CFR Subpart GG language. On July 8, 2004, the US EPA issued final rule revisions (effective the same date) to the New Source Performance Standards for Stationary Gas Turbines, 40 CFR Subpart GG (69 FR 41346). PSI Energy, Inc. – Wabash River Generating Station was issued Part 70 Operating Permit No. T167-7176-00021 on September 2, 2004.

Explanation of Modification

The permit modification will consist of the following: Incorporation of revisions to New Source

Performance Standard (NSPS) for Turbines, 40 CFR 60, Subpart GG. These revisions include: the use of a continuous emission monitoring system (CEMS) to replace steam-to-fuel ratios for NOx control; the elimination of fuel bound nitrogen determinations when the Permittee is not claiming any credit for fuel bound nitrogen; and, the removal of certain fuel sulfur analysis requirements when the gaseous fuel being combusted meets the definition of natural gas.

Existing Approvals

The source was issued a Part 70 Operating Permit (T167-7176-00021) on September 2, 2004.

Enforcement Issue

There are no enforcement actions pending.

Recommendation

The staff recommends to the Commissioner that the Significant Permit Modification be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on November 12, 2004.

Emission Calculations

The permit modification will not result in any new emissions.

Justification for Modification

The Part 70 Operating permit is being modified through a Part 70 Significant Permit Modification. This modification is being performed pursuant to 326 IAC 2-7-12(d)(1) for a request that does not qualify as a minor permit modification or administrative amendment, and is considered as a significant change to existing permit terms and conditions, including monitoring, record keeping and reporting.

County Attainment Status

The source is located in Vigo County.

Pollutant	Status
PM-10	Attainment
PM2.5	Attainment
SO_2	Maintenance Attainment
NO_2	Attainment
1-hour Ozone	Attainment
8-hour Ozone	Basic Non-Attainment
CO	Attainment
Lead	Attainment

(a) Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC emissions and NOx are considered when evaluating the rule applicability relating to ozone. Vigo County has been designated as basic non-attainment or unclassifiable for ozone. Therefore, VOC emissions and NOx were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3. See the State Rule Applicability for the source section.

(b) Vigo County has been classified as attainment for PM2.5. U.S. EPA has not yet established the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 for PM 2.5 emissions. Therefore, until the U.S. EPA adopts specific provisions for PSD review for PM 2.5 emissions, it has directed states to regulate PM10 emissions as a surrogate for PM 2.5 emissions. See the State Rule Applicability for the source section.

(c) Vigo County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability for the source section.

Federal Rule Applicability

There are no new federal or state rules applicable to this permit modification, as the changes presented herein do not involve construction of a new emissions unit, nor the modification or reconstruction of an existing emissions unit.

This permit modification involves a revision of 40 CFR 60 Subpart GG conditions in the original Part 70 permit, based on US EPA's final rule revisions, published in the Federal Register on July 8, 2004. The following section documents these changes.

Changes to the Part 70 Permit Due to This Modification:

The following changes are made as the Significant Permit Modification to Part 70 No. T167-7176-00021. New language is shown in **bold** and deleted language is shown with a line ~~through it~~ for emphasis).

1. Under the rule revision, pursuant to 40 CFR 60.334(b) and IDEM's authorization of alternative monitoring requirements under 326 IAC 12-1(b), NOx CEMs may be used in lieu of monitoring the water injection rate. The Permittee has opted to use the CEMS instead of monitoring water-to-fuel ratio. Condition D.1.11(c)(2) has been revised to reflect this change. Additionally, pursuant to 40 CFR 60.334(h)(2) and (3), if the Permittee claims zero allowance for fuel bound nitrogen, sampling the fuel for nitrogen content is not required, and if the fuel qualifies as natural gas, sampling the fuel for sulfur content is not required. The Permittee has elected not to monitor nitrogen content as the source is claiming zero allowance for fuel bound nitrogen. Conditions D.1.11(a), (d) and (e) have been revised to incorporate the above mentioned changes and the new language pertaining to sulfur and nitrogen content monitoring.

D.1.11 NSPS Test Methods and Procedures [326 IAC 12][40 CFR 60.335]

(a) Pursuant to 40 CFR 60.335(a), the Permittee shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the IDEM, OAQ and VCAPC to determine the nitrogen content of the fuel being fired. **Pursuant to 40 CFR Part 60.334(h)(2), the Permittee is not required to monitor the nitrogen content of the fuel combusted in the turbine if the Permittee does not claim any allowance for fuel bound nitrogen.**

(b) Pursuant to 40 CFR 60.335(b), the Permittee, in conducting the performance tests required in 40 CFR 60.8, shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this Condition.

(c) Pursuant to 40 CFR 60.335(c), the Permittee shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Condition D.1.2 and Condition D.1.4 as follows:

(1) The nitrogen oxides emission rate (NO_x) shall be computed for each run using the following equation:

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5}\, e^{19(Ho-0.00633)}(288K/T_a)1.53$$

where: NO_x= emission rate of NO_x at 15 percent O_2 and ISO standard conditions, volume percent;
NO_{xo}= observed NO_x concentration, ppm by volume;
P_r= reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg;
P_o= observed combustor inlet absolute pressure at test, mm Hg;
H_o= observed humidity of ambient air, g H_2O/g air;
e= transcendental constant, 2.718; and
T_a= ambient temperature, EK.

~~(2)~~ ~~The monitoring device of Condition D.1.12 shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Condition D.1.2 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.~~

(2) ~~(3)~~ Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this Condition.

(d) Pursuant to 40 CFR 60.335(d), the owner or operator shall determine compliance with the sulfur content standard in Condition D.1.4 as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference - see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the IDEM, OAQ and VCAPC. **Notwithstanding the provisions of 40 CFR 60.334(h)(3), the Permittee is not required to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Section 60.331(u), regardless of whether an existing custom schedule approved by IDEM, OAQ and VCAPC for Subpart GG requires such monitoring. The Permittee shall use one of the sources of information described in 40 CFR 60.334(h)(3)(i) and (ii).**

(e) Pursuant to 40 CFR 60.335(e), to meet the requirements of Condition D.1.13, the Permittee shall use the methods specified in paragraphs (a) and ~~(b)~~ **(d)** of this Condition to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the Permittee, a service contractor retained by the Permittee, the fuel vendor, or any other qualified agency. **Pursuant to 40 CFR 60.334(h)(2) and (3), the Permittee is not required to analyze the fuel nitrogen content when the Permittee claims a zero allowance for fuel bound nitrogen. The Permittee also does not have to analyze the fuel for sulfur content if it qualifies as natural gas.**

(f) Pursuant to 40 CFR 60.335(f) the Permittee may use the following alternatives to the reference methods and procedures specified in this condition: Instead of using the equation in paragraph (c)(1) of this Condition, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in 40 CFR 60.8 to ISO standard day conditions. These factors are developed for each gas turbine model they manufacturer in terms of combustion inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. They shall be substantiated with data and must be approved for use

by the IDEM, OAQ and VCAPC before the initial performance test required by 40 CFR 60.8. Notices of approval of custom ambient condition correction factors will be published in the Federal Register.

2. Under the rule revision, pursuant to 40 CFR 60.334(b) and IDEM's authorization of alternative monitoring requirements under 326 IAC 12-1(b), NOx CEMs may be used in lieu of monitoring the fuel consumption and water-to-fuel ratio. The Permittee has opted to use the CEMS instead of monitoring water-to-fuel ratio. Condition D.1.12 has been revised to reflect this change.

D.1.12 Nitrogen Oxide Controls

(a) Pursuant to CP 167-2610-00021 (Issued May 27, 1993) and SSM 167-11328-00021 (issued January 27, 2000), the steam injection shall be used to control nitrogen oxide emissions to the levels required in Condition D.1.2 and D.1.3. ~~The proper steam injection ratios at various levels was determined during initial compliance testing (pursuant to 40 CFR 60.335) and an injection schedule (based on the fuel being used) was established and programed into the control system.~~

(b) The steam injection system shall be in service and operating at the appropriate rate**, as determined by the continuous emission monitoring system (CEMS) which consists of NO_x and O_2 or CO_2 monitors,** whenever the turbine is in operation, except for the time specified for start-up and shutdown period.

3. Under the rule revision, pursuant to 40 CFR 60.334(b) and IDEM's authorization of alternative monitoring requirements under 326 IAC 12-1(b), NOx CEMs may be used in lieu of monitoring the water injection rate. The Permittee has opted to use the CEMS instead of monitoring water-to-fuel ratio. Conditions D.1.13(a) and (c)(1) have been revised to reflect this change. Additionally, pursuant to 40 CFR 60.334(h)(2) and (3), if the Permittee claims zero allowance for fuel bound nitrogen, sampling the fuel for nitrogen content is not required, and if the fuel qualifies as natural gas, sampling the fuel for sulfur content is not required. The Permittee has elected not to monitor nitrogen content as the source is claiming zero allowance for fuel bound nitrogen. Condition D.1.13(b) has been revised to incorporate the above mentioned changes and the new language pertaining to sulfur and nitrogen content monitoring.

D.1.13 NSPS Monitoring of Emissions [326 IAC 12][40 CFR 60.334]

(a) ~~The Permittee shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water (steam) to fuel being fired in the turbine. This system shall be accurate to within 5.0 percent and shall be approved by IDEM, OAQ and VCAPC.~~ **Pursuant to 40 CFR 60.334(b), the Permittee shall install, certify, maintain, operate, and quality assure a continuous emission monitoring system (CEMS) consisting of NOx and O2 or CO2 monitors. The CEMS shall be installed, certified, maintained and operated as specified in 40 CFR 60.334(b)(1) through (b)(3).**

(b) The Permittee shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The custom schedule for the combustion turbine shall be as follows:

(1) ~~Monitor the natural gas combusted through the analysis of pipeline gas from the natural gas supplier. Gas samples shall be taken once a calendar quarter at the closest proximity to the site of the turbine. In the event of less than 30 days of the turbine operation in a quarter, the quarterly sampling is waived. For these purposes, one day of operation shall be defined as any day that gas is burned for more than one (1) hour. Quarterly sampling and analysis of the gas shall be performed according to ASTM methods in 40 CFR 60.335(a) and 60.335(d).~~ **Pursuant to 40 CFR Part 60.334(h)(2), the Permittee is not required to monitor the nitrogen content of the fuel combusted in the turbine if the Permittee does not claim any allowance for fuel bound nitrogen.**

(2) **Notwithstanding the provisions of 40 CFR 60.334(h)(3), the Permittee is not required to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Section 60.331(u), regardless of whether an existing custom schedule approved by IDEM, OAQ and VCAPC for Subpart GG requires such monitoring. The Permittee shall use one of the sources of information described in 40 CFR 60.334(h)(3)(i) and (ii).**

(c) Periods of excess emissions **and monitor downtime** that shall be reported are defined as follows:

(1) Nitrogen oxides. ~~Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with Condition D.1.2 by the performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under § 60.335(a).~~

(i) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_X concentration" is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(ii) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).

(iii) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the Permittee has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. The Permittee does not have to report ambient conditions if the Permittee opts to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if the Permittee is not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) Ice fog. Each period during which an exemption provided in Condition D.1.2 is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

4. Under the rule revision, pursuant to 40 CFR 60.334(b) and IDEM's authorization of alternative monitoring requirements under 326 IAC 12-1(b), NOx CEMs may be used in lieu of monitoring the water injection rate. The Permittee has opted to use the CEMS instead of monitoring water-to-fuel ratio. Condition D.1.14(b) has been revised to reflect this change. Additionally, pursuant to 40 CFR

60.334(h)(2) and (3), if the Permittee claims zero allowance for fuel bound nitrogen, sampling the fuel for nitrogen content is not required, and if the fuel qualifies as natural gas, sampling the fuel for sulfur content is not required. The Permittee has elected not to monitor nitrogen content as the source is claiming zero allowance for fuel bound nitrogen. Condition D.1.14(b) has been revised to incorporate the above mentioned changes and the new language pertaining to sulfur and nitrogen content monitoring.

D.1.14 Record Keeping Requirements

(a) To document compliance with Conditions D.1.2, D.1.3, and D.1.4 the Permittee shall maintain all records generated in accordance with Conditions D.1.11 and D.1.12.

(b) To document compliance with Conditions D.1.5 and D.1.6 the Permittee shall maintain records containing the information necessary. The information shall, as a minimum, contain the following information.

(1) The date, fuel, and times for all periods of turbine operation;
~~(2) The maximum load and corresponding steam to fuel ratio for each period of operation (including a comparison to the demonstrated proper injection rate for the specific fuel);~~
~~(3)~~ **(2)** The fuel type **and** consumption ~~and actual ratio of steam to fuel~~ during all periods of the turbine operation;
~~(4)~~ **(3)** The sulfur content of the fuel**, unless the fuel is demonstrated to meet the definition of natural gas in which case it is not required to be monitored**; **and**
~~(5) The nitrogen content of each fuel being combusted (in percent by weight); and~~
~~(6)~~ **(4)** Records of NOx and SO2 CEM data.

(c) To document compliance with Section C - Opacity and Condition D.1.7, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and Condition D.1.7.

(1) Data and results from the most recent stack test.
(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5 and 40 CFR 75.14.
(3) The results of all visible emission (VE) notations and Method 9 visible emission readings taken during any periods of COM downtime.

(d) To document compliance with Condition D.1.9, the Permittee shall maintain records of any additional inspections prescribed by the Preventive Maintenance Plan.

(e) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

5. Under the rule revision, pursuant to 40 CFR 60.334(b) and IDEM's authorization of alternative monitoring requirements under 326 IAC 12-1(b), NOx CEMs may be used in lieu of monitoring the water injection rate. The Permittee has opted to use the CEMS instead of monitoring water-to-fuel ratio. Condition D.1.15(a) has been revised to reflect this change. Additionally, pursuant to 40 CFR 60.334(h)(2) and (3), if the Permittee claims zero allowance for fuel bound nitrogen, sampling the fuel for nitrogen content is not required, and if the fuel qualifies as natural gas, sampling the fuel for sulfur content is not required. The Permittee has elected not to monitor nitrogen content as the source is claiming zero allowance for fuel bound nitrogen. Condition D.1.15(b) has been revised to incorporate the above mentioned changes and the new language pertaining to sulfur and nitrogen content monitoring.

