APPENDIX K

Air Quality Impact Assessment
Brandon Generating Station
Licence Review

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EXECUTIVE SUMMARY

The Brandon Generating Station (Brandon G.S.), located on the eastern boundary of the City of Brandon, on the southern shore of the Assiniboine River, is an important part of Manitoba Hydro's integrated system. This document provides an air quality impact assessment to the Environmental Impact Statement (EIS) that has been prepared as part of the Environment Act Licence Review (EALR) for the coal-fired operation of Brandon Unit 5 (Unit #5).

The potential effects of air pollutant emissions from the Bandon G.S. on ambient air quality were evaluated using plume dispersion models to simulate the transport and diffusion of air pollutants that would be emitted from the boiler, sources of fugitive dust, and cooling tower emissions. Dispersion modelling was performed using two sets of coal properties (i.e., heating value, sulphur content, ash content, trace metal concentrations): one set representing the current coal that is being used at the plant, and a second set representing the range of properties associated with coal from ten potential alternative suppliers that could be used in the future. In addition, in order to account for the range of performance variation associated with the different burner row combinations in the boiler, dispersion modelling was performed for the most efficient combination and the least efficient combination. Modelling results for the most efficient (and most commonly used) burner row combination are referred to as Operating Scenario 1 (OS1), while results for the alternative (less efficient burner row combination) are referred to as Operating Scenario 2 (OS2). The modelling results for the OS2 estimate represent the greatest possible emission rates; however, they do not characterize typical Unit #5 operation. Air dispersion modelling results based on the current coal properties were used for the OS1 and OS2 emission estimates, while results based on the set of alternative (upper-bound) coal properties were assessed as Operational Scenario 3 (OS3) emission estimates.

The practical maximum generation for Unit #5 is expected to be 830 GWh (i.e., 90% of its maximum rated capacity of 920 GWh). The maximum annual generation in any given year from 1992-2005 was 639.6 GWh per year in 2003, or 69% of its rated capacity. The average generation rate over the most recent 5-year period 2001-2005 was 434.6 GWh, or 47% of Unit #5's rated capacity. However, for the purposes of the air quality and risk assessments, the analysis has been conservatively conducted at 100% capacity factor, or 920 GWh.

The air emissions from sub-bituminous coal combustion primarily consist of common contaminants such as oxides of nitrogen (NO_x) and carbon monoxide (CO), sulphur dioxide (SO_2) and particulate matter (SPM, PM_{10} and $PM_{2.5}$). There are also small quantities of some volatile organic compounds, hydrogen chloride (HCl), hydrogen fluoride (HF), and trace quantities of both organic compounds and inorganic elements associated with the particulate matter. The combustion of coal also results in emissions of carbon dioxide (CO_2), and small quantities of other greenhouse gases such as methane (CH_4) and nitrous oxide (N_2O). Ambient ground level concentrations were calculated for common contaminants (CO, NO_2, SO_2 and particulate matter), volatile organic compounds (VOCs), as well as trace organic (PAHs) and inorganic (e.g., metals) species. Deposition rates were calculated for particulate matter, as well as trace organic and inorganic contaminants. The predicted concentrations of common contaminants were compared with observed ambient air quality data from stations in Brandon. For pollutants not monitored in Brandon, comparisons were also made for available data from Winnipeg. Predicted air quality impacts were evaluated with respect to ambient air quality objectives standards and guidelines established by Manitoba Conservation. In addition, selected VOCs and trace contaminants were evaluated by comparison with ambient air quality criteria adopted in other provinces.

The results from the air quality impact assessment were then used to conduct screening-level human health and ecological (trees, plants, wild and domestic animals) risk assessments for common air contaminants, as well as for trace quantities of organic and inorganic emissions that are not covered by provincial or federal ambient air quality standards, objectives or guidelines. The results of the human health and ecological risk assessments are presented in the report: *Human Health and Ecological Risk Assessment, Brandon Generating Station Licence Review, Appendix N.*

Existing Air Quality

The NO_2 monitoring data in Brandon indicate that the Manitoba Maximum Acceptable objectives have not been exceeded over the available period of monitoring data since 1997. The annual average NO_2 concentration from all sources is only about one-tenth of the Maximum Acceptable Objective required by Manitoba Conservation. Similarly, the maximum observed 1-hour and 24-hour average NO_2 concentrations in Brandon are only about 25-35% of the provincial Maximum Acceptable objectives.

There is currently no SO_2 monitoring in Brandon. SO_2 monitoring was discontinued in Brandon in 1989, but readings prior to that were too low to register (0.0 ppm). Similarly, there is no CO monitoring for Brandon.

Fine particulate matter ($PM_{2.5}$) has been monitored in Brandon since 2001. $PM_{2.5}$ concentrations from all sources are well below the Canada-Wide Standard (CWS) level. No data are available for total suspended particulate matter (SPM), but the measured maximum 24-hour average PM_{10} concentrations at the Assiniboine Community College consistently exceed the Manitoba Guideline value of 50 $\mu g/m^3$. As discussed below, the contribution of Unit #5 to PM_{10} concentrations in Brandon is insignificant. Therefore, the primary cause for the high levels of

PM_{10} is believed to be related to fugitive dust emissions from agricultural activity in the area, as well as possibly due to seasonal burning of agricultural waste and stubble in fields. The magnitude of the highest PM_{10} concentrations also suggests that the provincial Maximum Acceptable SPM objective of 120 µg/m^3 is also being exceeded.

Source Data

The emission rates for common contaminants and mercury are listed below in various units of measure. The emission rates are listed at the maximum sustained generation rate for the preferred operating scenario (OS1)[1] and the least efficient operating scenarios (OS2 and OS3).

Contaminants	**Emission Rates**[a]								
	g/s			kg/hr			kg/MWh[b]		
	OS1	**OS2**	**OS3**[d]	**OS1**	**OS2**	**OS3**	**OS1**	**OS2**	**OS3**
SPM	2.5	4.1	5.6	9.0	14.8	20.0	0.086	0.141	0.190
PM_{10}	2.3	3.8	5.1	8.3	13.7	18.5	0.079	0.130	0.176
$PM_{2.5}$	1.5	2.3	3.2	5.4	8.4	11.3	0.051	0.080	0.108
SO_2	68.5	72.1	95.8	246.6	259.6	345.3	2.349	2.472	3.289
NO_2[c]	87.8	116.0	116.0	316.2	417.6	417.6	3.011	3.977	3.977
CO	5.8	6.90	6.90	20.9	24.8	24.8	0.199	0.236	0.236
Hg[e]	0.0006	0.0006	0.0006	0.0026	0.0026	0.0026	0.00002	0.00002	0.00002

[a] maximum sustained generation rate (105 MW)
[b] heat output basis
[c] assuming 100% conversion of NO to NO_2
[d] based on alternative (upper-bound) coal properties
[e] based on emission cap of 20 kg/year

Predicted Air Quality Impacts

The results of the dispersion modelling analysis for air contaminants indicate that the maximum predicted incremental impacts due to typical emissions from Unit #5 operations are below the Manitoba Maximum Acceptable Level air quality objectives or guidelines. Two exceptions to this conclusion are:

1) A hypothetical exceedance of the Maximum Acceptable 1-hour average NO_2 objective for the conservative (but scientifically unrealistic) assumption that all of the NO is immediately converted to NO_2 as it leaves the stack. For such an assumption, adding an assumed background concentration greater than 78 µg/m^3 to the maximum predicted NO_2 concentration would be expected to result in an exceedance of the objective level on no more than one hour per year. However, a realistic estimate of NO to NO_2 conversion

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[1] Based on burner configuration (see Section 3.1 of the report for a description of burner configurations).

indicates that the objective would never actually be exceeded under any operating conditions.

2) Conservatively estimated SPM emission rates for coal handling and storage suggest that the maximum predicted 24-hour average SPM concentrations may, on occasion, approach the provincial Maximum Acceptable objective at or near the fenceline. Coupled with the already high background SPM levels in the area, fugitive coal dust emissions may thus occasionally contribute to exceedances of the objective level. However, the emission estimates used for the dispersion modelling analysis do not fully account for all of the best management practices for controlling emissions that are employed at the plant. Consequently, the magnitude of the maximum predicted fugitive coal dust concentrations is uncertain, but is likely overestimated in this assessment.

Nitrogen Dioxide (NO_2)

The Manitoba Maximum Acceptable objective value for 1-hour average NO_2 concentrations is 400 µg/m^3. The highest NO_x emissions from the Unit #5 boiler occur with the less efficient OS2[2] burner configuration. The OS2 configuration is only used 10% of the time, compared with 60% for the most efficient OS1 configuration.

The major portion (64%) of NO_x emitted from the Unit #5 stack is emitted as NO, which is subsequently converted to NO_2 as the plume is transported downwind. For regulatory purposes, NO_x emissions are often evaluated using an assumption that all of the NO is immediately converted to NO_2 when it leaves the stack. This is an overly conservative assumption because, in reality, it takes quite a bit of time for this conversion to occur in the atmosphere. For the purposes of this assessment, the predicted NO_2 impacts due to Unit #5 NO_x emissions have been evaluated using both the conservative assumption of 100% conversion at the stack tip, as well as using a more realistic conversion estimate (referred to in the assessment as the Janssen method).

The maximum predicted 1-hour average NO_2 concentration using the preferred OS1 burner configuration is 243 µg/m^3. Adding the estimated background NO_2 concentrations to the predicted concentration for Unit #5 for the preferred OS1 configuration would not result in any exceedance of the provincial Maximum Acceptable objective, regardless of which NO to NO_2 conversion scheme is used.

At the measured NO_x emission rates for Unit #5 under the OS2 burner configuration, the highest off-site 1-hour average NO_2 concentration would be 322 µg/m^3, if the analysis is based on the assumption that all the NO is instantaneously converted to NO_2 as the exhaust gas leaves the

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[2] Note that emissions for the OS3 burner configuration are the same as for the OS2 configuration.

stack. This value is predicted to occur on 1 hour per year at a location SE of the Brandon G.S., near the sewage treatment plant. However, 99.95 percent of the time the predicted NO_2 concentration would be less than 75 µg/m^3 at this location. Adding an estimated[3] background NO_2 concentration of 102 µg/m^3 to the maximum predicted concentration of 322 µg/m^3 suggests that the provincial objective of 400 µg/m^3 might be exceeded on no more than 1 day per year. A more realistic assessment of maximum potential NO_2 impacts using the Janssen method indicates that the maximum predicted 1-hour average NO_2 concentrations due to Unit #5 emissions would be only 119 µg/m^3 for the OS2 configuration, and adding the background NO_2 concentration to this value would mean that the provincial objective would not in fact be exceeded at any time when operating in the OS2 configuration.

Air quality impacts due to NO_x emissions were also evaluated for the combined emissions of Unit #5 and the two combustion turbines at the plant (Units #6 and #7). The maximum predicted 1-hour average NO_2 concentration is 360 µg/m^3, which is predicted to occur on only 1 day per year if it is assumed that all of the NO from Unit #5 and the CTs is immediately converted to NO_2 upon leaving the stacks. If the background NO_2 concentration is assumed to be 102 µg/m^3, the provincial Maximum Acceptable objective of 400 µg/m^3 could be exceeded on one hour per year. If the more realistic Janssen conversion method is used, the maximum predicted 1-hour average NO_2 concentration for combined operations would be only 119 µg/m^3, and the provincial objective would not be exceeded.

Assuming 100% conversion of NO to NO_2 at the stack, the maximum predicted 24-hour average NO_2 concentration is estimated to be 24 µg/m^3 for OS2, and 17 µg/m^3 for OS1. If the highest 24-hour average NO_2 concentration of 57 µg/m^3 recorded in Brandon over the 5-year period 2000-2004 is assumed to be representative of background NO_2 levels at the maximum point of impingement for the Unit #5 plume, the combined impact of background levels plus emissions from Unit #5 would not exceed the Maximum Acceptable objective of 200 µg/m^3. The provincial Maximum Acceptable objective would also not be exceeded at any location even with the combined emissions of Unit #5 and the two combustion turbines.

The maximum predicted annual average NO_2 concentration due to emissions from the Brandon G.S. is estimated to provide an insignificant contribution of less than 1 µg/m^3 to overall NO_2 levels in the Brandon area.

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[3] The background NO_2 concentration at the Assiniboine Community College monitoring station was estimated by subtracting the maximum predicted NO_2 concentration due to Unit #5 emissions at that location from the maximum observed NO_2 concentration during the period 2000-2004.

Sulphur Dioxide (SO_2)

For power generation using the current coal supplied from the Spring Creek mine, maximum predicted 1-hour average SO_2 concentrations range from 200 µg/m^3 for OS2 to 190 µg/m^3 for the preferred OS1. After reviewing the coal properties of 16 other suppliers of coal, Manitoba Hydro screened out those that would not be considered acceptable on the basis of sulphur content. For alternative sub-bituminous coals that might be used in the future, the maximum 1-hour average SO_2 concentrations for OS3 would not exceed 265.5 µg/m^3. The results indicate that the provincial objective of 900 µg/m^3 would not be exceeded either for current or potential future operations using coal with a slightly higher sulphur content.

The maximum predicted 24-hour average SO_2 concentrations of 13.9 µg/m^3 for OS1 and 14.6 µg/m^3 for OS2 are well below the provincial Maximum Acceptable objective of 300 µg/m^3. Even if in the future the plant were to burn a coal with 33% higher sulphur content, the predicted concentrations of 18.5 µg/m^3 and 19.5 µg/m^3 for the two operating scenarios, respectively, would still be well below the provincial objective of 300 µg/m^3.

The maximum predicted annual average SO_2 concentration due to emissions from the Brandon G.S. is estimated to provide an insignificant contribution of less than 1 µg/m^3 to overall SO_2 levels in the Brandon area.

Carbon Monoxide (CO)

The maximum predicted 1-hour average CO concentrations of 19.1 µg/m^3 for OS2 and 16.1 µg/m^3 for OS1 are insignificant compared with the provincial Maximum Acceptable objective of 35,000 µg/m^3. Similarly, the maximum predicted 8-hour average CO concentrations of 4.2 µg/m^3 for OS2 and 3.5 µg/m^3 for OS1 are insignificant compared with the provincial Maximum Acceptable objective of 15,000 µg/m^3.

Maximum predicted CO concentrations for combined emissions from Unit #5 and the two combustion turbines results in much higher 1-hour and 8-hour average CO concentrations due to the higher impacts of the CO emissions from the combustion turbines. The maximum predicted 1-hour average CO concentration for combined emissions is 192 µg/m^3, consisting primarily of 188 µg/m^3 from the two turbines. Similarly, the maximum predicted 8-hour average CO concentration of 63 µg/m^3 for combined emissions is entirely derived from the turbines because the contribution of Unit #5 emissions to total CO concentration is insignificant at the maximum point of impingement for the emissions from the two CTs. Even with the higher predicted concentrations for the combined emissions from Unit #5 and the two combustion turbines, the provincial objectives for 1-hour and 8-hour averaged CO concentrations would not be exceeded at any time.

Particulate Matter (SPM, PM_{10} & $PM_{2.5}$)

The Canada-Wide Standard (CWS) parameter for $PM_{2.5}$ is 30 µg/m^3 (98th percentile, averaged over three consecutive years). Manitoba Conservation also uses a value of 30 ug/m^3 (100th percentile with no 3-year averaging) when evaluating emission sources for regulatory permitting. The value of the CWS parameter measured at the Assiniboine Community College in 2004 was 16 µg/m^3. At the maximum point of impingement, the highest predicted 24-hour average $PM_{2.5}$ concentration due to emissions from the Brandon G.S. Unit #5 stack is less than 0.7 µg/m^3, which would make it undetectable by a standard $PM_{2.5}$ monitor. The predicted concentration at the Assiniboine Community College monitoring station would be less than 0.3 µg/m^3. Even with combined emissions from Unit #5 and the two CTs, the maximum predicted $PM_{2.5}$ concentration would still be less than 1 µg/m^3.

The maximum predicted 24-hour average $PM_{2.5}$ concentrations for fugitive dust from coal and ash storage are conservatively estimated at 15 µg/m^3 and 1 µg/m^3, respectively. At the point of maximum predicted concentration, the 98th percentile 24-hour average concentration for fugitive coal dust is only 1.7 µg/m^3, while that for ash is much less than 1 µg/m^3. Although the maximum point of impingement for the Unit #5 stack emissions and fugitive coal/ash emissions do not occur at the same location, the CWS parameter in the area would not be exceeded even if they did coincide and were added to the 98th percentile level of 16 µg/m^3 measured at the Assiniboine Community College in Brandon.

The Manitoba guideline value for 24-hour averaged PM_{10} is 50 µg/m^3. For PM_{10} emissions from the Unit #5 stack, the maximum predicted 24-hour average incremental concentration is less than 1 µg/m^3. Based on potential future coal supplies having up to 35% higher ash content, the maximum predicted 24-hour average PM_{10} concentrations would be 1.1 µg/m^3 for OS2 and 0.7 µg/m^3 for the preferred OS1 burner configuration. These values are at or below the measurement accuracy of a PM_{10} monitor. Therefore, the contributions of particulate matter emissions from the Unit #5 stack do not significantly contribute to the exceedances of the provincial PM_{10} guideline of 50 µg/m^3 that have been consistently recorded at the PM_{10} monitor in Brandon.

The maximum predicted PM_{10} concentrations for fugitive dust emissions are conservatively estimated at: 1) 27 µg/m^3 for coal dust in a location approximately 200 metres south of the plant, and 2) at 7 µg/m^3 for ash emissions along the northern boundary of the ash storage area. Ninety-nine percent (99%) of the time, the maximum contribution of fugitive coal dust to ambient PM_{10}

levels anywhere in the area would be less than 15 µg/m^3. Moreover, the maximum predicted PM_{10} concentrations are less than 0.5 µg/m^3 at the Riverview Elementary School (i.e., in the closest residential area west of the Brandon G.S. and near the air quality monitoring station at the Assiniboine Community College), as well as at the nearest residence east of the plant. As such, the PM_{10} concentrations due to fugitive dust emissions would not be measurable at the nearest residences, and the fugitive emissions from the Brandon G.S. alone would not be sufficient to cause the high PM_{10} concentrations measured in Brandon.

The Manitoba objective value for 24-hour averaged SPM is 120 µg/m^3. The maximum 24-hour average incremental SPM concentrations of 0.8 µg/m^3 due to Unit #5 stack emissions is predicted to occur near the northwest corner of the Brandon G.S. property line**.** If the ash content of future coals that might be burned at the plant were up to 35% higher than for Spring Creek coal, the maximum predicted concentration (for the OS3 scenario) would be 1.1 µg/m^3. As such, the maximum contribution of any of the coals that may be considered suitable for future use in Unit #5 to the measured SPM levels in the Brandon area is negligible.

Maximum predicted SPM concentrations for fugitive dust from the coal and ash storage areas are 105 µg/m^3 and 8 µg/m^3, respectively. Background SPM concentrations are known, but may be assumed to be above the Maximum Acceptable objective at least some of the time, based on observed PM_{10} concentrations. In combination with background SPM concentrations, there is a potential for coal dust emissions from the coal storage area to occasionally contribute to such exceedances of the objective level at the fenceline. However, the estimate of fugitive coal dust contributions to ambient SPM concentrations in this assessment is considered to be conservative, in that the estimated SPM emission rates from the coal storage area cannot take into account all of the emission control measures that are used by the plant operators to reduce any such emissions. Consequently, it is likely that the predicted maximum SPM emissions estimated for the modelling analysis overstate actual emission rates. Even so, predicted concentrations would be less than 80 µg/m^3 on all but one day per year. Ninety-nine percent of the time (i.e., 361 of 365 days per year), the maximum predicted contribution to ambient SPM levels due to fugitive coal dust would be less than 27 µg/m^3. Furthermore, the predicted SPM concentrations at the nearest residential areas west of the plant due to fugitive dust from coal and ash storage of 0.5 µg/m^3 and 0.3 µg/m^3 respectively are negligible, and less than 0.2 µg/m^3 at the nearest residence east of the plant. Therefore, fugitive dust emissions from the Brandon G.S. alone would not be sufficient to account for the high PM_{10} (and by extension, SPM) concentrations that have been measured in Brandon.

