



DRAFT

**DISPERSION MODELING ANALYSIS OF PSD CLASS I
INCREMENT CONSUMPTION IN NORTH DAKOTA AND
EASTERN MONTANA**

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1. INTRODUCTION

The provisions of the Prevention of Significant Deterioration (PSD) program were enacted by Congress in the 1977 Clean Air Act (Act). The purpose of this program is to ensure that the air quality in clean air areas does not degrade significantly. To prevent significant deterioration of air quality, Congress set up the principle of only allowing a certain amount of increase in the ambient air concentration over the existing baseline concentration. These allowable increases are known as the "PSD increments." The Clean Air Act provides for three different classes of air quality protection, to reflect varying levels of protection from significant deterioration in air quality. In the 1977 Act, Congress designated a number of "Class I areas" that are to receive special protection from degradation of air quality and, thus, the most stringent PSD increments apply in these areas.

In 1999 North Dakota conducted a draft modeling analysis that shows numerous violations of the Class I PSD increments for sulfur dioxide (SO₂) in four Class I areas. Those Class I areas include Theodore Roosevelt National Park, the Lostwood Wilderness Area, the Medicine Lakes Wilderness Area, and the Fort Peck Class I Indian Reservation. In a March 13, 2001 letter to EPA, the North Dakota Department of Health (NDDH) committed to refine this modeling analysis and to subsequently adopt revisions to the State Implementation Plan (SIP) as may be necessary to address the increment violations that may be shown by the revised analysis (see EPA's May 29, 2001 Information Notice for more details, 66 FR 29127). However, in developing a modeling approach to finalize the study, EPA and North Dakota could not fully agree on the appropriate data to be used in the final modeling, or the emissions inputs that should be used in the modeling. This study represents what EPA believes to be a reasonable, but not necessarily the most conservative, methodology to assess the status of Class I increment consumption in North Dakota and eastern Montana, following appropriate EPA guidance and regulatory requirements. We believe this approach also best meets the intent of the increment modeling - to characterize the potential for increment violations under realistic emissions and meteorology conditions. EPA is soliciting public comments on this draft analysis before making a final determination on the status of increment consumption in these Class I areas, and the appropriate regulatory actions that may be necessary to address any PSD increment violations.

In issuing this draft report EPA Region 8 is seeking public input on all aspects of the modeling analysis, however, we are particularly interested in technical comments on the following areas: 1) EPA's characterization of PSD increment-consuming emissions and emissions from sources during the base year periods; and 2) whether the Calpuff model inputs and settings have been selected in a manner that is technically sound and suitable for regulatory purposes.

2. Application of Calpuff Modeling System

Consistent with current Interagency Workgroup for Air Quality Modeling (IWAQM)

guidance¹ EPA Region 8 selected the Calpuff long-range modeling system to evaluate air quality impacts in this analysis. Calpuff has been proposed nationally by EPA (Federal Register, April 21, 2000, 65 FR 21505) as a refined modeling technique for evaluating impacts from the long range transport of pollutants. The MESOPUFFII model is currently listed in the Guideline on Air Quality Models² for use on a case-by-case basis in evaluating long range transport. MESOPUFFII is considered obsolete and has not been proposed as either a preferred or an alternative model in the proposed revisions to the modeling guideline. For this modeling study data were obtained from 25 surface meteorological stations, 6 upper-air stations, and 96 precipitation stations located within and near the Calpuff modeling area. The modeling area, shown in Figure 2-1, covers most of North Dakota, eastern Montana, and small portions of South Dakota, and Southern Saskatchewan. The model was applied individually for each of five years of meteorological data (1990-1994) in accordance with longstanding EPA modeling guidance. Emissions inputs were based on the most recent two years (1999-2000) of source data and, where available, continuous emissions monitoring system (CEMS) data were used to determine appropriate emission rates for use in the modeling. The approach EPA used in characterizing emissions is discussed in Chapter 3.

In North Dakota's 1999 Calpuff modeling analysis, the State conducted a series of model tests to determine appropriate local settings for input parameters/options for which no national default value is available, or which did not seem applicable given local conditions. In addition, the State performed a limited performance evaluation to ensure correct implementation of the model. In this evaluation, model predictions were compared with observed concentrations from two SO₂ monitoring sites located in and near Theodore Roosevelt National Park. The performance tests were performed iteratively to determine the effect of adjustments to Calmet/Calpuff model default settings. The State changed a limited number of settings that they judged to be technically sound given local conditions, and generally resulted in improved model agreement with observations. As discussed in the following sections, in this study EPA has adopted many of the changes in default settings that North Dakota has selected in its modeling efforts. To demonstrate the effect these changes would have on overall model predictions, EPA has also performed some modeling runs to predict concentrations when IWAQM recommended defaults are fully implemented. North Dakota's testing suggested that the model performed well, with virtually all of the predicted/observed comparisons falling within a factor of two, with no significant over prediction/under prediction bias evident. These results are consistent with EPA's experience with Calpuff in model evaluation studies in other regions of the United States. However, NDDH's testing of the Calpuff with their model settings was based on data from a

¹ EPA, 1998 Interagency Workgroup on Air Quality Modeling, Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. Publication No. EPA-454/R-98-019, OAQPS, Research Triangle Park NC 27711.

² EPA 1996, Guideline on Air Quality Models. Code of Federal Regulations, 40 CFR part 51, Appendix W.

Figure 2-1. Class 1 Areas and Major Source Locations

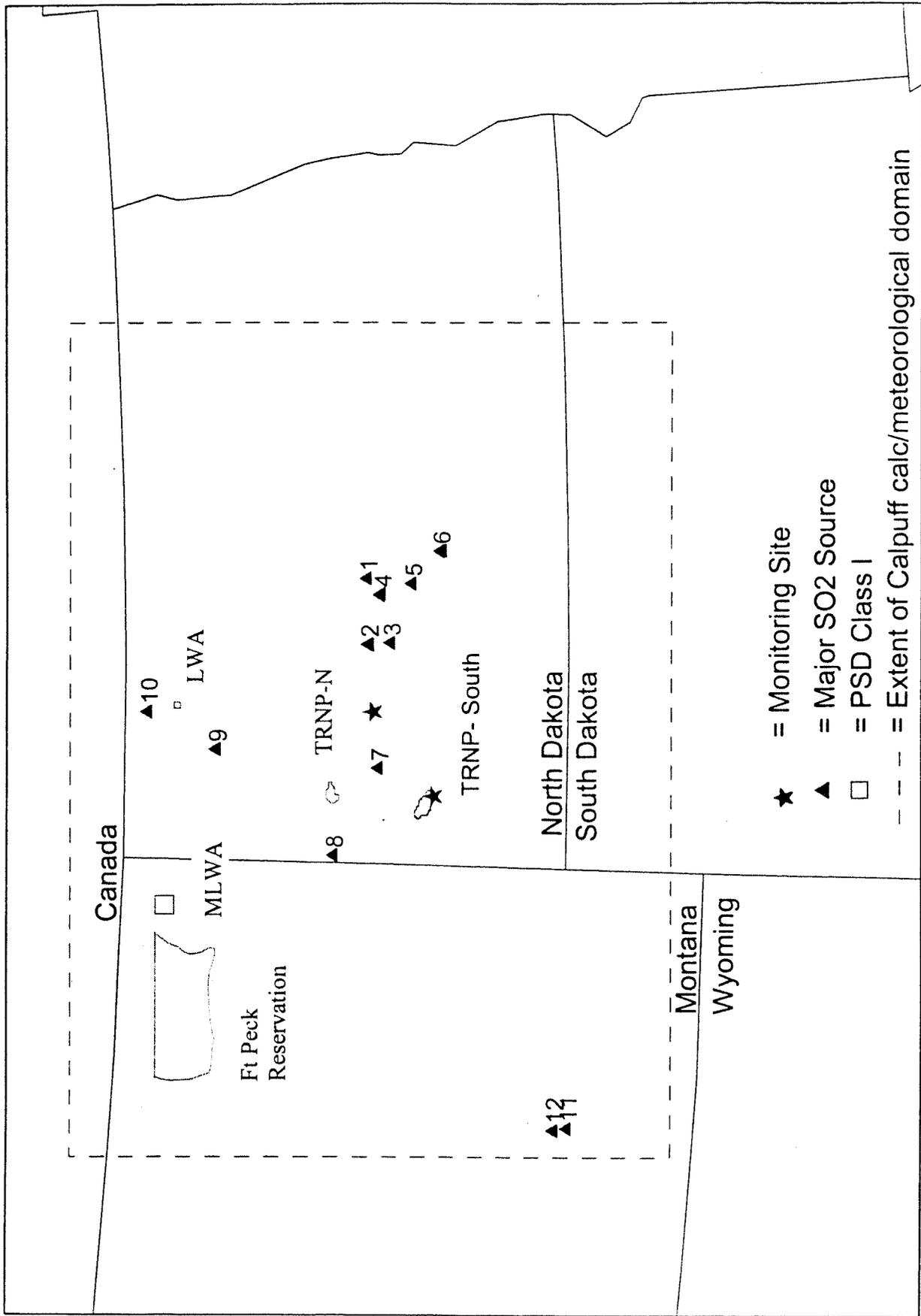


Figure 2-1. Key to Source Locations

1. Coal Creek Station
2. Antelope Valley Station, Great Plains Synfuels Plant
3. Coyote Station
4. Leland Olds Station, Stanton Station
5. Milton R Young Station
6. Heskett Station, Mandan Refinery
7. Little Knife Gas Plant
8. Grasslands Gas Plant
9. Tioga Gas Plant
10. Lignite Gas Plant
11. Colstrip Station
12. CELP Boiler

MLWA Medicine Lakes Wilderness Area

TRNP-N Theodore Roosevelt National Park- North Unit

TRNP-S Theodore Roosevelt National Park- South Unit

LWA Lostwood Wilderness Area

very limited number of monitoring sites so that a complete evaluation of the performance could not be conducted. As discussed in Section 4.1, EPA is soliciting public comment on the appropriate model control settings to be used in finalizing the current study.