D.1.15 Reporting Requirements

(a) The Permittee shall submit the following information on a quarterly basis:

(1) Records of excess NOx emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements of this permit.

(2) A quarterly excess emissions report shall be submitted, based on any continuous opacity monitor (COM) required by this section, pursuant to 326 IAC 3-5-7. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C - General Reporting Requirements, of this permit.

The reports submitted by the Permittee do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall submit the following information pursuant to 40 CFR 60.334 and 40 CFR 60.7:

To document compliance with Conditions D.1.2 and D.1.4, pursuant to 40 CFR 60.334, excess emissions and monitoring system performance (MSP) reports shall be submitted to the in accordance with Section C – General Reporting Requirements semi-annually for each six month period in the calendar year. All semi-annual reports shall be postmarked by the 30th day following the end of each six-month period. For the purpose of reports under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) For nitrogen oxides: ~~Any period which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8.~~ **Any unit operating hour in which the 4-hour rolling average NOx concentration exceeds the applicable emission limit.**

(2) For sulfur dioxide: Any daily period which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

6. Condition B.23(c) has been revised to reflect the correct name of the section.

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ and VCAPC, within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ or VCAPC, the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, ~~I/M &~~ Billing**, Licensing, and Training** Section), to determine the appropriate permit fee.

7. Condition B.24 has been revised to properly reflect 326 IAC 1-1-6.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314]**[326 IAC 1-1-6]**

~~Notwithstanding the conditions of this permit that state specific methods that may be used to demonstrate compliance with, or a violation of, applicable requirements, any~~

~~person (including the Permittee) may also use other credible evidence to demonstrate compliance with, or a violation of, any term or condition of this permit.~~ **For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.**

Conclusion

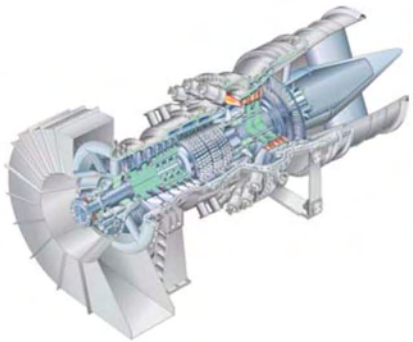
The proposed permit modification to this stationary electric generating source shall be subject to the conditions of the attached Part 70 Significant Permit Modification No. 167-19843-00021.

Gasification Technologies Council

SIEMENS

Harry Morehead, Manager, IGCC Business Development

2007 Gasification Technologies Conference
San Francisco, CA
October 15, 2007



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Service

Wind Power

Our New Business Segment:

Gasifiers for IGCC and industrial applications

2006
What We Said Last Year

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Market introduction
Issues & solutions

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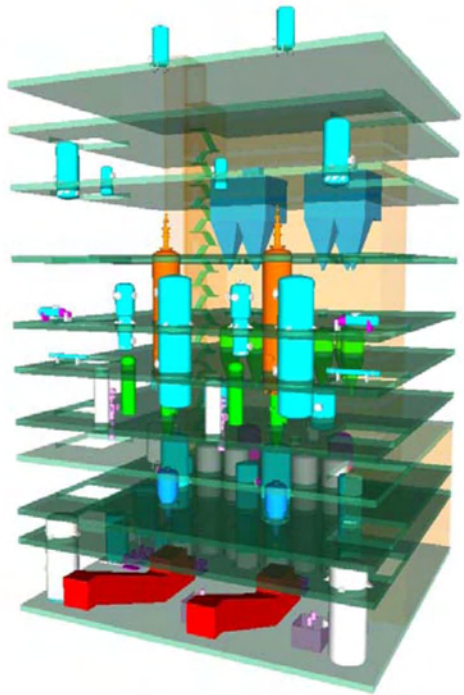
- Develop reference plants
- Build on CCPP reference design experience
  - 60% replication
  - 15% modification
  - 25% custom scopes
- Use more advanced technologies
- Scale up projects



- FEED study
- Phased approach to implementation/availability
- Flexibility from regulator
- Government incentives
- Stakeholder risk sharing
- Capture learning curve

3rd wave generation will require an innovative approach to risk allocation

IGCC Cost Reduction and Risk Reduction/Allocation are being addressed

2007
New Challenges

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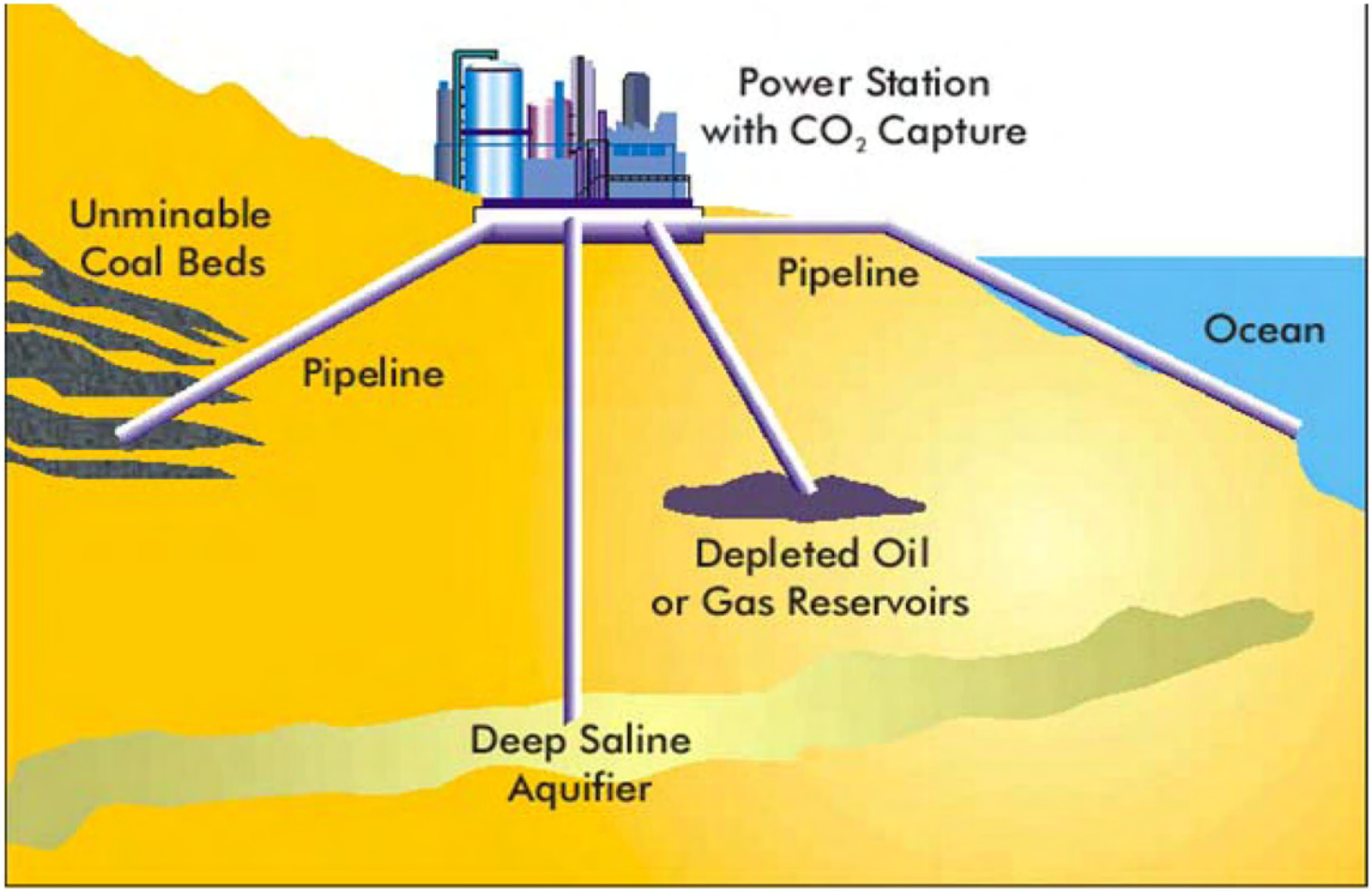

Increased Demand for IGCC with Carbon Capture and Storage

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Global Demand for Gasification is Increasing

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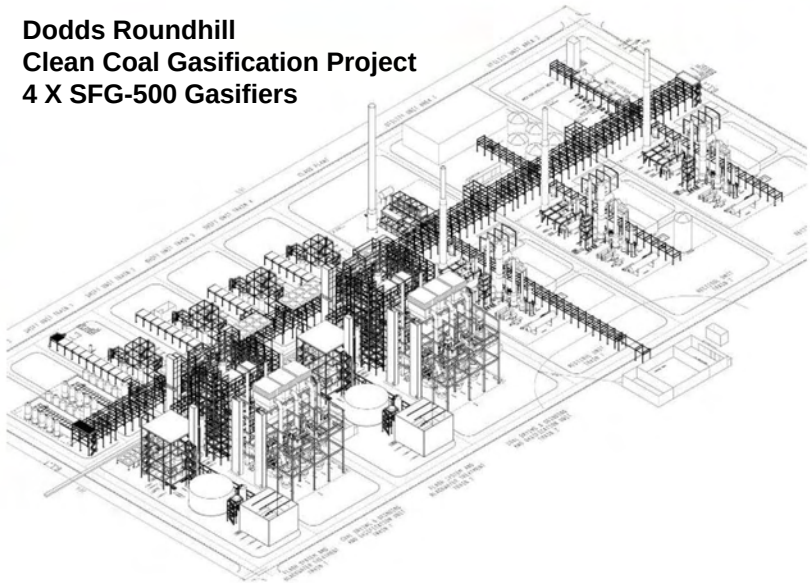


Interest in Gasification has Accelerated for Non-IGCC Applications

2007
Siemens SFG Gasification Technology

SIEMENS

SFG Gasifier

Current Gasifier Products

SFG-200	**200 MWth**
SFG-500	**500 MWth**

Siemens Gasification Test Facility

Highlights

- **OEM Support** - Siemens designs and manufactures the critical gasification equipment and provides basic engineering package for gasification island
- **Proven** – Started design in mid-1970s with more than 20 years of successful operating experience
- **Feedstock Flexibility** - This multi-fuel gasifier accepts a wide variety of feedstocks (e.g., bituminous coal, sub-bituminous coal, lignite, biomass and liquid wastes)
- **Operating Flexibility** - Major features include dry feed, a reliable cooling screen design, and high carbon conversion
- **Project Support** - Siemens comprehensive gasification test facility available to confirm feedstock characteristics, if needed

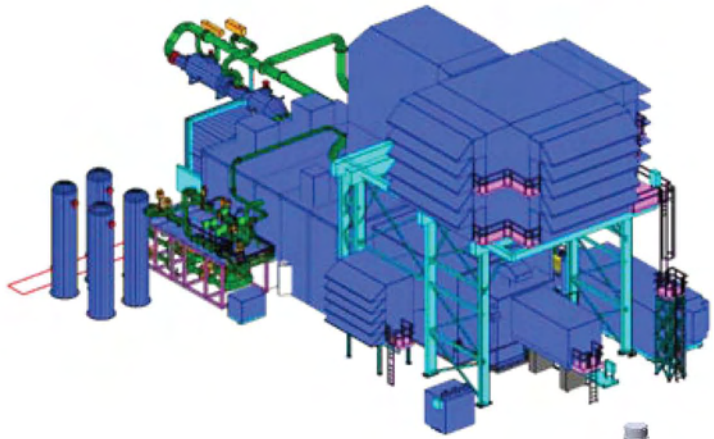
Nine SFG-500 Gasifiers on Order or are being Manufactured

2007
60 Hz IGCC Power Island Solutions

SIEMENS

SGT6-PAC 5000F

- 232 MWe GT-G for low-BTU fuel applications (ISO conditions)
- 15 ppm NO_x
- Can be integrated with wide range of gasifiers operating with a broad range of feedstocks



SGCC6-5000F 2X1

- 630 MWe combined cycle reference plant concept
- Based on standard SCC6-5000F 2X1