Trace Contaminants

As part of the Canada-wide Standard (CWS) proposed by the Canadian Council of Ministers of the Environment, Manitoba's' mercury stack emissions from the Brandon G.S. would be capped, commencing in the year 2010, at 20 kg/year. Manitoba Hydro has committed to meeting this cap effective immediately, and the dispersion modelling assessment has been conducted on this basis. At this emission rate, the contribution of mercury emissions from the Brandon G.S. to total mercury deposition in the area surrounding the plant represents approximately 2-4% of the total mercury deposition including all global sources.

For the remaining trace contaminants in the exhaust emissions (i.e., VOCs, as well as trace organics and inorganics), only HCl, HF, formaldehyde, arsenic, cadmium, copper, lead, nickel, and zinc have established ambient air quality guidelines in Manitoba. The maximum predicted 24-hour average HF concentration is 1.5% of the guideline level. All other constituents are less than 0.1% of the Manitoba guideline values. Comparisons of maximum predicted concentrations for constituents with available air quality criteria from other jurisdictions indicate that all impacts are less than or equal to 0.6% of criteria levels, with the exception of the 1-hour average HF concentration at 3.7% of the Alberta objective level. The potential health impacts of these emissions are addressed in Appendix N.

Greenhouse Gases (GHG)

At 100% of capacity factor, the total potential greenhouse gas (GHG) emissions from Unit #5 are estimated at 1.04 megatonnes/year (Mt/yr). Thus, the maximum potential GHG emissions from the Brandon G.S. are estimated at 5.7% of Manitoba's total GHG emissions, but on average the station will produce fewer emissions than this. Total GHG emissions in Manitoba represent approximately 3% of Canada's total GHG emissions, and Canada contributes approximately 2% of the world's GHG emissions.

Cooling Tower Emissions

From the modelling that was undertaken it was determined that the potential impact from the cooling tower, it was concluded that the water vapour and dissolved salt emissions have a minimal impact on adjacent areas. Fogging or icing were predicted to occur off-site on approximately 1 hour per year and thus there is only minimal impact on the nearby roads. Assuming that the plant operates 100% of the time, a visible plume from the cooling tower of 500 m in length is predicted to occur up to 175 hours per year, while a plume up to 2 km in length may be visible for up to 88 hours per year. The amount of water and salt that may be deposited from the plume is negligible.

1.0 INTRODUCTION

This document provides an air quality impact assessment to the Environmental Impact Statement (EIS) that has been prepared as part of the Environment Act Licence Review (EALR) for Brandon Unit 5 (Unit #5). The Brandon Generating Station (Brandon G.S.), located on the eastern boundary of the City of Brandon, on the southern shore of the Assiniboine River, is an important part of Manitoba Hydro's integrated system. Figure 1.1 provides an illustration of Brandon Manitoba and surrounding area with the relative locations of the Manitoba Hydro Brandon Thermal Generating Station and the Brandon Airport (which has a meteorological observation station).

Unit #5 (105 MW rated power) at the Brandon G.S. entered into service in 1969. Since that time, the station has undergone several provincial environmental reviews. Formal environmental, regulatory approvals for the Brandon Generating Station date back to April 1972 when the Manitoba Hydro-Electric Board submitted an application to the Clean Environment Commission ("CEC") for a licence to operate the station. This eventually resulted in the issuance of CEC Order No. 340 on March 19, 1974 by the Commission. This approval dealt entirely with station effluents entering the Assiniboine River.

The first full Environmental Impact Assessment ("EIA") was completed in 1976 (Environmental Impact Assessment of the Operations of the Brandon Generating Station, James F. MacLaren Ltd.). Specific terms and conditions regarding air emissions were established on April 22, 1984 with the issuance of CEC Order No. 1039. This order was subsequently revised in 1986 as Order No. 1039 VC and was significantly updated afterwards on January 26, 1989 as Environment Act Licence No. 1246. Licence No. 1246, however, remained entirely focused on air quality related issues.

In 1992, Manitoba Hydro submitted a proposal to upgrade the Brandon G.S. to assure reliable operation until 2006. This included a comprehensive EIA of all aspects of the operation of the station, and a full regulatory review under the Environment Act. This review resulted in the issuance of Environment Act Licence No. 1703, which was a comprehensive licence containing terms and conditions regarding air, water and solid waste. As part of this review, a closed-loop cooling system and electrostatic precipitator were installed on Unit #5. This licence was revised on February 14, 1994 as Licence No. 1703 R and is currently still in effect for the operation of the Brandon G.S. until 2006. It requires a review of the licence if Brandon G.S. Unit #5 continues operation beyond 2006.

In 2001, Manitoba Conservation issued Licence No. 2497 for the operation of two Combustion Turbine Units (CTs) at the Brandon G.S. (260 MW rated power). The licence for the operation of the CTs was subsequently revised in 2003 as Licence No. 2497 R.

1.1 HISTORICAL OPERATIONS

If Unit #5 operated at full load of 105 MW for a full year, it would produce 920 GWh of electrical energy. However, due to planned and unplanned maintenance requirements, the practical maximum generation is expected to be 830 GWh (90% of maximum theoretical generation). Over the period 1992-2005, the maximum annual generation occurred in 2003 at 640 GWh, representing approximately 69% of the plant's maximum theoretical generation. Over the same period of operation (i.e., 1992-2005), the average annual generation was 291 GWh, or 32% of the maximum theoretical generation, as listed below. Over the most recent 5-year period of operations (2001-2005), the average annual generation was 435 GWh, or less than 47% of the plant's maximum theoretical generation capacity factor (C.F.)[4].

Table 1.1
Unit #5 Annual Power Generation

Year	**Annual Generation**	
	(GWh)	C.F.
1992	163.6	18%
1993	98.7	11%
1994	127.4	14%
1995	54.7	6%
1996	88.3	10%
1997	111.6	12%
1998	440.4	48%
1999	326.0	35%
2000	487.5	53%
2001	434.6	47%
2002	296.6	32%
2003	639.6	69%
2004	315.6	34%
2005	486.5	53%
1992-2005 Average	290.8	32%
2001-2005 Average	434.6	47%

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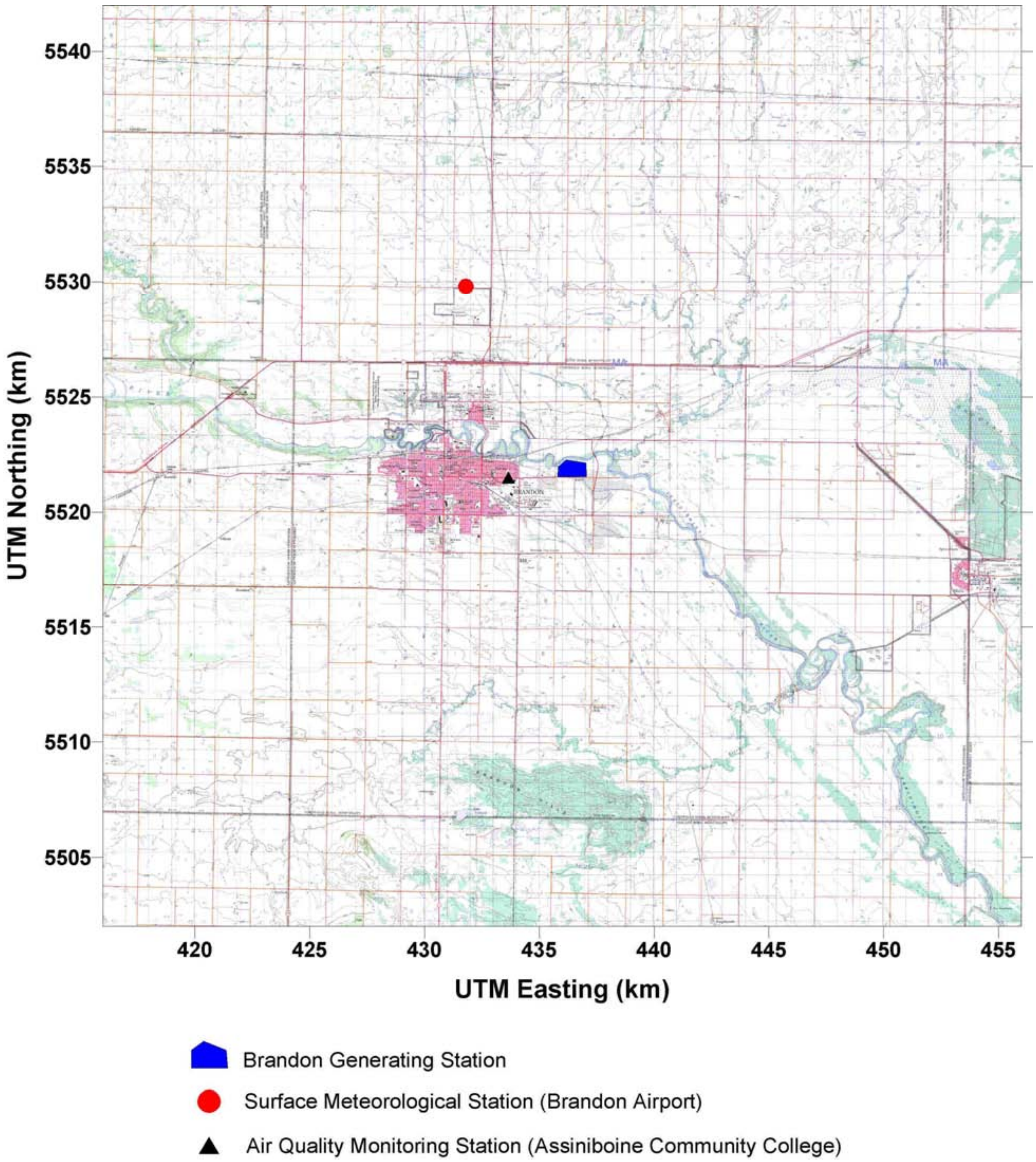
[4] Capacity Factor is calculated as the ratio of the actual power produced by a unit in any given year to the total power generation that the unit could hypothetically produce if it was operated 100% of the time (i.e., 290.8 GWh/920 GWh = 32%).

Figure 1.1
Brandon, MB and Surrounding Area



2.0 MODELLING METHODOLOGY

Due to the variety of sources present at the Brandon G.S., a number of different computer simulations were required to assess and characterize the emissions from the plant. Specifically, the sources that needed to be considered include:

- the Unit #5 exhaust gas stack;
- the associated cooling tower;
- fugitive dust from coal handling operations and residual ash storage; and,
- the combined emissions from Unit #5 and the two natural gas CTs.

The modelling methodology to be used for evaluating the emissions from these sources was first discussed with Manitoba Conservation to confirm the appropriateness of these methods for the purposes of the plant's licence review.

Emissions from the Unit #5 exhaust stack were modelled using the California Puff (CALPUFF) modelling system. CALPUFF is a sophisticated dispersion modelling system that was developed by Sigma Research Corporation (now part of Earth Tech Inc.) for the United States Environmental Protection Agency (USEPA). CALPUFF continues to be supported by Earth Tech and is listed as an 'Appendix A' preferred/recommended dispersion model in the USEPA *Guideline on Air Quality Models* (US EPA 2005). The CALPUFF model has previously been used for air quality assessment of the Selkirk G.S. (SENES 2001, 2005).

The CALPUFF system was the core model used in conducting the dispersion analyses for combustion related emissions. The meteorological processor within CALPUFF (CALMET) was used to construct 3-dimensional meteorological fields for the year 2003. These fields were then used with the CALPUFF dispersion model to assess the air contaminant releases from elevated sources (Unit 5 and the natural gas combustion turbines).

In addition, fugitive coal dust caused by wind erosion and handling and storage of coal and ash were assessed with the Industrial Source Complex Short Term Version 3 (ISCST3). Although the CALPUFF model is capable of modelling the dispersion of fugitive dust from large area sources, the deposition algorithm within the ISCST3 model is considered by the CALPUFF model's own developer to provide a better representation of plume transport from an area source.

Water-related emissions from the cooling tower were assessed using the Seasonal Annual Cooling Tower Impacts (SACTI) model. The SACTI model has previously been used to model emissions from the (at that time) proposed cooling tower for the licence review at the Brandon G.S. completed in 1992.

Both the ISCST3 and SACTI models require (simplified) meteorological inputs. These inputs were developed from the CALMET fields and are therefore consistent with the fields used for the elevated emission sources.

Deposition of air contaminants to the ground and water was also determined with the CALPUFF, SACTI and ISCST3 models. Due to an increased awareness and concern regarding deposition of mercury, separate modelling runs were completed using the CALPUFF model to assess annual deposition of oxidized, elemental and particulate-bound mercury from the combustion exhaust stack. The characteristic settling velocities and precipitation scavenging ratios for the modelling were based on a recent published study by the Brookhaven National Laboratory (Sullivan et al. 2003).

2.1 MODEL DESCRIPTIONS

2.1.1 CALPUFF Model

CALPUFF is a modern, non-steady-state air quality modelling system that includes a deterministic meteorological model (CALMET), the dispersion model itself (CALPUFF), and a postprocessor for analyzing and viewing output fields. There are many differences between the newer CALPUFF model and the Industrial Source Complex (ISC) model that has been used to model industrial air emissions from many facilities (including the Brandon G.S.) in the past. In particular, the CALPUFF model is able to treat emissions in a rigorous fashion with time-dependent releases of material that are transported and diluted within a 3-dimensional simulation of the atmosphere. In Canada, CALPUFF is considered a refined dispersion model that is recommended for situations involving complex terrain or complex atmospheric circulations. For elevated source releases from the Brandon G.S., SENES considers CALPUFF a more appropriate model to use than ISC.

CALPUFF advects ‘puffs’ of material released from modelled sources. Sources of air contaminants can be represented with point, area, line or volume designation. Released materials are subject to chemical removal, wet and dry deposition, complex terrain algorithms (i.e., channelling), building downwash, fumigation, and other effects. As opposed to earlier gaussian plume models (such as ISC), CALPUFF is a lagrangian model that requires 3-dimensional fields of wind and temperature, along with associated 2-dimensional fields such as mixing heights, surface characteristics and dispersion properties. To develop these fields, CALMET requires both hourly surface and twice-daily upper-air data from meteorological monitoring stations.

Another benefit of using the CALPUFF model is its ability to use meteorological inputs from a prognostic mesoscale (weather forecasting) model. Although prognostic models have sophisticated numerical code that commonly requires supercomputing facilities, the output from such models can now be purchased from research organizations for a region and specific time interval of interest. Typically, CALPUFF uses surface and upper-air meteorological station data as input. However, in situations where nearby station data are not available, the use of prognostic model fields represents a significant advancement over previous modelling methods where station data from a distant meteorological station are used with or without some manual adjustments.

2.1.2 ISCST3 Model

The Industrial Source Complex, Short-Term model (ISCST3) is a steady-state gaussian plume model that can be used to assess contaminant concentrations from a wide variety of sources associated with an industrial complex. The model is capable of explicitly handling multiple sources and types (point, area, and volume), building effects, particle deposition, and produces an hourly concentration for all terrain heights. ISCST3 uses actual hour-by-hour meteorological data that represent the conditions experienced by the source emissions to estimate ambient concentrations for differing sequential averaging periods (e.g., a multiple of one hour [2, 3, 4, 6, 8, and 12], daily, and annual) for an array of user-specified receptors. In addition, source emission rates can be treated as constant throughout the modelling period, or may vary by month, season, hour-of-day, or other time period. ISCST3 includes algorithms for modelling the effects of settling and removal of large particulates (dry deposition). In addition, there are algorithms to determine wet deposition of gases and particulates. Wet and dry depositions can be combined to provide total deposition.

Although SENES considers the CALPUFF model to be superior to the ISCST3 model for simulating emissions from elevated point sources such as the Unit #5 exhaust stack, an exception was made for the case of modelling fugitive coal dust from unloading and moving coal from coal trains to the storage pile and ultimately Brandon Unit #5, as well as for the wind erosion of ash from the ash storage area. According to J. Scire of Earth Tech Inc. (personal communication, May 2005), the developer of the CALPUFF model, the ISCST3 model provides a better representation of the vertical distribution of pollutant concentrations from an area source. In the CALPUFF model, the concentration of pollutants in a plume is evenly distributed in the vertical dimension, whereas in reality pollutant concentrations would tend to be more highly concentrated closer to the ground than above the surface, especially for larger particles. The latter is in fact how the ISCST3 model represents emissions from an area source. Since the vast majority of fugitive coal dust is of larger particulate size and settles out relatively close to the source, the ISCST3 model provides a more scientifically-correct representation of these emissions.

The ISCST3 model (Version 02035) was used to model fugitive emissions of coal dust within 2km of the coal and ash storage areas. ISCST3 is a simpler model than CALPUFF, and treats contaminant emissions as a continuous plume of material that advects and disperses with the mean wind each hour. Although a simpler model, ISCST3 is well suited to represent ground-level area sources of fugitive dust. ISCST3 requires surface meteorological data and mixing heights each hour. The needed data were extracted from the CALMET meteorological fields at the location of the coal storage pile and used for all ISCST3 model runs.

2.1.3 SACTI Model

The effects of air emissions from the Brandon G.S. cooling tower were modelled separately with the Seasonal Annual Cooling Tower Impacts (SACTI) model. Cooling towers remove heat from industrial cooling systems by exposing the coolant to the atmosphere. In the process, emissions of water droplets and water vapour occur. Plume effects from the cooling tower include drift deposition of salts, fogging, icing and solar energy loss at ground level due to shadowing. SACTI, a mathematical model that was designed specifically for cooling tower emissions, was developed by the Argonne National Laboratory, the University of Illinois at Urbana and the University of Illinois at Chicago for the Electric Power Research Institute (EPRI). This model has been available to the dispersion modelling community since 1984 and can represent the different types of cooling towers and controlling devices such as drift eliminators. A complete description of the model, with test case scenarios was published in *Atmospheric Environment* (Policastro et al. 1994).

SACTI chooses from 30 to 100 different representative meteorological scenarios by analyzing a full year of local meteorological data. The frequency of occurrence of each case is also recorded. The plume model itself then simulates each scenario using the cooling tower characteristics (size, orientation and circulation rates) and provides summaries by season or year of quantities such as hours of fogging and water or salt deposition.

2.2 CALMET METEOROLOGICAL MODEL

There are no upper-air meteorological stations near the Brandon G.S. To capture the variety of climatological conditions experienced in and around Brandon, the full year of 2003 was simulated with the CALMET model. The CALMET meteorological fields were then used for all CALPUFF and ISCST3 simulations and for meteorological inputs required by SACTI.

Instead of using upper-air data from stations located at Dauphin and The Pas in Manitoba, and Bismarck in North Dakota, that may not provide a good representation of conditions over Brandon, SENES purchased 6-hourly *analysis* fields that were generated by the U.S. National Centers for Environmental Prediction (NCEP) 'Eta' model during 2003. This model is run operationally four times a day to produce forecast fields over North America at 12 km horizontal resolution. The analysis fields are produced by the model via a four-dimensional data acquisition (4DDA) routine that ingests all available surface and upper-air data in North America to produce dynamically balanced meteorological fields over the continent every six hours. These analysis fields are used to drive the Eta forecasts; however, the actual forecasts themselves were not used by CALMET. CALMET internally interpolates between the 6-hourly fields based on time of day and magnitude of surface energy fluxes. The Eta fields were purchased from Que Tech, Inc., of Fort Collins CO, who archive the Eta output.