2.1 Meteorological Data Processing With Calmet

EPA was provided with copies of North Dakota modeling files from their 1999 draft modeling study³. EPA performed quality assurance testing on the files and determined that the data were adequate for use in dispersion modeling. For the 1999 study the NDDH processed five years of meteorological data (1990-1994) to use with Calpuff. Raw meteorological data was derived from National Weather Service, Federal Aviation Administration, U.S. Military, and Environment Canada observations. EPA has also made several changes to the Calmet IWAQM default settings based on NDDH model evaluation results. These changes are discussed below.

2.1.1 Input Data

In establishing the size of the modeling domain, the primary goal was to provide a modeling domain which would encompass new or existing emission sources located up to 250 km from any North Dakota Class I area. The domain extends into eastern Montana, and given the relatively sparse distribution of increment consuming sources in that area, provides sufficient coverage for two eastern Montana Class I areas. The dimensions of the modeling grid are 640 km east-west and 460 km north-south. The extent of EPA's Calmet grid is illustrated in Figure 2-1.

EPA selected a 10 km grid size for this application, compared to the 20 km spacing originally used by NDDH. While a very dense grid is desirable from a scientific standpoint, computer disk storage and model execution time requirements place practical limits on grid cell size. At the 10 km resolution, a single year of Calmet-processed meteorological data requires about 2.2 gigabytes of disk space. Given the gently rolling nature of terrain, relatively uniform land-use characteristics, and the general lack of large terrain features or water bodies large enough to cause persistent, strong local-scale flows, EPA believes a 10 km grid size is adequate for this study.

In the vertical, both the EPA and the NDDH Calmet grid is defined by eight vertical layers. Cell face heights are set at 22, 50, 100, 250, 500, 1000, 2000, and 4000 meters above ground level (AGL). IWAQM does not provide recommendations on this parameter, however, eight layers is consistent with some of the examples and guidance provided by the model developer in documentation for the Calpuff modeling system.

NDDH obtained surface meteorological data for the five-year period 1990-1994 in TD-

³ Calpuff Class 1 Area Analysis for Milton R Young Generating Station, North Dakota Dept of Health, May 24, 1999

1440 format from the National Climatic Data Center (NCDC). Data were obtained for 25 stations (National Weather Service, Federal Aviation Administration, U.S. Military, Environment Canada) located within or near the NDDH Calmet grid. EPA has used these same data sets in the current study, including modifications made to the data sets by NDDH described below.

In the processing of the above data NDDH's 1999 efforts found that some adjustments to the surface data files were required before Earth Tech programs METSCAN and SMERGE could be applied. Stations other than first-order National Weather Service (NWS) stations were missing opaque cloud cover for the entire five-year period. Based on a comparison of total and opaque cloud cover in the first-order NWS data sets, the NDDH developed an objective scheme to extrapolate opaque from total cloud cover. This scheme was coded into a computer program (TOT2OPQ) and applied to all surface data sets with missing opaque cloud cover.

In the 1999 study, NDDH followed EPA recommendations in data editing to account for missing data (ceiling height, wind, pressure, temperature, relative humidity). Substitutions were made if data elements were missing for one or two consecutive hours. Except for opaque cloud cover, substitutions were not made for longer missing periods (Calmet ignores stations with missing data). NDDH coded the EPA substitution scheme into a computer program (SUB144) and applied it to all surface data sets. Earth Tech's (the model developer) program METSCAN was next applied to scan each data set for missing or unreasonable values, and appropriate edits were made. Earth Tech's program SMERGE was applied to merge individual station data sets into a single input file (SURF.DAT) compatible with Calmet.

NDDH obtained upper-air meteorological data for 1990 through 1994 from the National Climatic Data Center, and precipitation data was obtained from Earth Info, Inc (Boulder, CO). Data were obtained for six upper-air stations and 96 precipitation sites located within or near the modeling domain. EPA used the same upper air and precipitation data files in the current study as NDDH employed in their original study. NDDH's data processing procedures for both the upper air and precipitation data are discussed in their 1999 report.

Most of the terrain elevation and land use data required by Calmet were originally downloaded by NDDH from the United States Geological Survey (USGS) internet web site. Grid cell terrain elevations were derived from 1:250,000-Scale Digital Elevation Models (DEM) and land use data were derived from 1:250,000-Scale Land Use and Land Cover (LULC). The geophysical file was generated based on Calmet default land use parameters, and the State's original 20 km gridding was reprocessed for this study to a 10 km grid to be consistent with the computational grid. Because of the relatively large modeling domain, the grid system, meteorological data, and geophysical data were fit to Lambert conformal mapping to account for the earth's curvature.

2.1.2 Calmet Code Revision

As noted above, in the original 1999 NDDH application of the model and in subsequent tests of year 2000 data, Calmet was tested to determine technically appropriate settings for control file options and parameters. For testing purposes, the Calmet software was modified to optionally output Surfer-compatible coordinate files (XYZ files) for winds (all levels), stability class, and mixing height for the entire Calmet grid for a selected time frame, in order to plot the horizontal distribution of these variables to better judge the appropriateness of Calmet's processing. A Surfer script was prepared to "mass produce" hourly plots of these three parameters for the selected time frame (usually 24 to 48 hours).

The NDDH examined several episodes of plotted wind vectors, stability classes, and contoured mixing heights, with emphasis on episodes (1990-1994 data) where winds might direct significant source emissions toward Class I areas. Episodes included cases with frontal passage or other wind shifts. During the iterative testing process, Calmet control file settings were individually and systematically adjusted primarily for wind and mixing height parameters. Parameters were adjusted so that plotted fields converged to a realistic and relatively smooth appearance. Output wind fields were examined to ensure that spatial variations due to frontal passage and terrain effects were reasonable, and to ensure a realistic transition from surface through upper-level winds.

One issue NDDH noted during the testing of Calmet was a chronic discontinuity between surface and upper wind levels. To mitigate this problem, the option to extrapolate surface wind observations to upper layers was deployed, using similarity theory (Option 4 in the model) and layer-dependent biases. Calmet Version 5 extrapolates surface winds both for setting the initial guess field, and for introducing observations in the Step 2 wind field. Unfortunately, the model utilizes the bias factors for the initial guess field only. The Step 2 vertical extrapolation has equal effect through all upper layers. The NDDH felt this was unrealistic because resultant upper layer wind fields reflected anomalous surface-layer (low-level) perturbations consistently, upward through all upper layers, even in the top layer (4000m). It was felt that such low-level features should dampen with height and not extend up into the middle troposphere. In other words, the Step 2 vertical extrapolation essentially undid the effective Step 1 (dampened) vertical extrapolation of the wind fields. Therefore, the NDDH modified the Calmet code to simply eliminate the vertical extrapolation in Step 2, resulting in a more realistic transition from surface to upper layers. EPA believes this relatively minor change to the code is technically sound for this application in view of the NDDH test results. The NDDH revised version of Calmet is available in electronic format from EPA Region 8. Note that except for the change noted above the Calmet software EPA used in this analysis is identical to the version (Version 5.2, level 000602a) available on the EPA ttn-SCRAM website. The revised source code was recompiled with a Lahey Fortran 95 compiler, which provides faster model execution time than the existing software.

2.1.3 Calmet Model Control Settings

Calmet was executed with surface data, upper-air data, precipitation data, and geophysical data as described previously, and with control file options/parameters generally established by published IWAQM guidance. As noted earlier, alternative settings were used in some cases where local testing of the model indicated an alternative setting is more appropriate. A listing of the most significant control file settings used by EPA are summarized in Table 2.1.3-1, and a listing of non-IWAQM settings used by EPA are shown in Table 2.1.3-2. The complete EPA Calmet input control file is available in electronic format from EPA Region 8.