Three IGCC Project Pre-FEEDs Completed or are Near Completion

2007
SGT6-5000F for IGCC Applications

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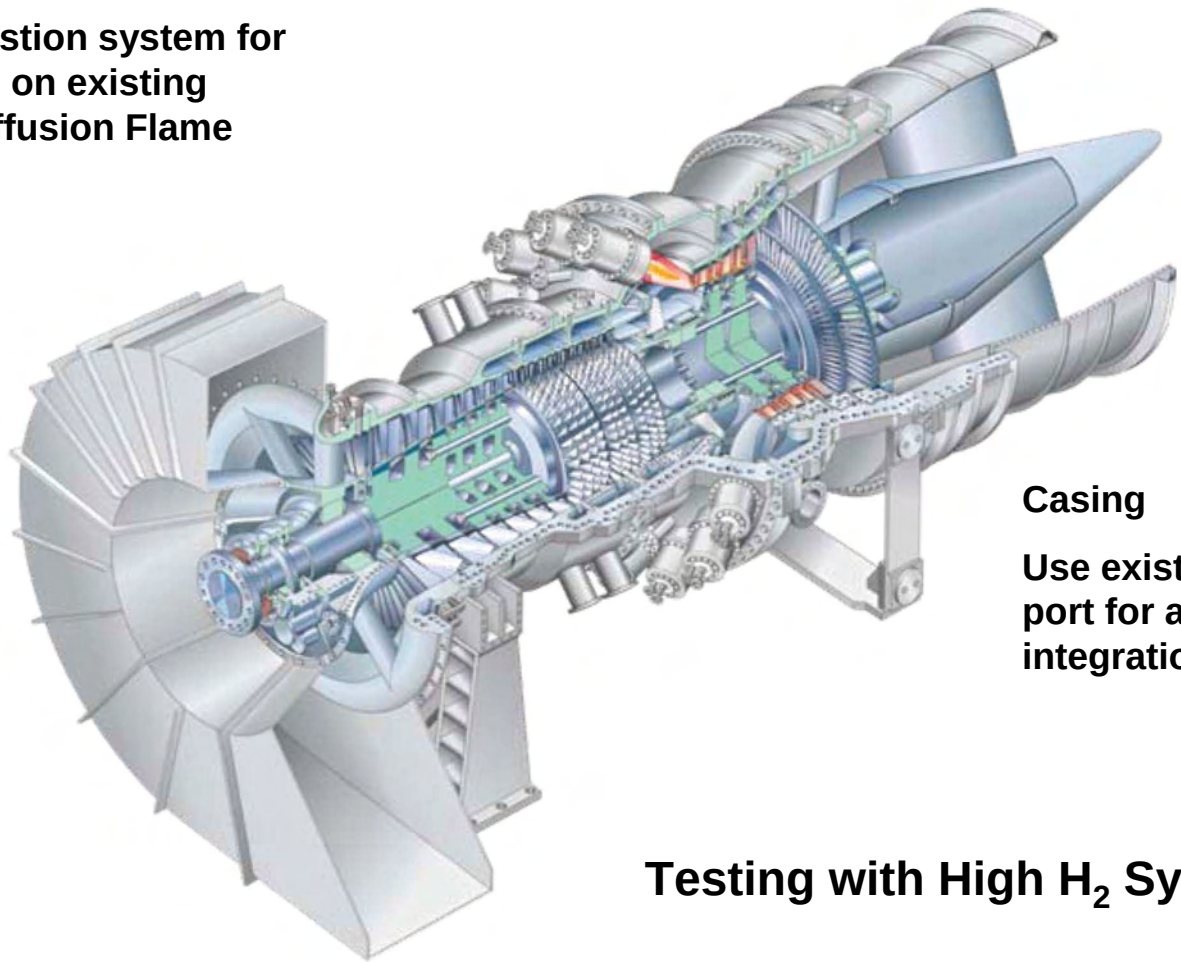
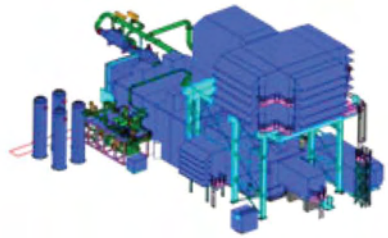
Combustion System

New combustion system for IGCC based on existing Siemens Diffusion Flame technology





Auxiliary Systems

Fuel handling auxiliaries and engine control system modified for IGCC application

Casing

Use existing access port for air extraction / integration purposes

Testing with High H_2 Syngas Completed

Next Steps
Advanced Gas Turbine Technology for IGCC

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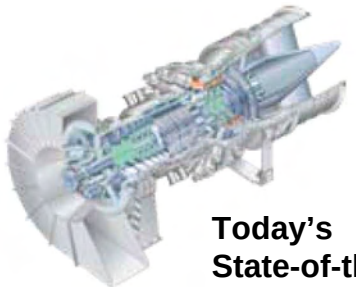
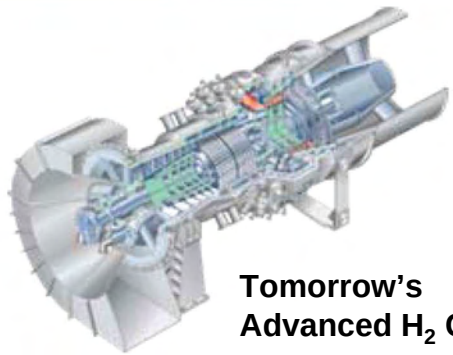


Today's
State-of-the-Art
F Class Gas Turbine



Tomorrow's
Advanced H_2 Gas Turbine

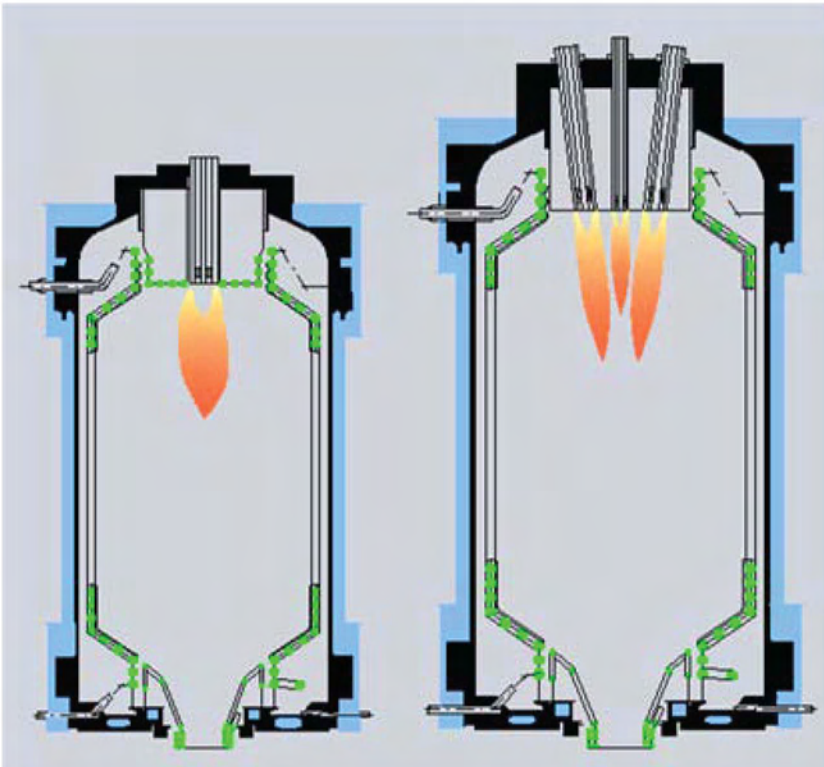
Program Results Expected to Lead to Lower $ / kW Plant Costs and Better Plant Efficiency

Next Steps

Optimizing Gasifiers for IGCC and Other Applications

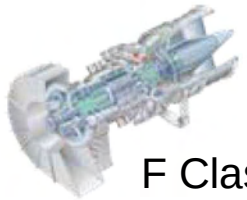
SIEMENS

SFG-500 Gasifier | **SFG-XXXX Gasifier**

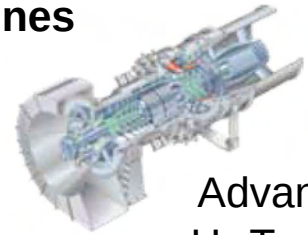


Objective is to Improve Plant Economics

60 Hz Gas Turbines

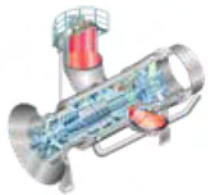


F Class

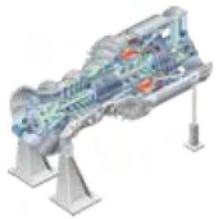


Advanced H_2 Turbine

50 Hz Gas Turbines



E Class



F Class

Chemicals | **Liquids**

Next Steps
Partial Quench with Heat Recovery

- Development of a waste heat recovery steam generator
- Efficient use of the high temperature heat in the steam generator for HP steam generation (optional: IP steam)
- Water quench of raw gas and slag
- Optimization of the reactor similar to current design
- Optimization and design of the partial quench system by investigation of mass and heat transfer (supported by CFD)

Objective is to Improve IGCC Plant Efficiency without Sacrificing Plant Reliability and Availability

Next Steps
Siemens Gasification Partnering Approach

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Gas Island

Power Island

Air Separation Unit

Oxygen

Combined Cycle

Electricity

Fuel
- Coal
- Biomass
- Refinery residuals

Gasifier

Raw Syngas

Gas Cleanup / Gas Shift

Clean Syngas

Chemicals, Liquids

Gasification Island

Includes :
- Fuel feeding system
- Mechanical cleaning system
- Slag removal system
- Black water treatment system

CO2 capture (optional)

Synthesis

Transportation Fuels
Methanol
SNG
Hydrogen

CO_2 sequestration or Enhanced Oil Recovery

Siemens Scope of Supply (with Partners)

Scope of EPC partner

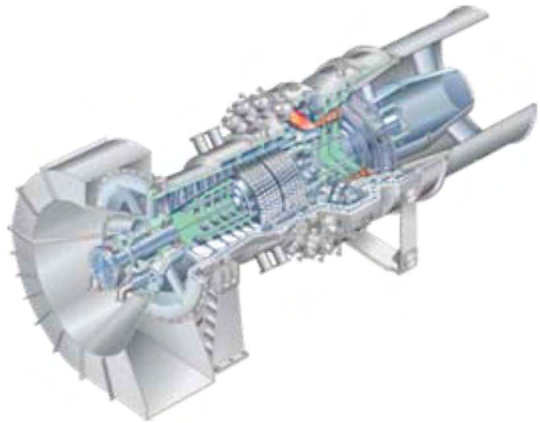
Not Siemens Scope

Partnering and Stakeholder Participation will be Key Success Factors

SIEMENS

Conclusions

- **Global Demand for Gasification is Increasing**
  - Chemicals / SNG
  - Transportation Liquids
  - IGCC
- **Gasification and IGCC Plant Developers Around the World are Facing more Challenges**
  - Global Materials and Labor Cost Increases
  - Carbon Capture and Storage
- **Progress is being Made on the Technology Front**
  - High H_2 Syngas Turbines
  - Better Gasification Technologies



IGCC has the Potential to be a Competitive Power Generation Option even in a Carbon Constrained World

2005 Generating Unit Statistical Brochure -- All Units Reporting

NOTE: This brochure contains data on all units, whether they reported event records or not. For a review of statistics containing only those units that reported events, see the brochure "2005 Generating Unit Statistical Brochure -- Units Reporting Events".

(The differences between statistics with or with events will appear in equations needing derating information such as EAF, EFOR, and other equations. The equations are more accurate if events are reported.)

