APPENDIX 3-II

AIR MODELLING METHODS

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1 INTRODUCTION

This appendix provides technical information regarding the air dispersion modelling conducted for the MEG Energy Corp. (MEG) Christina Lake Regional Project – Phase 3 (the Project).

Section 2 provides the following information:

- a description of the models considered for use and the rationale for the model selected;
- an overview of the dispersion meteorology used in the modelling;
- a description of the modelling domain and the receptor locations where ground-level concentrations and deposition values were calculated;
- a discussion of the dispersion modelling approach used to evaluate ground-level concentrations and deposition values, including the assumptions and model options selected; and
- an evaluation of the CALPUFF model performance.

Section 3 provides the following information:

- the emission sources associated with the Project; and
- the emission source characteristics used in the modelling.

2 MODELLING METHODS

2.1 MODEL SELECTION

The air quality assessment made use of an air dispersion model to predict ground-level concentrations and deposition patterns. While numerous models were available for use, not all of them were appropriate for the Project. The model selection process was based on the following criteria:

- the capability of the model to evaluate the various regional source types (e.g., point, area and volume);
- the capability of the model to predict the necessary pollutant concentrations or required deposition rates;
- the technical basis of the model must be scientifically sound, and must incorporate the most current understanding of the dispersion of airborne contaminants;
- the assumptions and algorithms used in the model must be clearly set out, and have undergone rigorous independent scrutiny by peers in the technical community;
- the model applicability to those situations for which it was developed (i.e., the model must be applicable for evaluating both the regional and local effects of airborne emissions); and
- the acceptability of the model by the regulatory agencies.

2.1.1 Regulatory Modelling Guidance

2.1.1.1 Alberta Air Quality Modelling Guidelines

Alberta Environment (AENV) has established modelling protocols for all regulatory assessments in the province (AENV 2003). The intent of the guidelines is to ensure consistency in the application of dispersion models for regulatory applications. The guideline recommends two levels of assessment, namely: screening and refined. In some situations a screening-level approach is not practical due to the complex nature of the source configurations and/or the topography surrounding the facility. Additional guidance includes recommendations on:

- how to assess model performance;
- meteorological data requirements;
- how to place receptors around a facility;

- whether to and/or how to assess building downwash effects;
- how to incorporate complex terrain into the model; and
- what assumptions should be used when preparing source information.

2.1.1.2 United States Environmental Protection Agency Guidance

Many of the models recommended in the Alberta guidelines were originally developed by and/or for the United States Environmental Protection Agency (U.S. EPA) for regulatory modelling purposes. To ensure such modelling is completed in a consistent manner, the U.S. EPA has developed national dispersion modelling guidelines for regulatory applications. These are contained in Appendix W of Section 40 of the *Code of Federal Regulations* (U.S. Government 2005). This document details each of the models accepted for regulatory use and offers guidance on the appropriateness of each for given applications.

2.1.2 Model Comparison

A range of dispersion models were considered for use in assessing the Project emissions. These models varied in complexity from simple models, which require minimal inputs to run, to more elaborate models, designed to include regional emission sources and chemical transformations.

To determine the most appropriate combination of model and meteorology for the air quality assessment, dispersion models were compared using one of the evaluation methods recommended by the U.S. EPA (1992). This involved a statistical method called fractional bias that compares the means and standard deviations of both modelled and monitored concentrations at any given number of locations. The predicted output concentrations from three dispersion models were compared to the monitoring data from 12 monitoring stations located in northeastern Alberta. The reference year used was 1995 because ambient monitoring data, emissions data and meteorological data were all available for this year. The performance of the models were compared using monitoring data from stations outside the Project Regional Study Area (RSA); however, the evaluation is applicable for the Project area since the Project is in the same airshed as these monitoring stations. Further evaluation of the selected model was conducted and is discussed in Section 2.4.

2.1.2.1 Models Compared

The models considered in the evaluation included the CALPUFF model in the dynamic or three-dimensional mode (CALPUFF 3-D), the CALPUFF model in the steady-state or two-dimensional mode (CALPUFF 2-D) and the Industrial Source Complex Model, Version 3 (ISC3). A brief description of each follows.

CALPUFF 3-D

The CALPUFF modelling system is a generalized non-steady-state air quality modelling system that is recommended by both AENV and the U.S. EPA for regulatory use. The CALPUFF system includes modules to model buoyant rise and dispersion from area sources, buoyant line sources and volume sources. It has enhanced treatment of complex terrain, additional model switches to facilitate its use in regulatory applications and enhanced treatment of wind shear through puff splitting.

In the dynamic or three-dimensional mode, wind fields determined by the CALMET meteorological model are allowed to vary across the modelling domain in both the horizontal and vertical direction. This spatial variation often results in better estimates of plume dispersion than non-varying wind fields. Furthermore, the effects of terrain are incorporated into the wind field derivations that subsequently allow the plumes to travel around and/or over terrain features rather than impacting them directly.

CALPUFF 2-D

The CALPUFF model can also be run in a steady-state or two-dimensional mode. In this mode, the wind field for a given hour is uniform across the entire modelling domain. This mode is similar to classical dispersion models such as ISC3. While wind field variation is not available in this mode, many of the other CALPUFF model features are available, including puff splitting, long-range transport estimates and chemical transformation. These are improvements over the ISC3 model.

Industrial Source Complex Model, Version 3 (ISC3)

The ISC3 dispersion model is a steady-state Gaussian plume model, recommended by AENV for evaluating pollutant releases from a wide variety of sources associated with industrial complexes. This model can account for: building downwash; area, line and volume sources; plume rise as a function of downwind distance; separation of point sources; and terrain influences to a limited degree. The model is not able to incorporate flow around terrain features or chemical transformation.

The model assumes constant, uniform (steady-state) winds for each hour modelled. The model accepts user-specific wind profiles or uses default wind profile exponents (Irwin 1979) for both rural and urban modelling situations. Hourly meteorological (surface weather) data are considered, including stability class, wind speed, wind direction, temperature and mixing height. For deposition calculations, an extended meteorological data set can be supplied. It contains precipitation information and other atmospheric parameters including Monin-Obukhov length, roughness height, friction velocity, potential temperature gradient and solar radiation.

Plume rise is accounted for using the equations developed by Briggs (1969, 1975). The Briggs equations are also used to account for the stack tip downwash.

Horizontal dispersion coefficients from Turner (1969), with no adjustments for surface roughness, are used in the rural setting. The effect of an elevated capping layer is accounted for in the model with multiple reflections of the plume. Perfect reflection (i.e., no loss of pollutant due to scavenging or increase in dispersion due to wind shear) is assumed at the ground.

2.1.2.2 Meteorology

Meteorological data for the model evaluation were derived from local and regional data sets. A detailed description of the three-dimensional meteorology used is provided in Section 2.2 of this Appendix. Surface data from Fort McMurray were used, as were upper air data from Fort Smith, Northwest Territories and Stony Plain, Alberta. For both CALPUFF 2-D and ISC3 modelling, data from the Mannix monitoring station (at 75 m above ground-level) were used.

2.1.2.3 Emissions

For the model evaluation, sulphur dioxide (SO_2) emissions from sources operating in 1995 were assessed. The SO_2 emission rates were obtained from published reports and from calculations based on historic facility information. Tables 1 and 2 present the point and area source characteristics used in the modelling.

Table 1 1995 Point Source Emission Characteristics Considered for Model Evaluation

Source Description	Easting [m]	Northing [m]	Base Elevation [m]	Stack Height [m]	Stack Diameter [m]	Exit Velocity [m/s]	Exit Temperature [K]	SO_2 Emission Rates [t/cd]
Canadian Natural Resources Limited (Canadian Natural) Burnt Lake – steam generators	541,850	6,072,338	691.04	27.00	1.50	9.30	423.15	0.30
Syncrude Canada Ltd. (Syncrude) Mildred Lake – main stack	462,632	6,322,111	307.79	183.00	7.90	28.80	513.00	213.00
Syncrude Mildred Lake – gas turbine	462,693	6,322,003	307.86	45.70	3.30	15.80	423.00	0.00
Syncrude Mildred Lake – gas turbine	462,721	6,322,012	307.98	45.70	3.30	15.80	423.00	0.00
Syncrude reformer furnaces	463,084	6,322,453	305.65	23.50	4.10	11.60	540.00	0.00
Suncor Energy Inc. (Suncor) – powerhouse	470,865	6,317,883	256.63	106.68	5.79	30.48	466.00	215.00
Suncor – sulphur plant incinerator	470,973	6,317,792	255.03	106.70	1.80	29.30	736.00	35.00
Suncor – hydrocarbon flare (continuous)	471,190	6,318,149	241.39	100.50	0.18	20.00	1273.00	7.00
sum of Syncrude furnaces/heater stacks	462,879	6,322,400	306.73	41.80	1.70	7.70	426.00	0.00
sum of Devon Canada Corporation (Devon) Underground Test Facilities (UTF) Stacks	444,022	6,324,240	428.85	12.20	0.54	29.00	533.00	0.50
sum of Suncor furnaces/heater stacks	470,914	6,318,046	250.07	48.77	1.91	5.49	733.00	1.00
Northland Forest products	477,831	6,286,040	231.43	20.00	5.00	2.50	643.00	0.02
sum of Conoco Phillips Canada Pilot stacks	501,820	6,229,670	582.76	12.20	0.66	20.00	1273.00	0.17
sum of Japan Canada Oil Sands Limited stacks	457,965	6,237,042	590.92	30.00	0.91	19.80	369.00	0.94
Canadian Natural Primrose and Wolf Lake	527,392	6,069,640	678.82	30.00	1.37	21.60	473.15	2.04

Table 2 1995 Area Source Emission Characteristics Considered for Model Evaluation

Source Description	Centre Easting [m]	Centre Northing [m]	Source Area [m²]	Base Elevation [m]	Initial σ_z [m]	SO_2 Emission Rate [t/cd]
Syncrude Canada Ltd. (Syncrude) Mildred Lake West mine fleet	458,760	6,317,220	3,450,000	334.1	10.0	0.100
Syncrude Mildred Lake North mine fleet	456,632	6,322,313	3,486,800	335.9	10.0	0.850
Suncor Energy Inc. mine fleet	480,353	6,312,175	7,875,000	361.3	10.0	0.030
Fort McMurray residential area	472,937	6,287,719	7,959,086	362.7	5.0	0.025
Fort McMurray downtown area	477,933	6,286,223	6,016,999	242.6	7.5	0.019
Fort McMurray southern industrial area	478,558	6,281,968	11,344,737	355.2	3.5	0.036
Fort McKay	461,500	6,337,500	6,000,000	250.8	7.0	0.001
Anzac	497,400	6,255,500	8,400,000	485.4	7.0	0.002
Conklin	494,254	6,165,275	2,000,000	578.5	7.0	0.001
Janvier/Chard	516,660	6,198,690	25,000,000	451.0	7.0	0.002

σ_z = Standard deviation of pollutant concentration in the vertical direction.

2.1.2.4 Monitoring Data

To evaluate the models, monitored 1-hour SO_2 concentrations for 1995 were required. Appropriate monitoring data were available from a series of air quality stations that were active in 1995. These stations are listed in Table 3, and the locations are shown in Figure 1.

The stations have been divided into two groups namely: "oil sands" and "non-oil sands" stations. The "oil sands" stations are located adjacent to, or near, the two large oil sands processing facilities that were in operation in 1995. The "non-oil sands" stations are located in either communities or within the region but not adjacent to the facilities.

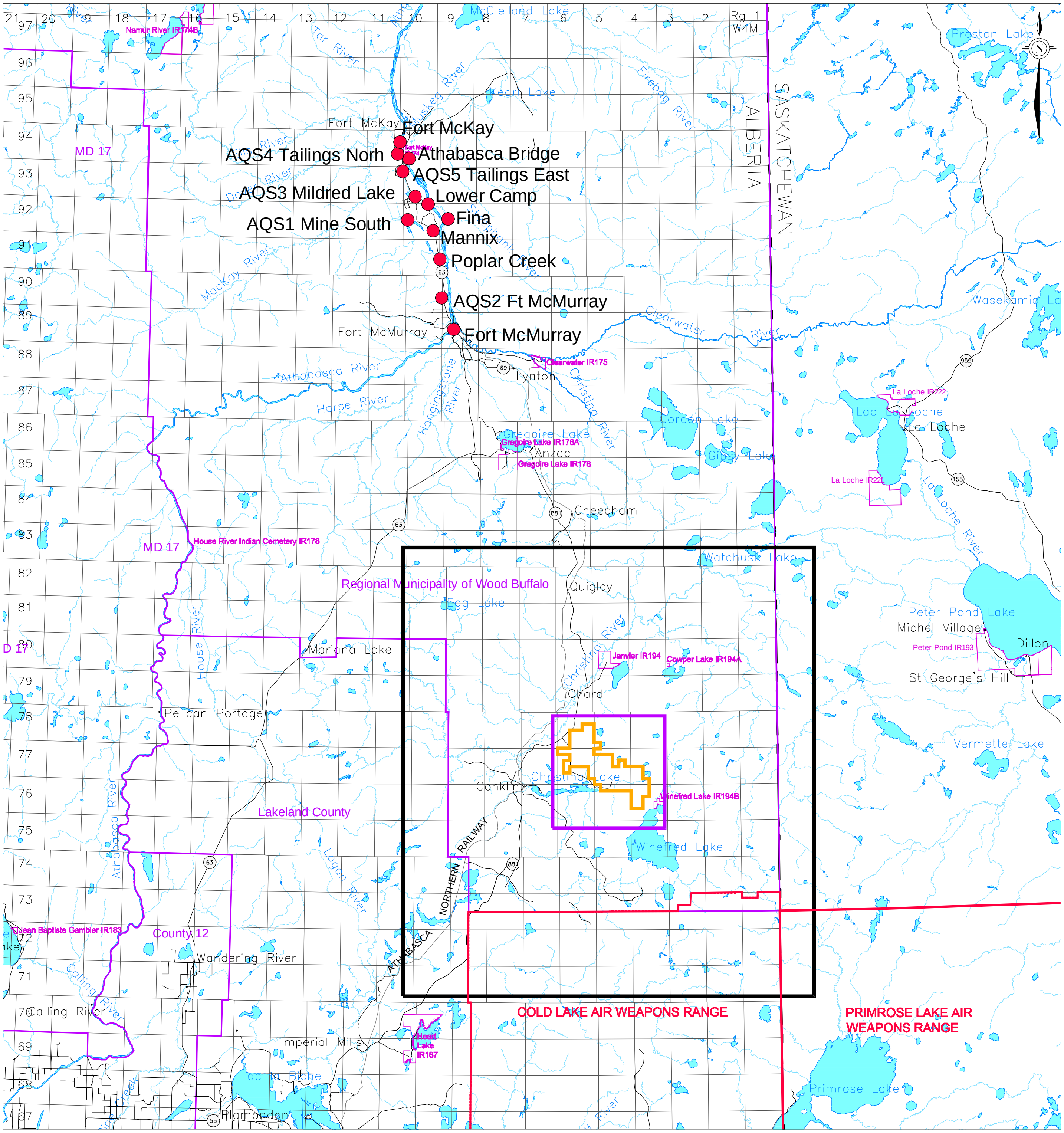
Table 3 Air Quality Monitoring Stations Used in the Model Comparison

Station Name	Location	Easting [m]	Northing [m]
Mannix	oil sands	470,600	6,313,700
Lower Camp	oil sands	469,300	6,320,800
Fina	oil sands	474,600	6,316,800
Poplar Creek	non-oil sands	472,400	6,306,000
Athabasca Bridge	non-oil sands	464,200	6,333,000
AQS1 Mine South[a]	oil sands	463,800	6,316,600
AQS2 Fort McMurray	non-oil sands	472,900	6,295,700
AQS3 Mildred Lake	oil sands	465,800	6,322,800
AQS4 Tailings North	oil sands	461,100	6,334,200
AQS5 Tailings East	oil sands	462,500	6,329,500
Fort McMurray	non-oil sands	476,100	6,287,300
Fort McKay	non-oil sands	461,800	6,337,400

[a] AQS = Air Quality Monitoring Station.

2.1.2.5 Comparison Approach and Results

As mentioned above, the model comparison tool used here is one of the evaluation methods recommended by the U.S. EPA (1992) for determining dispersion model performance. The statistic is called fractional bias, which provides a comparison of the means and standard deviations of the maximum 25 modelled and monitored concentrations at any given number of locations.



30 0 30

SCALE KILOMETRES

LEGEND

- ROAD
- RAILWAY
- RIVER
- OPEN WATER
- INDIAN RESERVE
- COLD LAKE AIR WEAPONS RANGE
- MODEL COMPARISON RECEPTOR
- MEG LEASE BOUNDARY
- AIR LOCAL STUDY AREA
- AIR REGIONAL STUDY AREA

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

LOCATIONS OF MODEL COMPARISON RECEPTORS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No. comparison receptors	
DESIGN	MS	28/11/07	SCALE AS SHOWN	REV. 0
CADD	TRE	28/03/08	FIGURE: 1	
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		

REFERENCE

ALBERTA NTDB DATA SUPPLIED BY GEOMATICS CANADA, AUGUST 2001. NAD 83 ZONE 12. SHEETS 74D, E AND 74L IN NAD 27 ZONE 12. SASKATCHEWAN NTDB DATA SUPPLIED BY ISC, AUG. 2001. NAD 83 ZONE 13. ALL DATA CONVERTED TO NAD 83 UTM ZONE 12.

Fractional bias (FB) is defined as follows:

$$FB = 2 \times \left(\frac{OB - PR}{OB + PR} \right)$$

In the above equation, *OB* represents the mean or standard deviation of the highest 25 observations and *PR* represents the mean or standard deviation of the highest 25 predictions. The fractional bias is preferred for measuring model performance because it is symmetrical and bounded (values range from –2.0 [extreme over prediction] to +2.0 [extreme under prediction]) and it is dimensionless, which is useful for comparing different compounds or concentration levels (U.S. EPA 1992).

The fractional bias values are typically plotted on a graph with the means (FB_{means}) on the X axis and the standard deviations (FB_{stdev}) on the Y axis. A box is placed on the plot enclosing the area of the graph where the model predictions are within a factor of two (corresponding to a fractional bias of between -0.67 and +0.67). The U.S. EPA states that predictions within a factor of two are a reasonable performance target for a model before it can be used for refined regulatory analysis (U.S. EPA 1992).

Fractional bias values were determined for the following three modelling scenarios:

- CALPUFF 3-D using CALMET;
- CALPUFF 2-D using 75-m Mannix data; and
- ISC3 using 75-m Mannix data.

Table 4 presents detailed statistics for the 1995 SO_2 monitoring data.

Table 4 Monitored 1995 Sulphur Dioxide Data Statistics Used in Model Comparison

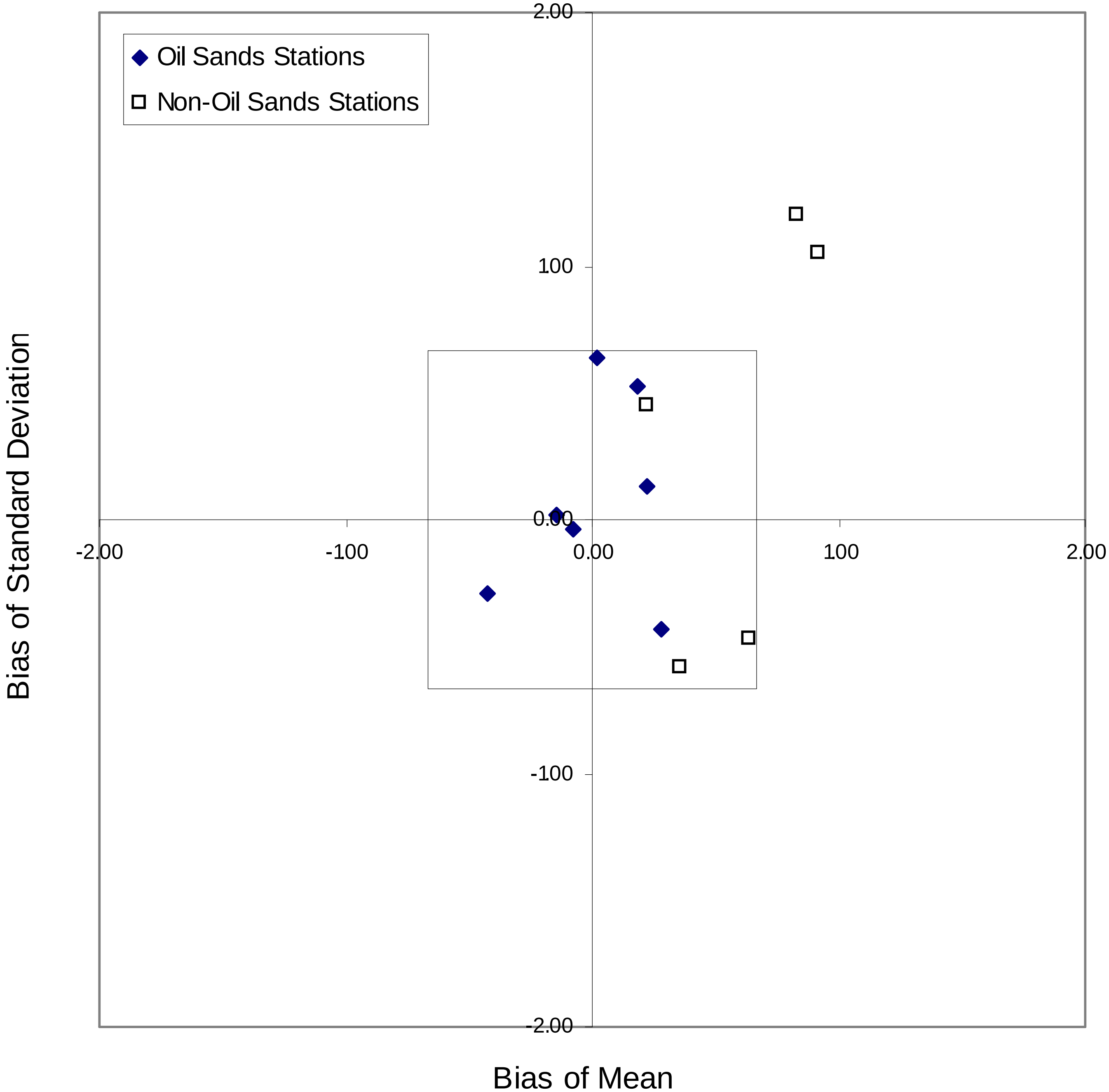
Parameter	Data Set Statistics										
	Mannix	**Lower Camp**	**Fina**	**Poplar Creek**	**Athabasca Bridge**	**AQS1[(a)]**	**AQS2**	**AQS3**	**AQS4**	**AQS5**	**Fort McMurray**	**Fort McKay**
first highest	1,257	1,349	1,163	615	623	744	618	668	644	382	450	605
fifth highest	1,110	917	848	503	424	445	508	534	361	275	325	369
ninth highest	1,105	699	694	487	414	348	388	388	306	196	293	312
> 450 µg/m³	74	53	89	38	2	4	7	6	3	0	1	2
> 900 µg/m³	13	5	3	0	0	0	0	0	0	0	0	0
5th percentile	0	8	0	0	0	0	0	0	0	0	0	3
25th percentile	3	13	0	3	0	0	0	0	0	0	0	3
50th percentile	5	18	3	5	3	0	0	3	0	0	3	3
75th percentile	10	26	10	10	5	3	5	5	3	3	3	5
90th percentile	55	45	26	34	21	10	24	26	16	8	16	16
95th percentile	126	81	111	73	47	34	47	65	42	24	31	34
99th percentile	419	359	541	338	398	128	123	189	139	93	97	119
valid data	7,927	8,401	7,737	7,807	8,336	7,757	8,108	7,267	6,424	7,351	8,705	8,146
mean	27	32	22	19	14	7	9	12	8	5	7	9
standard deviation	83	64	79	55	54	28	29	37	28	19	21	25
skewness	7	8	6	6	6	10	9	7	8	8	8	9
kurtosis	64	90	43	40	42	158	127	68	108	90	101	125

(a) AQS = Air Quality Monitoring Station.

The fractional bias plot comparing the CALPUFF 3-D predictions is given in Figure 2. The open squares in the figure correspond with the “non-oil sands” stations, while the solid diamonds correspond to the “oil sands” stations. The inner box bounds the area with a fractional bias of 0.67, which is considered adequate performance of the model. Overall, 10 of the 12 stations and all of the “oil sands” stations fell within the 0.67 threshold box. The model under-predicted the mean and standard deviation at the two “non-oil sands” stations located outside the 0.67 box.

Figure 3 shows the fractional bias plot of predicted concentrations from the CALPUFF 2-D model compared with the 75-m observations from the Mannix station. The results indicate that the predictions at 8 of the 12 stations fall within the 0.67 box. The model over predicts at the three “oil sands” stations that fall outside the 0.67 box and under predicts at the single “non-oil sands” station outside 0.67.

Figure 4 shows the fractional bias plot of predicted concentrations from the ISC3 model compared with monitored data from the Mannix station. The model under predicts at 5 of the 12 stations (two “oil sands” and three “non-oil sands”).



PROJECT

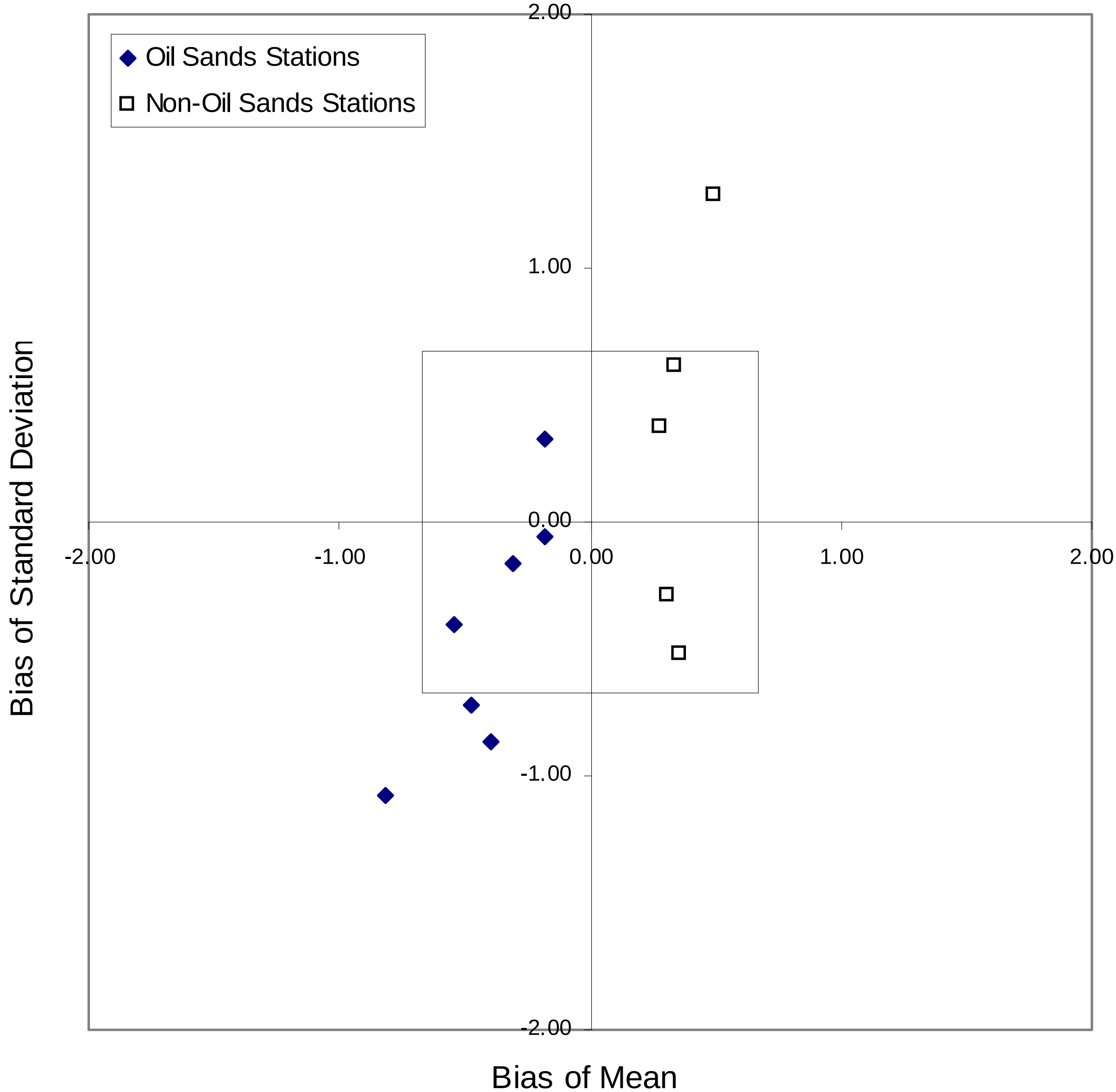
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

PERFORMANCE EVALUATION OF CALPUFF 3-D

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	CALPUFF 3-D
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TY	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 2**	
REVIEW	IGG	17/04/08		



L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 3 Performance evaluation of CALPUFF 2-D.dwg Apr 16, 2008 - 6:08pm

PROJECT

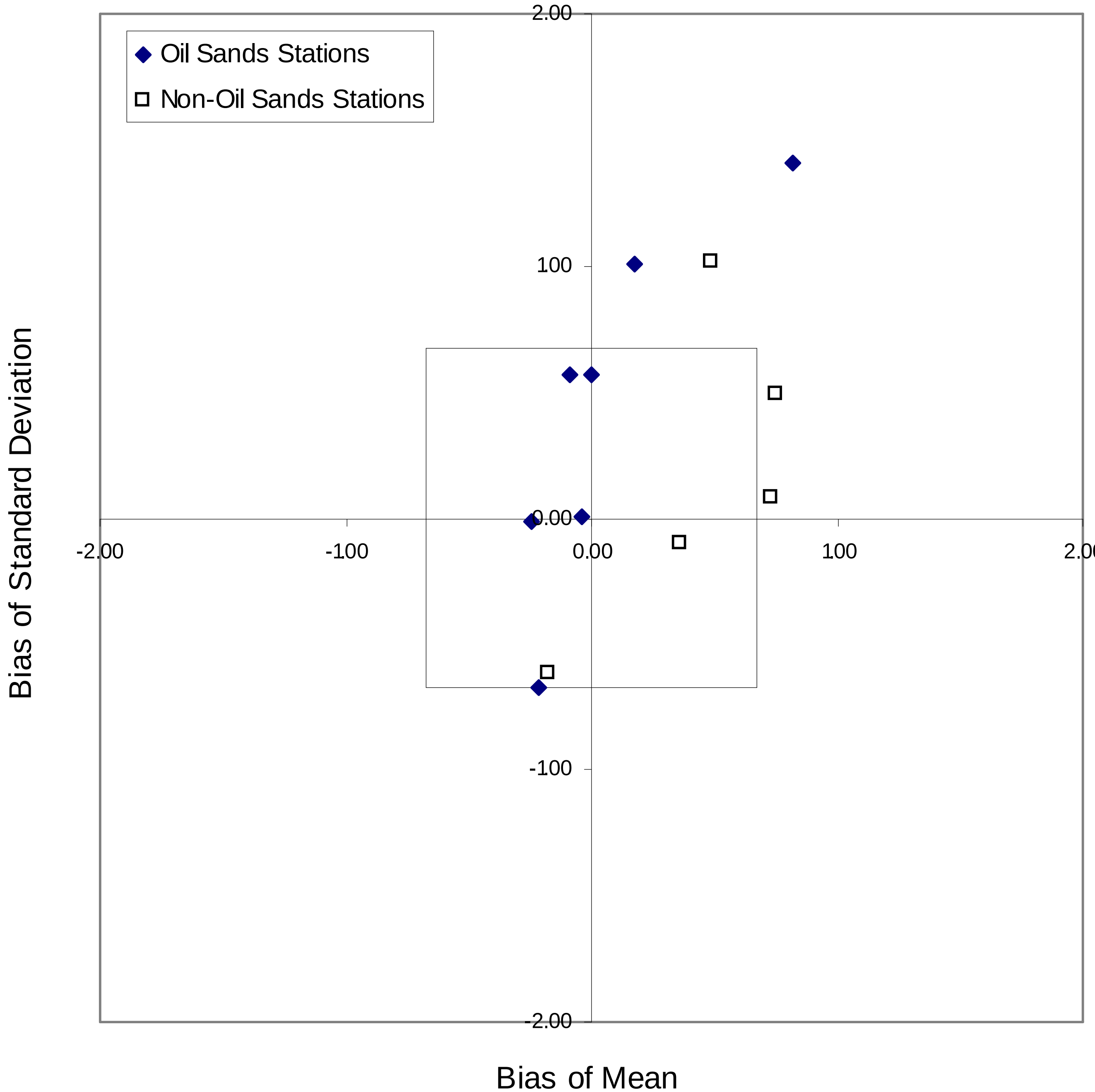
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

PERFORMANCE EVALUATION OF CALPUFF 2-D

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	CALPUFF 2-D	
DESIGN	MS	31/01/08	SCALE	AS SHOWN	REV. 0
CADD	TY	31/01/08			
CHECK	MS	14/04/08	**FIGURE: 3**		
REVIEW	IGG	17/04/08			



L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 4 Performance evaluation.dwg Apr 16, 2008 - 6:10pm

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

PERFORMANCE EVALUATION OF ISC3

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	ISC3
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TY	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 4**	
REVIEW	IGG	17/04/08		

In summary, the CALPUFF model produced more accurate predictions (i.e., having a fractional bias for the mean and standard deviation between -0.67 and +0.67) than the ISC3 model. When run in the three-dimensional mode using a regional data set that does not include Mannix observations, CALPUFF produced accurate predictions at 83% of the sites. The modelling was most accurate near the oil sands facilities and was less accurate within Fort McMurray. The performance in Fort McMurray may be influenced by local sources (e.g., diesel vehicles), which can impact the observations.

Based on the results of this model comparison, the CALPUFF model in three-dimensional mode is the preferred model for the Project air quality assessment.

2.1.3 Selected Model – CALPUFF Modelling System

The CALPUFF dispersion modelling system was chosen as the most appropriate tool for assessing the air quality impacts associated with the Project. The CALPUFF model in the dynamic mode (3-D) was used due to the feedback received from regulators and regional stakeholders regarding past modelling completed in support of other Environmental Impact Assessments (EIAs) in the Oil Sands Region. It is also recommended by AENV in its model guidelines (AENV 2003) for predicting acidic deposition.

The CALPUFF modelling system consists of the following three components:

- CALMET – A meteorological modelling package with both diagnostic and prognostic wind field generators;
- CALPUFF – A Gaussian puff dispersion model with chemical removal, wet and dry deposition, complex terrain algorithms, building downwash, plume fumigation and other effects; and
- CALPOST – A post-processing program for the output fields of meteorological data, concentrations and deposition fluxes.

The model was developed by Earth Tech (formerly Sigma Research Corporation) and was originally sponsored by the California Air Resources Board. Systems Applications Inc. was responsible for developing the wind field component of the system. The modelling system has been reviewed extensively by the Interagency Workgroup on Air Quality Modelling, which consists of representatives from the U.S. EPA, U.S. Forest Service, U.S. National Park Service and the U.S. Fish and Wildlife Service. This working group is responsible for making recommendations on modelling approaches suitable for estimating pollutant concentrations at Class I areas in the United States.

For assessing the Project, the CALPUFF model was run in the dynamic or three-dimensional mode, using a wind field developed from regional surface meteorological data and mesoscale data for Western Canada. The Regional Impact in Visibility and Acid Deposition/Acid Rain Mountain Mesoscale Model (RIVAD/ARM3) chemistry was used for calculations of wet and dry deposition of sulphate and nitrate compounds.

The CALPUFF system is suitable for modelling the following:

- time varying point, line, area and volume sources with averaging times ranging from one hour to one year;
- domains ranging from tens of metres to hundreds of kilometres from a source;
- building downwash effects;
- wind shear effects;
- inert pollutants and those subject to linear removal and chemical conversion mechanisms; and
- complex terrain.

Additional advantages of this model over traditional plume dispersion models include:

- capability to model calm wind speed conditions;
- plume dispersion is finite and pollutant mass is conserved;
- capability to use three-dimensional meteorological fields developed by CALMET or similar models;
- capability to incorporate mesoscale model output (e.g., MM5) to complement on-site or local data;
- multiple schemes available for calculating dispersion coefficients including direct turbulence measurements and/or similarity theory;
- capability to assess recirculation and gravity drainage flow conditions; and
- capability to predict the concentration and deposition patterns in the Oil Sands Region more accurately than the 2-D version of the CALPUFF model.

The CALPUFF model is one of the few models that has the chemistry required to characterize wet and dry deposition. CALPUFF can account for the chemical transformations of the emitted SO_2 and oxides of nitrogen (NO_X), as required for predicting Potential Acid Input (PAI), which is the preferred method for assessing the deposition of acid-forming chemicals. This method accounts for the acidifying effect of the sulphur and nitrogen species, as well as the neutralizing effect of available base cations.

In addition, the CALPUFF model can evaluate concentration and deposition values both close to the site and several hundred kilometres away. The use of any of the other models evaluated is appropriate for only a portion of this range. Finally, the CALPUFF model allows for the necessary concentration and deposition values to be determined using the same model.

2.2 DISPERSION METEOROLOGY

The three-dimensional wind fields used in the CALPUFF dispersion modelling completed for the Project air quality assessment were created using the CALMET model preprocessor developed specifically for use with the CALPUFF model. The CALMET wind fields were simulated over a 390 by 605 km area, which is much larger than the modelling domain used in the assessment. This was done to ensure the CALPUFF model uses the most representative wind fields across the entire study area.

For the Project, a 12-month meteorological data set covering January through December 2002 was used. The three-dimensional CALMET data included meteorological information from mesoscale meteorological models, upper air stations and surface stations.

2.2.1 CALMET Inputs

The CALMET model is composed of two main components: a wind field module and a boundary layer meteorological module. In Step 1 of the wind field module, the initial guess field is modified by kinematic effects of terrain, slope flows and blocking effects. Observational data is introduced in Step 2 through an objective analysis procedure. An inverse-distance squared interpolation scheme is used where observational data is weighted most heavily around the observation station.

The overlaid boundary layer model computes gridded fields of surface friction velocity, convective velocity scale, Monin-Obukhov length, mixing height, Pasquill-Gifford stability class, air temperature and precipitation rate using the energy balance method of Holtslag and van Ulden (1983).

The CALMET domain covers most of northeastern Alberta and part of northwestern Saskatchewan. The domains range from 53.5°N to 59°N latitude and from approximately 108°W to 114°W longitude. It covers an area of

235,950 km^2 (390 by 605 km). There are 78 grid cells in the east-west direction and 121 cells in the north-south direction with grid spacing of 5 km. The CALMET domain has 10 vertical layers with the following cell face heights: surface, 20, 50, 100, 200, 400, 800, 1,200, 1,600, 2,200 and 3,000 m.

Observations from upper air stations and surface stations were used in generating wind fields. The MM5 data was used for the initial guess field.

2.2.1.1 Fifth-Generation National Center of Atmosphere Research (NCAR)/Penn State Mesoscale Model (MM5) Data

The Fifth-Generation NCAR/Penn State Mesoscale Model (MM5) is a prognostic model that computes the following parameters: horizontal and vertical velocity components, pressure, temperature, relative humidity, and mixing ratios of water vapour, cloud, rain, snow, ice and graupel. The model was developed jointly by the National Center of Atmospheric Research (NCAR) and Pennsylvania State University (PSU).

The continental scale meteorological winds used as inputs to CALMET were simulated for 2002 using the MM5. The 2002 MM5 model data was provided by AENV. The MM5 data is important in the dispersion modelling as it provides information at the edge of the meteorological domain and in regions where observations are not readily available. In fact, studies conducted at the University of Washington (U of W) and presented on the U of W internet site show that the MM5 model is effective at characterizing winds in the Pacific Northwest (U of W, website).

The U of W scientists have suggested that the CALMET model should be run with MM5 data exclusively. Surface wind observations were felt to add little to the overall accuracy of the three-dimensional wind fields and could possibly result in local circulation patterns at the surface station during the brief passage of frontal systems. These local circulation patterns could result in unrepresentative predictions in the area of the weather stations at those times. In the CALPUFF three-dimensional modelling studies completed elsewhere in western Canada (BC Environment 2000; SE2 2000, 2001), the MM5 data was used exclusively when generating the CALMET three-dimensional wind fields.

However, there remains a concern that wind fields generated from continental scale inputs (such as MM5) may not match the local wind observations. To address this, wind observations from local surface stations were also used as inputs to the CALMET model.

2.2.1.2 Geophysical Parameters

The CALMET model requires a physical description of the ground surface to determine meteorological parameters in the boundary layer. The geophysical parameters are land use category, terrain elevation, roughness length, albedo, Bowen ratio, soil heat flux parameter, anthropogenic (man-made) heat flux and Leaf Area Index (LAI). Values for all parameters except land use category and elevation were determined for two seasons: foliage or summer (May through September) and non-foliage or winter (October through April). Table 5 gives a summary of the geophysical parameters for each land use category.

Land Use

The 2002 CALMET data set was generated using the most recent land use information from the Land Cover Map of Canada for the year 2000 (NRCan 2000). Eleven land use categories were used to describe the CALMET modelling domain. Each 5-km grid cell was assigned a category based on the most prevalent land use. These categories were then combined into more general categories provided by CALMET. The following summary provides the range of land use coverage of the CALMET domain:

- Deciduous, evergreen and mixed forests cover most of the modelling domain (55%). Evergreen forest land cover refers to land that is occupied by more than 80% coniferous trees. Mixed forests are composed of deciduous trees and 20 to 80% evergreen coniferous trees.
- Cropland and pasture cover approximately 9% of the modelling domain and is defined as land covered with herbaceous (typically annual) crops which may contain a small proportion (less than 10% in surface area) of trees or shrubs.

Table 5 Geophysical Parameters Used in CALMET

Land Use Category	Category Description	Roughness Length [m]		Albedo		Bowen Ratio		Soil Heat Flux Parameter [W/m^2]	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
13	industrial	1.0	1.0	0.18	0.5	1.5	1.5	0.25	0.25
21	cropland and pasture	0.25	0.1	0.15	0.5	1.0	1.0	0.15	0.15
31	herbaceous rangeland	0.05	0.05	0.25	0.5	1.0	1.0	0.15	0.15
32	shrub and brush rangeland	0.05	0.05	0.25	0.5	1.0	1.0	0.15	0.15
41	deciduous forest	1.0	0.6	0.1	0.25	1.0	1.0	0.15	0.15

Table 5 Geophysical Parameters Used in CALMET (continued)

Land Use Category	Category Description	Roughness Length [m]		Albedo		Bowen Ratio		Soil Heat Flux Parameter [W/m^2]	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
42	coniferous forest	1.0	1.0	0.1	0.25	1.0	1.0	0.15	0.15
43	mixed forest	1.0	1.0	0.1	0.25	1.0	1.0	0.15	0.15
52	lakes	0.001	0.001	0.1	0.75	0.1	0.1	1.0	1.0
62	nonforested wetlands	0.2	0.1	0.1	0.5	0.1	0.1	0.25	0.25
76	transitional areas	0.05	0.05	0.3	0.75	1.0	1.0	0.15	0.15
77	mixed barren land	0.05	0.05	0.3	0.75	1.0	1.0	0.15	0.15

- Mixed rangeland (or grassland) covers 17% of the domain. Shrub and brush rangeland (transition treed shrubland) refers to land that has a tree crown density less than 10%. It covers approximately 8% of the domain.
- Non-forested wetlands cover 0.01% of the domain and consist mainly of low to intermediate woody shrubs.
- Barren land (transitional areas and mixed barren land) covers 5% of the domain. This refers to areas that have recently burned and/or treeless areas with low vegetation cover (less than 40% of the ground is covered in shrubs, lichen or herbs).
- Lakes cover about 7% of the modelling domain.

Terrain

One of the main terrain features of the modelling domain is the Athabasca River valley, which runs north-south. The river valley is surrounded by Birch Mountain to the northwest, Muskeg Mountain to the east and Stony Mountain to the south. Terrain elevations were derived from the United States Geologic Service (USGS) Digital Elevation Model with 250 m resolution. This data was then gridded to 5 km resolution and the elevation at the centre of each grid cell is used to define the elevation of that grid cell. The highest grid point elevation is 883 m above sea level (masl), which is located near the western border of the modelling domain. The grid point with the lowest elevation (i.e., 209 masl) is located northeast of Birch Mountain.

Roughness Length

Roughness length (z_0) is a measure of the aerodynamic roughness of a surface and is related to the height, shape and density of the surface as well as the wind speed. It is defined as the height at which the vertical wind profile is extrapolated to zero. The model default values were used in the summer, but were changed for winter to reflect the effects of snow cover and less vegetation (Table 5).

For example, cropland has a roughness length of 0.25 m in the summer, but the value decreases to about 0.1 m in the winter when the crop is harvested and there is a layer of snow. This is also the case for non-forested wetlands where z_0 is reduced to 0.1 m due to snow cover. Deciduous forests also have a higher z_0 of 1.0 m during the summer but it decreases to about 0.6 m in the winter when the trees have lost their leaves. There is little or no variation in coniferous or mixed forest roughness lengths between summer and winter. Rangeland and barren land categories have a summer z_0 of 0.05 m. Since snow cover does not usually increase the roughness length, the winter value remains unchanged at 0.05 m.

The roughness length used for lakes is 0.001 m for both seasons since ice has a similar value to water. Urban roughness lengths are generally accepted to be 1.0 m for both summer and winter.

Albedo

Albedo is defined as the ratio of reflected solar radiation to the total incoming solar radiation received at the surface. Model default values of albedo were used for the summer season but were altered for winter to reflect the presence of snow. The albedo of snow-covered vegetation ranges from 0.2 to 0.8 (Henderson-Sellers and Robinson 1986) so an average of 0.5 was used for cropland and pasture, rangeland and non-forested wetlands.

A previous study on forest energy budgets show that forests with surface snow cover have an albedo of about 0.2 (McCaughey 1987). However, the value of 0.25 suggested by Hartmann (1994) was used. Snow-covered lakes and barren land are assigned a value of 0.75, which is the average of old and new snow values. The industrial albedo was increased from 0.18 in the summer to 0.5 in the winter due to the higher reflectivity of snow. Table 5 presents the albedo values used for each of the land use categories.

Bowen Ratio

The Bowen ratio is defined as the ratio of sensible heat flux to latent heat flux. The model defaults were used for both seasons. The Bowen ratio for lakes was set to 0.1 as per Oke (1987) and the CALMET User's Manual (Earth Tech 2000). Table 5 presents the Bowen ratio values used for each of the land use categories.

Soil Heat Flux Constant and Anthropogenic Heat Flux

The soil heat flux constant is a function of the surface properties and is used to compute the flux of heat into the soil. The model default values were used for both seasons and are shown in Table 5. Anthropogenic heat flux is a function of population density and energy usage. Since the value is small compared to other terms and there are no large urban population centres in the modelling domain, anthropogenic heat flux is set to zero W/m^2 for all land use categories.

Leaf Area Index (LAI)

Leaf Area Index (LAI) is defined as the ratio of leaf area to soil surface area. A summer and a winter value were assigned to each Land Cover of Canada category then weighted to each grid cell based on the most prevalent vegetation type. Leaf area indices are based on values found in literature. Values range from 0.0 to 6.0 for both summer and winter. Table 6 shows the relationship between land use category, season and LAI. The LAI values for the foliage period were used for the months of May through September. The non-foliage LAI values were used for the remaining months.

2.2.1.3 Surface and Precipitation Data

The CALMET model requires hourly values of the following observed parameters for at least one surface station in the domain:

- wind speed and direction;
- temperature;
- relative humidity;
- cloud (ceiling height and cloud opacity);
- station pressure; and
- precipitation rate and code.

Table 6 Leaf Area Indices Used in CALMET

CALMET Land Use Category	Land Cover of Canada (1995) Category	Foliage Period	Non-Foliage Period
(13) industrial	(29) urban and built-up	0.0	0.0
(21) cropland and pasture	(23) high biomass cropland	5.0	0.0
	(24) medium biomass cropland	4.0	0.0
	(25) low biomass cropland	3.0	0.0
	(26) cropland-woodland	4.5	<0.1
	(27) woodland-cropland	4.0	<0.5
	(28) cropland-other	3.6	<0.1
(31) herbaceous rangeland	(16) grassland	6.5	0.0
(32) shrub and brush rangeland	(13) transition treed shrubland	3.0	<0.1
(41) deciduous forest land	(6) deciduous coniferous forest	5.0	0.0
(42) evergreen forest land	(1) high-density evergreen coniferous forest	7.0	6.5
	(2) medium-density southern evergreen coniferous forest	4.0	3.5
	(3) medium density northern coniferous evergreen forest	4.0	3.5
	(4) low-density southern evergreen coniferous forest	3.5	3.0
	(5) low-density northern evergreen coniferous forest	3.5	3.0
(43) mixed forest land	(7) mixed coniferous forest	6.5	3.5
	(8) mixed intermediate uniform forest	6.0	2.0
	(9) mixed intermediate heterogeneous forest	6.0	2.0
	(10) mixed deciduous forest	5.5	1.5
(52) lakes	(30) water	0.0	0.0
(62) nonforested wetlands	(14) high-density wetlands/shrubland	2.5	0.5
	(15) medium-density wetlands/shrubland	2.0	<0.1
(76) transitional areas	(11) low green vegetation cover burn	1.5	<0.1
	(12) green vegetation cover burn	2.0	<0.1
(77) mixed barren land	(17) lichen and others barren land	0.5	0.0
	(18) shrub/lichen dominated barren land	1.5	0.0
	(19) heather and herb barren land	1.5	0.0
	(20) low vegetation cover barren land	1.0	0.0
	(21) very low vegetation cover barren land	0.5	0.0

Table 7 and Figure 5 show the surface and precipitation stations used for the 2002 CALMET data set. Meteorological data from the Wood Buffalo Environmental Association (WBEA) air quality monitoring stations were included in the 2002 CALMET modelling to provide information in the Oil Sands Region.

Since hourly precipitation was not available from any of the stations, daily total precipitation was used and divided evenly over the 24 hours in the day.

Precipitation code was based on the hourly temperature observed during precipitation events. If the temperature was lower than 0°C, the precipitation was classified as snow. If the temperature was higher than 0°C, the precipitation was classified as rain.