**Table 2-1
Calmet Control File**

<u>Parameter/Option</u>	<u>Value</u>
No. surface stations	24
No. upper-air stations	6
No. precip stations	96
No. X grid cells	64
No. Y grid cells	46
No. vertical layers	8
Diagnostic wind module	Yes
Use O'Brien procedure	No
Extrapolate surface wind observations	-4
RMAX1	300 km
RMAX2	1200 km
TERRAD	100 km
R1	125 km
R2	100 km
No. barriers (NBAR)	0
MNMDAV	8
ILEVZI	4

**Table 2-1
Calmet Control File**

Minimum overland mixing height	50 m
Maximum overland mixing height	4000 m
TRADKM	500 km
SIGMAP	100 km

Table 2-2 Non-IWAQM Settings used by EPA in Calmet Control File

Parameter	IWAQM	Current EPA Study
IKINE	0	1
BIAS (Values for each vertical level)	0,0,0,0, 0,0,0,0	-1.0, -0.9, -0.7, 0.0 0.5, 1.0, 1.0, 1.0
LVARY	F	T
MNDAY	1	8
ILEVZI	1	4
ZIMAX & ZMAXW(over water)	3000 m	4000 m

The reason EPA selected each non-IWAQM setting in the current study is discussed below:

IKINE - The inclusion of kinematic effects reduced predicted concentrations by about 10 percent at the two monitoring sites providing somewhat better agreement between Calpuff results and monitored observations. There is a risk that use of this option will create unrealistic wind fields.

BIAS(NZ) - The IWAQM recommendation provides neutral bias (between surface and upper-air data) for all vertical layers. The meteorological data set used in the modeling

includes data from a large number of both surface and upper-air sites. Given the relatively rich set of measured data, both at the surface and aloft, it does not seem reasonable to assume equal weighting of upper-air wind data with surface data at the lowest level, and to assume equal weighting of surface data with upper-air data at top levels.

LVARY - This option was selected to ensure that at least one station would always be available for model input.

MNMDAV/ILEVZI - NDDH found that IWAQM default values for these parameters, relating to spatial averaging of mixing heights, produced unrealistic spatial variations in the mixing height field. Severe gradients (bull's eyes) in mixing height were observed in the immediate vicinity of meteorological stations, and the selected values in these input parameters smoothed the gradients. The overall area-wide average value of mixing height was not significantly affected by this change.

ZIMAX/ZIMAXW - In the western part of the upper Great Plains maximum summertime mixing heights frequently exceed the default value of 3000 m. A value of 4000 m was selected based on reported maximum mixing heights for this region (Holzworth, 1972)⁴.

2.2 Calpuff Application and Postprocessing

EPA has generally used IWAQM default values in selecting Calpuff control file settings, unless local conditions indicate that alternative settings are more appropriate. In addition to selection of the most technically sound control settings, model execution time was a factor in selecting certain parameters. EPA reviewed the results of the NDDH testing discussed below and has initially selected Calpuff control file settings that are very similar to those used in the NDDH study.

2.2.1 Receptor Locations

A total of 49 receptor locations were selected for calculating concentrations in the 4 Class I areas in North Dakota and Montana. Maximum receptor spacing in the North Dakota Class I areas is about 5 kilometers. Receptor coverage for Medicine Lake and Fort Peck Class I areas was less dense because they are located further from the largest contributing sources, and local minor source emissions contributions could not be fully accounted for. Given the distances of the largest contributing sources from these Class I areas (150 - 300 km), concentration gradients would not be expected to be significant within individual areas, thus receptor coverage appears to be adequate. Additional receptors would also have the disadvantage of slowing Calpuff execution times. The receptor numbers correspond to receptor locations in the following Class I areas: Receptors 1 - 22, TRNP South Unit; Receptors 23 - 38 TRNP-North Unit; Receptor 39,

⁴ Holzworth, 1972, Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States, EPA, Office of Air Programs Publication AP-101

TRNP Elkhorn Unit; Receptors 40 - 44, Lostwood Wilderness Area; Receptor 45 Medicine Lake Wilderness; and Receptors 46 - 49 Fort Peck Reservation.

2.2.2 Calpuff Evaluation and Model Control Settings

To determine the effectiveness of selected Calpuff control file settings, as well as the utility of the Calmet/Calpuff implementation in general, NDDH conducted a limited model performance evaluation, using data from two monitoring sites located in or near Theodore Roosevelt National Park. The NDDH Calpuff evaluation is described in the NDDH 1999 Calpuff Class I Modeling Study. Calpuff was tested in the NDDH study using Calmet meteorological data files prepared as described in Section 2. In general IWAQM default values were used in selecting Calpuff control file settings when other information was not available. Testing was conducted primarily to determine sensitivity of results and execution time associated with parameters/options for which default values were not provided. The goal was to achieve a technically competent implementation of the model while maintaining reasonable execution time. Calpost was applied to summarize Calpuff hourly output. Values for selected Calpuff control file parameters/options were individually and systematically varied to determine effect on results and execution time. NDDH conducted testing, for example, to determine sensitivity of results to deployment of puff splitting, terrain effects, PDF (Probability Distribution Function) for convective conditions, and partial plume penetration of elevated inversion. All seemed to have some effect on model results but, with the exception of puff splitting, none of these options caused a significant execution time penalty. Therefore, as in North Dakota's 1999 analysis, EPA has concluded it is appropriate to deploy all of these options for modeling major sources. Given the number of minor sources (principally oil and gas sources) along with execution time considerations, puff splitting will not be deployed for minor sources.

NDDH has continued to test Calpuff performance using year 2000 emissions and meteorology data.⁵ The evaluation of Calpuff performance for Year 2000 data at Dunn Center and TRNP South Unit monitoring sites still indicates the modeling system performs relatively well, when implemented using IWAQM control file settings as modified by NDDH. In these latest results, shown in Figure 2-2, predicted-to-observed ratios (unpaired in time) for the fifty highest predicted/observed concentrations fell within the factor-of-two criteria suggested by EPA guidance, and did not exhibit a strong systematic bias toward underprediction or overprediction. EPA has some concern, however, that the 24-hour averages at TRNP South Unit are underpredicting concentrations, particularly for rankings lower than the top ten values. For increment consumption modeling, the limiting concentrations (i.e. the highest second-high predicted concentration for each year modeled) would not necessarily occur under conditions that

⁵ NDDH Draft Report, Evaluation of Calpuff Model Performance Using Year 2000 Data, November 2001

lead to the top 10 ranked values shown in the figure. This is due to the fact that increment analysis involves modeling a limited number of emitting sources in the region, while NDDH's performance testing of the model necessarily involved modeling all major sources in the region.

EPA has reviewed the NDDH testing and evaluation results along with the latest IWAQM guidance and selected the Calpuff control file settings summarized in Table 2-3. Non-IWAQM settings are shown in Table 2-4 and the reasons for their selection are discussed below. In the current draft analysis EPA has generally used the same NDDH model settings as were used in the Draft 2000 model evaluation study discussed above, despite some concerns about possible model underpredictions. A test run using regulatory default model settings has also been done and these results are discussed in Section 4.1.

Table 2-3 Calpuff Control File

<u>Parameter/Option</u>	<u>Value</u>
No. chemical species	5
Vertical distribution near field	1
Terrain adjustment method	3
Subgrid-scale complex terrain	0
Slug model	No
Transitional plume rise	Yes
Stack tip downwash	Yes
Vertical wind shear	No
Puff splitting	Yes
Chemical mechanism	1
Wet removal	Yes
Dry deposition	Yes
Dispersion coefficient method	2
Partial plume penetration - elev. inversion	Yes
PDF used under convective conditions	Yes
CSPEC	SO ₂ , SO ₄ , NO _x , HNO ₃ , NO ₃
Chemical parameters - dry gas deposition	Default

Table 2-3 Calpuff Control File

<u>Parameter/Option</u>	<u>Value</u>
Size parameters - dry particle deposition	Default
RCUTR	30.
RGR	10.
REACTR	8.
NINT	9
IVEG	2
Wet deposition parameters	Default
Ozone data input option	1
Background ammonia conc. (ppb)	2.
SYTDEP	550.
MHFTSZ	0
JSUP	5
XSAMLEN	0.5
MXNEW	99
MXSAM	99
Maximum mixing height (m)	4000.
Minimum mixing height (m)	50.
NSPLIT	3
IRESPLIT	Hour 17-22 = 1
ZISPLIT (m)	100.
ROLOMAX	0.25

Table 2-4 Non-IWAQM Settings Used by EPA in Calpuff Control File

Parameter	IWAQM	EPA
MSPLIT	0	1
MDISP	3	2
BCKO3	80 ppb	30 ppb
BCKNH3	10 ppb	2 ppb
XSAMLEN	1.0	0.5
XMAXZI	3000 m	4000 m
MPDF	0	1

MSPLIT - The option for puff splitting is employed when modeling source-receptor distances of 200 km or more, because of the tendency for Calpuff to otherwise overpredict at these distances. Deployment of this option also provided better agreement with observations.

MDISP - Use of dispersion coefficient option 2 provided better agreement with observations. Selection of this option reduced predicted concentrations by 25 percent or more at some receptors.

BCKO3 -EPA used files of measured hourly ozone concentrations to establish background values, however, the BCKO3 value is substituted by Calpuff when hourly data are missing. Based on local monitoring data the IWAQM value of 80 ppb appears to be too high for North Dakota conditions, and therefore was reset to 30 ppb.

BCKNH3 - The value of 2 ppb reflects the annual average of local, unbiased monitoring data.

XSAMLEN - This value was set lower than the IWAQM recommendations to improve model resolution by increasing the number of puffs and decreasing mass per puff. The

only negative consequence for revising this option would be extra computer processing time due to more puffs on the grid.

XMAXZI - Value was increased to 4000 m for consistency with ZIMAX/ZIMAXW setting in Calmet .