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	ART	SR	NCF	NOF	SF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	UOF	EUOF	EUOR	POF	MOF	WSF	WAF	WEAF	WFOR	WEFOR
FOSSIL	All Sizes	1,335	1331.67	298.04	98.00	58.86	80.41	66.78	88.34	85.89	4.98	7.05	6.35	8.16	3.50	5.29	7.03	9.76	6.37	1.78	73.20	87.72	85.32	4.56	6.56
All Fuel Types	1-99	306	303.67	173.69	99.06	36.82	69.48	49.88	90.42	88.20	6.52	8.86	7.52	6.10	3.48	5.00	6.35	11.58	4.58	1.52	52.99	91.22	88.82	5.17	7.76
	100-199	353	351.00	300.44	97.88	49.40	73.36	66.43	87.97	85.18	4.79	6.93	6.16	8.69	3.35	5.64	7.56	10.49	6.39	2.30	67.35	87.95	85.15	4.66	6.82
	200-299	160	160.00	360.01	98.51	59.45	77.98	76.23	88.23	85.51	4.76	6.26	5.92	7.96	3.81	5.32	6.94	8.51	6.45	1.51	76.23	88.28	85.51	4.76	6.29
	300-399	126	127.00	348.98	97.53	51.87	73.80	70.73	88.56	86.59	4.35	6.31	5.62	8.22	3.22	5.04	6.67	8.80	6.40	1.82	70.29	88.71	86.76	4.30	6.24
	400-599	222	222.00	334.53	97.51	59.66	80.75	73.32	86.90	84.52	4.84	7.10	6.63	9.38	3.73	5.48	7.45	9.45	7.62	1.75	73.89	87.04	84.72	4.79	6.97
	600-799	119	119.00	488.20	95.86	66.67	86.72	77.33	87.09	84.33	4.71	7.05	6.61	9.09	3.83	5.37	7.73	9.34	7.55	1.54	76.88	87.08	84.30	4.77	7.15
	800-999	36	36.00	507.52	97.09	62.74	82.47	75.49	88.31	87.38	2.61	3.20	3.01	9.66	2.02	3.28	3.93	4.99	8.41	1.26	76.07	88.42	87.48	2.57	3.16
	1000 Plus	13	13.00	933.39	88.70	75.58	89.38	83.64	85.41	82.31	5.17	6.95	6.85	10.03	4.56	5.94	8.20	9.15	8.66	1.38	84.57	86.04	83.08	5.00	6.67
Coal	All Sizes	840	839.58	511.81	96.89	74.14	85.86	83.77	88.20	85.17	4.75	6.75	6.54	7.62	4.18	5.85	8.00	8.93	5.95	1.67	86.35	87.92	85.21	4.45	6.32
Primary	1-99	142	141.58	249.73	98.61	55.00	74.00	73.06	88.61	85.20	5.72	8.33	7.47	6.96	4.43	6.28	8.48	10.69	5.11	1.85	74.32	89.14	85.71	4.92	7.60
	100-199	228	227.92	560.25	96.24	66.68	79.07	83.58	88.35	84.95	5.14	7.09	6.83	7.12	4.53	6.62	8.97	9.94	5.03	2.09	84.33	88.34	84.99	4.93	6.87
	200-299	114	114.00	627.66	98.47	74.03	84.15	87.77	89.73	86.50	3.69	5.10	5.03	6.91	3.37	4.74	6.57	7.10	5.53	1.38	87.98	89.82	86.53	3.62	5.05
	300-399	76	77.00	688.75	95.34	73.63	83.00	88.49	88.94	86.33	4.10	6.15	6.12	7.28	3.78	5.26	7.37	7.86	5.80	1.48	88.71	89.15	86.54	4.03	6.05
	400-599	151	150.08	596.17	96.31	74.04	86.56	85.34	86.09	83.36	5.03	7.39	7.34	9.39	4.52	6.18	8.46	9.25	7.72	1.66	85.54	86.28	83.63	4.97	7.21
	600-799	92	92.00	724.56	94.22	78.02	89.04	87.64	88.17	85.48	4.42	6.26	6.23	7.78	4.06	5.23	7.42	7.99	6.61	1.17	87.63	88.15	85.44	4.47	6.34
	800-999	25	25.00	885.84	94.81	79.66	89.83	88.58	88.74	87.81	2.95	3.57	3.56	8.57	2.69	3.62	4.38	4.76	7.64	0.92	88.67	88.83	87.91	2.89	3.51
	1000 Plus	12	12.00	953.16	88.00	79.09	91.33	86.18	86.68	83.52	5.03	6.72	6.69	8.76	4.56	5.73	8.01	8.72	7.60	1.16	86.61	87.08	84.07	4.89	6.48
Oil	All Sizes	111	102.00	89.88	99.59	27.30	57.63	42.41	85.10	83.16	5.11	8.06	6.32	12.61	2.28	5.56	7.01	14.61	9.34	3.27	47.38	83.08	81.10	4.23	7.12
Primary	1-99	31	30.58	54.83	99.71	27.00	61.92	36.74	86.94	85.42	8.83	11.70	9.68	9.50	3.56	6.15	7.42	17.30	6.91	2.59	43.60	90.52	88.45	5.00	8.24
	100-199	30	26.58	91.83	99.32	21.97	56.43	35.26	85.63	83.21	3.23	7.00	4.23	13.19	1.18	5.00	6.45	16.01	9.37	3.82	38.93	84.47	81.95	3.33	7.10
	200-299	7	6.83	68.17	100.00	19.78	62.47	34.38	86.43	84.51	6.19	8.33	5.41	11.30	2.27	4.47	5.35	13.78	9.10	2.20	31.66	86.72	84.73	6.71	9.11
	300-399	15	15.00	190.98	99.79	37.79	61.97	62.07	84.25	82.15	2.00	4.55	3.71	14.48	1.27	5.38	7.24	10.73	10.37	4.12	60.99	84.40	82.37	2.11	4.58
	400-599	14	10.92	122.22	99.57	35.29	60.14	57.43	88.75	87.42	4.00	5.01	4.15	8.86	2.40	5.81	6.70	10.60	5.44	3.42	58.68	88.55	87.18	3.90	4.85
	600-799	8	7.33	75.26	99.02	17.61	50.55	35.61	70.79	67.45	9.24	17.12	11.26	25.59	3.62	7.53	10.82	25.08	21.69	3.91	34.84	69.60	66.37	9.67	17.40
	800-999	5	3.75	374.17	100.00	22.20	53.17	42.03	88.67	88.42	0.72	0.91	0.78	11.03	0.30	2.07	2.31	5.24	9.26	1.76	41.75	88.79	88.55	0.74	0.94
Gas	All Sizes	352	341.00	100.35	98.76	14.32	40.67	31.00	89.62	88.53	6.11	8.25	6.62	8.37	2.02	3.72	4.55	13.10	6.67	1.70	35.22	88.33	87.05	5.27	7.57
Primary	1-99	107	104.58	86.58	99.15	8.35	41.94	17.24	94.01	93.44	11.84	13.28	11.59	3.68	2.31	3.26	3.56	17.39	2.74	0.94	19.92	94.65	93.89	7.12	9.18
	100-199	99	96.42	99.69	99.12	15.63	45.27	34.53	87.71	86.23	3.22	5.98	4.24	11.15	1.15	3.51	4.56	12.00	8.79	2.36	34.53	87.90	86.34	3.45	6.47
	200-299	37	35.17	117.86	98.28	19.54	40.93	47.57	85.69	84.24	6.00	8.16	6.97	11.27	3.04	4.84	6.04	11.51	9.47	1.80	47.74	85.81	84.33	5.92	8.11
	300-399	35	35.00	112.79	98.46	11.56	33.04	35.36	89.58	89.07	7.35	8.44	5.97	7.62	2.81	4.41	4.88	12.26	6.01	1.60	34.99	89.70	89.19	7.38	8.47
	400-599	53	51.00	92.36	98.33	14.62	39.81	37.82	88.01	86.73	4.86	6.96	5.66	10.06	1.93	3.67	4.91	11.79	8.32	1.74	36.73	88.21	87.00	4.86	6.92
	600-799	12	11.58	96.83	97.03	8.78	40.08	22.04	86.85	84.58	9.72	16.59	9.52	10.78	2.37	4.89	7.15	26.53	8.27	2.52	21.90	86.71	84.47	9.80	16.57
	800-999	9	7.25	141.87	99.06	22.72	46.90	47.66	86.65	85.34	1.26	1.87	1.45	12.75	0.61	2.76	3.21	6.37	10.59	2.15	48.46	86.73	85.36	1.20	1.81
Lignite Primary	All Sizes	18	18.00	753.14	98.52	84.92	92.80	91.74	91.74	88.50	2.72	4.98	4.98	5.70	2.56	3.79	6.03	6.31	4.47	1.23	91.51	91.51	88.30	2.99	5.36

ORIGINAL

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 07_____-EI
IN RE: TAMPA ELECTRIC'S
PETITION TO DETERMINE NEED FOR
POLK POWER PLANT UNIT 6

TESTIMONY AND EXHIBIT
OF
MICHAEL R. RIVERS

DOCUMENT NUMBER-DATE
06175 JUL 20 5
FPSC-COMMISSION CLERK

TAMPA ELECTRIC COMPANY
DOCKET NO. 07_____-EI
FILED: 7/20/2007

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MICHAEL R. RIVERS

Q. Please state your name, business address, occupation and employer.

A. My name is Michael R. Rivers. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Engineering and Construction.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Civil Engineering in 1977 from the University of Florida, and I received a Masters of Business Administration in 1989 from the University of Tampa. I am a Registered Professional Engineer in the state of Florida. In December 1981, I joined Tampa Electric as an Associate Engineer. Between 1981 and 1990 I held various engineering and construction positions. In 1990 I was promoted to Manager of Project Controls and, in 1993, I

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FPSC-COMMISSION CLERK

was promoted to Construction Manager for Tampa Electric's Polk Unit 1, which is the company's 255 MW integrated gasification combined cycle ("IGCC") unit. In June 1997, I was promoted to Director, Engineering and Technical Services, and in October 2002, I was promoted to Director, Engineering and Construction. My present responsibilities include the areas of engineering and construction within Tampa Electric's Energy Supply Department for major plant improvement projects and additional generating capacity.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the engineering and construction of the proposed Polk Unit 6 Project. I will describe the proposed unit's operating characteristics along with a description of the proposed facilities. Additionally, I will discuss the schedule for completing construction of Polk Unit 6 and Tampa Electric's project execution plan. Finally, I will describe the development of the reasonable and prudent Project cost estimates.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, Exhibit No. ____ (MRR-1) was prepared under my direction and supervision. It consists of the following documents:

Document No. 1	Process Diagram
Document No. 2	Project Schedule
Document No. 3	Cost Estimate
Document No. 4	Plot Plan

Q. Are you sponsoring any sections of Tampa Electric's Determination of Need Study for Electrical Power: Polk Unit 6 ("Need Study")?

A. Yes. I sponsor the section of the Need Study regarding Tampa Electric's Proposed Unit. Specifically, I sponsor sections VII.A "Overview," VII.B "Description," VII.E "Cost" and VII.F "Schedule."

Q. Did you participate in Tampa Electric's evaluation of supply alternatives?

A. Yes. In addition to IGCC technology, Tampa Electric considered natural gas combined cycle and other coal fired technologies including atmospheric fluidized bed combustion and supercritical pulverized coal technologies. I provided capital costs and construction

schedules for these alternatives. Witness William A. Smotherman describes the company's evaluation of alternative generating technologies, which demonstrates that the proposed IGCC unit is the most cost-effective, reliable option for Tampa Electric.

PROJECT DESCRIPTION

Q. Please describe the planned project.

A. Tampa Electric plans to make use of its extensive experience with IGCC technology to construct Polk Unit 6 ("Project"), a second IGCC power plant at Polk Station, the site of Tampa Electric's existing IGCC facility. Polk Station occupies over 2,800 acres on State Road 37 in Polk County, Florida, approximately 40 miles southeast of Tampa and about 60 miles southwest of Orlando. The Project's feedstock will be bituminous coal with the capability of gasifying up to 100 percent petroleum coke ("pet coke"). The Project will also be capable of gasifying renewable biomass as part of the feedstock.

As described in the testimony of witness Chrys A. Remmers, Tampa Electric was awarded Section 48A tax credits for Polk Unit 6. To qualify for the tax

credits, Polk Unit 6 must burn at least 75 percent coal for the first five years of service. After meeting the tax credit requirements, the unit's fuel flexibility will allow Tampa Electric to continue to burn the most cost-effective fuel blends.

Polk Unit 6 is expected to generate a net 647 MW of electricity in winter at 32 degrees Fahrenheit and 610 MW in the summer at 92 degrees Fahrenheit. The average annual net heat rate, higher heating value, is expected to be about 9,111 Btu/kWh, and the instantaneous heat rate is expected to be 9,014 Btu/kWh at 75 degrees Fahrenheit. The combustion turbines will have the capability of firing natural gas as a backup fuel.

Q. Please briefly describe the power generation technology that Polk Unit 6 will utilize.

A. While traditional pulverized coal plants grind and burn coal, slurry-fed IGCC units grind coal and mix it with water to create slurry that is then gasified. The technology for Polk Unit 6 will be similar to what Tampa Electric has successfully used at Polk Unit 1, namely IGCC. The fuel feedstock will first be ground into slurry. This fuel feedstock slurry will be transported

to two gasifier systems that will convert the fuel slurry into a synthetic gas. This gas will then be treated to remove pollutants such as sulfur, mercury and particulate matter. The cleaned gas will then be used to fire two 232 MW General Electric ("GE") 7FB combustion turbines and generate electrical power. The exhaust heat from the combustion turbines will be utilized in a heat recovery steam generator ("HRSG") to create steam for the steam turbine. This steam will power the steam turbine and produce approximately 325 MW of additional power. The total net output of Polk Unit 6 will be approximately 632 MW. IGCC technology is called "clean coal technology" because it results in lower emissions, compared to traditional pulverized coal units. In fact, Polk Unit 1 has been named the cleanest coal plant in North America.

Q. Please describe the various components and systems that will make up Polk Unit 6.

A. Tampa Electric will use technology for Polk Unit 6 that builds on the company's experiences with Polk Unit 1. Tampa Electric will utilize GE's gasification and power generation technologies. Coal, pet coke and biomass will be received at Polk Station in trains and/or by

truck. The solid fuels will be stored on-site and then blended in the desired ratio using weigh feeders as they are reclaimed from storage for use.

Fuel and process water will be ground in rod mills to produce slurry, which will be stored in tanks. A pump will deliver the slurry to the gasifier's feed injector. Main air compressors and extraction air from the two combustion turbines will feed a distillation column, which separates oxygen from nitrogen. Oxygen compressors or pumps will transfer oxygen to the gasifiers, and diluent nitrogen compressors will supply the combustion turbines with nitrogen for nitrogen oxides ("NO_x") suppression and power augmentation. Two GE gasifiers of about the same size as Polk Unit 1 will each operate at 650 psig. A radiant syngas cooler for each gasifier will cool the syngas and make steam, while removing most of the ash particles from the syngas. For each gasifier train, a single water/gas scrubber with multiple steps of water/gas contact will be installed to remove the remaining ash particles.

Several stages of heat recovery followed by a final cooler will be provided in low temperature syngas cooling. An activated carbon bed will remove mercury

from the syngas. The system will include two carbonyl sulfide ("COS") hydrolysis systems, one for each gasification train, each consisting of one superheater followed by a COS hydrolysis reactor. A Selexol acid gas removal system will provide high sulfur removal rates. A 700 to 800 ton per day sulfuric acid plant will produce sulfuric acid for sale into the sulfuric acid market. A single saturator column will add water vapor to the syngas for supplemental NO_x suppression. Two 232 MW GE 7FB combustion turbines, each with a HRSG, and a single 325 MW steam turbine will produce approximately 632 MW net output of electrical power. Selective catalytic reduction equipment will be added to each HRSG for additional NO_x control. Design provisions will be made for the addition of carbon dioxide ("CO_2") removal equipment.

Make-up water to the plant will be provided by on-site wells. The existing 750 acre cooling reservoir, along with a supplemental cooling tower will provide cooling for the various heat exchangers in the system.

Polk Unit 6 facilities are described below, and a Process Diagram is provided in Document No. 1 of my Exhibit No. ____ (MRR-1).

Coal Receiving and Storage

Most solid fuel will be delivered via rail, water or a combination of the two methods. Rail and rail unloading equipment will be added to site. Conveyors will transport fuel from the rail car unloader to an active fuel storage area. The active fuel storage area will have two sections: one for coal and the other for pet coke. This area will also have two reclaimers to transport fuel from the active storage area to fuel blending bins. The blending bins will allow the company to combine coal and pet coke in appropriate ratios for use in the gasifiers. Two conveyors will allow transport of the blended fuel to the slurry preparation building. The long term fuel storage area may contain up to 225,000 tons of solid fuel.

Slurry Preparation

The slurry preparation area will contain two rod mills which will grind the fuel and mix it with water to make slurry for injection into the gasifiers. Two slurry tanks will provide a few hours of storage of the slurry. Slurry pumps, one per gasifier, will pump the slurry to the feed injector in each gasifier.

Air Separation Plant

An air separation plant will separate air into its primary components; nitrogen and oxygen. The air plant will include main air compressors, heat exchanger filters, and nitrogen and oxygen compressors or pumps.

Gasification

There will be two gasification trains. Each gasifier will sit on top of a radiant syngas cooler. The radiant syngas cooler will cool the syngas generated in the gasifier, produce steam in the process, and separate most of the ash (slag) from the syngas. Slag will be removed from each radiant syngas cooler through lock hoppers located at the bottom of each cooler.

Slag Removal and Handling

The slag exiting the lock hoppers will travel across screens where it is washed to remove fines which contain carbon that can be reused to enhance efficiency. The slag will continue along conveyors to bins where the material is tested before removal for sale to industrial users. Fines containing high amounts of carbon are returned to slurry preparation and combined with fuel to be re-gasified.

Syngas Scrubbing (Particulate Removal)

The cooled syngas leaving the radiant syngas cooler will go to scrubbers which wash out any remaining particulate matter from the gas. The particulate matter, mixed with water, will be returned to the slurry preparation equipment to be regasified for recovery of the remaining carbon. The scrubbed gas continues on to low temperature gas cooling.