Table 7 Surface and Precipitation Stations

Station Name	Data Source	Station Type
Andrew	MSC	precipitation
Athabasca	MSC	precipitation
Buffalo Viewpoint	WBEA	surface
Calling Lake	MSC	precipitation
Cold Lake	MSC	surface/precipitation
Fort Chipewyan	MSC	surface/precipitation
Fort McKay	WBEA	surface
Fort McMurray	MSC	surface/precipitation
Lower Camp	WBEA	surface
Mannix	WBEA	surface
Mildred Lake	MSC	surface/precipitation
Millennium	WBEA	surface
Redwater	MSC	precipitation
Westlock	MSC	precipitation

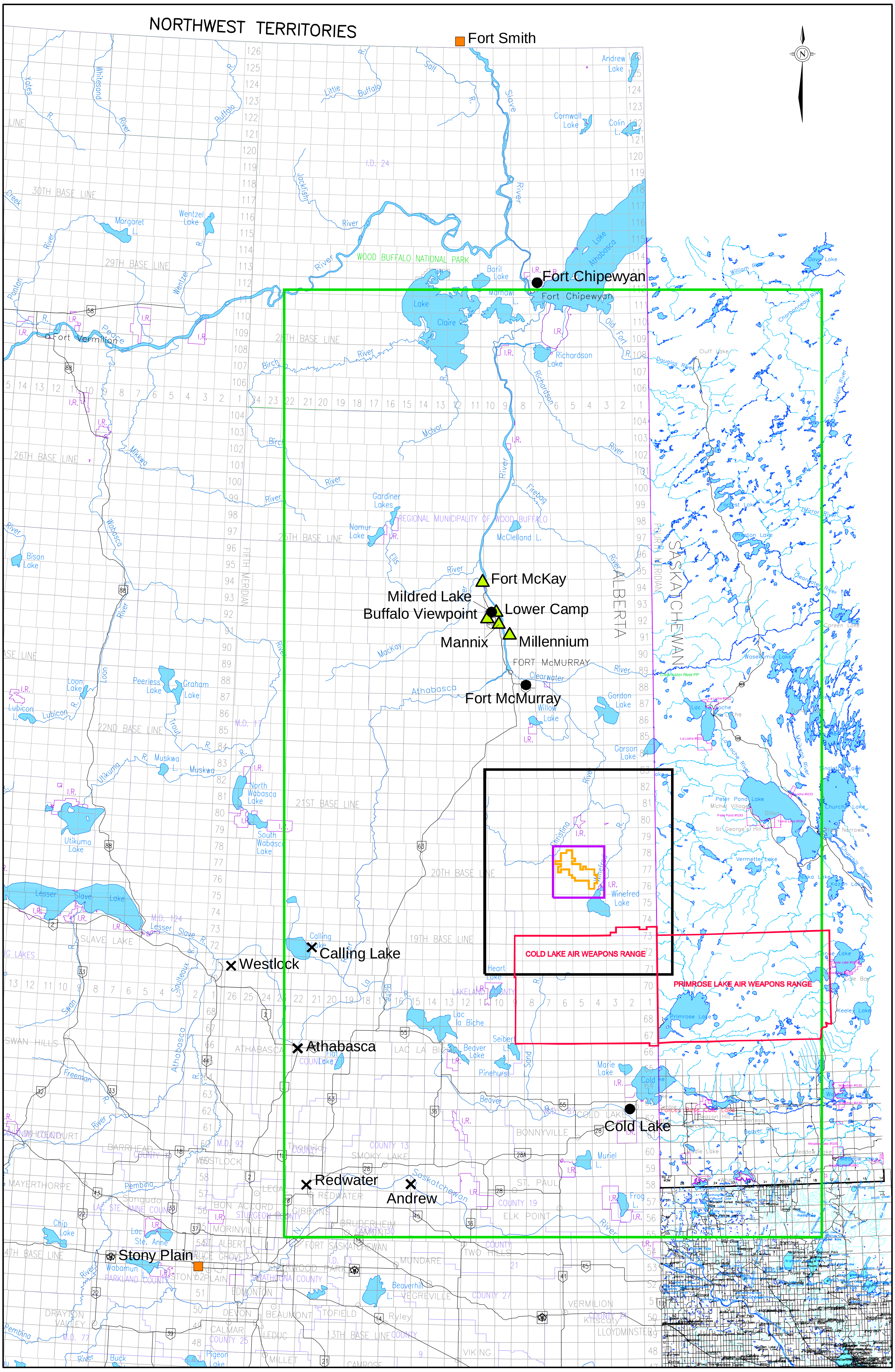
Note: MSC = Meteorological Service of Canada; WBEA = Wood Buffalo Environmental Association.

2.2.1.4 Upper Air Data

The two upper air stations used were Fort Smith, Northwest Territories and Stony Plain, Alberta (Figure 5). Since these are the two closest stations to the modelling domain, they provide a representation of the larger circulation patterns in the oil sands area. Fort Smith is located about 275 km northwest of the modelling domain. Stony Plain is located 50 km southwest of the domain. Wind and temperature data were extracted from each pressure level up to 500 mb or the next closest level containing wind data. If any soundings were missing, they were replaced with the adjacent sounding.

2.2.2 CALMET Model Options

The CALMET model contains several options for calculating the domain wind field. Surface winds are extrapolated to upper layers using the similarity theory. Surface data from the upper air stations is not used in this computation. There are also layer-dependent biases that determine the weights of surface and upper air data. All but the top two layers have a zero bias which means the inverse distance-squared method is used for all stations. The weight of the upper air data at the second-highest level is increased by 50% (weight of surface data is decreased by 50%). The top level uses only upper air data (weight increased by 100%).



LEGEND

- ROAD
- RAILWAY
- RIVER OR STREAM
- OPEN WATER
- INDIAN RESERVE
- AIR WEAPONS RANGE
- MEG LEASE BOUNDARY
- AIR LOCAL STUDY AREA
- AIR REGIONAL STUDY AREA
- AIR MODELLING DOMAIN
- SURFACE STATION
- SURFACE AND PRECIPITATION STATION
- PRECIPITATION STATION
- UPPER AIR STATION

50 0 50
SCALE KILOMETRES

REFERENCES

ALBERTA NTDB DATA SUPPLIED BY GEOMATICS CANADA, AUGUST 2001. NAD 83 ZONE 12. SHEETS 74D, E AND 74L IN NAD 27 ZONE 12. SASKATCHEWAN NTDB DATA SUPPLIED BY ISC, AUG. 2001. NAD 83 ZONE 13. ALL DATA CONVERTED TO NAD 83 UTM ZONE 12.

PROJECT
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE
MAP OF SURFACE, PRECIPITATION AND UPPER AIR STATIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Stations Map
DESIGN	MS	10/07/07	SCALE 1:2,500,000	REV. 0
CADD	TRE	14/04/08		
CHECK	MS	16/04/08	**FIGURE: 5**	
REVIEW	IGG	17/04/08		

The maximum radius of influence over land in the surface layer is 50 km. At upper levels, the radius of influence is 300 km. The minimum radius of influence in the wind field interpolation is 1 km. The radius of influence of terrain features is set to 5 km.

Mixing heights are computed using the hourly surface heat fluxes and observed morning and afternoon temperature soundings. The minimum and maximum allowed mixing heights for both land and water are 50 and 3,000 m, respectively.

Air temperature is interpolated using the inverse distance method, with a radius of influence of 250 km. Smaller radii were tested but a strong horizontal temperature gradient occurs between the two surface stations. A larger radius of 250 km produces a representative temperature field, especially at the surface.

The inverse distance-squared method was used for precipitation interpolation, which was recommended by Dean and Snyder (1977) and Wei and McGuinness (1973). The radius of influence was set to 150 km.

2.2.3 CALMET Output

A summary of the meteorological parameters generated by CALMET for the Project area, including winds, mixing heights and stability class, are provided in this section.

2.2.3.1 Wind

The dispersion and transport of atmospheric emissions are driven primarily by the wind. A “windrose” is often used to illustrate the frequency of wind direction and the magnitude of wind velocity. The lengths of the bars on the windrose indicate the frequency and speed of wind, and the direction from which the wind blows is illustrated by the orientation of the bar in one of 16 directions.

Figure 6 presents comparative windroses for Fort McMurray for 2002. The annual windroses are based on observed data as well as data derived for the CALMET grid cell containing Fort McMurray. The wind pattern at the Fort McMurray airport is generally east-west. The dominant winds observed in 2002 were from the east and east-southeast with stronger winds (i.e., wind speed greater than 30 km/hr) occurring from the west to northwest sector.

In comparison, the 2002 CALMET winds for Fort McMurray are similar to the observations with a higher frequency from the west-southwest and a lower frequency from the east. These slight differences between observed and predicted winds are to be expected as the observed data represent the conditions at a single location, while the CALMET predictions represent the winds expected over an area that is 5 by 5 km in size.

Figure 7 presents windroses for Cold Lake for 2002. The observed winds at Cold Lake were predominantly from the west and west-northwest during 2002. In comparison, the 2002 CALMET winds showed a similar pattern to the observations for the same time period with slight differences in frequency. These differences between observed and predicted winds are to be expected as the observed data represent the conditions at a single location, while the CALMET predictions represent the winds expected over an area that is 5 by 5 km in size.

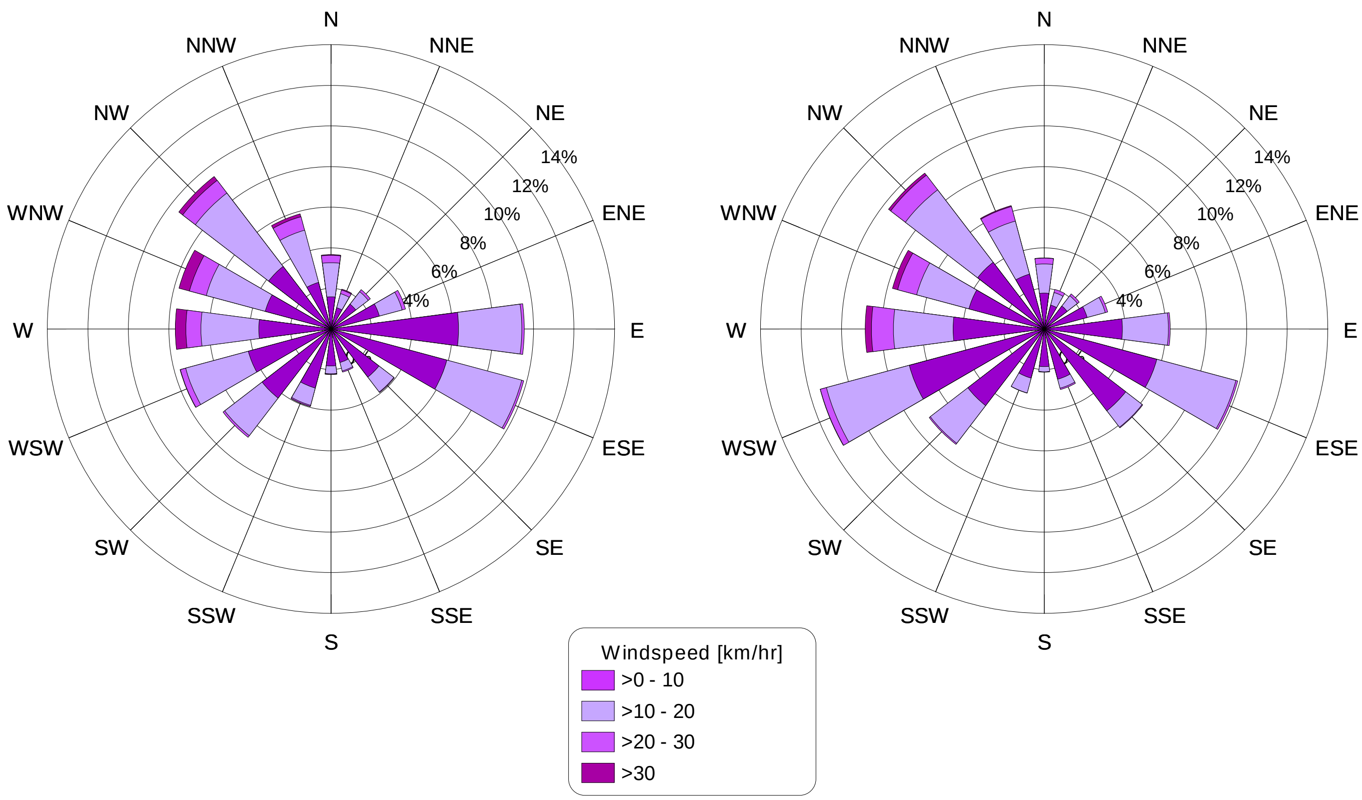
2.2.3.2 Mixing Height

Mixing height is a measure of the depth of the atmosphere through which mixing of emissions can occur. Mixing heights often exhibit a strong diurnal and seasonal variation: they are lower during the night and higher during the day. Seasonally, mixing heights are typically lower in the winter and higher in the late spring and early summer.

The CALMET method calculates an hourly convective mixing height for each grid cell from hourly surface heat fluxes and vertical temperature profiles from twice-daily soundings. Mechanical mixing heights are calculated using an empirical relationship that is a function of friction velocity. To incorporate advective effects, mixing height fields are smoothed by incorporating values from upwind grid cells. The higher of the two mixing heights (convective or mechanical) in a given hour is used. A more detailed description of this method is given in the CALMET User's Manual Version 5.0 (Earth Tech 2000).

Figure 8 shows the frequency of mixing heights derived by CALMET for Fort McMurray and Cold Lake for 2002. Mixing heights below 300 m were predicted to occur 44% of the time in 2002 at Fort McMurray. Mixing heights below 300 m were predicted to occur 60% of the time in 2002 at Cold Lake. The average CALMET mixing height for Fort McMurray was 542 m. The average CALMET mixing height for Cold Lake was 377 m. The lower mixing heights predicted by CALMET will tend to result in decreased dispersion and higher ground-level concentrations. The minimum and maximum mixing heights were set to 50 and 3,000 m, respectively.

OBSERVED 2002 CALMET 2002



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

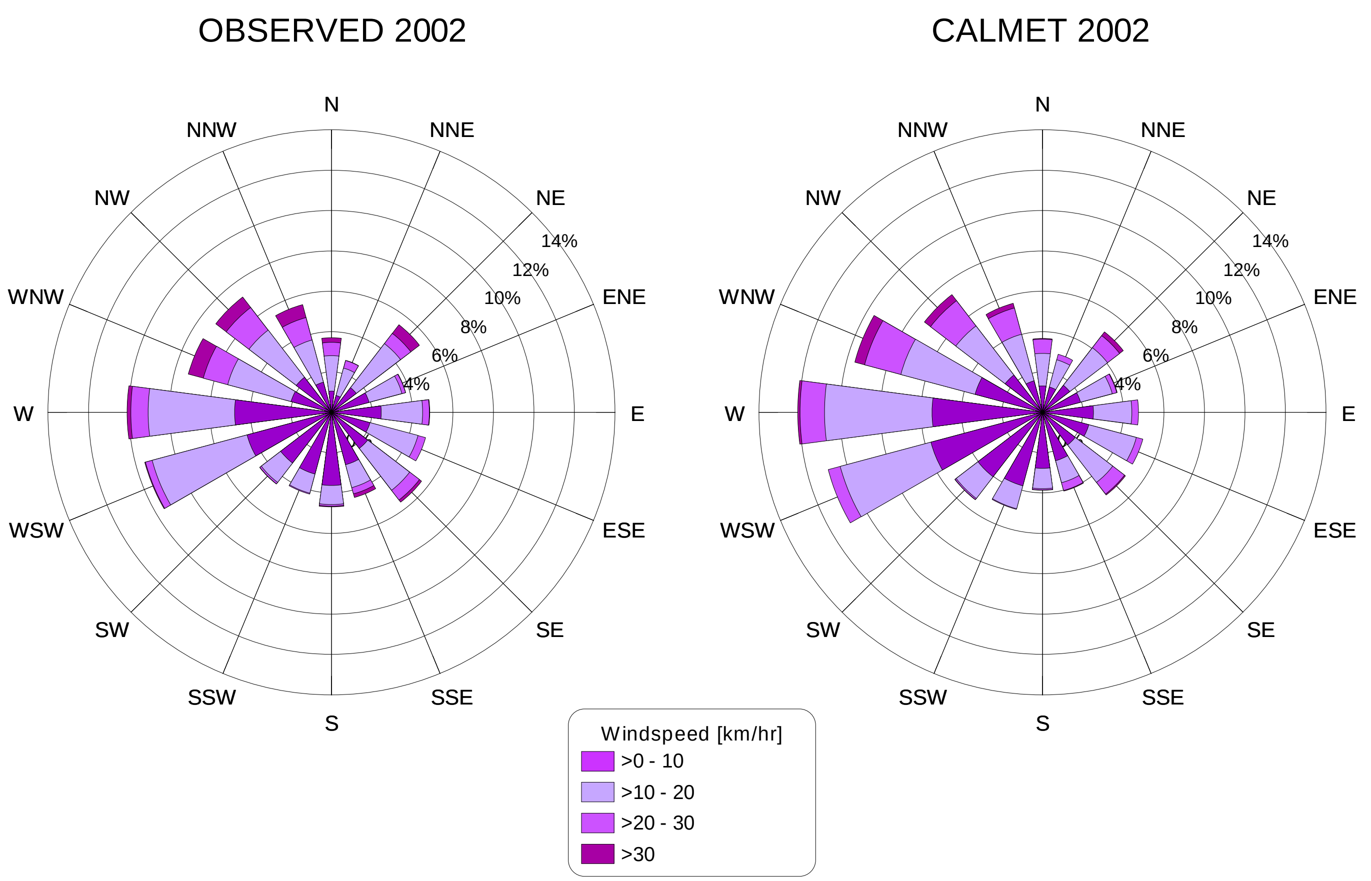
TITLE

FORT MCMURRAY WINDROSE - OBSERVED VS. CALMET PREDICTIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Windroses
DESIGN	MS	29/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 6**	
REVIEW	IGG	17/04/08		

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 6 Fort McMurray Windrose -Observed vs. CALMET Predictions.dwg Apr 16, 2008 - 6:11pm



L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 7 Cold Lake Windrose - Observed vs. CALMET Predictions.dwg Apr 16, 2008 - 6:12pm

PROJECT

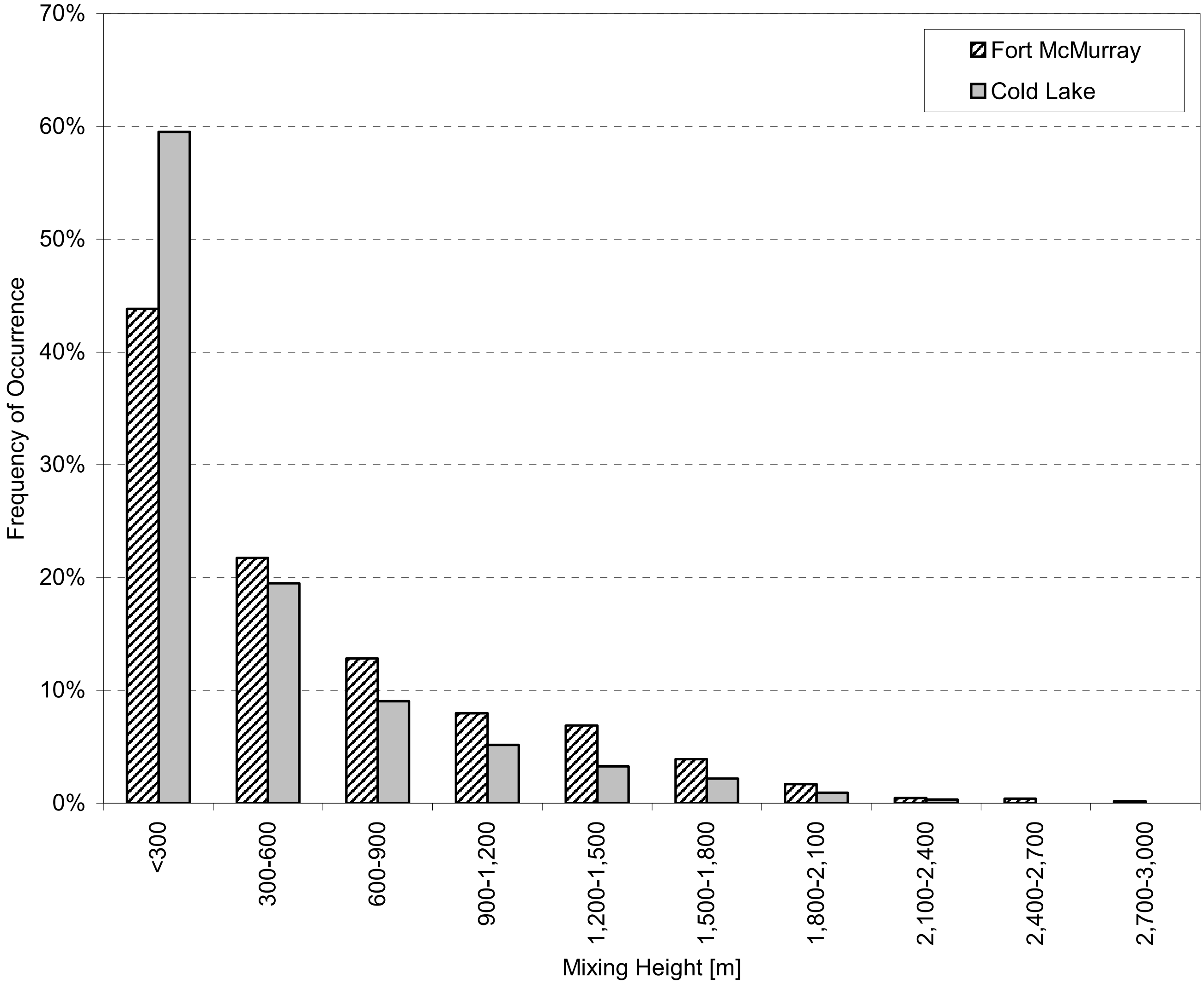
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COLD LAKE WINDROSE - OBSERVED VS. CALMET PREDICTIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Windroses
DESIGN	MS	29/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 7**	
REVIEW	IGG	17/04/08		



L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 8 CALMET - derived mixing heights.dwg Apr 16, 2008 - 6:18pm

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

CALMET-DERIVED MIXING HEIGHTS FOR McMURRAY AND COLD LAKE

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	CALMET-derived
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TY	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 8**	
REVIEW	IGG	17/04/08		

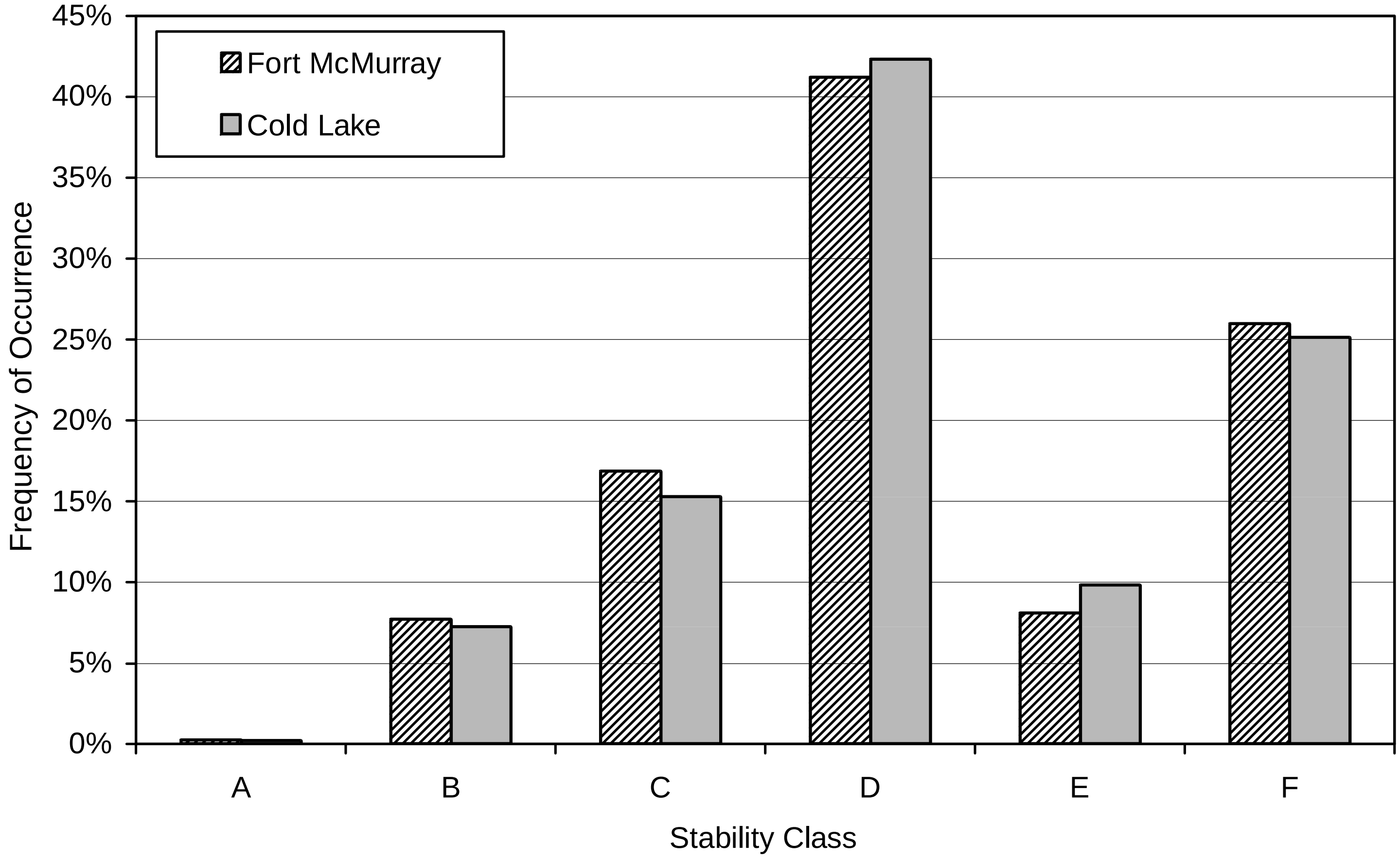
2.2.3.3 Stability Class

Atmospheric stability can be viewed as a measure of the atmosphere's capability to disperse emissions. The amount of turbulence plays an important role in the dilution of a plume as it is transported by the wind. Turbulence can be generated by either thermal or mechanical mechanisms. Surface heating or cooling by radiation contributes to the generation or suppression of thermal turbulence, while high wind speeds contribute to the generation of mechanical turbulence.

The Pasquill-Gifford (PG) stability classification scheme is one classification of the atmosphere. The classification ranges from Unstable (Stability Classes A, B and C), Neutral (Stability Class D) to Stable (Stability Classes E and F). Unstable conditions are primarily associated with daytime heating conditions which result in enhanced turbulence levels (enhanced dispersion). Stable conditions are associated primarily with nighttime cooling conditions, which result in suppressed turbulence levels (poorer dispersion). Neutral conditions are primarily associated with higher wind speeds or overcast conditions.

Figure 9 provides a comparison between the stability conditions derived by CALMET at Fort McMurray and Cold Lake for 2002. The following can be observed from the comparison:

- The CALMET model estimated that unstable (A, B and C) conditions would occur 25% of the time in 2002 at Fort McMurray and 23% of the time at Cold Lake.
- Neutral conditions were estimated to occur 41% of the time in 2002 at Fort McMurray and 42% of the time at Cold Lake.
- The CALMET model estimated stable (E and F) conditions 34% of the time in 2002 at Fort McMurray and 35% of the time at Cold Lake. These stable conditions are typically associated with periods with poor dispersion.



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

CALMET-DERIVED PASQUILL-GIFFORD STABILITY CLASSES FOR FORT McMURRAY AND COLD LAKE FOR 2002

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	CALMET
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	28/03/08		
CHECK	MS	14/04/08		
REVIEW	IGG	14/04/08		

FIGURE: 9

2.3 DISPERSION MODELLING APPROACH

2.3.1 Dispersion Modelling Assumptions

The air quality assessment for the Project included several assumptions regarding assessment scenarios, emission rates and dispersion modelling approaches. Whenever possible, assumptions were made to ensure model predictions were not underestimated. The main assumptions included in the air quality assessment are as follows:

- For each modelling scenario, it was assumed that all developments were operating at their maximum capacity at the same time. In reality, the operational life of each development will be staggered over time.
- The 2002 meteorological data was deemed to be appropriate for use in preparing the 3-D meteorological data set.
- The modelling assumes that all of the nitrogen that gets deposited is available to contribute to PAI (i.e., no vegetation or soil uptake).
- It was assumed that 100% of the airborne sulphates and nitrates form secondary aerosols, resulting in maximum estimations of particulate ($PM_{2.5}$ and PM_{10}) concentrations.
- Mine fleet emissions from mining projects in the region were based on U.S. EPA emission standards. Future emission reductions based on more stringent standards were not accounted for in the modelling.

2.3.2 Modelling Domain

The air quality assessment of the Project was based on the following regions:

- The **modelling domain** defines the region over which air quality predictions were performed. Emission sources located within the modelling domain were quantified and used in the air quality predictions. The modelling domain chosen for the air quality assessment of the Project is shown in Figure 10. It extends north of the Athabasca Oil Sands Region, south of Cold Lake, east into Saskatchewan and west to Ranges 22 and 23. It is large enough to encompass the effects related to air emissions from oil sands developments in the region. The modelling domain includes key communities in Alberta and Saskatchewan.
- The **Regional Study Area (RSA)** defines the regional study area over which the graphic results of the air quality modelling are presented and defines the area over which the assessment of air effects are evaluated. The RSA can be increased or decreased to represent the modelling results, and is typically smaller than the modelling domain. The air

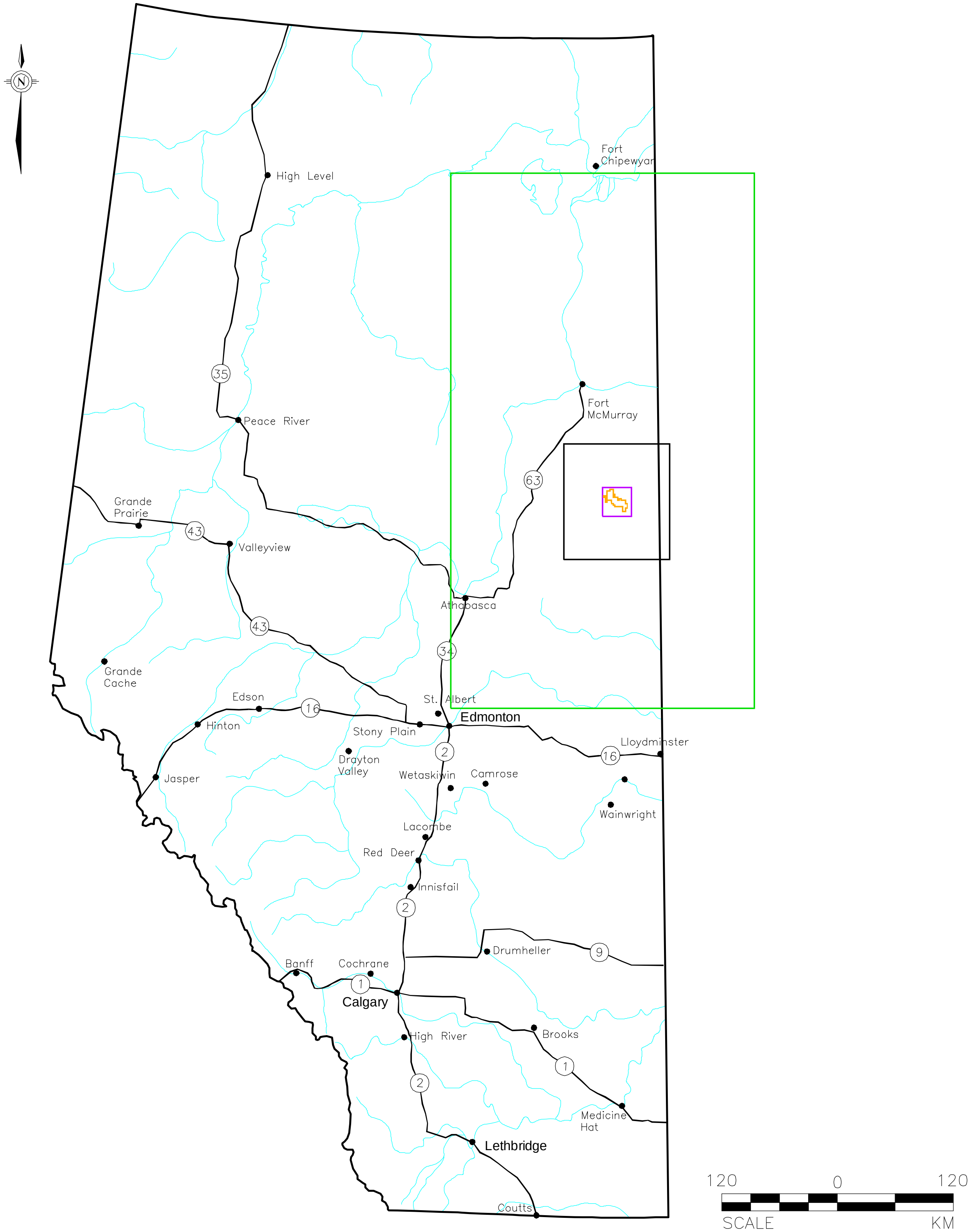
quality RSA for the Project is defined by a 110 by 120 km area, as shown in Figure 11. It was chosen to be sufficiently large enough to ensure inclusion of the 0.17 keq/ha/yr PAI isopleth. The RSA is also large enough to capture the air quality effects associated with the Project. The RSA has been extended into the province of Saskatchewan to ensure that air quality effects near the Alberta/Saskatchewan border are shown.

- The **Local Study Area (LSA)** defines the immediate area of the Project where the majority of air quality effects are expected to occur. The LSA represents a subset of the RSA and a more focused assessment of the effects associated with the Project. The LSA has been sized to meet the *Alberta Air Model Guideline* requirements for study areas (AENV 2003). The air quality LSA (Figure 11) covers an area of approximately 30 by 30 km, encompassing the Project area. The LSA also encompasses predicted ground-level concentration levels equivalent to 10% of the Alberta Ambient Air Quality Objectives for SO_2 and NO_2 that result from the Project alone, as required by the *Alberta Air Quality Model Guideline* (AENV 2003). It is within this LSA that the majority of air quality effects associated with the Project is expected to be quantifiable.

2.3.3 Receptors

Ground-level concentrations and deposition rates were modelled at selected locations within the modelling domain. The selection of these locations (referred to as receptors), was based primarily on AENV modelling guidance (AENV 2003) which recommends the following receptor placement:

- spacing of 50 m within 1 km of the sources of interest;
- spacing of 250 m within 2 km of the sources of interest;
- spacing of 500 m within 5 km of the sources of interest; and
- spacing of 1,000 m between 5 and 10 km from the Project.



LEGEND

- ROAD
- RIVER
- MEG LEASE BOUNDARY
- AIR LOCAL STUDY AREA
- AIR REGIONAL STUDY AREA
- AIR MODELLING DOMAIN

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

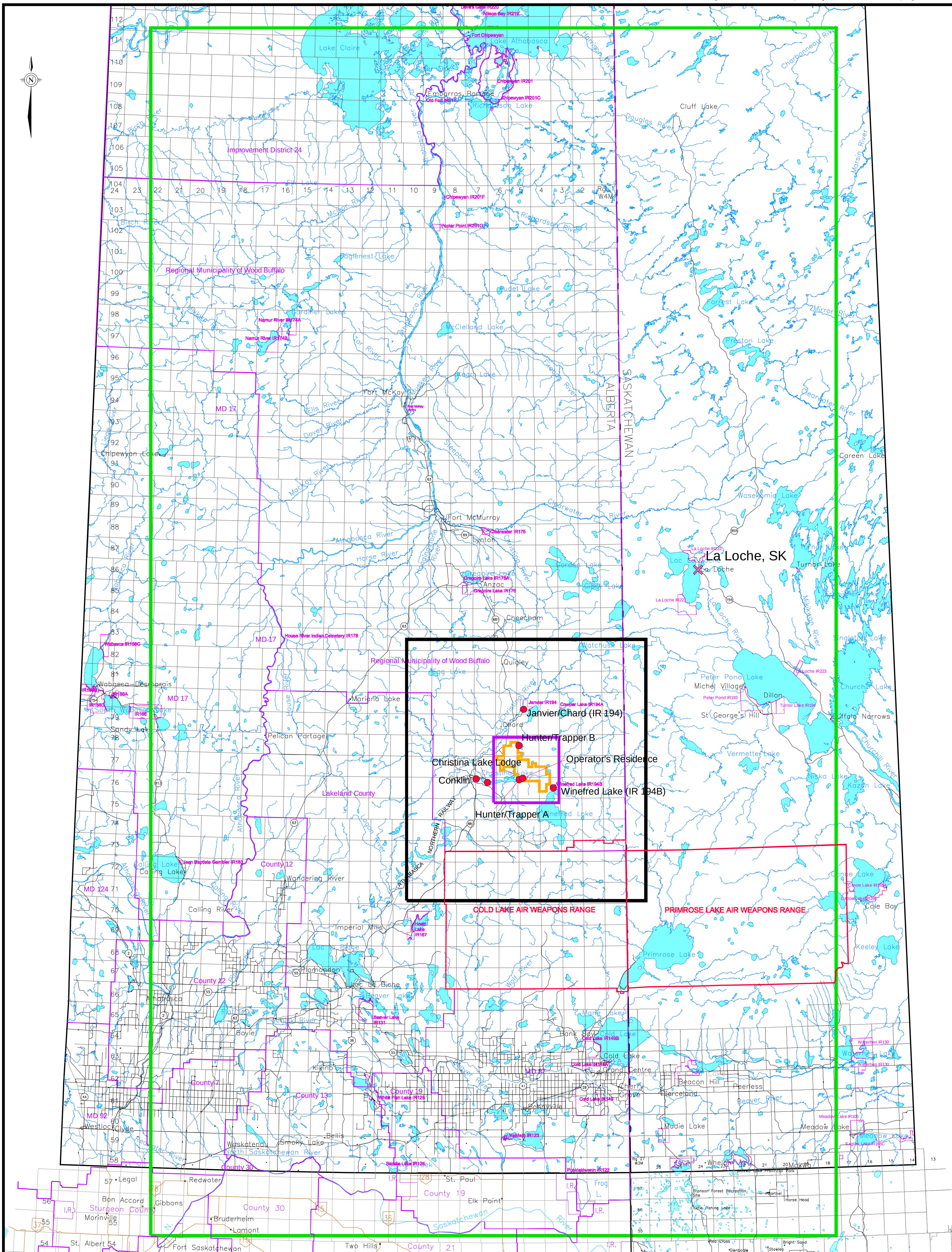
LOCATION OF AIR QUALITY MODELLING DOMAIN

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Modelling Domain
DESIGN	MS	28/11/07	SCALE 1:6,000,000	REV. 0
CADD	TRE	14/04/08		
CHECK	MS	16/04/08	**FIGURE: 10**	
REVIEW	IGG	17/04/08		

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\8070\ Drawing file: Fig 10 Modelling Domain.dwg Apr 16, 2008 - 5:26pm

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 11 Air Quality Study Areas and Modelling Domain.dwg Apr 16, 2008 - 6:23pm Image:MEGcube-R.bmp Image:MEGcube-R_1.png



LEGEND

- ROAD
- RAILWAY
- RIVER
- OPEN WATER
- INDIAN RESERVE
- COLD LAKE AIR WEAPONS RANGE
- SELECTED RECEPTOR
- SASKATCHEWAN RECEPTOR
- MEG LEASE BOUNDARY
- AIR LOCAL STUDY AREA
- AIR REGIONAL STUDY AREA
- AIR MODELLING DOMAIN

30 0 30
SCALE KILOMETRES

REFERENCE

ALBERTA NTDB DATA SUPPLIED BY GEOMATICS CANADA, AUGUST 2001. NAD 83 ZONE 12. SHEETS 74D, E AND 74L IN NAD 27 ZONE 12. SASKATCHEWAN NTDB DATA SUPPLIED BY ISC, AUG. 2001. NAD 83 ZONE 13. ALL DATA CONVERTED TO NAD 83 UTM ZONE 12.

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

AIR QUALITY STUDY AREAS AND MODELLING DOMAIN

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Air Study Areas...
DESIGN	MS	28/11/07	SCALE AS SHOWN	REV. 0
CADD	TRE	07/03/08		
CHECK	MS	14/04/08	**FIGURE: 11**	
REVIEW	IGG	17/04/08		

In addition to the receptors placed near the Project operations, the air quality assessment included additional receptors distributed across the modelling domain. These receptors were spaced at 15-km intervals. Receptors near the RSA were placed 6 km apart, while a denser receptor grid (3-km spacing) was placed near the LSA. Additional 20-m-spaced receptors were also placed along the Project property boundary. This receptor scheme is shown in Figure 12.

One of the aims of this air quality evaluation is to put the potential effects into perspective for regional stakeholders. To facilitate this, maximum air quality concentrations were predicted for each of the receptors indicated in Table 8. This list includes one community and two locations in Alberta that are of importance to First Nations groups. These represent the primary population centres in or near the region that could potentially experience increased concentrations due to the Project. In addition, concentrations were predicted at two cabins, the Operator's Residence, the Christina Lake Lodge and along the maximum property boundary where persons could experience prolonged exposure to air emissions. For the purposes of this assessment, these eight receptors are referred to as the selected receptors.

Table 8 Selected Receptors Included in the Air Assessment

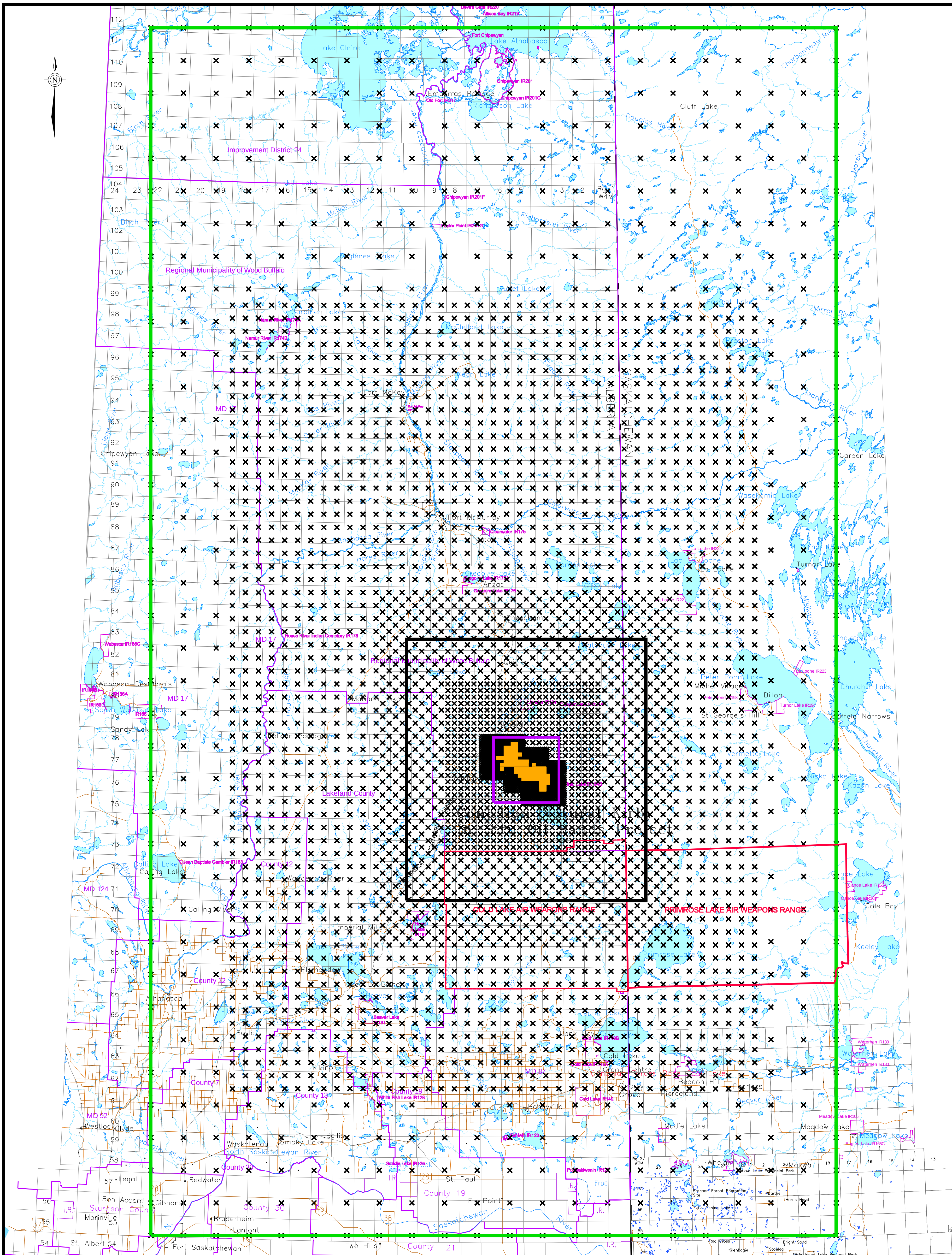
Receptors	Location[a]	
	Distance [km]	Direction
Conklin	24	W
Janvier/Chard (IR 194)	28	N
Winefred Lake (IR 194B)	15	SE
Hunter/Trapper A	6	SW
Hunter/Trapper B	12	NNW
Operator's Residence	4	SSW
Christina Lake Lodge	19	WSW
Maximum Property Boundary	—	—

[a] Distance and direction are relative to the Central Plant

– = Maximum Property Boundary Receptors are spaced 20 m apart around Plant 3A, 3B and the Central Plant.

The effects of the Project were also evaluated in Saskatchewan due to its proximity. A receptor was placed at La Loche since it is one of the largest communities in Saskatchewan and is close to the Alberta-Saskatchewan border and to the Project. La Loche is located approximately 120 km NE of the Project.

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 12 Regional Receptors.dwg Apr 16, 2008 - 6:31pm



LEGEND

- ROAD
- RAILWAY
- RIVER
- OPEN WATER
- INDIAN RESERVE
- COLD LAKE AIR WEAPONS RANGE
- × LOCATION OF RECEPTOR
- MEG LEASE BOUNDARY
- AIR LOCAL STUDY AREA
- AIR REGIONAL STUDY AREA
- AIR MODELLING DOMAIN

30 0 30
SCALE KILOMETRES

REFERENCE

ALBERTA NTDB DATA SUPPLIED BY GEOMATICS CANADA, AUGUST 2001. NAD 83 ZONE 12. SHEETS 74D, E AND 74L IN NAD 27 ZONE 12. SASKATCHEWAN NTDB DATA SUPPLIED BY ISC, AUG. 2001. NAD 83 ZONE 13. ALL DATA CONVERTED TO NAD 83 UTM ZONE 12.

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

LOCATIONS OF REGIONAL RECEPTORS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Air receptors
DESIGN	MS	28/11/07	SCALE AS SHOWN	REV. 0
CADD	PSR	29/02/08		
CHECK	MS	14/04/08	**FIGURE: 12**	
REVIEW	IGG	17/04/08		

2.3.4 Model Options

The CALPUFF dispersion model requires numerous user-specified options. The selection of options used in the analysis requires great care and understanding of the underlying model algorithms.

Several modelling options were changed from the default value for the reasons discussed below.

Vertical wind shear is modelled above the stack top (MSHEAR=1), allowing for different rates of dispersion and transport across individual puffs. This may result in an increased rate of horizontal growth of the plume under certain conditions. This is also important in puff splitting, which is allowed in the model (MSPLIT=1). When shear across a puff becomes significant, the puff is allowed to split into two (NSPLIT = 2). Each new puff is then advected and dispersed independently by its local average wind speed and direction.

The RIVAD/ARM3 scheme is used for chemical transformation as opposed to the default MESOPUFF II method. The RIVAD/ARM3 method models nitric oxide (NO) and NO_2 separately, whereas MESOPUFF II models total NO_X.

Dispersion coefficients are calculated internally using similarity theory and micrometeorological variables instead of the default ISC3 multi-segment approximation method. The similarity theory is a more sophisticated and precise method of determining dispersion coefficients.

The Probability Density Function (PDF) is used for dispersion during convective conditions (MPDF = 1). This method is more representative of events than the Gaussian distribution method.

The maximum number of puffs released from one source during one timestep is 50 (MXNEW = 50). This number was chosen as a mid-range value between 5, which was used in previous EIAs, and the default value of 99.

The Plume Path Coefficients (PPC) were based on the parameters recommended for use in Alberta by Angle and Sakiyama (1991) as well as Lott (1984, 1986). These plume path coefficients were also incorporated in the ADEPT2 model, as described in the user's manual (AENV 1992).

A background ozone value of 26.6 ppb was used in the model and is based on passive ozone data collected at all WBEA stations between 2001 and 2005. The background ammonia value of 0.45 ppb was based on continuous ammonia data collected from 2001 to 2005 at the Range Road 220 station in the Fort Airshed.

Table 9 provides a detailed summary of the input and output options, dispersion options, chemistry mechanisms selected and other parameters that were used in the modelling for the Project. The table provides a comparison of the options selected for this assessment to the default values recommended for use in the United States. A sample CALPUFF SO2 and NO2 output file is available upon request.