Local meteorological data were also used in the CALMET simulation. At a relatively coarse resolution of 12 km, Eta winds are somewhat 'smoothed' and may not be an appropriate representation of localized winds near the earth's surface in certain areas of the modelling domain (i.e., in or near the river valley). Surface data from the Brandon (airport) meteorological station were purchased from Environment Canada. The surface station data were used in CALMET to 'correct' the Eta winds in the vicinity of Brandon. In addition, the station data on precipitation, cloud cover and ceiling height parameters were used to determine precipitation and stability factors for the entire modelling domain.

The CALMET input file is presented in Attachment A, which includes a record of all meteorological modelling options used in this study. A summary of the important features of the meteorological simulation is provided below.

2.2.1 Modelling Domain for CALMET

A modelling domain of 30 km by 30 km was used, with individual grid cell spacing of 200m in both east-west and north-south direction. The CALMET/CALPUFF modelling domain used for this assessment is depicted in Figure 1.1 (see Section 1.1).

2.2.2 Meteorology

Table 2.1 lists the atmospheric levels used in the CALMET modelling. Greater vertical resolution was used near the earth's surface, which gradually was reduced with height. This methodology is suggested in the CALMET user's manual (TRC 2006), due to greater potential variation in meteorological variables near the surface.

Table 2.1: Vertical Layers Used in CALMET Meteorological Modelling

Vertical Height of Layer (metres)	**Height at Top of Layer** (metres)
20	20
30	50
50	100
100	200
100	300
100	400
100	500
300	800
200	1000
500	1500
500	2000
800	3300

Figure 2.1 presents an illustration of the surface wind patterns at the Brandon Airport in a wind rose (WR) diagram. The winds were extracted from the CALMET output fields. A WR diagram shows the frequency of direction the wind blows from, with distribution of wind speeds. In this case, it is representative of the entire year of 2003. The diagram shows that westerly winds are the most dominant, and that northerly and southerly winds are relatively infrequent. Calm conditions (wind speeds less than 0.5 m/s) occur 7.2 % of the time. The average surface wind speed for this location (not shown on the diagram) during 2003 was 3.6 m/s.

Figure 2.2 is a WR diagram for CALMET Layer 5 winds, which are representative for a layer of the atmosphere between 100 and 200m above the surface. For this layer, the average wind speed for the year was 8.4 m/s. Emissions from elevated sources, such as the stack from Unit #5, are influenced by these winds to a greater extent than by surface winds. Winds at this elevation are representative of regional circulation patterns and are not strongly influenced by surface features. Comparability between winds at the surface (which derive from surface station data) and winds in Layer 5 (which derive from the Eta mesoscale model) is quite good. Within the earth’s boundary layer, wind speeds tend to increase with height, and wind direction tends to rotate clockwise (Barry and Chorley 1971). The latter effect is known as the Ekman Spiral, and this effect is present in the difference between the surface winds in Figure 2.1 versus the winds at about 150 metres above the surface in Figure 2.2. Whereas the predominant winds at the surface are westerly, those above the surface have a strong north-westerly component.

Figure 2.1 CALMET Surface (10m) Winds at Brandon Airport

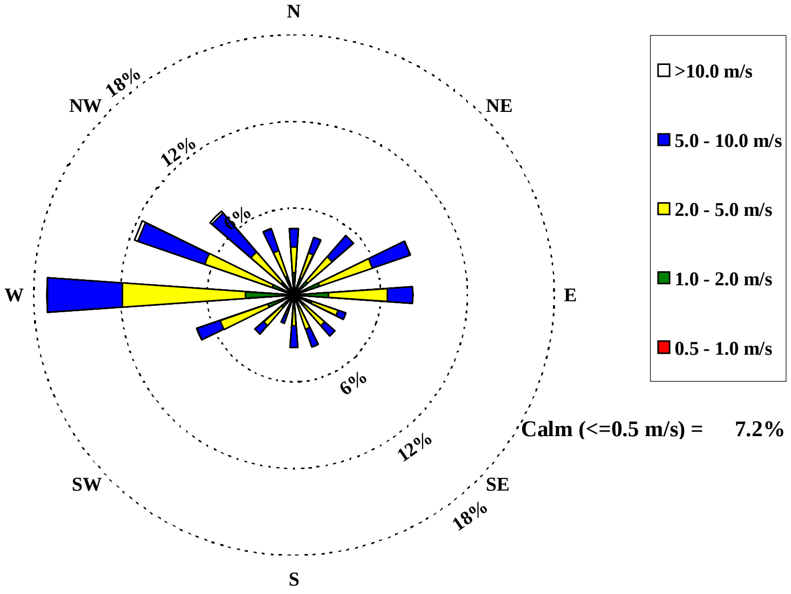
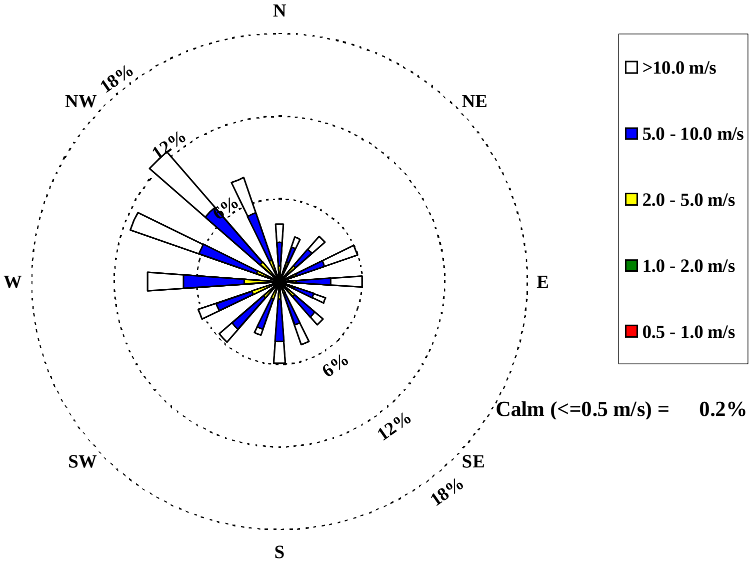


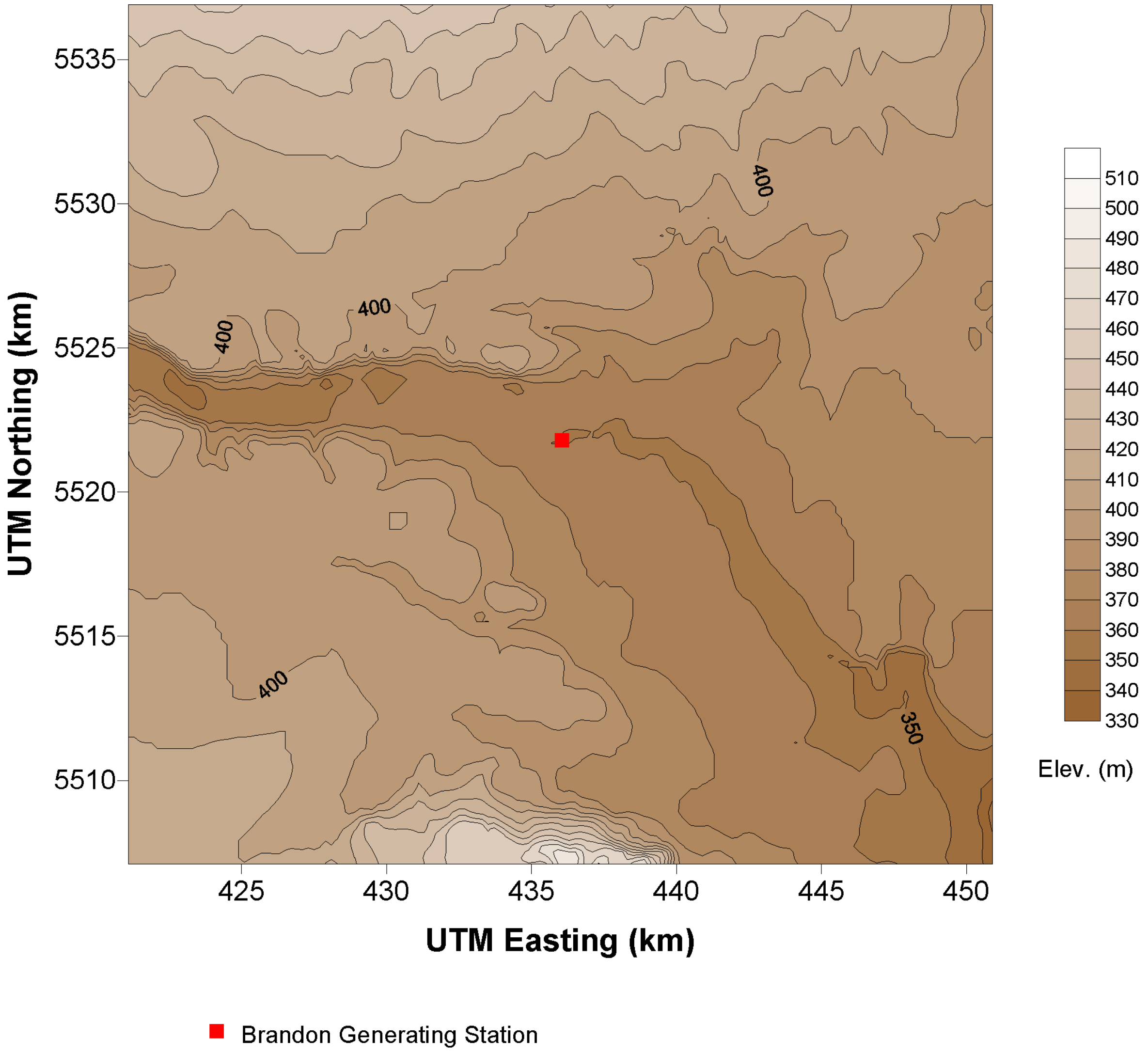
Figure 2.2 CALMET Layer 5 (150m) Winds at Brandon Airport



2.2.3 Terrain

United States Geological Service (USGS) terrain data were used to construct the topographical heights of each grid cell in the modelling domain. The data were acquired as 3 arc-second resolution (approximately 90 m) digital elevation maps (DEMs) from Geomatics Canada. These data were processed in the CALPUFF routine 'TERREL' that re-samples the height data to produce averaged heights for each grid cell. Within CALMET, these heights are smoothed to avoid problematic gradients. Figure 2.3 depicts the terrain used in the CALMET modelling. Much of the modelling domain is flat, or gently sloping terrain, with the river valley and Brandon Hills at the southern edge of domain as obvious landmarks.

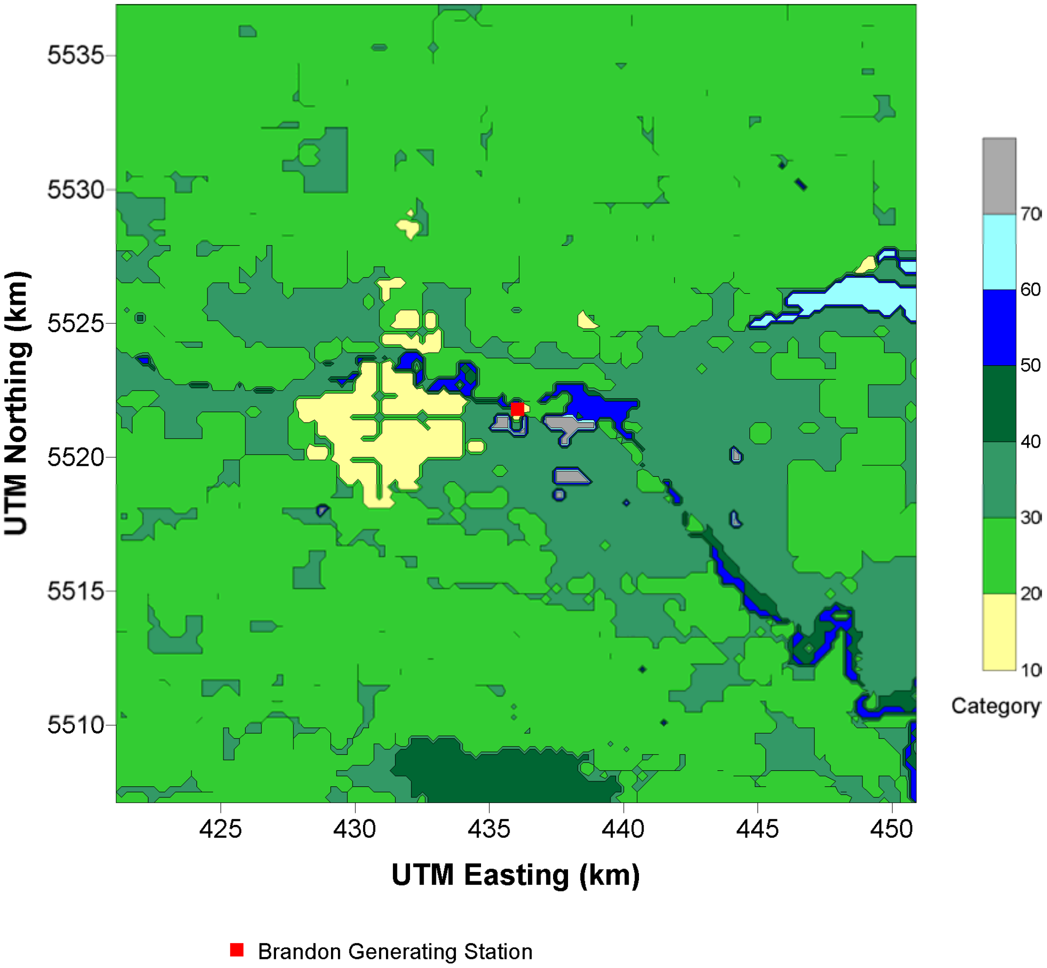
Figure 2.3: CALMET Terrain



2.2.4 Land Use Categories

Land use categories describe the dominant surface features of each grid cell and have influence on model parameters such as surface roughness and Bowen ratio (which is related to moisture availability). The land use characteristic information for the modelling domain was based on the land cover data obtained from DMTI Spatial (Natural Resources Canada distributor). The CTGPROC land use processor program, included with the CALPUFF package, was used to process this data for input to CALMET. The land use categories for use in CALMET are based on the United States Geological Survey (USGS) land use classification system. These categories are listed in Table 2.2. The spatial distribution of land use categories in the modelling domain is provided in Figure 2.4. Much of the modelling domain is characterized by agricultural land and rangeland, with smaller areas of rangeland, forest, water and urban.

Figure 2.4: CALMET Land Use Categories



10 = Urban, 20 = Agricultural, 30 = Rangeland, 40 = Forest, 50 = Water, 60 = Wetland, 70 = Barren Land

Table 2.2
CALMET Land Use Categories

Based on the U.S. Geological Survey Land Use
and Land Cover Classification System (52-Category System)

	Level I		Level II
10	Urban or Built-up Land	11	Residential
		12	Commercial and Services
		13	Industrial
		14	Transportation, Communications and Utilities
		15	Industrial and Commercial Complexes
		16	Mixed Urban or Built-up Land
		17	Other Urban or Built-up Land
20	Agricultural Land — Unirrigated	21	Cropland and Pasture
		22	Orchards, Groves, Vineyards, Nurseries, and Ornamental Horticultural Areas
		23	Confined Feeding Operations
		24	Other Agricultural Land
!20	Agricultural Land — Irrigated	!21	Cropland and Pasture
		!22	Orchards, Groves, Vineyards, Nurseries, and Ornamental Horticultural Areas
		!23	Confined Feeding Operations
		!24	Other Agricultural Land
30	Rangeland	31	Herbaceous Rangeland
		32	Shrub and Brush Rangeland
		33	Mixed Rangeland
40	Forest Land	41	Deciduous Forest Land
		42	Evergreen Forest Land
		43	Mixed Forest Land
50	Water	51	Streams and Canals
		52	Lakes
		53	Reservoirs
		54	Bays and Estuaries
		55	Oceans and Seas
60	Wetland	61	Forested Wetland
		62	Non-forested Wetland
70	Barren Land	71	Dry Salt Flats
		72	Beaches
		73	Sandy Areas Other than Beaches
		74	Bare Exposed Rock
		75	Strip Mines, Quarries, and Gravel Pits
		76	Transitional Areas
		77	Mixed Barren Land
80	Tundra	81	Shrub and Brush Tundra
		82	Herbaceous Tundra
		83	Bare Ground
		84	Wet Tundra
		85	Mixed Tundra
90	Perennial Snow or Ice	91	Perennial Snowfields
		92	Glaciers

2.2.5 CALMET Configuration

Attachment A contains a copy of the CALMET control file. Many of the settings ('switches') are used to characterize the modelling domain and specify the names and locations of associated files (i.e., meteorological files). There are several switches that are of importance in developing the 3-dimensional wind fields. The choices used for these switches are based on guidance in the CALMET user's guide, operator experience, and published accounts of previous CALMET studies. A summary of the significant wind field switches used for Brandon G.S. modelling is provided in Table 2.3. All switches using model default options are not indicated.

Table 2.3
CALMET Model Configuration

Option	Setting
ZFACE (number of atmospheric layers)	12
IPROG (prognostic wind field model)	14
ISTEPPG (prognostic model timestep)	6
RMAX1 (station influence parameter)	10 km
RMAX2 (station influence parameter)	50 km
TERRAD (influence of terrain features)	10 km
R1 (station influence parameter)	5 km
R2 (station influence parameter)	15 km
ITPROG (3D temperature data)	1
TRADKM (influence of temp station)	40 km

2.3 CALPUFF MODEL

The CALMET meteorological fields were used with the CALPUFF model to predict ground-level concentrations of particle-based and gaseous pollutants over both short-term and long-term averaging periods. CALPUFF was set to determine both gridded (i.e., at regular intervals throughout the entire modelling domain) concentration estimates and *discrete receptor* concentration estimates at 11 locations to use in the risk analysis. In addition to concentrations at the discrete receptors, the maximum modelled off-site ground-level concentration within the modelling domain was determined and recorded for each modelling scenario.

Table 2.4 lists the non-default settings (switches) used in the CALPUFF dispersion modelling. Choice of switches was based on guidance from the CALPUFF user's guide and operator experience. A full CALPUFF input file is provided in Attachment B.