Low Temperature Gas Cooling

The low temperature gas cooling system is a series of heat exchangers that will cool the syngas further, recovering more of the heat from the syngas for use in other portions of the process to improve overall efficiency.

Mercury Removal

A sorbent bed will be included which will remove mercury from the syngas prior to going to the combustion turbines. Approximately 90 percent of the mercury is expected to be removed.

COS Hydrolysis

Equipment will be installed which will convert COS to hydrogen sulfide, which will increase the amount of

sulfur removed from the syngas prior to going to the combustion turbines.

Acid Gas Removal

A Selexol acid gas removal system will be included. This equipment will remove sulfur compounds from the syngas prior to it going to the combustion turbines. The resultant acid gas will go to a sulfuric acid plant.

Sulfur Recovery

Sulfur recovery equipment will take the acid gas from the acid gas removal system and convert it to sulfuric acid. The resultant sulfuric acid byproduct will be sold into the sulfuric acid market.

Syngas Saturator

A syngas saturator will add moisture to the syngas prior to its use in the combustion turbine. This saturation step will help to lower NO_x emissions from the combustion turbine/HRSG stacks.

Power Block

There will be two combustion turbines with connected electric generators, two HRSG, and one steam turbine with a connected generator. The combustion turbines

will burn the syngas to produce electricity. The hot exhaust gas from the combustion turbines will flow through the HRSG producing steam. The cooled exhaust gas will exit through a stack on each HRSG. The steam produced in the HRSG produces electricity in the steam turbine.

Water Use

Water will be recycled to the maximum extent practical to minimize groundwater use. For instance, the water required for slurry preparation will be derived from internal streams of water recycled from low-temperature cooling. Water wells will draw water from the Upper Floridian Aquifer. Tampa Electric expects any additional water supplies that may be needed will be drawn from wells in this region. This water will be used for process water, potable water and service water. In addition, water will be used for make-up to the cooling reservoir to replace water evaporated from the reservoir and cooling tower.

Cooling Water

Cooling water pumps will take water from the cooling reservoir and route it to the steam turbine condensers. The cooling water from the condensers will return to the

discharge portion of the reservoir. This heated water will travel a very long route, cooling off in the process, before arriving back at the intake structure where it will be used again. Other pumps will also take water from the reservoir and will provide make-up water to the new cooling tower basin. This make-up water will replace water evaporated from the cooling tower and water that is discharged to the deep waste water wells. Cooling water pumps will take water from the cooling tower basin and route it to various heat exchangers through out the plant.

Process Water Treatment

Water used throughout the gasification and gas clean up systems will concentrate impurities due to the evaporation or decomposition of water in these processes. To keep these process waters from becoming too concentrated, a stream from these systems will be treated and injected into deep waste water wells located on the site.

OPERATING CHARACTERISTICS

Q. What is the expected heat rate for the Polk Unit 6 IGCC technology?

A. Polk Unit 6 is expected to have an average annual net heat rate of 9,111 Btu/kWh, and an instantaneous net heat rate of 9,014 Btu/kWh at 75 degrees Fahrenheit. Net electric output is expected to be approximately 647 MW in the winter at 32 degrees Fahrenheit and 610 MW in the summer at 92 degrees Fahrenheit.

Q. Please describe the expected availability for Polk Unit 6.

A. The expected Equivalent Availability Factor ("EAF") for Polk Unit 6 is 95 percent, and the availability of the unit is expected to be greater than that of Polk Unit 1. Design changes, such as the elimination of the convective syngas coolers, will contribute heavily to this improvement. In addition, having two gasifiers and two combustion turbines means that a single gasifier or combustion turbine outage will not prevent the entire unit from operating and the unit will still be capable of producing about half of the rated output. Additionally, the ability to utilize natural gas as the backup fuel during gasifier outages will enhance the availability of the unit. If the unit EAF was calculated based upon firing syngas only and without the backup fuel, the EAF would be 86 percent.

Q. What is your conclusion regarding the reasonableness of these heat rate and availability expectations?

A. Based on my experience in engineering and constructing power plants, the estimated heat rate and availability factors are reasonable. Tampa Electric has developed industry-leading knowledge and experience in operating IGCC technology, which further supports the reasonableness of the expected heat rate and availability. In support of my conclusion, witness Mark J. Hornick describes the company's successful experience with operating IGCC technology.

CONSTRUCTION

Q. What is the expected construction schedule for Polk Unit 6?

A. Construction will begin in 2009, and Polk Unit 6 is expected to enter commercial operation in January 2013.

Q. Please describe Tampa Electric's efforts to obtain the required certifications and permits to begin construction of Polk Unit 6.

A. Tampa Electric began developing design information to

support permit application preparation in November 2006. The company entered into a contract with GE and Bechtel, an architect/engineer ("A/E") firm, to prepare a preliminary basis for design, block flow diagram, layout drawing and performance and emissions data in support of project development. Both companies continue to support Tampa Electric in the preparation of permit application documents. Tampa Electric has engaged the services of an environmental consultant to prepare air modeling studies and other evaluations, as well as prepare the permit application documents. The permit activities are described in the testimony of witness Paul L. Carpinone.

Q. What is the current schedule for the project?

A. Document No. 2 of my Exhibit No. ____ (MRR-1) outlines the project schedule. Conceptual design began in 2006, and the preliminary engineering package development began in April 2007 and is expected to be completed in April 2008. The Site Certification Application will be filed with the Florida Department of Environmental Protection in August 2007. The detailed design and procurement will begin in January 2008, starting with the engineering for the gasification process and the combined cycle equipment. Detailed design and

procurement activities are expected to continue through February 2011. Construction activities are expected to begin in first quarter 2009 with general site work. Major equipment erection includes the combustion turbines, starting in July 2010, the gasification and air separation equipment, starting in October 2010 and the steam turbine and generator equipment, starting in November 2010. Commissioning of the equipment is expected to begin in March 2012. Finally, the unit is expected to begin commercial operation in January 2013.

Q. What is Tampa Electric doing to mitigate the effects of potential construction schedule uncertainty?

A. Tampa Electric is planning to use an approach similar to that used for Polk Unit 1. The construction effort will be managed by a Tampa Electric construction management group that will use multiple prime contractors to perform the construction. Due to the large number of major projects currently planned in the utility industry, the availability of skilled craft labor as well as the ability to secure engineered equipment is a concern in meeting the construction schedule for any project of this magnitude. The use of multiple prime contractors is expected to reduce the potential labor

constraints on any one contractor during this time frame. The preliminary engineering work that is currently ongoing will be used to develop a detailed construction schedule that can be optimized to minimize the required work force to construct the plant.

Tampa Electric may also take a phased approach to the construction of the plant. This phased approach will stagger the construction of various portions of the plant. Manpower for each craft will be spread out, minimizing the peak manpower requirements for a given craft at any given time.

Tampa Electric has initiated contract negotiations with critical equipment suppliers to ensure delivery of key equipment such as combustion turbines, steam turbines, and gasification vessels. The balance of plant equipment and material supply packages will be developed and sent out for proposals to qualified suppliers. The supply contracts will include requirements for delivery of design information and materials to support the construction schedule needs. Assuring design information is available in a timely manner, along with assurances on material delivery schedules, will allow the company to manage the constructors efficiently and

minimize schedule or cost impacts. Major construction packages will be prepared with complete detailed engineering. These packages will be sent out for proposal to several qualified constructors. This process will result in competitive pricing and minimize change orders once the contracts are in place.

INSTALLED COST

Q. What is Tampa Electric's estimate of the overnight construction costs for Polk Unit 6?

A. The overnight construction cost estimate is $1.614 billion in January 2007 dollars. The primary components are the gasification components with an estimated cost of [redacted] and the balance of plant and power block at an estimated cost of [redacted].

Q. Please explain what is included in the cost estimate.

A. Document No. 3 of my Exhibit No. ____ (MRR-1) provides the details of the cost estimate. The $1.614 billion cost estimate represents overnight construction costs for all direct work at Polk Unit 6. This includes all engineering, procurement, construction, startup and commissioning costs. The project estimate does not

include owner's costs, related transmission additions or modifications, or contingency.

Q. What is Tampa Electric's estimate of the total in-service costs for Polk Unit 6?

A. The total in-service cost estimate for Polk Unit 6 is $2.013 billion, which includes the aforementioned overnight construction costs as well as owner's costs, contingency, escalation, and transmission costs. Owner's costs include project development costs such as technology development and environmental permitting; project management and operational support and training; legal and other professional services costs; and insurance. Tampa Electric estimated the owner's costs for Polk Unit 6 based on its experience developing and constructing generating units in Florida, including Tampa Electric's existing IGCC unit, Polk Unit 1.

The estimate also includes contingency and escalation. Contingency is based on Tampa Electric's experience with power plant construction projects. The $25 million costs of required transmission facilities to integrate and interconnect Polk Unit 6 with Tampa Electric's system are separately identified and are described in

the testimony of witness Thomas J. Szelistowski.

Q. Will subsequent engineering work result in changes to the installed cost estimate for Polk Unit 6?

A. Perhaps. The cost estimate represents the best estimate Tampa Electric has to date for the planned project configuration. The estimate does not include contingency for changes in the scope of the project or significant modifications of the planned configuration. Such changes will be evaluated and justified based on the impact to the cost and performance of the project. Approved changes could result in increases or decreases to the cost estimate.

Q. What contracting strategy and competitive pricing options will Tampa Electric pursue to manage the cost and schedule of Polk Unit 6?

A. Tampa Electric is planning to competitively bid the use of multiple prime contractors to execute the construction of Polk Unit 6. A construction management team will oversee and coordinate the multiple prime contractors. Tampa Electric believes this approach is more cost-effective than an Engineer, Procure and

Construct ("EPC") contract, considering the size of the project as well as the current market conditions. Very few EPC contractors have the ability to handle a project of this scope and dollar value. In addition, the technology is specific to GE, the process licensor. The process is highly integrated between the gasifier's syngas cooler, low temperature gas cooling, combustion turbines, HRSG and steam turbine. GE primarily uses Bechtel as its A/E for IGCC projects, and both companies have vast experience in the design and engineering of IGCC projects, including their 10-year partnership with Tampa Electric in refining the technology at Polk Unit 1. The expertise of GE and Bechtel will enable Tampa Electric to develop Requests for Proposals ("RFP") for equipment and labor for the project and will result in a wide variety of participants. This process will provide opportunities to control costs and reduce schedule risks.

Q. What scope of services will Bechtel be providing?

A. Under Tampa Electric's direction, Bechtel will provide design coordination between the various suppliers of technology, equipment and materials required to build the plant. They will also provide the required

technical specifications, design basis documents, process flow diagrams, drawings and procurement services.

Q. What gasification technology is Tampa Electric planning to use?

A. Tampa Electric is using the same gasification technology as Polk Unit 1, and some major equipment will be provided by the technology provider, GE, such as gasifiers, radiant syngas coolers and combustion turbines. Other major equipment will be competitively bid to qualified suppliers. Some equipment, such as the air separation plant, may be bid to multiple suppliers on a lump sum turnkey basis. Others will be grouped into compatible equipment types such as horizontal pumps or high pressure valves and bid to multiple suppliers of the particular type of equipment.

Q. How has this contracting strategy influenced the estimated installed cost for Polk Unit 6?

A. Tampa Electric believes that using multiple prime contractors overseen by the company's construction management team is the most cost-effective approach. An

EPC contract approach would require a contractor to add a significant risk premium to the price. EPC contractors would not have firm pricing or quantities for materials or labor prior to supplying a lump sum proposal. Both the material and labor costs may have significant variability during the progress of the project. These factors would result in the EPC contractor adding a significant risk premium to their proposal price. Tampa Electric's experience with managing large power plant projects demonstrates the company's ability to manage the projects within the planned cost, schedule and performance without incurring these additional risk premiums. Tampa Electric has not added any risk premium to the cost estimate.

Q. What is the current status of Polk Unit 6?

A. Tampa Electric is currently engaged in preliminary engineering to develop permit data. Additional engineering efforts are also ongoing to define the major aspects of the plant design. This information will be used to manage the detailed engineering effort and refine cost estimates and the project schedule.

Q. Does Tampa Electric's cost estimate include indexed

components?

A. No. The current cost estimate is based on preliminary estimates by various equipment suppliers, factored quantities from other projects and overnight construction costs. However, it is possible that suppliers may utilize established cost indices in their bid offerings due to the current volatility in prices of construction materials and raw products. Tampa Electric's bid evaluation process will consider indexed bids on a case by case basis.

Q. How has Tampa Electric considered the effects of carbon capture and sequestration ("CCS") on the Project, given the potential for future environmental regulations?

A. As shown in Document No. 4 of my exhibit, the Project plot plan allows for the space to include carbon capture equipment to be installed once the regulations are developed, and Tampa Electric will continue to consider the effects of CCS on the design of the Project. Tampa Electric has reviewed numerous studies regarding CCS. As described in greater detail in the testimony of witness Mark J. Hornick, these studies have generally concluded that both capital costs and the cost of

electricity are lower for IGCC technology with CO_2 capture than for any other coal-based generating technology. Tampa Electric, using cost estimates published by the DOE, performed sensitivity analysis of the effects of possible future CCS regulations on the total installed cost of Polk Unit 6 as compared to other fossil fuel fired generating technologies. This is further described in the testimony of witness William A. Smotherman.

Q. Why, when considering CCS, does IGCC technology have an advantage?

A. IGCC's advantage arises from the fact that the CO_2 is captured prior to combustion. This allows the CO_2 to be removed while the synthesis gas is still under high pressure and absent the large quantity of nitrogen associated with combustion air. This means that there is a small volume of gas to be processed relative to post-combustion flue gas volumes. This results in the equipment necessary for CO_2 removal being much smaller and less costly. Another advantage is that some of the physical sorbents presently used in IGCC technology for sulfur removal are also effective for removal of CO_2. This advantage results in equipment modifications to an

IGCC system for carbon capture which are less extensive than for other coal based technologies. Finally, IGCC technology is highly efficient, producing less CO_2 per megawatt hour of electricity produced than existing solid fuel units.