MPDF- This option should be deployed when dispersion option 2 is selected.

3. Emission Inventory for Class I Increment Analysis

In general, the source emission inventory for any increment analysis consists of all increment-affecting sources⁶. Specifically, this would include actual emissions from:

- (1) any major stationary sources for which construction began after the major source baseline date (which, for SO₂ is January 6, 1975);
- (2) any existing major stationary sources having undergone construction (*i.e.*, a physical change or change in the method of operation) after the major source baseline date;
- (3) any existing stationary sources having undergone a physical change or change in the method of operation, or having increased hours of operation or capacity utilization, after the minor source baseline date;
- (4) any new stationary sources which were constructed after the minor source baseline date; and
- (5) any changes in emissions from area and mobile sources since the minor source baseline date.

The "minor source baseline date" is defined as the earliest date after the "trigger date" (which for SO₂ is August 7, 1977) that a major stationary source or major modification submits a complete PSD permit application. The minor source baseline date is set for the baseline area for the increment pollutant which the source would emit in significant amounts. (See 40 CFR 51.166(b)(14)(ii) and (iii), 40 CFR 52.21(b)(14)(ii) and (iii)). The applicable minor source baseline date in any increment analysis is the minor source baseline date *for the area that is being modeled for impacts*. The SO₂ minor source baseline date was triggered for the North Dakota "Rest of State" (Air Quality Control Region 172) SO₂ attainment area on December 17, 1977. So, for assessing the impacts in Theodore Roosevelt National Park and Lostwood

⁶ New Source Review Workshop Manual, Part I, Chapter C, Section IV.C.2, p. C.35, Draft October 1990, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, <http://www.epa.gov/ttnsr01/gen/wkshpman.pdf>.

Wilderness Area (both included in Air Quality Control Region 172), the applicable minor source baseline date is December 17, 1977. The SO₂ minor source baseline date for the Medicine Lakes Wilderness Area and the Fort Peck Indian Reservation in Montana was triggered on March 26, 1979, over a year later. Therefore, two emission inventories were compiled for this analysis: the inventory for the North Dakota Class I areas includes all increment affecting sources based on a minor source baseline date of December 17, 1977 and the inventory for the Montana Class I areas includes all increment affecting sources based on a minor source baseline date of March 26, 1979. Note that, the NDDH did not develop a separate inventory for the Montana Class I areas in their 1999 draft modeling analysis. Their results are based only on North Dakota's December 17, 1977 minor source baseline date.

The two inventories include increment consuming, as well as increment expanding sources and consist of all major PSD sources located within 250 km of each Class I area as well as minor sources located within 50 km of each North Dakota Class I area⁷. The major source inventory includes increment consuming emissions from eight coal-burning power plants (one of which is located in Montana), two gas processing plants and a coal gasification plant (see Figure 2-1) as well as increment expanding emissions from five major sources that all shut down after the applicable minor source baseline dates.

Modeled emissions (*i.e.*, increment consuming/expanding emissions) are determined by subtracting base year emissions from current year emissions, for each existing source. For sources constructed after the applicable baseline date, modeled emissions are the source's current year emissions minus zero emissions in the base year (*i.e.*, all emissions are modeled as increment consuming). For sources shut down after the applicable baseline date, modeled emissions are zero emissions in the current year minus the source's base year emissions (*i.e.*, all emissions are modeled as increment expanding).

3.1 Current Year Inventory

In general, emissions for the current year inventory are based on actual emissions reflected by normal source operation for a period of two years. The two-year study period should generally be the most recent two years, provided that the two-year period is representative of normal source operation. Another two-year period may be used, only if that other period of time is more typical of normal source operation than the two years immediately preceding the date of

⁷ The minor source inventory consists primarily of emissions from oil and gas facilities located in North Dakota. At the time of this report, emission and stack data were not available for the oil and gas production facilities found in the vicinity of Medicine Lakes Wilderness Area and Fort Peck Indian Reservation in Montana. Therefore, these minor source contributions were not accounted for in modeling PSD increment consumption in Montana Class I areas. Also, NDDH is updating the base year and current year oil and gas emission inventory for North Dakota. The current EPA modeling does not include emissions, either increment expanding or increment consuming, from these sources. EPA intends to incorporate NDDH's revised oil and gas emissions inventory, if available, into the final modeling analysis. We note, however, that given the relatively small magnitude of SO₂ emissions from oil and gas sources, the effect of including these sources in the final modeling analysis is likely to be small.

concern. (See 45 FR 52718, August 7, 1980). For the most part, the current year inventory for this analysis is based on continuous emission monitor system (CEMS) data from 1999 and 2000 as reported to the EPA Acid Rain Database.

Following is a brief description of each major source that was constructed after the major source baseline date for SO₂ (see Section 3.2 for similar descriptions on the baseline sources, all constructed before the major source baseline date). Information is based on data from EPA's Acid Rain Database (see <http://www.epa.gov/airmarkets/picturethis/index.htm>):

Basin Electric Power Cooperative - Antelope Valley Station

Unit 1 - 435 MW, tangentially-fired lignite boiler, SO₂ control - (dry lime) flue gas desulfurization (FGD)

Unit 2 - 435 MW, tangentially-fired lignite boiler, SO₂ control - (dry lime) FGD

Otter Tail - Coyote Station

Unit 1 - 450 MW, cyclone-fired lignite boiler, SO₂ control - (dry lime) FGD

Great River Energy - Coal Creek Station

Unit 1 - 506 MW, tangentially-fired lignite boiler, SO₂ control - (dry lime) FGD

Unit 2 - 506 MW, tangentially-fired lignite boiler, SO₂ control - (dry lime) FGD

PPL Corp. - Colstrip (Montana)

Unit 3 - 778 MW, tangentially-fired boiler, SO₂ control - (wet lime) FGD

Unit 4 - 778 MW, tangentially-fired boiler, SO₂ control - (wet lime) FGD

Great River Energy - Stanton Station

Unit 10 - 60 MW, tangentially-fired boiler, SO₂ control - (dry lime) FGD

Hourly CEMS data for 1999 and 2000 for each of the eight power plants in the major source inventory (including 4 baseline sources) were obtained from EPA's Acid Rain Program. For each source, daily average emissions (24 hour averages) were calculated. Since it is highly unlikely that, simultaneously, all sources would operate at their peak actual emissions during the same 24-hour averaging time, we chose to model the 90th percentile actual emissions for each unit. In reviewing the 1999 and 2000 CEMS data, EPA found that the 90th percentile cumulative emission rate (*i.e.*, the sum of all of the 90th percentile emission rates at each facility) did actually occur several times. Therefore, given that, and the fact that these power plants are primarily used as base-load facilities, this seems like the most representative method for determining current year emissions, and provides a reasonable estimate of worst case conditions that may recur in the future.

The 90th percentile emission rate for each source was determined by ranking (from highest to lowest) the source's 24-hour average emission rates over 2 years - for a total of 730 emission rates (where the data record is 100% complete) - and selecting the 73rd highest 24-hour

average emission rate from the list. This single emission rate was then modeled for every 24-hour period over the 5 years of meteorology data used in the model.

There are a couple exceptions to the above method for determining current year emissions. Current year emissions for Great River Energy's Coal Creek Station are based on year 2000 CEMS data only. Both units at the Coal Creek Station reduced their SO₂ emissions by approximately 20,000 tons (combined) in 2000. Prior to 2000, roughly 40% of the units' emissions were bypassing the wet lime scrubbers used to control SO₂ emission from the stacks. In 2000, the facility greatly reduced this bypass, resulting in approximately 20,000 tons of SO₂ emissions reduction over the year. Both units at Coal Creek Station are subject to the Acid Rain Program's Phase II requirements (which applied, starting in 2000, to all existing utility units serving generators with an output capacity of greater than 25 megawatts). Therefore, the source was able to sell surplus SO₂ emission allowances that resulted from this reduction. While the reduction at Coal Creek is not necessarily permanent or enforceable, the facility has indicated that it intends to continue to operate at year 2000 emission levels. EPA agreed to model the source's current year emissions using only 2000 data with the understanding that the source would need to make those reductions permanent and enforceable if, in fact, they are needed to show compliance with the SO₂ Class I increments.

Montana-Dakota Utilities Co.'s Heskett Station (Unit 1) emissions are also only based on year 2000 CEMS data. Unit 1, at 25 MW, is not required to report to the EPA Acid Rain Database. Since hourly CEMS data were only available for the year 2000 from the State we did not include 1999 emissions in our calculations. Unit 1 is a relatively small part of the inventory so we did not pursue obtaining 1999 CEMS data for the Unit.

PPL Corporation's Colstrip power plant in Montana has 4 units. Units 1 and 2 were both constructed before the major source baseline date for SO₂ (January 6, 1975). We did not obtain baseline emission information for these units but know, from reviewing the available data in the EPA Acid Rain Database, that emission trends from 1980 to today are relatively flat or even slightly down. This suggests that increment consuming emissions would be low and so we did not include these units in the inventories. Units 3 and 4 were both constructed after the major source baseline date for SO₂; emissions for both units were obtained from the EPA Acid Rain Database and are based on 1999 and 2000 CEMS data divided by 365 days to estimate 24 hour emissions. A more refined analysis could be made of Units' 3 and 4 increment consuming emissions, to be consistent with the methodology used for major North Dakota sources, however such an analysis did not seem warranted given the units' geographic location and, consequently, their negligible contribution to increment concentrations in any of the Class I areas modeled.