Table 2.4
CALPUFF Model Configuration

Option	**Setting**
MSHEAR (vertical wind shear)	1
MCHEM (chemical transformation)	0
MDISP (determination of dispersion coefficients)	2

2.3.1 Discrete Receptors

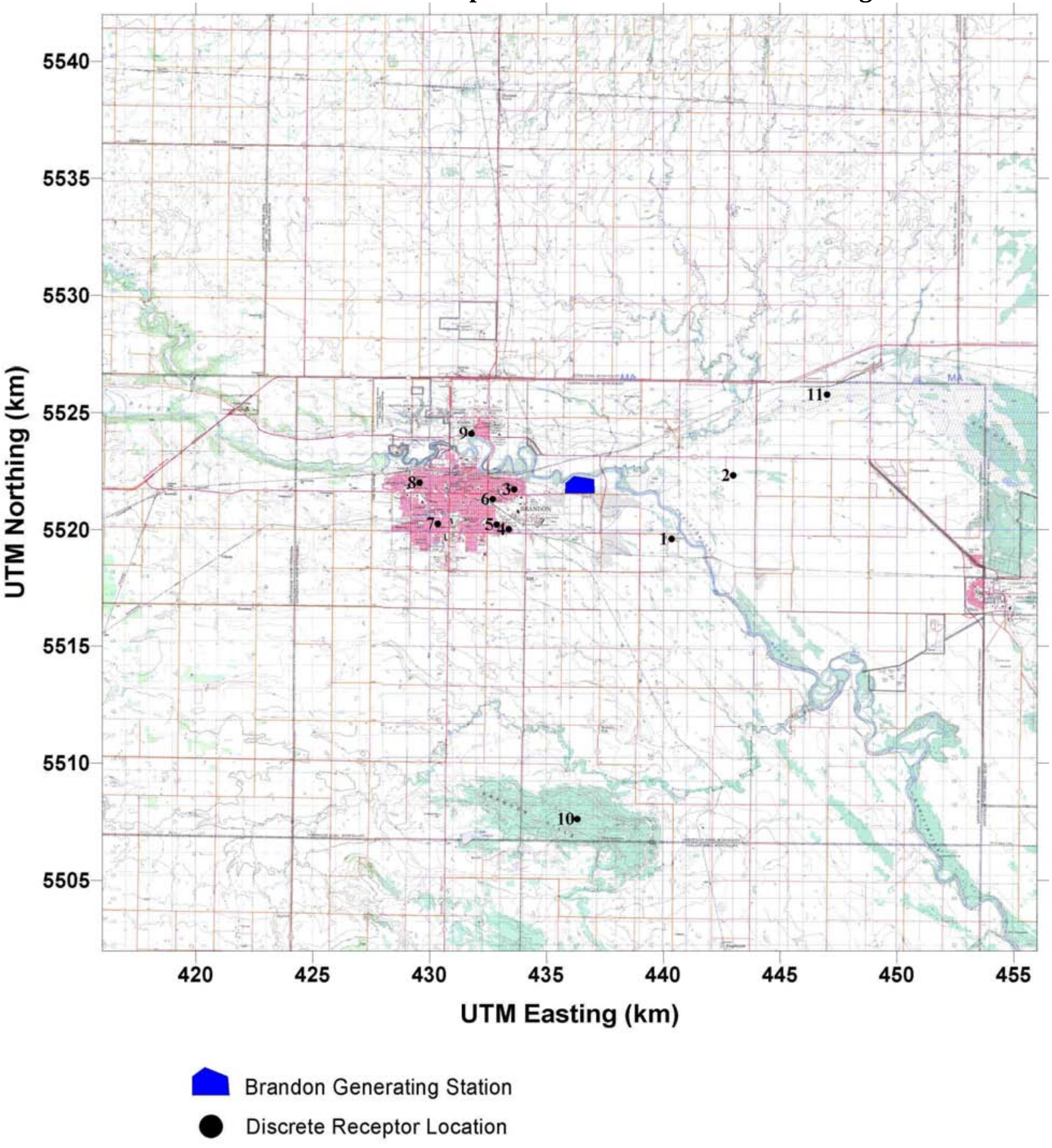
The locations of the discrete receptors were chosen based on potential sensitivity – due to either human exposure or terrain characteristics. The discrete receptor points are listed in Table 2.5 and can be graphically located from Figure 2.5. A sample CALPUFF input file showing all model options selected for the dispersion analysis is provided in Attachment B.

Table 2.5
Discrete Receptor Coordinates

Receptor No.	UTM Receptor Coordinates[1]		Description
	Easting (m)	Northing (m)	
R1	440350	5519601	Chemical plant
R2	443000	5522300	Residence at eastern edge of Brandon
R3	433622	5521702	Riverview Elementary School
R4	433389	5520026	Inglewood St. Residence
R5	432870	5520218	Green Acres Elementary School
R6	432703	5521283	Hospital
R7	430356	5520258	Meadows Elementary School
R8	429569	5521995	Valleyview Elementary School
R9	431779	5524104	Kirkcaldy Heights Elem/Jr. High School
R10	436330	5507634	Brandon Hills, 15 km South of Brandon
R11	447017	5525774	Douglas Marsh, east of Brandon

[1] NAD 83 reference

Figure 2.5
Location of Discrete Receptors used in CALPUFF Modelling



2.3.2 Unit #5 Stack Parameters

The emissions from Brandon G.S. Unit #5 were simulated with the CALPUFF model using the source characteristics listed in Table 2.6. CALPUFF runs were conducted using a unit emission rate of 1 g/s for a generic gas and two generic particulate simulations. Modelled concentrations were then scaled for each air contaminant based on type (gas-based or particulate–based) and emission rate. Two different particulate simulations were required due to the fact that stack sampling conducted at the plant in 2005 has shown that emission characteristics were different depending on which combination of coal fuel trains (referred to in the stack sampling reports as A, B, C and D) were being used for combustion. In addition, separate model runs were conducted for PM_{10} and $PM_{2.5}$. Although these sub-fractions of total suspended particulate (TSP) disperse horizontally at the same rate, the settling velocities differ, resulting in different ambient concentrations and deposition rates.

Table 2.6
Modelled Stack Parameters used for Brandon G.S. Unit #5

Location X (UTM) (km)	Location Y (UTM) (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Gas Exit Velocity (m/s)	Gas Exit Temperature (deg. K)	Emission Rate (g/s)
436.058	5521.802	106.7	358.8	3.6	21.0	454.0	1.0

The gas exit velocity and gas exit temperature for Brandon Unit 5 were determined from stack sampling data taken in April 2005. The sampled measurements provide emission rates for the air contaminants of interest and representative mass fractions for each sub-grouping of particulate matter size fraction. Further discussion of emission rates for Unit #5 is provided in Section 3.

Separate modelling runs were conducted to determine annual average mercury deposition. Rather than taking a representative portion of the total particulate deposition amounts, a more thorough approach was used that relies on specific mercury species (i.e., elemental, oxidized, or particle-bound mercury) characteristics/behaviours in the atmosphere. These parameters were taken from a recent assessment paper (Sullivan et al. 2003) produced by the Brookhaven National Laboratory, and are presented in Table 2.7.

Table 2.7
Mercury Deposition Parameters used in CALPUFF Modelling

Form of Mercury	Liquid Scavenging Coefficient $(\text{s-mm/hr})^{-1}$	Frozen Scavenging Coefficient $(\text{s-mm/hr})^{-1}$	Deposition Velocity (cm/s)
Hg – elemental	3.31×10^{-7}	1.0×10^{-7}	0.06
Hg – reactive	2.5×10^{-4}	5.0×10^{-5}	2.9
Hg particle (< 2.5 µm)	7.0×10^{-5}	2.0×10^{-5}	0.09
Hg particle (> 2.5 µm)	2.8×10^{-4}	5.0×10^{-5}	0.45

As with other modelling runs, the mercury deposition simulations were completed using unit emission rates, and resulting deposition amounts were scaled to the measured mercury emission rates from recent stack testing in April 2005. Three separate simulations were completed, to account for the different behaviours of emitted mercury species (elemental, reactive (gaseous) and particle-based). The particle simulation separated emissions into a fine component, with average diameter of 0.68 microns, and a coarser component with average diameter of 3.5 microns. Finally, the total annual deposition amount was determined by summing the deposition values from the three simulations.

2.3.3 Combustion Turbines (CTs)

The combustion turbines at the Brandon G.S. operate under a separate permit, and as such are not a formal part of the Brandon G.S. licence review. However, in view of the fact that there is a potential for the CTs to be operating at the same time that Unit #5 is operating, the combined impacts on air quality from emissions due to both the CTs and Unit #5 were evaluated in this assessment.

Table 2.8 lists the source characteristics used for each CT in the CALPUFF model. Turbine properties were available from ABB Alstom Ltd. (Switzerland), the CT manufacturers, who also provide operational data such as gas exit temperature and velocity under different loads (percentage of maximum power).

Table 2.8
Modelled Stack Parameters used for Brandon G.S. Combustion Turbines

Location X (UTM) (km)	Location Y (UTM) (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Gas Exit Velocity (m/s)	Gas Exit Temperature (deg. K)	Emission Rate (g/s)
435.766	5521.583	30.0	360.0	5.5	39.5	778.0	1.0
435.766	5521.616	30.0	360.0	5.5	39.5	778.0	1.0

Further discussion of emission rates used for the Brandon CTs is provided in Chapter 3.

2.4 ISCST3 MODELLING

The primary sources of fugitive dust emissions at coal-fired power plants are coal handling and storage, and ash handling and disposal. Coal handling operations at the Brandon G.S. which can produce fugitive dust emissions consist of: 1) coal train unloading, 2) continuous drop of coal from the slew conveyor to the active coal storage area, and 3) reclaim of the coal from the active coal storage area to the coal bunker for transfer to the combustion boilers, 4) removal of coal from the active storage pile to the long-term storage pile, 5) reclaim of coal from the long-term storage pile, and 6) wind erosion of the active and long-term storage piles. Ash handling consists of sluicing the ash from the boilers in a wet slurry, such that ash handling is not a source of fugitive emissions from plant operations. However, wind erosion of both the coal and ash storage areas is also a source of fugitive dust emissions.

The entire coal storage pile covers an area of approximately 3.5 hectares, while the ash lagoon is estimated at 5.6 hectares. The active coal storage stockpile, that fraction of the coal pile that is accessed on a regular basis, was estimated to be 0.16 hectares. Only the exposed (dried out) portions of the ash lagoon can contribute fugitive dust emissions due to wind erosion. To be conservative, 40% of the dried out portion of the ash lagoon was assumed to be exposed to the wind. Table 2.9 provides a description of the source characteristics used in ISCST3 modelling to predict ambient concentrations and deposition of fugitive dust. The calculation of estimated fugitive dust emission rates from these areas is described in Chapter 3.

In general, fugitive dust emissions do not travel very far. Approximately 60-90% of the suspended particles will remain below a height of two metres above the surface, and up to 90% will be re-deposited to the surface within a distance of about 50 metres (Watson and Chow 2000). Thus, the impact of fugitive dust emissions on ambient air quality is typically limited to a few hundred metres downwind of the source. Consequently, the size of the modelling domain used to predict air concentrations of fugitive coal dust was limited to 4km by 4km.

Table 2.9: Source Characteristics for Fugitive Dust Emissions

Source	**SW Corner** X (UTM) (km)	**SW Corner** Y (UTM) (km)	**Total Area** (m^2)
Shaker House	435.971	5521.558	480
Active Stockpile	436.002	5521.580	1580
Long-term Storage Stockpile	436.002	5521.580	35400
(Exposed) Ash Lagoon	436.195	5521.921	22640

2.5 COOLING TOWER (SACTI) MODELLING

The effects of cooling tower plumes (e.g., drift deposition, fogging, icing, solar energy loss) are usually experienced within 10 km of the tower(s). Because of this, it is important to acquire representative (local) meteorological data for use as input to the model. The SACTI model requires hourly values of wind speed and direction, temperature, relative humidity and cloud cover. In addition, the mixing height is required every 12 hours for determination of atmospheric stability. Mixing height is the depth of the layer above the earth's surface through which mixing of air pollutants (or other quantities) freely occurs and is estimated from parameters such as time of day, cloud cover and vertical temperature gradients. For SACTI modelling of the air emissions from the Brandon G.S. cooling tower, hourly surface observations from the Brandon airport were used, with mixing heights extracted from the CALMET meteorological fields every 12 hours.

For modelling of the Brandon G.S. cooling tower, the design parameters required by the SACTI model were taken from the cooling tower schematic and operating values reported in the document *Design Description Brandon Cooling Tower System* (3987-0541-45EC-0001) dated 96/04/15. These parameters are listed below:

- Type: Linear-Mechanical (LMDCT) with 5 cells;
- each cell 9.8m long and 15.5m wide, with an effective source diameter (D_{eff})of 22.4 m, where $D_{eff} = \sqrt{n} \times d$
  n - number of cells
  d - cell diameter(m);
- total inflow air rate: 4050 kg/s;
- surface roughness: 25 cm;
- total heat dissipation rate: 558.6 MMBtu/hr (163.5 MW);
- drift loss: 0.001% of circulating rate
- circulation rate: 47,300 USgal/min

- length of LMDCT housing: 50.0 m;
- width of LMDCT housing: 22.5 m;
- height of tower: 18.4 m;
- LMDCT orientation: east – west;
- number of water drop sizes: 31;
- water salt concentration: 0.0044 g salt / g solution, and;
- salt density: 2.17g/cm^3.

2.5.1 Plume Parameters

Important properties of the cooling tower plumes and their effects are described below.

Relative Humidity

Water vapour is the major emission to the atmosphere from a cooling tower. The amount of water vapour in the air is referred to as humidity. Relative humidity is defined as the ratio of observed vapour pressure to the saturation vapour pressure for the observed temperature. The relative humidity can increase either by the increase in vapour content by evaporation or by the decrease of the saturation vapour pressure from a decrease in temperature. If the relative humidity is raised above 100 percent by either of these processes, condensation will occur. When the relative humidity exceeds the saturation point of the air immediately above the ground surface, fog forms; when this occurs aloft, clouds develop. When the temperature is below 0ºC, icing may occur on the ground or on buildings.

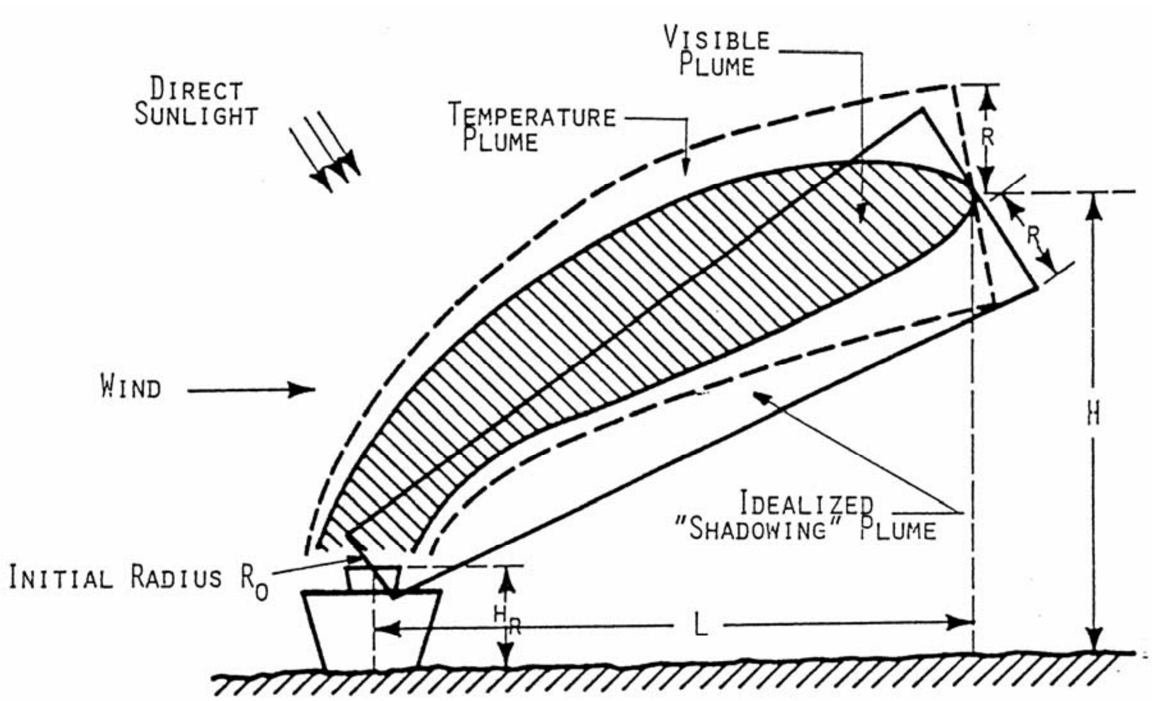
Visible Plume

The plume is visible when the initial flux of moisture is greater than the saturation deficit flux, which is function of height. Both of these parameters have to be known for calculations of visible plume. The important parameters which describe visible plume are: plume height (H), plume length (L) and plume radius (R), (Figure 2.6). The idealized "shadowing plume" is also shown in Figure 2.6. The projection of this plume to the ground represents shadow and it is measured and expressed as the number of hours in a season or year during which shadowing effects occur on the ground.

Energy Loss

During visible plume shadowing, there can be a decrease in the amount of short wave (solar) radiation reaching the ground. This effect, expressed as hours of shadowing, may be important above agricultural land. The actual amount of radiation attenuation is not determined.

Figure 2.6: Characteristics of a Cooling Tower Plume



Note: Adapted from EPRI (1984)

Fogging

Ground fogging is an environmental effect that can occur at some sites under appropriate meteorological conditions. This effect occurs when a visible plume intersects the ground.

Drift or Drift Loss

Drift refers to the liquid water droplets that escape from the cooling tower. Drift loss causes salt deposition in areas near the tower. The salt emission rate from a cooling tower is estimated from the drift loss factor (%) and the water circulation rate. Modern cooling towers can be equipped with ‘drift eliminators’ that greatly reduce drift loss and hence salt deposition. The Brandon cooling tower has such a drift eliminator.

Water and salt deposition

Water and salt deposition are defined as the rate of water or salt deposited on the ground, and are generally expressed as kilograms per square kilometre per month or grams per square metre per month.

3.0 EMISSIONS DATA

Coal is the primary fuel with No. 2 fuel oil used for lighting off the burners and flame stabilization during low load operation on Unit #5. Since emissions of various contaminants of potential concern (COPC) are higher for coal operations than for fuel oil operations, only the impacts due to coal-fired operations were considered in this assessment.

The air emissions from coal combustion primarily consist of common air contaminants such as oxides of nitrogen (NO_x), carbon monoxide (CO), sulphur dioxide (SO_2) and particulate matter. There are also small quantities of some volatile organic compounds, and trace quantities of both organic compounds and inorganic elements associated with the particulate matter, as well as emissions of carbon dioxide (CO_2) and small quantities of other greenhouse gases such as methane (CH_4) and nitrous oxide (N_2O).

Air emissions from natural gas combustion in the two combustion turbines contain much of the same air contaminants, but in different proportions. In particular, the emission of particulate matter and sulphur dioxide from natural gas combustion is significantly lower compared to coal combustion. In addition to combustion products from the use of natural gas as an energy source, direct venting of the gas in the section of pipeline leading to the combustion turbines may infrequently occur.

There are two general methods of determining air emissions from sources of air contaminants. Where possible, the preferred method is to use direct measurement data from sampling programs. The emission rates for the common air contaminants, as well as for most of the inorganic (trace metal species) and organic compounds (polycyclic aromatic hydrocarbons (PAH), dioxins and furans) were derived from stack sampling tests conducted in 2005 (ORTECH 2005). The sampling was conducted on the exhaust from Unit #5, operating at an average generation rate of 102 MW, and scaled upward to 105 MW to represent the potential maximum emissions rate at the maximum (short-term) sustained generation rate of 105 MW. Maximum sustained generation assumes a coal combustion rate of 60 tonnes/hr at the rated capacity of 105 MW.

The second method involves use of activity-based emission factors available from the U.S. EPA (AP-42, 1.1). An emission factor ”*…is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant.*” (US EPA AP-42 1995). Associated emissions of volatile organic compounds (VOCs) from coal combustion in Unit #5 were estimated in this manner. The emission factors were used with the maximum hourly coal consumption rate.