Table 9 CALPUFF Model Input Options

Input Group	Parameter	Default	Project	Description
Group 1 General Run Control Parameters	METRUN	0	0	run period explicitly defined below
	IBYR	-	2002	starting year for run if METRUN = 0
	IBMO	-	1	starting month for run if METRUN = 0
	IBDY	-	1	starting day for run if METRUN = 0
	IBHR	-	0	starting hour for run if METRUN = 0
	XBTZ	-	7.0	base time zone (PST = 8, MST = 7, CST = 6, EST = 5)
	IRLG	-	744 (for January input file)	length of run in hours
	NSPEC	5	6	number of chemical species
	NSE	3	3	number of chemical species to be emitted
	ITEST	2	2	program is executed after SETUP phase
	MRESTART	0	0	does not read or write a restart file
	NRESPD	0	0	restart file written only at last period
	METFM	1	1	CALMET binary file (CALMET.MET)
	AVET	60	60	averaging time in minutes
	PGTIME	60	60	PG averaging time in minutes
Group 2 Technical Options	MGAUSS	1	1	Gaussian distribution used in near field
	MCTADJ	3	3	partial plume path terrain adjustment
	MCTSG	0	0	subgrid-scale complex terrain not modelled
	MSLUG	0	0	near-field puffs not modelled as elongated
	MTRANS	1	1	transitional plume rise modelled
	MTIP	1	1	stack tip downwash used
	MBDW	2	2	method to simulate building downwash (PRIME method)
	MSHEAR	0	1	vertical wind shear modelled
	MSPLIT	0	1	puffs are split
	MCHEM	1	3	transformation rates computed internally using RIVAD/ARM3 scheme
	MAQCHEM	0	0	aqueous phase transformation rates not modelled
	MWET	1	1	wet removal modelled
	MDRY	1	1	dry deposition modelled
	MDISP	3	2	dispersion coefficients from internally calculated sigma v, sigma w using micrometeorological variables (u*, w*, L, etc.)
	MTURBVW	3	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)
	MDISP2	3	3	PG dispersion coefficients for RURAL areas (computed using the ISCST multi-segment approximation) and MP coefficients in urban areas
	MROUGH	0	0	PG sigma-y and sigma-z not adjusted for roughness
	MPARTL	1	1	partial plume penetration of elevated inversion
	MTINV	0	0	strength of temperature inversion not computed from measured/default gradients
	MPDF	0	1	PDF used for dispersion under convective conditions
	MSGTIBL	0	0	sub-grid TIBL module not used for shoreline
	MBCON	0	0	boundary conditions not modelled
	MFOG	0	0	do not configure for FOG Model output

Table 9 CALPUFF Model Input Options (continued)

Input Group	Parameter	Default	Project	Description
	MREG	1	0	do not test options specified to see if they conform to regulatory values
Group 3 Species List	CSPEC	-	SO_2, SO_4, NO, NO_2, HNO_3, NO_3	list of chemical species
		-	1	is SO_2 modelled? (0=no, 1=yes)
		-	1	is SO_4 modelled? (0=no, 1=yes)
		-	1	is NO modelled? (0=no, 1=yes)
		-	1	is NO_2 modelled? (0=no, 1=yes)
		-	1	is HNO_3 modelled? (0=no, 1=yes)
		-	1	is NO_3 modelled? (0=no, 1=yes)
		-	1	is SO_2 emitted? (0=no, 1=yes)
		-	0	is SO_4 emitted? (0=no, 1=yes)
		-	1	is NO emitted? (0=no, 1=yes)
		-	1	is NO_2 emitted? (0=no, 1=yes)
		-	0	is HNO_3 emitted? (0=no, 1=yes)
		-	0	is NO_3 emitted? (0=no, 1=yes)
		1	1	SO_2 dry deposition method (0=no, 1=computed-gas, 2=computed-particle, 3=user specified)
		2	2	SO_4 dry deposition method (0=no, 1=computed-gas, 2=computed-particle, 3=user specified)
	CSPEC (continued)	1	1	NO dry deposition method (0=no, 1=computed-gas, 2=computed-particle, 3=user specified)
		1	1	NO_2 dry deposition method (0=no, 1=computed-gas, 2=computed-particle, 3=user specified)
		1	1	HNO_3 dry deposition method (0=no, 1=computed-gas, 2=computed-particle, 3=user specified)
		2	2	NO_3 dry deposition method (0=no, 1=computed-gas, 2=computed-particle, 3=user specified)
		-	0	SO_2 output group number
		-	0	SO_4 output group number
		-	0	NO output group number
		-	0	NO_2 output group number
		-	0	HNO_3 output group number
		-	0	NO_3 output group number
Group 4 Map Projection and Grid Control Parameters	PMAP	UTM	UTM	map projection
	FEAST	0	0	false Easting (km) at the projection origin
	FNORTH	0	0	false Northing (km) at the projection origin
	IUTMZN	-	12	UTM zone
	UTMHEM	N	N	hemisphere for UTM projection (N = north, S = south)
	RLAT0	-	0N	latitude of projection origin (not used if PMAP = UTM)
	RLON0	-	0E	longitude of projection origin (not used if PMAP = UTM)
	XLAT1	-	0N	matching parallel(s) of latitude (decimal degrees) for projection (used only if PMAP = LCC or PS)
	XLAT2	-	0N	matching parallel(s) of latitude (decimal degrees) for projection (used only if PMAP = LCC or PS)
	DATUM	WGS-G	WGS-G	datum-region for output coordinates
	NX	-	78	number of X grid cells in meteorological grid
	NY	-	121	number of Y grid cells in meteorological grid
	NZ	-	10	number of vertical layers in meteorological grid
	DGRIDKM	-	5	grid spacing in kilometres
	ZFACE	-	0, 20, 50, 100, 200, 400, 800, 1200, 1600, 2200, 3000	cell face heights in meteorological grid (metres)
	XORIGKM	-	305	reference X coordinate for south-west corner of grid cell (1,1) of meteorological grid (kilometres)

Table 9 CALPUFF Model Input Options (continued)

Input Group	Parameter	Default	Project	Description
	YORIGKM	-	5935	reference Y coordinate for south-west corner of grid cell (1,1) of meteorological grid (kilometres)
Group 4 Map Projection and Grid Control Parameters	IBCOMP	-	1	X index of lower left corner of the computational grid
	JBCOMP	-	1	Y index of lower left corner of the computational grid
	IECOMP	-	78	X index of upper right corner of the computational grid
	JECOMP	-	121	Y index of upper right corner of the computational grid
	LSAMP	T	F	sampling grid is not used
	IBSAMP	-	4	X index of lower left corner of the sampling grid
	JBSAMP	-	36	Y index of lower left corner of the sampling grid
	IESAMP	-	35	X index of upper right corner of the sampling grid
	JESAMP	-	88	Y index of upper right corner of the sampling grid
	MESHDN	1	1	nesting factor of the sampling grid
Group 5 Output Options	ICON	1	1	output file CONC.DAT containing concentration fields is created
	IDRY	1	1	output file DFLX.DAT containing dry flux fields is created
	IWET	1	1	output file WFLX.DAT containing wet flux fields is created
	IVIS	1	0	output file containing relative humidity data is not created
	LCOMPRS	T	F	do not perform data compression in output files
	IMFLX	0	0	mass flux across specified boundaries for selected species not reported hourly
	IMBAL	0	0	mass balance for each species not reported hourly
	ICPRT	0	0	do not print concentration fields to the output list file
	IDPRT	0	0	do not print dry flux fields to the output list file
	IWPRT	0	0	do not print wet flux fields to the output list file
	ICFRQ	1	1	concentration fields are printed to output list file every 1 hour
	IDFRQ	1	1	dry flux fields are printed to output list file every 1 hour
	IWFRQ	1	1	wet flux fields are printed to output list file every 1 hour
	IPRTU	1	3	units for line printer output are in µg/m^3 for concentration and µg/m^2/s for deposition
	IMESG	2	2	messages tracking the progress of run are written on screen
	-	-	0,0,0,0,0,0	concentrations printed to output list file (0 = no, 1 = yes)
	-	-	1,1,1,1,1,1	concentrations saved to disk (0 = no, 1 = yes)
	-	-	0,0,0,0,0,0	dry fluxes printed to output list file (0 = no, 1 = yes)
	-	-	1,1,1,1,1,1	dry fluxes saved to disk (0 = no, 1 = yes)
	-	-	0,0,0,0,0,0	wet fluxes printed to output list file (0 = no, 1 = yes)
	-	-	1,1,1,1,1,1	wet fluxes saved to disk (0 = no, 1 = yes)
	-	-	0,0,0,0,0,0	mass fluxes saved to disk (0 = no, 1 = yes)
	LDEBUG	F	F	logical value for debug output
	IPFDEB	1	1	first puff to track
	NPFDEB	1	1	number of puffs to track
	NN1	1	1	meteorological period to start output
	NN2	10	10	meteorological period to end output
Group 6 Subgrid Scale Complex Terrain Inputs	NHILL	0	0	number of terrain features
	NCTREC	0	0	number of special complex terrain receptors
	MHILL	-	1	input terrain and receptor data for CTSG hills input in CTDM format not used
	XHILL2M	1	1	conversion factor for changing horizontal dimensions to metres
	ZHILL2M	1	1	conversion factor for changing vertical dimensions to metres
	XCTDMKM	-	0.0E00	X origin of CTDM system relative to CALPUFF coordinate system in kilometres
	YCTDMKM	-	0.0E00	Y origin of CTDM system relative to CALPUFF coordinate system in kilometres

Table 9 CALPUFF Model Input Options (continued)

Input Group	Parameter	Default	Project	Description
Group 7 Chemical Parameters for Dry Deposition of Gases	-	0.1509	0.1509	diffusivity for SO_2 (cm^2/s)
	-	1,000.0	1,000.0	alpha star for SO_2
	-	8.0	8.0	reactivity for SO_2
	-	0.0	0.0	mesophyll resistance for SO_2 (s/cm)
	-	0.04	0.04	Henry's Law coefficient for SO_2
	-	0.1345	0.1345	diffusivity for NO (cm^2/s)
	-	1.0	1.0	alpha star for NO
	-	2.0	2.0	reactivity for NO
	-	25.0	25.0	mesophyll resistance for NO (s/cm)
	-	18.0	18.0	Henry's Law coefficient for NO
	-	0.1656	0.1656	diffusivity for NO_2 (cm^2/s)
	-	1.0	1.0	alpha star for NO_2
	-	8.0	8.0	reactivity for NO_2
	-	5.0	5.0	mesophyll resistance for NO_2 (s/cm)
	-	3.5	3.5	Henry's Law coefficient for NO_2
	-	0.1628	0.1628	diffusivity for HNO_3 (cm^2/s)
	-	1.0	1.0	alpha star for HNO_3
	-	18.0	18.0	reactivity for HNO_3
	-	0.0	0.0	mesophyll resistance for HNO_3 (s/cm)
	-	0.001	0.001	Henry's Law coefficient for HNO_3
Group 8 Size Parameters for Dry Deposition of Particles	-	0.48	0.48	geometric mass mean diameter of SO_4 (µm)
	-	2.0	2.0	geometric standard deviation of SO_4 (µm)
	-	0.48	0.48	geometric mass mean diameter of NO_3 (µm)
	-	2.0	2.0	geometric standard deviation of NO_3 (µm)
Group 9 Miscellaneous Dry Deposition Parameters	RCUTR	30	30	reference cuticle resistance in s/cm
	RGR	10	10	reference ground resistance in s/cm
	REACTR	8	8	reference pollutant reactivity
	NINT	9	9	number of particle size intervals used to evaluate effective particle deposition velocity
	IVEG	1	2	vegetation in unirrigated areas is active and stressed
Group 10 Wet Deposition Parameters	-	0.00003	0.00003	the SO_2 scavenging coefficient for liquid precipitation (sec^{-1})
	-	0.0	0.0	the SO_2 scavenging coefficient for frozen precipitation (sec^{-1})
	-	0.0001	0.0001	the SO_4^{-2} scavenging coefficient for liquid precipitation (sec^{-1})
	-	0.00003	0.00003	the SO_4^{-2} scavenging coefficient for frozen precipitation (sec^{-1})
	-	0.00006	0.00006	the HNO_3 scavenging coefficient for liquid precipitation (sec^{-1})
	-	0.0	0.0	the HNO_3 scavenging coefficient for frozen precipitation (sec^{-1})
	-	0.0001	0.0001	the NO_3^- scavenging coefficient for liquid precipitation (sec^{-1})
	-	0.00003	0.00003	the NO_3^- scavenging coefficient for frozen precipitation (sec^{-1})
Group 11 Chemistry Parameters	MOZ	1	0	a monthly background ozone value is used in chemistry calculation
	BCKO3	12*80	12*26.6	background ozone concentrations in ppb
	BCKNH3	12*10	12*0.45	background ammonia concentration in ppb
	RNITE1	0.2	0.2	nighttime SO_2 loss rate in percent/hour
	RNITE2	2	2	nighttime NO_X loss rate in percent/hour
	RNITE3	2	2	nighttime HNO_3 formation rate in percent/hour
	MH202	1	1	H_2O_2 data input option not used since MAQCHEM = 0
	BCKH2O2	12*1	1, 1, 1, 1, 1, 1, 1, 1, 1, 1, 1, 1	monthly H_2O_2 concentrations in ppb

Table 9 CALPUFF Model Input Options (continued)

Input Group	Parameter	Default	Project	Description
Group 12 Miscellaneous Dispersion and Computational Parameters	SYTDEP	550	550	horizontal size of a puff in metres beyond which the time dependant Heffter dispersion equation is used
	MHFTSZ	0	0	do not use Heffter formulas for sigma z
	JSUP	5	5	stability class used to determine dispersion rates for puffs above boundary layer
	CONK1	0.01	0.01	vertical dispersion constant for stable conditions
	CONK2	0.1	0.1	vertical dispersion constant for neutral/unstable conditions
	TBD	0.5	0.5	use ISC transition point for determining the transition point between the Schulman-Scire to Huber-Snyder Building Downwash scheme
	IURB1	10	10	lower range of land use categories for which urban dispersion is assumed
	IURB2	19	19	upper range of land use categories for which urban dispersion is assumed
	ILANDUIN	20	20	land use category for modelling domain
	Z0IN	0.25	0.25	roughness length in metres for modelling domain
	XLAIXN	3	3	leaf area index for modelling domain
	ELEVIN	0	0	elevation above sea level in metres
	XLATIN	-999	-999	latitude of station in degrees
	XLONIN	-999	-999	longitude of station in degrees
	ANEMHT	10	10	anemometer height in metres
	ISIGMAV	1	1	sigma-v is read for lateral turbulence data
	IMIXCTDM	0	0	predicted mixing heights are used
	XMXLEN	1	1	maximum length of emitted slug in meteorological grid units
	XSAMLEN	1	1	maximum travel distance of slug or puff in meteorological grid units during one sampling unit
	MXNEW	99	50	maximum number of puffs or slugs released from one source during one time step
	MXSAM	99	99	maximum number of sampling steps during one time step for a puff or slug
	NCOUNT	2	2	number of iterations used when computing the transport wind for a sampling step that includes gradual rise
	SYMIN	1	1	minimum sigma y in metres for a new puff or slug
	SZMIN	1	1	minimum sigma z in metres for a new puff or slug
	SVMIN	0.5	0.5	minimum turbulence (σ_v) for A stability (m/s)
		0.5	0.5	minimum turbulence (σ_v) for B stability (m/s)
		0.5	0.5	minimum turbulence (σ_v) for C stability (m/s)
		0.5	0.5	minimum turbulence (σ_v) for D stability (m/s)

Table 9 CALPUFF Model Input Options (continued)

Input Group	Parameter	Default	Project	Description
Group 12 Miscellaneous Dispersion and Computational Parameters	SVMIN (continued)	0.5	0.5	minimum turbulence (σ_v) for E stability (m/s)
		0.5	0.5	minimum turbulence (σ_v) for F stability (m/s)
	SWMIN	0.20	0.20	minimum turbulence (σ_w) for A stability (m/s)
		0.12	0.12	minimum turbulence (σ_w) for B stability (m/s)
		0.08	0.08	minimum turbulence (σ_w) for C stability (m/s)
		0.06	0.06	minimum turbulence (σ_w) for D stability (m/s)
		0 03	0 03	minimum turbulence (σ_w) for E stability (m/s)
		0.016	0.016	minimum turbulence (σ_w) for F stability (m/s)
	CDIV	0.0,0.0	0.0, 0.0	divergence criteria for dw/dz in met cells
	WSCALM	0.5	1.0	minimum wind speed allowed for non-calm conditions in metres per second
	XMAXZI	3,000	3,000	maximum mixing height in metres
	XMINZI	50	50	minimum mixing height in metres
	WSCAT	1.54	1.54	wind speed category 1 (m/s)
		-	3.09	wind speed category 2 (m/s)
		5.14	5.14	wind speed category 3 (m/s)
		8.23	8.23	wind speed category 4 (m/s)
		10.80	10.80	wind speed category 5 (m/s)
	PLX	-	0.21	wind speed profile exponent for A stability
		-	0.21	wind speed profile exponent for B stability
		-	0.23	wind speed profile exponent for C stability
		-	0.40	wind speed profile exponent for D stability
		-	0.62	wind speed profile exponent for E stability
		-	0.50	wind speed profile exponent for F stability
	PTG0	0.020	0.020	potential temperature gradient for E stability (K/m)
		0.035	0.035	potential temperature gradient for F stability (K/m)
	PPC	0.50	0.80	plume path coefficient for A stability
		0.50	0.70	plume path coefficient for B stability
		0.50	0.60	plume path coefficient for C stability
		0.50	0.50	plume path coefficient for D stability
		0.35	0.50	plume path coefficient for E stability
		0.35	0.50	plume path coefficient for F stability
	SL2PF	10	10	slug-to-puff transition criterion factor equal to sigma y/length of slug
	NSPLIT	3	2	number of puffs that result every time a puff is split
	IRESPLIT	0,0,0,0,0, 0,0,0,0,0, 0,0,0,0,0, 0,0,1,0,0, 0,0,0,0	0,0,0,0,0,0,0 ,0,0,0,0,0,0, 0,0,0,0,1,0,0 ,0,0,0,0	time(s) of day when split puffs are eligible to be split once again
	ZISPLIT	100	100	minimum allowable last hour's mixing height for puff splitting (metres)
	ROLDMAX	0.25	0.25	maximum allowable ratio of last hour's mixing height and maximum mixing height experienced by the puff for puff splitting
	NSPLITH	5	5	number of puffs that result every time a puff is split
	SYSPLITH	1	1	minimum sigma-y (grid cells units) of puff before it may be split
	SHSPLITH	2	2	minimum puff elongation rate (SYSPLITH/hr) due to wind shear, before it may be split
	CNSPLITH	1.0E-07	1.0E-07	minimum concentration (g/m^3) of each species in puff before it may be split
	EPSSLUG	1.00E-04	1.00E-04	fractional convergence criterion for numerical SLUG sampling integration

Table 9 CALPUFF Model Input Options (continued)

Input Group	Parameter	Default	Project	Description
Group 12 Miscellaneous Dispersion and Computational Parameters (continued)	EPSAREA	1.00E-06	1.00E-06	fractional convergence criterion for numerical AREA source integration
	DSRISE	1	1	trajectory step-length (m) used for numerical rise integration
Group 13 Point Source Parameters	NPT1	-	313	number of point sources
	IPTU	1	1	units for point source emission rates is grams per second
	NSPT1	0	0	number of source-species combinations with variable emissions scaling factors
	NPT2	-	0	number of point sources with variable emission parameters provided in external file
Group 14 Area Source Parameters	NAR1	-	49	number of polygon area sources
	IARU	1	1	units for area source emission rates is grams per square metre per second
	NSAR1	0	0	number of source-species combinations with variable emissions scaling factors
	NAR2	-	0	number of buoyant polygon area sources with variable location and emission parameters
Group 15 Line Source Parameters	NLN2	-	0	number of buoyant line sources with variable location and emission parameters
	NLINES	-	0	number of buoyant line sources
	ILNU	1	1	units for line source emission rates is grams per second
	NSLN1	0	0	number of source-species combinations with variable emissions scaling factors
	MXNSEG	7	0	maximum number of segments used to model each line
	NLRISE	6	0	number of distances at which transitional rise is computed
	XL	-	0	average line source length in metres
	HBL	-	0	average height of line source height in metres
	WBL	-	0	average building width in metres
	WML	-	0	average line source width in metres
	DXL	-	0	average separation between buildings in metres
	FPRIMEL	-	0	average buoyancy parameter in m^4/s^3
Group 16 Volume Source Parameters	NVL1	-	0	number of volume sources
	IVLU	1	1	units for volume source emission rates is grams per second
	NSVL1	0	0	number of source-species combinations with variable emissions scaling factors
	NSVL2	-	0	number of volume sources with variable location and emission parameters
Group 17 Non-Gridded Receptor Information	NREC	-	10,030	number of non-gridded receptors

- = Not applicable.

2.3.5 Building Downwash

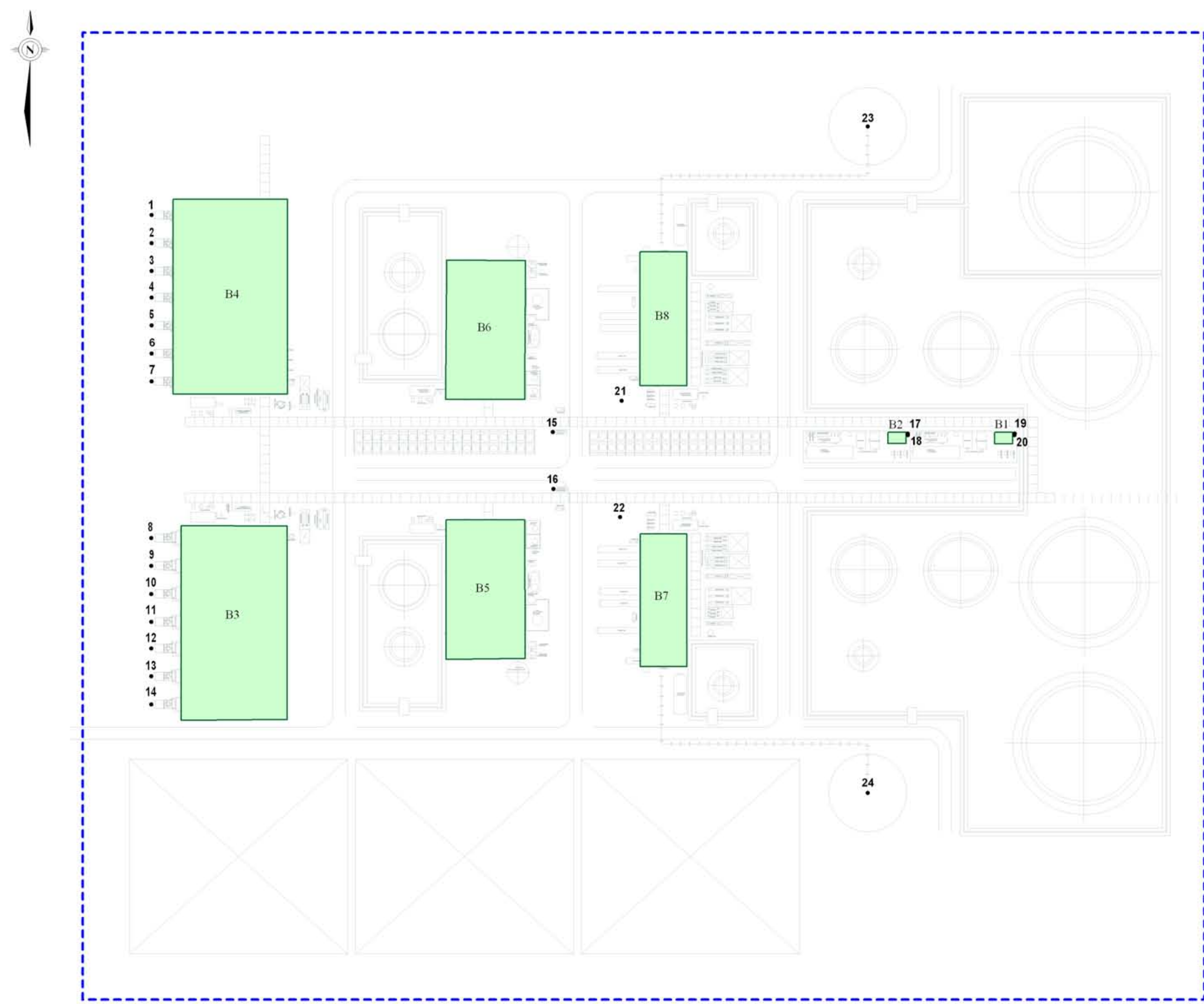
Building downwash was incorporated in the modelling of the Project facility. The effect of the buildings and structures at these facilities were evaluated using the PRIME algorithm in the CALPUFF model. Building and source locations and dimensions used in the assessment are presented in Figures 13a through 13c.

2.3.6 Oxides of Nitrogen (NO_X) to Nitrogen Dioxide (NO_2) Conversion

The CALPUFF dispersion modelling completed for the Project used the RIVAD/ARM3 chemical transformation scheme. The RIVAD/ARM3 algorithms enable CALPUFF to calculate atmospheric deposition rates of sulphur and nitrogen as well as the airborne concentrations of sulphates and nitrates. The RIVAD/ARM3 mechanism is the CALPUFF transformation scheme that is most applicable for non-urban areas such as the Oil Sands Region (Earth Tech 1999). Descriptions of the RIVAD/ARM3 chemical transformation mechanisms are provided in various literature (Earth Tech 1999; Morris et al. 1988; Syncrude 1999). Since the Project NO_2 predictions were low, the NO_2 concentrations obtained from the CALPUFF model were used and the ambient ratio method and the ozone limiting method were not used.

2.3.7 Potential Acid Input

Deposition includes both wet and dry processes and can result in the long-term accumulation of compounds in aquatic and terrestrial ecosystems. Wet processes involve the removal of emissions vented into the atmosphere by precipitation. Dry processes involve the removal by direct contact with surface features (e.g., vegetation). Both wet and dry deposition values are expressed as a flux in units of mass per area per time (e.g., kg/ha/yr). Because several chemical species of nitrogen, sulphur and base cations are considered in the estimate of deposition, the flux is expressed in “keq/ha/yr” where “keq” refers to the number of equivalent hydrogen ions (1 keq = 1 kmol H^+). For sulphur species, each molecule is equivalent to two hydrogen ions. Each molecule of nitrogen species is equivalent to one hydrogen ion. The deposition of sulphur and nitrogen compounds to these systems has been associated with changes in water and soil chemistry, and with the acidification of water and soil.



Sources

ID	Description	Stack Height [m]
1	Phase 3A-Steam Generator 1	30.0
2	Phase 3A-Steam Generator 2	30.0
3	Phase 3A-Steam Generator 3	30.0
4	Phase 3A-Steam Generator 4	30.0
5	Phase 3A-Steam Generator 5	30.0
6	Phase 3A-Steam Generator 6	30.0
7	Phase 3A-Steam Generator 7	30.0
8	Phase 3A-Steam Generator 8	30.0
9	Phase 3A-Steam Generator 9	30.0
10	Phase 3A-Steam Generator 10	30.0
11	Phase 3A-Steam Generator 11	30.0
12	Phase 3A-Steam Generator 12	30.0
13	Phase 3A-Steam Generator 13	30.0
14	Phase 3A-Steam Generator 14	30.0
15	Phase 3A-Glycol Heater 1	15.0
16	Phase 3A-Glycol Heater 2	15.0
17	Phase 3A-Slop Treater 1A	15.0
18	Phase 3A-Slop Treater 1B	15.0
19	Phase 3A-Slop Treater 2A	15.0
20	Phase 3A-Slop Treater 2B	15.0
21	Phase 3A-Amine Preheater 1	15.0
22	Phase 3A-Amine Preheater 2	15.0
23	Phase 3A-Flare 1	55.2
24	Phase 3A-Flare 2	55.2

Buildings

ID	Name	Height [m]
B1	Slop Treater Building	6.4
B2	Slop Treater Building	6.4
B3	Steam Generation Building	12.0
B4	Steam Generation Building	12.0
B5	Water Treatment Building	12.2
B6	Water Treatment Building	12.2
B7	Process Building	15.8
B8	Process Building	15.8

LEGEND

MEG PLANT 3A BOUNDARY.

BUILDING STRUCTURES INCLUDED IN BUILDING DOWNWASH ASSESSMENT.

200 0 200

SCALE METRES

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.)
USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR
DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

PLANT 3A - STACK AND BUILDING INFORMATION USED IN PRIME DOWNWASH ASSESSMENT

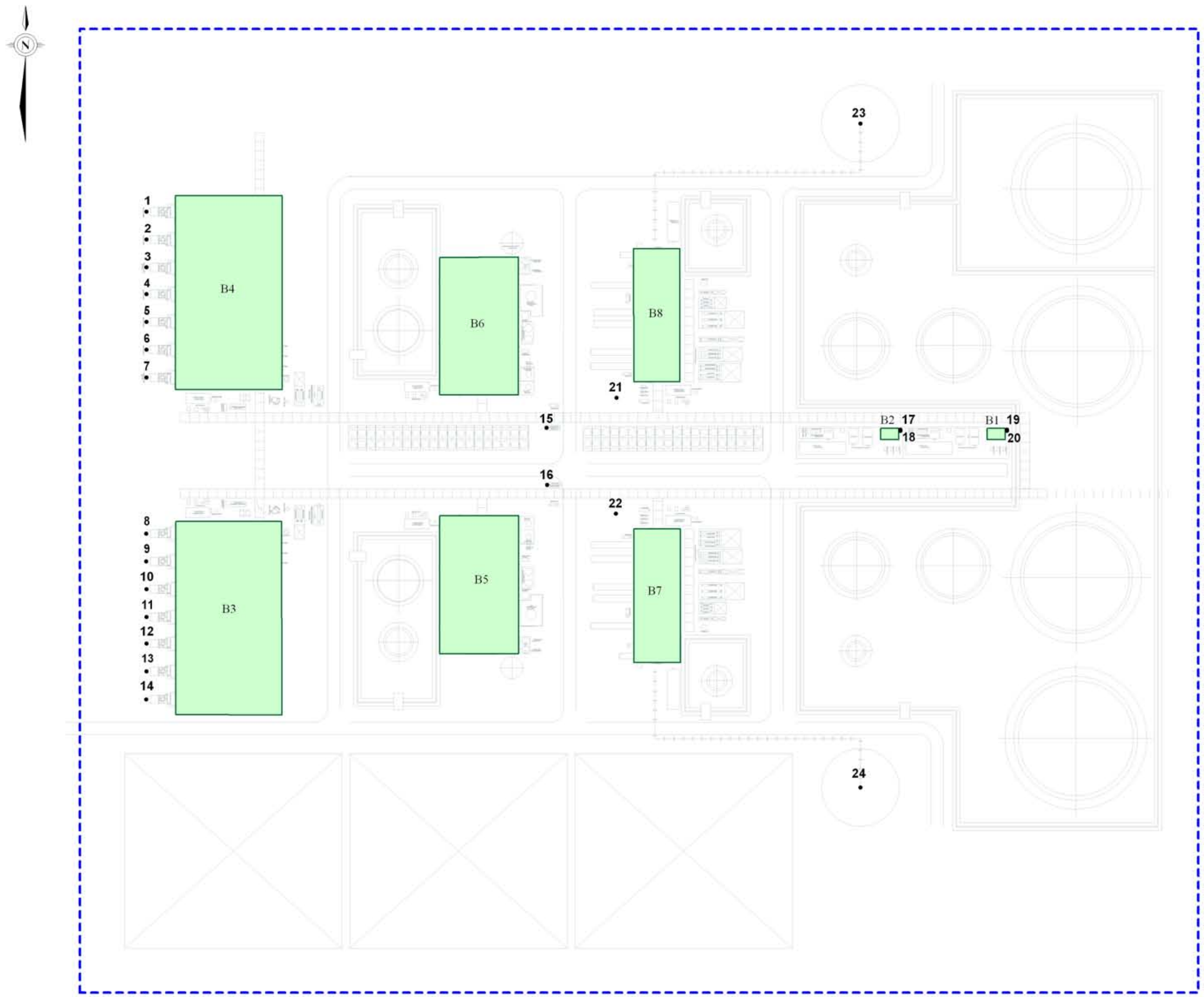
MEG ENERGY CORP.

DESIGN	MS	06/02/08
AIR	DK	19/02/08
CHECK	MS	20/02/08
REVIEW	IGG	17/04/08

FIGURE: 13a

R:/ACTIVE/_2007/1346/07-1346-0009 MEG CHRISTINA LAKE REGIONAL EXPANSION/8000 AIR/8070 EIA REPORTING/FIGURES/PLANT_3A_STACK_AND_BUILDING.srf

R:/ACTIVE/_2007/1346/07-1346-0009 MEG CHRISTINA LAKE REGIONAL EXPANSION/8000 AIR/8070 EIA REPORTING/FIGURES/PLANT_3B_STACK_AND_BUILDING.srf



Sources

ID	Description	Stack Height [m]
1	Phase 3B-Steam Generator 1	30.0
2	Phase 3B-Steam Generator 2	30.0
3	Phase 3B-Steam Generator 3	30.0
4	Phase 3B-Steam Generator 4	30.0
5	Phase 3B-Steam Generator 5	30.0
6	Phase 3B-Steam Generator 6	30.0
7	Phase 3B-Steam Generator 7	30.0
8	Phase 3B-Steam Generator 8	30.0
9	Phase 3B-Steam Generator 9	30.0
10	Phase 3B-Steam Generator 10	30.0
11	Phase 3B-Steam Generator 11	30.0
12	Phase 3B-Steam Generator 12	30.0
13	Phase 3B-Steam Generator 13	30.0
14	Phase 3B-Steam Generator 14	30.0
15	Phase 3B-Glycol Heater 1	15.0
16	Phase 3B-Glycol Heater 2	15.0
17	Phase 3B-Slop Treater 1A	15.0
18	Phase 3B-Slop Treater 1B	15.0
19	Phase 3B-Slop Treater 2A	15.0
20	Phase 3B-Slop Treater 2B	15.0
21	Phase 3B-Amine Preheater 1	15.0
22	Phase 3B-Amine Preheater 2	15.0
23	Phase 3B-Flare 1	55.2
24	Phase 3B-Flare 2	55.2

Buildings

ID	Name	Height [m]
B1	Slop Treater Building	6.4
B2	Slop Treater Building	6.4
B3	Steam Generation Building	12.0
B4	Steam Generation Building	12.0
B5	Water Treatment Building	12.2
B6	Water Treatment Building	12.2
B7	Process Building	15.8
B8	Process Building	15.8

LEGEND

MEG PLANT 3B BOUNDARY.

BUILDING STRUCTURES INCLUDED IN BUILDING DOWNWASH ASSESSMENT.

200 0 200

SCALE METRES

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.)
USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR
DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

PLANT 3B - STACK AND BUILDING INFORMATION USED IN PRIME DOWNWASH ASSESSMENT

MEG ENERGY CORP.

DESIGN	MS	06/02/08
AIR	DK	19/02/08
CHECK	MS	20/02/08
REVIEW	IGG	17/04/08

FIGURE: 13b

Sources

ID	Description	Stack Height [m]
1	Pilot-Steam Generator	30.0
2	Pilot-Glycol Heater	7.5
3	Pilot-Low Pressure Flare	13.2
4	Pilot-High Pressure Flare	31.5
5	Phase 2-Steam Geberator	30.0
6	Phase 2-Cogeneration Unit	24.0
7	Phase 2-Glycol Heater	5.0
8	Phase 2-Slop Treater 1	9.0
9	Phase 2-Slop Treater 2	9.0
10	Phase 2-Flare	55.2
11	Phase 2B-Steam Generator 1	30.0
12	Phase 2B-Steam Generator 2	30.0
13	Phase 2B-Steam Generator 3	30.0
14	Phase 2B-Cogeneration Unit	24.0
15	Phase 2B-Glycol Heater	15.0
16	Phase 2B-Amine Preheater	15.0
17	Phase 2B-Flare	55.2
18	SRU Incinerator 1	45.7
19	SRU Incinerator 2	80.0
20	SRU Incinerator 3	80.0

Buildings

ID	Name	Height [m]
B1	Process Building	5.9
B2	Deoiling Building	4.5
B3	Water Treatment/Steam Generation Buildings	9.5 / 8.2
B4	Glycol/Utility Building	4.5
B5	MCC #1 Building	4.8
B6	MCC #2 Building	4.8
B7	VRU Building	5.3
B8	Inlet Separation Building	15.8
B9	Water Treatment Building	12.2
B10	Steam Generation Building	12.0
B11	GTG Building	25.5
B12	Diluent/Sales Pumps Building	6.0
B13	Amine Building	10.0
B14	Steam Genearation MCC Building	7.0
B15	Water Treatment MCC Building	7.0
B16	Lift Gas Building	6.4
B17	Administration/Control Building	10.0
B18	Process Building	10.8
B19	Deoiling Building	8.8
B20	ORF Building	10.9
B21	Water Treatment Building	12.5
B22	Steam Generation Building	11.1
B23	GTG Co-gen Building	24.0
B24	Diluent Pump Building	4.5
B25	Slop Treater Building	6.4
B26	Glycol Utility Building	4.6
B27	VRU Building	4.2
B28	Lift gas / Compressor Building	6.4
B29	Potable Water Building	5.1
B30	MCC #3 Building	5.7
B31	MCC #4 Building	4.9
B32	Radio Equipment Building	3.8
B33	Sulphur Recovery A Building	6.4
B34	Sulphur Recovery B Building	6.4
B35	Sulphur Recovery C Building	6.4

LEGEND

MEG CENTRAL PLANT SITE BOUNDARY.

BUILDING STRUCTURES INCLUDED IN BUILDING DOWNWASH ASSESSMENT.

200 0 200

SCALE METRES

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.)
USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR
DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

CENTRAL PLANT SITE - STACK AND BUILDING INFORMATION USED IN PRIME DOWNWASH ASSESSMENT

MEG ENERGY CORP.

DESIGN	MS	06/02/08
AIR	DK	19/02/08
CHECK	MS	16/04/08
REVIEW	IGG	17/04/08

FIGURE: 13c

The Clean Air Strategic Alliance (CASA) Acid Deposition Management Framework (CASA 1999) recommended using PAI as the means of evaluating the level of acidic deposition from existing, approved and planned operations. Potential acid input incorporates the following:

- the effects of both nitrogen and sulphur species;
- the effects of both dry and wet deposition mechanisms; and
- the effect of base cations in mitigating acidity.

The calculation of PAI is based on the wet and dry deposition of sulphur compounds (e.g., SO_2 gas, SO_4^{2-} particle), nitrogen compounds (e.g., NO gas, NO_2 gas, HNO_3 gas, NO_3^- particle) and base cations (e.g., Ca^{2+} particle, Mg^+ particle and K^+ particle). Since PAI combines both sulphur and nitrogen, the individual deposition rates need to be converted to a common measure, namely "keq/ha/yr" (kilomoles of equivalent hydrogen ions [H^+] per hectare per year), given these molecules have different equivalences to hydrogen ions as discussed above. The steps for completing the calculations are as follows:

- The PAI resulting from sulphur species is calculated from the annual sulphur deposition rates (expressed as kg/ha/yr). These are converted to keq/ha/yr by dividing the predicted deposition by the molecular weight and multiplying by the hydrogen ion equivalents, according to the following equation:

$$PAI_{sulphur} = \frac{\left([SO_2]_{dep,wet} + [SO_2]_{dep,dry}\right)\times 2}{64} + \frac{\left([SO_4^{2-}]_{dep,wet} + [SO_4^{2-}]_{dep,dry}\right)\times 2}{96}$$

- The PAI resulting from nitrogen species is calculated from the annual nitrogen deposition rates (expressed as kg/ha/yr). These are converted to keq/ha/yr by dividing the predicted deposition by the molecular weight and multiplying by the hydrogen ion equivalents, as follows:

$$PAI_{nitrogen} = \frac{\left([NO]_{dep,wet} + [NO]_{dep,dry}\right)}{30} + \frac{\left([NO_2]_{dep,wet} + [NO_2]_{dep,dry}\right)}{46} + \frac{\left([HNO_3]_{dep,wet} + [HNO_3]_{dep,dry}\right)}{63} + \frac{\left([NO_3^-]_{dep,wet} + [NO_3^-]_{dep,dry}\right)}{62}$$

The total PAI is calculated as the sum of the sulphur and nitrogen deposition rates from sources within the study area together with the background PAI for the region.

$$PAI = PAI_{sulphur} + PAI_{\mathrm{nitrogen}} + PAI_{\mathrm{back}}$$

In this equation, the PAI_{back} accounts for the background sulphur, nitrogen and base cations. Background PAI levels for the modelling domain were provided through Regional Lagrangian Acid Deposition (RELAD) modelling completed by AENV (Cheng 2001, 2005). This background data includes the contribution of acid-forming emissions across Western Canada (excluding oil sands regional sources) and also includes the effect of base cations in the modelling domain. A detailed discussion of background PAI is provided in Section 2.3.8.

The buffering capacity of base cations would be calculated according to the following equation:

$$PAI_{\mathrm{base\ cation}} = -\left(\frac{\left[Ca^{2+}\right]_{\mathrm{dep,\ back}} \times 2}{40} + \frac{\left[Mg^{2+}\right]_{\mathrm{dep,\ back}} \times 2}{24} + \frac{\left[K^{+}\right]_{\mathrm{dep,\ back}}}{39} \right)$$

The base cations have been included in the RELAD data.

2.3.8 Background Levels of Acid-Forming Compounds

The selection of the background PAI that best represents the background conditions is important. Ideally, this background value would not include influences from oil sands activities; however, the majority of the monitoring data available for use in determining background PAI levels come from stations that include some influences from the Oil Sands Region. The total PAI values calculated from measurements taken in Fort McMurray and the stations outside the study area are presented in Table 10. The PAI measured in Fort McMurray is estimated to be 0.14 keq/ha/yr, while the PAI for the other stations in and around the region is estimated to be 0.10 keq/ha/yr. However, the monitoring data used to establish this regional background PAI value includes the effect of emissions transported from sources within the Oil Sands Region. Therefore this value is an existing rather than a background PAI value.

Table 10 Monitored Potential Acid Input in the Study Area

PAI Component	Current PAI Value [keq/ha/yr]	
	Fort McMurray	Regional Background
wet PAI	0.08	0.04
dry PAI	0.06	0.06
Total PAI	**0.14**	**0.10**

One method to determine the "true" background would be to extract the effect of industrial activities in the Oil Sands Region from the calculated values. Given that this cannot be confirmed through monitoring, AENV agreed to run the RELAD model, which is described extensively in literature (Cheng and Angle 1993, 1996; Cheng et al. 1995, 1997; McDonald et al. 1996), to determine the background PAI values in the region. This was done by running the RELAD model using the 1995 emissions and meteorology for Western Canada. To find the PAI values that would occur in the absence of oil sands activities, all of the sources in the Oil Sands Region were excluded from the modelling. The resulting data for the modelling domain considered in this assessment were provided by AENV (Cheng 2001, 2005).

Although the RELAD model is an appropriate tool for assessing acid deposition on a provincial or continental scale, the model is unable to characterize deposition patterns within the Oil Sands Region. In fact, the RELAD model is only capable of assessing PAI values at a resolution of 1° of latitude by 1° of longitude. Therefore, the background PAI values determined by AENV using the RELAD model were added to the predictions made within the Oil Sands Region using the CALPUFF model. This approach is appropriate since both the CALPUFF and RELAD model yield comparable results when evaluated on the basis of 1° by 1° areas.

Table 11 provides a summary of the predicted 1995 background PAI values determined by AENV. These values are presented in Figure 14. Background PAI data for 2002 were not available; therefore, the 1995 data were applied to the 2002 PAI predictions.

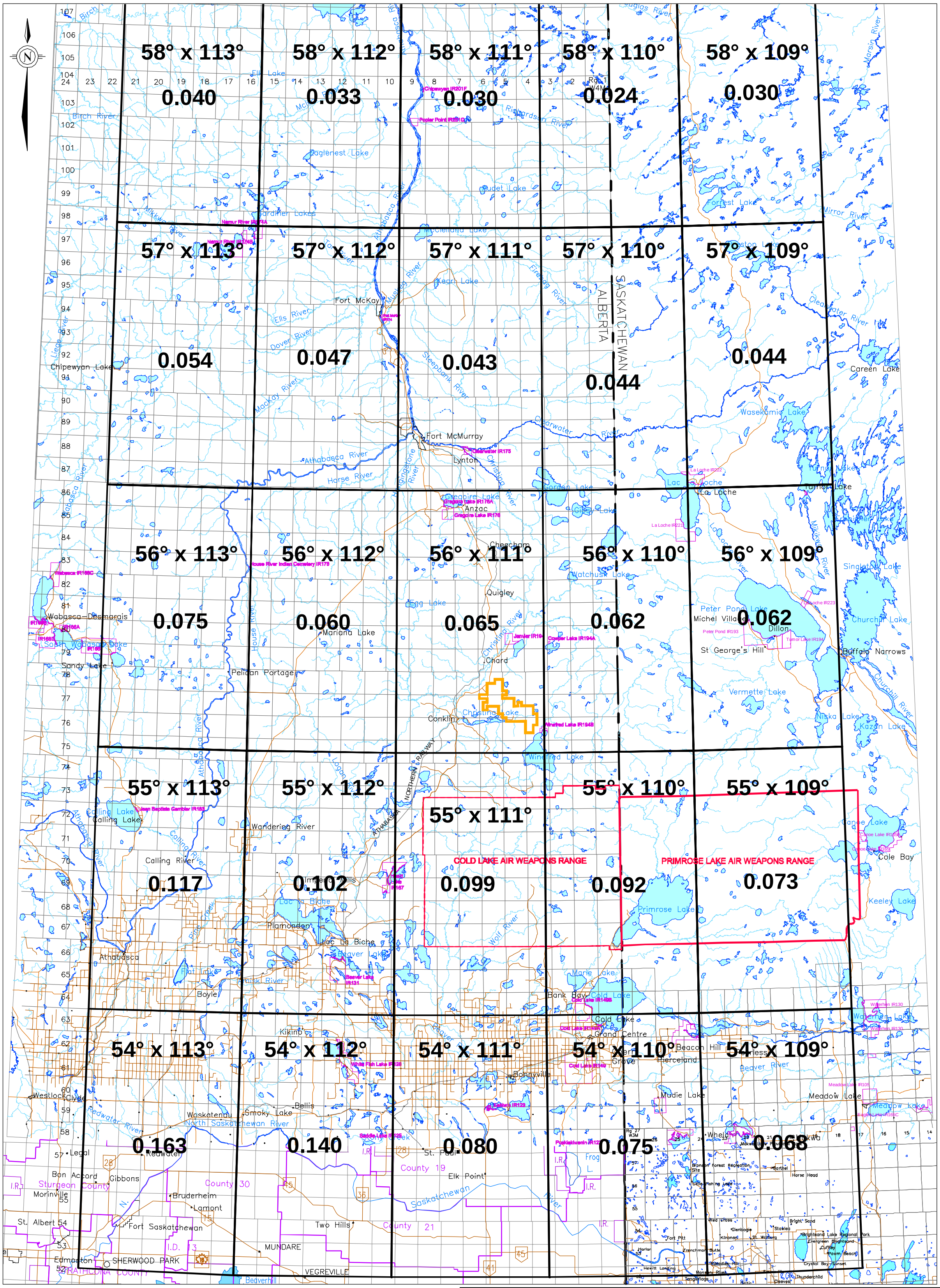
Table 11 Background Potential Acid Input Values Predicted by Alberta Environment

Grid Cell[a]	1995 Background PAI[b] [keq/ha/yr]
58º×113º	0.040
58º×112º	0.033
58º×111º	0.030
58º×110º	0.024
58º×109º	0.030
57º×113º	0.054
57º×112º	0.047
57º×111º	0.043
57º×110º	0.044
57º×109º	0.044
56º×113º	0.075
56º×112º	0.060
56º×111º	0.065
56º×110º	0.062
56º×109º	0.062
55º×113º	0.117
55º×112º	0.102
55º×111º	0.099
55º×110º	0.092
55º×109º	0.073
54º×113º	0.163[c]
54º×112º	0.140[c]
54º×111º	0.080[c]
54º×110º	0.075[c]
54º×109º	0.068[c]

(a) The 1° by 1° grid cells are centred on the listed latitude and longitude.

(b) Background PAI values were determined by AENV using the RELAD model (Cheng 2001), except where noted.

(c) Background PAI values were determined by AENV using the RELAD model (Cheng 2005).



LEGEND

- ROAD
- RAILWAY
- RIVER
- OPEN WATER
- INDIAN RESERVE
- AIR WEAPONS RANGE
- MEG LEASE BOUNDARY
- RELAD 95 BACKGROUND

50 0 50
SCALE KILOMETRES

REFERENCE

ALBERTA NTDB DATA SUPPLIED BY GEOMATICS CANADA, AUGUST 2001. NAD 83 ZONE 12. SHEETS 74D, E AND 74L IN NAD 27 ZONE 12. SASKATCHEWAN NTDB DATA SUPPLIED BY ISC, AUG. 2001. NAD 83 ZONE 13. ALL DATA CONVERTED TO NAD 83 UTM ZONE 12.

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

BACKGROUND POTENTIAL ACID INPUT FOR 1995

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No. Background PAI 1995	
DESIGN	MS	28/11/07	SCALE 1:2,500,000	REV. 0
CADD	TRE	14/04/08	**FIGURE: 14**	
CHECK	MS	16/04/08		
REVIEW	IGG	17/04/008		

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 14 Background PAI 1995.dwg Apr 16, 2008 - 5:32pm

2.3.9 Community Background Concentrations

To accurately determine ground-level concentrations in the regional communities, emissions from activities occurring within the communities themselves must be considered in some manner. One approach is to calculate the emissions from local activities and include items in the modelling. However, information about community activities such as the number of vehicles, the amount of travel within the community and the number of wood-burning fireplaces is often difficult to estimate. Therefore, background concentrations were applied to the two largest communities assessed in the Project EIA: Janvier/Chard and Conklin.

Background concentrations of SO_2, NO_2 and carbon monoxide (CO) for Janvier/Chard and Conklin were taken from the Canadian Natural Resources Limited Primrose East Project EIA (Canadian Natural 2006). The $PM_{2.5}$ background concentrations were based on ambient air quality monitoring data from the Cold Lake air quality station operated by the Lakeland Industry and Community Association (LICA). A summary of the background values used in the air quality assessment is presented in Table 12.

Community contributions to hydrogen sulphide (H_2S), Total Reduced Sulphur (TRS), Polycyclic Aromatic Hydrocarbons (PAHs) and metals were assumed to be emitted primarily from industrial sources, and background values from the communities for these compounds were assumed to be zero.

Table 12 Community Background Concentrations

Parameter	Janvier/Chard	Conklin
SO_2		
1-hour peak [µg/m³]	7.2	7.2
1-hour maximum [µg/m³]	0.9	0.9
24-hour peak [µg/m³]	0.5	0.5
annual average [µg/m³]	0.1	0.1
NO_2		
1-hour peak [µg/m³]	39.2	39.2
1-hour maximum [µg/m³]	24.7	24.7
24-hour peak [µg/m³]	8.3	8.3
annual average [µg/m³]	1.5	1.5
$PM_{2.5}$		
1-hour maximum [µg/m³]	7.5	7.5
24-hour maximum [µg/m³]	5.9	5.9
Carbon Monoxide		
1-hour peak [µg/m³]	345.4	204.5
8-hour peak [µg/m³]	196.6	116.4
annual average [µg/m³]	40.7	24.1

2.3.10 Scientific Uncertainty

2.3.10.1 Predicted Concentrations

The evaluation of changes in air quality depends primarily on the use of air dispersion models to estimate future ambient levels. As with any form of prediction, there are uncertainties associated with the model's capability to predict concentrations accurately. An accepted dispersion model (i.e., CALPUFF) was selected for the analysis to minimize some of these uncertainties.

Another uncertainty associated with air quality predictions is tied to the predicted emissions within the region. Emissions associated with industrial activities are reasonably well defined and were largely taken from recent applications and approvals. However, the emissions from non-industrial activities within regional communities are harder to predict. In this assessment, three approaches were considered to develop community background concentrations. The first was to assume that the community contribution of a particular compound is negligible when compared to industrial sources. This was the approach used to determine the community background concentrations for H_2S, TRS, PAHs and metals.

The second approach, when community emissions are not negligible, was to calculate the emissions from local activities and include these emissions in the dispersion modelling. This was the approach used for SO_2, NO_X, CO and Volatile Organic Compounds (VOCs). When reliable emission estimation methods were not available for a particular compound, the preferred approach was to use representative community monitoring data. This approach was used for $PM_{2.5}$.

2.3.10.2 Predicted Deposition Levels

The evaluation of changes in the deposition of acid-forming compounds depends on the use of air dispersion models to estimate future ambient levels. As with any form of prediction, there are uncertainties associated with the model's capability to predict concentrations accurately. To minimize some of these uncertainties, an accepted dispersion model (i.e., CALPUFF) was selected for the analysis.

The capability of the CALPUFF model to predict accurately PAI in the region is difficult to confirm through ambient monitoring programs since there is a lack of dry deposition monitoring data. However, a program was undertaken by the Terrestrial Environmental Effects Monitoring (TEEM) group of the WBEA to compare CALPUFF results to monitoring data. This report compared CALPUFF predictions from the OPTI Canada Inc./Nexen Canada Ltd. (OPTI/Nexen) Long Lake Project EIA with measured annual SO_2 and NO_2 concentrations and predicted dry SO_2 deposition levels (EPCM 2002). This study concluded that monitored SO_2 and NO_2 concentrations were similar to the CALPUFF predictions (within 1 µg/m³ for SO_2 and within 5 µg/m³ for NO_2). It also concluded that the CALPUFF predictions were similar to the dry SO_2 deposition estimates using an alternate approach in the study.

The CALPUFF model is recommended by AENV (2003) for predicting regional acid deposition in Alberta. The federal government has also indicated that it "encourages application of the fully capable CALPUFF model for regulatory dispersion and deposition predictions in the Oil Sands Region" (Environment Canada 1998). Accurate predictions of acid deposition in Alberta can be made by other models. The RELAD model is capable of determining the PAI values on a provincial scale. However, the RELAD model can only determine PAI at a 1° by 1° resolution, which is not suitable for assessing impacts associated with individual projects. Project impacts occur on both the local and regional scale and need to be evaluated at a finer resolution using a model more suitable for assessing local airsheds (EUB 2001a).

To minimize the uncertainty associated with background PAI values, AENV agreed to determine the PAI values that would occur in the absence of oil sands activities, using the RELAD model. The Project air quality assessment used the background PAI values determined by AENV (Cheng 2001, 2005), which are presented in Section 2.3.8 of this appendix.

Another area of uncertainty associated with PAI levels is related to effects of acidifying emissions on the receiving environment. Acid deposition will affect different elements of the ecosystem in different ways. A complete evaluation of the effects of acidifying emissions on the ecosystem is presented in the Air Emission Effects on Ecological Receptors Assessment (Volume 3, Section 4).