Current year emissions for the power plants are summarized in Table 3-1.

Table 3-1
CURRENT YEAR SO₂ EMISSIONS FOR POWER PLANTS
Based on CEMS data from EPA's Acid Rain Database

Source	1999 Actual Emissions			2000 Actual Emissions			Current Year Emissions	
	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	2yr-90% 24 hour [lb/hr]	2-yr avg annual [TPY]
Basin Electric Power Cooperative - Antelope Valley Station								
Units 1 + 2	4,350	3,620	15,516	4,940	3,291	13,047	3,598	14,282
Otter Tail - Coyote Station								
Unit 1	5,799	5,126	20,040	5,115	4,655	14,521	5,077	17,281
Great River Energy - Coal Creek								
Unit 1 ¹	7,744	7,194	23,551	5,287	4,195	14,332	4,195	14,332
Unit 2 ¹	7,175	6,891	26,192	4,608	3,552	12,817	3,552	12,817
PPL Corp. - Colstrip (Montana)								
Unit 3 ²	n/a	n/a	3,030	n/a	n/a	2,859	672	2,945
Unit 4 ²	n/a	n/a	3,293	n/a	n/a	2,315	640	2,804
Minnkota Power Cooperative - Milton R. Young Station								
Unit 1	7,088	5,575	19,481	7,082	5,599	18,095	5,575	18,788
Unit 2	7,535	6,161	21,863	6,838	6,089	21,134	6,128	21,499
Basin Electric Power Cooperative - Leland Olds Station								
Unit 1	5,956	4,891	16,802	5,970	4,965	16,864	4,931	16,833
Unit 2	11,623	10,282	33,306	11,796	9,877	28,587	10,179	30,947
Montana-Dakota Utilities Co. - Heskett Station								
Unit 1	1999 CEMS data not available			537	348	1,022	348	1,022
Unit 2	1,227	833	2,208	1,080	822	1,778	831	1,993
Great River Energy - Stanton Station								
Unit 1	3,078	2,371	8,241	3,047	2,523	7,017	2,456	7,629
Unit 10	357	327	1,241	402	307	972	320	1,107

Source	1999 Actual Emissions			2000 Actual Emissions			Current Year Emissions	
	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	max 24 hour [lb/hr]	90 % 24 hour [lb/hr]	annual [TPY]	2yr-90% 24 hour [lb/hr]	2-yr avg annual [TPY]
TOTAL	63,931	53,271	194,764	56,702	46,223	155,360	48,502	164,277

¹ Current year emissions are based on year 2000 CEMS data only. See discussion above.

² 24-hour current year emissions are based on annual CEMS data divided by 365 days. See discussion above.

No CEMS data or recent emissions data were readily available for the two gas processing plants (Grasslands Gas and Little Knife Gas Plant) and the coal gasification plant (Greatplains Synfuels Plant), so EPA used the same emissions estimates that NDDH used in their 1999 draft study. Modeled short-term emission rates for these plants are as follows:

Grasslands Gas Plant:	273 lb/hr
Little Knife Gas Plant:	427 lb/hr
Dakota Gasification - Greatplains Synfuels Plant:	3323 lb/hr

3.2 Base Year Inventory

As in the current year inventory, emissions for the base year inventory are generally based on actual emissions reflected by normal source operation for a period of 2 years. The two-year study period should generally be the two years preceding the minor source baseline date, provided that the two-year period is representative of normal source operation. Another two-year period may be used, only if that other period of time is more typical of normal source operation than the two years immediately preceding the baseline date (see 45 FR 52718, August 7, 1980). EPA rules and guidance allow the potential to emit to be used if little or no operating data are available, as in the case of a permitted emission unit constructed before the major source baseline date but not yet in operation at the time of the minor source baseline date (see 40 CFR 51.166(b)(13), p. C.11 of the NSR workshop manual⁶, and 45 FR 52718, col. 3, August 7, 1980).

Four of the seven coal-burning power plants in North Dakota commenced construction before the major source baseline date for SO₂ (January 6, 1975). These include Minnkota Power Cooperative's Milton R. Young Station (Units 1 and 2), Basin Electric Power Cooperative's LeLand Olds Station (Units 1 and 2), Montana-Dakota Utilities Company's Heskett Station (Units 1 and 2) and Great River Energy's Stanton Station (Unit 1). These units are all included in the major source base year emission inventory. No major sources in this analysis that were built before the major source baseline date reported any physical change or change in the method of operation after the major source baseline date but before the minor source baseline dates (*i.e.*, all emissions prior to the applicable minor source baseline dates are considered to be baseline emissions).

Following is a brief description of each baseline source, based on information from EPA's Acid Rain Database (see <http://www.epa.gov/airmarkets/picturethis/index.htm>):

Minnkota Power Cooperative - Milton R. Young Station

Unit 1 - 257 MW, lignite-fired cyclone boiler, uncontrolled for SO₂

Unit 2 - 477 MW, lignite-fired cyclone boiler, SO₂ control - (dry alkali) flue gas desulfurization

Basin Electric Power Cooperative - Leland Olds Station

Unit 1 - 216 MW, lignite-fired dry bottom boiler, uncontrolled for SO₂

Unit 2 - 440 MW, lignite-fired cyclone boiler, uncontrolled for SO₂

Montana-Dakota Utilities Co. - Heskett Station

Unit 1 - 25 MW, lignite-fired, uncontrolled for SO₂

Unit 2 - 75 MW, lignite-fired boiler retrofitted to a fluidized bed combustor in 1987, uncontrolled for SO₂

Great River Energy - Stanton Station

Unit 1 - 187 MW, lignite-fired dry bottom boiler, uncontrolled for SO₂

3.2.1 Base Year Inventory for North Dakota Class I Areas

In general, the base year inventory for the North Dakota Class I areas is based on actual emissions averaged over the two-year period 1976-1977. For all baseline emissions we used AP-42 emission factors for uncontrolled lignite-fired boilers (see AP-42⁸, section 1.7, Table 1.7-1).

The only data available to us for these baseline sources for the years 1976 and 1977 are what is reported to the State in the Annual Emission Inventory Reports (*e.g.*, coal use, sulfur content, coal feed rates, etc.). Based on this information, several options existed for determining the short term maximum actual emission rates needed for the modeling analysis.

One option for determining short-term emissions is to calculate an emission rate based on an AP-42 emission factor (in units of lb_{SO₂}/ton_{coal}) and the maximum sulfur content (wt. %) and maximum coal feed rate (ton_{coal}/hr) supplied in the Annual Emission Inventory Reports. However, we believe that the maximum coal feed rate numbers are very uncertain. We are not aware of any official method or quality assurance process that has been used to arrive at these numbers. According to the State, at least one company has questioned the accuracy of these data. For these reasons, we dismissed this option for calculating short-term emissions. In using maximum hourly feed rates and maximum sulfur content, this option would likely overpredict SO₂ emissions in the base year.

⁸ Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, January 1995, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, <http://www.epa.gov/ttn/chief/ap42/index.html>.

A second option for determining short-term emissions is to calculate annual emissions (based on an AP-42 emission factor (in lb_{SO_2}/ton_{coal}), average sulfur content (in wt. %) and annual coal usage (in ton_{coal}/yr) and divide this number by 365 days per year to arrive at a lb per day emission rate. Since this method is based on *average* annual operation data, this option would likely underpredict SO_2 emissions in the base year. For this reason we also dismissed this option, except as a screening approach for sources with very low emission rates, or at great distances from the Class I areas.

A third option for determining short-term emissions is to calculate annual emissions (again, based on an AP-42 emission factor (in lb_{SO_2}/ton_{coal}), average sulfur content (in wt. %) and annual coal usage (in ton_{coal}/yr) and then apply the peak-to-mean ratio from the current year CEMS emissions to the mean annual base year emissions to get peak base year emissions. Specifically, the ratio of the annual average emission rate from the 1999-2000 CEMS data to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) is applied to the annual average emission rate in the base year to calculate the 24-hr emission rate in the base year. Since short-term emission rates in the current year inventory are based on the 90th percentile of the 24-hour average (see Section 3.1), this option would give the best estimate of the 90th percentile 24-hr emission rate in the base year and would, therefore, be consistent with the short-term emissions used in the current year inventory. For this reason we chose this option for calculating short-term SO_2 emissions in the base year.

EPA believes any increment analysis should follow the same methodology for determining emissions in the base year as in the current year, particularly where like data are available, as is the case here. Using the same methodology allows an objective comparison (and use) of the two data sets. To do otherwise does not provide "comparable" data sets. If different methodologies were used to determine emissions for the base year and the current year, comparing the two data sets would produce inappropriate conclusions since the data sets had been derived using different methodologies.