The emission factor approach is also widely used for estimating fugitive dust emissions, since these are much harder to measure than stack emissions. The emission factors are empirically determined using data from previous sampling programs and are specific to industrial activity. In many cases, the equations also factor in environmental variables such as moisture and wind speed. Typically, the equations are very conservative and represent 'upper-bound' conditions. As such, the EPA recommends a general approach that accounts for mitigative measures such as watering to reduce dust transport. The equation shown below is representative of this approach (US EPA 1995):

$$E = A \times EF \times (1 - ER/100)$$

where: E = emission rate
A = activity
EF = emission factor
ER = emission reduction (or control) efficiency (%)

Fugitive coal dust emissions are in the form of particulate matter, and mainly consist of larger size fractions (i.e., TSP rather than PM_{10} or $PM_{2.5}$). Trace quantities of inorganic elements, including some heavy metal species are included within the TSP. In addition, emissions from ash lagoons also include trace inorganic elements and organic products of incomplete combustion.

The emission rates at the maximum sustained power generation rate (100% capacity factor) were used to calculate all short-term and long-term ambient air concentrations (i.e., 1-hour, 8-hour, 24-hour and annual averages) for comparison with Provincial and Federal ambient air quality guidelines and objectives, as well as for estimating deposition rates for organic and inorganic contaminants. Thus, all potential human health and ecological risks (Appendix N) were calculated assuming Unit #5 operates entirely at a capacity factor of 100%.

Emissions from a cooling tower include salts and water vapour. In sufficient quantities, salt deposition can be damaging to crops, vegetation or aquatic life. Ambient water vapour concentrations can lead to a reduction of visibility, an unattractive viewscape or icing due to impingement of the plume on the ground.

3.1 UNIT #5 FUEL DELIVERY SYSTEM DESCRIPTION

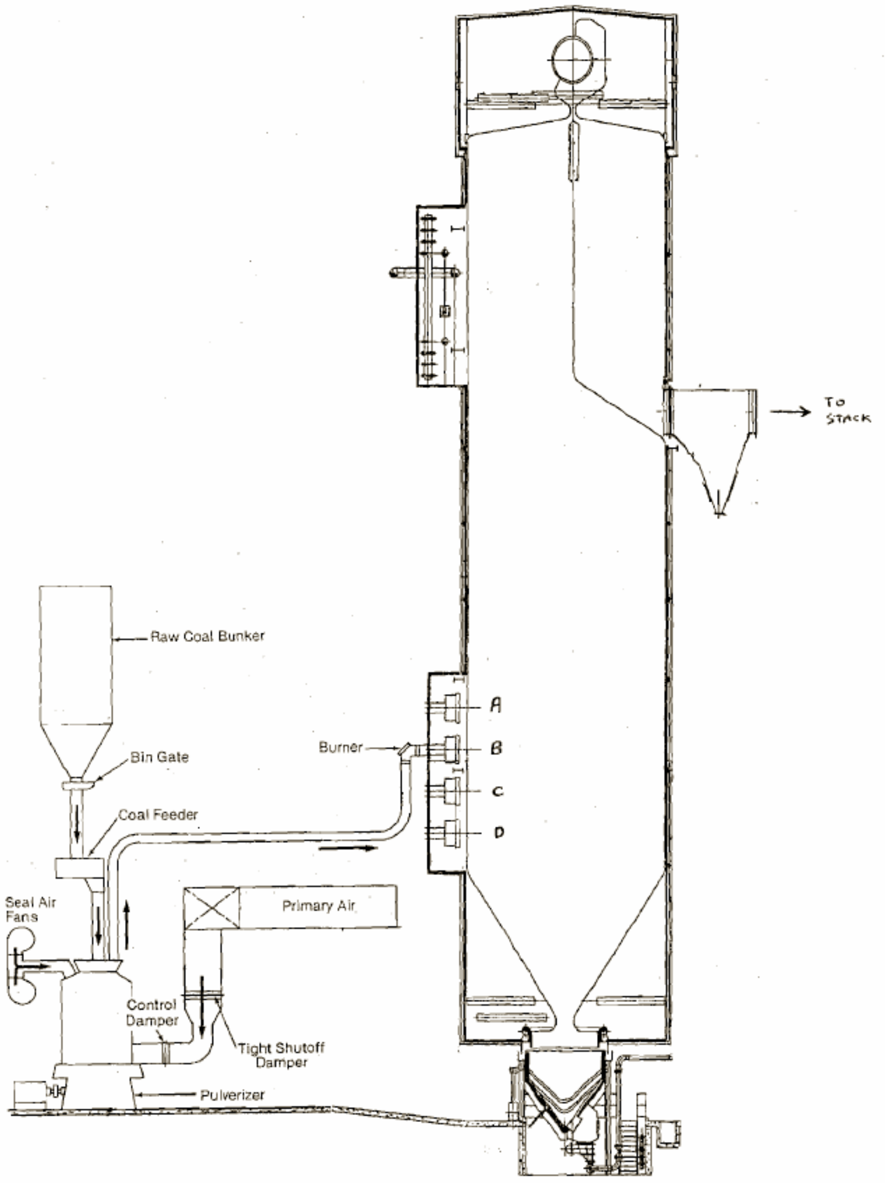
The Unit #5 boiler has four rows of burners designated A, B, C, and D, with row A located at the highest elevation and row D located at the lowest. Each row has three individual burners for a total of 12 burners. Pulverized coal is delivered to the burner rows by "fuel trains" which correspond to each row of burners. Each fuel train consists of the following major components; a raw coal bunker to store the coal, a coal feeder to control the flow of coal, a pulverizer to grind the coal, piping to deliver the pulverized coal to the burner row, and the burner row itself. Raw coal moves from the bunker through the feeder, then to the pulverizer where is it ground into a fine powder, mixed with air, and delivered by pipes to the burner row for combustion. The boiler can be operated at maximum load using only three of the four rows of burners and is usually operated in this configuration as operation with all four burner rows results in decreased boiler efficiency and increased pulverizer maintenance costs. For this reason there is usually a "spare" burner row and associated fuel train that is not in service when the boiler is in operation at full load. The result is that there are five possible combinations of burner rows that can be used to operate the boiler at maximum load; ABC, ABD, ACD, BCD, and ABCD. Figure 3.1 below provides a schematic of the Unit #5 boiler with the B row illustrating a typical fuel train.

Each burner row combination has different operational and thermodynamic characteristics. Of the five possible burner row combinations, combination BCD provides the best operational and thermodynamic performance. This is the preferred combination for normal full-load operation, with the boiler being operated in the BCD burner row combination approximately 60% of the time. Burner row combination ABC provides the least efficient operational and thermodynamic performance. Operation of the boiler in this combination (ABC) is minimized to the extent possible and is estimated to be used approximately 10% of the time. However, due to fuel train equipment maintenance requirements and occasional operational problems, such as frozen coal plugging bunkers, chutes, and feeders in the winter, operation in the preferred combination is not always possible and the boiler must be operated in one of the other four burner row combinations approximately 40% of the time (i.e., approximately 10% of the time in each of ABC, ABD, ACD, and ABCD).

Stack emission tests conducted in 2005 have shown that, for some air contaminants, amounts released can be substantially lower with the preferred burner row combination BCD than with the least efficient burner row combination ABC. This is the case for nitrogen dioxide (NO_2) and particulate matter, and to a lesser extent for SO_2 and CO emissions.

When Unit #5 is on-line, there are often periods of time when full load operation is not required. During these periods, two rows of burners are typically used instead of three. In this mode of operation, the preferred burner row combinations are AB and AC. Relative to full load operation with three rows of burners, there is a significant reduction in the amount of contaminants released when operating the boiler at part load with two rows of burners regardless of the burner combinations used. Because emissions are lower during this type of operation, these emissions were not considered in the air quality impact assessment.

Figure 3.1
Schematic Diagram of Unit #5 Boiler 'B" Fuel Train



3.2 DESCRIPTION OF OPERATING SCENARIOS MODELLED

In order to account for the range of performance variation associated with the different burner row combinations, stack sampling and dispersion modelling was performed for the best performing combination BCD and the poorest performing combination ABC. Modelling results for the preferred burner row combination BCD are referred to as Operating Scenario 1 (OS1), while results for the alternative burner row combination ABC are referred to as Operating Scenario 2 (OS2). The modelling results for the OS2 estimate represent the greatest possible emission rates; however, they do not characterize normal Unit #5 operation.

All modelling was performed using the "maximum theoretical generation" for Unit #5 (i.e., 105 MW). For emission of common air contaminants (CO, NO_2, SO_2, SPM, PM_{10} and $PM_{2.5}$), modelling results are provided for both the OS1 and the OS2 emission estimates. For all other pollutants (i.e., trace inorganic and organic constituents), only the results for the OS2 emission estimates are considered.

A secondary issue stems from the fact that, due to supply and demand, Manitoba Hydro cannot guarantee that coal for all future operations can be supplied by the current coal supplier. Manitoba Hydro currently obtains sub-bituminous coal from the Spring Creek mine operated by Kennecott Energy in Decker, Montana. For the Brandon G.S. Licence Review, Manitoba Hydro conducted an evaluation of coal quality for a total of 16 other coal suppliers in order to identify alternative supplies that would be suitable for use in the future. Six coal suppliers were rejected as being unsuitable for the Brandon G.S. on the basis of potentially unacceptable increases in the emission of some air contaminants. In addition to the Spring Creek mine, five other mines were deemed to be suitable for use at all times as substitutes for Spring Creek coal, while another five mines were considered to have coal that would be acceptable for operation some of the time, but not for extended use, primarily because their higher mercury levels could limit the availability of the plant in respect to meeting the proposed cap on emissions under the Canada-Wide Standards.

For the purposes of the air quality impact assessment, dispersion modelling was performed using two sets of coal properties (i.e., heating value, sulphur content, ash content, trace metal concentrations); one set representing the current coal (i.e., from the Spring Creek mine) that is being used and a second set representing the range of properties associated with coal from ten potential alternative suppliers that could be used in the future. The properties of the sub-bituminous coal from the Spring Creek mine are based on a proximate analysis provided by the supplier. The set of properties that represents the range of potential future coals was determined by selecting the maximum value for each parameter from the coal proximate analysis associated with each of the ten alternative mines. This set of properties is not intended to represent a specific coal from a specific mine, but rather is intended to account for the upper-bound range of properties associated with potential use of alternative coal suppliers. This set of properties therefore provides a conservative estimate of the emissions that would result if Manitoba Hydro must switch coal suppliers in the future.

Air dispersion modelling results based on the current coal properties were used for the OS1 and OS2 emission estimates, while results based on the set of future coal properties were assessed as Operational Scenario 3 (OS3) emission estimates. In order to simplify the presentation and interpretation of the modelling analysis results, only the OS3 emission estimates were considered for the trace organic and inorganic constituents, in conjunction with the least efficient alternative ABC burner row combination. Thus, the estimated air quality impacts for trace organic and inorganic elements are extremely conservative in that they assumed continuous operation of the Unit #5 boiler at the maximum theoretical generation rate, using only the upper bound estimates of trace metal concentrations in all coals that may be burned at the plant in the future, and using the least efficient burner row combination at all times.

Table 3.1 summarizes the air contaminants, burner row combinations and coal properties that were evaluated for each of the three "Operational Scenarios".

Table 3.1
Definition of Operational Scenarios Considered
In the Air Quality Modelling Assessment

Operational Scenario (OS)		Air Contaminants	Description
Preferred Burner Combination	OS1	CO, NO_2, SO_2, SPM, PM_{10} & $PM_{2.5}$	Burner row combination BCD using current coal properties for ash and sulphur content
Alternate Burner Combination	OS2	CO, NO_2, SO_2, TSP, PM_{10} & $PM_{2.5}$	Burner row combination ABC using current coal properties for ash and sulphur content
Upper Bound Emission Estimate + Future Coal	OS3	SO_2, TSP, PM_{10}, $PM_{2.5}$, trace organic & inorganic constituents	Burner row combination ABC using upper bound future coal properties for ash, sulphur content and trace inorganic constituents

3.3 COAL QUALITY

The sub-bituminous coal that is currently being used at the Brandon G.S. has been supplied by the Spring Creek coal mine in the Montana portion of the Powder River Basin. Manitoba Hydro has expressed some concerns about the long-term reliability of coal supply from the Spring Creek mine that may be affected by current and future market trends. The generating station may have to switch to another coal supplier from time-to-time in the future, if supplies from the Spring Creek mine were to become unavailable or are unreasonably priced.

For this reason, Manitoba Hydro commissioned an analysis of coal quality to determine the composition of coal from various alternative candidate mines that could be used to supply fuel to the Brandon G.S. in the future. The objective of the analysis was to provide a ranking of the different coals in terms of their relative impacts on potential future air pollutant emissions from station operation. The highest ranked sources of coal were those that would lower, or at least not increase, emissions of four key parameters compared to current emission levels, when operating on coal from the Spring Creek mine in Montana. These four parameters included emission of mercury (Hg), selenium (Se), sulphur dioxide (SO_2) and particulate matter from unburned ash. Secondary consideration is also given to the potential effect on emissions of other trace elements in the coal.

Coals from a total of 16 mines were ranked in order of preference relative to Spring Creek coal, in the event that Spring Creek coal could not be purchased. The quality of each candidate coal is summarized in Tables 3.2 and 3.3, in which the highest value for each parameter is highlighted in bold. The analysis determined that no single coal source offers a reduction in emissions for all desired parameters from levels already achieved based on Spring Creek coal. In addition to Spring Creek coal, five alternative mines (coloured coded green in Tables 3.2 and 3.3) offered the best choices for future use at the Brandon G.S. because they would maintain the emission of the four key parameters within a reasonable range of current emissions. Coal from five additional mines (coloured coded yellow in Tables 3.2 and 3.3) may be used for limited periods of operation at the plant if coal from the top ranked mines are not available, but the amount of power generation may be limited by the relatively higher mercury content of these coals and the need to stay within the anticipated Canada-Wide Standard (CWS) cap on mercury emissions of 20 kg/year for the Brandon G.S.[5] Six other mines (coloured coded tan in Tables 3.2 and 3.3) were determined to be unsuitable for future use at the Brandon G.S. because they would cause significant increases in the emissions of either SO_2 or particulate matter, or else the mercury content of the coal was so high that it would limit the availability of the plant for power generation in order to remain within the limits of the anticipated CWS mercury cap.

After appropriate adjustments for differences in heating value and ash content of each candidate coal, the potential future emission rate of each element, plus SO_2 and particulate matter, were compared to that of Spring Creek, and the maximum ratios were used to provide estimates of maximum future emission rates from the Unit #5 stack, as well as for concentrations in fugitive dust from coal and ash storage. Therefore, the predicted ambient air concentrations and

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[5] Manitoba Hydro has agreed in principle to limit air emissions of mercury from Unit #5 to 20 kg per year beginning in the implementation year. In the meantime, Manitoba Hydro has committed to voluntarily begin limiting mercury air emissions as a bridge to the Manitoba mercury cap. Manitoba Hydro has communicated to Manitoba Conservation that effective in 2006, Manitoba Hydro began limiting Unit #5 mercury emissions an average of 20 kg per year.

deposition rates presented in this report provide an assessment of both current and potential future impacts from operations using any of the coals deemed to be suitable (highlighted in green and yellow in Table 3.2) for use at the Brandon G.S. The values used for the human health and ecological risk assessments also considered risk due to operations with Spring Creek coal as well as for potential increases due to operations using other suitable coals. Only the six mines deemed to be unsuitable were not considered further in this analysis.

In order to account for the varying hating value and ash content between the various coals, the emission rates of trace elements from the Unit #5 ESP outlet (expressed in g/MWh) were obtained from the stack sampling program completed in 2005. Trace element emission rates (in g/MWh) for other candidate coals were then estimated by adjusting for the difference in trace element concentration between coals and the average heating value of the candidate coals. This was done to account for the differential partitioning that occurs in the boiler for different elements during the combustion process. However, the correction was not applied to mercury because this element is primarily released in gaseous form. In addition, the calculated emission rate was further adjusted for the difference in ash content between Spring Creek coal and the other candidate coals. The following is a sample calculation for arsenic from the Mine H coal versus Spring Creek (A) coal:

$$\text{As (g/kWh)}_{H} = (\text{HV}_{A} / \text{HV}_{H}) \ \text{x} \ (\text{C}_{H} / \text{C}_{A}) \ \text{x} \ \text{ER}_{A} \ \text{x} \ (\text{Ash}_{H} / \text{Ash}_{A})$$

where

HV_{A}	is the as supplied heating value of Spring Creek coal (9350 BTU/lb)
HV_{H}	is the as supplied heating value of Mine H coal (8781 BTU/lb)
C_{H}	is the arsenic concentration in Mine H coal (1.04 mg/kg)
C_{A}	is the arsenic concentration in Spring Creek coal (1.50 mg/kg)
Ash_{H}	is the ash content of Mine H coal (6.49 lb/MMBTU)
Ash_{H}	is the ash content of Spring Creek coal (4.55 lb/MMBTU)
ER_{A}	is the measured arsenic emission rate for Spring Creek coal (0.016 g/MWh)

Using this method, the arsenic emission rate for Mine H coal is estimated at 0.0168 g/MWh.

Table 3.4 lists the ratios of estimated emission rates for the 10 alternative candidate coals considered to be suitable for use at the Brandon G.S. relative to coal from the Spring Creek mine that is currently in use at the station. The highest ratios (indicated in bold) are those that were used for defining the upper bound emission rates for operation scenario OS3. The relative difference in emissions (both higher and lower) measured emission rates for Spring Creek coal in 2005 and the 10 alternative candidate coals is illustrated in Figure 3.2, where Spring Creek coal emissions are designated as zero on the X-axis.