Natural gas combined cycle ("NGCC") units produce significantly less CO_2 than coal fired units. However, the fuel price savings for the IGCC unit as compared to the NGCC unit results in the selection of the IGCC unit since there are no current requirements to capture and sequester carbon. Furthermore, studies by the U.S. Department of Energy and others comparing these two generating technologies with carbon capture demonstrate that IGCC remains the lowest cost option for carbon control equipment. This is primarily due to the significantly lower cost per ton of carbon capture commercially available to IGCC as compared to the high cost of commercially available carbon capture from the flue gas of a NGCC unit. Therefore, an IGCC unit is more cost-effective than an NGCC unit in the case of potential future carbon control requirements. Witnesses Paul L. Carpinone, Mark J. Hornick and William A. Smotherman discuss potential future CO_2 regulation, technology capabilities for carbon controls and the

company's carbon control sensitivity analysis, respectively.

The costs of carbon storage or sequestration are unaffected by the process used to capture CO_2; therefore, sequestration costs are essentially the same for all coal based technologies.

Q. Please summarize Tampa Electric's efforts to ensure the reasonableness of the Polk Unit 6 total estimated installed cost.

A. Tampa Electric has constructed many large capital projects using a similar approach to the Polk Unit 6 approach. Tampa Electric employs several strategies to monitor and manage all phases of these projects including: (1) establishing project contracts that will provide the best value; (2) monitoring the work of the engineering company to ensure that work is done in an efficient manner; and (3) assigning full time project controls personnel to manage the costs and the schedule throughout the project execution. Dedicated Tampa Electric personnel lead the project management throughout construction and are integrally involved in each phase of its development. The company's track

record using this approach is excellent.

Q. Is the total installed cost estimate reasonable?

A. Yes. The total estimated cost represents the best efforts of the companies with the most experience in IGCC in the United States: Tampa Electric; GE, the technology supplier; and the A/E, Bechtel.

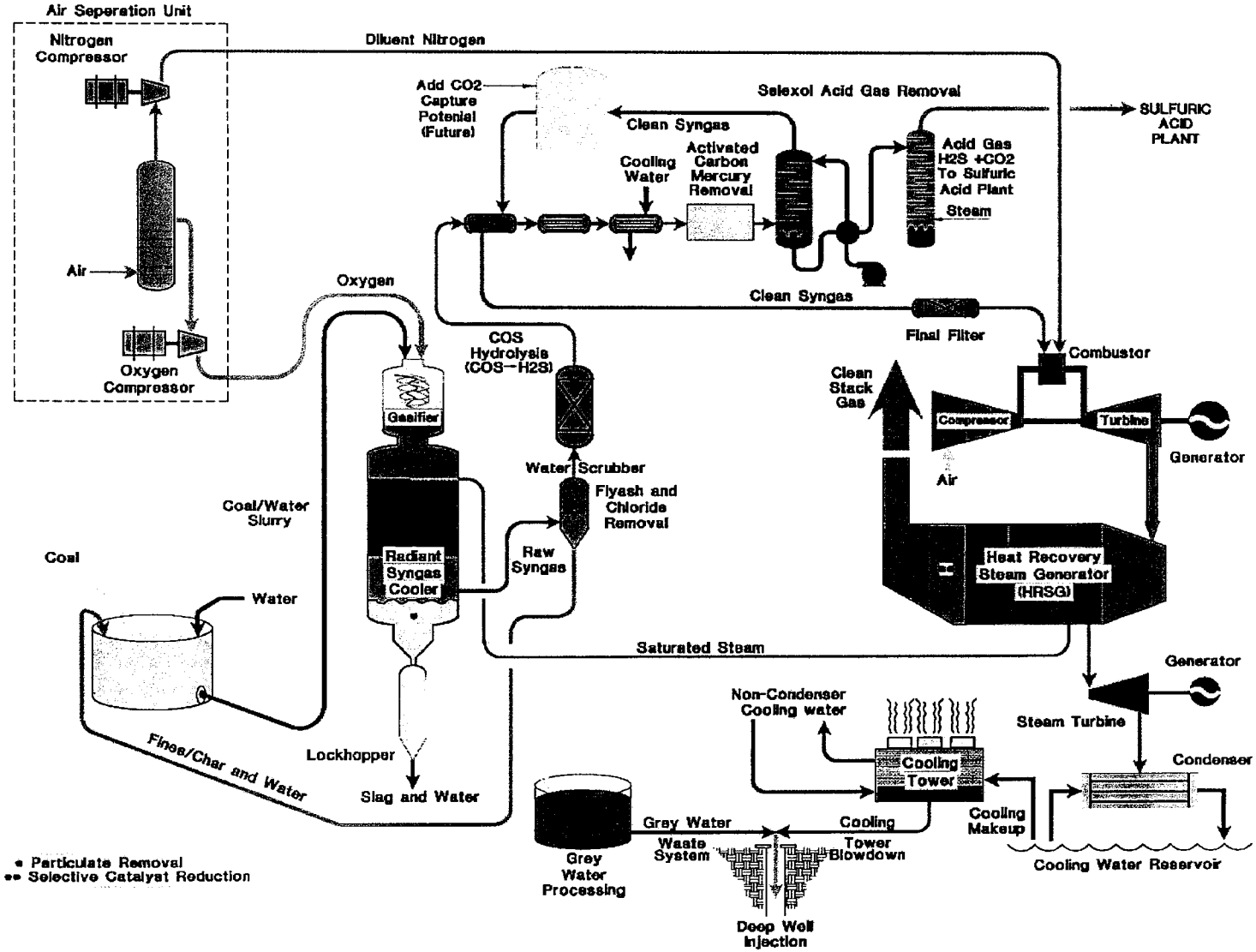
Q. Please summarize your testimony.

A. Polk Unit 6 will be designed and installed for $2.013 billion in a cost-efficient manner in accordance with the project schedule to provide cost-effective, clean power for Tampa Electric's customers. Tampa Electric has operated Polk Unit 1 successfully for over 10 years and will apply that knowledge and experience to the design, construction and operation of Polk Unit 6. The design of Polk Unit 6 will include proven technologies as well as known improvements. Polk Unit 1 experience has led to the addition of COS hydrolysis, syngas saturation, combustion turbine air extraction and carbon rich fine slag re-injection to the Polk Unit 6 design. The Polk Unit 6 design does not include the convective syngas coolers used at Polk Unit 1, which will improve

reliability. Tampa Electric's expertise in managing large power plant projects, even with new technologies, will allow the company to keep costs and schedule under control while also assuring the unit will perform within expected parameters. Polk Unit 6 will be capable of burning a variety of fuels that will provide low cost energy for many years. Finally, the company's plan considers CO_2 capture and sequestration in the future should regulations change.

Q. Does this conclude your testimony?

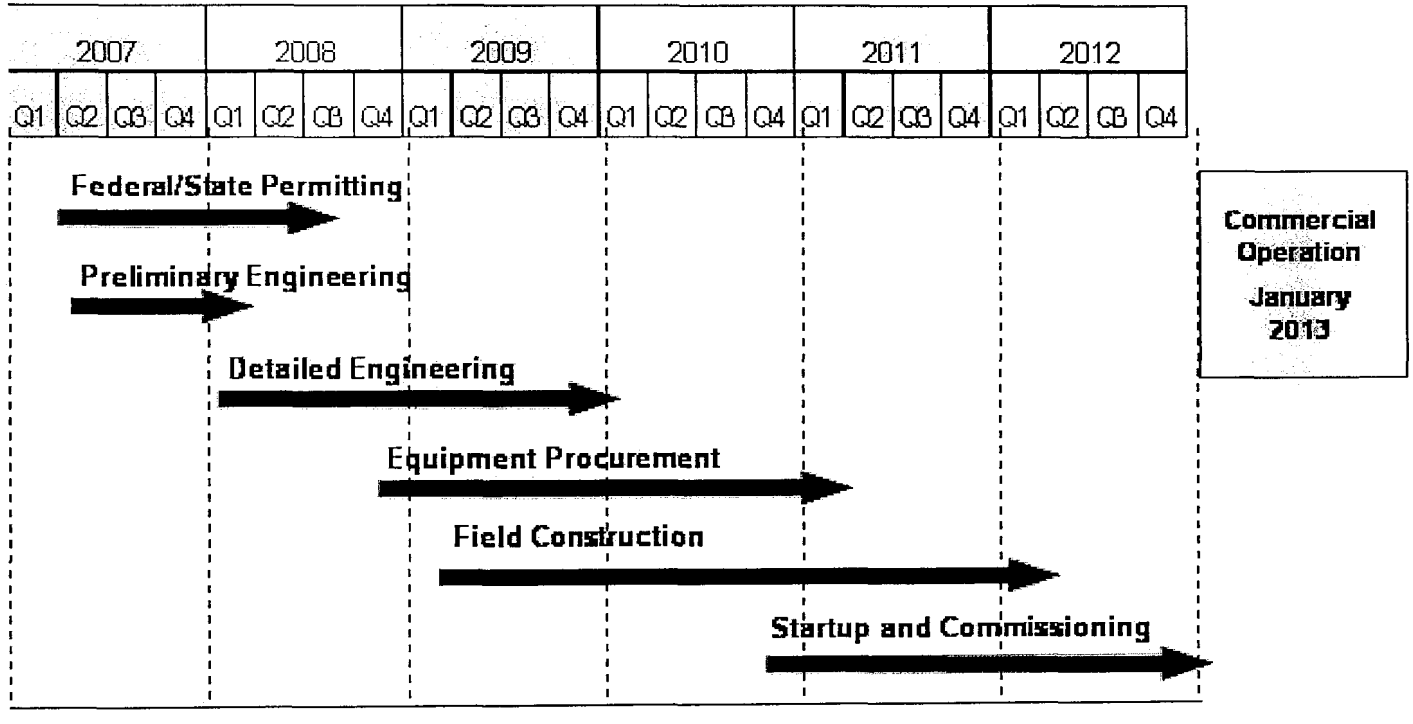
A. Yes, it does.



POLK 6 PROCESS

DOCKET NO. 07___-EI
PROCESS DIAGRAM
EXHIBIT NO. ___ (MRR-1)
DOCUMENT NO. 1
PAGE 1 OF 1

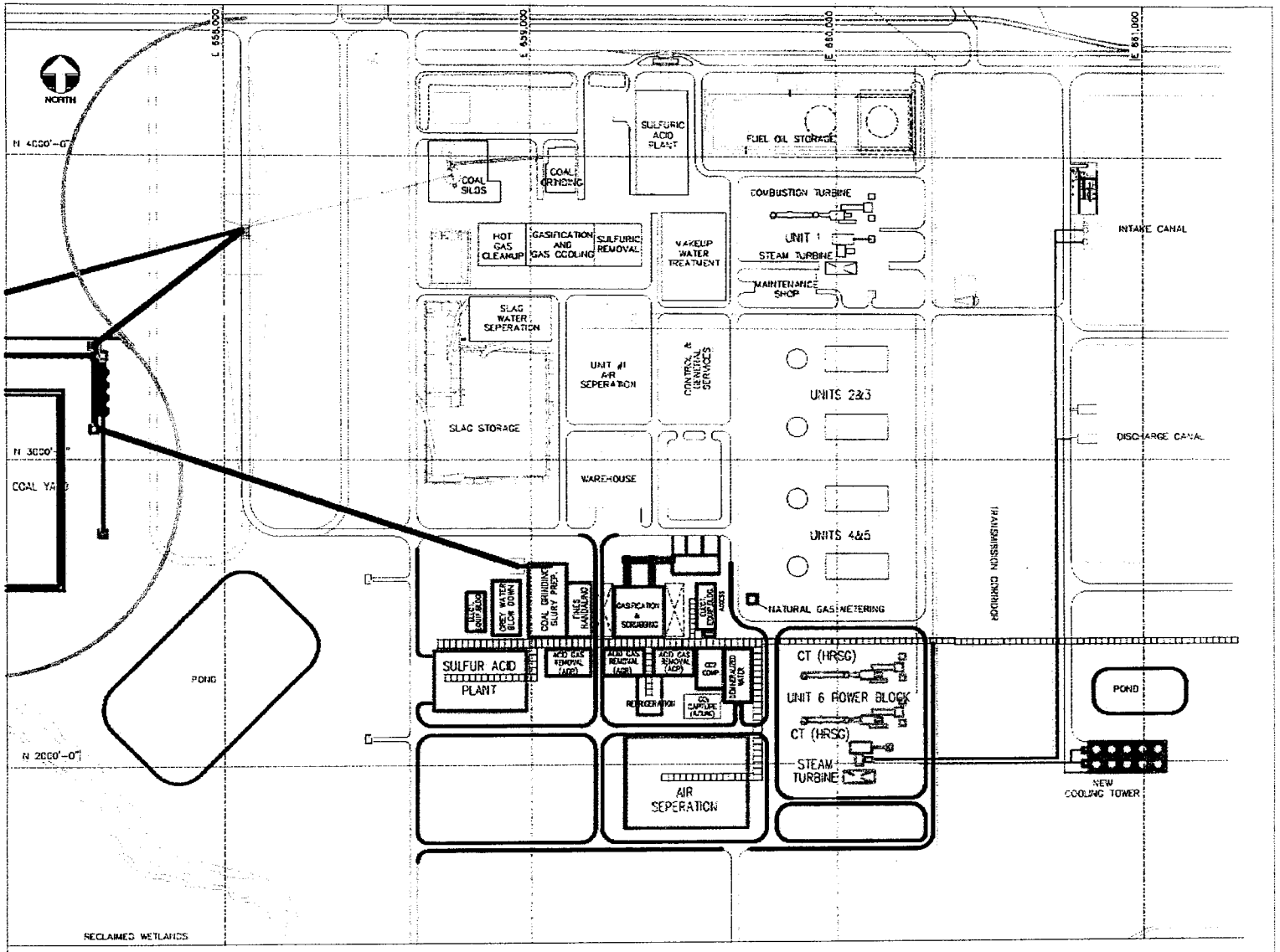
Polk Unit 6 Project Execution Plan



Polk Unit 6 Cost Estimate

	($000)
Gasification	
Coal Grinding & Slurry Feed	[redacted]
Gasification (LTGC, Black Water Flash and Slag Handling)	
Fine Slag Handling	
Acid Gas Removal (Ammonia Strippers)	
CO_2 Recycle	
Sulfuric Acid Plant	
Syngas Saturation	
Grey Water Blowdown Pretreatment	
Air Separation Unit	
Zero Process Water Discharge	
Gasification Subtotal	
Power Block & Balance of Plant	
Power Block	[redacted]
Balance of Plant	
Coal Handling Addition	
Power Block and BOP Subtotal	
Overnight Direct Engineering, Procurement, Construction & Startup Costs[1]	**$ 1,614,150**
Transmission[1]	25,000
Owner's Costs[1]	100,000
Contingency and Escalation	273,658
Total In-Service Costs	**$ 2,012,808**

[1] Costs are in 2007 dollars.