Annual average emissions (for use in option 3 above) are based on an AP-42 emission factor for uncontrolled lignite-fired boilers of 30 S (see AP-42, section 1.7, Table 1.7-1). Annual Emission Inventory Reports for each baseline source were obtained from the State of North Dakota for 1976 and 1977. From these reports, annual coal usage and average sulfur content data were used to calculate annual average SO_2 emissions. For example, annual average base year SO_2 emissions for Minnkota's Milton R Young Unit 1 are:

$$SO_2 \text{ emissions}_{1976} [TPY] = 30 * (0.52\%) \frac{lb_{SO_2}}{ton_{coal}} * 1,581,000 \frac{ton_{coal}}{yr} * \frac{1 ton_{SO_2}}{2000 lb_{SO_2}} = 12,332 \frac{ton_{SO_2}}{yr}$$

$$SO_2 \text{ emissions}_{1977} [TPY] = 30 * (0.63\%) \frac{lb_{SO_2}}{ton_{coal}} * 1,527,511 \frac{ton_{coal}}{yr} * \frac{1 ton_{SO_2}}{2000 lb_{SO_2}} = 14,435 \frac{ton_{SO_2}}{yr}$$

$$2\text{ yr average } SO_2 \text{ emissions [TPY]} = \frac{(12,332 + 14,435)}{2} = \underline{\underline{13,383 \text{ TPY}}}$$

Short-term emissions are then calculated based on the peak-to-mean ratio from current year emissions. For example, short-term SO₂ base year emissions for Minnkota's Milton R Young Unit 1 boiler are:

$$\text{peak-to-mean ratio}_{1999-2000} = \frac{18,788 \frac{\text{ton}}{\text{yr}} (2\text{ yr annual avg}_{1999-2000})}{5575 \frac{\text{lb}}{\text{hr}} (90^{\text{th}}\% \text{ 24hr avg}_{1999-2000}) * \frac{8760 \text{ hr}}{\text{yr}} * \frac{\text{ton}}{2000 \text{ lb}}} = 1.30$$

$$\text{base year } SO_2 \text{ emissions} \left[\frac{\text{lb}}{\text{hr}} \right] = 13,383 \frac{\text{ton}}{\text{yr}} * 1.30 * \frac{\text{yr}}{8760 \text{ hr}} * \frac{2000 \text{ lb}}{\text{ton}} = \underline{\underline{3972 \frac{\text{lb}}{\text{hr}}}}$$

For the most part we used the above method for calculating base year emissions. However there are a few exceptions. Minnkota's Milton R Young Unit 2 had only been in operation for 9 months as of the minor source baseline date and those 9 months do not appear to be representative of normal operating conditions. The unit was apparently out of compliance with its allowable emissions for many months after the unit began operation. Considering that we do not have two years of actual emissions at the time of the minor source baseline date for this unit, as well as the fact that the unit really did not begin "normal operations" until after the baseline date was triggered, we believe it is appropriate in this situation to consider the allowable emissions of Minnkota's Unit 2 as its emissions at the time of the baseline date (see 45 FR 52718, col. 3, August 7, 1980). Furthermore, since any emissions increases above a source's allowable emission rate at the time of the minor source baseline date must be considered as increment consuming emissions, it would not be appropriate to use Unit 2's actual emission rate at the time of the minor source baseline date as the baseline emission rate. Therefore, we modeled a short-term emission rate of 5635 lb/hr (the allowable emission rate) for this unit.

The other exception in calculating baseline emissions is for Montana-Dakota Utilities Co.'s Heskett Unit 1 emissions. Since Heskett Unit 1 is not an acid rain source, no CEMS emissions are reported to the Acid Rain Database. Hourly CEMS data were only available for the year 2000 from the State of North Dakota. Therefore, the peak-to-mean ratio used to calculate short-term emissions in the base year is only based on year 2000 data (as opposed to both 1999 and 2000 data, used for all other baseline sources).

Baseline emissions for the Class I areas in North Dakota are summarized in Table 3-2.

Table 3-2
SO₂ BASELINE EMISSIONS FOR NORTH DAKOTA CLASS I AREAS
 Based on AP-42 and annual emission inventory reports provided by ND for 1976-1977
 SO₂ minor source baseline date = December 17, 1977

Source	Emission Factor [lb _{SO₂} /ton _{coal}]	1976 Actual Emissions			1977 Actual Emissions			Baseline Emissions	
		avg. S [%]	coal burned [TPY]	annual emissions [TPY]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	annual [TPY]	24-hr ¹ [lb/hr]
Minnkota Power Cooperative - Milton R. Young Station									
Unit 1	30(S)	0.52	1,581,000	12,332	0.63	1,527,511	14,435	13,383	3,972
Unit 2 ²	n/a	n/a	n/a	24,682	n/a	n/a	24,682	24,682	5,635
Basin Electric Power Cooperative - Leland Olds Station									
Unit 1	30(S)	0.45	1,255,995	8,478	0.44	1,306,785	8,625	8,551	2,499
Unit 2	30(S)	0.45	1,958,680	13,221	0.44	1,964,660	12,967	13,094	4,305
Montana-Dakota Utilities Co. - Heskett Station									
Unit 1	30(S)	0.75	159,196	1,791	0.68	171,162	1,746	1,768	602
Unit 2	30(S)	0.75	376,017	4,230	0.68	406,145	4,143	4,186	1,749
Great River Energy - Stanton Station									
Unit 1	30(S)	0.65	746,205	7,275	0.64	737,106	7,076	7,176	2,310
TOTAL								72,841	21,072

¹ Based on the ratio of annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

² Unit 2 had only been operating 9 months as of the minor source baseline date (12/19/77) and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine baseline emissions. See 45 FR 52718, col. 3, August 7, 1980.

3.2.2 Base Year Inventory for Montana Class I Areas

In general, the base year inventory for the Montana Class I areas was compiled using the same method as for the North Dakota Class I inventory. The only difference is the use of 1977 and 1978 emission inventory data for calculating the annual average emission rates. While we still used allowable emissions for Minnkota's Milton R Young Unit 2 in 1977, we were able to calculate actual emissions for 1978. Since Unit 2 commenced construction after August 17, 1971, it was permitted according to the New Source Performance Standards (NSPS) in 40 CFR

Part 60 Subpart D. Therefore, we calculated actual emissions for the unit based on this 1.2 lb_{so2}/mmBtu standard, the average heat content of the coal in 1978 and the annual coal usage rate for that year. We then applied the peak-to-mean ratio from 1999-2000 CEMS data to calculate a short-term emission rate and averaged that with the 1977 allowable emission rate of 5635 lb/hr to arrive at a short-term emission rate for the unit for the base year. Other possibilities we considered for determining baseline emissions for this unit were: (1) to just use the 1978 actual numbers (not averaged with the allowable emissions for 1977); and (2) to use the allowable emission rate for both 1977 and 1978 emissions. EPA solicits comments from the public on how to determine the most representative baseline emission rate for this source.

Baseline emissions for the Class I areas in Montana are summarized in Table 3-3.

Table 3-3
SO₂ BASELINE EMISSIONS FOR MONTANA CLASS I AREAS
 Based on AP-42 and annual emission inventory reports provided by ND for 1977-1978
 SO₂ minor source baseline date = March 26, 1979

Source	Emission Factor [lb _{SO2} /ton _{coal}]	1977 Actual Emissions			1978 Actual Emissions			Baseline Emissions	
		avg. S [%]	coal burned [TPY]	annual emissions [TPY]	avg. S [%]	coal burned [TPY]	annual emissions [TPY]	annual [TPY]	24-hr ¹ [lb/hr]
Minnkota Power Cooperative - Milton R. Young Station									
Unit 1	30(S)	0.63	1,527,511	14,435	0.65	1,427,485	13,918	14,176	4,208
Unit 2 ²	1.2 lb/mmBtu	n/a	n/a	24,682	0.65	1,956,191	15,087	19,884	4,970
Basin Electric Power Cooperative - Leland Olds Station									
Unit 1	30(S)	0.44	1,306,785	8,625	0.74	1,361,539	15,113	11,869	3,469
Unit 2	30(S)	0.44	1,964,660	12,967	0.74	2,435,160	27,030	19,999	6,575
Montana-Dakota Utilities Co. - Heskett Station									
Unit 1	30(S)	0.68	171,162	1,746	0.71	161,755	1,723	1,734	590
Unit 2	30(S)	0.68	406,145	4,143	0.71	342,560	3,648	3,895	1,628
Great River Energy - Stanton Station									
Unit 1	30(S)	0.64	737,106	7,076	0.61	577,004	5,280	6,178	1,989
TOTAL								77,736	23,428

¹ Based on the ratio of annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

² Unit 2 had only been operating 9 months in 1977 and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine 1977 emissions. See 45 FR 52718, col. 3, August 7, 1980. 1978 emissions are based on an emission limit of 1.2 lb_{SO₂}/mmBtu for NSPS boilers (see 40 CFR Part 60 Subpart D) and an average heat content of 6427 Btu/lb_{coal}.

3.3 Increment Consuming Emissions

Tables 3-4 and 3-5 summarize the increment consuming emissions from the inventories in Section 3.1 (Current Year Emissions) and 3.2 (Base Year Emissions).