2.3.10.3 Planned Development Case Emissions

Another uncertainty associated with the air quality predictions is related to the predicted emissions for planned developments. Varying levels of information are available for planned projects. Some planned projects have submitted regulatory approvals, while others have submitted public disclosure information only. Because these developments are in varying stages of planning, the following should be noted:

- There is uncertainty about whether these planned developments will proceed.

- Information available for the planned developments is incomplete and assumptions are made to fill these gaps.
- The planned developments must submit applications and undergo an assessment to receive approval to proceed. Consequently the final designs of some of these developments may be different than those used in PDC for this assessment. It is also possible that some developments may not proceed at all.

2.4 CALPUFF/CALMET MODEL EVALUATION

The model approach was assessed to determine the appropriateness of the meteorological data and model configuration used in the air quality assessment of the Project. This exercise included the following:

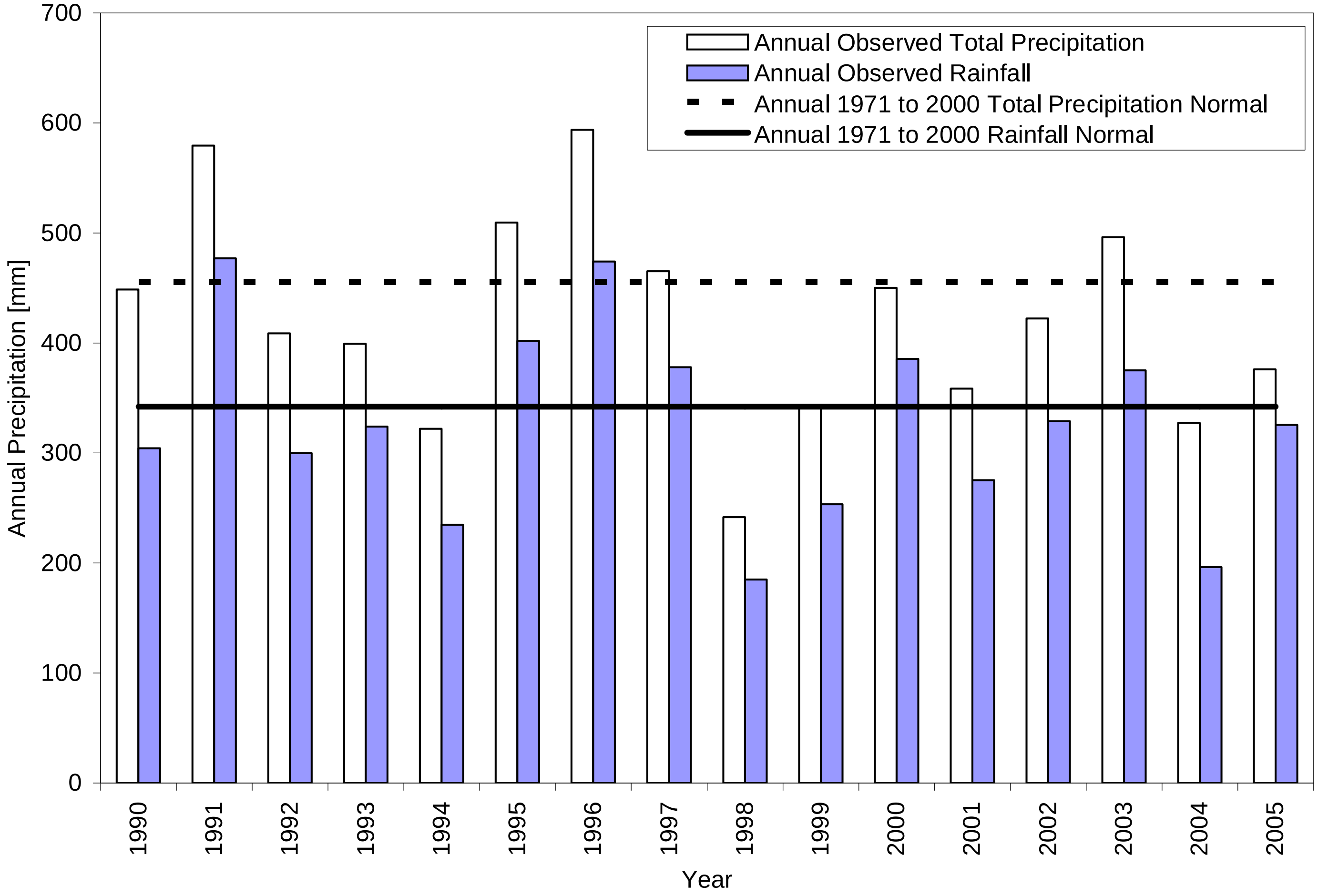
- a comparison of 2002 meteorological data to more recent data to determine the suitability of the 2002 data to represent future meteorological conditions in the region;
- a comparison of 2002 meteorological observations to the wind fields predicted with the CALMET model to determine the accuracy of the CALMET wind fields;
- the development of a modelling scenario representing emission sources in the Oil Sands Region for the years 2002 and 2003 (for simplicity, this will be referred to as the “Existing Scenario”); and
- a comparison of predicted concentrations of the Existing Scenario to 2002 and 2003 WBEA monitoring data.

The evaluation was conducted for the Oil Sands Region since it has the greatest amount of available data (e.g., monitoring data for a range species, frequency of data collection, etc.) in the region. Also, the model evaluation incorporated the same methodologies and 2002 MM5 data set that were used in the current assessment of the Project.

2.4.1 Suitability of the 2002 Meteorological Data

The three-dimensional CALMET meteorological data sets used in the Project air quality assessment were developed using predicted and monitored meteorological data based on the year 2002. This year was selected in developing the meteorological data set primarily because of the availability of required data. To determine the appropriateness of the 2002 data in air quality assessments in the region, a comparison between 2002 meteorological parameters and more recent years has been completed for Fort McMurray and Cold Lake. Fort McMurray and Cold Lake were selected for this comparison since the stations have a full set of parameters, they meet Environment Canada monitoring requirements and they have a long period of record.

Figure 15 provides a comparison of the annual precipitation and rainfall observed at Fort McMurray from 1990 to 2005. This comparison also includes 1971 to 2000 climate normal values for comparison to historic trends. The year 2002 had slightly less than normal precipitation and rainfall.



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF FORT McMURRAY ANNUAL PRECIPITATION FROM 1990 TO 2005

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Comparison
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08	**FIGURE: 15**	
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		

Figure 16 provides a comparison of the annual precipitation and rainfall observed at Cold Lake from 1990 to 2005. This comparison also includes 1971 to 2000 climate normal values for comparison to historic trends. The year 2002 received the least rainfall and total precipitation of the 16 years shown.

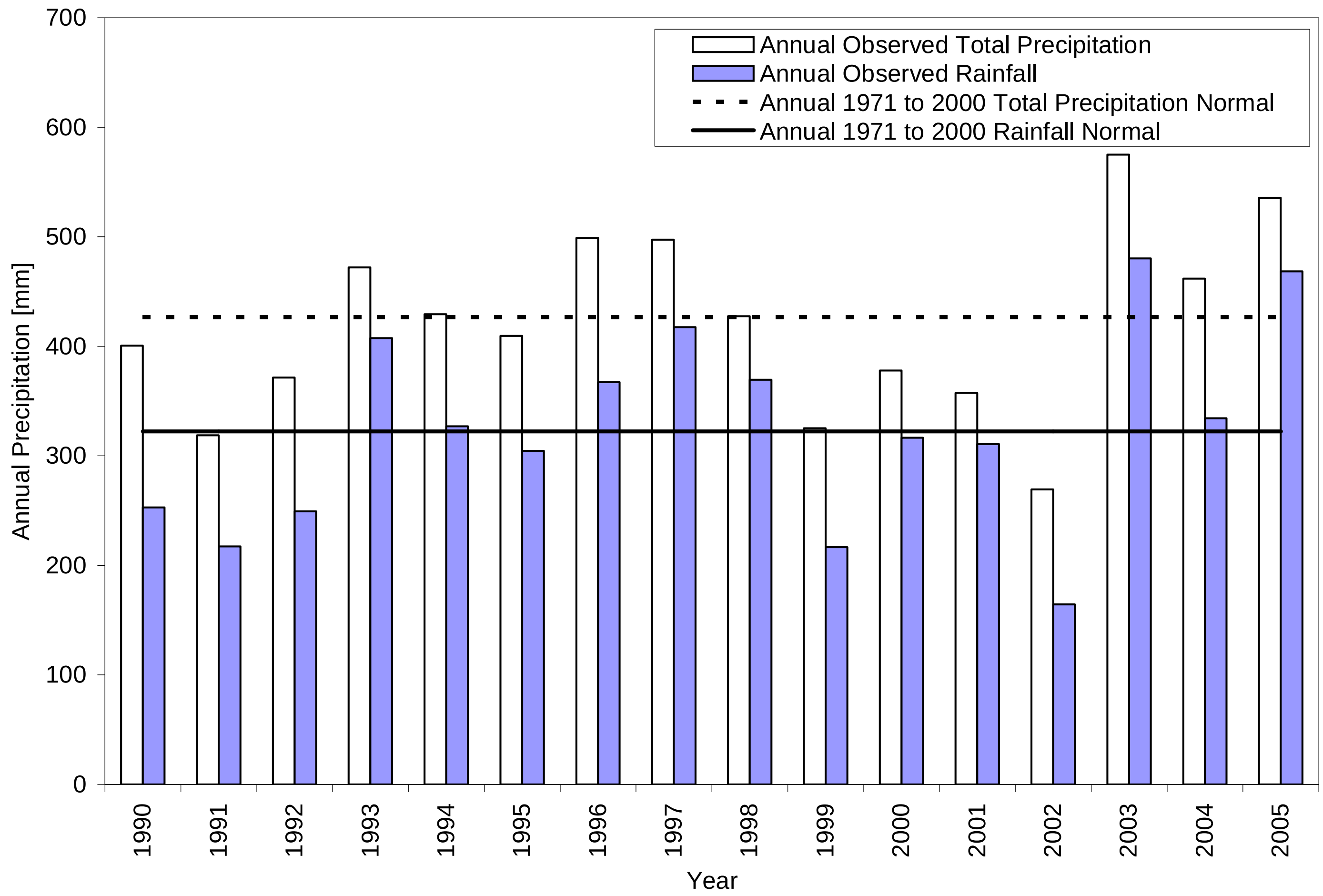
Figure 17 presents a comparison of annual temperatures at Fort McMurray from 1990 to 2005. This comparison also includes 1971 to 2000 climate normal values for comparison to historic trends. The 2002 annual average temperature is 1°C below the long-term average; however, this year is still considered representative of the long-term conditions in the region.

Figure 18 presents a comparison of annual temperatures at Cold Lake from 1990 to 2005. The 1971 to 2000 climate normal values are also shown for comparison to historic trends. The 2002 annual average temperature was 0.4°C cooler than normal. Although 2002 was cooler than normal, it is considered representative of annual temperatures in the Cold Lake region.

Figure 19 presents a comparison between the 2002 windrose and the cumulative 1990 to 2005 windrose from the Fort McMurray airport. The lengths of the bars on the windrose indicate the frequency and speed of wind, and the direction from which the wind blows is illustrated by the orientation of the bar in one of 16 directions. The dominant winds observed at Fort McMurray airport blow from the east and east-southeast. The 2002 windrose displays a higher frequency of high wind speeds (more than 30 km/hr) from the west to northwest sector compared to the cumulative windrose; however, the same general wind pattern is observed. The similarity in the wind patterns between the 2002 windrose and the cumulative windrose indicates that 2002 is representative of winds in the Fort McMurray region.

Figure 20 presents a comparison between the 2002 windrose and the cumulative 1990 to 2005 windrose from the Cold Lake airport. The dominant winds observed at Cold Lake are from the west. The 2002 windrose displays a higher frequency of high wind speeds (more than 30 km/hr) in the northwest quadrant and a higher frequency of westerly and northwesterly winds overall compared to the cumulative windrose. The similarity in the wind patterns between the 2002 windrose and the cumulative windrose indicates that 2002 is representative of winds in the Cold Lake region.

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 16 Comparison of cold lake annual precipitation from 1990 to 2005.dwg Apr 16, 2008 – 6:42pm



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

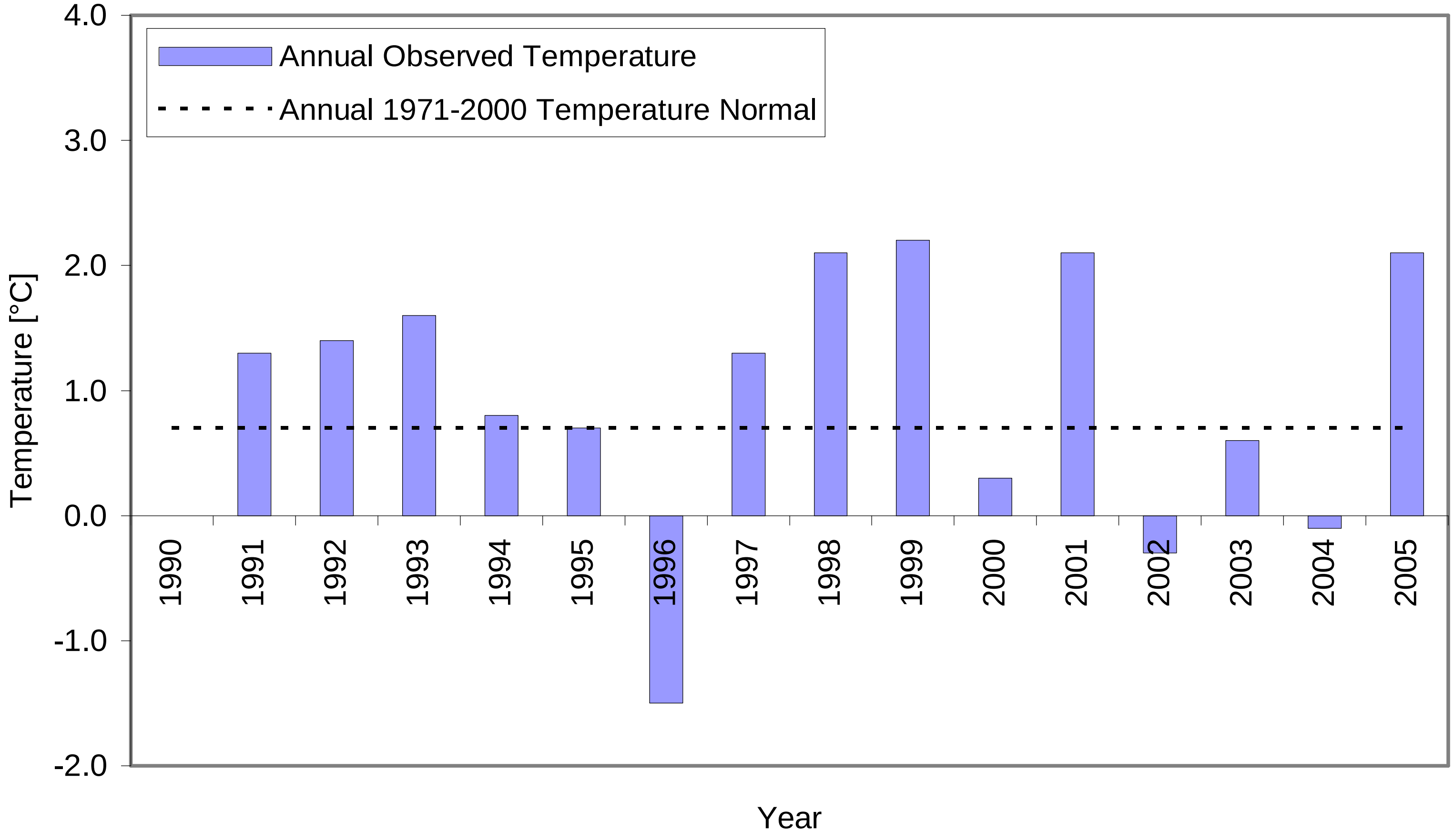
TITLE

COMPARISON OF COLD LAKE ANNUAL PRECIPITATION FROM 1990 TO 2005

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	cold lake
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 16**	
REVIEW	IGG	17/04/08		

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 17 Comparison of Fort McMurray annual temperatures from 1990 to 2005.dwg Apr 16, 2008 - 6:43pm



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

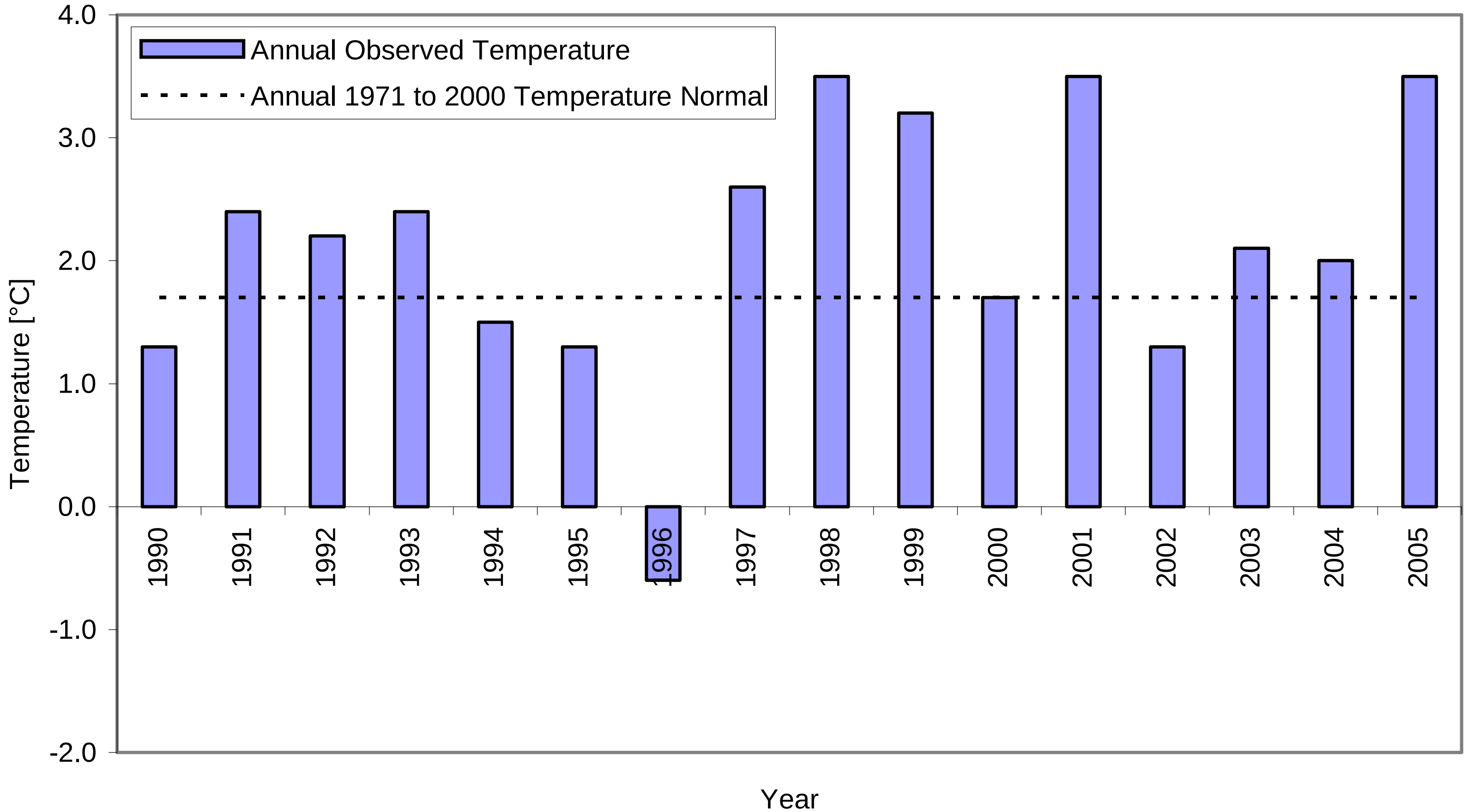
TITLE

COMPARISON OF FORT McMURRAY ANNUAL TEMPERATURES FROM 1990 TO 2005

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Fort Mc Temp
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08		
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		

FIGURE: 17



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

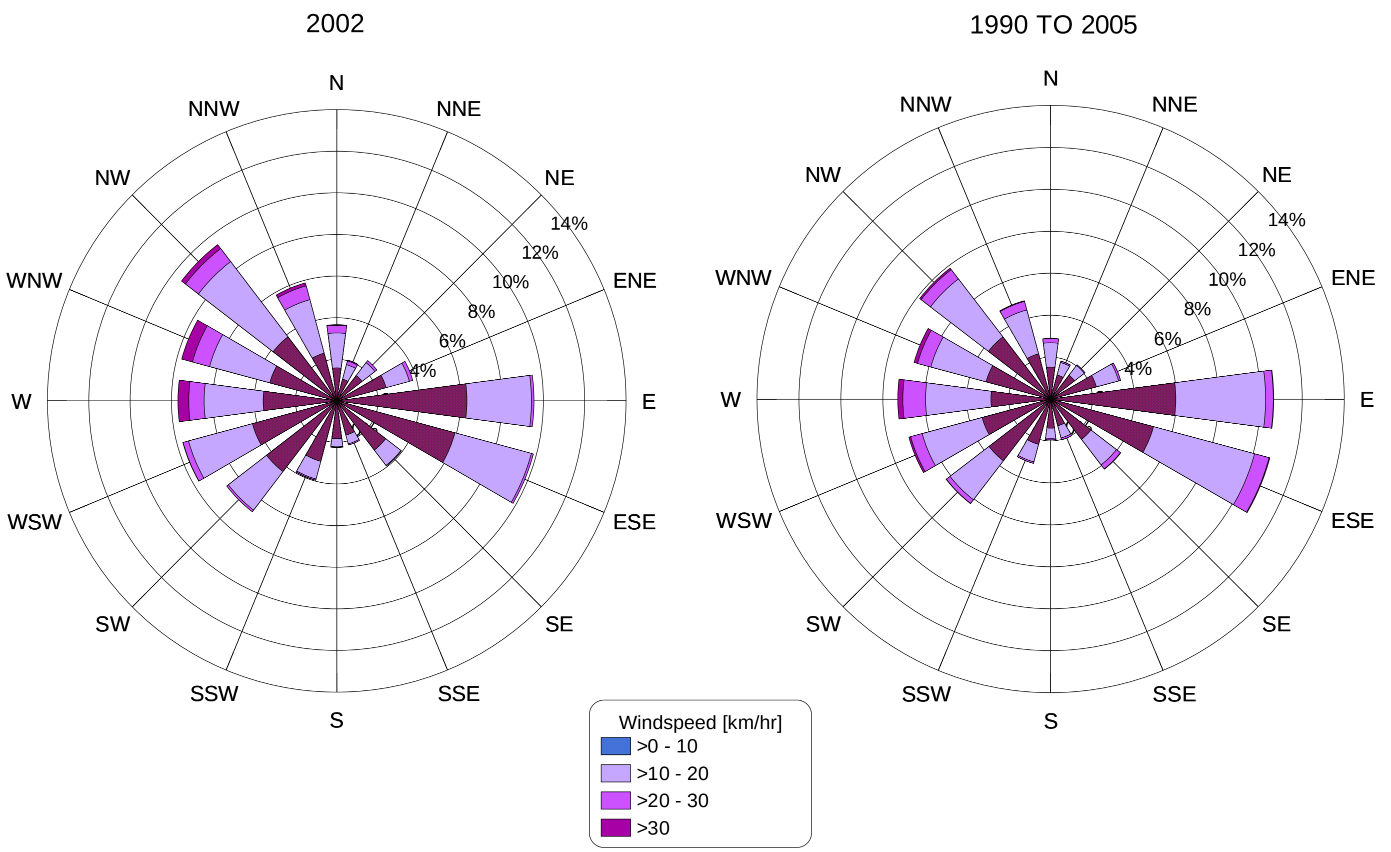
TITLE

COMPARISON OF COLD LAKE ANNUAL TEMPERATURES FROM 1990 TO 2005

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Cold lake temp
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08		
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		

FIGURE: 18



PROJECT

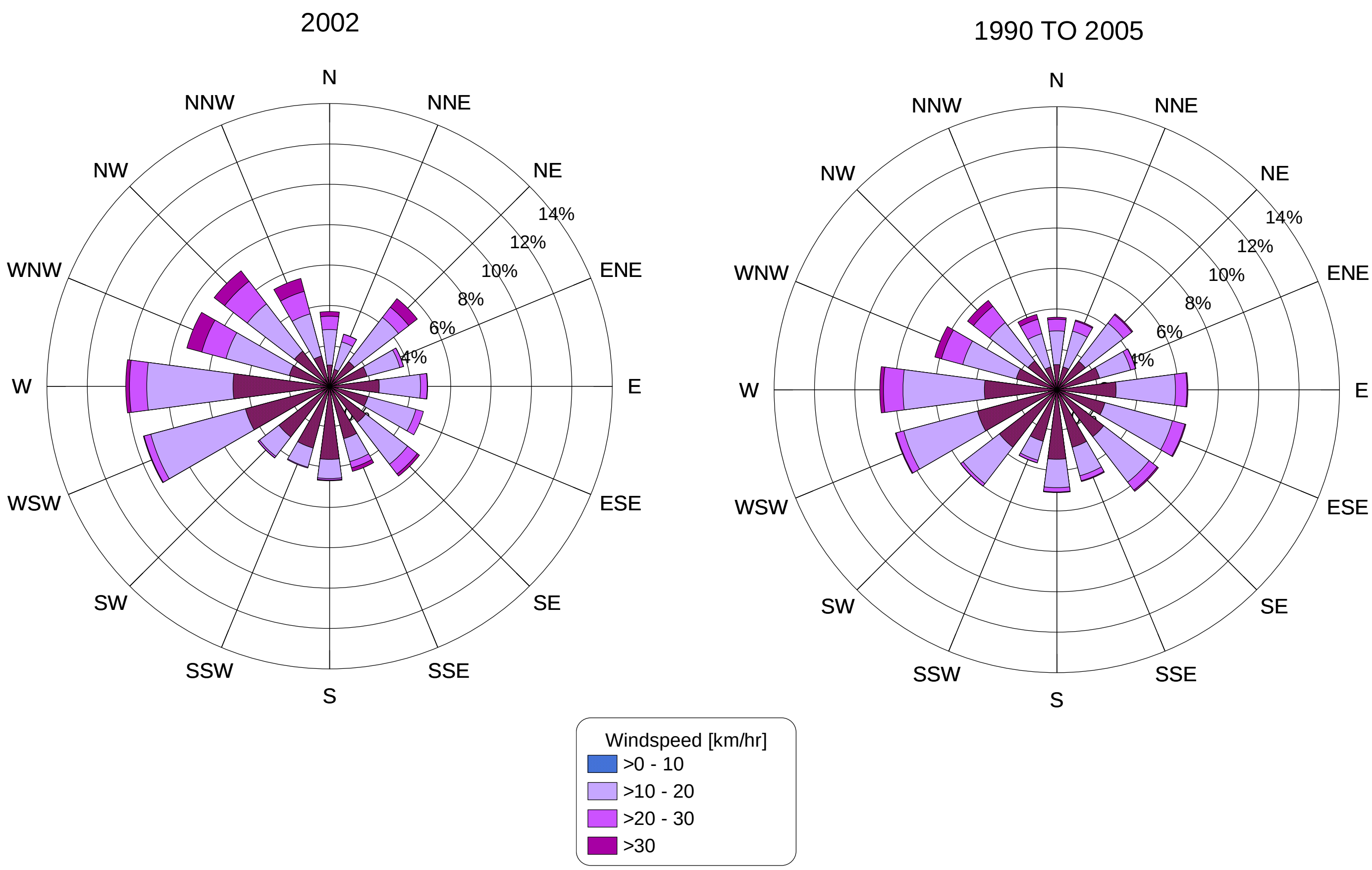
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF FORT McMURRAY WINDS FROM 1990 TO 2005

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Windroses
DESIGN	MS	29/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	31/01/08	**FIGURE: 19**	
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF COLD LAKE WINDS FROM 1990 TO 2005

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Windroses
DESIGN	MS	29/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 20**	
REVIEW	IGG	17/04/08		

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 20 Comparison of Cold Lake Winds From 1990 to 2005.dwg Apr 16, 2008 - 6:47pm

The comparison between 2002 and 1990 to 2005 meteorological parameters at Fort McMurray and Cold Lake indicates that 2002 is a representative year overall. Based on this comparison, 2002 data was found to be suitable for the development of the CALMET three-dimensional meteorological data set.

2.4.2 Evaluation of CALMET Wind Fields

The three-dimensional wind fields used in the CALPUFF dispersion modelling were simulated over an area of 390 by 605 km, which is larger than the modelling domain used in the assessment. This was done to ensure the CALPUFF model used the most representative wind fields across the entire study area.

In preparing the three-dimensional CALMET data, meteorological information from continental meteorological models, upper air stations and surface stations were used. One of the strengths of the CALMET model is that it allows the user to make full use of all or some of the available meteorological data for the region.

The continental scale meteorological winds used as inputs to CALMET were simulated for 2002 using the MM5 model. The 2002 MM5 model data was reviewed and provided by AENV.

The dispersion and transport of the atmospheric emissions are driven primarily by the wind. Windroses comparing the observed and CALMET predicted winds at the Fort McMurray and Cold Lake airports were presented in Section 2.2.3. The comparison of observed and CALMET winds at Fort McMurray showed that winds from the east-southeast dominate. The 2002 CALMET winds are similar to the observations with a higher frequency from the west-southwest and a lower frequency from the east. At Cold Lake, the 2002 CALMET winds showed a similar pattern to the 2002 observations. These slight differences between observed and predicted winds are to be expected as the observed data represent the conditions at a single location, while the CALMET predictions represent the winds expected over an area that is 5 by 5 km in size.

One of the key features of a three-dimensional wind field is that it allows for wind speeds and directions to vary spatially across the modelling domain during a single hour as well as allowing variations from one hour to the next. Illustrating this capability of the CALMET model is not a simple undertaking given the number of wind values included in the modelling domain. For each hour, there are 86,588 wind speed and wind direction values determined by CALMET (one wind speed and direction is calculated for each of the 10 layers in every one of the 8,658 grid cells). In an entire year, this would result in more than 750 million values.

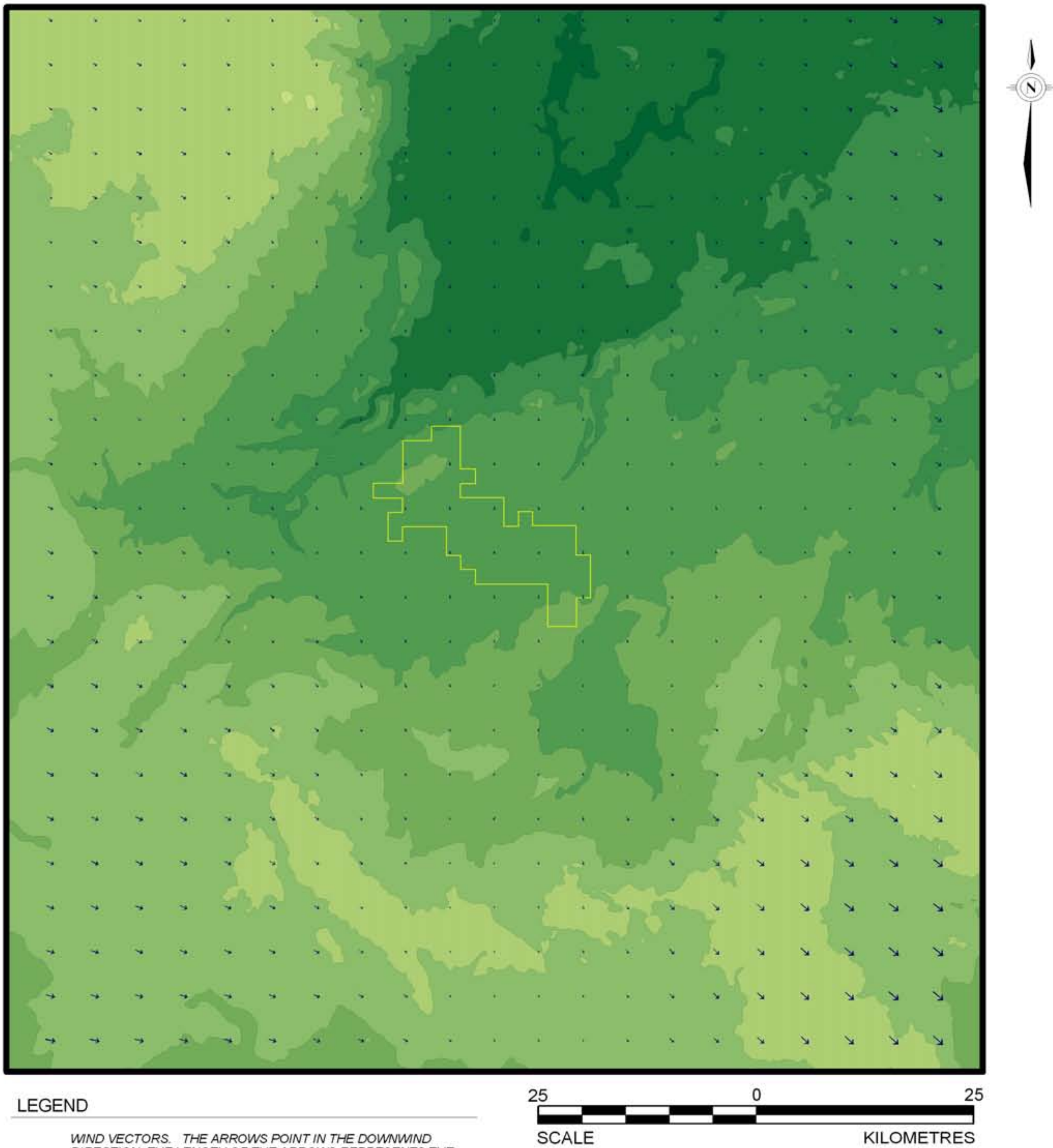
One technique to represent this data is to provide a wind vector diagram showing the wind speeds and directions at each of the grid cells during a single hour. A series of vector figures illustrating the variation in CALMET wind fields has been presented in Figures 21 and 22. The figures present the CALMET model wind fields at the surface (10 m) and 150 m levels for 2002. In each grid cell (5 by 5 km in size) the arrow points toward the direction that the wind is blowing. The length of each arrow represents the relative wind speed within the layer (as a function of the highest speed at that level).

2.4.3 Evaluation of CALPUFF Predictions

A performance evaluation of the CALPUFF model was conducted by comparing the modelling results of emission sources in the Oil Sands Region for the years 2002 and 2003 (i.e., “Existing Scenario”) to WBEA monitoring data collected over the same time period. In particular, the predicted SO_2, NO_X, NO_2, $PM_{2.5}$ and VOCs concentrations as well as PAI levels were compared to available monitoring data. The performance evaluation was completed using different graphical comparison tools including fractional bias, logarithmic plots of predicted versus monitored values (Quartile-Quartile plots) and percentile graphs.

Fractional bias is one of the evaluation methods recommended by the U.S. EPA for determining dispersion model performance (U.S. EPA 1992), as discussed in Section 2.1 of this appendix. Fractional bias provides a comparison of the means and standard deviation of both modelled and monitored concentrations for any given number of locations. Fractional bias compares the maximum 25 predicted concentrations to monitored concentrations. The fractional bias values are typically plotted on a graph with the means (FB_{means}) on the X axis and the standard deviations (FB_{stdev}) on the Y axis. A box is placed on the plot enclosing the area of the graph where the model predictions are within a factor of two (corresponding to a fractional bias of between -0.67 and +0.67). This box will be referred to as the 0.67 box in this evaluation. The U.S. EPA states that predictions within a factor of two are a reasonable performance target for a model before it is used for refined regulatory analysis (U.S. EPA 1992). Data points appearing on the left half of the plot indicate an over prediction and those on the right half of the plot represent under predictions.

R:/ACTIVE/_2007/1346/07-1346-0009 MEG CHRISTINA LAKE REGONAL EXPANSION/8000 AIR/8070 EIA REPORTING/FIGURES/CALMET_wind_sfc_2002.srf



LEGEND

WIND VECTORS. THE ARROWS POINT IN THE DOWNWIND DIRECTION. THE LENGTH OF THE ARROWS REPRESENTS THE RELATIVE WIND SPEED WITHIN THE LAYER. THE LONGEST ARROWS, WHICH REPRESENT THE HIGHEST SPEED IN THE LAYER, MAY REPRESENT DIFFERENT SPEEDS FROM ONE LAYER TO THE NEXT.

MEG LEASE BOUNDARY

THE HORIZONTAL WINDS DEPICTED IN THE FIGURE CORRESPOND WITH THE CALMET WIND FIELD AT 12:00 ON MAY 12, 2002.

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.) USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

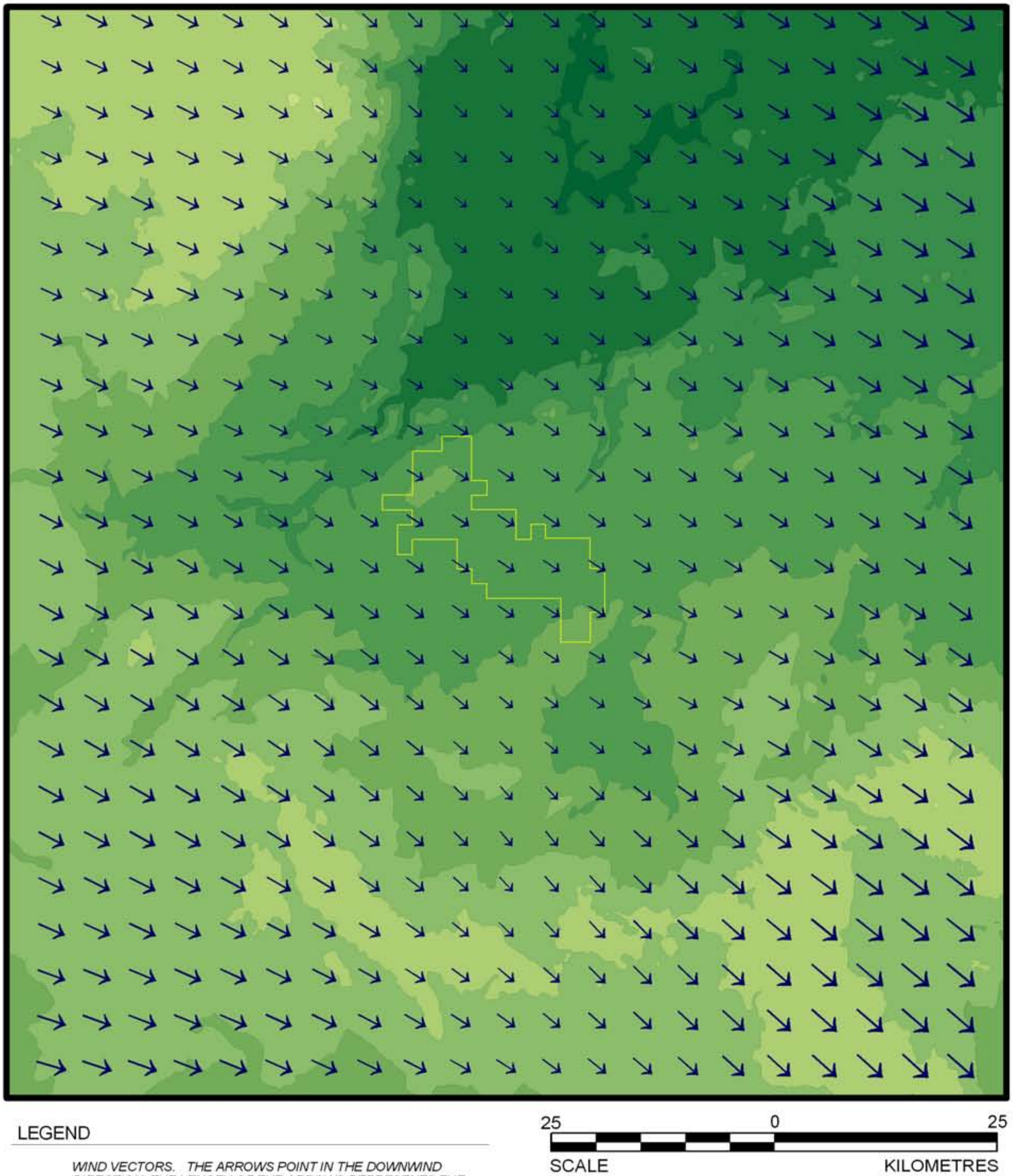
2002 CALMET WINDS ACROSS THE RSA - SURFACE LAYER

MEG ENERGY CORP.

DESIGN	MS	19/02/08
AIR	MS	20/02/08
CHECK	NP	14/04/08
REVIEW	IGG	17/04/08

FIGURE: 21

R:/ACTIVE/_2007/1346/07-1346-0009 MEG CHRISTINA LAKE REGIONAL EXPANSION/8000 AIR/8070 EIA REPORTING/FIGURES/CALMET_wind_150m_2002.srf



LEGEND

WIND VECTORS. THE ARROWS POINT IN THE DOWNWIND DIRECTION. THE LENGTH OF THE ARROWS REPRESENTS THE RELATIVE WIND SPEED WITHIN THE LAYER. THE LONGEST ARROWS, WHICH REPRESENT THE HIGHEST SPEED IN THE LAYER, MAY REPRESENT DIFFERENT SPEEDS FROM ONE LAYER TO THE NEXT.

MEG LEASE BOUNDARY

THE HORIZONTAL WINDS DEPICTED IN THE FIGURE CORRESPOND WITH THE CALMET WIND FIELD AT 12:00 ON MAY 12, 2002.

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.) USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

2002 CALMET WINDS ACROSS THE RSA - 150 m LAYER

MEG ENERGY CORP.

DESIGN	MS	19/02/08
AIR	MS	20/02/08
CHECK	NP	14/04/08
REVIEW	IGG	17/04/08

FIGURE: 22

To provide a more detailed evaluation of predicted and monitored data at specific monitoring stations, Quartile-Quartile plots were used. The Quartile-Quartile plots provide a logarithmic comparison of ranked predicted and observed concentrations. If a ranked predicted concentration is equal to the correspondingly ranked observed concentration, it will fall on the diagonal solid line on the plot, which represents unbiased predictions (i.e., neither an under nor over prediction). Values are over predicted if they appear above the line, while values below the line are under predicted. The Quartile-Quartile plots also delineate when the predicted values are within a factor of two and four of the observed values.

Percentile graphs provide a comparison of predicted and monitored data over different percentile values. Percentile graphs were used when limitations in monitoring data did not allow the use of fractional bias plots or Quartile-Quartile plots.

2.4.3.1 Existing Scenario Emissions

To complete the CALPUFF model validation, it was necessary to develop a regional emissions profile for a specific time period. An emissions inventory was developed to represent the years 2002 and 2003 in the Oil Sands Region. The emissions inventory was based on regulatory application and approval documents, information collected from developers as well as professional judgement. Table 13 presents a summary of the emission rates used in the Existing Scenario modelling assessment.

Table 13 Existing Scenario Emissions

Source	Emission Rates[a]				
	Stream-Day SO_2 [t/sd]	Calendar-Day SO_2 [t/cd]	NO_X [t/d]	$PM_{2.5}$ [t/d]	VOC [t/d]
Suncor Oil Sands Facility	41.44	58.98	75.28	6.77	209.69
Suncor in-situ sources	0.17	0.17	0.21	0.01	0.03
Syncrude Mildred Lake	245.06	249.06	54.43	6.59	58.17
Syncrude Aurora North	0.04	0.04	15.48	0.56	7.90
Albian Sands Energy Inc. (Albian Sands) Muskeg River Mine	0.20	0.20	17.34	1.07	13.84
other industries	1.52	1.52	5.53	0.40	2.57
communities	0.17	0.17	1.04	-	-
Total	**288.58**	**310.12**	**169.32**	**15.39**	**292.21**

(a) Emissions are expressed as tonnes per stream-day (t/sd), tonnes per calendar-day (t/cd) or tonnes per day (t/d).

The mine fleet emissions in this scenario were calculated using the load factor approach (U.S. EPA 2004). Suncor Energy Inc.'s (Suncor's) tailings ponds were modelled using variable emission rates, as outlined in Section 3.2 of this appendix.

Monitoring Data

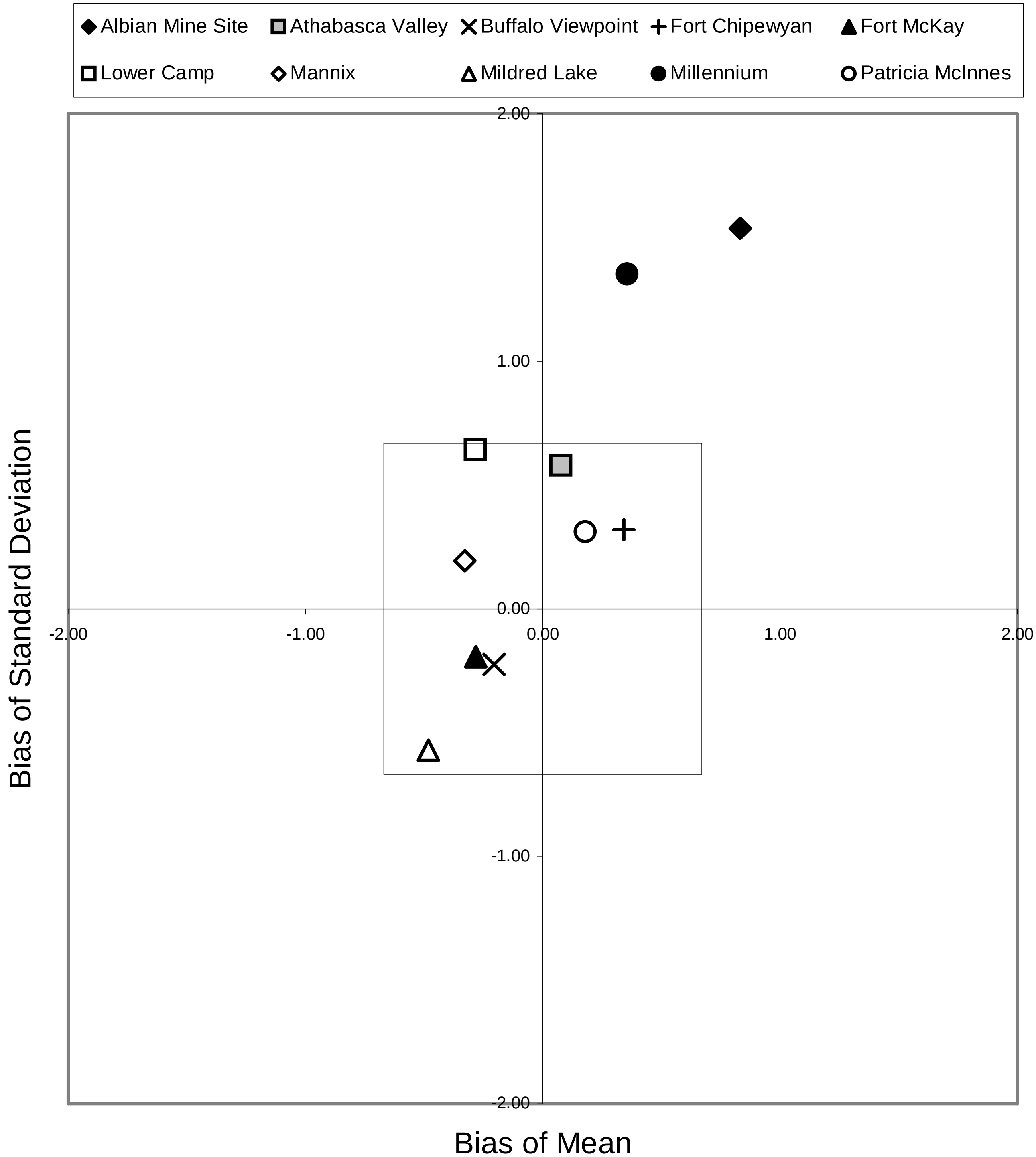
Monitoring data collected at WBEA monitoring stations in 2002 and 2003 was used in the performance evaluation. Data was used from the continuous monitoring stations (SO_2, NO_X, NO_2, $PM_{2.5}$), the non-continuous samples (VOCs) and the TEEM monitoring stations (annual SO_2 and NO_2 to represent PAI). The monitoring data were reviewed to try to account for the influence of regional forest fires on monitored $PM_{2.5}$ concentrations. Periods with greatly elevated $PM_{2.5}$ concentrations across the region that could reasonably be related to forest fire events were excluded from datasets.

2.4.3.2 Sulphur Dioxide Predictions

Figure 23 presents the 2002 fractional bias plots for the Existing Scenario predicted 1-hour SO_2 concentrations at 10 monitoring stations in the region. The fractional bias results for 8 of the 10 monitoring stations for both years fall within the 0.67 box, indicating that the predictions are within a factor of two of the observed values. The horizontal axis of the plot represents the bias of the mean for the 25 highest predictions and observations. Five monitoring stations have predicted concentrations higher than corresponding observations. The fractional bias values for the Patricia McInnes, Athabasca Valley and Fort Chipewyan stations suggest that there was a slight under prediction.

The 2002 1-hour SO_2 concentrations were under predicted at the Albian Mine and Millennium stations. The fractional bias values for Millennium station indicate that the bias of the mean is within a factor of two but the bias of the standard deviation is greater than a factor of two. The fractional bias values for the Albian Mine indicate that both the bias of the mean and the bias of the standard deviation are greater than a factor of two.

Since the model performed adequately for most of the stations, it is unlikely that the under predictions at the three stations are due to shortcomings in the CALPUFF model. It is more likely that the emissions used in the assessment did not account for all of the local SO_2 emissions near these sites. The fractional bias plot indicates that the CALPUFF modelling of SO_2 concentrations performed satisfactorily for most of the monitoring stations considered.



L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 23 Fractional bias plot.dwg Apr 16, 2008 - 6:49pm

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

FRACTIONAL BIAS PLOT FOR 1-HOUR SULPHUR DIOXIDE PREDICTIONS

MEG ENERGY CORP.