PROPOSED PLOT PLAN OF POLK UNIT 6

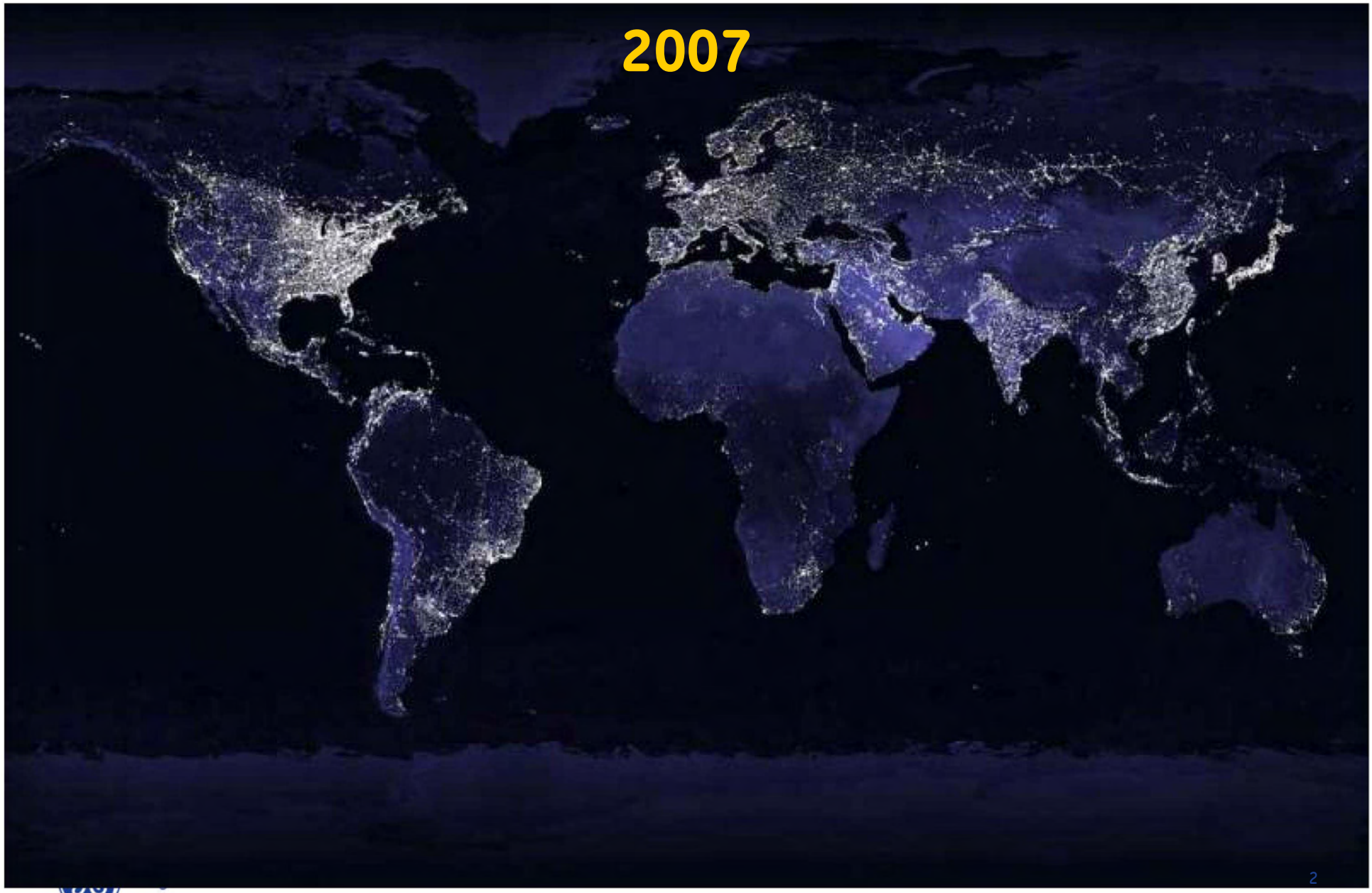
DOCKET NO. 07___-EI
PLOT PLAN
EXHIBIT NO. ___ (MRR-1)
DOCUMENT NO. 4
PAGE 1 OF 1

GE
Energy

GE's Gasification Business

John Lavelle
General Manager, Gasification

imagination at work



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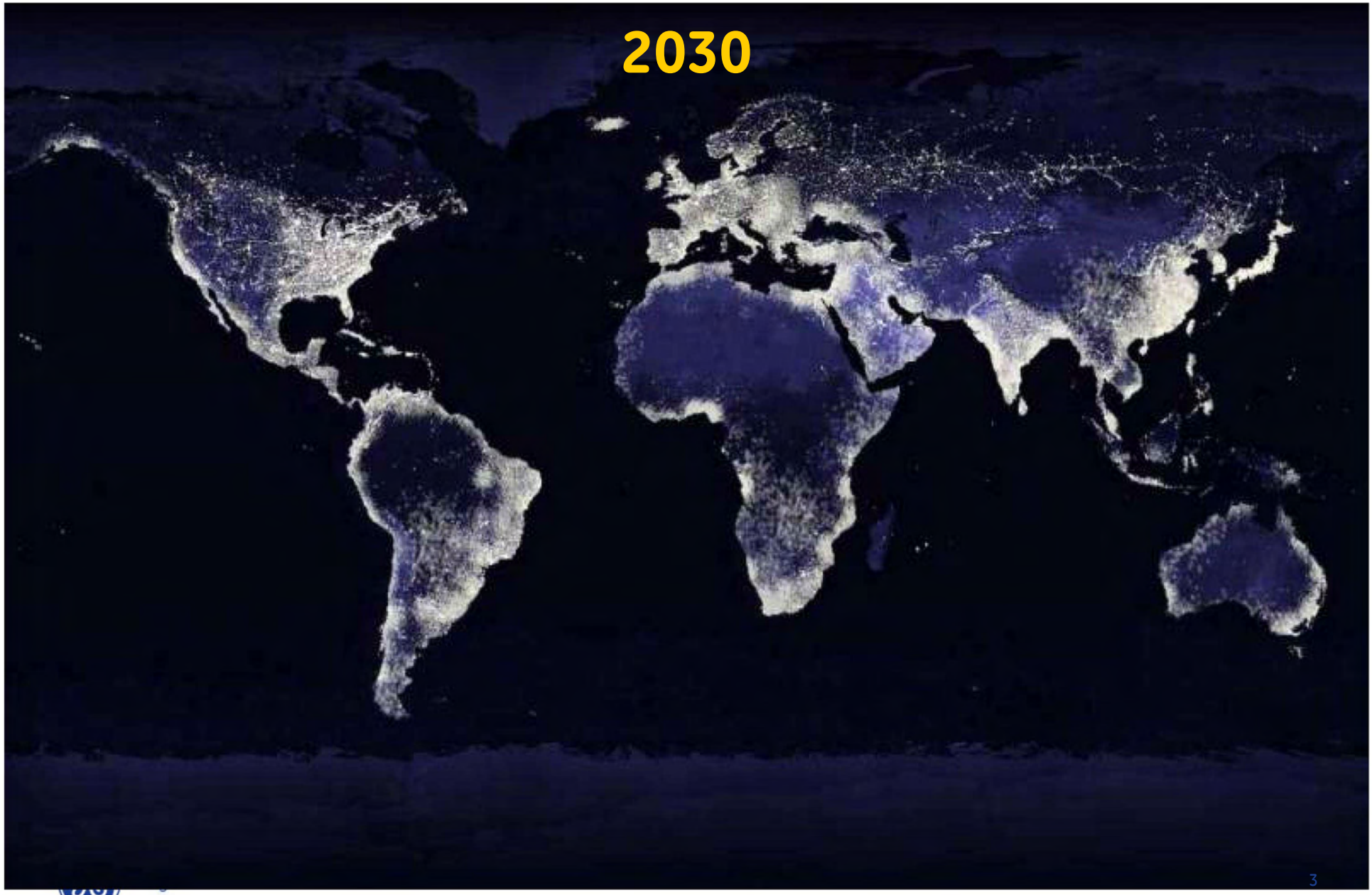

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Global dynamics …Gasification has a role

Rapid economic growth continues …
China/India/Middle East…+ all regions of world

Rising capital costs & skilled personnel shortage …
rising cost structure of energy supply

Gas & oil prices remain high …
interest in alternatives continues to grow

Energy security concerns rise …
infrastructure investment in all areas

Global warming concerns force action …
including technology incentives

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ecomagination℠

Grow revenues to $20B

Double R&D to $1.5B

Reduce GHG

Inform public

GE imagination at work

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Growing gasification in multiple segments

IGCC/Coal to Power

- Low cost fuels/feedstock
- Reduced emissions
- Fuel diversity

Coal to Chemicals

Refinery Polygeneration

Coal to Liquids (CTL)

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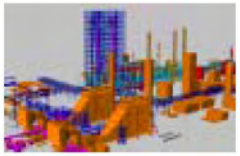
GE & Bechtel IGCC reference plant

RSC

ASU

Gas turbines



Engineering

Steam turbines

Controls

Reference plant well defined

- 2 +years engineering & 3 FEED's complete
- Full performance & availability models developed
- Bulks quantified (pipe, steel, concrete)
- Emissions for permit & detailed EPC schedule complete

Value proposition:

- Cycle: 12 month reduction in Feasibility/FEED
- Flexible contracting structure: LSTK, EEPs, equipment
- Wide bituminous fuel envelope: Sulfur, ash, chlorides
- Carbon capture capability
- Operability

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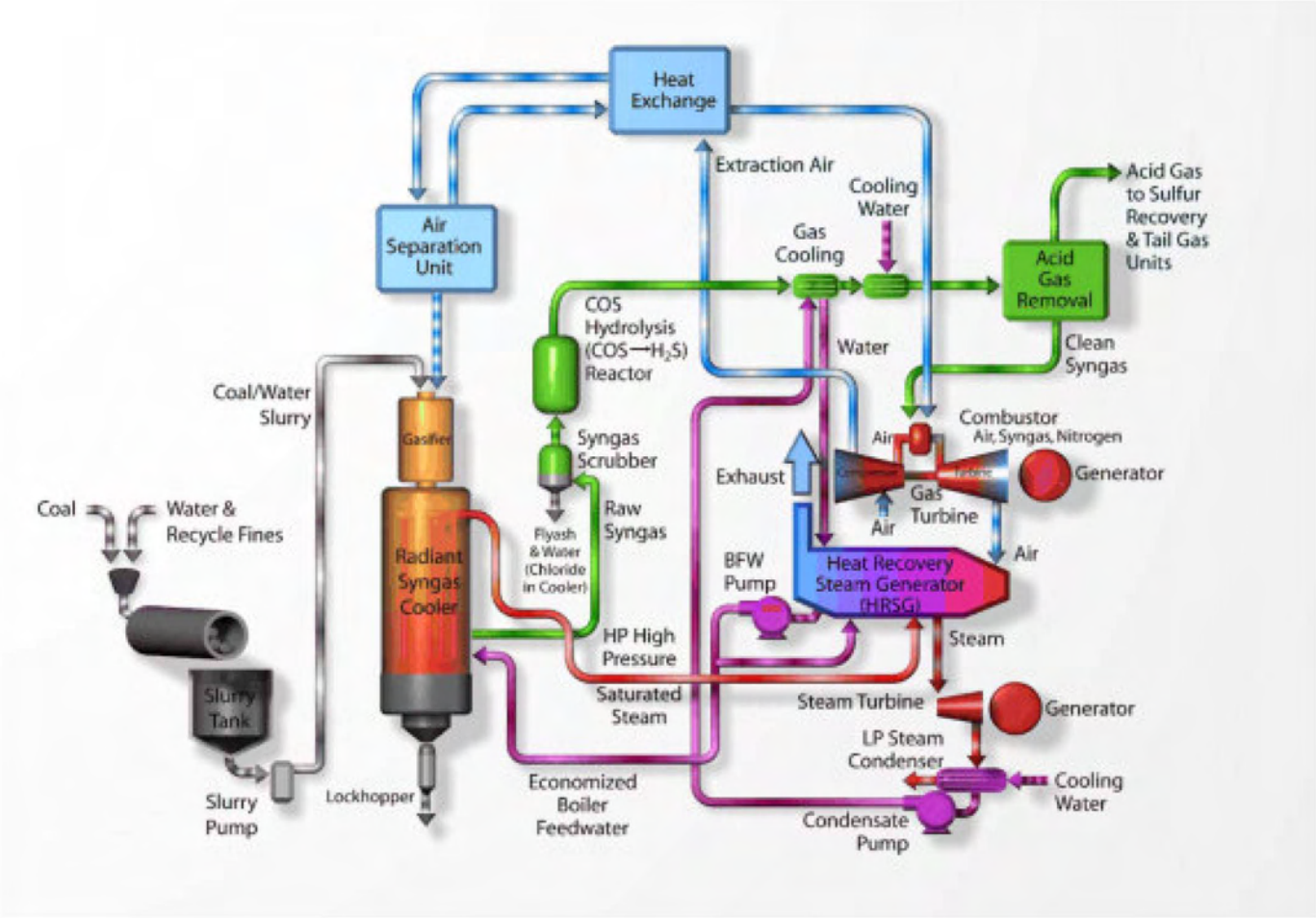
IGCC plant integration & control