Table 3-4
SO₂ INCREMENT CONSUMING EMISSIONS FOR NORTH DAKOTA CLASS I AREAS

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions ¹	
	24-hr ² [lb/hr]	annual [TPY]	24-hr ³ [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Basin Electric Power Cooperative - Antelope Valley Station						
Units 1+2	n/a	n/a	3,598	14,282	3,598	14,282
Otter Tail - Coyote Station						
Unit 1	n/a	n/a	5,077	17,281	5,077	17,381
Great River Energy - Coal Creek Station						
Unit 1 ⁴	n/a	n/a	4,195	14,332	4,195	14,332
Unit 2 ⁴	n/a	n/a	3,552	12,817	3,552	12,817
PPL Corp. - Colstrip (Montana)						
Unit 3	n/a	n/a	672	2,945	672	2,945
Unit 4	n/a	n/a	640	2,804	640	2,804
Minnkota Power Cooperative - Milton R. Young Station						
Unit 1	3,972	13,383	5,575	18,788	1,603	5,405
Unit 2 ⁵	5,635	24,682	6,128	21,499	493	(3,184)
Basin Electric Power Cooperative - Leland Olds Station						
Unit 1	2,499	8,551	4,931	16,833	2,432	8,282
Unit 2	4,305	13,094	10,179	30,947	5,874	17,853

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions ¹	
	24-hr ² [lb/hr]	annual [TPY]	24-hr ³ [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Montana Dakota Utilities Co. - Heskett Station						
Unit 1 ⁶	602	1,768	348	1,022	(254)	(746)
Unit 2	1,749	4,186	831	1,993	(918)	(2,193)
Great River Energy - Stanton Station						
Unit 1	2,310	7,176	2,456	7,629	146	453
Unit 10	n/a	n/a	320	1,107	320	1,107
Gas Processing Plants						
Grasslands	n/a	n/a	273	n/a	273	n/a
Little Knife	n/a	n/a	427	n/a	427	n/a
Dakota Gasification Plant						
Greatplain Synfuels	n/a	n/a	3,323	n/a	3,323	n/a
TOTAL	21,072	72,840	52,525	164,277	31,453	91,538

¹ Negative numbers indicate increment expanding emissions (*i.e.*, current year emissions are lower than base year emissions).

² Annual numbers are based on the Annual Emission Inventory Reports from 1976-1977 (e.g., avg S, annual coal use) and AP-42 emission factors. 24-hr numbers are based on the ratio of the annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

³ Based on the 90th percentile of the 24-hr average from 1999 and 2000 CEMS data.

⁴ Based on 2000 CEMS data only.

⁵ Unit 2 had only been operating 9 months as of the minor source baseline date (12/19/77) and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine baseline emissions. See 45 FR 52718, col 3, August 7, 1980.

⁶ Current year emissions based on 2000 CEMS data only. Unit 1 does not report to the Acid Rain Database; hourly CEMS data were only available for 2000 from the State.

Table 3-5

SO₂ INCREMENT CONSUMING EMISSIONS FOR MONTANA CLASS I AREAS

Source	BaseYear Emissions		Current Year Emissions		Increment Consuming Emissions ¹	
	24-hr ² [lb/hr]	annual [TPY]	24-hr ³ [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Basin Electric Power Cooperative - Antelope Valley Station						
Units 1+2	n/a	n/a	3,598	14,282	3,598	14,282
Otter Tail - Coyote Station						
Unit 1	n/a	n/a	5,077	17,281	5,077	17,381
Great River Energy - Coal Creek Station						
Unit 1 ⁴	n/a	n/a	4,195	14,332	4,195	14,332
Unit 2 ⁴	n/a	n/a	3,552	12,817	3,552	12,817
PPL Corp. - Colstrip (Montana)						
Unit 3	n/a	n/a	672	2,945	672	2,945
Unit 4	n/a	n/a	640	2,804	640	2,804
Minnkota Power Cooperative - Milton R. Young Station						
Unit 1	4,208	14,176	5,575	18,788	1,367	4,612
Unit 2 ⁵	4,970	18,092	6,128	21,499	1,158	3,407
Basin Electric Power Cooperative - Leland Olds Station						
Unit 1	3,469	11,869	4,931	16,833	1,462	4,964
Unit 2	6,575	19,999	10,179	30,947	3,604	10,948
Montana Dakota Utilities Co. - Heskett Station						
Unit 1 ⁶	590	1,734	348	1,022	(242)	(712)
Unit 2	1,628	3,895	831	1,993	(797)	(1,902)
Great River Energy - Stanton Station						
Unit 1	1,989	6,178	2,456	7,629	467	1,451
Unit 10	n/a	n/a	320	1,107	320	1,107
Gas Processing Plants						
Grasslands	n/a	n/a	273	n/a	273	n/a

Source	Base Year Emissions		Current Year Emissions		Increment Consuming Emissions ¹	
	24-hr ² [lb/hr]	annual [TPY]	24-hr ³ [lb/hr]	annual [TPY]	24-hour [lb/hr]	annual [TPY]
Little Knife	n/a	n/a	427	n/a	427	n/a
Dakota Gasification Plant						
Greatplain Synfuels	n/a	n/a	3,323	n/a	3,323	n/a
TOTAL	23,429	75,943	52,525	164,277	29,096	88,435

¹ Negative numbers indicate increment expanding emissions (*i.e.*, current year emissions are lower than base year emissions).

² Annual numbers are based on the Annual Emission Inventory Reports from 1977-1978 (e.g., avg S, annual coal use) and AP-42 emission factors. 24-hr numbers are based on the ratio of the annual average emission rate (from 1999-2000 CEMS data) to the 90th percentile 24-hr emission rate (from 1999-2000 CEMS data) applied to the annual average emission rate in the base year.

³ Based on the 90th percentile of the 24-hr average from 1999 and 2000 CEMS data.

⁴ Based on 2000 CEMS data only.

⁵ Unit 2 had only been operating 9 months in 1977 and those 9 months were not considered representative of actual operation. Therefore, allowable emissions were used to determine 1977 emissions. See 45 FR 52718, col. 3, August 7, 1980. 1978 emissions are based on an emission factor of 16.8 S for NSPS boilers (see AP-42, Table 1.7-2).

⁶ Current year emissions based on 2000 CEMS data only. Unit 1 does not report to the Acid Rain Database; hourly CEMS data were only available for 2000 from the State.

3.4 Increment Expanding Emissions

We modeled six major sources as increment-expanding sources. Montana Dakota Utilities Co.'s Heskett Station had a reduction in actual emissions since the minor source baseline dates (12/17/77 for North Dakota and 3/26/79 for Montana) and its emissions were therefore modeled as increment expanding. Five other sources in North Dakota shut down after the applicable minor source baseline dates (12/17/77 in North Dakota and 3/26/79 in Montana). These sources include the Amerada Hess Tioga Gas Plant, Basin Electric Power Cooperative's Neal Station (Units 1 and 2), Flying J Inc.'s Williston Refinery, Montana-Dakota Utilities Co.'s Beulah Station (Units 1-2 and 3-5), and the Royal Oak Briquetting Plant (Units 1, 2 and 3).

For the five sources that shut down since the minor source baseline dates, we modeled the same emission rates the NDDH used in their 1999 draft analysis and outlined in Table 3-6.

Table 3-6
SO₂ INCREMENT EXPANDING EMISSIONS

Source	Increment Expanding Emissions	
	ND modeled annual [g/s]	annual [TPY]
Basin Electric Power Coop. - Neal Station	37.4	1,301.5
Montana-Dakota Utilities Co. - Beulah Station	78.2	2,721.4
Flying J Inc. - Williston Refinery	5.7	198.4
Amerada Hess Tioga Gas Plant	62.9	2,188.9
Royal Oak Briquetting Plant	68.9	2,397.7
TOTAL	253	8,808

4. Results

The Calpuff modeling results are shown in Tables 4-1 through 4-5. To determine PSD compliance these modeled results are compared with the applicable Class I increments.

The PSD increments for SO₂ are specified in section 163(b) of the Act. For Class I areas, those increments are:

annual arithmetic mean.....2 µg/m³
 twenty-four hour average.....5 µg/m³
 three hour average.....25 µg/m³.

For any averaging period other than an annual averaging period, section 163(a) of the Act allows the increment to be exceeded during one such period per year. Otherwise, section 163 of the Act provides that the increments are not to be exceeded and that the State Implementation Plan must contain measures assuring that the increments will not be exceeded in the future. In the following tables, the number of exceedances indicates the number of times in each year that Calpuff predicted concentrations exceeding the applicable increment. Any number larger than one indicates a violation of the Class I increment.