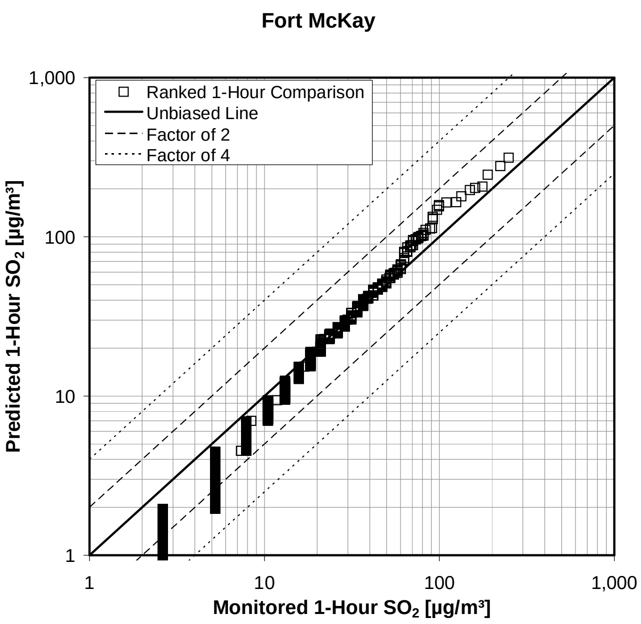
PROJECT	07.1346.0009.8000		FILE No.	1 hour SO2
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TY	31/01/08	**FIGURE: 23**	
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		

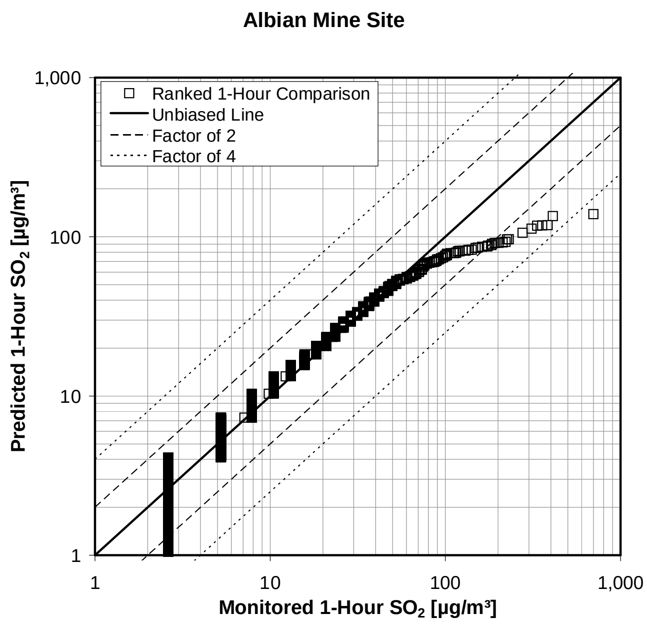
Figure 24 presents Quartile-Quartile plots comparing the ranked 1-hour predicted SO_2 concentrations and observations at the Fort McKay, Albian Mine and Millennium stations. The Fort McKay data indicates that the predicted 1-hour SO_2 concentrations represent the monitored concentrations within the community. Predicted concentrations in Fort McKay are typically within a factor of two of measured data, with the highest predicted concentrations being within a factor of one. As is shown on the fractional bias plot, the predicted 1-hour SO_2 concentrations at the Albian Mine station are lower than the highest monitored concentrations. Again, it is believed that these higher monitored values are associated with start-up conditions and the fire that occurred in January 2003. The majority of the predictions at the Millennium station show a good correlation with the observed 1-hour SO_2 concentrations; however, the maximum 1-hour prediction is a factor of four lower than the maximum monitored value.

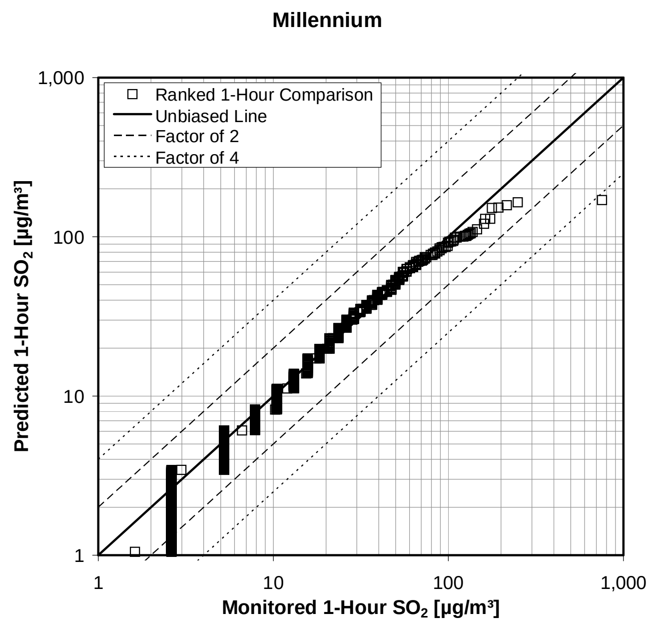
2.4.3.3 Oxides of Nitrogen Predictions

Figure 25 presents the 2002 fractional bias plot for the Existing Scenario predicted 1-hour NO_X concentrations at six regional monitoring stations. Four of the six monitoring stations considered were within the 0.67 box, indicating that the predictions are within a factor of two of the observed values. The 25 highest 1-hour NO_X predictions at two of the oil sands mining operations (Albian Mine and Millennium stations) were over predicted in the Existing Scenario modelling. Experience in the region is consistent with the finding that predicted NO_X concentrations due to mining activities in the region are overestimated. The fractional bias plot indicates that the CALPUFF modelling performed satisfactorily for most stations. Where the model did not perform satisfactorily, predicted concentrations were over predicted.

The predicted NO_X concentrations are converted to NO_2 concentrations based on a combination of the CALPUFF internal chemistry and the ambient mine ratio. Figure 26 presents the 2002 fractional bias plot for the Existing Scenario predicted 1-hour NO_2 concentrations at six regional monitoring stations. Three of the six monitoring stations considered were within the 0.67 box. The 25 highest 1-hour NO_2 concentrations at the Albian Mine and Millennium stations were over predicted. A comparison between the NO_X and NO_2 fractional bias plots indicate that the conversion of NO_X to NO_2 removes some of the conservatism in the NO_X predictions, resulting in more representative predictions. The fractional bias plot indicates that the CALPUFF modelling performed satisfactorily for NO_2 predictions at most stations, and resulted in over predictions at the Millennium and Albian Mine stations. The fractional bias value for the Athabasca Valley station suggests that there was a slight under prediction for this station.







PROJECT

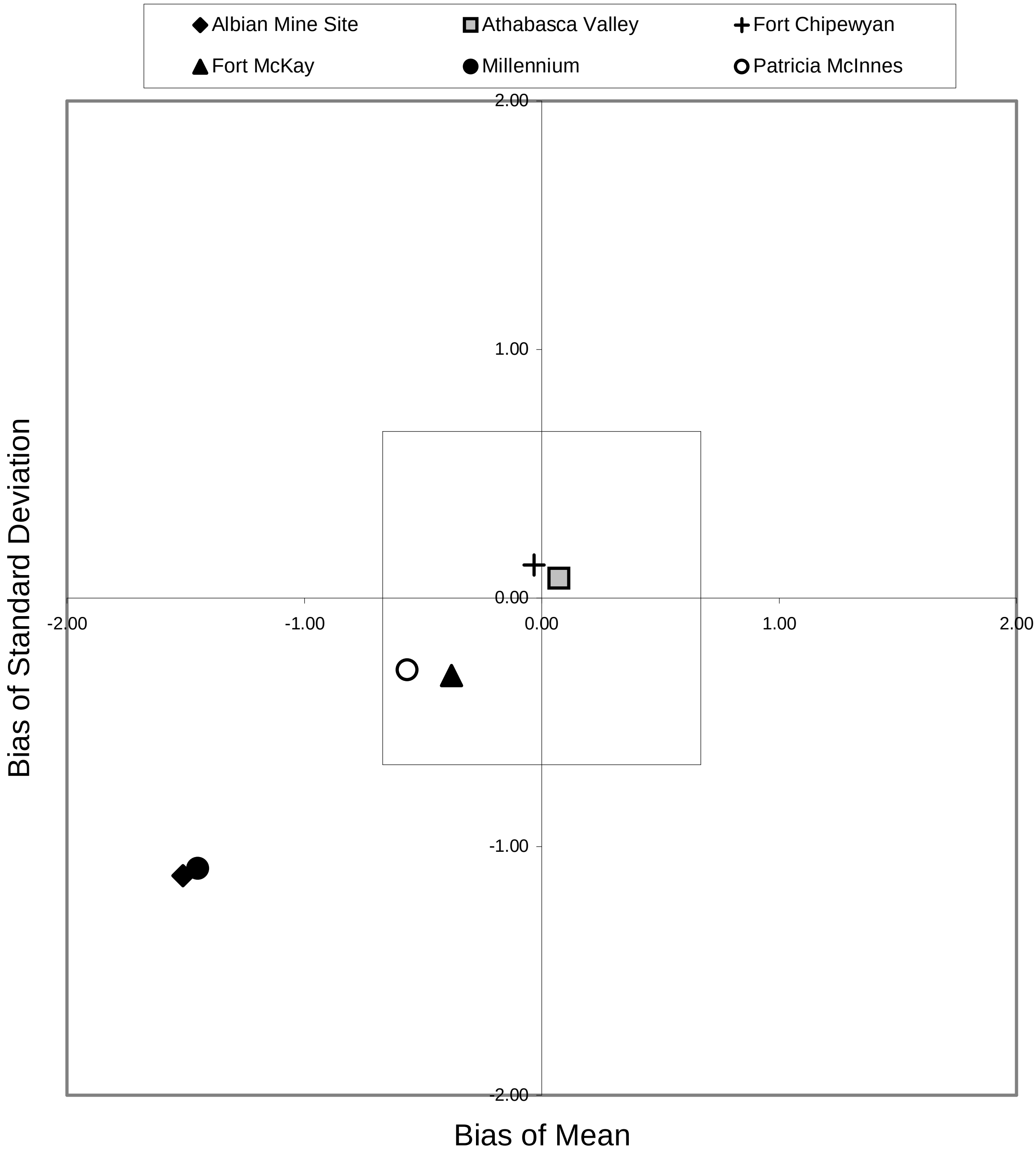
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

QUARTILE-QUARTILE PLOTS OF 1-HOURS SULPHUR DIOXIDE CONCENTRATIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Quartile-quartile
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 24**	
REVIEW	IGG	17/04/08		



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

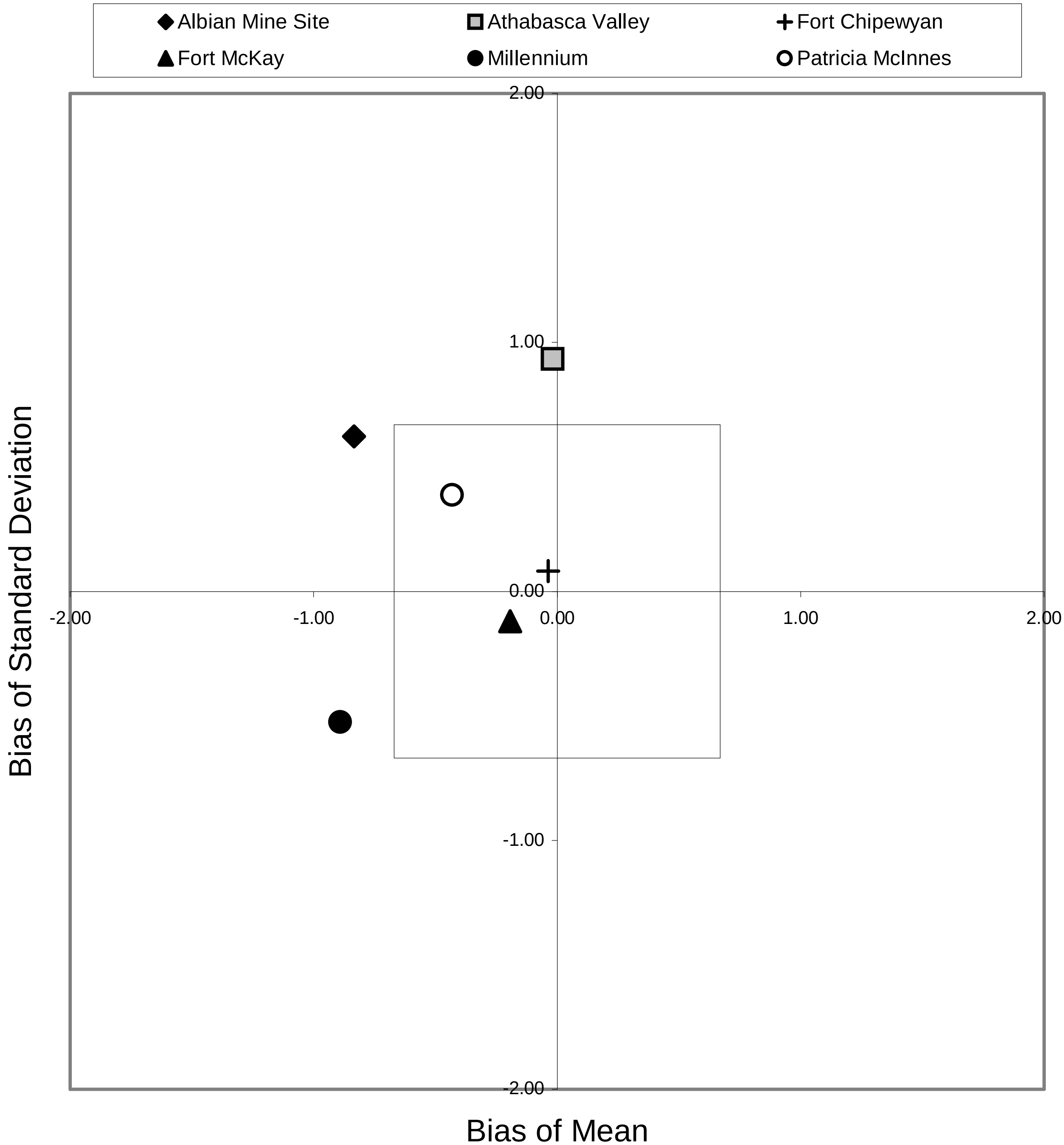
TITLE

FRACTIONAL BIAS PLOT FOR 1-HOUR OXIDES OF NITROGEN PREDICTIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	1 hour NOX
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TY	31/01/08		
CHECK	MS	14/04/08	**FIGURE: 25**	
REVIEW	IGG	17/04/08		

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 25 Fractional bias plot.dwg Apr 16, 2008 - 6:51pm



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

FRACTIONAL BIAS PLOT FOR 1-HOUR NITROGEN DIOXIDE PREDICTIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	1 hour NO2	
DESIGN	MS	31/01/08	SCALE	AS SHOWN	REV. 0
CADD	TY	31/01/08	**FIGURE: 26**		
CHECK	MS	14/04/08			
REVIEW	IGG	17/04/08			

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 26 Fractional bias plot.dwg Apr 16, 2008 - 6:52pm

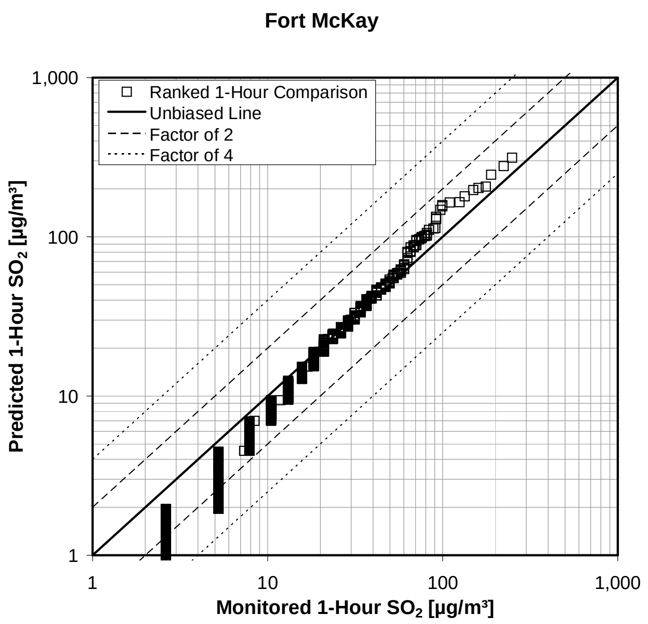
Figure 27 presents the Quartile-Quartile plots comparing the ranked predicted 1-hour NO_X and NO_2 concentrations to observations at the Fort McKay, Albian Mine and Millennium stations. The Fort McKay data show a good correlation with the observed 1-hour NO_X and NO_2 concentrations within the community. As was shown on the fractional bias plots, the predicted 1-hour NO_X concentrations at the Albian Mine and Millennium stations overestimate the observed concentrations, sometimes by more than a factor of four. However, the conversion of NO_X to NO_2 results in maximum concentrations that are generally within a factor of two of observed data at these stations. The over predictions of NO_X and NO_2 concentrations near mine sites are believed to be associated with the conservative emission estimates for the mine fleet vehicles. Also, the over predictions at the Albian Mine station are likely partially related to the fact that the Albian mine fleet emissions were modelled as being less than 900 m away from the monitoring station, which was likely not the case in 2002 and 2003.

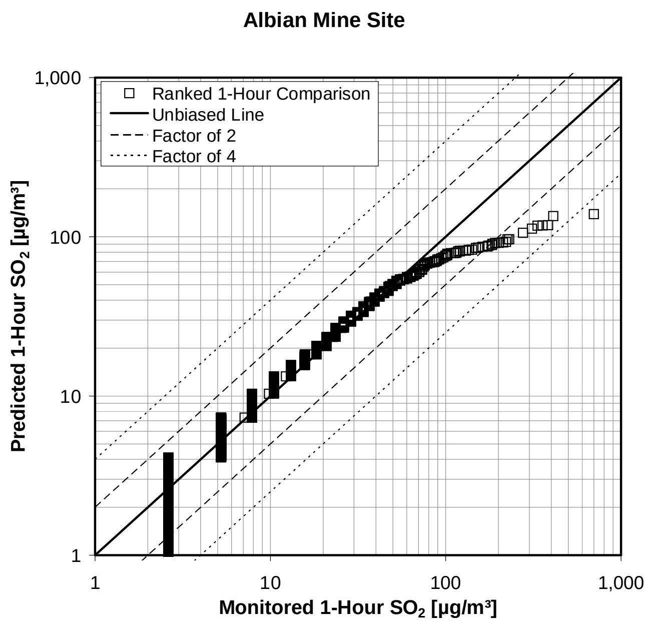
2.4.3.4 Particulate Matter Predictions

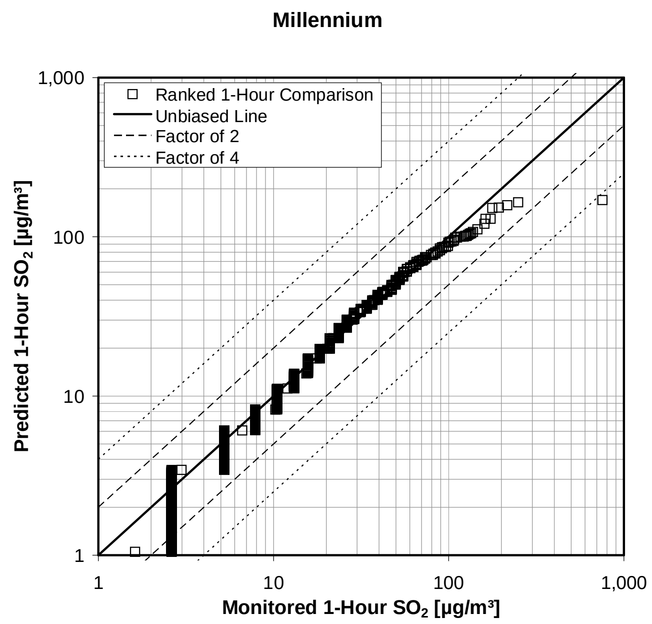
Figure 28 presents the 2002 fractional bias plot for the Existing Scenario predicted 24-hour $PM_{2.5}$ concentrations at six regional monitoring stations. The fractional bias results indicate none of the stations are within the 0.67 box. The horizontal axis of the plot represents the bias of the mean for the 25 highest predictions and observations. The bias of the mean at five stations is over predicted (on the left half of plot) and one station is slightly under predicted (on the right half of plot). The bias of the standard deviation is greater than a factor of two for five of the stations. This means that the range of concentrations predicted in the 25 highest predictions is either larger or smaller than the range monitored at the monitoring stations. For example, at the Fort McKay station, the 25 highest predicted 24-hour $PM_{2.5}$ concentrations ranged from about 28 to 39 $\mu g/m^3$, while the observed data ranged from 11 to 34 $\mu g/m^3$.

Figure 29 presents Quartile-Quartile plots comparing the ranked 24-hour $PM_{2.5}$ predictions and observations at the Fort McKay, Albian Mine and Millennium stations for 2002. The Fort McKay 2002 predictions show a reasonable correlation with the observed 24-hour $PM_{2.5}$ concentrations within the community. The 2002 values show a maximum 24-hour value that is over predicted by less than a factor of two. As was indicated in the fractional bias plot, the predicted 24-hour $PM_{2.5}$ concentrations at the Albian Mine station were overestimated. The over predictions are likely related to the fact that the Albian mine fleet emissions were modelled as being less than 900 m away from the monitoring station, which, as stated earlier, was likely not the case in 2002 and 2003. The predictions at the Millennium station indicate that 24-hour $PM_{2.5}$ concentrations overestimate the observed concentrations; however, the maximum predicted concentrations are within a factor of two of observed values.

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 27 Quartile-quartile plots.dwg Apr 16, 2008 - 6:54pm







PROJECT

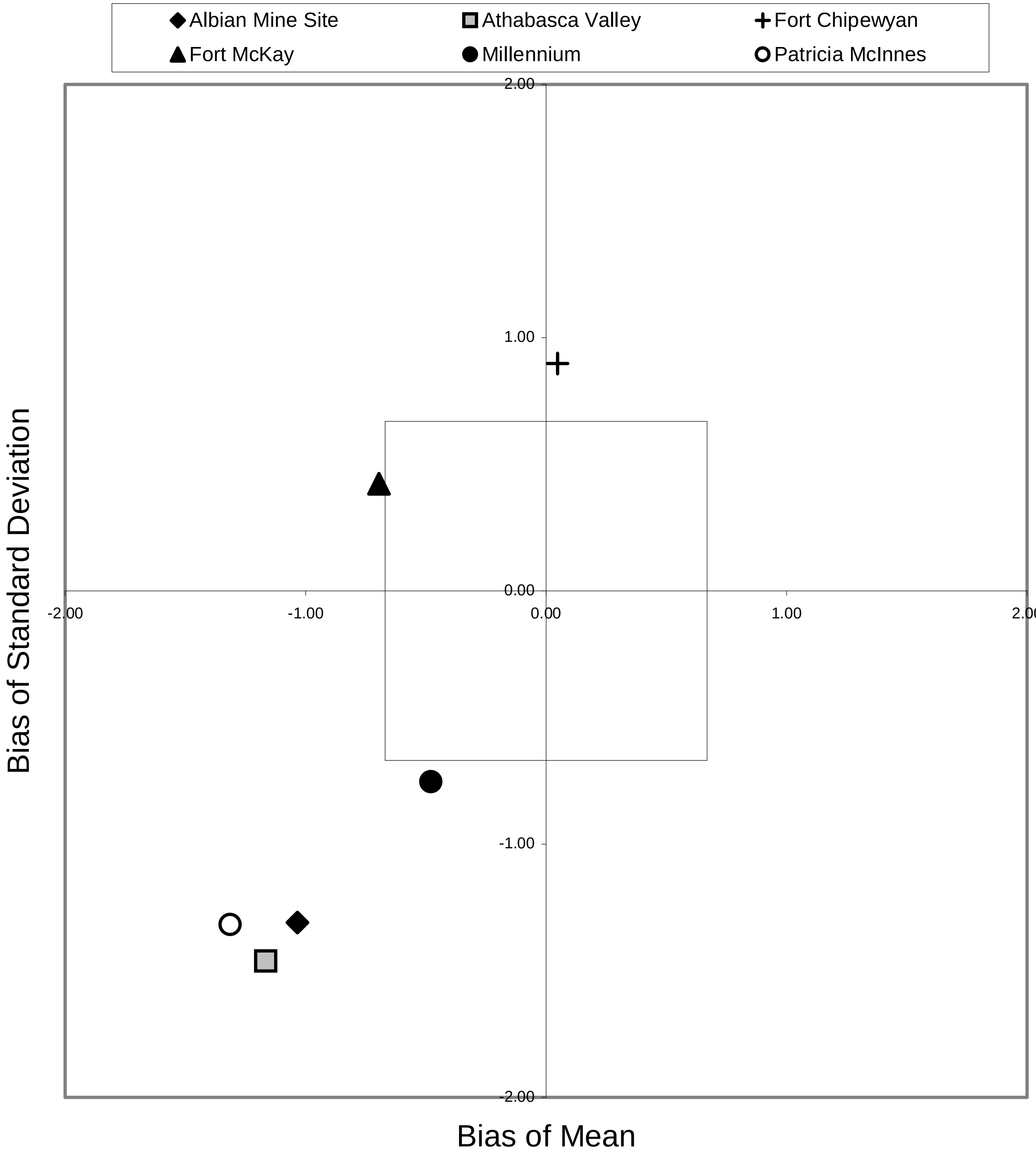
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

QUARTILE-QUARTILE PLOTS OF 1-HOURS OXIDES OF NITROGEN AND NITROGEN DIOXIDE CONCENTRATIONS

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Quartile-quartile
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08		
CHECK	MS	14/04/08	FIGURE: 27	
REVIEW	IGG	17/04/08		



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

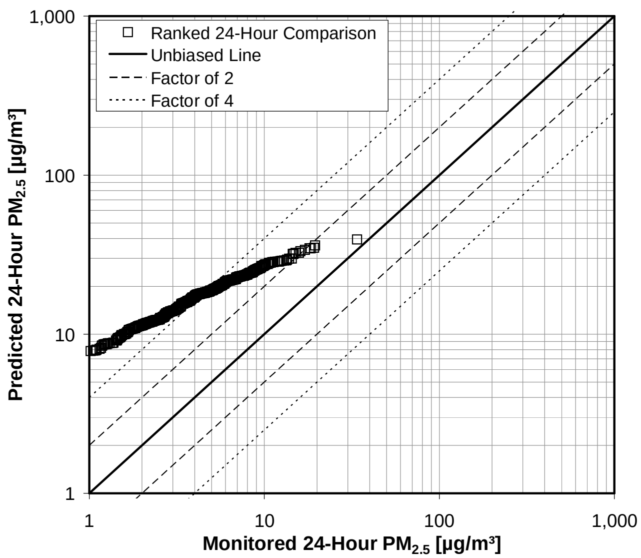
FRACTIONAL BIAS PLOT FOR 24-HOUR $PM_{2.5}$ PREDICTIONS

MEG ENERGY CORP.

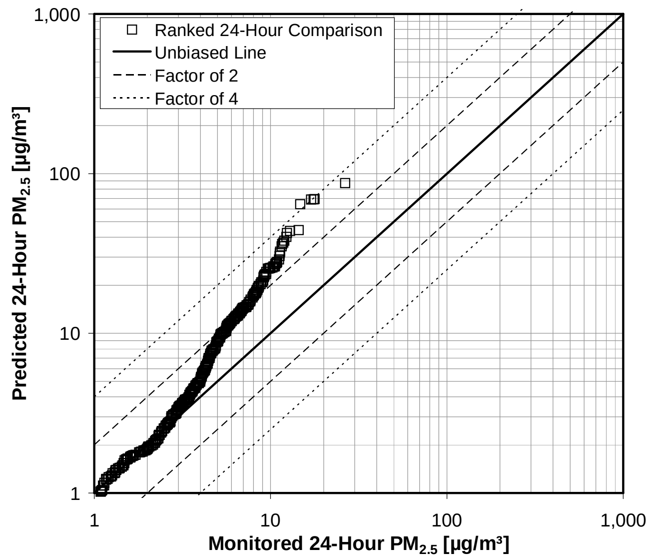
PROJECT	07.1346.0009.8000	FILE No.	PM2.5 predictions
DESIGN	MS	31/01/08	SCALE AS SHOWN — REV. 0
CADD	TRE	14/04/08	
CHECK	MS	16/04/08	**FIGURE: 28**
REVIEW	IGG	17/04/08	

L:\2007\1346 Oil Sands\07-1346-0009-MEG EXPANSION\8000\Appendix 3-II\Fig 28 Fractional bias plot for 24-hour pm.dwg Apr 16, 2008 - 5:34pm

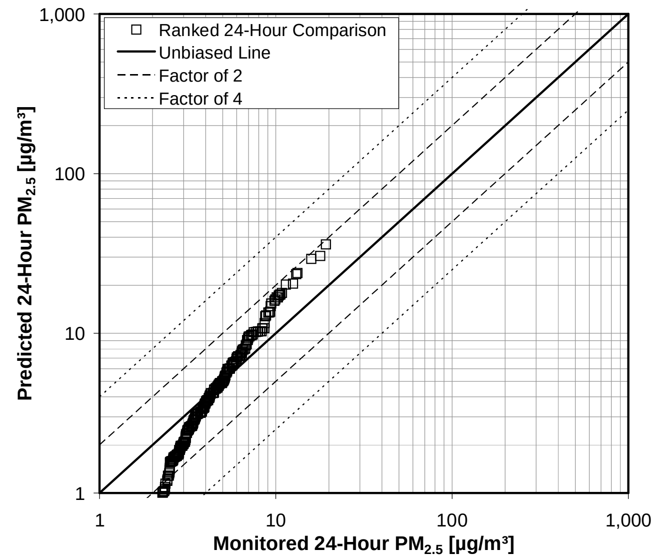
Fort McKay



Albian Mine Site



Millennium



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

QUARTILE-QUARTILE PLOTS OF 24-HOUR $PM_{2.5}$ CONCENTRATIONS

MEG ENERGY CORP.

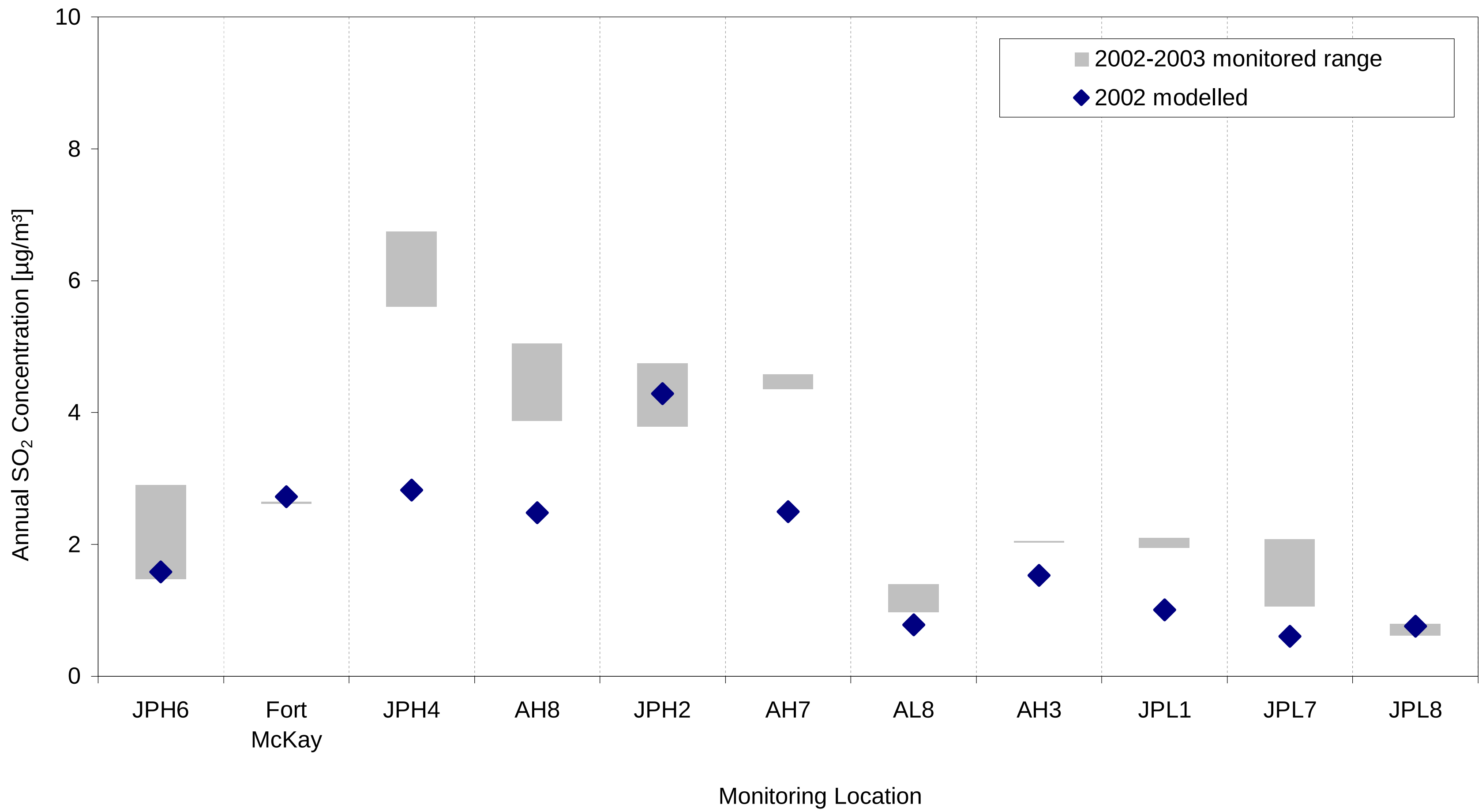
PROJECT 07.1346.0009.8000			FILE No. Quartile-quartile	
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	14/04/08	**FIGURE: 29**	
CHECK	MS	16/04/08		
REVIEW	IGG	17/04/08		

One of the primary challenges of completing a performance evaluation of $PM_{2.5}$ modelling is trying to determine the influence of natural sources which cannot be easily included in the modelling. Although an attempt was made to exclude elevated concentrations related to natural events (e.g., forest fires) from the monitoring data, it is believed that the influence of natural sources will skew the results of the analysis.

2.4.3.5 Potential Acid Input Predictions

Although PAI monitoring was not conducted in the region during 2002 and 2003, the WBEA TEEM monitoring sites did measure annual SO_2 and NO_2 concentrations, which have been used to estimate the potential dry sulphur and nitrogen deposition rates at these sites. Figure 30 compares 2002 predicted Existing Scenario annual SO_2 concentrations to the range of annual TEEM monitoring data collected in 2002 and 2003. The figure indicates that the predicted annual SO_2 concentrations at all of the monitoring stations are either within the monitored data range or underestimate the annual concentration. The largest under prediction was at the JPH4 station, where predicted concentrations were about 2 $\mu g/m^3$ below monitored values. These under predictions suggest that the emissions may not account for all the SO_2 released from the facilities. In particular, the modelling did not include the emissions from unusual events such as upsets and emergency releases. It is difficult to represent these types of transient events in regional modelling assessments. Overall, the comparison indicates that the CALPUFF modelling is performing satisfactorily for annual SO_2 predictions in the region.

Figure 31 compares 2002 predicted Existing Scenario annual NO_2 concentrations to the range of annual TEEM monitoring data collected in 2002 and 2003. The figure indicates that the predicted annual NO_2 concentrations at 10 of the 11 monitoring stations are within the monitored data range or overestimate the annual concentrations. Experience in the region is consistent with the finding that predicted NO_2 concentrations due to the mining activities in the region are overestimated. Predictions at two of the monitoring stations underestimate the monitored concentrations, with the largest under prediction of 2 $\mu g/m^3$ occurring at the JPH6 station. The predictions with the greatest over prediction occur at monitoring stations close to oil sands mining activities. Overall, the comparison indicates that the CALPUFF modelling is providing over predictions of annual NO_2 concentrations in the region.



PROJECT

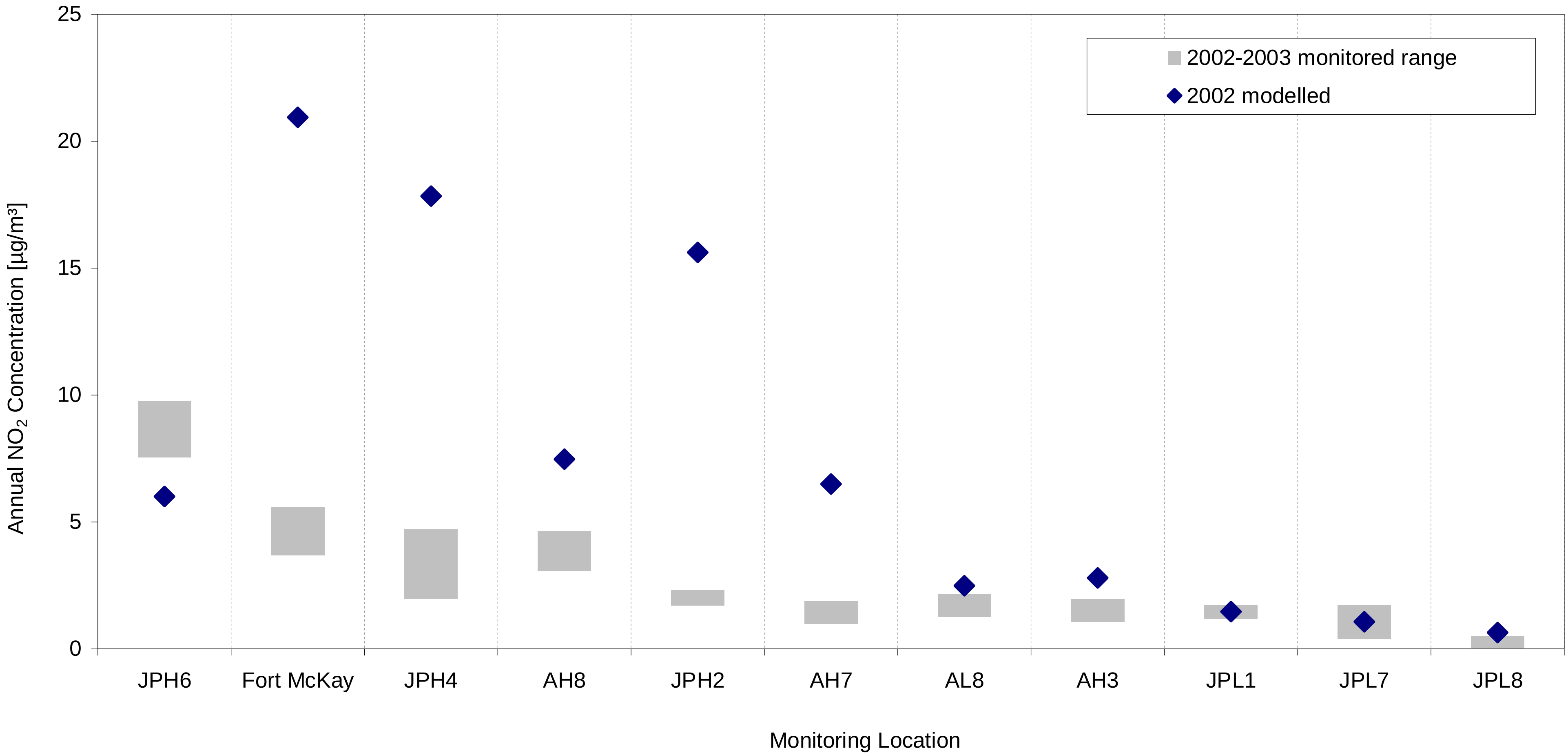
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF ANNUAL SULPHUR DIOXIDE CONCENTRATIONS AT TEEM SITES

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	TEEM sites
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	14/04/08		
CHECK	MS	16/04/08	**FIGURE: 30**	
REVIEW	IGG	17/04/08		



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF ANNUAL NITROGEN DIOXIDE CONCENTRATIONS AT TEEM SITES

MEG ENERGY CORP.

PROJECT 07.1346.0009.8000			FILE No.	NO2
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	PSR	31/01/08		
CHECK	MS	14/04/08		
REVIEW	IGG	17/04/08		

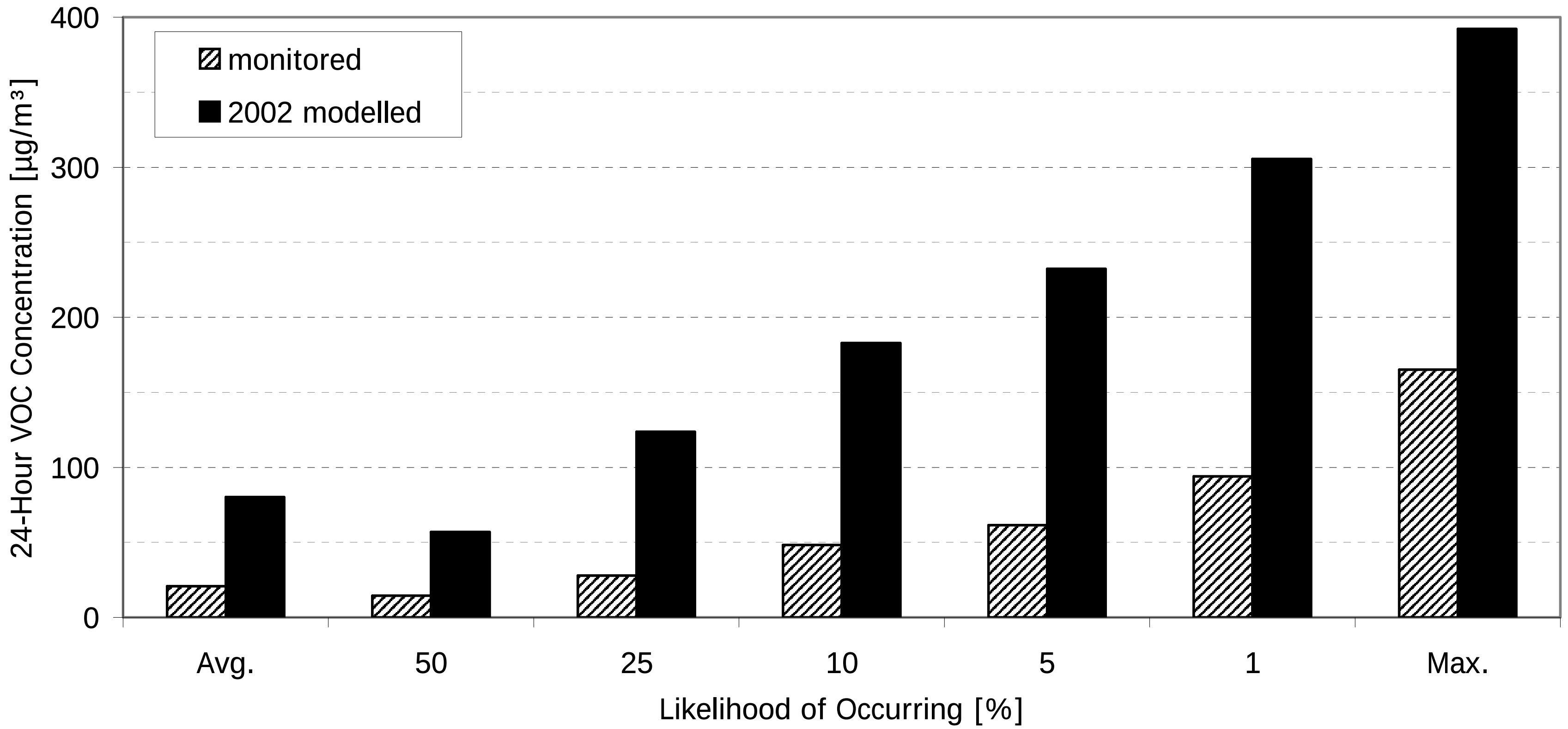
FIGURE: 31

2.4.3.6 Volatile Organic Compound Predictions

The VOC monitoring conducted in the region relies on non-continuous techniques that collect 24-hour samples on a set schedule. Since continuous monitoring data are not available for VOCs in the region, it was not possible to generate fractional bias plots and Quartile-Quartile plots for VOCs. Therefore, an alternate method was used to present a comparison of monitored and observed data.

Figure 32 presents a percentile graph for Existing Scenario 24-hour VOC predictions and monitored data at the Fort McKay station for 2002. The percentile graph indicates that the CALPUFF modelling over predicted 24-hour VOC concentrations at the Fort McKay station.

Figure 33 presents a percentile graph for Existing Scenario 24-hour VOC predictions and observed data at the Millennium station for 2002. The monitored data is lower than the predicted 24-hour concentrations. This over prediction is likely related to the assumption that 100% of the diluent lost to the Suncor tailings ponds is released as VOC emissions during the warmer months of the year (Section 3.2 of this appendix). The percentile graph indicates that the CALPUFF modelling over predicted VOC concentrations at the Millennium station.



PROJECT

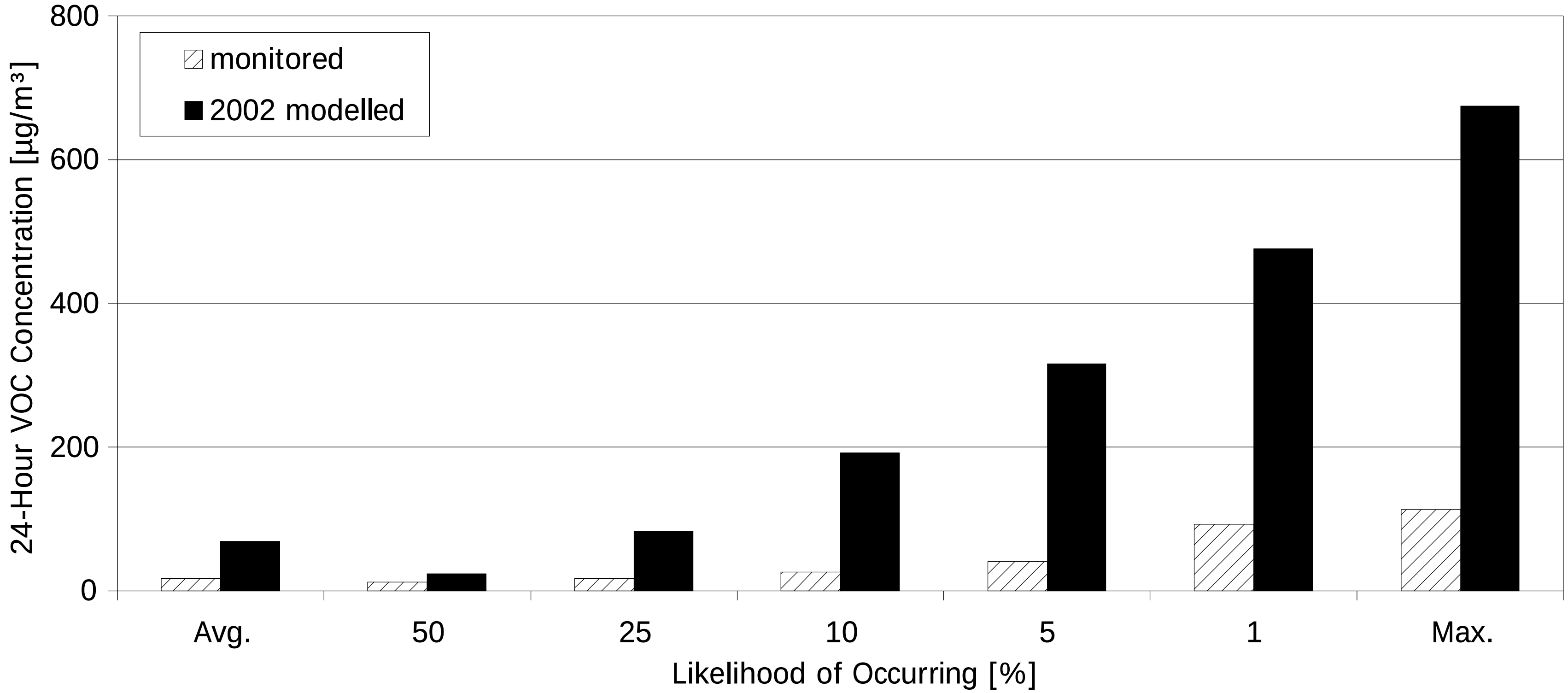
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF MONITORED AND MODELLED VOLATILE ORGANIC COMPOUND CONCENTRATIONS AT THE FORT McKAY STATION

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No. Fort Mckay
DESIGN	MS	31/01/08	SCALE AS SHOWN REV. 0
CADD	PSR	31/01/08	FIGURE: 32
CHECK	MS	14/04/08	
REVIEW	IGG	17/04/08	



PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

COMPARISON OF MONITORED AND MODELLED VOLATILE ORGANIC COMPOUND CONCENTRATIONS AT THE MILLENNIUM STATION

MEG ENERGY CORP.

PROJECT	07.1346.0009.8000		FILE No.	Millennium station
DESIGN	MS	31/01/08	SCALE AS SHOWN	REV. 0
CADD	TRE	14/04/08		
CHECK	MS	16/04/08	**FIGURE: 33**	
REVIEW	IGG	17/04/08		

3 EMISSION SOURCE DETAILS

This section of the appendix provides additional details on key information used to calculate air emission information in the air quality assessment. Emission Rate terminology

In the Project air quality assessment, atmospheric emission rates were calculated for the following:

- **Normal Operations (Calendar-day)**: The average annual release rates are often referred to as "calendar-day" emissions and are determined by dividing the annual emissions from the facility by 365 days. These emission rates include releases during upset conditions and are comparable to the licensed emission limits from the facilities. The calendar-day emission rates have been used for evaluating long-term (i.e., annual) concentrations and deposition patterns in the region.
- **Normal Operations (Stream-day)**: The emissions during normal operations are often referred to as "stream-day" emissions, as these represent conditions when all pollution control and facility processes are operating. The normal operating emission rates are typically lower than the operating license limits since they exclude releases during upset conditions. The stream-day emissions represent the release rates that occur on a day-to-day basis and hence have been used for evaluating short-term (i.e., 1-hour, 8-hour and 24-hour) concentrations within the region. The calendar-day emission rates are unlikely to occur for more than a few brief moments during the year since release rates will occur at either the stream-day or upset rates. Therefore, the use of calendar-day or licensed emission rates is not appropriate for evaluating short-term concentrations of compounds such as SO_2. For most of the compounds evaluated, there is no appreciable difference between the calendar day and stream day emission rates. Consequently, these emission rates have been discussed in terms of tonnes per day (t/d) and have not been categorized as either stream-day or calendar-day.
- **Facility Upset Events**: Facility upset events occur when pollution control systems or facility processes are not operating as planned. Typically, emission rates during upset conditions are much higher than during normal operating conditions. Only upsets associated with the Project were evaluated since upset events at other facilities in the region will have been evaluated as part of their respective project applications.

3.1.1 MEG Project Emissions in the Project Case

The MEG Project emissions sources considered as part of the Project Case air quality assessment are as follows:

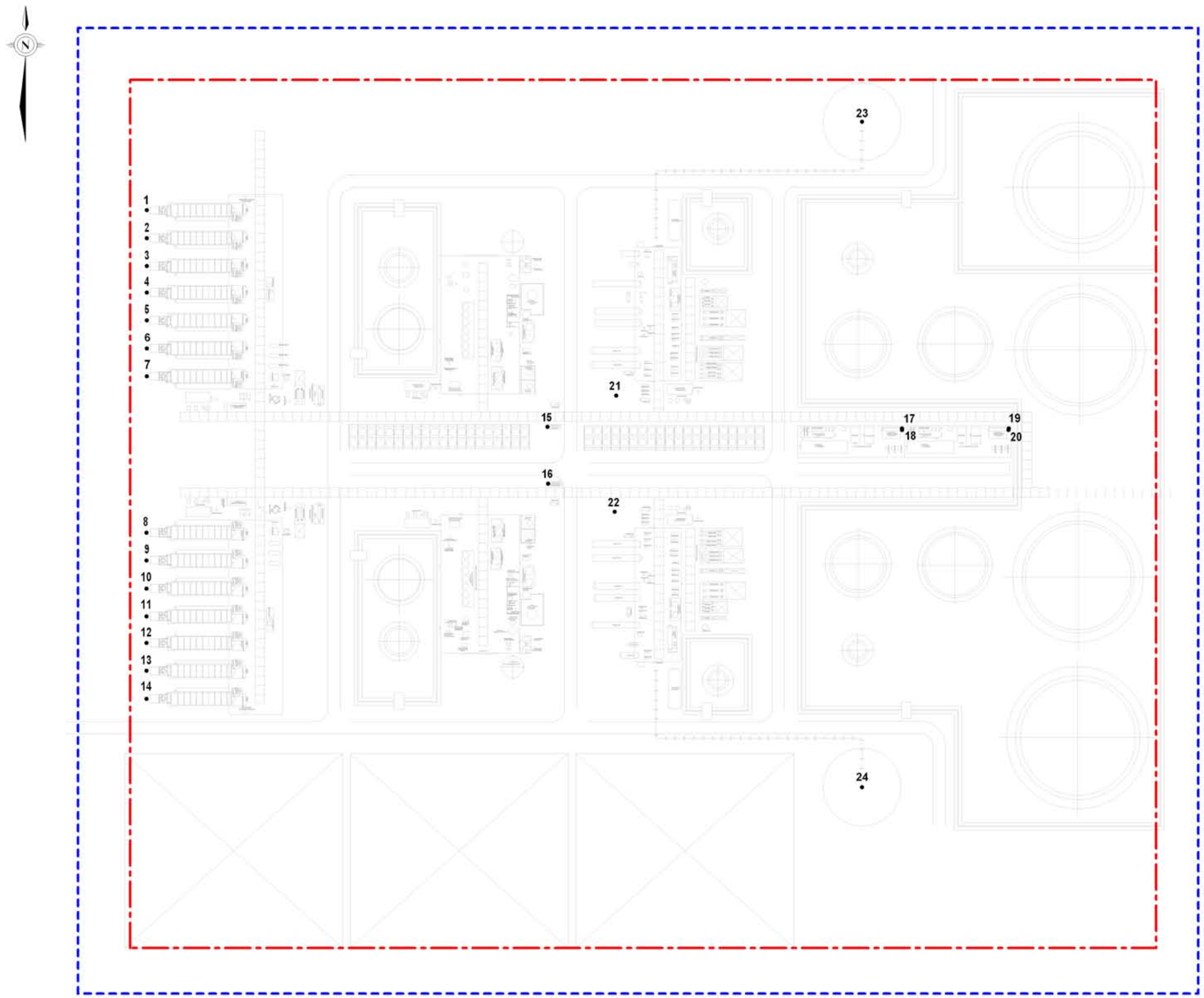
- 14 Once Through Steam Generators (OTSGs) fired on sweetened produced gas at Plant Sites 3A and 3B;
- two glycol heaters fired on sweetened produced gas at Plant Sites 3A and 3B;
- two slop treaters fired on sweetened produced gas at Plant Sites 3A and 3B;
- two amine preheaters fired on sweetened produced gas at Plant Sites 3A and 3B;
- two flares, each has a natural gas fired pilot running continuously at Plant Sites 3A and 3B;
- one Sulphur Recovery Unit (SRU) incinerator at the Central Plant Site; and
- plant fugitive emissions from tank losses as well as leaks from piping and other process equipment.