Table 3.2: Coal Quality Data – Proximate Analysis

Coal Mine	BTU / Ib	Dry BTU / lb	As Rec'd Ash (%)	As Rec'd Sulphur (S) (%)	SO$_2$ lbs /MMBTU (Calculated)	lbs S /MMBTU (Calculated)	lbs Ash /MMBTU (Calculated)
A (Spring Creek)	9350	12513	4.25	0.34	0.73	0.36	4.55
B	8800	12054	4.5	0.2	0.45	0.23	5.11
C	9400	11573	4.32	0.4	0.85	0.43	4.60
D	10445	12493	6.27	0.38	0.73	0.36	6.00
E	8800	12005	5.25	0.24	0.55	0.27	5.97
F	8300	11850	4.9	0.4	0.96	0.48	5.90
G	8800	12046	5.4	0.34	0.77	0.39	6.14
H	8781	12087	5.7	0.5	1.14	0.57	6.49
I	8500	11966	5.1	0.4	0.94	0.47	6.00
J	8456	12013	5.02	0.33	0.78	0.39	5.94
K	8400	11991	5.15	0.35	1.20	0.61	8.00
L	8683	11517	9.3	**0.7**	**1.61**	**0.81**	10.71
M	7399	9342	**18.60**	0.2	0.54	0.27	**25.14**
N	7850	9812	15.30	0.24	0.61	0.31	19.49
O	6800	10381	9.8	0.35	1.03	0.51	14.41
P	8550	12197	4.6	0.28	0.65	0.33	5.38
Q	8400	12104	4.7	0.34	0.81	0.40	5.6

Colour Key:

🟩	Suitable for future use
🟨	Suitable for limited use
🟧	Unsuitable for future use

Table 3.3
Coal Quality Data – Trace Element Concentrations (mg/kg)

Element	**COAL MINE**																
	A	**H**	**D**	**E**	**B**	**I**	**F**	**J**	**G**	**L**	**C**	**K**	**M**	**N**	**O**	**P**	**Q**
Sb	**1.70**	0.23	1	0.88	1.00	1.00	1.00	1.00	0.15	1.25	1.27	0.21	N/A	N/A	1	1	1
As	1.50	1.04	1	1.08	1.00	1.00	1.00	1.39	1.18	1.2	1.34	1.7	**2.4**	2.2	2	1	1
Ba	821	323.81	227	346	297	289	293	373.21	390.75	213.25	284.27	379	489	**494**	822	280.84	268.17
Be	0.21	0.27	0.6	0.28	0.20	0.20	0.20	0.29	0.25	0.44	0.24	0.3	1.1	**1.2**	0.7	0.2	0.2
B	34	54.35	50.0	28.23	36.00	40.00	37.00	44.04	41.50	**72.54**	40.77	50	82	49	N/A/	37.03	38.22
Cd	0.18	0.16	0.2	0.21	0.20	0.20	0.20	0.20	0.07	0.24	**0.27**	0.05	0.1	0.1	0.4	0.2	0.2
Cr	2.40	4.83	6	4.24	4.00	5.00	4.00	6.14	4.50	5.65	2.13	3	**13.3**	6	7	4.02	3.96
Co	3.00	2.43	1	**3.14**	2.00	3.00	2.00	2.89	1.98	2.65	1.19	1.5	2.3	1.7	N/A	2.08	2.13
Cu	9.00	**12.77**	5	9.94	10.0	13.0	9.00	14.46	11.0	6.1	9	9	9.5	4.3	N/A	11.21	8.92
Li	5.10	1.91	3.00	2.33	3.00	2.00	3.00	3.25	2.90	**16.9**	3.62	N/A	N/A	N/A	N/A	2.08	2.84
Mn	16.20	20.37	18	11.98	9.00	21.0	15.00	24.11	10.50	75.9	11.48	12	**99.3**	58	N/A	25.11	18.47
Hg	0.07	0.08	0.03	0.065	0.06	0.09	0.06	0.09	0.09	0.07	0.07	0.08	0.04	0.05	**0.13**	0.07	0.08
Mo	1.10	1.51	2	2.14	2.00	2.00	2.00	2.11	0.58	**4.05**	2.05	N/A	2.3	2.3	N/A	2.73	2
Ni	1.53	5.82	3	3.83	3.00	4.00	4.00	2.54	4.75	4.3	1.41	5	**7.3**	4.3	N/A	N/A	3.93
Pb	2.60	1.97	3.0	2.71	2.00	3.00	2.00	3.14	2.23	5.65	2.77	1.9	9.6	**13**	12	2.49	2.61
Se	1.20	0.64	1	1.04	1.00	1.00	1.00	1.15	0.68	1	**1.25**	1.1	0.15	0.3	N/A	1	1
Ag	0.08	0.21	0.2	0.21	0.20	0.20	0.20	0.27	0.09	0.25	0.51	N/A	N/A	N/A	**3**	0.2	0.02
Sr	436	168.34	140	213.47	168.00	218.00	231.00	253.93	150.50	**447.2**	337.49	270	N/A	N/A	N/A	210.41	239.84
Tl	0.05	**6.43**	1	1.11	1.00	1.00	1.00	1.00	0.08	N/A	0.94	N/A	N/A	N/A	1	N/A	N/A
Th	0.70	N/A	N/A	2.00	N/A	N/A	N/A	2.15	N/A	N/A	0.79	N/A	4.8	**5.7**	N/A	N/A	N/A
Sn	0.20	**11.38**	1.0	4.19	1.00	1.00	1.00	1.04	0.30	2.26	1.34	N/A	N/A	N/A	N/A	1	1
U	0.60	**7.60**	0.5	3.43	N/A	N/A	N/A	0.64	0.50	N/A	0.47	0.5	2.1	2.7	N/A	N/A	N/A
V	11.00	16.67	11	13.52	12.00	15.00	12.00	**21.71**	14.50	12.6	10.83	11	16.3	8.7	N/A	12.88	12.8
Zn	13.80	15.85	6	12.52	5.00	7.00	10.00	10.21	12.25	5.1	7.1	11	**18**	2	N/A	4.14	6.57

Table 3.4
Ratios of Coal Constituent Emissions Relative to Spring Creek Coal

Element	**COAL MINE**									
	B	**C**	**E**	**D**	**F**	**G**	**J**	**I**	**P**	**Q**
Sb	0.70	0.75	0.72	0.70	**0.86**	0.13	0.85	0.85	0.76	0.81
As	0.80	0.90	1.00	0.79	0.98	1.12	**1.34**	0.97	0.86	0.91
Ba	0.43	0.35	0.59	0.33	0.52	**0.68**	0.66	0.51	0.44	0.45
Be	1.14	1.15	1.86	**3.38**	1.39	1.71	1.99	1.38	1.23	1.30
B	1.27	1.21	1.16	1.74	1.59	1.75	**1.87**	1.71	1.41	1.54
Cd	1.33	1.51	**1.63**	1.31	**1.63**	0.56	1.60	1.61	1.44	1.52
Cr	1.99	0.89	2.46	2.96	2.44	2.69	**3.69**	3.03	2.17	2.26
Co	0.80	0.40	**1.46**	0.39	0.98	0.94	1.39	1.45	0.90	0.97
Cu	1.33	1.01	1.54	0.66	1.46	1.75	**2.32**	2.10	1.61	1.36
Li	0.70	0.71	0.64	0.70	0.86	0.82	**0.92**	0.57	0.53	0.76
Mn	0.66	0.71	1.03	1.31	1.35	0.93	**2.15**	1.88	2.01	1.56
Hg	0.91	0.99	0.99	0.38	0.97	1.31	1.42	1.41	1.29	**1.57**
Mo	2.17	1.87	2.71	2.15	2.66	0.75	2.77	2.64	**3.21**	2.49
Ni	2.34	0.93	3.49	2.32	3.83	**4.45**	2.40	3.80	N/A	3.52
Pb	0.92	1.07	1.45	1.36	1.13	1.23	**1.74**	1.68	1.24	1.38
Se	1.00	1.05	1.21	0.99	1.22	0.81	**1.38**	1.21	1.08	1.14
Ag	2.99	**6.41**	3.66	2.96	3.66	1.52	4.87	3.63	3.24	0.34
Sr	0.46	0.78	0.68	0.38	0.78	0.50	**0.84**	0.73	0.62	0.75
Tl	23.91	18.91	**30.96**	23.64	29.26	2.15	28.88	29.04	N/A	N/A
Th	N/A	1.13	3.98	N/A	N/A	N/A	**4.44**	N/A	N/A	N/A
Sn	5.98	6.74	**29.22**	5.91	7.32	2.15	7.51	7.26	6.47	6.85
U	N/A	0.79	7.97	0.99	N/A	1.20	**1.54**	N/A	N/A	N/A
V	1.30	0.99	1.71	1.18	1.60	1.89	**2.85**	1.98	1.52	1.59
Zn	0.43	0.52	**1.27**	0.51	1.06	**1.27**	1.07	0.74	0.39	0.65
SO_2	0.63	1.17	0.75	1.00	**1.33**	1.06	1.07	1.29	0.90	1.11
Ash	1.13	1.01	1.31	1.32	1.30	**1.35**	1.31	1.32	1.18	1.23

N/A – not available

Values in bold - maximum ratios

Figure 3.2
Maximum Range of Potential Increased/Decreased Emissions For Alternative Coals Relative to Spring Creek Coal

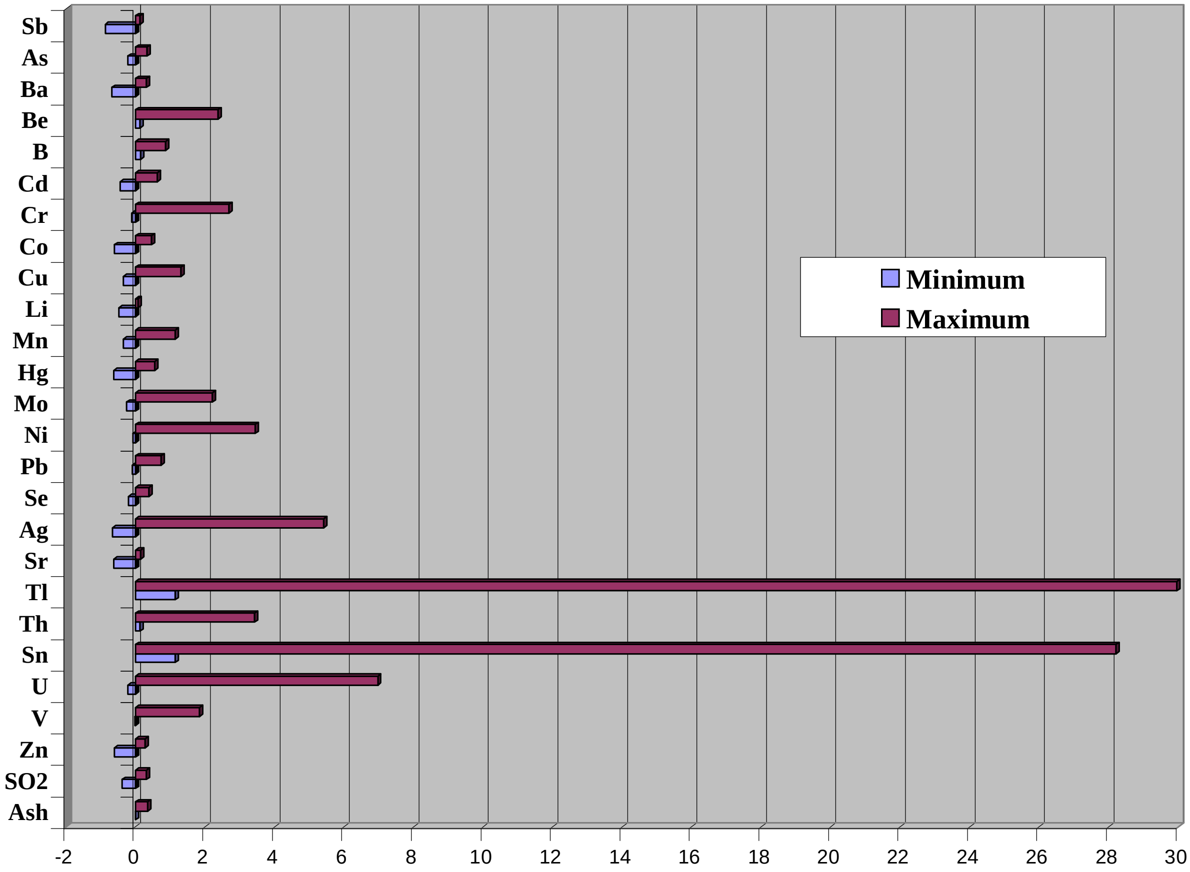

Figure 3.2 indicates that the largest potential increases in emissions due to the use of alternative coals would be for thallium (Tl) and tin (Sn). SO_2 emissions could be up to 33% higher than for Spring Creek coal (see Table 3.4), while particulate matter emissions could be up to 35% higher.

3.4 ESTIMATED CONTAMINANT EMISSIONS

3.4.1 Common Air Contaminants

Emission rates for common air contaminants such as CO, SO_2, NO_x, particulate matter (SPM, PM_{10} and $PM_{2.5}$) and mercury from combustion of sub-bituminous coal were determined through stack sampling. The emission rates for these pollutants are listed in Tables 3.5 at the maximum sustained generation rate for the preferred operating scenario (OS1) and the least efficient operating scenarios (OS2 and OS3) in various units of measure for ease of comparison with regulated limits. The values for OS2 are based on a full set of compliance stack test runs, while those for OS1 are based on more limited stack test runs.

Table 3.5
Emission Rates for Common Air Contaminants and Mercury

Contaminants	**Emission Rates**[a]								
	g/s			kg/hr			kg/MWh[b]		
	OS1	**OS2**	**OS3**[d]	**OS1**	**OS2**	**OS3**	**OS1**	**OS2**	**OS3**
SPM	2.5	4.1	5.6	9.0	14.8	20.0	0.086	0.141	0.190
PM_{10}	2.3	3.8	5.1	8.3	13.7	18.5	0.079	0.130	0.176
$PM_{2.5}$	1.5	2.3	3.2	5.4	8.4	11.3	0.051	0.080	0.108
SO_2	68.5	72.1	95.8	246.6	259.6	345.3	2.349	2.472	3.289
NO_2[c]	87.8	116.0	116.0	316.2	417.6	417.6	3.011	3.977	3.977
CO	5.8	6.90	6.90	20.9	24.8	24.8	0.199	0.236	0.236
Hg[e]	0.0006	0.0006	0.0006	0.0026	0.0026	0.0026	0.00002	0.00002	0.00002

[a] maximum sustained generation rate (105 MW)

[b] heat output basis

[c] assuming 100% conversion of NO to NO_2

[d] based on alternative (upper-bound) coal properties

[e] based on emission cap of 20 kg/year

3.4.2 Trace Contaminants

Trace contaminants include both inorganic and organic compounds and elements emitted in the combustion exhaust gas stream. Inorganic contaminants include gaseous compounds such as hydrogen chloride (HCl) and hydrogen fluoride (HF) produced in the combustion process, as well as various elements, heavy metals and radionuclides such as arsenic, cadmium, mercury, uranium, etc. which are present in small quantities in coal. Organic compounds include various products of incomplete combustion, including polycyclic aromatic hydrocarbons (PAHs), dioxins and furans.

All of the emission rates for trace contaminant species were determined through stack sampling in 2005. The emission rates from Unit #5 were measured at an average generation rate of approximately 102 MW while burning Spring Creek sub-bituminous coal. The measured emission rates at the maximum sustained generation rate (i.e., 105 MW) are listed in Table 3.6 for HCl and HF, Table 3.7 for inorganic trace elements, Table 3.8 for PAHs, and Table 3.9 for dioxins and furans. For trace contaminants, potential maximum future emissions of trace inorganic elements in Table 3.7 were scaled upward for the maximum potential increase in emissions indicated in Table 3.4, while the trace organic compounds in Tables 3.8 and 3.9 were scaled upward by 35% to reflect increased SPM emission rates for alternative coals that might be used in the future (i.e., operating scenario OS3).

Table 3.6
Estimated Emission Rates of Hydrogen Chloride and Hydrogen Fluoride

Compound	**Emission Rate** (g/s)
HCl	0.0697
HF	0.0639

Note: emissions assumed to be the same for OS1, OS2 and OS3

Table 3.7
Estimated Emission Rates for Trace Inorganic Elements

Element	**Emission Rate** (g/s)	
	OS2	OS3
Aluminium	0.30071	0.30071
Antimony	0.00005	0.00005
Arsenic	0.00047	0.00062
Barium	0.14058	0.14058
Beryllium	0.00002	0.00008
Boron	0.01283	0.02401
Cadmium	0.00004	0.00006
Chromium	0.00061	0.00226
Cobalt	0.00009	0.00014
Copper	0.00149	0.00345
Iron	0.11083	0.11083
Lithium	0.00245	0.00245
Manganese	0.00163	0.00351
Molybdenum	0.00055	0.00178
Nickel	0.00041	0.00182
Palladium	0.00035	0.00035
Lead	0.00041	0.00071
Selenium	0.00038	0.00052
Silver	0.00002	0.00016
Strontium	0.02858	0.02858
Thallium	0.00005	0.00163
Thorium	0.00013	0.00057
Tin	0.00058	0.01704
Uranium	0.00006	0.00047
Vanadium	0.00090	0.00258
Zinc	0.00038	0.00048

Table 3.8
Estimated Emission Rates for Polycyclic Aromatic Hydrocarbons (PAH)

Compound	**Emission Rate** (g/s) **OS3**
Acenaphthene	5.67E-05
Acenaphthylene	3.94E-07
Anthracene	2.48E-06
Benzo(a)anthracene	3.54E-07
Benzo(b)anthracene	5.91E-07
Benzo(b)fluoranthene	5.51E-07
Benzo(k,j)fluoranthene	6.69E-07
Benzo(a)flourene	8.66E-07
Benzo(b)flourene	1.97E-07
Benzo(g,h,i)perylene	1.58E-06
Benzo(a)pyrene	5.12E-07
Benzo(e)pyrene	2.28E-06
Biphenyl	2.68E-05
2-chloronaphthalene	8.27E-08
Coronene	9.45E-07
Dibenzo(a,c & a,h)anthracene	2.87E-08
Dibenzo(a,j)acridine	1.42E-08
7H-dibenzo(c,g)carbazole	2.21E-08
Dibenzo(a,e)pyrene	3.94E-09
Dibenzo(a,i)pyrene	5.12E-09
9,10-dimethylanthracene	2.17E-07
7,12-dimethylanthracene	6.69E-08
1,2-dimethylnaphthalene	3.35E-07
2,6 & 2,7-dimethylnaphthalene	1.30E-06
Fluoranthene	6.69E-06
Fluorene	7.88E-06
Indeno(1,2,3-cd)pyrene	2.72E-07
2-methylanthracene	4.33E-07
3-methylcholanthrene	1.18E-06
1-methylnaphthalene	7.88E-06
2-methylnaphthalene	1.18E-05
1-methylphenanthrene	3.27E-06
9-methylphenanthrene	2.91E-06
Naphthalene	2.36E-05
Perylene	1.61E-07
Phenanthrene	4.33E-05
Picene	2.64E-08
Pyrene	4.33E-06
Quinoline	3.27E-07
m-Terphenyl	1.14E-06
o-Terphenyl	1.81E-06
p-Terphenyl	5.91E-07
Tetralin	2.56E-06
Triphenylene/chrysene	1.50E-06

Table 3.9
Estimated Emission Rates for Polychlorinated Dibenzo-p-Dioxins (PCDD) and Polychlorinated Dibenzofurans (PCDF)

Compound	**Emission Rate** (g/s)
	OS3
Tetrachlorodibenzo-p-dioxins	1.95E-11
Pentachlorodibenzo-p-dioxins	1.53E-11
Hexachlorodibenzo-p-dioxins	8.48E-10
Heptachlorodibenzo-p-dioxins	227E-09
Octachlorodibenzo-p-dioxins	3.18E-09
Total Dioxins	5.49E-09
Tetrachlorodibenzofurans	3.60E-09
Pentachlorodibenzofurans	3.28E-09
Hexachlorodibenzofurans	1.21E-09
Heptachlorodibenzofurans	6.67E-10
Octachlorodibenzofurans	1.43E-08
Total Furans	4.86E-10

3.4.3 Volatile Organic Compounds (VOCs)

Estimates of volatile organic compound emissions from coal combustion were derived from Section 1.1 of the U.S. Environmental Protection Agency’s compilation of air pollution emission factors (USEPA 1998), commonly referred to as AP-42. The compounds, their related emission factors, and estimated emission rates are listed in Table 3.10.

Table 3.10
VOC Emission Factors and Estimated Emission Rates

Compound	**AP42 Emission Factor** (lb/ton)	**Emission Rate** (g/s)
Acetaldehyde	0.00057	0.00475
Acetophenone	0.000015	0.00013
Acrolien	0.00029	0.00242
Benzene	0.0013	0.01083
Benzyl chloride	0.0007	0.00583
Bis(2-ethylhexyl)phthalate (DEHP)	0.000073	0.00061
Bromoform	0.000039	0.00033
Carbon disulphide	0.00013	0.00108
2-Chloroacetophenone	0.000007	0.00006
Chlorobenzene	0.000022	0.00018
Chloroform	0.000059	0.00049
Cumene	0.0000053	0.00004
Cyanide	0.0025	0.02083

Compound	**AP42 Emission Factor** (lb/ton)	**Emission Rate** (g/s)
2,4-Dinitrotoluene	0.00000028	0.00000
Dimethyl Sulphate	0.000048	0.00040
Ethyl benzene	0.000094	0.00078
Ethyl chloride	0.000042	0.00035
Ethylene dichloride	0.00004	0.00033
Ethylene dibromide	0.0000012	0.00001
Formaldehyde	0.00024	0.00200
Hexane	0.000067	0.00056
Isophorone	0.00058	0.00483
Methylbromide	0.00016	0.00133
Methyl chloride	0.00053	0.00442
Methyl ethyl ketone	0.00039	0.00325
Methyl hydrazine	0.00017	0.00142
Methyl methacrylate	0.00002	0.00017
Methyl tert-butyl ether	0.000035	0.00029
Methylene chloride	0.00029	0.00242
Phenol	0.000016	0.00013
Propionaldehyde	0.00038	0.00317
Tetrachloroethylene	0.000043	0.00036
Toluene	0.00024	0.00200
1,1,1-Trichloroethane	0.00002	0.00017
Styrene	0.000025	0.00021
Xylenes	0.000037	0.00031
Vinyl acetate	0.0000076	0.00006

Note: emissions assumed to be the same for OS1, OS2 and OS3

3.4.4 Greenhouse Gases (GHGs)

Brandon G.S. Unit #5 emissions of greenhouse gases were measured during the stack sampling program conducted in 2005. Table 3.11 summarizes the rates at the maximum sustained generation rate of 105 MW.