Air integration

- Extraction air from GT
- N2 for NOx management

Thermal integration

- High pressure steam from RSC to HRSG
- BFW management with Auxiliary systems)

Syngas cleanup

- Heat integration … use low level process heat to remove sulfur

One integrated control system

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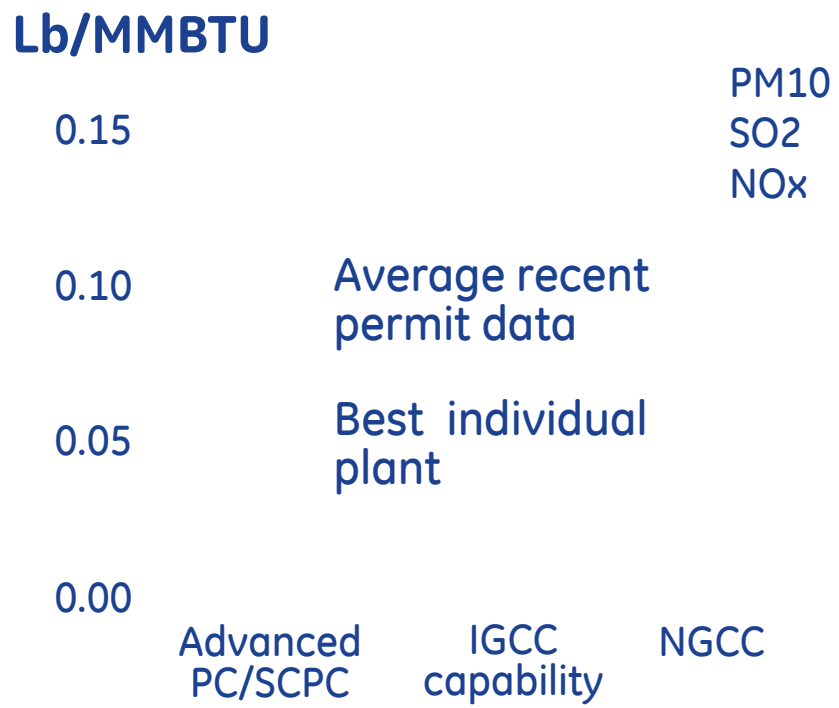
IGCC reference plant performance

Net Output[1]	**630 MW**
Net HR (HHV)[1]	**8751 Btu/kWh**
Availability Target	**92%, 85% on syngas**
Net Eff.[1]	**39% HHV**
Turndown	**50%**
Coal type	**Eastern Bituminous Coal**
Fuel Envelope	**Up to 14% Ash 0.8 – 4% Sulfur Chlorides 2500 ppm**

[1]Plant performance - will vary according to specific coal and site conditions



Source: GE internal data, average of 30 permits granted, applications and publicly reported emissions, Aug 2006

IGCC reference plant benefits compared to supercritical pulverized coal

- 33% less NO_x
- 75% less SO_x
- 40% less PM_{10}
- 90% + Hg removal
- CO_2 capture ready

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Industrial/Chemicals: 50 years of experience

- Syngas for multiple applications
- Methanol, Ammonia, Fuels, Oxo-Chems
- Advancements & Technology flow-down
  - Large Quench Gasifier
  - Refractory and Feed Injectors
- Process Engineering & Integration
- Coal, Petcoke, Oil, Resids and Gas Fuels
- Technical Advisory Services
- Experienced Start-up Teams
- 50+ years delivering gasification solutions

Alternatives to Natural Gas
Chemicals and Fuels
Higher Capacity Gasifiers

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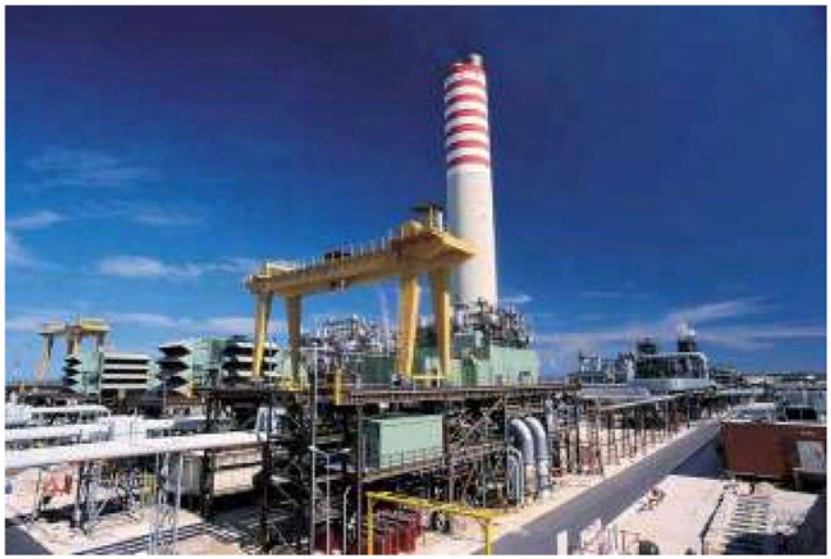
Refinery polygeneration: driving customer success



Courtesy of ISAB Energy

- H2 to Power.... hydrogen energy
- Oil Sands Solutions....H2
- Over 2 GW Power Using GE Gasification in Refineries

- Customer Expansions....ex. ISAB
- Advancements & Technology flow-down

  .....RSC and product packages
- Process Engineering & Integration expertise
- Leading Petcoke Experience
- Power Equipment Solutions
- S/U, Commissioning & Tech Advisory Svcs
- Delivering commercial solutions
- Partnering with Industry Leaders

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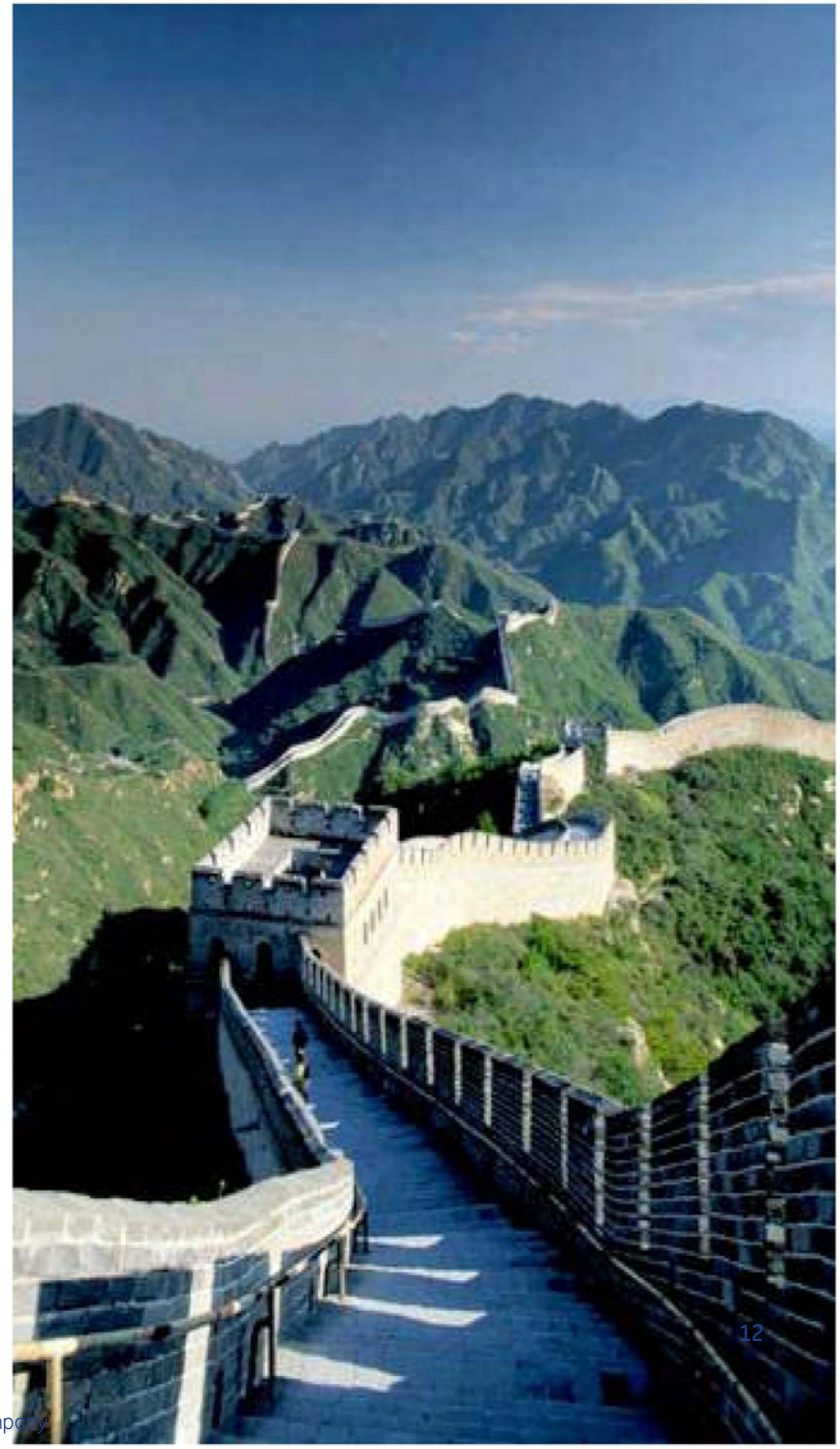
China...successful operations and continued growth

Total Orders:	**32**
Solids Feed	**22**
Liquid Feed	**8**
Gas Feed	**2**

1978: First order in China

- 3 New Licensees this Year
- Local Presence and Customer Support....China Technology Center



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GE's gasification experience & IGCC leadership

- Gasification leader since 1948 with 62 facilities operating worldwide
- First coal gasification plant in 1978
- 21 gas turbines operating on syngas … over 1 million operating hours
- IGCC leader: >3 GW with GE technologies
- >6 centuries team gasification experience
- TECO… operated > 12 million MW-hours
- 25 projects worldwide, which capture CO2

GE's gasification experience ~120 vessels in operation

77	Plants operating Plants in design or under construction
Total plants on all fuels	Total plants on solid fuels
	28

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Building supply chain capacity

Current landscape

- Capacity limitations
- Long cycle, large complex systems … ASU, SC, GT, HRSG
- Volatility in commodities
- Dollar weakness
- Customer schedule expectations
- Volume timing uncertainty

Phased approach

- Line of sight to suppliers
- Evaluating timing based on commitments

- Ready to support launch project
- Partners for critical systems identified

Time

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Expanding the fuel envelope

Coal range handled

100%

Lignite

Sub-Bituminous

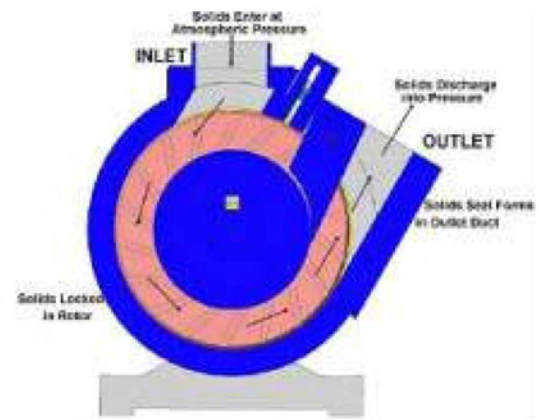
50%

Bituminous

0%

U.S. **ROW**

High Pressure Feed Pump Technology....



Coal Characteristic	Bituminous	Sub-Bituminous	Lignite	**US Ref Plant capability**
Btu/lb	10,000 – 12,500	8,000 – 8,900	5,100 – 7,000	
Ash (%)	6 – 14	4 - 7	8 – 25	**Up to 14%**
Sulfur (%)	0.8 - 4	0.1 - 0.6	0.5 – 2.5	**Up to 4%**
Challenges	Chlorides	Moisture, Ash Fusion Temp	Moisture, Heating value	**Chlorides up to 2,500 ppm**
US Ref Plant capability	**>90%**	**>90%**	**Future (?)**	

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Carbon capture ready … more than plot space

Capture ready features

- "Bolt on design" of carbon capture unit
- Plot space for AGR expansion, shift unit/s, CO2 compression
- AGR system already captures CO2 for recycle … expandable for future
- No gas turbine hot gas path modification

GE estimates show a NG equivalent case (~65% carbon capture) most economical… Retrofit cost near greenfield

DOE study* results for 90% capture

Relative to Baseline *(no CCS)*	**Impact on IGCC** (Avg of 3 technologies)	**Impact on PC** (PC & SCPC)
Capital Cost ($MM)**	+36%	+85%
Efficiency Impact (points HHV%)	-5.7 to -9.1	-11.9
Levelized Cost of Electricity Impact	+36%	+84%
Cost of CO2 Avoided	$32-$42/Ton	$68/Ton
Increase in Raw H20 Usage, CCS	1.15X	2.25X
Raw H20 Usage Comparison	Base	~3 X Base

*U.S. DOE/NETL-2007/1282, May 2007
** CCS costs incl transport, storage & monitoring

IGCC Alliance

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Utilizing a Diverse Global Team
>300 Technologists

Houston, TX – process & product design & IGCC experience
Niskayuna, NY – materials, design, system analysis
Shanghai, China – materials, chemistry, instrumentation
Schenectady, NY/ Salem, VA – controls, simulation
Bangalore, India – computational, experimental
Greenville, SC – design, adv materials &manufacturing
Irvine, CA – gasification modeling & experimental experts
Warsaw, Poland – reliability and maintenance analysis

... to lower CAPEX, plus increase efficiency & RAM

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GE Growing Across the Gasification Segments

Power

Chemicals

CTL

Refining

- ✓ Accelerating technology development
- ✓ Partnering with industry leaders
- ✓ Delivering commercial solutions

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GE
Energy

GE's Gasification Business

John Lavelle
General Manager, Gasification

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Advanced Fossil Power Systems Comparison Study

Final Report

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