The plot plans of the Plant Site 3A, Plant Site 3B and the Central Plant that were used in this assessment are provided in Figures 34a, 34b and 34c, respectively. The locations of the equipment stacks and flares are also shown in these figures.

3.1.1.1 Steam Generation

There will be 14 steam generators fired on sweetened produced gas at Plant Sites 3A and 3B. The emission rates from the steam generators were determined as follows:

- the SO_2 emission rates were calculated based on a sweetened produced gas sulphur content of 4 ppmv (due to sulphur recovery);
- the NO_X emission rates were calculated assuming the units would meet the emission limits in the CCME *National Emission Guideline for Commercial/Industrial Boilers and Heaters* (CCME 1998);
- the CO, $PM_{2.5}$, VOC, benzene and PAH emission rates were calculated based on emission factors from Chapter 1.4 of AP-42 (U.S. EPA 1995); and
- the TRS and H_2S emission rates were assumed to be negligible.



Sources

ID	Description	Stack Height [m]
1	Phase 3A-Steam Generator 1	30.0
2	Phase 3A-Steam Generator 2	30.0
3	Phase 3A-Steam Generator 3	30.0
4	Phase 3A-Steam Generator 4	30.0
5	Phase 3A-Steam Generator 5	30.0
6	Phase 3A-Steam Generator 6	30.0
7	Phase 3A-Steam Generator 7	30.0
8	Phase 3A-Steam Generator 8	30.0
9	Phase 3A-Steam Generator 9	30.0
10	Phase 3A-Steam Generator 10	30.0
11	Phase 3A-Steam Generator 11	30.0
12	Phase 3A-Steam Generator 12	30.0
13	Phase 3A-Steam Generator 13	30.0
14	Phase 3A-Steam Generator 14	30.0
15	Phase 3A-Glycol Heater 1	15.0
16	Phase 3A-Glycol Heater 2	15.0
17	Phase 3A-Slop Treater 1A	15.0
18	Phase 3A-Slop Treater 1B	15.0
19	Phase 3A-Slop Treater 2A	15.0
20	Phase 3A-Slop Treater 2B	15.0
21	Phase 3A-Amine Preheater 1	15.0
22	Phase 3A-Amine Preheater 2	15.0
23	Phase 3A-Flare 1	55.2
24	Phase 3A-Flare 2	55.2

LEGEND

MEG PLANT 3A BOUNDARY.

MEG PLANT 3A FUGITIVE EMISSIONS AREA SOURCES.

200 0 200
SCALE METRES

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.)
USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR
DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

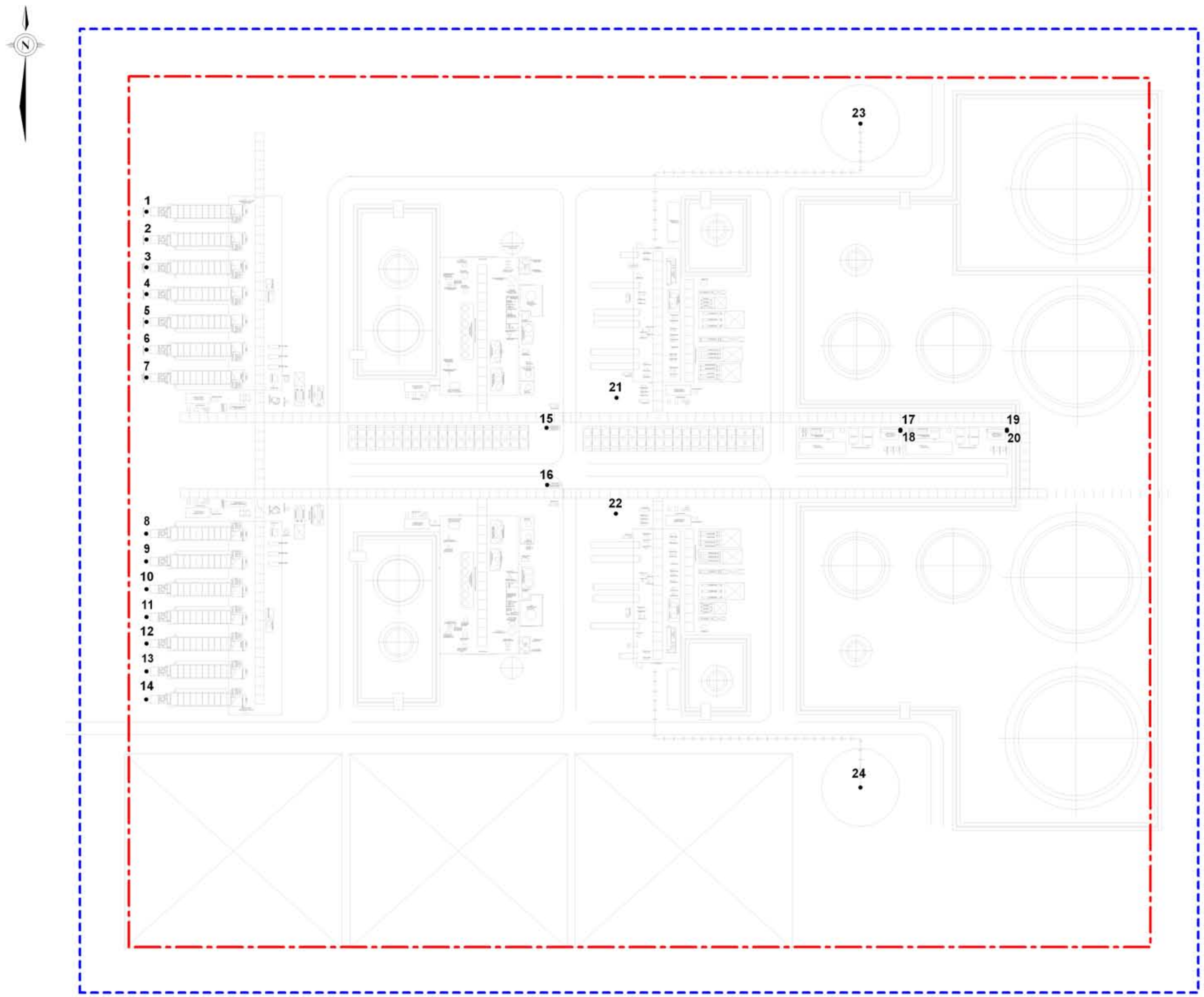
MEG PLANT 3A PLOT PLAN

MEG ENERGY CORP.

DESIGN	MS	06/02/08
AIR	DK	19/02/08
CHECK	MS	20/02/08
REVIEW	IGG	17/04/08

FIGURE: 34a

R:/ACTIVE/_2007/1346/07-1346-0009 MEG CHRISTINA LAKE REGIONAL EXPANSION/8000 AIR/8070 EIA REPORTING/FIGURES/PLANT_3B_PLOT_PLAN.srf



Sources

ID	Description	Stack Height [m]
1	Phase 3B-Steam Generator 1	30.0
2	Phase 3B-Steam Generator 2	30.0
3	Phase 3B-Steam Generator 3	30.0
4	Phase 3B-Steam Generator 4	30.0
5	Phase 3B-Steam Generator 5	30.0
6	Phase 3B-Steam Generator 6	30.0
7	Phase 3B-Steam Generator 7	30.0
8	Phase 3B-Steam Generator 8	30.0
9	Phase 3B-Steam Generator 9	30.0
10	Phase 3B-Steam Generator 10	30.0
11	Phase 3B-Steam Generator 11	30.0
12	Phase 3B-Steam Generator 12	30.0
13	Phase 3B-Steam Generator 13	30.0
14	Phase 3B-Steam Generator 14	30.0
15	Phase 3B-Glycol Heater 1	15.0
16	Phase 3B-Glycol Heater 2	15.0
17	Phase 3B-Slop Treater 1A	15.0
18	Phase 3B-Slop Treater 1B	15.0
19	Phase 3B-Slop Treater 2A	15.0
20	Phase 3B-Slop Treater 2B	15.0
21	Phase 3B-Amine Preheater 1	15.0
22	Phase 3B-Amine Preheater 2	15.0
23	Phase 3B-Flare 1	55.2
24	Phase 3B-Flare 2	55.2

LEGEND

MEG PLANT 3B BOUNDARY.

MEG PLANT 3B FUGITIVE EMISSIONS AREA SOURCES.

200 0 200
SCALE METRES

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.)
USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR
DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT
CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE
MEG PLANT 3B PLOT PLAN

MEG ENERGY CORP.

DESIGN	MS	06/02/08
AIR	DK	19/02/08
CHECK	MS	20/02/08
REVIEW	IGG	17/04/08

FIGURE: 34b

R:/ACTIVE/_2007/1346/07-1346-0009 MEG CHRISTINA LAKE REGIONAL EXPANSION/8000 AIR/8070 EIA REPORTING/FIGURES/CENTRAL_PLANT-SITE_PLOT_PLAN.srf

Sources

ID	Description	Stack Height [m]
1	Pilot-Steam Generator	30.0
2	Pilot-Glycol Heater	7.5
3	Pilot-Low Pressure Flare	13.2
4	Pilot-High Pressure Flare	31.5
5	Phase 2-Steam Geberator	30.0
6	Phase 2-Cogeneration Unit	24.0
7	Phase 2-Glycol Heater	5.0
8	Phase 2-Slop Treater 1	9.0
9	Phase 2-Slop Treater 2	9.0
10	Phase 2-Flare	55.2
11	Phase 2B-Steam Generator 1	30.0
12	Phase 2B-Steam Generator 2	30.0
13	Phase 2B-Steam Generator 3	30.0
14	Phase 2B-Cogeneration Unit	24.0
15	Phase 2B-Glycol Heater	15.0
16	Phase 2B-Amine Preheater	15.0
17	Phase 2B-Flare	55.2
18	SRU Incinerator 1	45.7
19	SRU Incinerator 2	80.0
20	SRU Incinerator 3	80.0

LEGEND

MEG CENTRAL PLANT SITE BOUNDARY.

MEG CENTRAL PLANT SITE FUGITIVE EMISSIONS AREA SOURCES.

200 0 200

SCALE METRES

SCALE: AS SHOWN

REFERENCE

ALBERTA DIGITAL DATA OBTAINED FROM ALTALIS LTD. (SEPTEMBER 2004.)
USED UNDER LICENSE. PROJECTION: TRANSVERSE MERCATOR
DATUM: NAD 83 COORDINATE SYSTEM: UTM ZONE 12

PROJECT

CHRISTINA LAKE REGIONAL PROJECT - PHASE 3

TITLE

MEG CENTRAL PLANT SITE PLOT PLAN

MEG ENERGY CORP.

DESIGN	MS	06/02/08
AIR	DK	19/02/08
CHECK	MS	16/04/08
REVIEW	IGG	17/04/08

FIGURE: 34c

Table 14 provides a summary of steam generator emission rates from the Project.

Table 14 Summary of the Project Case Emissions

Source	Duty Rating [MW][a]	Emission Rates[b]						
		Stream-day SO_2 [t/sd]	Calendar-day SO_2 [t/cd]	NO_X [t/d]	CO [t/d]	$PM_{2.5}$ [t/d]	VOC [t/d]	TRS [t/d]
Plant 3A								
steam generator 1	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 2	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 3	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 4	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 5	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 6	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 7	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 8	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 9	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 10	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 11	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 12	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 13	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 14	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
glycol heater 1	24.4	0.001	0.001	0.055	0.075	0.007	0.005	—
glycol heater 2	24.4	0.001	0.001	0.055	0.075	0.007	0.005	—
slop treater 1	3.6	0.000	0.000	0.008	0.011	0.001	0.001	—
slop treater 2	3.6	0.000	0.000	0.008	0.011	0.001	0.001	—
amine preheater 1	5.2	0.000	0.000	0.012	0.016	0.001	0.001	—
amine preheater 2	5.2	0.000	0.000	0.012	0.016	0.001	0.001	—
flare pilot 1	—	0.000	0.000	0.001	0.008	—	0.002	—
flare pilot 2	—	0.000	0.000	0.001	0.008	—	0.002	—
plant fugitives	—	—	—	—	—	—	0.011	0.021
Plant 3B								
steam generator 1	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 2	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 3	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 4	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 5	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 6	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 7	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 8	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 9	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 10	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 11	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—

Table 14 Summary of the Project Case Emissions (continued)

Source	Duty Rating [MW][a]	Emission Rates[b]						
		Stream-day SO_2 [t/sd]	Calendar-day SO_2 [t/cd]	NO_X [t/d]	CO [t/d]	$PM_{2.5}$ [t/d]	VOC [t/d]	TRS [t/d]
steam generator 12	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 13	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
steam generator 14	96.2	0.003	0.003	0.332	0.294	0.027	0.019	—
glycol heater 1	24.4	0.001	0.001	0.055	0.075	0.007	0.005	—
glycol heater 2	24.4	0.001	0.001	0.055	0.075	0.007	0.005	—
slop treater 1	3.6	0.000	0.000	0.008	0.011	0.001	0.001	—
slop treater 2	3.6	0.000	0.000	0.008	0.011	0.001	0.001	—
amine preheater 1	5.2	0.000	0.000	0.012	0.016	0.001	0.001	—
amine preheater 2	5.2	0.000	0.000	0.012	0.016	0.001	0.001	—
flare pilot 1	—	0.000	0.000	0.001	0.008	—	0.002	—
flare pilot 2	—	0.000	0.000	0.001	0.008	—	0.002	—
plant fugitives	—	—	—	—	—	—	0.011	0.021
Central Plant Site								
SRU incinerator	—	0.835	0.835	0.002	0.002	0.000	0.000	—
Total[c]		**0.909**	**0.909**	**9.612**	**8.676**	**0.782**	**0.595**	**0.043**

(a) Duty ratings represent the input ratings based on Higher Heating Value (HHV).

(b) Emissions are expressed as tonnes per stream-day (t/sd), tonnes per calendar-day (t/cd) or tonnes per day (t/d).

(c) Some numbers are rounded for presentation purposes. Therefore, it may appear that the totals do not equal the sum of the individual values.

3.1.1.2 Glycol Heater

There will be two glycol heaters fired on sweetened produced gas at Plant Sites 3A and 3B. The emission rates from the glycol heaters were determined as follows:

- the SO_2 emission rates were calculated based on a sweetened produced gas sulphur content of 4 ppmv (due to sulphur recovery);
- the NO_X emission rates were calculated assuming the units would meet the emission limits in the CCME *National Emission Guideline for Commercial/Industrial Boilers and Heaters* (CCME 1998);
- the CO, $PM_{2.5}$, VOC, benzene and PAH emission rates were calculated based on emission factors from Chapter 1.4 of AP-42 (U.S. EPA 1995); and
- the TRS and H_2S emission rates were assumed to be negligible.

Table 14 provides a summary of glycol heater emission rates from the proposed Project.

3.1.1.3 Slop Treater

There will be two slop treaters fired on sweetened produced gas at Plant Sites 3A and 3B. The emission rates from the slop treaters were determined as follows:

- the SO_2 emission rates were calculated based on a sweetened produced gas sulphur content of 4 ppmv (due to sulphur recovery);
- the NO_X emission rates were calculated assuming the units would meet the emission limits in the CCME *National Emission Guideline for Commercial/Industrial Boilers and Heaters* (CCME 1998);
- the CO, $PM_{2.5}$, VOC, benzene and PAH emission rates were calculated based on emission factors from Chapter 1.4 of AP-42 (U.S. EPA 1995); and
- the TRS and H_2S emission rates were assumed to be negligible.

Table 14 provides a summary of slop treater emissions from the proposed Project.

3.1.1.4 Amine Preheater

There will be two amine preheaters fired on sweetened produced gas at Plant 3A and 3B. The emission rates from the amine preheaters were determined as follows:

- the SO_2 emission rates were calculated based on a sweetened produced gas sulphur content of 4 ppmv (due to sulphur recovery);
- the NO_X emission rates were calculated assuming the units would meet the emission limits in the CCME *National Emission Guideline for Commercial/Industrial Boilers and Heaters* (CCME 1998);
- the CO, $PM_{2.5}$, VOC, benzene and PAH emission rates were calculated based on emission factors from Chapter 1.4 of AP-42 (U.S. EPA 1995); and
- the TRS and H_2S emission rates were assumed to be negligible.

Table 14 provides a summary of amine preheater emissions from the Project.

3.1.1.5 Flare

There will be no continuous flaring at the Project. However, emissions from the flare pilots were included in the assessment. The SO_2 emission rates were calculated based on a natural gas sulphur content of 4 ppmv. The NO_X, CO and VOC emission rates were calculated based on emissions factors from Chapter 13.5 of AP-42 (U.S. EPA 1995). A summary of the flare pilot emissions from the Project is included in Table 14.

3.1.1.6 Plant Fugitive Emission Sources

Plant fugitive emissions can be related to, but are not limited to, tank losses and leaks in piping and other process equipment. Site-wide plant fugitive emissions including VOCs and TRS were scaled off of the plant fugitive emissions from the Firebag SAGD Project (Suncor 2003) based on bitumen production. A summary of the plant fugitive emissions from the Project is included in Table 14.

3.1.1.7 Sulphur Recovery Unit Incinerator

There will be one additional SRU incinerator at the Central Plant Site. The emission rates from the SRU incinerator were calculated as follows:

- the SO_2 emission rates were calculated based on a sulphur inlet rate of 11 t/d and a sulphur recovery rate of 96.2% as per Alberta Energy Resources Conservation Board (ERCB) sulphur recovery guidelines (EUB 2001b);
- the NO_X, CO, $PM_{2.5}$, VOC, benzene and PAH emission rates were calculated based on emission factors from Chapter 1.4 of AP-42 (U.S. EPA 1995); and
- the TRS and H_2S emission rates were assumed to be negligible.

Table 14 provides a summary of SRU incinerator emissions from the Project.

One of the two existing SRU incinerators at the Central Plant Site will be operating at a sulphur inlet rate of 5 t/d and a corresponding sulphur recovery rate of 90%, and the other will be operating at a sulphur inlet rate of 11 t/d and a corresponding sulphur recovery rate of 96.2%.

3.2 VARIABLE TAILINGS POND EMISSIONS FROM OIL SANDS MINES

Suncor Energy Inc., Canadian Natural Resources Limited and Imperial Oil Resources Limited provided variable emission rates to represent their tailings pond VOC and TRS emissions for use in this air quality assessment (Suncor 2005, Canadian Natural 2003, Imperial Oil 2005). Suncor's Pond 2/3 and South Tailings Pond, Canadian Natural's Horizon tailings pond and Imperial Oil's Kearl tailings pond emissions were assessed as variable emissions. The monthly variable emission scheme from Appendix II of the Voyageur Project Environmental Impact Assessment (EIA), Volume 3 (Suncor 2005) and from the Appendix 2B of the Kearl Project EIA, Volume 5 (Imperial Oil 2005) were used in the air quality assessment.

3.3 SOURCE INPUTS

One of the most important factors in any dispersion modelling is the source input characteristics used to simulate the ground-level concentration or deposition values. Tables A-1 and A-2 of Attachment A present the point and area source input characteristics for the Existing and Approved Case. Table B-1 of Attachment B present the point and area source input characteristics for the Project emission sources. Tables C-1 and C-2 of Attachment C present the point and area source input characteristics for the Planned Development Case.

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ATTACHMENT A

POINT AND AREA SOURCE EMISSIONS CHARACTERISTICS USED IN THE EXISTING AND APPROVED CASE

Table A1 Existing and Approved Case Point Source Emission Characteristics

No.	Source Description	UTM Coordinates [m][a]		Base Elevation [m]	Stack Height [m][b]	Stack Diameter [m][b]	Exit Velocity [m/s]	Exit Temperature [K]	Emission Rate [t/d]				
		Easting	Northing						SO_2[c]	NO_X	CO	$PM_{2.5}$	VOC
MEG Energy Corp. – Christina Lake Regional Project - Pilot													
	MEG Christina Lake Pilot – Steam Generator	517,796	6,168,843	579.0	30.00	1.384	20.7	445	0.002	0.199	0.177	0.016	0.012
	MEG Christina Lake Pilot – Glycol Heater	517,828	6,168,816	579.0	7.50	0.508	4.5	434	0.000	0.006	0.005	0.000	0.000
	MEG Christina Lake Pilot – Low Pressure Flare	517,870	6,168,764	579.0	13.16	2.397	0.2	1,273	0.000	0.001	0.005	0.000	0.001
	MEG Christina Lake Pilot – High Pressure Flare	517,850	6,168,732	579.0	31.46	2.878	0.1	1,273	0.000	0.001	0.005	0.000	0.001
MEG Energy Corp. – Christina Lake Regional Project - Phase 2													
	MEG Christina Lake Phase 2 – Steam Generator	517,772	6,168,836	579.0	30.00	1.676	19.7	445	0.002	0.283	0.251	0.023	0.016
	MEG Christina Lake Phase 2 – Cogeneration Unit	517,704	6,168,835	579.0	24.00	5.182	21.4	437	0.012	2.447	1.426	0.119	0.053
	MEG Christina Lake Phase 2 – Glycol Heater	517,818	6,168,886	579.0	5.00	1.016	5.8	434	0.000	0.021	0.028	0.003	0.002
	MEG Christina Lake Phase 2 – Slop Treater 1	517,867	6,168,901	579.0	9.00	0.610	5.3	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 2 – Slop Treater 2	517,867	6,168,900	579.0	9.00	0.610	5.3	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 2 – Flare	517,874	6,169,058	579.0	55.17	5.753	0.0	1,273	0.000	0.001	0.007	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 2B													
	MEG Christina Lake Phase 2B – Steam Generator 1	517,373	6,169,140	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Steam Generator 2	517,378	6,169,122	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Steam Generator 3	517,383	6,169,105	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Cogeneration Unit	517,632	6,168,815	579.0	24.00	5.182	21.4	437	0.012	2.447	1.426	0.119	0.053
	MEG Christina Lake Phase 2B – Glycol Heater	517,639	6,169,235	579.0	15.00	1.524	9.5	618	0.001	0.051	0.070	0.006	0.005
	MEG Christina Lake Phase 2B – Amine Preheater	517,917	6,168,990	579.0	15.00	0.305	76.3	533	0.000	0.019	0.025	0.002	0.002
	MEG Christina Lake Phase 2B – Flare	517,860	6,169,109	579.0	55.18	7.191	0.0	1,273	0.000	0.001	0.007	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project													
	MEG Christina Lake Regional Project – SRU Incinerator 1	517,929	6,168,916	579.0	45.70	0.610	6.9	873	0.000	0.001	0.001	0.000	0.000
	MEG Christina Lake Regional Project – SRU Incinerator 2	517,950	6,168,923	579.0	80.00	0.406	18.3	873	1.496	0.002	0.002	0.000	0.000
EnCana Corporation – Christina Lake Thermal Project													
	EnCana Christina Lake Phase 1B – Steam Generator 1 and Space Heaters	506,877	6,159,497	573.2	25.90	1.370	24.7	501	0.351	0.237	0.202	0.019	0.013
	EnCana Christina Lake Phase 1B – Steam Generator 2	506,871	6,159,489	573.2	15.20	0.910	16.3	495	0.103	0.044	0.058	0.005	0.004
	EnCana Christina Lake Phase 1B – Steam Generator 3	506,892	6,159,505	574.1	27.00	1.680	21.0	495	0.446	0.293	0.249	0.023	0.016
	EnCana Christina Lake Phase 2 – Steam Generator 1 and Heater	512,530	6,161,023	573.3	25.91	1.372	26.1	458	0.704	0.272	0.237	0.021	0.011
	EnCana Christina Lake Phase 2 – Steam Generator 2	512,528	6,161,023	573.3	25.91	1.372	26.1	458	0.565	0.182	0.162	0.015	0.011
	EnCana Christina Lake Phase 2 – Steam Generator 3	512,526	6,161,023	573.3	25.91	1.372	26.1	458	0.565	0.182	0.162	0.015	0.011
	EnCana Christina Lake Phase 2 – Steam Generator 4	512,524	6,161,023	573.3	25.91	1.372	26.1	458	0.565	0.182	0.162	0.015	0.011
	EnCana Christina Lake Phase 3 – Steam Generator 1 and Heater	510,589	6,158,047	577.2	25.91	1.372	26.1	458	0.704	0.272	0.237	0.021	0.011
	EnCana Christina Lake Phase 3 – Steam Generator 2	510,587	6,158,047	577.2	25.91	1.372	26.1	458	0.565	0.182	0.162	0.015	0.011
	EnCana Christina Lake Phase 3 – Steam Generator 3	510,585	6,158,047	577.2	25.91	1.372	26.1	458	0.565	0.182	0.162	0.015	0.011
	EnCana Christina Lake Phase 3 – Steam Generator 4	510,583	6,158,047	577.2	25.91	1.372	26.1	458	0.565	0.182	0.162	0.015	0.011
EnCana Corporation – Foster Creek Pilot													
	EnCana Foster Creek Pilot – Steam Generator 1, Boilers and Plant Fugitives	529,437	6,102,950	670.6	12.20	1.070	10.8	467	0.092	0.201	0.069	0.006	0.017
	EnCana Foster Creek Pilot – Steam Generator 2	529,437	6,102,963	670.6	8.50	0.910	14.7	467	0.072	0.153	0.054	0.005	0.004
	EnCana Foster Creek Pilot – Steam Generator 3	529,437	6,102,972	670.6	8.90	1.000	12.8	467	0.072	0.041	0.054	0.005	0.004
EnCana Corporation – Foster Creek Phases 1 and 2													
	EnCana Foster Creek Phase 1 – Cogeneration Units	529,657	6,102,420	670.0	25.90	3.660	21.1	448	1.420	1.834	1.251	0.101	0.044
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 1, Heaters and Wellpad Heaters	529,725	6,102,556	670.5	27.00	1.370	15.6	447	0.257	0.340	0.268	0.026	0.022
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 2	529,718	6,102,546	670.5	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 3	529,675	6,102,590	670.5	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 4	529,668	6,102,580	670.5	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 5	529,702	6,102,520	670.4	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 6	529,787	6,102,902	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 7	529,775	6,102,911	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 8	529,763	6,102,919	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 9	529,750	6,102,928	670.8	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 10	529,824	6,102,847	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 11	529,833	6,102,859	670.6	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 12	529,841	6,102,871	670.5	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 13	529,850	6,102,884	670.5	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 14	529,858	6,102,896	670.4	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 15	529,867	6,102,909	670.3	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
EnCana Corporation – Gas Plants and Field Compressors													
	EnCana – North Caribou Gas Plant	526,855	6,099,971	673.9	8.79	0.510	29.6	632	0.000	0.860	2.311	0.135	0.025
	EnCana – South Caribou Gas Plant	524,250	6,089,020	701.0	12.20	1.520	32.3	733	0.000	0.660	1.450	0.070	0.019
	EnCana – Primrose North Gas Plant	512,775	6,127,525	703.5	11.81	0.450	34.2	748	0.000	0.830	0.190	0.020	0.024
	EnCana – Field Compressor 1	535,684	6,076,979	670.9	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 2	526,615	6,093,106	702.6	3.70	0.130	23.6	830	0.000	0.071	0.005	0.000	0.002
	EnCana – Field Compressor 3	527,003	6,096,346	691.1	6.80	0.130	35.0	811	0.000	0.433	0.034	0.001	0.013
	EnCana – Field Compressor 4	524,195	6,089,451	699.8	4.70	0.100	25.8	836	0.000	0.036	0.003	0.000	0.001
	EnCana – Field Compressor 5	493,666	6,095,053	677.6	7.00	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 6	526,589	6,097,550	685.0	7.00	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 7	529,810	6,102,030	669.6	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 8	529,407	6,101,620	666.1	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 9	518,847	6,102,780	670.7	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 10	509,386	6,107,214	638.8	6.80	0.130	35.0	811	0.000	0.217	0.017	0.001	0.006
	EnCana – Field Compressor 11	502,836	6,117,762	671.0	8.30	0.360	37.0	649	0.000	0.053	0.004	0.000	0.002
	EnCana – Field Compressors 12 and 13	479,998	6,119,024	672.3	6.90	0.300	21.5	886	0.000	0.189	0.015	0.000	0.005
	EnCana – Field Compressor 14	537,288	6,080,634	708.2	5.60	0.130	34.0	813	0.000	0.120	0.009	0.000	0.003
	EnCana – Field Compressor 15	537,279	6,081,845	712.3	5.60	0.130	34.0	813	0.000	0.241	0.019	0.001	0.007
	EnCana – Field Compressor 16	530,734	6,085,442	724.0	5.60	0.130	34.0	813	0.000	0.120	0.009	0.000	0.003
	EnCana – Field Compressor 17	524,600	6,089,855	700.0	3.70	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 18	516,045	6,091,432	699.6	6.70	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 19	528,995	6,102,432	666.6	5.60	0.130	34.0	813	0.000	0.241	0.019	0.001	0.007
	EnCana – Field Compressor 20	530,210	6,102,842	666.7	5.60	0.130	34.0	813	0.000	0.120	0.009	0.000	0.003
	EnCana – Field Compressor 21	531,405	6,106,092	662.0	10.00	0.300	47.1	738	0.000	0.121	0.009	0.000	0.004
	EnCana – Field Compressor 22	494,256	6,111,289	652.0	3.70	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 23	519,151	6,120,629	698.8	6.70	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 24	532,980	6,129,210	706.7	6.70	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 25	527,637	6,135,649	648.8	3.70	0.130	23.6	830	0.000	0.071	0.005	0.000	0.002
Devon Canada Corporation – Jackfish SAGD Project													
	Devon Jackfish – Steam Generator 1	507,936	6,153,851	610.6	25.90	1.680	18.3	461	1.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 2	507,946	6,153,833	610.7	25.90	1.680	18.3	461	1.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 3	507,951	6,153,825	610.8	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 4	507,961	6,153,807	611.0	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 5	507,982	6,153,771	611.3	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 6	507,992	6,153,753	611.4	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Glycol Heaters	508,036	6,153,741	611.5	5.50	0.460	8.9	561	0.000	0.010	0.008	0.000	0.000
Devon Canada Corporation – Compressor Stations													
	Devon – Hangingstone Compressor Station	469,198	6,236,234	648.3	11.60	0.310	37.4	862	0.000	1.146	0.089	0.003	0.033
	Devon – Surmont Compressor Station	501,167	6,216,280	679.1	10.00	0.300	20.0	773	0.000	4.359	0.339	0.011	0.126
	Devon – Surmont West Compressor Station	486,562	6,218,730	739.6	10.00	0.300	20.0	773	0.000	1.743	0.135	0.004	0.050
	Devon – Pony Creek Compressor Station 1	491,500	6,198,700	647.8	8.54	0.250	60.6	863	0.000	0.055	0.004	0.000	0.002
	Devon – Pony Creek Compressor Station 2	491,500	6,198,700	647.8	8.54	0.250	60.6	863	0.000	0.055	0.004	0.000	0.002
	Devon – Kirby North Compressor Station	505,784	6,157,211	580.6	10.00	0.300	20.0	773	0.000	0.040	0.140	0.000	0.001
	Devon – Kirby South Compressor Station	517,659	6,147,123	640.5	11.00	0.250	34.5	878	0.000	0.739	0.057	0.002	0.021
	Devon – Chard Compressor Station	508,197	6,175,417	612.7	10.00	0.300	20.0	773	0.000	0.304	0.024	0.001	0.009
	Devon – Leismer East Compressor Station	494,777	6,167,326	554.6	13.80	0.590	35.8	644	0.000	3.012	0.234	0.007	0.087
Orion Oil Canada Ltd. – Whitesands Pilot													
	Orion Oil Whitesands Pilot – Steam Generator	484,277	6,168,716	585.0	12.30	1.520	5.5	477	0.000	0.047	0.056	0.005	0.004
	Orion Oil Whitesands Pilot – Compressors	484,216	6,168,723	586.0	6.10	0.300	34.3	720	0.000	0.210	0.191	0.003	0.041
	Orion Oil Whitesands Pilot – Combustion Vent Stack	484,315	6,168,851	578.8	35.00	0.203	121.2	353	0.075	0.000	9.124	0.000	0.042
ConocoPhillips Canada Resource Ltd. – Surmount Commercial SAGD Project													
	ConocoPhillips Surmont – Phase 1	503,363	6,227,513	626.8	27.00	1.676	20.1	469	0.015	0.698	1.103	0.082	0.072
	ConocoPhillips Surmont – Phase 2	504,122	6,227,796	613.8	27.00	1.676	20.1	469	0.283	2.398	3.803	0.282	0.249
	ConocoPhillips Surmont – SRU Incinerator	504,354	6,227,661	606.5	30.50	0.915	0.9	923	0.100	0.000	0.120	0.000	0.008
Petro-Canada Oil and Gas – Meadow Creek In-Situ Project													
	Petro-Canada Meadow Creek Phase I – Cogeneration Units and Plant Fugitives	482,144	6,242,326	719.4	30.50	6.096	23.6	478	0.752	6.007	4.388	0.368	0.160
	Petro-Canada Meadow Creek Phase I – OTSGs, Glycol Heaters and Flares	482,251	6,242,013	717.8	27.00	1.756	20.6	478	0.728	1.173	1.232	0.112	0.081
Petro-Canada Oil and Gas – MacKay River Phase 1													
	Petro-Canada MacKay River Phase I – Cogeneration Unit and Plant Fugitives	445,067	6,322,175	417.7	26.20	6.310	20.0	452	0.000	3.600	3.720	0.156	0.087
	Petro-Canada MacKay River Phase I – Steam Generators and Glycol Heaters	445,136	6,322,011	415.1	27.00	1.340	27.5	553	1.000	1.408	0.726	0.036	0.091
Petro-Canada Oil and Gas – Dover SAGD Project													
	Petro-Canada Dover – Steam Generators, Heaters and Flare	444,012	6,324,240	428.8	10.90	0.540	39.7	466	0.500	0.330	0.120	0.020	0.010
OPTI Canada Inc./Nexen Canada Ltd. – Long Lake Pilot Project													
	OPTI/Nexen Long Lake Pilot – Steam Generator, Main Plant and Emergency Generators, Glycol Heater and Incinerator	504,204	6,251,133	482.1	12.92	1.520	15.2	453	0.150	0.499	0.268	0.018	0.031
OPTI Canada Inc./Nexen Canada Ltd. – Long Lake Commercial Project													
	OPTI/Nexen Long Lake – Sulphur Incinerator	503,410	6,251,145	498.0	115.00	1.524	30.0	811	7.773	0.040	0.030	0.000	0.002
	OPTI/Nexen Long Lake – Sulphur Incinerator	503,732	6,250,845	487.4	115.00	1.524	30.0	811	7.773	0.040	0.030	0.000	0.002
	OPTI/Nexen Long Lake – Cogeneration Units	503,159	6,251,532	499.2	30.00	5.180	18.2	433	1.182	4.840	3.664	0.256	0.159
	OPTI/Nexen Long Lake – Steam Generators, Heaters, Boilers and Thermal Crackers	503,237	6,251,626	498.4	30.00	1.676	18.8	464	1.693	6.011	5.226	0.474	0.342
	OPTI/Nexen Long Lake – Plant Fugitives	503,603	6,251,473	495.9	10.00	1.000	2.0	288	0.000	0.000	0.000	0.000	1.974
Connacher Oil and Gas Limited – Great Divide Oil Sands Project													
	Connacher – Great Divide Project	448,553	6,218,911	710.1	20.00	1.220	20.0	469	0.396	0.249	0.378	0.034	0.025
Canadian Natural Resources Limited – Primrose North													
	Canadian Natural Primrose North – FGD Stack 1	526,706	6,081,204	692.5	30.00	2.636	13.0	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose North – FGD Stack 2	526,715	6,081,181	692.4	30.00	2.636	13.0	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose North – OTSGs (Mixed Fuel Gas) and Glycol Heater	526,745	6,081,172	692.5	26.10	1.500	11.8	441	0.187	1.514	0.542	0.049	0.035
Canadian Natural Resources Limited – Burnt Lake													
	Canadian Natural Burnt Lake – Steam Generators, Glycol Heater and Flare Stack	541,396	6,072,999	679.8	13.50	1.100	6.1	423	0.300	0.270	0.227	0.021	0.015
Canadian Natural Resources Limited – Primrose South													
	Canadian Natural Primrose South – FGD Stack 1	527,142	6,069,603	676.8	30.00	2.175	13.0	330	0.579	1.338	0.147	0.131	0.008
	Canadian Natural Primrose South – FGD Stack 2	527,143	6,069,624	676.9	30.00	2.523	13.0	330	0.778	1.781	0.198	0.174	0.011
	Canadian Natural Primrose South – OTSGs (Natural Gas), Utility Boilers and Glycol Heaters	527,041	6,069,619	676.2	27.00	1.372	18.5	444	0.342	1.717	0.988	0.089	0.065
	Canadian Natural Primrose South – Cogeneration Unit	527,013	6,069,627	676.0	27.00	5.100	18.3	375	0.000	1.851	1.202	0.100	0.044
	Canadian Natural Primrose South – Well Pad Flare Stack	526,602	6,069,810	674.2	14.64	1.601	0.5	1,273	0.005	0.007	0.004	0.000	0.001
Canadian Natural Resources Limited – Primrose East													
	Canadian Natural Primrose East – OTSGs (Mixed Fuel Gas) and Glycol Heater	541,430	6,071,861	697.2	29.44	1.676	19.2	420	0.233	0.696	0.553	0.050	0.036
	Canadian Natural Primrose East – FGD Stack 1	541,466	6,071,727	691.2	30.00	2.641	25.9	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose East – FGD Stack 2	541,441	6,071,727	691.1	30.00	2.641	25.9	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose East – FGD Stack 3	541,416	6,071,727	691.1	30.00	2.251	25.9	330	0.617	1.459	0.157	0.143	0.009
Canadian Natural Resources Limited – Wolf Lake													
	Canadian Natural Wolf Lake – OTSGs (Mixed Fuel Gas), Utility Boilers, Fuel Gas Heater and Flare Stack	517,568	6,061,052	642.6	30.00	1.372	20.5	444	2.000	1.960	1.220	0.104	0.092
Canadian Natural Resources Limited – Horizon Oil Sands Project													
	Canadian Natural Horizon – Sulphur Plant Incinerator	455,573	6,355,395	277.1	106.70	3.400	17.0	811	11.706	0.277	0.123	0.011	0.008
	Canadian Natural Horizon – Cogeneration Units	455,922	6,354,992	277.5	38.00	5.500	21.7	405	0.028	5.147	3.383	0.281	0.120
	Canadian Natural Horizon – Hydrogen Plants	455,448	6,355,106	276.2	60.96	3.920	15.0	421	0.061	3.115	2.759	0.250	0.181
	Canadian Natural Horizon – Heaters, Boilers and Flare Stacks	455,002	6,355,298	277.3	30.50	3.000	6.2	474	0.477	7.002	6.290	0.562	0.427
Canadian Natural Resources Limited – Field Compressors													
	Canadian Natural – Field Compressor 1	533,900	6,070,290	671.0	5.49	0.102	43.0	830	0.000	0.056	0.004	0.000	0.002
	Canadian Natural – Field Compressor 2	535,461	6,079,198	694.6	7.92	0.254	37.9	886	0.000	0.390	0.022	0.001	0.008
	Canadian Natural – Field Compressor 4	520,802	6,074,255	663.2	3.66	0.102	61.6	811	0.000	0.089	0.006	0.000	0.002
	Canadian Natural – Field Compressor 5	519,594	6,061,312	641.0	3.66	0.102	43.0	830	0.000	0.056	0.004	0.000	0.002
	Canadian Natural – Field Compressors 6 and 7	537,899	6,080,840	711.5	3.66	0.102	61.6	811	0.000	0.105	0.008	0.000	0.003
	Canadian Natural – Field Compressor 8	533,429	6,079,183	692.5	3.66	0.102	61.6	811	0.000	0.089	0.006	0.000	0.002
	Canadian Natural – Field Compressor 9	532,609	6,078,774	701.4	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 10	528,122	6,079,152	685.5	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 11	517,081	6,086,385	691.2	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 12	516,749	6,061,300	643.0	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 3 and 13	543,202	6,080,894	731.6	6.71	0.203	43.1	721	0.000	0.042	0.016	0.000	0.006
	Canadian Natural – Field Compressor 14	537,047	6,085,693	722.5	3.66	0.102	61.6	811	0.000	0.089	0.006	0.000	0.002

Table A1 Existing and Approved Case Point Source Emission Characteristics (Continued)

No.	Source Description	UTM Coordinates [m][a]		Base Elevation [m]	Stack Height [m][b]	Stack Diameter [m][b]	Exit Velocity [m/s]	Exit Temperature [K]	Emission Rate [t/d]				
		Easting	Northing						SO_2[c]	NO_X	CO	$PM_{2.5}$	VOC
Canadian Natural Resources Limited – Gas Plants													
	Canadian Natural – Moose Hills Gas Plant	515,621	5,955,283	643.5	7.0	0.360	8.1	423	0.000	0.026	0.022	0.002	0.001
	Canadian Natural – Elk Point Gas Plant	510,711	5,959,730	663.6	7.0	0.360	9.9	423	0.000	0.063	0.044	0.004	0.003
	Canadian Natural – Chard Gas Plant	510,967	6,195,656	489.1	18.3	0.250	60.6	863	0.000	0.136	0.011	0.000	0.004
	Canadian Natural – Cowpar Gas Plant	523,589	6,200,560	483.9	18.0	0.177	20.0	1,273	0.500	0.460	0.036	0.001	0.013
	Canadian Natural – Kettle River Gas Plant	520,207	6,228,483	476.5	29.0	0.247	20.0	1,237	0.600	0.029	0.002	0.000	0.001
	Canadian Natural – Newby Gas Plant	510,363	6,243,820	480.0	20.0	0.247	20.0	1,237	1.080	0.062	0.005	0.000	0.002
	Canadian Natural – Wiau Lake Gas Plant	486,375	6,137,409	674.7	18.3	0.250	31.3	863	0.000	0.040	0.003	0.000	0.001
	Canadian Natural – Kirby West Gas Plant	493,678	6,135,368	701.1	18.3	0.250	31.3	863	0.000	0.037	0.003	0.000	0.001
Japan Canada Oil Sands Limited – Hangingstone Pilot In-Situ Project													
	JACOS Hangingstone – Pilot	460,281	6,241,976	558.6	30.00	0.911	19.8	369	1.630	0.700	0.530	0.040	0.040
Imperial Oil Resources Ventures Limited – Cold Lake In-Situ Project, Nabiye Expansion and Mahihkan North Expansion													
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 1	529,392	6,054,203	614.9	22.90	1.370	19.2	443	0.540	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 2	529,382	6,054,202	614.9	22.90	1.370	19.2	443	0.540	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 3	529,371	6,054,201	614.9	22.90	1.370	19.2	443	0.540	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 4	529,336	6,054,197	614.8	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 5	529,326	6,054,196	614.8	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 6	529,315	6,054,195	614.8	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Utility Steam Generators	529,302	6,054,174	614.7	16.00	1.295	11.0	523	0.000	0.148	0.144	0.013	0.009
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 1	528,940	6,054,059	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 2	528,950	6,054,060	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 3	528,960	6,054,061	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 4	528,971	6,054,063	614.0	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 5	528,982	6,054,064	614.0	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 6	528,993	6,054,065	614.0	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 7	528,948	6,053,996	613.8	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 8	528,958	6,053,997	613.8	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 9	528,969	6,053,998	613.8	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 10	528,979	6,053,999	613.9	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 11	528,990	6,054,000	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 12	529,000	6,054,002	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 1	534,185	6,051,945	608.6	22.90	1.370	19.2	443	0.775	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 2	534,175	6,051,945	608.6	22.90	1.370	19.2	443	0.775	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 3	534,164	6,051,945	608.6	22.90	1.370	19.2	443	0.775	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 4	534,129	6,051,945	608.7	22.90	1.370	19.2	443	0.000	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 5	534,118	6,051,945	608.7	22.90	1.370	19.2	443	0.000	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 6	534,108	6,051,945	608.7	22.90	1.370	19.2	443	0.000	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Utility Steam Generators	534,091	6,051,929	608.7	18.45	1.295	11.0	503	0.000	0.148	0.144	0.013	0.009
	Imperial Oil Maskwa (Plant 3) – Steam Generator 1	534,042	6,051,945	608.9	22.90	1.370	19.2	443	0.775	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 2	534,032	6,051,945	608.9	22.90	1.370	19.2	443	0.775	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 3	534,021	6,051,945	608.9	22.90	1.370	19.2	443	0.775	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 4	533,985	6,051,945	609.0	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 5	533,975	6,051,945	609.0	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 6	533,965	6,051,945	609.0	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Leming – Steam Generator 1	536,881	6,050,441	610.8	27.00	1.370	14.3	443	1.120	0.186	0.181	0.016	0.012
	Imperial Oil Leming – Steam Generator 2	536,909	6,050,493	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 3	536,910	6,050,498	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 4	536,910	6,050,503	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 5	536,910	6,050,508	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 6	536,909	6,050,512	610.7	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 7	536,908	6,050,517	610.7	9.00	0.840	14.3	473	0.000	0.048	0.047	0.004	0.003
	Imperial Oil Leming – Steam Generator 8	536,881	6,050,517	610.4	15.20	0.850	14.3	473	0.000	0.049	0.048	0.004	0.003
	Imperial Oil Leming – Steam Generator 9	536,887	6,050,527	610.4	18.30	1.490	14.3	413	0.000	0.175	0.170	0.015	0.011
	Imperial Oil Leming – Steam Generator 10	536,892	6,050,539	610.4	18.30	1.370	14.3	443	1.040	0.172	0.168	0.015	0.011
	Imperial Oil Leming – Steam Generator 11	536,892	6,050,547	610.4	18.30	1.370	14.3	443	1.040	0.172	0.168	0.015	0.011
	Imperial Oil Makheses – Congeneration Unit 1	539,241	6,048,749	644.5	24.00	5.180	20.3	417	0.640	1.500	0.600	0.110	0.065
	Imperial Oil Makheses – Congeneration Unit 2	539,280	6,048,721	644.6	24.00	5.180	20.3	417	0.640	1.500	0.600	0.110	0.065
	Imperial Oil Makheses – Steam Generator	539,191	6,048,695	644.7	24.00	1.520	15.3	479	0.820	0.203	0.200	0.050	0.011
	Imperial Oil Makheses – Glycol Heaters	539,202	6,048,676	644.8	16.00	0.760	7.5	552	0.000	0.020	0.056	0.003	0.002
	Imperial Oil Nabiye – Steam Generator 1	542,191	6,064,322	627.0	24.00	1.520	15.3	479	1.270	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 2	542,197	6,064,357	627.7	24.00	1.520	15.3	479	1.270	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 3	542,203	6,064,381	628.4	24.00	1.520	15.3	479	1.270	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 4	542,209	6,064,401	628.9	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 5	542,214	6,064,421	629.5	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 6	542,248	6,064,319	626.7	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 7	542,254	6,064,338	627.0	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 8	542,261	6,064,363	627.5	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 9	542,267	6,064,383	627.9	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 10	542,272	6,064,403	628.4	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Glycol Heaters	542,325	6,064,282	625.0	16.00	0.760	7.5	552	0.000	0.025	0.067	0.013	0.000
Imperial Oil Resources Ventures Limited – Kearl Oil Sands Project													
	Imperial Oil Kearl – Cogeneration Units	496,039	6,362,017	356.3	30.00	5.00	18.30	387	0.034	6.562	4.137	0.348	0.166
	Imperial Oil Kearl – Auxiliary Boilers	495,784	6,362,017	346.4	30.00	3.50	17.03	387	0.030	4.674	3.699	0.335	0.242
Husky Energy Inc. – Tucker Thermal Project													
	Husky Tucker – Steam Generator 1 and Heater	528,572	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.289	0.085	0.027	0.024
	Husky Tucker – Steam Generator 2	528,585	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
	Husky Tucker – Steam Generator 3	528,609	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
	Husky Tucker – Steam Generator 4	528,609	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
	Husky Tucker – Steam Generator 5	528,621	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
Husky Energy Inc.– Sunrise Thermal Project													
	Husky Sunrise – Steam Generators, Glycol Heaters and Flare Stacks	496,251	6,344,268	478.9	27.00	1.650	24.0	458	1.180	6.610	20.560	0.000	0.190
Husky Energy Inc. – Gas Plant													
	Husky – Agnes Lake Gas Plant	429,749	6,194,185	697.4	20.70	0.310	37.7	863	0.000	0.706	0.055	0.002	0.020
	Husky – Thornbury Gas Plant	448,802	6,217,386	732.6	20.70	0.310	37.7	863	0.000	0.441	0.034	0.001	0.013
Shell Canada Limited – Orion EOR Project													
	Shell Orion EOR – Steam Generators	538,730	6,043,490	556.4	27.40	1.680	21.0	471	0.900	1.260	0.406	0.095	0.093
Shell Canada Limited – Jackpine Mine – Phase 1													
	Shell Jackpine Phase 1 – Cogeneration Unit and Plant Fugitives	477,158	6,344,508	314.4	30.00	5.500	15.0	393	0.017	3.375	1.960	0.164	0.075
	Shell Jackpine Phase 1 – Boiler 1	477,174	6,344,545	314.2	25.00	4.510	15.0	453	0.024	3.467	2.939	0.266	0.192
Suncor Energy Ltd. – Voyageur Upgrader													
	Suncor Voyageur – Sulphur Plant Incinerator	469,120	6,314,086	320.9	89.92	4.174	15.2	673	7.074	0.362	0.104	0.009	0.007
	Suncor Voyageur – (Plant 206) Hydrogen Plant, Hydrogen Reforming Furnace	469,248	6,314,274	322.1	42.67	4.041	13.7	422	0.013	1.407	1.200	0.109	0.079
	Suncor Voyageur – (Plant 216) Hydrogen Plant, Hydrogen Reforming Furnace	469,332	6,314,233	322.8	42.67	3.301	13.7	422	0.008	0.939	0.801	0.072	0.052
	Suncor Voyageur – Delayed Coker Units (Plant 205)	468,934	6,314,241	319.2	39.62	4.311	7.6	444	1.170	1.576	1.396	0.126	0.091
	(Plant 207) Diesel, Gas Oil and Naphtha Hydrotreaters, Fired Heater Combined Feed Heater, Stripper Reboiler, Heaters, Vapour Recovery Unit, (Plant 202) Vacuum Tower Heater, (plant 203) Gasifier, HP Boiler Package Heater and Low Pressure Flares	468,976	6,314,380	319.5	45.72	2.461	7.6	444	6.069	1.058	1.034	0.093	0.069
Suncor Energy Ltd. – Upgrader Complex													
	Suncor – FGD Stack	471,043	6,317,825	250.8	137.20	7.010	13.1	322	18.749	31.971	0.781	4.053	0.172
	Suncor – Powerhouse Stack	471,026	6,317,764	253.6	106.68	5.790	7.0	466	16.153	4.780	2.053	0.485	0.143
	Suncor – Gas Turbine Generators	470,360	6,318,450	266.8	30.50	6.100	15.9	383	0.000	4.512	3.456	0.289	0.133
	Suncor – Sulphur Plant Incinerator	471,003	6,318,016	247.7	106.68	1.981	22.0	673	12.417	0.113	0.027	0.002	0.002
	Suncor Base Plant – Plant 5, Plant 6, Plant 7 and Plant 25	470,986	6,317,928	250.3	48.77	1.803	5.5	733	0.960	4.666	2.388	0.216	0.156
	Suncor Millenium - Sulphur Plant Incinerator	470,933	6,318,211	246.7	106.07	3.353	8.6	673	5.959	0.332	0.108	0.010	0.007
	Suncor Millennium – Plant 52 Diluent Tower Fired Heaters, Plant 52 Coker Charge Heaters and Plant 55	470,804	6,318,588	245.2	54.86	2.972	7.6	489	0.559	1.288	1.390	0.126	0.091
Suncor Energy Ltd. – Millenium Coker Unit													
	Suncor Base Plant – Acid Gas Flare	471,202	6,318,106	242.3	88.81	3.864	15.5	1,273	3.648	0.019	0.106	0.000	0.026
	Suncor Millennium – Plant 52 Coker Charge Heaters	470,912	6,318,381	245.2	60.66	3.280	7.6	487	0.317	0.340	0.305	0.028	0.020
	Suncor Millennium – Hydrogen Plant #3	470,465	6,318,577	259.6	42.67	3.502	13.7	422	0.190	0.443	0.350	0.032	0.023
Suncor Energy Ltd. – Millenium Vacuum Unit													
	Suncor Millennium – Plant 57	470,733	6,318,662	247.1	49.06	1.727	10.1	483	0.542	0.571	0.522	0.047	0.034
	Suncor Millennium – Acid Gas Flare	471,157	6,318,390	236.5	130.93	10.775	1.0	1,273	1.422	0.000	0.003	0.000	0.001
	Suncor Millennium – Acid Gas Flare	471,121	6,318,473	235.9	130.93	10.775	1.0	1,273	1.422	0.000	0.003	0.000	0.001
	Suncor Millennium – SWAG Flare	470,936	6,318,211	246.7	105.78	1.512	6.1	1,273	0.493	0.000	0.001	0.000	0.000
Suncor Energy Ltd. – Firebag Enhanced thermal Solvent (ETS) Pilot Project													
	Suncor Firebag ETS Pilot and ETS2 – Flare Stacks	509,627	6,341,492	579.0	3.80	0.152	79.5	813	0.165	0.214	0.124	0.007	0.032
Suncor Energy Ltd. – Firebag SAGD Project													
	Suncor Firebag SAGD – Steam Generators, Cogeneration Units, Diluent Stripper Units and SRU Heaters	508,932	6,343,662	582.0	30.00	1.700	22.4	432	7.178	21.208	14.452	1.657	0.771
Syncrude Canada Ltd. – Mildred Lake Upgrader													
	Syncrude Mildred Lake – 8-3 Diverter Stack	462,807	6,322,880	305.5	94.49	6.600	10.5	348	15.000	3.500	13.500	2.100	0.000
	Syncrude Mildred Lake – Main Stack	462,632	6,322,111	307.8	183.00	7.900	18.2	381	81.000	14.800	55.200	1.550	0.000
	Syncrude Mildred Lake – Gas Turbine Generators, Bitumen Column Feed Heaters and Steam Superheaters	462,596	6,322,427	307.5	51.80	3.200	5.7	422	0.000	8.330	1.772	0.611	0.059
	Syncrude Mildred Lake – Reformer Furnaces	463,084	6,322,453	305.6	23.50	4.100	11.6	540	0.000	13.650	4.825	1.509	0.172
	Syncrude Mildred Lake – Diluent Reboiler, Hydrogen Heaters, Fractionator Reboilers, Bitumen Heaters and VDU Bitumen Feed Heaters	462,865	6,323,038	304.7	6.10	0.300	29.0	839	0.000	2.252	0.717	0.270	7.246
	Syncrude Mildred Lake – Coker Diverter Stacks and Acid Gas Flare Stack	462,742	6,322,246	307.8	73.20	3.700	34.6	761	4.000	0.000	0.000	0.000	0.000
Syncrude Canada Ltd. – Aurora South Mine													
	Syncrude Aurora South – Cogeneration Units and Boilers	483,059	6,341,731	340.5	25.00	2.740	37.7	455	0.000	2.380	0.540	0.220	0.040
Syncrude Canada Ltd. – Aurora North Mine													
	Syncrude Aurora North – Cogeneration Units and Boilers	469,370	6,350,733	288.0	25.00	2.740	37.7	455	0.000	2.380	0.540	0.220	0.040
Albian Sands Energy Inc. – Muskeg River Mine and Muskeg River Mine Expansion													
	Albian Sands Muskeg River Mine – Cogeneration Unit 1 and Plant Fugitives	469,565	6,346,240	276.0	37.50	5.000	18.3	398	0.000	4.253	1.980	0.242	0.112
	Albian Sands MRME – Boilers, Heaters and Flare Pilot	469,600	6,346,125	275.5	37.50	2.400	18.3	448	0.000	2.037	1.333	0.184	0.119
	Albian Sands MRME – Auxiliary and Debottlenecking Boilers, Heaters	469,565	6,345,851	274.9	38.00	1.975	18.0	442	0.000	2.853	2.439	0.221	0.160
Total E&P Canada Ltd. – Joslyn Creek SAGD Project Phase 2													
	Total E&P Joslyn SAGD Phase 2 – Steam Generators,Boiler, Heaters and Recycle Treater	445,741	6,348,200	326.4	30.00	3.500	5.0	553	0.744	0.514	0.480	0.044	0.036
Petro-Canada Oil Sands Inc. – Fort Hills Oil Sands Project													
	Petro-Canada Oil Sands Inc. Fort Hills – Gas Turbines, Auxiliary Boilers and Space Heaters	462,000	6,360,000	279.6	38.00	4.000	28.6	378	0.050	5.329	0.440	0.190	0.000
Other Compressor Stations													
	Paramount – Quigley Compressor Station	510,225	6,224,400	513.2	12.40	0.432	27.6	683	0.000	0.264	0.028	0.001	0.008
	Paramount – Hangingstone Compressor Station	477,850	6,205,850	699.1	15.43	0.440	31.3	683	0.000	0.198	0.018	0.001	0.006
	Paramount – Kettle River Compressor Station	511,100	6,205,700	470.1	8.00	0.432	26.8	672	0.000	0.230	0.036	0.002	0.007
	Viking Energy – Wappau Compressor Station	451,854	6,137,651	655.2	10.00	0.300	20.0	773	0.000	0.355	0.028	0.001	0.010
	AltaGas – John Lake North Compressor Station	562,715	5,971,048	670.1	12.20	0.250	68.6	881	0.000	0.636	0.066	0.002	0.024
	BP – St. Lina Compressor Station	486,624	6,032,149	564.7	14.00	0.250	56.0	862	0.000	0.913	0.133	0.004	0.049
	Canadian Natural – Kehiwin Compressor Station	507,197	5,997,740	589.2	11.00	0.300	21.0	928	0.000	0.479	0.032	0.001	0.012
	Northstar – Frenman Lake Compressor Station	480,139	6,045,128	630.9	14.90	0.305	33.4	851	0.000	0.492	0.034	0.001	0.013
Other Industries													
	Northland Forest Products Mill	477,831	6,286,040	231.4	20.00	5.000	2.5	643	0.020	0.190	25.000	0.190	2.120
	Pengrowth Lindberg – Steam Generators and Glycol Heaters	525,249	5,984,860	665.5	17.50	0.789	20.0	469	0.230	0.079	0.107	0.010	0.007
	Williams Energy Chemical Plant – Heat Medium Heater and Plant Fugitives	471,754	6,314,125	321.6	32.40	1.400	6.2	553	0.000	0.020	0.017	0.002	0.240