Table 3.11
Estimated Emission Rates for Greenhouse Gases

Compound	**Emission Rate** (g/s)	CO$_2$-equivalent (tonnes/hr)
CO$_2$	32,838	118.22
CH$_4$	0.548656	0.04
N$_2$O	0.34291	0.38
Total		**118.6**

Note: emissions assumed to be the same for OS1, OS2 and OS3

The global warming potential of these compounds is often expressed as CO_2–equivalents by multiplying the methane emission rate by a factor of 21, and the N_2O emission rate by a factor of 310. Thus, the total GHG emission rate in CO_2-equivalents at the maximum sustained generation rate is estimated at 118.6 tonnes/hr.

3.5 FUGITIVE DUST EMISSIONS

The primary sources of fugitive dust emissions at coal-fired power plants are coal handling and storage, and ash handling and disposal. At the Brandon G.S., ash handling consists of sluicing the ash from the Unit #5 boiler in a wet slurry, such that ash handling is not a source of fugitive emissions from plant operations.

As previously discussed, fugitive emissions from bulk material storage and handling are generally estimated using emission factors. Much of the information about fugitive emissions from coal-fired power plants was first developed or published in the mid-1970’s. Most of the reported emission factors are not based on actual test data, are highly variable, and are often contradictory. According to a report published by the Electric Power Research Institute (EPRI 1984), much of the information in published sources is based on conjecture and is thus of questionable validity. As such, a conservative approach was used, based on methodologies that are well supported in the literature.

3.5.1 Coal Handling and Storage

Coal handling operations at the Brandon G.S. that can produce fugitive dust emissions consist of: 1) coal train unloading, 2) continuous drop of coal from the slew conveyor to the active coal storage area, 3) reclaim of the coal from the active coal storage area to the coal bunker for transfer to the combustion boiler, 4) removal of coal from active storage pile to long-term storage pile, 5) reclaim of coal from the long-term storage pile, and 6) wind erosion of the active and long-term storage piles. Emission factors for these operations were based on emission equations published in a Canadian Council of Ministers of the Environment (CCME) study of fugitive coal dust emissions (Cope and Bhattacharyya 2001), and AP-42 Emission Factors (US EPA 1995; Chapter 11 – Mineral Products Industry).

An hour-by-hour emissions estimation methodology was used with the goal of representing both continual emissions due to coal handling activities and sporadic bursts of emissions due to erosion during high wind speeds. As such, dispersion modelling results are indicative of both long-term (monthly, annual) and short-term maximum (24-hour) ambient air concentrations and deposition amounts. To be conservative, one coal train was assumed to arrive every week, with unloading of 13,425 tonnes of coal occurring over 2 ½ days. A total of 1,440 tonnes of coal per day (i.e., 66 tons per hour) was assumed to be fed directly into the Unit #5 boiler, while the remainder of 3,930 tonnes was assumed to be directed onto the active coal storage pile. For the remaining 4 ½ days, coal was assumed to be reclaimed from the active storage pile at a rate of 1,440 tonnes per day. On all days, erosion of the coal storage piles was simulated.

The coal storage pile was subdivided into two distinct areas: 1) the active area where the coal is unloaded from the railcars and distributed in an arc by a mechanical, pivoted conveyor system, and 2) a longer term storage area where the coal is disturbed less frequently, thus reducing the potential for fugitive dust emissions. The entire coal storage pile covers an area of approximately 3.5 hectares. The active coal storage pile comprises approximately 5% of the entire coal storage area.

The longer term coal storage area experiences far less frequent disturbance. Such areas experience much lower emission rates because a surface crust forms after the suspendable material is removed in a few erosion events between disturbances. In addition, this portion of the coal storage area tends to freeze over during the winter, and much of the area tends to remain frozen through the spring until July. In order to further reduce fugitive dust emissions from this area, Manitoba Hydro applies a chemical binder to the surface over the summer months. Such binders are estimated to reduce fugitive dust emissions from exposed areas by up to 90%. The effects of freezing and the chemical binder were incorporated into the dispersion modelling by application of control factors. On an infrequent basis, a scraper may be used to move or reshape a portion of the long-term storage pile. Although this activity leads to fugitive emissions, it is a discretionary activity that can be curtailed if it causes unacceptably high emission rates. As such, these emissions were not represented in the modelling. The conservative assumption that a coal train arrives every week (thus ensuring that the active storage pile always has sufficient quantity to supply Unit #5), leads to higher emissions than if the long-term storage pile was accessed. Therefore, the conservative approach of coal handling activity being ‘on’ during the entire year was used. This likely leads to an over-estimate of annual emissions, but is more representative of maximum short-term (i.e., 24-hour) emissions.

Erosion of a coal storage pile depends on the frequency of disturbance, the size of the storage pile, and the magnitude of short-term gust wind speeds. On a very infrequent basis, a sustained gust has a high enough speed to liberate a large amount of particulate matter from the active storage pile. For each hour of the year, the fastest mile wind speed was estimated and if this speed was higher than the threshold speed required to liberate dust from the active storage pile, a calculation of dust emission for that hour was performed. This approach assumes that the erosion potential (amount of material available for suspension) is completely replenished each hour, which in reality is only true for active storage piles that are being continuously disturbed.

Fastest mile wind speeds were determined by multiplying hour-average wind speeds by a factor of 1.4. This scaling factor is a conservative estimate based on measured wind data published in a recent article (Vickery and Skerlj 2005) and likely overestimates sustained gust speeds for most hours. Table 3.12 provides a summary of the assumptions used in characterizing the fugitive dust emission sources. The application of control factors (reduction efficiencies) is also indicated. A control factor accounts for the mitigating effect of a process or device that reduces net emissions.

Table 3.12: Assumptions Used to Characterize Fugitive Dust Emissions

ACTIVITY	PROCESSING AMOUNT	CONTROL FACTOR
coal train unloading	5370 tonnes/day unloading train to Shaker House 1440 tonnes/day transferred to Unit #5 3930 tonnes/day transferred to active storage pile	90% reduction in Shaker House due to baghouse
active storage pile	1440 tonnes/day reclaimed through conveyor to Unit #5 wind erosion – storage pile size 0.158 hectares	none used
long-term storage pile	wind erosion – 100,000 tonnes stored over an area of 3.5 hectares	75% reduction July-September 90% reduction April-June 100% reduction October-March (pile is frozen)

Table 3.13 provides a description of the emission equations and rates used to determine total hourly fugitive dust emissions due to coal handling and storage. Total annual emissions of fugitive coal dust amount to 8.7 tonnes of total suspended particulate matter, due in large part to wind erosion of the active pile.

Table 3.13: Equations used for Estimating Emissions Due to Coal Handling and Storage

PROCESS	EMISSION EQUATION	PARAMETER VALUES
Unloading coal to shaker house	$0.580/M^{1.2}$ kg/tonne (US EPA AP-42, 11.9-2)	moisture (M) = 10%
Coal dump to active pile	$k \times (0.0016) \times (u/2.2)^{1.3} / (M/2)^{1.4}$ kg/tonne (Cope and Bhattacharyya 2001)	wind speed (u) varies by hour k (particle multiplier) = 0.74 moisture (M) = 10%
Wind erosion of active stockpile	$58(u^* - u_t^*)^2 + 25(u^* - u_t^*)$ (US EPA AP-42, 13.2.5) during high gust winds	u_t^* = threshold friction velocity, u^* = hourly friction velocity during high gusts
Reclaim from active stockpile	$k \times (0.0016) \times (u/2.2)^{1.3} / (M/2)^{1.4}$ kg/tonne (Cope and Bhattacharyya 2001)	wind speed (u) varies by hour k (particle multiplier) = 0.74 moisture (M) = 10%
Wind erosion of long-term storage pile	0.045 kg/tonne/yr (Cope and Bhattacharyya 2001)	

Two of the equations listed in Table 3.13 have a dependence on coal moisture level. A moisture value of 20% was considered, which is the average coal moisture content from the most recent stack testing assessment of Unit #5 (ORTECH 2005). Instead of using this value, a 10% moisture level was used in the emission equations, since these equations were not developed for coal with a high moisture level. The use of the lower moisture level results in a higher emission rate from the equation than might actually occur. As such, the estimated coal dump fugitive emission amounts are likely over-estimated.

Use of the emission methodologies listed in Table 3.13 results in the following annual emission estimates of fugitive coal dust:

Erosion of the active storage pile:	5.59 tonnes
Unloading of the coal trains:	2.50 tonnes
Coal handling at the active storage pile:	210 kg
Erosion of the long-term storage pile:	400 kg

Wind erosion of the active coal storage pile occurs on relatively few days. As a maximum, an emission rate of 130 g/s (470 kg/hour) was determined.

Mitigation measures used by Manitoba Hydro cannot be accounted for in the dispersion/dust transport modelling. In particular, proactive management procedures that reduce or stop coal handling processes during periods with observed off-site dust transport and the interception of horizontal dust transport by terrain and vegetation surrounding the coal pile are not represented. This is because there is simply no practical method to determine how much reduction in emissions is/was achieved by the implementation of these measures. Similarly, there is no practical method in the dispersion modelling analysis for incorporating the effect of interception of fugitive emissions by surface features such as trees or buildings, or the effect of buildings on wind speed near the active storage coal pile.

3.5.2 Ash Lagoon

Ash from Unit #5 is sluiced to one of two ash lagoons. The disposal of ash into one of the lagoons is alternated such that one lagoon is used at a time, while the other is dewatered. The total area covered by the one ash lagoon was estimated at 5.66 hectares. From aerial photographs of the site, it was estimated that over 80% of the ash lagoon is covered by either water or vegetation.

An emission factor of 0.85 tonnes per hectare per year was applied to the *exposed* areas of the ash lagoon. This value is representative of fugitive dust emissions due to wind erosion of exposed areas (AP-42 Section 11.9). To be conservative, the emission factor was applied to 40% of the total area, to account for the possibility of greater areas exposed to wind erosion from use of one or both of the two ash lagoons. This resulted in a consistent emission rate of 0.15 g/s of TSP, which results in an estimated 4.7 tonnes of fugitive dust being emitted over a full year.

3.5.3 Particle Size Distributions for Particulate Matter

Separate particle size distributions were defined for the particulate matter emitted from the coal and ash storage areas. The equations described in Table 3.13 were used to estimate total emissions of fugitive suspended particulate matter (i.e., SPM). To partition the fugitive SPM into size categories, the particle size distributions listed in Table 3.14 were used. For fugitive dust due to coal pile erosion and handling, the particle size distribution was taken from AP-42 (11.9-2).

For the ash lagoon, there were two possible choices for defining the particle size distribution, namely: 1) using the distribution for wind erosion of stockpiles defined in US EPA AP-42 (1995), or 2) the distribution used in a dispersion modelling analysis in a report submitted to the U.S. Congress on managing wastes from the combustion of fossil fuels (US EPA 1998). The latter was directed specifically at fugitive emissions from ash impoundments at coal-fired power plants. Although the analysis was specific to the type of waste being considered for the emission of fugitive dust from the ash lagoon at the Brandon G.S., the particle size distribution used in the report to Congress was based on an earlier analysis (US EPA 1990) in which the particle size distribution was largely based on conjecture and not on any actual measurements of emitted particles. The two particle size fractions for fugitive emissions from the ash lagoon from AP-42 and the report to Congress were as listed in Table 3.15, below.

Table 3.14
Coal Particle Size Distribution Used for ISCST3 Dispersion Modelling

	Cumulative Particle Size Fractions (Percent Passing)					
Particle Size Categories (µm)	≤1	≤2.5	≤5	≤10	≤20	≤30
Mid-class Diameter (µm)	0.5	1.625	3.25	7.5	15	25
Fugitive Coal Dust	1%	1.95%	7.5%	20%	50%	100%
Fugitive Ash Dust	10%	20%	50%	70%	100%	

Table 3.15
Alternative Cumulative Particle Size Distributions for Fugitive Dust Emissions from Ash Lagoon

Particle Size Category (µm)	Percent Passing AP-42 (US EPA 1995)	Percent Passing Report to Congress (US EPA 1998)
2.5	20%	(20%)
5	(40%)	50%
10	50%	(70%)
15	60%	(85%)
20	(75%)	100%
30	100%	

Brackets denote interpolated values.

Since the report to Congress was a relatively recent analysis specific to ash lagoon emissions, the particle size distribution used in the current analysis for the Brandon G.S. was made consistent with the US EPA (1998) analysis. However, it is recognized that the use of this distribution may somewhat overestimate PM_{10} emissions.

3.5.4 Chemical Composition of Fugitive Dust Emissions

The chemical composition of the fugitive coal and ash emissions consists of trace elements contained in the coal and ash, as well as organic products of incomplete combustion associated with the ash. The elemental composition of the ash lagoon waste materials (Chemical Combustion By-Products – CCBP) was provided by Manitoba Hydro, and is specific to the Brandon G.S. Estimates of trace organic compounds (dioxins and furans) in the ash lagoon wastes were derived from a survey of co-managed wastes at 11 disposal sites (US EPA 1998) which were included in the waste characterization technical background document in the US EPA (1999) report to Congress.

The composition of the trace elements in the sub-bituminous coal from the Spring Creek mine in Wyoming was provided by the mining company, Kennecott Energy Company. However, data were not available for all of the trace elements from the mining company data on coal composition. Data on these elements were obtained from a database on coal quality (COALQUAL) compiled and maintained by the U.S. Geological Service (USGS 1998). The data are available for each coal producing region in the United States. Therefore, data derived from the Powder River Basin are reasonably representative of the coal from the Spring Creek mine, located within this basin.

The elemental composition of Spring Creek coal is provided in Table 3.3, above. Table 3.16 summarizes the chemical composition of coal and ash used for fugitive dust emissions for both current and potential future operations. Where there was no information on trace elements in coal specific to Spring Creek coal, data from the COALQUAL database was used instead. The maximum future concentrations of trace elements in coal was based on the maximum concentration of each element in any of the coals considered to be suitable for future use listed in Table 3.2. The ratio between the concentration of an element in current coal and its maximum concentration in future coals was carried over into the difference between the current and maximum future concentration of that element in future ash. Since there is no rational basis on which to assume any difference between current and future emission rates of dioxins and furans from the use of different coals, it was assumed that there would be no difference between current and future concentrations of these organic compounds in the ash. For the purposes of the air quality impact assessment, only the values listed for operational scenario OS3 in Table 3.16 were used for the calculation of maximum ambient concentrations and deposition rates.

Table 3.16
Chemical Composition of Coal Stock and Ash Waste

CONTAMINANT	**CONCENTRATION** (µg/g)			
	COAL		**ASH**	
	OS1 & OS2	OS3	OS1 & OS2	OS3
Inorganic Elements				
Aluminium	6456.6	6456.6	43680	43680
Antimony	1.7	1.7	2.8	2.8
Arsenic	1.5	1.5	18.9	18.9
Barium	821	821	4580	4580
Beryllium	0.21	0.6	2.28	6.51
Boron	34	50	312	458.82
Bromine	9	26		
Bismuth			0.24	0.24
Cadmium	0.18	0.27	0.61	0.92
Calcium	10462.7	10462.7	122900	122900
Chloride	200	200	208.9	208.9
Chromium	2.4	6.14	56	143.3
Cobalt	3	3	10.3	10.3
Copper	9	14.46	118.3	190.1
Fluoride	41.9	78	364.4	678.4
Iron	5255.4	5255.4	14000	14000
Lithium	5.1	5.1		
Magnesium	2551.8	2551.8	18900	18900
Manganese	16.4	25.11	376	575.69
Mercury	0.07	0.09	0.08	0.10

CONTAMINANT	**CONCENTRATION** (µg/g)			
	COAL		**ASH**	
	OS1 & OS2	OS3	OS1 & OS2	OS3
Molybdenum	1.1	2.73	3.8	9.36
Nickel	1.53	4.75	37.1	115.2
Lead	2.6	3.14	20.9	25.2
Phosphorus	15.08	15.08		
Potassium	464.4	464.4	22.7	22.7
Selenium	1.2	1.25	1.5	1.6
Silver	0.2	0.51	1	2.55
Sodium	3018.4	3018.4	14300	14300
Strontium	436	436	2790	2790
Thallium	0.05	1.11	0.7	15.54
Thorium	0.7	2.15		
Tin	0.2	4.19	1	20.95
Titanium	421.9	421.9	2960	2960
Uranium	0.6	3.43	6.7	38.2
Vanadium	11	21.71	138.2	272.8
Zirconium	9.1	35.32		
Zinc	13.8	13.8	54	54.0
Dioxins/Furans				
2,3,7,8-TCDD			0.00017	0.00017
1,2,3,7,8-PeCDD			0.00025	0.00025
1,2,3,4,7,8-HxCDD			0.00035	0.00035
1,2,3,6,7,8-HxCDD			0.00028	0.00028
1,2,3,7,8,9-HxCDD			0.0003	0.0003
1,2,3,4,6,7,8-HpCDD			0.00059	0.00059
OCDD			0.01054	0.01054
2,3,7,8-TCDF			0.00019	0.00019
1,2,3,7,8-PeCDF			0.00017	0.00017
2,3,4,7,8-PeCDF			0.00017	0.00017
1,2,3,4,7,8-HxCDF			0.00025	0.00025
1,2,3,6,7,8-HxCDF			0.00018	0.00018
2,3,4,6,7,8-HxCDF			0.00028	0.00028
1,2,3,7,8,9-HxCDF			0.00024	0.00024
1,2,3,4,6,7,8-HpCDF			0.00029	0.00029
1,2,3,4,7,8,9-HpCDF			0.00035	0.00035
OCDF			0.00059	0.00059

3.6 WATER VAPOUR EMISSIONS

The concentration of salt in the blowdown water of the cooling tower was determined to be 0.0044 g salt/g solution. A sample was collected on-site and analyzed by the Chemical Laboratory Services of Manitoba Hydro Laboratories, Analysis 51121. The 'salt' is a measure of the total dissolved solids in water and includes common compounds such as sulphates and nitrates and elements such as calcium and magnesium.

3.7 COMBUSTION TURBINES

Performance and emissions data collected for one of the two Brandon CTs by ABB Alstom Ltd. (Switzerland) were used to characterize each generating unit operating on natural gas. ABB Alstom provided expected (i.e., design) emissions at different loads and ambient temperatures (ABB Alstom 2000). To be conservative, the highest emission rates recorded were used in the modelling. These maximum rates occurred at –20°C ambient temperature, at 100% load (140 MW output) Table 3.17 lists the emission rates used in CALPUFF modelling. Emission rates for CO at startup (25% load factor) are also included, since emissions of CO increase considerably at lower loads, due to incomplete combustion. As indicated in Table 3.18, the actual measured emission rates for CO and NO_x for the two CTs are much lower than the design values used for the modelling analysis.