**Table 4-1. Calpuff Class I Increment Results
TRNP-South Unit
($\mu\text{g}/\text{m}^3$)**

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>
<u>3-hr Predictions</u>					
Highest	36.4	31.4	25.6	35.0	29.9
High, 2 nd High	31.4	30.0	<25	25.1	<25
Max # of Exceedances	4	2	1	2	0
<u>24-hr Predictions</u>					
Highest	14.1	15.3	6.9	8.5	10.1
High, 2 nd High	12.8	8.5	5.4	7.3	7.7
Max # of Exceedances	8	7	2	5	10

**Table 4-2. Calpuff Class I Increment Results
TRNP-North Unit
($\mu\text{g}/\text{m}^3$)**

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>
<u>3-hr Predictions</u>					
Highest	29.4	30.7	33.8	32.3	32.0
High, 2 nd High	29.0	28.5	27.7	<25	31.4
Max # of Exceedances	2	2	3	1	2
<u>24-hr Predictions</u>					
Highest	12.3	11.9	12.1	13.1	13.4
High, 2 nd High	10.5	9.2	7.0	7.9	9.6
Max # of Exceedances	9	7	6	8	7

**Table 4-3. Calpuff Class I Increment Results
TRNP- Elkhorn Unit
($\mu\text{g}/\text{m}^3$)**

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>
<u>3-hr Predictions</u>					
Highest	< 25	< 25	< 25	25.8	35.7
High, 2 nd High	< 25	< 25	< 25	< 25	< 25
Max # of Exceedances	0	0	0	1	1
<u>24-hr Predictions</u>					
Highest	9.4	11.5	< 5	6.5	11.9
High, 2 nd High	6.9	7.1	< 5	6.4	11.4
Max # of Exceedances	5	6	0	5	6

**Table 4-4. Calpuff Class I Increment Results
Lostwood Wilderness Area
($\mu\text{g}/\text{m}^3$)**

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>
<u>3-hr Predictions</u>					
Highest	< 25	< 25	31.5	< 25	25.6
High, 2 nd High	< 25	< 25	< 25	< 25	< 25
Max # of Exceedances	0	0	1	0	1
<u>24-hr Predictions</u>					
Highest	7.6	9.1	8.9	5.9	6.4
High, 2 nd High	6.6	6.8	7.7	5.5	6.4
Max # of Exceedances	7	10	8	4	7

**Table 4-5. Calpuff Class 1 Increment Results
Medicine Lakes Wilderness Area
($\mu\text{g}/\text{m}^3$)**

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>
<u>3-hr Predictions</u>					
Highest	26.0	< 25	< 25	< 25	< 25
High, 2 nd High	25.9	< 25	< 25	< 25	< 25
Max # of Exceedances	2	0	0	0	0
<u>24-hr Predictions</u>					
Highest	6.3	< 5	8.0	6.4	6.1
High, 2 nd High	< 5	< 5	5.0	5.9	5.1
Max # of Exceedances	1	0	2	2	3

**Table 4-6 Calpuff Class 1 Increment Results
Fort Peck Reservation
($\mu\text{g}/\text{m}^3$)**

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>
<u>3-hr Predictions</u>					
Highest	27.9	< 25	< 25	< 25	< 25
High, 2 nd High	< 25	< 25	< 25	< 25	< 25
Max # of Exceedances	1	0	0	0	0
<u>24-hr Predictions</u>					
Highest	7.4	< 5	11.8	6.2	7.0
High, 2 nd High	6.2	< 5	5.5	5.2	6.3
Max # of Exceedances	2	0	2	2	3

Table 4-7
Calpuff Class I SO₂ PSD Increment Results
Summary of 5-year Maximum Values (1990-1994)
(µg/m³)

	<u>TRNP</u> <u>South</u>	<u>TRNP</u> <u>North</u>	<u>TRNP</u> <u>Elkhorn R.</u>	<u>Lostwood</u> <u>Wilderness</u>	<u>Med. Lake</u> <u>Wilderness</u>	<u>Ft. Peck</u> <u>Reservation</u>
<u>3-hr Predictions</u>						
Highest	36.4	32.3	35.7	31.5	26.0	27.9
High, 2 nd High	31.4	31.4	< 25	< 25	25.9	< 25
Max # of Exceedances	4	3	1	1	2	1
<u>24-hr Predictions</u>						
Highest	15.3	13.4	11.9	9.1	8.0	11.8
High, 2 nd High	12.8	10.5	11.4	7.7	5.9	6.3
Max # of Exceedances	10	9	6	10	3	3

4.1 Results Using Regulatory Default Input Values

EPA conducted a sensitivity test to show the difference in predicted concentrations compared to a regulatory default application of the Calmet and Calpuff models. With the exception of directly monitored North Dakota values (e.g. mixing height, O₃/ NH₃ background concentrations, etc.), all IWAQM recommendations were selected, and the unrevised EPA regulatory version of the model was used. The results of this test run are shown in Table 4.1-1. From the table it can be seen that the regulatory default selections result in higher predicted concentrations than the selections used in the current study. Non-IWAQM parameters related to the method of dispersion (MDISP, MPDF) were responsible for a large portion of the observed differences. EPA based its selection of non-IWAQM settings largely on the NDDH testing of the model. In these tests Calpuff/Calmet model predictions were compared with observed concentrations for two SO₂ monitoring sites located in and near the Theodore Roosevelt National Park located in western North Dakota. The evaluation was limited by the lack of representative monitoring sites so that a full evaluation using American Meteorological Society performance statistics could not be generated, and predictions/observations were not paired in time. Given the relatively sparse set of SO₂ monitoring data that has been used in testing the model, EPA solicits public comment on which default values should be used in the final modeling to complete the current study.

Table 4-8
Calpuff PSD Increment Analysis
Comparing Modeling Results Using Regulatory Defaults (bold) and Locally Developed Input Settings.

1990 Modeling Results	TRNP South	TRNP North	TRNP Elkhorn R.	Lostwood Wilderness	Med. Lake Wilderness	Ft. Peck Reservation
<u>3-hr Predictions</u>						
Highest	61.5 / 36.4	35.1 / 29.4	27.5 / < 25	31.2 / < 25	< 25 / 26.0	25.5 / 27.9
High, 2 nd High	45.1 / 31.4	33.1 / 29.0	25.8 / < 25	< 25 / < 25	< 25 / 25.9	< 25 / < 25
Max # of Exceedances	12 / 4	9 / 2	2 / 0	1 / 0	0 / 2	1 / 1
<u>24-hr Predictions</u>						
Highest	22.4 / 14.1	15.2 / 12.3	8.8 / 9.4	8.4 / 7.6	< 5 / 6.3	5.6 / 7.4
High, 2 nd High	18.6 / 12.8	13.8 / 10.5	8.4 / 6.9	7.7 / 6.6	< 5 / < 5	< 5 / 6.2
Max # of Exceedances	16 / 8	14 / 9	6 / 5	9 / 7	0 / 1	1 / 2

5. Conclusion

In summary, EPA has applied the Calmet/Calpuff model to assess increment consumption in four Class I areas in North Dakota and eastern Montana. We based our analysis on long-standing EPA methodologies, including the use of two years of actual emissions data and five years of historical meteorology data. We employed the locally-developed inputs for the model used by the North Dakota Department of Health (NDDH) in their draft 1999 analysis. The results of our analysis show numerous violations of the Class I PSD increments for SO₂ in all four Class I areas assessed. Specifically, the number of violations in each Class I area are shown below:

Table 5-1: Summary of Class I Violations

	<u>3-hr Predictions</u> 2 nd High	<u>3-hr Predictions</u> # Violations	<u>24-hr Predictions</u> 2 nd High	<u>24-hr Predictions</u> # Violations
<i>Theodore Roosevelt National Park, South Unit</i>	31.4 µg/m ³	3	12.8 µg/m ³	9
<i>Theodore Roosevelt National Park, North Unit</i>	31.4 µg/m ³	2	10.5 µg/m ³	8
<i>Theodore Roosevelt National Park, Elkhorn Unit</i>	<25 µg/m ³	0	11.4 µg/m ³	5
<i>Lostwood Wilderness Area</i>	<25 µg/m ³	0	7.7 µg/m ³	9
<i>Medicine Lakes Wilderness Area</i>	25.9 µg/m ³	1	5.9 µg/m ³	2
<i>Fort Peck Indian Reservation</i>	<25 µg/m ³	0	6.3 µg/m ³	2
EPA's Class I SO ₂ Increments	25 µg/m ³		5 µg/m ³	

Note that, under EPA's PSD regulations, one exceedance of the short term (3-hour and 24-hour) increments is allowed per year, which is why Table 5-1 identifies the modeled second high concentration.

The PSD permitting program and the State's Implementation Plan, or SIP, are the mechanisms intended by Congress for protecting the PSD increments. Specifically, section 161 of the Clean Air Act and 40 CFR 51.166(a)(1) provide that the SIP must contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality. Section 163(a) of the Clean Air Act states that each SIP shall contain measures assuring that the maximum allowable increases over baseline concentrations shall not be

exceeded.

EPA's regulations require States to periodically review their plans for preventing significant deterioration. (See 40 CFR 51.166(a)(4).) If a State determines that an applicable increment is being violated, the State must revise the SIP to correct the violation as required by 40 CFR 51.166(a)(3). In addition, 40 CFR 51.166(a)(2) provides that, if a SIP revision would result in increased air quality deterioration over any baseline concentration, the SIP revision must include a demonstration that it will not cause or contribute to a violation of the applicable increments. Thus, there are several provisions of the Clean Air Act and EPA's regulations which require the protection of the PSD increments.

EPA performed this modeling analysis in order to provide a technical basis for defining the appropriate regulatory actions necessary to address any increment violations. EPA is taking comments from interested parties on this draft report for thirty days. We will consider all comments received before finalizing the results. This draft modeling report does not constitute final agency action; such action may be taken at some point in the future as may be necessary to address any PSD increment violations.