[a] Source coordinates are in UTM NAD 83.
[b] For flare stack pseudo stack height and pseudo stack diameter were used in the disperion modelling.
[c] SO_2 emissions are based on calendar–day emission rates.

Table A-2 Existing and Approved Case Area Source Emission Characteristics

No.	Source Description	Centre Easting [m]	Centre Northing [m]	Source Area [m²]	Effective Height [m]	Base Elevation [m]	Initial σ_z [m]	Emission Rate [t/d]				
								SO_2[(a)]	NO_X	CO	$PM_{2.5}$	VOC
MEG Energy Corp. – Christina Lake Regional Project - Phase 2B												
	MEG Christina Lake Phase 2B – Plant Fugitives	517,842	6,169,014	429,029	7.30	579.0	3.4	0.000	0.000	0.000	0.000	0.009
Petro-Canada – McKay River Project												
	Petro-Canada McKay River Project – Central Processing Area	445,065	6,322,000	33,600	3.00	415.9	1.5	0.000	0.000	0.000	0.000	0.263
Canadian Natural Resources Limited – Primrose North												
	Canadian Natural Primrose North – Plant Fugitives	526785.8156	6081226.688	40715.71069	3.00	692.85	1.5	0.000	0.000	0.000	0.000	0.004
Canadian Natural Resources Limited – Primrose South												
	Canadian Natural Primrose South – Plant Fugitives	527179.952	6069627.563	137530.2974	3.00	677.14	1.5	0.000	0.000	0.000	0.000	0.008
Canadian Natural Resources Limited – Primrose East												
	Canadian Natural Primrose East – Plant Fugitives	541476.9214	6071777.477	39614.49536	3.00	693.73	1.5	0.000	0.000	0.000	0.000	0.004
Canadian Natural Resources Limited – Wolf Lake												
	Canadian Natural Wolf Lake – Plant Fugitives	517628.85	6061111.7	184403.8198	3.00	642.18	1.5	0.000	0.000	0.000	0.000	0.018
Canadian Natural Resources Limited – Horizon Oil Sands Project												
	Canadian Natural Horizon – Mine Area	456163.5	6352841.5	7282341	7.50	280.36	7.0	0.432	33.125	20.886	1.205	13.051
	Canadian Natural Horizon – Tailings Pond	445625	6355250	16875000	0.00	334.88	1.4	0.000	0.000	0.000	0.000	139.361
	Canadian Natural Horizon – Plant Fugitives	455389	6355125	977900	3.00	276.45	1.5	0.000	0.000	0.000	0.000	4.130
Imperial Oil Resources Ventures Limited – Kearl Oil Sands Project												
	Imperial Oil Kearl – Space Heating at Plant Site	495750	6362000	1500000	9.00	344.99	4.5	0.002	0.576	0.255	0.023	0.017
	Imperial Oil Kearl – Space Heating at Mine Maintenance	496319.2796	6361102.559	319183.8086	9.00	362.85	4.5	0.021	2.413	2.471	0.229	0.167
	Imperial Oil Kearl – Mine Area 1	489617.7518	6363495.716	3027543.706	7.50	298.37	7.0	0.061	3.009	1.908	0.109	1.544
	Imperial Oil Kearl – Mine Area 2	491265.2697	6362400.315	6732295.508	7.50	302.27	7.0	0.136	6.691	4.242	0.242	3.434
	Imperial Oil Kearl – Mine Area 3	493593.0001	6361618.516	3113699.56	7.50	318.95	7.0	0.063	3.095	1.962	0.112	1.588
	Imperial Oil Kearl – Mine Area 4	493097.787	6359779.665	7974591.359	7.50	320.04	7.0	0.162	7.926	5.025	0.287	4.067
	Imperial Oil Kearl – Mine Area 5	493120.8085	6357627.086	7779471.147	7.50	331.27	7.0	0.158	7.732	4.902	0.280	3.968
	Imperial Oil Kearl – Tailings Pond	496208.461	6364433.306	19160717.02	0.00	415.00	1.4	0.000	0.000	0.000	0.000	137.949
	Imperial Oil Kearl – Plant Fugitives	495750	6362000	1500000	3.00	344.99	1.5	0.000	0.000	0.000	0.000	3.545
Shell Canada Limited – Jackpine Mine – Phase 1												
	Shell Jackpine Phase 1 – Mine Area	479,189	6,345,905	13,183,106	7.50	313.6	7.0	0.288	11.202	6.967	0.398	7.756
	Shell Jackpine Phase 1 – Tailings Pond	479,189	6,341,968	6,855,469	0.00	324.8	1.4	0.000	0.000	0.000	0.000	9.920
	Shell Jackpine Phase 1 – Space Heating	476,626	6,344,555	53,280	9.00	312.8	4.5	0.003	0.234	0.358	0.032	0.023
Suncor Energy Ltd. – South Tailings Pond												
	Suncor – South Tailings Pond	479,946	6,303,293	13,499,746	0.00	357.1	1.4	0.000	0.000	0.000	0.000	4.536
Suncor Energy Ltd. – Lease 86/17, Steepbank & Millennium Mines												
	Suncor Millennium – Mine Area 1	476,337	6,308,933	16,927,841	7.50	327.9	7.0	0.030	5.330	5.719	0.280	2.260
	Suncor Millennium – Mine Area 2	479,889	6,309,136	12,157,244	7.50	353.4	7.0	0.022	3.828	4.107	0.201	1.623
	Suncor Millennium – Mine Area 3	479,460	6,312,914	10,583,788	7.50	355.4	7.0	0.019	3.332	3.576	0.175	1.413
	Suncor Millennium – Mine Area 4	475,875	6,313,337	16,121,151	7.50	329.7	7.0	0.029	5.076	5.447	0.266	2.152
	Suncor Millennium – Mine Area 5	474,615	6,316,054	1,588,191	7.50	317.6	7.0	0.003	0.500	0.537	0.026	0.212
	Suncor Millennium – Mine Area 6	473,520	6,317,438	1,203,634	7.50	275.8	7.0	0.002	0.379	0.407	0.020	0.161
	Suncor Millennium – Mine Area 7	472,518	6,318,750	1,073,979	7.50	264.6	7.0	0.002	0.338	0.363	0.018	0.143
	Suncor Millennium – Tailings Ponds 2/3	468,846	6,316,410	1,595,400	0.00	311.7	1.4	0.000	0.000	0.000	0.000	176.866
	Suncor Millennium – Plant Fugitives	470,840	6,317,948	795,855	3.00	255.9	1.5	0.000	0.000	0.000	0.000	16.982
Suncor Energy Ltd. – Voyageur Upgrader												
	Suncor Voyageur – Coke Handling Fleet	469,453	6,312,758	2,696,581	7.50	317.7	7.0	0.009	0.771	0.478	0.027	0.107
	Suncor Voyageur – Plant Fugitives	469,284	6,314,266	772,176	3.00	322.4	1.5	0.000	0.000	0.000	0.000	0.609
	Suncor Voyageur – Tank Farm Fugitives	471,383	6,313,327	431,354	3.00	321.1	1.5	0.000	0.000	0.000	0.000	0.261
Suncor Energy Ltd. – North Steepbank Extension Mine												
	Suncor North Steepbank Extension – Mine Area 1	475,888	6,319,693	3,423,903	7.50	336.3	7.0	0.041	7.199	7.725	0.378	3.052
	Suncor North Steepbank Extension – Mine Area 2	478,653	6,317,607	2,759,239	7.50	341.4	7.0	0.033	5.802	6.225	0.304	2.460
	Suncor North Steepbank Extension – Mine Area 3	476,490	6,317,776	1,800,591	7.50	338.1	7.0	0.022	3.786	4.062	0.199	1.605
Suncor Energy Ltd. – Firebag SAGD Project												
	Suncor Firebag SAGD – Plant Fugitives	509,033	6,343,966	1,523,598	3.00	582.4	1.5	0.000	0.000	0.000	0.000	0.058
Syncrude Canada Ltd. – Mildred Lake Upgrader												
	Syncrude Mildred Lake – North Mine Area	457,682	6,322,263	8,140,000	7.50	335.0	7.0	0.051	17.200	4.500	0.490	6.953
	Syncrude Mildred Lake – West Base Mine Area	459,594	6,317,471	3,680,000	7.50	325.0	7.0	0.006	2.000	0.500	0.060	0.887
	Syncrude Mildred Lake – Basin Tailings Pond	462,170	6,325,360	11,560,000	0.00	307.6	1.4	0.000	0.000	0.000	0.000	33.216
	Syncrude Mildred Lake – Basin Beach Tailings Ponds	461,490	6,325,460	18,490,000	0.00	288.9	1.4	0.000	0.000	0.000	0.000	0.315
	Syncrude Mildred Lake – East Mine In-Pit Tailings Ponds	464,259	6,318,850	10,236,800	0.00	310.5	1.4	0.000	0.000	0.000	0.000	0.708
	Syncrude Mildred Lake – West Mine In-Pit Tailings Ponds	461,312	6,318,630	6,250,000	0.00	312.4	1.4	0.000	0.000	0.000	0.000	0.461
	Syncrude Mildred Lake – Southwest Sand Storage Area	455,050	6,316,790	23,040,000	0.00	357.4	1.4	0.000	0.000	0.000	0.000	7.504
	Syncrude Mildred Lake – Southwest Sand Storage Pond	453,480	6,315,780	1,960,000	0.00	375.9	1.4	0.000	0.000	0.000	0.000	0.650
Syncrude Canada Ltd. – Aurora South Mine												
	Syncrude Aurora South – Mine Area	486,311	6,344,136	6,000,000	7.50	360.1	7.0	0.027	9.900	2.400	0.260	6.611
	Syncrude Aurora South – Tailings Pond	480,453	6,337,883	3,610,000	0.00	339.4	1.4	0.000	0.000	0.000	0.000	1.120
Syncrude Canada Ltd. – Aurora North Mine												
	Syncrude Aurora North – Mine Area	467,965	6,353,037	6,000,000	7.50	299.6	7.0	0.035	13.100	3.200	0.340	6.741
	Syncrude Aurora North – Tailings Pond	473,940	6,351,540	3,610,000	0.00	288.4	1.4	0.000	0.000	0.000	0.000	1.120
Albian Sands Energy Inc. – Muskeg River Mine and Muskeg River Mine Expansion												
	Albian Sands MRME – Mine Area 1	463,677	6,347,888	4,500,000	7.50	274.2	7.0	0.560	20.598	19.447	0.877	10.990
	Albian Sands MRME – Mine Area 2	468,138	6,338,213	4,534,313	7.50	273.6	7.0	0.053	1.943	1.835	0.083	1.037
	Albian Sands MRME – Tailings Ponds	464,195	6,346,514	3,037,608	0.00	269.8	1.4	0.000	0.000	0.000	0.000	14.384
Petro-Canada Oil Sands Inc. – Fort Hills Oil Sands Project												
	Fort Hils Energy L.P. Fort Hills – Mine Area	463,000	6,358,000	8,000,000	7.50	285.2	7.0	1.682	21.411	4.800	0.534	0.921
	Fort Hills Energy L.P. Fort Hills – Tailings Pond	461,250	6,355,250	250,000	0.00	285.1	1.4	0.000	0.000	0.000	0.000	14.220
Other Industries												
	Birch Mountain Muskeg Valley – Quarry	466,281	6,338,172	62,500	5.00	255.4	4.7	0.020	0.880	0.300	0.050	0.050
	CAF[(b)] Cold Lake Air Force Base	547,389	6,029,644	20,599,370	5.00	521.1	5.0	0.001	0.060	0.040	0.004	0.003
	CAF[(b)] Cold Lake Air Weapons Range	521,964	6,100,208	5,281,660,440	0.00	681.7	30.5	0.530	9.990	40.190	0.210	0.142
Communities												
	Anzac	497,400	6,255,500	8,400,000	0.00	485.4	7.0	0.005	0.018	0.132	0.298	0.060
	Janvier/Chard	516,660	6,198,690	25,000,000	0.00	451.0	7.0	0.001	0.004	0.029	0.064	0.013
	Conklin	494,254	6,165,275	2,000,000	0.00	578.5	7.0	0.002	0.007	0.051	0.116	0.023
	Beaver Lake (IR 131)	441,941	6,059,727	2,000,026	0.00	579.0	7.0	0.002	0.008	0.059	0.133	0.027
	Bonnyville	517,192	6,012,974	3,750,040	0.00	568.4	7.0	0.032	0.166	0.885	1.657	0.341
	Cold Lake	552,943	6,035,613	2,925,006	0.00	548.8	7.0	0.006	0.031	0.168	0.315	0.065
	Cold Lake - Grand Centre	551,443	6,030,225	6,000,021	0.00	535.6	7.0	0.012	0.064	0.345	0.645	0.133
	Cold Lake Air Force Base	547,389	6,029,644	20,599,370	0.00	521.1	7.0	0.043	0.221	1.184	2.215	0.456
	Cold Lake (IR 149)	549,943	6,021,225	3,999,953	0.00	521.1	7.0	0.002	0.010	0.055	0.103	0.021
	Cold Lake (IR 149B)	548,943	6,040,725	1,999,944	0.00	546.2	7.0	0.000	0.002	0.013	0.024	0.005
	Elizabeth Metis Settlement	558,944	6,007,976	3,000,025	0.00	551.0	7.0	0.005	0.017	0.125	0.282	0.057
	Heart Lake (IR 167)	465,442	6,091,727	1,000,025	0.00	614.3	7.0	0.001	0.003	0.020	0.044	0.009
	Kehiwin (IR 123)	509,441	5,996,226	6,001,057	0.00	573.0	7.0	0.005	0.019	0.140	0.317	0.064
	La Loche	596,482	6,260,975	15,586,704	0.00	444.7	7.0	0.015	0.075	0.576	1.358	0.259
	Lac La Biche	437,191	6,069,477	2,250,020	0.00	551.8	7.0	0.015	0.078	0.419	0.785	0.161
	Peter Pond (IR 193)	626,199	6,199,973	2,499,768	0.00	423.0	7.0	0.005	0.018	0.127	0.287	0.058
	Pierceland	579,444	6,021,725	1,000,028	0.00	526.7	7.0	0.003	0.016	0.121	0.160	0.055
	St. Paul	480,818	5,982,726	6,500,083	0.00	639.4	7.0	0.030	0.157	0.837	1.566	0.322

(a) SO_2 emissions are based on calendar-day emission rates.

(b) CAF = Canadian Air Force

ATTACHMENT B

POINT AND AREA SOURCE EMISSIONS CHARACTERISTICS FOR PROJECT EMISSION SOURCES

Table B-1 Project Case MEG Energy Corp. Christina Lake In-Situ Oil Sands Project Point Source Emission Characteristics

No.	Source Description	UTM Coordinates [m][a]		Base Elevation [m]	Stack Height [m][b]	Stack Diameter [m][b]	Exit Velocity [m/s]	Exit Temperature [K]	Emission Rate [t/d]				
		Easting	Northing						SO_2[c]	NO_X	CO	$PM_{2.5}$	VOC
MEG Energy Corp. – Christina Lake Regional Project - Pilot													
	MEG Christina Lake Pilot – Steam Generator	517,796	6,168,843	579.0	30.00	1.384	20.7	445	0.002	0.199	0.177	0.016	0.012
	MEG Christina Lake Pilot – Glycol Heater	517,828	6,168,816	579.0	7.50	0.508	4.5	434	0.000	0.006	0.005	0.000	0.000
	MEG Christina Lake Pilot – Low Pressure Flare	517,870	6,168,764	579.0	13.16	2.397	0.2	1,273	0.000	0.001	0.005	0.000	0.001
	MEG Christina Lake Pilot – High Pressure Flare	517,850	6,168,732	579.0	31.46	2.878	0.1	1,273	0.000	0.001	0.005	0.000	0.001
MEG Energy Corp. – Christina Lake Regional Project - Phase 2													
	MEG Christina Lake Phase 2 – Steam Generator	517,772	6,168,836	579.0	30.00	1.676	19.7	445	0.002	0.283	0.251	0.023	0.016
	MEG Christina Lake Phase 2 – Cogeneration Unit	517,704	6,168,835	579.0	24.00	5.182	21.4	437	0.012	2.447	1.426	0.119	0.053
	MEG Christina Lake Phase 2 – Glycol Heater	517,818	6,168,886	579.0	5.00	1.016	5.8	434	0.000	0.021	0.028	0.003	0.002
	MEG Christina Lake Phase 2 – Slop Treater 1	517,867	6,168,901	579.0	9.00	0.610	5.3	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 2 – Slop Treater 2	517,867	6,168,900	579.0	9.00	0.610	5.3	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 2 – Flare	517,874	6,169,058	579.0	55.17	5.753	0.0	1,273	0.000	0.001	0.007	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 2B													
	MEG Christina Lake Phase 2B – Steam Generator 1	517,373	6,169,140	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Steam Generator 2	517,378	6,169,122	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Steam Generator 3	517,383	6,169,105	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Cogeneration Unit	517,632	6,168,815	579.0	24.00	5.182	21.4	437	0.012	2.447	1.426	0.119	0.053
	MEG Christina Lake Phase 2B – Glycol Heater	517,639	6,169,235	579.0	15.00	1.524	9.5	618	0.001	0.051	0.070	0.006	0.005
	MEG Christina Lake Phase 2B – Amine Preheater	517,917	6,168,990	579.0	15.00	0.305	76.3	533	0.000	0.019	0.025	0.002	0.002
	MEG Christina Lake Phase 2B – Flare	517,860	6,169,109	579.0	55.18	7.191	0.0	1,273	0.000	0.001	0.007	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 3A													
	MEG Christina Lake Phase 3A – Steam Generator 1	525,543	6,162,802	606.6	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 2	525,543	6,162,785	606.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 3	525,543	6,162,767	607.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 4	525,543	6,162,750	607.2	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 5	525,543	6,162,732	607.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 6	525,543	6,162,714	607.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 7	525,543	6,162,696	607.9	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 8	525,542	6,162,595	609.1	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 9	525,543	6,162,578	609.2	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 10	525,543	6,162,560	609.3	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 11	525,543	6,162,542	609.3	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 12	525,543	6,162,525	609.4	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 13	525,542	6,162,507	609.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 14	525,542	6,162,489	609.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Glycol Heater 1	525,800	6,162,663	609.6	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3A – Glycol Heater 2	525,801	6,162,627	609.9	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3A – Slop Treater 1A	526,028	6,162,662	607.9	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Slop Treater 1B	526,028	6,162,661	607.9	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Slop Treater 2A	526,097	6,162,662	606.6	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Slop Treater 2B	526,097	6,162,661	606.6	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Amine Preheater 1	525,844	6,162,684	609.3	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3A – Amine Preheater 2	525,843	6,162,609	609.8	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3A – Flare 1	526,002	6,162,859	606.9	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
	MEG Christina Lake Phase 3A – Flare 2	526,002	6,162,432	608.9	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 3B													
	MEG Christina Lake Phase 3B – Steam Generator 1	506,443	6,174,903	601.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 2	506,443	6,174,885	601.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 3	506,443	6,174,867	601.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 4	506,443	6,174,850	601.9	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 5	506,443	6,174,832	601.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 6	506,443	6,174,814	601.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 7	506,443	6,174,796	601.6	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 8	506,442	6,174,695	601.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 9	506,442	6,174,678	600.9	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 10	506,442	6,174,660	600.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 11	506,443	6,174,642	600.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 12	506,443	6,174,625	600.6	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 13	506,443	6,174,607	600.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 14	506,442	6,174,589	600.3	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Glycol Heater 1	506,700	6,174,763	603.3	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3B – Glycol Heater 2	506,701	6,174,727	602.9	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3B – Slop Treater 1A	506,928	6,174,762	604.8	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Slop Treater 1B	506,928	6,174,761	604.8	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Slop Treater 2A	506,997	6,174,762	605.3	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Slop Treater 2B	506,997	6,174,761	605.3	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Amine Preheater 1	506,745	6,174,783	603.7	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3B – Amine Preheater 2	506,745	6,174,708	603.1	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3B – Flare 1	506,902	6,174,959	606.3	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
	MEG Christina Lake Phase 3B – Flare 2	506,902	6,174,532	602.3	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project													
	MEG Christina Lake Regional Project – SRU Incinerator 1	517,929	6,168,916	579.0	45.70	0.610	6.9	873	0.999	0.001	0.001	0.000	0.000
	MEG Christina Lake Regional Project – SRU Incinerator 2	517,950	6,168,923	579.0	80.00	0.406	18.3	873	0.835	0.002	0.002	0.000	0.000
	MEG Christina Lake Regional Project – SRU Incinerator 3	517,967	6,168,927	579.0	80.00	0.406	18.3	873	0.835	0.002	0.002	0.000	0.000

(a) Source coordinates are in UTM NAD 83.

(b) For flare stack pseudo stack height and pseudo stack diameter were used in the disperion modelling.

(c) SO_2 emissions are based on calendar–day emission rates.

Table B-2 Project Case MEG Energy Corp. Christina Lake In-Situ Oil Sands Project Area Source Emission Characteristics

No.	Source Description	Centre Easting	Centre Northing	Source Area	Effective Height	Base Elevation	Initial σ_z	Emission Rate [t/d]				
								SO_2[a]	NO_X	CO	$PM_{2.5}$	VOC
MEG Energy Corp. – Christina Lake Regional Project - Phase 2B												
	MEG Christina Lake Phase 2B – Plant Fugitives	517,842	6,169,014	429,029	7.30	579.0	3.4	0.000	0.000	0.000	0.000	0.009
MEG Energy Corp. – Christina Lake Regional Project - Phase 3A												
	MEG Christina Lake Phase 3A – Plant Fugitives	525,862	6,162,608	367,587	7.30	609.7	3.4	0.000	0.000	0.000	0.000	0.011
MEG Energy Corp. – Christina Lake Regional Project - Phase 3B												
	MEG Christina Lake Phase 3B – Plant Fugitives	506,760	6,174,709	367,891	7.30	603.2	3.4	0.000	0.000	0.000	0.000	0.011

[a] SO_2 emissions are based on calendar-day emission rates.

ATTACHMENT C

POINT AND AREA SOURCE EMISSIONS CHARACTERISTICS USED IN THE PLANNED DEVELOPMENT CASE

Table C-1 Planned Development Case Point Source Emission Characteristics

No.	Source Description	UTM Coordinates [m][(a)]		Base Elevation [m]	Stack Height [m][(b)]	Stack Diameter [m][(b)]	Exit Velocity [m/s]	Exit Temperature [K]	Emission Rate [t/d]				
		Esting	Northing						SO_2[(c)]	NO_X	CO	$PM_{2.5}$	VOC
MEG Energy Corp. – Christina Lake Regional Project - Pilot													
	MEG Christina Lake Pilot – Steam Generator	517,796	6,168,843	579.0	30.00	1.384	20.7	445	0.002	0.199	0.177	0.016	0.012
	MEG Christina Lake Pilot – Glycol Heater	517,828	6,168,816	579.0	7.50	0.508	4.5	434	0.000	0.006	0.005	0.000	0.000
	MEG Christina Lake Pilot – Low Pressure Flare	517,870	6,168,764	579.0	13.16	2.397	0.2	1,273	0.000	0.001	0.005	0.000	0.001
	MEG Christina Lake Pilot – High Pressure Flare	517,850	6,168,732	579.0	31.46	2.878	0.1	1,273	0.000	0.001	0.005	0.000	0.001
MEG Energy Corp. – Christina Lake Regional Project - Phase 2													
	MEG Christina Lake Phase 2 – Steam Generator	517,772	6,168,836	579.0	30.00	1.676	19.7	445	0.002	0.283	0.251	0.023	0.016
	MEG Christina Lake Phase 2 – Cogeneration Unit	517,704	6,168,835	579.0	24.00	5.182	21.4	437	0.012	2.447	1.426	0.119	0.053
	MEG Christina Lake Phase 2 – Glycol Heater	517,818	6,168,886	579.0	5.00	1.016	5.8	434	0.000	0.021	0.028	0.003	0.002
	MEG Christina Lake Phase 2 – Slop Treater 1	517,867	6,168,901	579.0	9.00	0.610	5.3	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 2 – Slop Treater 2	517,867	6,168,900	579.0	9.00	0.610	5.3	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 2 – Flare	517,874	6,169,058	579.0	55.17	5.753	0.0	1,273	0.000	0.001	0.007	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 2B													
	MEG Christina Lake Phase 2B – Steam Generator 1	517,373	6,169,140	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Steam Generator 2	517,378	6,169,122	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Steam Generator 3	517,383	6,169,105	579.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 2B – Cogeneration Unit	517,632	6,168,815	579.0	24.00	5.182	21.4	437	0.012	2.447	1.426	0.119	0.053
	MEG Christina Lake Phase 2B – Glycol Heater	517,639	6,169,235	579.0	15.00	1.524	9.5	618	0.001	0.051	0.070	0.006	0.005
	MEG Christina Lake Phase 2B – Amine Preheater	517,917	6,168,990	579.0	15.00	0.305	76.3	533	0.000	0.019	0.025	0.002	0.002
	MEG Christina Lake Phase 2B – Flare	517,860	6,169,109	579.0	55.18	7.191	0.0	1,273	0.000	0.001	0.007	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 3A													
	MEG Christina Lake Phase 3A – Steam Generator 1	525,543	6,162,802	606.6	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 2	525,543	6,162,785	606.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 3	525,543	6,162,767	607.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 4	525,543	6,162,750	607.2	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 5	525,543	6,162,732	607.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 6	525,543	6,162,714	607.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 7	525,543	6,162,696	607.9	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 8	525,542	6,162,595	609.1	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 9	525,543	6,162,578	609.2	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 10	525,543	6,162,560	609.3	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 11	525,543	6,162,542	609.3	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 12	525,543	6,162,525	609.4	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 13	525,542	6,162,507	609.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Steam Generator 14	525,542	6,162,489	609.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3A – Glycol Heater 1	525,800	6,162,663	609.6	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3A – Glycol Heater 2	525,801	6,162,627	609.9	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3A – Slop Treater 1A	526,028	6,162,662	607.9	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Slop Treater 1B	526,028	6,162,661	607.9	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Slop Treater 2A	526,097	6,162,662	606.6	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Slop Treater 2B	526,097	6,162,661	606.6	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3A – Amine Preheater 1	525,844	6,162,684	609.3	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3A – Amine Preheater 2	525,843	6,162,609	609.8	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3A – Flare 1	526,002	6,162,859	606.9	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
	MEG Christina Lake Phase 3A – Flare 2	526,002	6,162,432	608.9	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project - Phase 3B													
	MEG Christina Lake Phase 3B – Steam Generator 1	506,443	6,174,903	601.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 2	506,443	6,174,885	601.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 3	506,443	6,174,867	601.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 4	506,443	6,174,850	601.9	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 5	506,443	6,174,832	601.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 6	506,443	6,174,814	601.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 7	506,443	6,174,796	601.6	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 8	506,442	6,174,695	601.0	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 9	506,442	6,174,678	600.9	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 10	506,442	6,174,660	600.8	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 11	506,443	6,174,642	600.7	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 12	506,443	6,174,625	600.6	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 13	506,443	6,174,607	600.5	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Steam Generator 14	506,442	6,174,589	600.3	30.00	1.956	17.0	444	0.003	0.332	0.294	0.027	0.019
	MEG Christina Lake Phase 3B – Glycol Heater 1	506,700	6,174,763	603.3	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3B – Glycol Heater 2	506,701	6,174,727	602.9	15.00	1.524	10.2	618	0.001	0.055	0.075	0.007	0.005
	MEG Christina Lake Phase 3B – Slop Treater 1A	506,928	6,174,762	604.8	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Slop Treater 1B	506,928	6,174,761	604.8	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Slop Treater 2A	506,997	6,174,762	605.3	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Slop Treater 2B	506,997	6,174,761	605.3	15.00	0.610	5.7	533	0.000	0.004	0.005	0.000	0.000
	MEG Christina Lake Phase 3B – Amine Preheater 1	506,745	6,174,783	603.7	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3B – Amine Preheater 2	506,745	6,174,708	603.1	15.00	0.305	29.8	533	0.000	0.012	0.016	0.001	0.001
	MEG Christina Lake Phase 3B – Flare 1	506,902	6,174,959	606.3	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
	MEG Christina Lake Phase 3B – Flare 2	506,902	6,174,532	602.3	55.22	7.191	0.0	1,273	0.000	0.001	0.008	0.000	0.002
MEG Energy Corp. – Christina Lake Regional Project													
	MEG Christina Lake Regional Project – SRU Incinerator 1	517,929	6,168,916	579.0	45.70	0.610	6.9	873	0.999	0.001	0.001	0.000	0.000
	MEG Christina Lake Regional Project – SRU Incinerator 2	517,950	6,168,923	579.0	80.00	0.406	18.3	873	0.835	0.002	0.002	0.000	0.000
	MEG Christina Lake Regional Project – SRU Incinerator 3	517,967	6,168,927	579.0	80.00	0.406	18.3	873	0.835	0.002	0.002	0.000	0.000
EnCana Corporation – Christina Lake Thermal Project													
	EnCana Christina Lake Phase 1C/1D – Steam Generator 1	506,870	6,159,485	573.2	25.90	1.372	24.7	501	0.220	0.227	0.194	0.018	0.013
	EnCana Christina Lake Phase 1C/1D – Steam Generator 2	506,864	6,159,476	573.2	15.20	0.914	16.3	495	0.065	0.044	0.058	0.005	0.004
	EnCana Christina Lake Phase 1C/1D – Steam Generator 3	507,026	6,159,437	574.0	27.00	1.676	20.5	475	0.297	0.317	0.262	0.024	0.017
	EnCana Christina Lake Phase 1C/1D – Steam Generator 4	507,177	6,159,598	573.8	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Steam Generator 5	507,169	6,159,611	573.7	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Steam Generator 6	507,162	6,159,624	573.6	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Steam Generator 7	507,155	6,159,637	573.6	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Glycol Heater 1	507,362	6,159,590	574.0	8.20	0.915	4.1	580	0.000	0.022	0.029	0.003	0.002
	EnCana Christina Lake Phase 1C/1D – Steam Generator 8	507,148	6,159,651	573.5	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Steam Generator 9	507,140	6,159,664	573.4	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Steam Generator 10	507,133	6,159,677	573.3	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Steam Generator 11	507,126	6,159,690	573.3	27.00	1.680	19.7	490	0.281	0.296	0.247	0.022	0.016
	EnCana Christina Lake Phase 1C/1D – Glycol Heater 2	507,356	6,159,587	574.0	8.20	0.915	4.1	580	0.000	0.022	0.029	0.003	0.002
	EnCana Christina Lake Phase 1C/1D – Flash Treater	507,239	6,159,632	573.8	9.50	0.610	14.1	889	0.000	0.009	0.012	0.001	0.001
	EnCana Christina Lake Phase 1C/1D – SRU Heater	507,271	6,159,368	575.1	6.10	0.762	6.9	889	0.000	0.014	0.019	0.002	0.001
EnCana Corporation – Foster Creek Pilot													
	EnCana Foster Creek Pilot – Steam Generator 1, Boilers and Plant Fugitives	529,437	6,102,950	670.6	12.20	1.070	10.8	467	0.092	0.201	0.069	0.006	0.017
	EnCana Foster Creek Pilot – Steam Generator 2	529,437	6,102,963	670.6	8.50	0.910	14.7	467	0.072	0.153	0.054	0.005	0.004
	EnCana Foster Creek Pilot – Steam Generator 3	529,437	6,102,972	670.6	8.90	1.000	12.8	467	0.072	0.041	0.054	0.005	0.004
EnCana Corporation – Foster Creek Phase 1 Project													
	EnCana Foster Creek Phase 1 – Cogeneration Units	529,657	6,102,420	670.0	25.90	3.660	21.1	448	1.420	1.834	1.251	0.101	0.044
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 1, Heaters and Wellpad Heaters	529,725	6,102,556	670.5	27.00	1.370	15.6	447	0.257	0.340	0.268	0.026	0.022
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 2	529,718	6,102,546	670.5	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 3	529,675	6,102,590	670.5	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 4	529,668	6,102,580	670.5	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 5	529,702	6,102,520	670.4	27.00	1.370	15.6	447	0.257	0.197	0.145	0.016	0.011
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 6	529,787	6,102,902	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 7	529,775	6,102,911	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 8	529,763	6,102,919	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 9	529,750	6,102,928	670.8	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 10	529,824	6,102,847	670.7	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 11	529,833	6,102,859	670.6	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 12	529,841	6,102,871	670.5	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 13	529,850	6,102,884	670.5	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 14	529,858	6,102,896	670.4	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
	EnCana Foster Creek Phase 1 – Steam Generator Boiler 15	529,867	6,102,909	670.3	27.00	1.676	19.7	490	0.000	0.259	0.785	0.019	0.051
EnCana Corporation – Borealis SAGD Project													
	EnCana – Borealis SAGD plant total	537,628	6,333,828	508.4	25.91	1.372	26.1	458	2.850	4.710	1.970	0.260	0.070
EnCana Corporation – Gas Plants and Field Compressors													
	EnCana – North Caribou Gas Plant	526,855	6,099,971	673.9	8.79	0.510	29.6	632	0.000	0.860	2.311	0.135	0.025
	EnCana – South Caribou Gas Plant	524,250	6,089,020	701.0	12.20	1.520	32.3	733	0.000	0.660	1.450	0.070	0.019
	EnCana – Primrose North Gas Plant	512,775	6,127,525	703.5	11.81	0.450	34.2	748	0.000	0.830	0.190	0.020	0.024
	EnCana – Field Compressor 1	535,684	6,076,979	670.9	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 2	526,615	6,093,106	702.6	3.70	0.130	23.6	830	0.000	0.071	0.005	0.000	0.002
	EnCana – Field Compressor 3	527,003	6,096,346	691.1	6.80	0.130	35.0	811	0.000	0.433	0.034	0.001	0.013
	EnCana – Field Compressor 4	524,195	6,089,451	699.8	4.70	0.100	25.8	836	0.000	0.036	0.003	0.000	0.001
	EnCana – Field Compressor 5	493,666	6,095,053	677.6	7.00	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 6	526,589	6,097,550	685.0	7.00	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 7	529,810	6,102,030	669.6	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 8	529,407	6,101,620	666.1	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 9	518,847	6,102,780	670.7	6.80	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 10	509,386	6,107,214	638.8	6.80	0.130	35.0	811	0.000	0.217	0.017	0.001	0.006
	EnCana – Field Compressor 11	502,836	6,117,762	671.0	8.30	0.360	37.0	649	0.000	0.053	0.004	0.000	0.002
	EnCana – Field Compressors 12 and 13	479,998	6,119,024	672.3	6.90	0.300	21.5	886	0.000	0.189	0.015	0.000	0.005
	EnCana – Field Compressor 14	537,288	6,080,634	708.2	5.60	0.130	34.0	813	0.000	0.120	0.009	0.000	0.003
	EnCana – Field Compressor 15	537,279	6,081,845	712.3	5.60	0.130	34.0	813	0.000	0.241	0.019	0.001	0.007
	EnCana – Field Compressor 16	530,734	6,085,442	724.0	5.60	0.130	34.0	813	0.000	0.120	0.009	0.000	0.003
	EnCana – Field Compressor 17	524,600	6,089,855	700.0	3.70	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 18	516,045	6,091,432	699.6	6.70	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 19	528,995	6,102,432	666.6	5.60	0.130	34.0	813	0.000	0.241	0.019	0.001	0.007
	EnCana – Field Compressor 20	530,210	6,102,842	666.7	5.60	0.130	34.0	813	0.000	0.120	0.009	0.000	0.003
	EnCana – Field Compressor 21	531,405	6,106,092	662.0	10.00	0.300	47.1	738	0.000	0.121	0.009	0.000	0.004
	EnCana – Field Compressor 22	494,256	6,111,289	652.0	3.70	0.130	35.0	811	0.000	0.108	0.008	0.000	0.003
	EnCana – Field Compressor 23	519,151	6,120,629	698.8	6.70	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 24	532,980	6,129,210	706.7	6.70	0.250	31.0	886	0.000	0.151	0.012	0.000	0.004
	EnCana – Field Compressor 25	527,637	6,135,649	648.8	3.70	0.130	23.6	830	0.000	0.071	0.005	0.000	0.002
Devon Canada Corporation – Jackfish SAGD Project													
	Devon Jackfish – Steam Generator 1	507,936	6,153,851	610.6	25.90	1.680	18.3	461	1.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 2	507,946	6,153,833	610.7	25.90	1.680	18.3	461	1.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 3	507,951	6,153,825	610.8	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 4	507,961	6,153,807	611.0	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 5	507,982	6,153,771	611.3	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Steam Generator 6	507,992	6,153,753	611.4	25.90	1.680	18.3	461	0.000	0.199	0.260	0.030	0.020
	Devon Jackfish – Glycol Heaters	508,036	6,153,741	611.5	5.50	0.460	8.9	561	0.000	0.010	0.008	0.000	0.000
	Devon Jackfish Phase 2 – Steam Generator	503,953	6,150,936	659.3	25.90	1.680	18.3	461	2.000	1.205	1.568	0.180	0.120
Devon Canada Corporation – Compressor Stations													
	Devon – Hangingstone Compressor Station	469,198	6,236,234	648.3	11.60	0.310	37.4	862	0.000	1.146	0.089	0.003	0.033
	Devon – Surmont Compressor Station	501,167	6,216,280	679.1	10.00	0.300	20.0	773	0.000	4.359	0.339	0.011	0.126
	Devon – Surmont West Compressor Station	486,562	6,218,730	739.6	10.00	0.300	20.0	773	0.000	1.743	0.135	0.004	0.050
	Devon – Pony Creek Compressor Station 1	491,500	6,198,700	647.8	8.54	0.250	60.6	863	0.000	0.055	0.004	0.000	0.002
	Devon – Pony Creek Compressor Station 2	491,500	6,198,700	647.8	8.54	0.250	60.6	863	0.000	0.055	0.004	0.000	0.002
	Devon – Kirby North Compressor Station	505,784	6,157,211	580.6	10.00	0.300	20.0	773	0.000	0.040	0.140	0.000	0.001
	Devon – Kirby South Compressor Station	517,659	6,147,123	640.5	11.00	0.250	34.5	878	0.000	0.739	0.057	0.002	0.021
	Devon – Chard Compressor Station	508,197	6,175,417	612.7	10.00	0.300	20.0	773	0.000	0.304	0.024	0.001	0.009
	Devon – Leismer East Compressor Station	494,777	6,167,326	554.6	13.80	0.590	35.8	644	0.000	3.012	0.234	0.007	0.087
Orion Oil Canada Ltd. – Whitesands Pilot Project													
	Orion Whitesands Pilot – Steam Generator	484,277	6,168,716	585.0	12.30	1.520	5.5	477	0.000	0.047	0.056	0.005	0.004
	Orion Whitesands Pilot – Compressor driver	484,216	6,168,723	586.0	6.10	0.300	34.3	720	0.000	0.210	0.191	0.003	0.041
	Orion Whitesands Pilot – Combustion Vent Stack	484,315	6,168,851	578.8	35.00	0.203	121.2	353	0.075	0.000	9.124	0.000	0.042
Canadian Natural Resources Limited – Primrose North													
	Canadian Natural Primrose North – FGD Stack 1	526,706	6,081,204	692.5	30.00	2.636	13.0	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose North – FGD Stack 2	526,715	6,081,181	692.4	30.00	2.636	13.0	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose North – Steam Generator	526,745	6,081,172	692.5	26.10	1.500	11.8	441	0.187	1.514	0.542	0.049	0.035
Canadian Natural Resources Limited – Burnt Lake													
	Canadian Natural Burnt Lake – Steam Generator	541,396	6,072,999	679.8	13.50	1.100	6.1	423	0.300	0.270	0.227	0.021	0.015
Canadian Natural Resources Limited – Primrose South													
	Canadian Natural Primrose South – FGD Stack 1	527,142	6,069,603	676.8	30.00	2.175	13.0	330	0.579	1.338	0.147	0.131	0.008
	Canadian Natural Primrose South – FGD Stack 2	527,143	6,069,624	676.9	30.00	2.523	13.0	330	0.778	1.781	0.198	0.174	0.011
	Canadian Natural Primrose South – Steam Generator	527,041	6,069,619	676.2	27.00	1.372	18.5	444	0.342	1.717	0.988	0.089	0.065
	Canadian Natural Primrose South – Cogeneration Unit	527,013	6,069,627	676.0	27.00	5.100	18.3	375	0.000	1.851	1.202	0.100	0.044
	Canadian Natural Primrose South – Flare Stack	526,602	6,069,810	674.2	14.64	1.601	0.5	1,273	0.005	0.007	0.004	0.000	0.001
Canadian Natural Resources Limited – Primrose East													
	Canadian Natural Primrose East – Steam Generator	541,430	6,071,861	697.2	29.44	1.676	19.2	420	0.233	0.696	0.553	0.050	0.036
	Canadian Natural Primrose East – FGD Stack 1	541,466	6,071,727	691.2	30.00	2.641	25.9	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose East – FGD Stack 2	541,441	6,071,727	691.1	30.00	2.641	25.9	330	0.850	2.008	0.216	0.197	0.012
	Canadian Natural Primrose East – FGD Stack 3	541,416	6,071,727	691.1	30.00	2.251	25.9	330	0.617	1.459	0.157	0.143	0.009
Canadian Natural Resources Limited – Wolf Lake													
	Canadian Natural Resources Limited – Wolf Lake	517,568	6,061,052	642.6	30.00	1.372	20.5	444	2.000	1.960	1.220	0.104	0.092
Canadian Natural Resources Limited – Horizon													
	Canadian Natural Horizon – Sulphur Plant Incinerator	455,573	6,355,395	277.1	106.70	3.400	17.0	811	11.706	0.277	0.123	0.011	0.008
	Canadian Natural Horizon – Sulphur Plant Incinerator	455,922	6,354,992	277.5	38.00	5.500	21.7	405	0.028	5.147	3.383	0.281	0.120
	Canadian Natural Horizon – Sulphur Plant Incinerator	455,448	6,355,106	276.2	60.96	3.920	15.0	421	0.061	3.115	2.759	0.250	0.181
	Canadian Natural Horizon – Sulphur Plant Incinerator	455,002	6,355,298	277.3	30.50	3.000	6.2	474	0.477	7.002	6.290	0.562	0.427
	Canadian Natural Horizon – Sulphur Plant Incinerator	451,350	6,354,385	289.2	30.00	1.372	21.6	473	0.387	2.102	2.039	0.184	0.133

Table C-1 Planned Development Case Point Source Emission Characteristics (Continued)