Table 3.17: Design Maximum Emission Rates of Common Air Contaminants for CTs*

Air Contaminant	Emission Rate at 100% Load (g/s)	Emission Rate at 25% Load (g/s)
TSP	1.89	1.83
CO	1.89	189.56
NO_x (as NO_2)	29.33	29.33

* Maximum measured emission rates occurred with an ambient temperature of –20°C.

Table 3.18: CT Stack Test Measured Emission Rates

Air Contaminant	Emission Rate at 100-105% Load (g/s)	Emission Rate at 20-25% Load (g/s)
Unit #6		
CO	0.0	33.3
NO_x (as NO_2)	17.0	10.8
Unit #7		
CO	0.0	29.1
NO_x (as NO_2)	17.1	10.1

Other contaminant species than those listed in Table 3.17 are also produced during natural gas combustion. These species were not considered in the dispersion modelling either due to insignificant amounts released (e.g., SO_2) or lack of ambient guidelines or standards (i.e., VOCs). For particulate matter, virtually all SPM released from the combustion of natural gas is in the form of respirable particulate matter ($PM_{2.5}$). As such, particulate matter emissions from the CTs were considered to be entirely in the form of $PM_{2.5}$. Further information about emissions and ambient concentrations due to the operation of the CTs can be found in a recent environmental impact assessment conducted in 2000 (UMA and Jacques Whitford 2000).

4.0 EXISTING AIR QUALITY

Nitrogen dioxide (NO_2) and particulate matter (as PM_{10} and $PM_{2.5}$) are monitored at the Assiniboine Community College in Brandon. Table 4.1 provides a summary of NO_2, PM_{10} and $PM_{2.5}$ concentrations reported for the period 1997 – 2004 (Manitoba Conservation 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004). Ambient air quality criteria are also listed for comparison purposes.

Table 4.1
Ambient Air Quality Levels in Brandon

Contaminant	**Measured Concentrations ($\mu g/m^3$)**								**Criterion Value**	**Criterion Classification**	**Jurisdiction**
	5131 Brandon Assiniboine Community College										
	1997	1998	1999	2000	2001	2002	2003	2004			
Nitrogen Dioxide											
Mean	11	15	17	13	10	11	11	10	100	Maximum Acceptable Objectives	Manitoba
Max. 1-hour	147	122	124	133	149	94	86	124	400		
Max. 24-hour	55	58	62	56	56	51	49	57	200		
PM_{10}											
Mean	16	23	21	20	22	22	23	21			
Max. 24-hour	49	127	153	202	131	229	154	157	50	Guideline	Manitoba
$PM_{2.5}$											
Mean					6	5	6	5			
Max. 24-hour					18	26	23	23			
98th percentile					17[b]	18	15	16			
CWS parameter[a]							17	16	30	CWS [a]	National

[a] CWS - Canada-Wide Standard: achievement based on the 98th percentile ambient measurement annually, averaged over three consecutive years

[b] June-December

The NO_2 monitoring data in Brandon indicate that the Manitoba Maximum Acceptable objectives have not been exceeded over the available period of monitoring data since 1997. The annual average NO_2 concentration is only about one-tenth of the Maximum Acceptable Objective required by Manitoba Conservation. Similarly, the maximum observed 1-hour and 24-hour average NO_2 concentrations in Brandon are only about one-quarter of the Provincial Maximum Acceptable Objectives.

There is currently no SO_2 monitoring in either Brandon or Selkirk, nor in Winnipeg for that matter. SO_2 monitoring was discontinued in Brandon in 1989, but readings prior to that were too low to register (0.0 ppm). Therefore, it can reasonably be assumed that the emissions from the

Brandon G.S. are the largest source of SO_2 emission in the area, and that the SO_2 concentrations calculated for Brandon G.S. based on dispersion modelling can be directly compared with the ambient air quality objectives for Manitoba, without consideration of additional background SO_2 levels.

Similarly, there is no CO monitoring for Brandon. There are only two stations that monitor CO in Manitoba, and both are located in Winnipeg. Table 4.2 lists the observed values at Scotia and Jefferson (Manitoba Conservation 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004). Due to the higher traffic levels in Winnipeg, CO levels in Brandon are likely to be much lower than those listed in Table 4.2.

Table 4.2
Measured CO Concentrations (µg/m^3) in Winnipeg

Averaging Period	**9118 WINNIPEG, SCOTIA & JEFFERSON**										**Manitoba Objective**	**Classification**
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004		
Mean	467	433	422	456	388	547	524	422	331	278		
Max. 1-hour	5928	6156	4674	6612	7866	4674	7980	3192	3726	3016	35000	Maximum Acceptable
Max. 8-hour	4104	3078	3306	4560	3534	2736	3990	2280	1596	1705	15000	

Table 4.1 also summarizes the ambient monitoring data for particulate matter at Brandon for the period 1997-2004. No data are available for total suspended particulate matter (SPM). The measured maximum 24-hour average PM_{10} concentrations at the Assiniboine Community College consistently exceed the Manitoba Guideline value of 50 µg/m^3. The primary cause for the high levels of PM_{10} is believed to be related to fugitive dust emissions from agricultural activity in the area, as well as possibly due to seasonal burning of agricultural waste and stubble in fields. $PM_{2.5}$ concentrations, which are of greater concern with respect to human health, were not monitored in Brandon prior to 2001. The $PM_{2.5}$ concentrations over the period 2001-2004 are well below the Canada-Wide Standard (CWS) level.

Table 4.3 lists the mean concentrations of trace organic compounds measured at the Ellen Street monitoring station in downtown Winnipeg by Manitoba Environment in 1995-96 (Manitoba Conservation 2000). Only those PAHs relevant to emissions from the Brandon G.S. are listed. There are no ambient air quality criteria specific to PAH or dioxin/furan concentrations, and the impacts of these contaminants are addressed in this assessment through the risk assessment analyses. The levels of PAH, dioxins and furans measured in Winnipeg are simply provided here for comparative purposes.

Table 4.3: Mean Concentrations(ng/m^3) of Trace Organic Compounds Measured in Winnipeg (1995 - 1996)

Station 9119, Winnipeg (65 Ellen Street)			
Polycyclic Aromatic Hydrocarbons (PAHs)	**Arithmetic Mean**	**Dioxins and Furans**	**Arithmetic Mean**
Benzo(a)pyrene	0.113	2,3,7,8-TCDD	0.002
Benzo(b)fluoranthene	0.462	Total TCDD	0.001
Chrysene	0.302	Total PeCDD	not detected
Indeno(1,2,3-cd)pyrene	0.176	Total HxCDD	0.116
Benzo(g,h,i)perylene	0.339	Total HpCDD	0.448
Fluoranthane	2.497	Total OCDD	1.022
Naphthalene	0.380	Total PCDD	1.587
Phenanthrene	11.764	2,3,7,8-TCDF	0.021
Pyrene	2.069	Total TCDF	0.012
		Total PeCDF	0.021
		Total HxCDF	0.339
		Total HpCDF	0.307
		Total OCDF	0.111
		Total PCDF	0.795
		Total PCDD/PCDF	2.382

Similarly, Table 4.4 lists mean concentrations for a selected set of volatile organic compounds (VOCs) measured in Winnipeg at the Ellen Street monitoring station by Manitoba Conservation for the period 1995-1996 (Manitoba Conservation 2000). More recent data on trace element concentrations in particulate matter (as PM_{10}) for the same location are listed in Table 4.5 for 2004 (Manitoba Conservation 2005). As with the PAHs and dioxins/furans, the data in Tables 4.4 and 4.5 are simply provided for comparative purposes.

Table 4.4: Mean Concentrations (µg/m^3) of Selected Volatile Organic Compounds (VOCs) Measured in Winnipeg (1995 – 1996)

Compound	Arithmetic Mean
Benzene	1.59
Bromoform	0.015
Chlorobenzene	0.015
Chloroform	0.13
Ethyl benzene	1.02
Ethylene dibromide	0.02
Hexane	1.1
Tetrachloroethylene	0.3
Toluene	5.9
1,1,1-Trichloroethane	0.9
Styrene	0.3
Xylenes	4.9

Table 4.5: Maximum and Mean Concentrations (μg/m^3) of Selected Trace Elements Measured in Winnipeg (2004)

Trace Element	**NAPS No. 70119 65 Ellen Street**	
	Maximum	Mean
Aluminium	1.1123	0.2198
Antimony	0.0080	0.0007
Arsenic	0.0018	0.0004
Barium	0.0271	0.0130
Cadmium	0.0032	0.0004
Chromium	0.0281	0.0063
Cobalt	0.0076	0.0021
Copper	0.0355	0.0095
Iron	0.6877	0.1880
Manganese	0.0371	0.0103
Mercury	0.0040	0.0020
Molybdenum	0.0016	0.0008
Nickel	0.0094	0.0012
Palladium	0.0016	0.0002
Lead	0.0101	0.0036
Selenium	0.0026	0.0006
Silver	0.0014	0.0003
Strontium	0.0060	0.0016
Tin	0.0038	0.0008
Vanadium	0.0330	0.0066
Zinc	0.0612	0.0142

5.0 PREDICTED AIR QUALITY

The results from the dispersion modelling analysis are presented in the following sections. The analysis is presented for emissions from coal-fired operation of the Unit #5 stack, fugitive dust emissions from the coal and ash storage areas, and the associated cooling tower. In addition, the analysis provides an assessment of the combined impacts for common air contaminants (CO, NO_2 and $PM_{2.5}$) from the operation of Unit #5 concurrent with the two natural gas-fired combustion turbines (CTs – Units #6 and #7). Although Manitoba Hydro operates the CTs under a separate permit and the operation of the CTs is not part of this licence review for Unit #5, the potential for cumulative short-term impacts on air quality was considered an appropriate issue for consideration in this review.

In addition to a discussion of predicted ambient air quality concentrations, significant characteristics of the meteorological fields are also described. Where appropriate, the predicted concentrations [expressed in units of micrograms per cubic metre of air ($\mu g/m^3$)] have been compared to applicable ambient air quality criteria for Manitoba. Deposition of trace air contaminants to the surface [expressed in units of micrograms per square metre per year ($\mu g/m^2$-year)] was also calculated by accounting for aerodynamic settling velocities (‘dry’ deposition) and precipitation amounts with contaminant-specific scavenging ratios (‘wet’ deposition). Emissions of SO_2, particulate matter and the inorganic trace elements, which are associated with particulate matter from the Unit #5 stack and fugitive coal dust, were based on both current coal quality and upper-bound coal quality in the future. The evaluation of potential risks to human health and the environment for both short-term and long-term exposure due to ambient air concentrations and deposition of Contaminants of Potential Concern (COPC) is addressed in a separate document (Appendix N).

For some air contaminants, there are chemical transformations that occur over time as emitted amounts mix with the ambient air, although in most cases the transformations have significance only at large distances from the source(s). Of importance to this assessment, most of the NO_x emitted from high temperature combustion is in the form of NO. Much of the NO is transformed into NO_2 by a variety of free radical species such as oxygen (O_2), ozone (O_3), hydrogen peroxide (H_2O_2) and hydroperoxyl (HO_2) (Radojevic 1992). To account for the maximum ambient NO_2 concentrations in the community, a conservative approach can be used, which assumes that all of the NO is released from the combustion process in the form of NO_2. Alternatively, a representative conversion rate can be applied to provide a more realistic estimate of NO_2 concentration. Both approaches are used and presented in this report.

Dispersion modelling results of Unit #5 stack emissions in the following sections of the report are presented as follows:

1) ambient concentrations for the common air contaminants CO, NO_2, are presented for both the preferred operating scenario (OS1; see discussion of operating scenarios in Sections 3.1 and 3.2) and the least efficient operating scenario (OS2);
2) ambient concentrations for SO_2, PM_{10} and $PM_{2.5}$are presented for all three operating scenarios (i.e., OS1, OS2 and OS3);
3) ambient concentrations for selected trace inorganic elements, trace organic compounds, and VOCs for which there exist ambient air quality criteria, are presented for the upper bound estimate of emissions (OS3); ;
4) ambient concentrations for trace organic compounds (PAH, dioxins and furans) are presented in Section 5.0for the upper bound estimate of emissions (OS3), and these estimates are subsequently used for human health risk assessment;
5) results for VOCs are assumed to be the same for all three operating scenarios;
6) annual average deposition of trace inorganic elements (except mercury) and organic compounds is presented for the upper bound estimate of emissions (OS3);
7) ambient concentrations and annual average deposition rates for mercury are presented based on an emission cap of 20 kg/year; and,
8) ambient concentrations for CO, NO_2 and $PM_{2.5}$ from the combined emissions of Unit #5 for the OS2 scenario and the two CTs operating on natural gas.

Dispersion modelling results for fugitive dust from coal and ash storage and handling are presented as 24-hour average concentrations of particulate matter, and as annual average deposition rates for the upper bound estimate of trace element emissions.

Modelling results for the cooling tower are presented for:

1) total annual hours of fogging and icing;
2) annual visible plume length frequencies; and
3) total annual water and salt deposition.

Finally, it should be recognized that the dispersion model (i.e., CALPUFF) used in the Brandon G.S. air quality assessment of the Unit #5 emission stack and CTs is a newer-generation model that has a significantly improved structure for evaluating fine scale atmospheric motions. Wind shear and obstacle-induced turbulence are represented to an extent that was not possible with previous regulatory models. Vigorous vertical mixing induced by wind shear and turbulence can cause dramatically higher ground-level concentrations of air pollutants, but on a very infrequent basis, for tall stacks such as the 107 metre stack on Unit #5. The CALPUFF model represents these occurrences, whereas models used in pervious assessments (e.g., for the 1992 licence review of the Brandon G.S.) may not have captured such atmospheric motions. A study conducted by the U.S. Environmental Protection Agency (EPA) found that short-term ground-level concentrations predicted by CALPUFF can be significantly higher near a tall stack than those predicted with the Industrial Source Complex Short-term (Version 3 – ISCST3) dispersion model (US EPA 1998).

On the other hand, the CALPUFF model does not accurately represent emission plumes of fugitive dust from area sources. The model assumes a uniform vertical distribution of particles in the emission plume, whereas actual particle distributions would have higher concentrations closer to the surface. The ISC model provides a better representation of such plumes. For this reason, and with prior approval from Manitoba Conservation, the fugitive dust emissions from the coal and ash storage areas have been modelled using the ISCST3 model instead of the CALPUFF model.

Emissions from the cooling tower were modelled using the SACTI model developed by EPRI. This is the same model that was previously used to estimate the impacts of the proposed cooling tower in the 1992 licence review for the Brandon G.S.

5.1 AMBIENT AIR QUALITY CRITERIA

The Province of Manitoba has adopted a set of time-based maximum pollutant concentration levels for the protection and preservation of ambient air quality. Criteria for each contaminant are classified as either objectives or guidelines depending upon several factors. The ‘objective’ classification is intended to be applied to those air pollutants that are sufficiently ubiquitous in presence (i.e., common contaminants) and potential environmental effect that national limits have been developed. The ‘guideline’ classification is used for those pollutants of a more localized presence for which provincial limits have been developed.

Manitoba air quality criteria are specified for the following two levels:

- The **Maximum Tolerable Level** which denotes a time-based concentration of air contaminant beyond which, due to a diminishing margin of safety, appropriate action is required to protect the health of the general population;
- The **Maximum Acceptable Level** that is deemed essential to provide adequate protection for soils, water, vegetation, materials, animals, visibility, personal comfort and well-being.

The selection of the appropriate level depends upon the degree of protection to be afforded to affected receptors. Maximum Tolerable Levels are only intended for evaluation purposes to identify the severity of an anthropogenic or natural phenomenon in order to protect public health and institute appropriate corrective action. In general, Maximum Acceptable Levels are not to be exceeded in any urban centre, including areas that are in the vicinity of industries with atmospheric emissions.

Table 5.1 lists the Manitoba air quality objectives for the common contaminants CO, SO_2, NO_2 and particulate matter, as well as the guidelines for a number of trace elements or compounds that may be emitted from the combustion of coal. Since the maximum predicted impacts of emissions from the Brandon G.S. occur near residential areas in and around the City of Brandon, the Maximum Acceptable Levels are the applicable criteria for comparison with predicted impacts.

Table 5.1: Manitoba Ambient Air Quality Criteria

Contaminant	**Criterion Classification**	**Averaging Period**	**Maximum Acceptable Level** ($\mu g/m^3$)	**Maximum Tolerable Level** ($\mu g/m^3$)
NO_2	Objective	1-hour	400	1000
		24-hour	200	-
		Annual	100	-
CO	Objective	1-hour	35,000	-
		8-hour	15,000	20,000
SO_2	Objective	1-hour	900	-
		24-hour	300	800
		Annual	60	-
SPM	Objective	24-hour	120	400
		Annual	70	-
PM_{10}	Guideline	24-hour	50	-
$PM_{2.5}$	CWS[6]	24-hour	30	-
Fluorides (as HF)	Guideline	24-hour	0.85	-
Hydrogen Chloride	Guideline	1-hour	100	-
Formaldehyde	Guideline	1-hour	60	-
Phenol	Guideline	1-hour	63	-
Styrene	Guideline	24-hour	400	-
Arsenic	Guideline	24-hour	0.3	-
Cadmium	Guideline	24-hour	2	-
Copper	Guideline	24-hour	50	-
Lead	Guideline	24-hour	2	-
Nickel	Guideline	24-hour	2	-
Zinc	Guideline	24-hour	120	-

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[6] 98th percentile calculated annually, average over 3 consecutive years

Manitoba has defined criteria for only a limited number of pollutants that would be emitted from the Brandon G.S. Table 5.2 lists ambient air quality criteria for selected contaminants from other regulatory jurisdictions, which may be used to provide some measure for comparison with predicted concentrations due to Brandon G.S. releases. Most of these contaminants would be emitted in trace quantities.

Table 5.2
Selected Ambient Air Quality Criteria from Other Jurisdictions

Contaminant	Criterion Classification	Averaging Period	Criterion ($\mu g/m^3$)	Jurisdiction
Benzene	Objective	1-hour	30	Alberta
Toluene	AAQC (Odour)	24-hour	2000	Ontario
Xylenes	Standard	24-hour	730	Ontario
Naphthalene	AAQC (Health)	24-hour	22.5	Ontario
Antimony	Standard	24-hour	25	Ontario
Barium	AAQC	24-hour	10	Ontario
Beryllium	Standard	24-hour	0.01	Ontario
Boron	Standard	24-hour	120	Ontario
Chromium	Objective	1-hour	1	Alberta
	AAQC	24-hour	1.5	Ontario
Cobalt	AAQC	24-hour	0.1	Ontario
Lithium	Standard	24-hour	20	Ontario
Manganese	AAQC	24-hour	2.5	Ontario
Mercury	Standard	24-hour	2	Ontario
Molybdenum	AAQC	24-hour	120	Ontario
Selenium	AAQC	24-hour	6	Ontario
Silver	Standard	24-hour	1	Ontario
Strontium	AAQC	24-hour	120	Ontario
Tin	Standard	24-hour	1	Ontario
Titanium	Standard	24-hour	120	Ontario
Vanadium	Standard	24-hour	2	Ontario

AAQC – ambient air quality criterion

5.2 AMBIENT CONCENTRATIONS DUE TO UNIT #5 EMISSIONS

Figure 5.1 shows the various locations of maximum predicted air pollutant concentrations (i.e., maximum point of impingement - POI) from emissions of the Unit #5 stack and the fugitive dust from coal and ash storage areas. The locations of the maximum POI for emissions from the CTs is not shown.