No.	Source Description	UTM Coordinates [m][a]		Base Elevation [m]	Stack Height [m][b]	Stack Diameter [m][b]	Exit Velocity [m/s]	Exit Temperature [K]	Emission Rate [t/d]				
		Esting	Northing						SO_2[c]	NO_X	CO	$PM_{2.5}$	VOC
Canadian Natural Resources Limited – Kirby In-Situ Oil Sands Project													
	Canadian Natural Kirby – Steam Generator 1	498,263	6,132,807	732.0	45.50	2.000	18.3	450	0.332	0.474	0.398	0.036	0.026
	Canadian Natural Kirby – Steam Generator 2	498,263	6,132,791	732.0	45.50	2.000	18.3	450	0.332	0.474	0.398	0.036	0.026
	Canadian Natural Kirby – Steam Generator 3	498,263	6,132,775	732.0	45.50	2.000	18.3	450	0.332	0.474	0.398	0.036	0.026
	Canadian Natural Kirby – Steam Generator 4	498,312	6,132,807	732.0	45.50	2.000	18.3	450	0.332	0.474	0.398	0.036	0.026
	Canadian Natural Kirby – Steam Generator 5	498,312	6,132,791	732.0	45.50	2.000	18.3	450	0.332	0.474	0.398	0.036	0.026
	Canadian Natural Kirby – Steam Generator 6	498,312	6,132,775	732.0	45.50	2.000	18.3	450	0.332	0.474	0.398	0.036	0.026
	Canadian Natural Kirby – Glycol Heater	498,262	6,132,828	732.0	12.00	0.914	13.7	609	0.000	0.030	0.040	0.004	0.003
	Canadian Natural Kirby – High Pressure Flare	498,663	6,132,984	730.2	41.59	2.393	0.5	1,273	0.000	0.002	0.013	0.000	0.003
	Canadian Natural Kirby – Low Pressure Flare	498,663	6,132,984	730.2	41.59	2.872	0.4	1,273	0.000	0.002	0.013	0.000	0.003
Canadian Natural Resources Limited – Field Compressor													
	Canadian Natural – Field Compressor 1	533,900	6,070,290	671.0	5.49	0.102	43.0	830	0.000	0.056	0.004	0.000	0.002
	Canadian Natural – Field Compressor 2	535,461	6,079,198	694.6	7.92	0.254	37.9	886	0.000	0.390	0.022	0.001	0.008
	Canadian Natural – Field Compressor 3	520,802	6,074,255	663.2	3.66	0.102	61.6	811	0.000	0.089	0.006	0.000	0.002
	Canadian Natural – Field Compressor 4	519,594	6,061,312	641.0	3.66	0.102	43.0	830	0.000	0.056	0.004	0.000	0.002
	Canadian Natural – Field Compressor 5	537,899	6,080,840	711.5	3.66	0.102	61.6	811	0.000	0.105	0.008	0.000	0.003
	Canadian Natural – Field Compressor 6	533,429	6,079,183	692.5	3.66	0.102	61.6	811	0.000	0.089	0.006	0.000	0.002
	Canadian Natural – Field Compressor 7	532,609	6,078,774	701.4	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 8	528,122	6,079,152	685.5	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 9	517,081	6,086,385	691.2	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 10	516,749	6,061,300	643.0	2.13	0.051	46.3	811	0.000	0.016	0.001	0.000	0.000
	Canadian Natural – Field Compressor 11	543,202	6,080,894	731.6	6.71	0.203	43.1	721	0.000	0.042	0.016	0.000	0.006
	Canadian Natural – Field Compressor 12	537,047	6,085,693	722.5	3.66	0.102	61.6	811	0.000	0.089	0.006	0.000	0.002
Canadian Natural Resources Limited – Gas Plants													
	Canadian Natural Burnt Lake – Moose Hills Gas Plant	515,621	5,955,283	643.5	7.00	0.360	8.1	423	0.000	0.026	0.022	0.002	0.001
	Canadian Natural Burnt Lake – Elk Point Gas Plant	510,711	5,959,730	663.6	7.00	0.360	9.9	423	0.000	0.063	0.044	0.004	0.003
	Canadian Natural – Chard Gas Plant	510,967	6,195,656	489.1	18.30	0.250	60.6	863	0.000	0.136	0.011	0.000	0.004
	Canadian Natural – Cowpar Gas Plant	523,589	6,200,560	483.9	18.00	0.177	20.0	1,273	0.500	0.460	0.036	0.001	0.013
	Canadian Natural – Kettle River Gas Plant	520,207	6,228,483	476.5	29.00	0.247	20.0	1,237	0.600	0.029	0.002	0.000	0.001
	Canadian Natural – Newby Gas Plant	510,363	6,243,820	480.0	20.00	0.247	20.0	1,237	1.080	0.062	0.005	0.000	0.002
	Canadian Natural – Wiau Lake Gas Plant	486,375	6,137,409	674.7	18.30	0.250	31.3	863	0.000	0.040	0.003	0.000	0.001
	Canadian Natural – Kirby West Gas Plant	493,678	6,135,368	701.1	18.30	0.250	31.3	863	0.000	0.037	0.003	0.000	0.001
Statoil ASA – Kai Kos Dehseh													
	Statoil Kai Kos Dehseh – Steam Generator 1	471,821	6,185,791	644.1	27.00	1.676	16.7	444	1.080	1.015	0.045	0.076	0.340
	Statoil Kai Kos Dehseh – Steam Generator 2	473,613	6,224,868	718.5	30.00	1.676	18.8	464	0.000	1.284	1.121	0.101	0.496
	Statoil Kai Kos Dehseh – Steam Generator 3	455,832	6,190,202	680.3	30.00	1.676	18.8	464	0.000	5.562	4.856	0.436	2.147
	Statoil Kai Kos Dehseh – Steam Generator 4	485,698	6,202,951	722.6	30.00	1.676	18.8	464	0.000	8.557	7.471	0.671	3.303
	Statoil Kai Kos Dehseh – Steam Generator 5	471,821	6,185,791	644.1	30.00	1.676	18.8	464	0.000	2.567	2.241	0.201	0.991
ConocoPhillips Canada Resource Ltd. – Surmont Commercial SAGD Project													
	ConocoPhillips Surmont – Phase 1	503,363	6,227,513	626.8	27.00	1.676	20.1	469	0.015	0.698	1.103	0.082	0.072
	ConocoPhillips Surmont – Phase 2	504,122	6,227,796	613.8	27.00	1.676	20.1	469	0.283	2.398	3.803	0.282	0.249
	ConocoPhillips Surmont – SRU Incinerator	504,354	6,227,661	606.5	30.50	0.915	0.9	923	0.100	0.000	0.120	0.000	0.008
OPTI Canada Inc./Nexen Canada Ltd. – Long Lake Pilot Project													
	OPTI/Nexen Long Lake South Phase 2 – Continuous Flare	504,204	6,251,133	482.1	12.92	1.520	15.2	453	0.150	0.499	0.268	0.018	0.031
OPTI Canada Inc./Nexen Canada Ltd. – Long Lake Commercial Project													
	OPTI/Nexen Long Lake – Sulphur Incinerator 1	503,410	6,251,145	498.0	115.00	1.524	30.0	811	7.773	0.040	0.030	0.000	0.002
	OPTI/Nexen Long Lake – Sulphur Incinerator 2	503,732	6,250,845	487.4	115.00	1.524	30.0	811	7.773	0.040	0.030	0.000	0.002
	OPTI/Nexen Long Lake – Cogeneration Unit	503,159	6,251,532	499.2	30.00	5.180	18.2	433	1.182	4.840	3.664	0.256	0.159
	OPTI/Nexen Long Lake – Steam Generator	503,237	6,251,626	498.4	30.00	1.676	18.8	464	1.693	6.011	5.226	0.474	0.342
	OPTI/Nexen Long Lake – Plant Fugitives	503,603	6,251,473	495.9	10.00	1.000	2.0	288	0.000	0.000	0.000	0.000	1.974
OPTI Canada Inc./Nexen Canada Ltd. – Long Lake South SAGD Project													
	OPTI/Nexen Long Lake South Phase 1 – Cogeneration Unit	500,465	6,239,611	500.7	30.00	5.180	18.2	433	0.589	2.436	1.834	0.127	0.081
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 1	500,521	6,239,541	502.4	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 2	500,539	6,239,530	502.9	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 3	500,557	6,239,520	503.5	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 4	500,575	6,239,509	504.0	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 5	500,593	6,239,499	504.5	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 6	500,554	6,239,619	502.8	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 7	500,572	6,239,608	503.4	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 8	500,590	6,239,598	503.9	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 9	500,606	6,239,588	504.4	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 10	500,624	6,239,578	504.9	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Steam Generator 11	500,642	6,239,568	505.4	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 1 – Glycol Heater	500,689	6,239,602	506.5	30.00	1.800	6.0	422	0.001	0.117	0.104	0.009	0.006
	OPTI/Nexen Long Lake South Phase 1 – Line Heater 1	500,941	6,240,033	507.3	7.40	0.510	1.4	477	0.000	0.002	0.002	0.000	0.000
	OPTI/Nexen Long Lake South Phase 1 – Line Heater 2	504,806	6,246,080	452.8	7.40	0.510	1.4	477	0.000	0.002	0.002	0.000	0.000
	OPTI/Nexen Long Lake South Phase 1 – Continuous Flare	501,160	6,239,853	512.8	37.46	3.853	0.0	1,273	0.000	0.000	0.001	0.000	0.001
	OPTI/Nexen Long Lake South Phase 2 – Cogeneration Unit 1	500,993	6,240,485	502.4	30.00	5.180	18.2	433	0.589	2.436	1.834	0.127	0.081
	OPTI/Nexen Long Lake South Phase 2 – Cogeneration Unit 2	501,033	6,240,460	502.7	30.00	5.180	18.2	433	0.589	2.436	1.834	0.127	0.081
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 1	501,084	6,240,393	503.4	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 2	501,102	6,240,383	503.5	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 3	501,120	6,240,372	503.5	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 4	501,117	6,240,471	502.6	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 5	501,134	6,240,462	502.7	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 6	501,152	6,240,451	502.8	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Steam Generator 7	501,170	6,240,441	502.9	30.00	1.680	18.8	464	0.094	0.318	0.282	0.026	0.017
	OPTI/Nexen Long Lake South Phase 2 – Glycol Heater	501,217	6,240,475	502.7	30.00	1.800	6.0	422	0.001	0.117	0.104	0.009	0.006
	OPTI/Nexen Long Lake South Phase 2 – Line Heater	501,474	6,240,603	502.0	7.40	0.510	1.4	477	0.000	0.002	0.002	0.000	0.000
	OPTI/Nexen Long Lake South Phase 2 – Continuous Flare	501,688	6,240,726	501.9	47.20	3.730	10.4	1,273	3.776	0.108	0.587	0.008	0.402
Great Divide Oil Corporation – Great Divide SAGD Project													
	Great Divide SAGD – Steam Generator	448,553	6,218,911	710.1	20.00	1.220	20.0	469	0.396	0.249	0.378	0.034	0.025
Great Divide Oil Corporation – Algar SAGD Project													
	Great Divide Algar SAGD – Steam Generator	455,534	6,218,957	740.6	30.30	1.680	15.6	450	0.082	0.482	0.402	0.036	0.026
Petro-Canada Oil and Gas – Meadow Creek Phase 1													
	Petro-Canada Meadow Creek Phase 1 – Cogeneration Unit	482,144	6,242,326	719.4	30.50	6.096	23.6	478	0.752	6.007	4.388	0.368	0.160
	Petro-Canada Meadow Creek Phase 1 – Steam Generator	482,251	6,242,013	717.8	27.00	1.756	20.6	478	0.728	1.173	1.232	0.112	0.081
Petro-Canada Oil and Gas – Meadow Creek Expansion													
	Petro-Canada Meadow Creek Expansion – Cogeneration Unit	468,656	6,246,028	562.2	30.50	6.096	23.6	478	0.752	6.007	4.388	0.368	0.160
	Petro-Canada Meadow Creek Expansion – Steam Generator	468,756	6,246,128	562.3	27.00	1.756	20.6	478	0.728	1.173	1.232	0.112	0.081
Petro-Canada Oil and Gas – MacKay River Phase 1													
	Petro-Canada MacKay River Phase 1 – Cogeneration Unit	445,067	6,322,175	417.7	26.20	6.310	20.0	452	0.000	3.600	3.720	0.156	0.087
	Petro-Canada MacKay River Phase 1 – Steam Generator	445,136	6,322,011	415.1	27.00	1.340	27.5	553	0.590	1.408	0.726	0.036	0.091
Petro-Canada Oil and Gas – MacKay River Expansion													
	Petro-Canada Mackay River Expansion – Cogeneration Unit	445,083	6,322,944	417.1	27.00	5.490	32.5	460	0.374	3.970	1.238	0.187	0.095
	Petro-Canada Mackay River Expansion – Steam Generator	445,167	6,322,830	415.8	27.00	1.680	18.7	444	0.235	0.489	0.302	0.056	0.031
Petro-Canada Oil and Gas – Dover SAGD Project													
	Petro-Canada Dover – Cogeneration Unit	444,012	6,324,240	428.8	10.90	0.540	39.7	466	0.500	0.330	0.120	0.020	0.010
Petro-Canada Oil and Gas – Lewis SAGD Project													
	Petro-Canada Lewis – Cogeneration Unit	494,816	6,305,173	461.0	30.50	6.100	24.8	478	1.300	6.140	4.490	0.380	0.160
	Petro-Canada Lewis – Steam Generator	495,045	6,304,972	460.9	27.00	1.760	21.6	478	0.330	0.870	0.900	0.090	0.060
Japan Canada Oil Sands Limited – Hangingstone Pilot In-Situ Project													
	JACOS Hangingstone – Pilot	460,281	6,241,976	558.6	30.00	0.911	19.8	369	1.630	0.700	0.530	0.040	0.040
Japan Canada Oil Sands Limited – Hangingstone Commercial Project													
	JACOS Hangingstone – Commercial Project	453,933	6,238,599	534.4	30.00	1.372	21.6	473	3.120	3.890	4.220	0.260	0.960
Imperial Oil Resources Ventures Limited – Cold Lake In-Situ Project, Nabiye Expansion and Mahihkan North Expansion													
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 1	529,392	6,054,203	614.9	22.90	1.370	19.2	443	0.540	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 2	529,382	6,054,202	614.9	22.90	1.370	19.2	443	0.540	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 3	529,371	6,054,201	614.9	22.90	1.370	19.2	443	0.540	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 4	529,336	6,054,197	614.8	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 5	529,326	6,054,196	614.8	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Steam Generator 6	529,315	6,054,195	614.8	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Mahihkan (Plant 2) – Utility Steam Generators	529,302	6,054,174	614.7	16.00	1.295	11.0	523	0.000	0.148	0.144	0.013	0.009
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 1	528,940	6,054,059	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 2	528,950	6,054,060	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 3	528,960	6,054,061	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 4	528,971	6,054,063	614.0	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 5	528,982	6,054,064	614.0	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 6	528,993	6,054,065	614.0	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 7	528,948	6,053,996	613.8	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 8	528,958	6,053,997	613.8	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 9	528,969	6,053,998	613.8	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 10	528,979	6,053,999	613.9	27.00	1.524	12.9	433	0.530	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 11	528,990	6,054,000	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Mahihkan (Plant 4) – Steam Generator 12	529,000	6,054,002	613.9	27.00	1.524	12.9	398	0.000	0.180	0.180	0.016	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 1	534,185	6,051,945	608.6	22.90	1.370	19.2	443	0.775	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 2	534,175	6,051,945	608.6	22.90	1.370	19.2	443	0.775	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 3	534,164	6,051,945	608.6	22.90	1.370	19.2	443	0.775	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 4	534,129	6,051,945	608.7	22.90	1.370	19.2	443	0.000	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 5	534,118	6,051,945	608.7	22.90	1.370	19.2	443	0.000	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Steam Generator 6	534,108	6,051,945	608.7	22.90	1.370	19.2	443	0.000	0.190	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 1) – Utility Steam Generator	534,091	6,051,929	608.7	18.45	1.295	11.0	503	0.000	0.148	0.144	0.013	0.009
	Imperial Oil Maskwa (Plant 3) – Steam Generator 1	534,042	6,051,945	608.9	22.90	1.370	19.2	443	0.775	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 2	534,032	6,051,945	608.9	22.90	1.370	19.2	443	0.775	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 3	534,021	6,051,945	608.9	22.90	1.370	19.2	443	0.775	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 4	533,985	6,051,945	609.0	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 5	533,975	6,051,945	609.0	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Maskwa (Plant 3) – Steam Generator 6	533,965	6,051,945	609.0	22.90	1.370	19.2	443	0.000	0.188	0.183	0.017	0.012
	Imperial Oil Leming – Steam Generator 1	536,881	6,050,441	610.8	27.00	1.370	14.3	443	1.120	0.186	0.181	0.016	0.012
	Imperial Oil Leming – Steam Generator 2	536,909	6,050,493	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 3	536,910	6,050,498	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 4	536,910	6,050,503	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 5	536,910	6,050,508	610.8	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 6	536,909	6,050,512	610.7	9.00	0.790	14.3	473	0.000	0.043	0.042	0.004	0.003
	Imperial Oil Leming – Steam Generator 7	536,908	6,050,517	610.7	9.00	0.840	14.3	473	0.000	0.048	0.047	0.004	0.003
	Imperial Oil Leming – Steam Generator 8	536,881	6,050,517	610.4	15.20	0.850	14.3	473	0.000	0.049	0.048	0.004	0.003
	Imperial Oil Leming – Steam Generator 9	536,887	6,050,527	610.4	18.30	1.490	14.3	413	0.000	0.175	0.170	0.015	0.011
	Imperial Oil Leming – Steam Generator 10	536,892	6,050,539	610.4	18.30	1.370	14.3	443	1.040	0.172	0.168	0.015	0.011
	Imperial Oil Leming – Steam Generator 11	536,892	6,050,547	610.4	18.30	1.370	14.3	443	1.040	0.172	0.168	0.015	0.011
	Imperial Oil Makheses – Congeneration Unit 1	539,241	6,048,749	644.5	24.00	5.180	20.3	417	0.640	1.500	0.600	0.110	0.065
	Imperial Oil Makheses – Congeneration Unit 2	539,280	6,048,721	644.6	24.00	5.180	20.3	417	0.640	1.500	0.600	0.110	0.065
	Imperial Oil Makheses – Steam Generator	539,191	6,048,695	644.7	24.00	1.520	15.3	479	0.820	0.203	0.200	0.050	0.011
	Imperial Oil Makheses – Glycol Heaters	539,202	6,048,676	644.8	16.00	0.760	7.5	552	0.000	0.020	0.056	0.003	0.002
	Imperial Oil Nabiye – Steam Generator 1	542,191	6,064,322	627.0	24.00	1.520	15.3	479	1.270	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 2	542,197	6,064,357	627.7	24.00	1.520	15.3	479	1.270	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 3	542,203	6,064,381	628.4	24.00	1.520	15.3	479	1.270	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 4	542,209	6,064,401	628.9	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 5	542,214	6,064,421	629.5	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 6	542,248	6,064,319	626.7	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 7	542,254	6,064,338	627.0	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 8	542,261	6,064,363	627.5	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 9	542,267	6,064,383	627.9	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Steam Generator 10	542,272	6,064,403	628.4	24.00	1.520	15.3	479	0.000	0.268	0.264	0.066	0.013
	Imperial Oil Nabiye – Glycol Heaters	542,325	6,064,282	625.0	16.00	0.760	7.5	552	0.000	0.025	0.067	0.013	0.000
Imperial Oil Resources Ventures Limited – Kearl Oil Sands Project													
	Imperial Oil Kearl – Cogeneration Units	496,039	6,362,017	356.3	30.00	5.000	18.3	387	0.034	6.562	4.137	0.348	0.166
	Imperial Oil Kearl – Auxiliary Boilers	495,784	6,362,017	346.4	30.00	3.500	17.0	387	0.030	4.674	3.699	0.335	0.242
Husky Energy Inc. – Tucker Thermal Project													
	Husky Tucker – Steam Generator 1 and Heater	528,572	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.289	0.085	0.027	0.024
	Husky Tucker – Steam Generator 2	528,585	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
	Husky Tucker – Steam Generator 3	528,609	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
	Husky Tucker – Steam Generator 4	528,609	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
	Husky Tucker – Steam Generator 5	528,621	6,046,671	617.0	26.00	1.600	21.0	421	0.240	0.288	0.084	0.027	0.024
Husky Energy Inc. – Sunrise Thermal Project													
	Husky Sunrise – Steam Generator	496,251	6,344,268	478.9	27.00	1.650	24.0	458	1.180	6.610	20.560	0.000	0.190
Husky Energy Inc. – Gas Plant													
	Husky – Agnes Lake Gas Plant	429,749	6,194,185	697.4	20.70	0.310	37.7	863	0.000	0.706	0.055	0.002	0.020
	Husky – Thornbury Gas Plant	448,802	6,217,386	732.6	20.70	0.310	37.7	863	0.000	0.441	0.034	0.001	0.013
Shell Canada Limited – Orion EOR Project													
	Shell Orion EOR – Steam Generator	538,730	6,043,490	556.4	27.40	1.680	21.0	471	0.900	1.260	0.406	0.095	0.093
Shell Canada Limited – Jackpine Mine – Phase 1													
	Shell Jackpine Phase 1 – Cogeneration Unit and Plant Fugitives	477,158	6,344,508	314.4	30.00	5.500	15.0	393	0.017	3.375	1.960	0.164	0.075
	Shell Jackpine Phase 1 – Boiler 1	477,174	6,344,545	314.2	25.00	4.510	15.0	453	0.024	3.467	2.939	0.266	0.192
Shell Canada Limited – Jackpine Expansion													
	Shell Jackpine Expansion – Cogeneration Unit	477,208	6,344,558	314.2	30.00	5.500	15.0	393	0.020	3.421	2.450	0.215	0.134
Shell Canada Limited – Pierre River Mine													
	Shell Pierre River Mine – Cogeneration Unit	464,547	6,372,049	242.4	30.00	5.500	15.0	393	0.044	7.076	5.258	0.462	0.291

Table C-1 Planned Development Case Point Source Emission Characteristics (Continued)

No.	Source Description	UTM Coordinates [m][a]		Base Elevation [m]	Stack Height [m][b]	Stack Diameter [m][b]	Exit Velocity [m/s]	Exit Temperature [K]	Emission Rate [t/d]				
		Esting	Northing						SO_2[c]	NO_X	CO	$PM_{2.5}$	VOC
Suncor Energy Ltd. – Voyageur Upgrader													
	Suncor Voyageur – Sulphur Plant Incinerator	469,120	6,314,086	320.9	89.92	4.174	15.2	673	7.074	0.362	0.104	0.009	0.007
	Suncor Voyageur – Hydrogen Plant 1	469,248	6,314,274	322.1	42.67	4.041	13.7	422	0.013	1.407	1.200	0.109	0.079
	Suncor Voyageur – Hydrogen Plant 2	469,332	6,314,233	322.8	42.67	3.301	13.7	422	0.008	0.939	0.801	0.072	0.052
	Suncor Voyageur – Coker Heaters	468,934	6,314,241	319.2	39.62	4.311	7.6	444	1.170	1.576	1.396	0.126	0.091
	Suncor Voyageur – Diesel Hydrotreater	468,976	6,314,380	319.5	45.72	2.461	7.6	444	6.069	1.058	1.034	0.093	0.069
Suncor Energy Ltd. – Upgrader Complex													
	Suncor - FGD Stack	471,043	6,317,825	250.8	137.20	7.010	13.1	322	18.749	31.971	0.781	4.053	0.172
	Suncor - Powerhouse Stack	471,026	6,317,764	253.6	106.68	5.790	7.0	466	16.153	4.780	2.053	0.485	0.143
	Suncor - Gas Turbine Generator	470,360	6,318,450	266.8	30.50	6.100	15.9	383	0.000	4.512	3.456	0.289	0.133
	Suncor - Sulphur Plant Incinerator	471,003	6,318,016	247.7	106.68	1.981	22.0	673	12.417	0.113	0.027	0.002	0.002
	Suncor Base Plant – Plant 5, Plant 6, Plant 7 and Plant 25	470,986	6,317,928	250.3	48.77	1.803	5.5	733	0.960	4.666	2.388	0.216	0.156
	Suncor Millenium - Sulphur Plant Incinerator	470,933	6,318,211	246.7	106.07	3.353	8.6	673	5.959	0.332	0.108	0.010	0.007
	Suncor Millennium – Plant 52 Diluent Tower Fired Heaters, Plant 52 Coker Charge Heaters and Plant 55	470,804	6,318,588	245.2	54.86	2.972	7.6	489	0.559	1.288	1.390	0.126	0.091
	Suncor Millennium – Plant 52 Coker Charge Heaters	470,912	6,318,381	245.2	60.66	3.280	7.6	487	0.317	0.340	0.305	0.028	0.020
	Suncor Millennium – Hydrogen Plant #3	470,465	6,318,577	259.6	42.67	3.502	13.7	422	0.190	0.443	0.350	0.032	0.023
	Suncor Millennium – Flaring	471,121	6,318,473	235.9	130.93	10.775	1.0	1,273	1.422	0.000	0.003	0.000	0.001
Suncor Energy Ltd. – Millenium Vacuum Unit													
	Suncor Base Plant – Plant 57 Diluent Tower Heater	470,733	6,318,662	247.1	49.06	1.727	10.1	483	0.542	0.571	0.522	0.047	0.034
	Suncor Millennium – Acid Gas Flare	471,202	6,318,106	242.3	88.81	3.864	15.5	1,273	3.648	0.019	0.106	0.000	0.026
	Suncor Millennium – Acid Gas Flare	471,157	6,318,390	236.5	130.93	10.775	1.0	1,273	1.422	0.000	0.003	0.000	0.001
	Suncor Millennium – SWAG Flare	470,936	6,318,211	246.7	105.78	1.512	6.1	1,273	0.493	0.000	0.001	0.000	0.000
Suncor Energy Ltd. – Firebag ETS Pilot													
	Suncor Firebag ETS Pilot – Steam Generator	509,627	6,341,492	579.0	3.80	0.152	79.5	813	0.165	0.214	0.124	0.007	0.032
Suncor Energy Ltd. – Firebag SAGD													
	Suncor Firebag SAGD – Steam Generator	508,932	6,343,662	582.0	30.00	1.700	22.4	432	7.178	21.208	14.452	1.657	0.771
Suncor Energy Ltd. – Voyageur South													
	Suncor Voyageur South – Cogeneration Unit	468,452	6,314,717	315.9	30.48	5.182	18.9	366	0.082	3.692	2.399	0.201	0.093
	Suncor Voyageur South – Boiler	468,606	6,314,832	315.7	30.48	3.658	24.4	450	0.036	1.298	1.055	0.095	0.069
Syncrude Canada Ltd. – Mildred Lake Upgrader													
	Syncrude Mildred Lake – 8-3 Diverter Stack	462,807	6,322,880	305.5	94.49	6.600	10.5	348	15.000	3.500	13.500	2.100	0.000
	Syncrude Mildred Lake – Main Stack	462,632	6,322,111	307.8	183.00	7.900	18.2	381	81.000	14.800	55.200	1.550	0.000
	Syncrude Mildred Lake – Gas Turbine Generators, Bitumen Column Feed Heaters and Steam Superheaters	462,596	6,322,427	307.5	51.80	3.200	5.7	422	0.000	8.330	1.772	0.611	0.059
	Syncrude Mildred Lake – Reformer Furnaces	463,084	6,322,453	305.6	23.50	4.100	11.6	540	0.000	13.650	4.825	1.509	0.172
	Syncrude Mildred Lake – Diluent Reboiler, Hydrogen Heaters, Fractionator Reboilers, Bitumen Heaters and VDU Bitumen Feed Heaters	462,865	6,323,038	304.7	6.10	0.300	29.0	839	0.000	2.252	0.717	0.270	7.246
	Syncrude Mildred Lake – Coker Diverter Stacks and Acid Gas Flare Stack	462,742	6,322,246	307.8	73.20	3.700	34.6	761	4.000	0.000	0.000	0.000	0.000
Syncrude Canada Ltd. – Aurora South Mine													
	Syncrude Aurora South – Cogeneration Units and Boilers	483,059	6,341,731	340.5	25.00	2.740	37.7	455	0.000	2.380	0.540	0.220	0.040
Syncrude Canada Ltd. – Aurora North Mine													
	Syncrude Aurora North – Cogeneration Units and Boilers	469,370	6,350,733	288.0	25.00	2.740	37.7	455	0.000	2.380	0.540	0.220	0.040
Birch Mountain Resources Ltd. – Hammerstone													
	Birch Mountain Hammerstone – Activated Lime Kiln 1	466,006	6,338,958	254.9	65.00	3.260	20.0	533	1.686	14.413	6.870	0.486	1.570
	Birch Mountain Hammerstone – Quicklime Kiln	466,034	6,338,924	255.0	65.00	1.780	20.0	563	7.465	6.005	3.272	0.245	0.746
	Birch Mountain Hammerstone – Coke Mill Filter	465,915	6,338,938	254.5	35.00	0.780	20.0	373	7.557	3.477	2.402	0.385	0.467
Albian Sands Energy Inc. – Muskeg River Mine and Muskeg River Mine Expansion													
	Albian Sands Muskeg River Mine – Cogeneration Unit 1 and Plant Fugitives	469,565	6,346,240	276.0	37.50	5.000	18.3	398	0.000	4.253	1.980	0.242	0.112
	Albian Sands MRME – Boilers, Heaters and Flare Pilot	469,600	6,346,125	275.5	37.50	2.400	18.3	448	0.000	2.037	1.333	0.184	0.119
	Albian Sands MRME – Auxiliary and Debottlenecking Boilers, Heaters	469,565	6,345,851	274.9	38.00	1.975	18.0	442	0.000	2.853	2.439	0.221	0.160
Total E&P Canada Ltd. – Joslyn Creek SAGD Project Phase 2													
	Total E&P Joslyn SAGD Phase 2 – Steam Generators, Boiler, Heaters and Recycle Treater	445,741	6,348,200	326.4	30.00	3.500	5.0	553	0.744	0.514	0.480	0.044	0.036
Total E&P Canada Ltd. – Joslyn Creek SAGD Project Phase 3A													
	Total E&P Joslyn SAGD Phase 3A – Steam Generators	445,794	6,348,200	326.2	30.00	1.800	17.3	437	0.956	0.713	0.673	0.061	0.045
Total E&P Canada Ltd. – Joslyn Creek SAGD Project North Mine													
	Total E&P Joslyn North Mine – Cogeneration Unit	450,875	6,349,645	306.8	38.00	4.600	22.0	393	0.095	2.661	1.787	0.199	0.414
Petro-Canada Oil Sands Inc. – Fort Hills Oil Sands Project													
	Petro-Canada Oil Sands Inc. Fort Hills – Gas Turbines, Auxiliary Boilers and Space Heaters	462,000	6,360,000	279.6	38.00	4.000	28.6	378	0.050	3.401	0.440	0.190	0.000
Synenco Energy Inc. – Northern Lights Project													
	Synenco Northern Lights – Cogeneration Unit	498,565	6,378,840	288.8	37.50	3.400	25.5	483	0.040	4.140	3.600	0.320	0.164
Pengrowth Corporation – Lindbergh													
	Pengrowth Lindbergh – Steam Generator	525,249	5,984,860	665.5	17.50	0.789	20.0	469	0.230	0.079	0.107	0.010	0.007
Williams Energy – Chemical Plant													
	Williams Energy Chemical Plant – Heat Medium Heater and Plant Fugitives	471,754	6,314,125	321.6	32.40	1.400	6.2	553	0.000	0.020	0.017	0.002	0.240
Other Compressor Stations													
	Paramount – Quigley Compressor Station	510,225	6,224,400	513.2	12.40	0.432	27.6	683	0.000	0.264	0.028	0.001	0.008
	Paramount – Hangingstone Compressor Station	477,850	6,205,850	699.1	15.43	0.440	31.3	683	0.000	0.198	0.018	0.001	0.006
	Paramount – Kettle River Compressor Station	511,100	6,205,700	470.1	8.00	0.432	26.8	672	0.000	0.230	0.036	0.002	0.007
	Viking Energy – Wappau Compressor Station	451,854	6,137,651	655.2	10.00	0.300	20.0	773	0.000	0.355	0.028	0.001	0.010
	AltaGas – John Lake North Compressor Station	562,715	5,971,048	670.1	12.20	0.250	68.6	881	0.000	0.636	0.066	0.002	0.024
	BP – St. Lina Compressor Station	486,624	6,032,149	564.7	14.00	0.250	56.0	862	0.000	0.913	0.133	0.004	0.049
	Canadian Natural – Kehiwin Compressor Station	507,197	5,997,740	589.2	11.00	0.300	21.0	928	0.000	0.479	0.032	0.001	0.012
	Northstar – Frenman Lake Compressor Station	480,139	6,045,128	630.9	14.90	0.305	33.4	851	0.000	0.492	0.034	0.001	0.013

[a] Source coordinates are in UTM NAD 83.
[b] For flare stack pseudo stack height and pseudo stack diameter were used in the disperion modelling.
[c] SO_2 emissions are based on calendar–day emission rates.

Table C-2 Planned Development Case Area Source Emission Characteristics

No.	Source Description	Centre Easting [m]	Centre Northing [m]	Source Area [m²]	Effective Height [m]	Base Elevation [m]	Initial σ_z [m]	Emission Rate [t/d]				
								SO_2[(a)]	NO_X	CO	$PM_{2.5}$	VOC
MEG Energy Corp. – Christina Lake Regional Project - Phase 2B												
	MEG Christina Lake Phase 2B – Plant Fugitives	517,842	6,169,014	429,029	7.30	579.0	3.4	0.000	0.000	0.000	0.000	0.009
MEG Energy Corp. – Christina Lake Regional Project - Phase 3A												
	MEG Christina Lake Phase 3A – Plant Fugitives	525,862	6,162,608	367,587	7.30	609.7	3.4	0.000	0.000	0.000	0.000	0.011
MEG Energy Corp. – Christina Lake Regional Project - Phase 3B												
	MEG Christina Lake Phase 3B – Plant Fugitives	506,760	6,174,709	367,891	7.30	603.2	3.4	0.000	0.000	0.000	0.000	0.011
Canadian Natural Resources Ltd. – Primrose North												
	Canadian Natural Primrose North – Plant Fugitives	526,786	6,081,227	40,716	3.00	692.8	1.5	0.000	0.000	0.000	0.000	0.004
Canadian Natural Resources Ltd. – Primrose South												
	Canadian Natural Primrose South – Plant Fugitives	527,180	6,069,628	137,530	3.00	677.1	1.5	0.000	0.000	0.000	0.000	0.008
Canadian Natural Resources Ltd. – Primrose East												
	Canadian Natural Primrose East – Plant Fugitives	541,477	6,071,777	39,614	3.00	693.7	1.5	0.000	0.000	0.000	0.000	0.004
Canadian Natural Resources Ltd. – Wolf Lake												
	Canadian Natural Wolf Lake – Plant Fugitives	517,629	6,061,112	184,404	3.00	642.2	1.5	0.000	0.000	0.000	0.000	0.018
Canadian Natural Resources Ltd. – Horizon												
	Canadian Natural Horizon – Mine Fleet	456,164	6,352,842	7,282,341	7.50	280.4	7.0	0.432	33.125	20.886	1.205	13.051
	Canadian Natural Horizon – Tailings Pond	445,625	6,355,250	16,875,000	0.00	334.9	1.4	0.000	0.000	0.000	0.000	139.361
	Canadian Natural Horizon – Plant Fugitives	455,389	6,355,125	977,900	3.00	276.4	1.5	0.000	0.000	0.000	0.000	4.130
Canadian Natural Resources Ltd. – Kirby												
	Canadian Natural Kirby – Plant Fugitives	498,450	6,132,880	179,564	3.00	731.9	1.5	0.000	0.000	0.000	0.000	0.004
Petro-Canada Oil and Gas – MacKay River Phase 1												
	Petro-Canada MacKay River – Central Processing Area	445,065	6,322,000	33,600	3.00	415.9	1.5	0.000	0.000	0.000	0.000	0.263
Petro-Canada Oil and Gas – MacKay River Expansion												
	Petro-Canada MacKay River Expansion – Central Processing Area	444,965	6,322,685	59,500	3.00	419.2	1.5	0.000	0.000	0.000	0.000	0.039
Imperial Oil Resources Ventures Limited – Kearl Oil Sands Project												
	Imperial Oil Kearl – Space Heating at Plant Site	495,750	6,362,000	1,500,000	9.00	345.0	4.5	0.002	0.576	0.255	0.023	0.017
	Imperial Oil Kearl – Space Heating at Mine Maintenance	496,319	6,361,103	319,184	9.00	362.9	4.5	0.021	2.413	2.471	0.229	0.167
	Imperial Oil Kearl – Mine Area 1	489,618	6,363,496	3,027,544	7.50	298.4	7.0	0.061	3.009	1.908	0.109	1.544
	Imperial Oil Kearl – Mine Area 2	491,265	6,362,400	6,732,296	7.50	302.3	7.0	0.136	6.691	4.242	0.242	3.434
	Imperial Oil Kearl – Mine Area 3	493,593	6,361,619	3,113,700	7.50	318.9	7.0	0.063	3.095	1.962	0.112	1.588
	Imperial Oil Kearl – Mine Area 4	493,098	6,359,780	7,974,591	7.50	320.0	7.0	0.162	7.926	5.025	0.287	4.067
	Imperial Oil Kearl – Mine Area 5	493,121	6,357,627	7,779,471	7.50	331.3	7.0	0.158	7.732	4.902	0.280	3.968
	Imperial Oil Kearl – Tailings Pond	496,208	6,364,433	19,160,717	0.00	415.0	1.4	0.000	0.000	0.000	0.000	137.949
	Imperial Oil Kearl – Plant Fugitives	495,750	6,362,000	1,500,000	3.00	345.0	1.5	0.000	0.000	0.000	0.000	3.545
Shell Canada Limited – Jackpine Phase 1												
	Shell Jackpine Phase 1 – Mine Fleet	486,236	6,359,812	20,186,420	7.50	299.0	7.0	0.013	8.544	10.450	0.248	10.379
	Shell Jackpine Phase 1 – Tailings Pond	479,189	6,341,968	6,855,469	0.00	324.8	1.4	0.000	0.000	0.000	0.000	9.920
	Shell Jackpine Phase 1 – Space Heating	476,626	6,344,555	53,280	9.00	312.8	4.5	0.004	0.351	0.537	0.049	0.035
Shell Canada Limited – Jackpine Expansion												
	Shell Jackpine Expansion – Tailings Pond	483,183	6,357,493	3,427,682	0.00	299.8	1.4	0.000	0.000	0.000	0.000	4.960
Shell Canada Limited – Pierre River Mine												
	Shell Pierre River Mine – Mine Area	461,568	6,371,140	13,012,525	7.50	274.7	7.0	0.009	5.696	6.967	0.165	6.920
	Shell Pierre River Mine – Tailings Pond	462,445	6,381,485	6,737,024	0.00	285.2	1.4	0.000	0.000	0.000	0.000	9.920
Suncor Energy Ltd. – South Tailings Pond												
	Suncor – South Tailings Pond	479,946	6,303,293	13,499,746	0.00	357.1	1.4	0.000	0.000	0.000	0.000	4.536
Suncor Energy Ltd. – Lease 86/17, Steepbank & Millennium Mines												
	Suncor Millennium – Mine Area 1	476,337	6,308,933	16,927,841	7.50	327.9	7.0	0.024	4.195	4.502	0.220	1.779
	Suncor Millennium – Mine Area 2	479,889	6,309,136	12,157,244	7.50	353.4	7.0	0.017	3.013	3.233	0.158	1.277
	Suncor Millennium – Mine Area 3	479,460	6,312,914	10,583,788	7.50	355.4	7.0	0.015	2.623	2.815	0.138	1.112
	Suncor Millennium – Mine Area 4	475,875	6,313,337	16,121,151	7.50	329.7	7.0	0.023	3.995	4.287	0.210	1.694
	Suncor Millennium – Mine Area 5	484,986	6,304,653	11,160,247	7.50	425.0	7.0	0.016	2.766	2.968	0.145	1.173
	Suncor Millennium – Mine Area 6	484,822	6,314,425	8,842,793	7.50	407.1	7.0	0.013	2.191	2.352	0.115	0.929
	Suncor Millennium – Tailings Ponds	468,846	6,316,410	1,595,400	0.00	311.7	1.4	0.000	0.000	0.000	0.000	215.441
	Suncor Millenium – Plant Fugitives	470,840	6,317,948	795,855	3.00	255.9	1.5	0.000	0.000	0.000	0.000	16.982
Suncor Energy Ltd. – Voyageur Upgrader												
	Suncor Voyageur – Coke Handling Fleet	469,453	6,312,758	2,696,581	7.50	317.7	7.0	0.009	0.771	0.478	0.027	0.107
	Suncor Voyageur – Plant Fugitives	469,284	6,314,266	772,176	3.00	322.4	1.5	0.000	0.000	0.000	0.000	0.609
	Suncor Voyageur – Tank Farm Fugitives	471,383	6,313,327	431,354	3.00	321.1	1.5	0.000	0.000	0.000	0.000	0.261
Suncor Energy Ltd. – North Steepbank Extension Mine												
	Suncor North Steepbank Extension – Mine Area 1	475,888	6,319,693	3,423,903	7.50	336.3	7.0	0.041	7.199	7.725	0.378	3.052
	Suncor North Steepbank Extension – Mine Area 2	478,653	6,317,607	2,759,239	7.50	341.4	7.0	0.033	5.802	6.225	0.304	2.460
	Suncor North Steepbank Extension – Mine Area 3	476,490	6,317,776	1,800,591	7.50	338.1	7.0	0.022	3.786	4.062	0.199	1.605
Suncor Energy Ltd. – Firebag SAGD Project												
	Suncor Firebag SAGD – Plant Fugitives	509,033	6,343,966	1,523,598	3.00	582.4	1.5	0.000	0.000	0.000	0.000	0.058
Suncor Energy Ltd. – Voyageur South Project												
	Suncor Voyageur South – Mine Area 1	458,987	6,311,238	9,029,534	7.50	351.8	7.0	0.002	3.345	2.131	0.122	0.463
	Suncor Voyageur South – Mine Area 2	464,814	6,308,902	10,034,149	7.50	324.8	7.0	0.002	3.717	2.368	0.135	0.515
	Suncor Voyageur South – Mine Area 3	467,902	6,306,238	4,297,413	7.50	319.4	7.0	0.001	1.592	1.014	0.058	0.220
	Suncor Voyageur South – Mine Face	459,427	6,306,137	20,508,453	0.00	376.3	1.4	0.000	0.000	0.000	0.000	1.680
	Suncor Voyageur South – Tailings Pond (primary)	463,376	6,311,402	15,948,083	7.50	324.9	7.0	0.000	0.000	0.000	0.000	3.763
Syncrude Canada Ltd. – Mildred Lake Upgrader												
	Syncrude Mildred Lake – North Mine Area	457,682	6,322,263	8,140,000	7.50	335.0	7.0	0.051	17.200	4.500	0.490	6.953
	Syncrude Mildred Lake – West Base Mine Area	459,594	6,317,471	3,680,000	7.50	325.0	7.0	0.006	2.000	0.500	0.060	0.887
	Syncrude Mildred Lake – Basin Tailings Pond	462,170	6,325,360	11,560,000	0.00	307.6	1.4	0.000	0.000	0.000	0.000	33.216
	Syncrude Mildred Lake – Basin Beach Tailings Ponds	461,490	6,325,460	18,490,000	0.00	288.9	1.4	0.000	0.000	0.000	0.000	0.315
	Syncrude Mildred Lake – East Mine In-Pit Tailings Ponds	464,259	6,318,850	10,236,800	0.00	310.5	1.4	0.000	0.000	0.000	0.000	0.708
	Syncrude Mildred Lake – West Mine In-Pit Tailings Ponds	461,312	6,318,630	6,250,000	0.00	312.4	1.4	0.000	0.000	0.000	0.000	0.461
	Syncrude Mildred Lake – Southwest Sand Storage Area	455,050	6,316,790	23,040,000	0.00	357.4	1.4	0.000	0.000	0.000	0.000	7.504
	Syncrude Mildred Lake – Southwest Sand Storage Pond	453,480	6,315,780	1,960,000	0.00	375.9	1.4	0.000	0.000	0.000	0.000	0.650
Syncrude Canada Ltd. – Aurora South Mine												
	Syncrude Aurora South – Mine Area	486,311	6,344,136	6,000,000	7.50	360.1	7.0	0.027	9.900	2.400	0.260	6.611
	Syncrude Aurora South – Tailings Pond	480,453	6,337,883	3,610,000	0.00	339.4	1.4	0.000	0.000	0.000	0.000	1.120
Syncrude Canada Ltd. – Aurora North Mine												
	Syncrude Aurora North – Mine Area	467,965	6,353,037	6,000,000	7.50	299.6	7.0	0.035	13.100	3.200	0.340	6.741
	Syncrude Aurora North – Tailings Pond	473,940	6,351,540	3,610,000	0.00	288.4	1.4	0.000	0.000	0.000	0.000	1.120
Birch Mountain Resources Ltd. – Muskeg Valley Quarry												
	Birch Mountain Muskeg Valley Quarry – Quarry	466,281	6,338,172	62,500	5.00	255.4	4.7	0.020	0.880	0.300	0.050	0.050
	Birch Mountain Muskeg Valley Quarry – Aggregate 1	466,650	6,336,219	90,000	5.00	264.0	4.7	0.018	0.710	0.239	0.059	0.041
	Birch Mountain Muskeg Valley Quarry – Aggregate 2	465,860	6,336,164	35,721	5.00	257.5	4.7	0.004	0.168	0.056	0.014	0.010
	Birch Mountain Muskeg Valley Quarry – Aggregate 3	466,065	6,335,550	71,289	5.00	257.5	4.7	0.009	0.335	0.113	0.029	0.019
	Birch Mountain Muskeg Valley Quarry – Aggregate 4	466,634	6,335,550	71,289	5.00	264.1	4.7	0.009	0.335	0.113	0.029	0.019
	Birch Mountain Muskeg Valley Quarry – Aggregate Transport Paved	466,862	6,338,658	1,069,588	5.00	259.0	4.7	0.042	1.629	0.548	0.057	0.094
	Birch Mountain Muskeg Valley Quarry – Aggregate Transport Unpaved 1	466,474	6,335,879	1,032,852	5.00	262.2	4.7	0.015	0.576	0.193	0.006	0.034
	Birch Mountain Muskeg Valley Quarry – Aggregate Transport Unpaved 2	466,609	6,339,112	149,606	5.00	257.7	4.7	0.000	0.010	0.003	0.002	0.001
Albian Sands Energy Inc. – Muskeg River Mine Expansion												
	Albian Sands MRME – Mine Area 1	463,677	6,347,888	4,500,000	7.50	274.2	7.0	0.560	20.598	19.447	0.877	10.990
	Albian Sands MRME – Mine Area 2	468,138	6,338,213	4,534,313	7.50	273.6	7.0	0.053	1.943	1.835	0.083	1.037
	Albian Sands MRME – Tailings Pond	464,195	6,346,514	3,037,608	0.00	269.8	1.4	0.000	0.000	0.000	0.000	14.384
Total E&P Canada Ltd. – Joslyn Creek SAGD North Mine												
	Total E&P Joslyn SAGD North Mine – Mine Area and Fugitives	452,994	6,349,343	6,590,220	7.50	307.2	7.0	0.006	9.200	7.824	0.237	3.208
	Total E&P Joslyn SAGD North Mine – Space Heating	450,975	6,349,968	53,280	9.00	306.8	4.5	0.001	0.360	0.069	0.017	0.003
	Total E&P Joslyn SAGD North Mine – Tailings Pond	451,378	6,346,682	3,427,312	0.00	308.5	1.4	0.000	0.000	0.000	0.000	43.197
Petro-Canada Oil Sands Inc. – Fort Hills												
	Petro-Canada Fort Hills – Mine Area	463,000	6,358,000	8,000,000	7.50	285.2	7.0	1.950	25.200	5.481	0.610	1.028
	Petro-Canada Fort Hills – Tailings Pond	461,250	6,355,250	250,000	0.00	285.1	1.4	0.000	0.000	0.000	0.000	14.220
Synenco Energy Inc. – Northern Lights Project												
	Synenco Northern Lights – Mine Area	500,100	6,375,500	3,600,000	7.50	300.7	7.0	0.350	11.570	7.790	0.450	4.660
	Synenco Northern Lights – Tailings Pond	506,950	6,383,950	4,590,000	0.00	305.0	1.4	0.000	0.000	0.000	0.000	58.590
	Synenco Northern Lights – Plant Fugitives	500,100	6,378,850	500,000	3.00	295.9	1.5	0.000	0.000	0.000	0.000	1.500
Other Industries												
	CAF[(b)] Cold Lake Air Force Base	547,389	6,029,644	20,599,370	5.00	521.1	5.0	0.001	0.060	0.040	0.004	0.003
	CAF[(b)] Cold Lake Air Weapons Range	521,964	6,100,208	5,281,660,440	0.00	681.7	30.5	0.530	9.990	40.190	0.210	0.142
	Parsons Creek North Quarry	473,427	6,300,607	621,282	5.00	246.3	4.7	0.001	0.063	0.021	0.004	0.004
Other Industries												
	Anzac	497,400	6,255,500	8,400,000	0.00	485.4	7.0	0.005	0.018	0.132	0.298	0.060
	Janvier	516,660	6,198,690	25,000,000	0.00	451.0	7.0	0.001	0.004	0.029	0.064	0.013
	Conklin	494,254	6,165,275	2,000,000	0.00	578.5	7.0	0.002	0.007	0.051	0.116	0.023
	Beaver Lake (IR 131)	441,941	6,059,727	2,000,026	0.00	579.0	7.0	0.002	0.008	0.059	0.133	0.027
	Bonnyville	517,192	6,012,974	3,750,040	0.00	568.4	7.0	0.032	0.166	0.885	1.657	0.341
	Cold Lake	552,943	6,035,613	2,925,006	0.00	548.8	7.0	0.006	0.031	0.168	0.315	0.065
	Cold Lake - Grand Centre	551,443	6,030,225	6,000,021	0.00	535.6	7.0	0.012	0.064	0.345	0.645	0.133
	Cold Lake Air Force Base	547,389	6,029,644	20,599,370	0.00	521.1	7.0	0.043	0.221	1.184	2.215	0.456
	Cold Lake (IR 149)	549,943	6,021,225	3,999,953	0.00	521.1	7.0	0.002	0.010	0.055	0.103	0.021
	Cold Lake (IR 149B)	548,943	6,040,725	1,999,944	0.00	546.2	7.0	0.000	0.002	0.013	0.024	0.005
	Elizabeth Metis Settlement	558,944	6,007,976	3,000,025	0.00	551.0	7.0	0.005	0.017	0.125	0.282	0.057
	Heart Lake (IR 167)	465,442	6,091,727	1,000,025	0.00	614.3	7.0	0.001	0.003	0.020	0.044	0.009
	Kehiwin (IR 123)	509,441	5,996,226	6,001,057	0.00	573.0	7.0	0.005	0.019	0.140	0.317	0.064
	La Loche	596,482	6,260,975	15,586,704	0.00	444.7	7.0	0.015	0.075	0.576	1.358	0.259
	Lac La Biche	437,191	6,069,477	2,250,020	0.00	551.8	7.0	0.015	0.078	0.419	0.785	0.161
	Peter Pond (IR 193)	626,199	6,199,973	2,499,768	0.00	423.0	7.0	0.005	0.018	0.127	0.287	0.058
	Pierceland	579,444	6,021,725	1,000,028	0.00	526.7	7.0	0.003	0.016	0.121	0.160	0.055
	St. Paul	480,818	5,982,726	6,500,083	0.00	639.4	7.0	0.030	0.157	0.837	1.566	0.322

[(a)] SO_2 emissions are based on calendar-day emission rates.
[(b)] CAF = Canadian Air Force