North Dakota
Regional Haze
State Implementation Plan
Periodic Progress Report

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Table of Contents

List of Tables

List of Figures

List of Acronyms

AIRS	Aerometric Information Retrieval System
AQS	EPA's Air Quality System
AVS	Antelope Valley Station
ASOFA	Advanced separated overfire air
BADL	Badlands National Park, SD
Bag	Baghouse
BART	Best Available Retrofit Technology
B_{ext}	Light extinction (typically measured in inverse megameters: 1/Mm or Mm^{-1})
BOWA	Boundary Waters Canoe Area Wilderness Area, MN
Btu	British thermal unit
CAA	Clean Air Act (42 United States Code Sections 7401, et seq)
CALPUFF	Multi-layer, multi-species, non-steady state, puff, long range transport dispersion modeling system
CEM	Continuous emissions monitor
CENRAP	Central Regional Air Planning Association
CFR	Code of Federal Regulations
CMAQ	Community Multiscale Air Quality model
DGC	Dakota Gasification Company
DOI	United States Department of the Interior
dv	deciview
Δdv	Change in deciviews
EC	Elemental carbon
EDMS	Emissions Data Management System
EGU	Electrical Generating Unit
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
FLM	Federal Land Manager
FM	Fine mass ($PM_{2.5}$ mass)
FR	Federal Register
FS	United States Forest Service (DOA)
FWS	United States Fish and Wildlife Service (DOI)
GCP	Gas Capture Plan
GPSP	Great Plains Synfuels Plant
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPM	Integrated Planning Model
ISLE	Isle Royale National Park, MI
km	Kilometers
lb	Pounds

$lb/10^6$ Btu	Pounds per million British thermal units
LOST	Lostwood National Wildlife Refuge Wilderness Area, ND
LNB	Low NO_x burner
LTS	Long Term Strategy
LWA	Lostwood National Wildlife Refuge Wilderness Area, ND
MACT	Maximum Achievable Control Technology
MELA	Medicine Lake National Wildlife Refuge Wilderness Area, MT
Mm	Megameters
MN	Minnesota
MT	Montana
NAAQS	National Ambient Air Quality Standards
ND	North Dakota
NDAC	North Dakota Administrative Code (state rules)
NDCC	North Dakota Century Code (state laws)
NDDoH	North Dakota Department of Health
NDIC	North Dakota Industrial Commission
NEI	National Emissions Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NO_3	Nitrate
NO_x	Oxides of nitrogen or nitrogen oxides
NPS	National Park Service (DOI)
NSPS	New Source Performance Standard
OC	Organic carbon
OFA	Overfire air
PM	Particulate matter
PMC	Coarse particulate matter, $PM_{10} – PM_{2.5}$
PM_{coarse}	Coarse particulate matter, $PM_{10} – PM_{2.5}$
PMF	Fine particulate matter, $PM_{2.5}$
PM_{fine}	Fine particulate matter, $PM_{2.5}$
$PM_{2.5}$	Fine particulate matter; particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers as measured by an EPA approved reference method
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers as measured by an EPA approved reference method
POA	Primary Organic Aerosol
PSAT	Particulate Matter Source Apportionment Technology
PSD	Prevention of Significant Deterioration
RPG	Reasonable Progress Goal
RH	Regional Haze
RP	Reasonable Progress
RHR	Regional Haze Rule/Regulation
ROW	Right-of-Way
SCR	Selective catalytic reduction
SD	South Dakota
SD	Spray dryer

SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_4	Sulfate
SO_x	Sulfur oxides
SRU	Sulfur recovery unit
THRO	Theodore Roosevelt National Park, ND
TRNP	Theodore Roosevelt National Park, ND
TPY	tons per year; also listed as tpy
TSS	WRAP Technical Support System
URP	Uniform rate of progress
USC	United States Code
VIEWS	Visibility Information Exchange Web System
VOC	Volatile organic compounds
VOYA	Voyageurs National Park, MN
VR	Visual Range
WEP	Weighted Emissions Potential
WICA	Wind Cave National Park, SD
WRAP	Western Regional Air Partnership
WS	Wet scrubber

1. Background

1.1 Federal Regional Haze Program Requirements

Section 169(A) of the Clean Air Act (CAA) establishes the national visibility goal of "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." Based on the requirements of Section 169(A), the North Dakota Department of Health (NDDH) developed a State Implementation Plan (SIP) to address the national visibility goal. The Regional Haze (RH) SIP was submitted to the U.S. Environmental Protection Agency (EPA) in March 2010.

The regional haze rules (RHR) in 40 CFR 51.308 requires that each state develop periodic progress reports describing their progress toward the reasonable progress goals established in the RH SIP. The first periodic progress report is due to EPA five years after submittal of the initial RH SIP. EPA has established general principles for the 5-year reports for the initial RH SIP which are intended to assist states in the preparation of the report[1] (hereafter referred to as EPA guidance).

The specific items that must be addressed in the periodic progress report include:

- Status of Control Strategies in the Regional Haze SIP (40 CFR 51.308(g)(1))
- Emissions Reductions from the Regional Haze SIP Strategies (40 CFR 51.308(g)(2))
- Visibility Progress (40 CFR 51.308(g)(3))
- Emissions Progress (40 CFR 51.308(g)(4))
- Assessment of Changes Impeding Visibility Progress (40 CFR 51.308(g)(5))
- Assessment of Current Strategy (40 CFR 51.308(g)(6))
- Review of Visibility Monitoring Strategy (40 CFR 51.308(g)(7))
- Determination of Adequacy (40 CFR 51.308(h))

States are required to develop their periodic progress reports and must provide the Federal Land Manager's (FLMs) with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the report. The periodic progress report must document that this consultation has taken place and must address any comments provided by the FLMs.

The periodic report, which is submitted to EPA in the form of a SIP revision, must be provided for public review and comment. A public hearing is required if requested by the public. All comments that are received must be addressed in the report. The deadline for submitting the periodic progress report is five years after the initial submittal of the RH SIP. For North Dakota, the deadline is March 3, 2015.

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[1] General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans; USEPA, Office Air Quality Planning and Standards; April 2013.

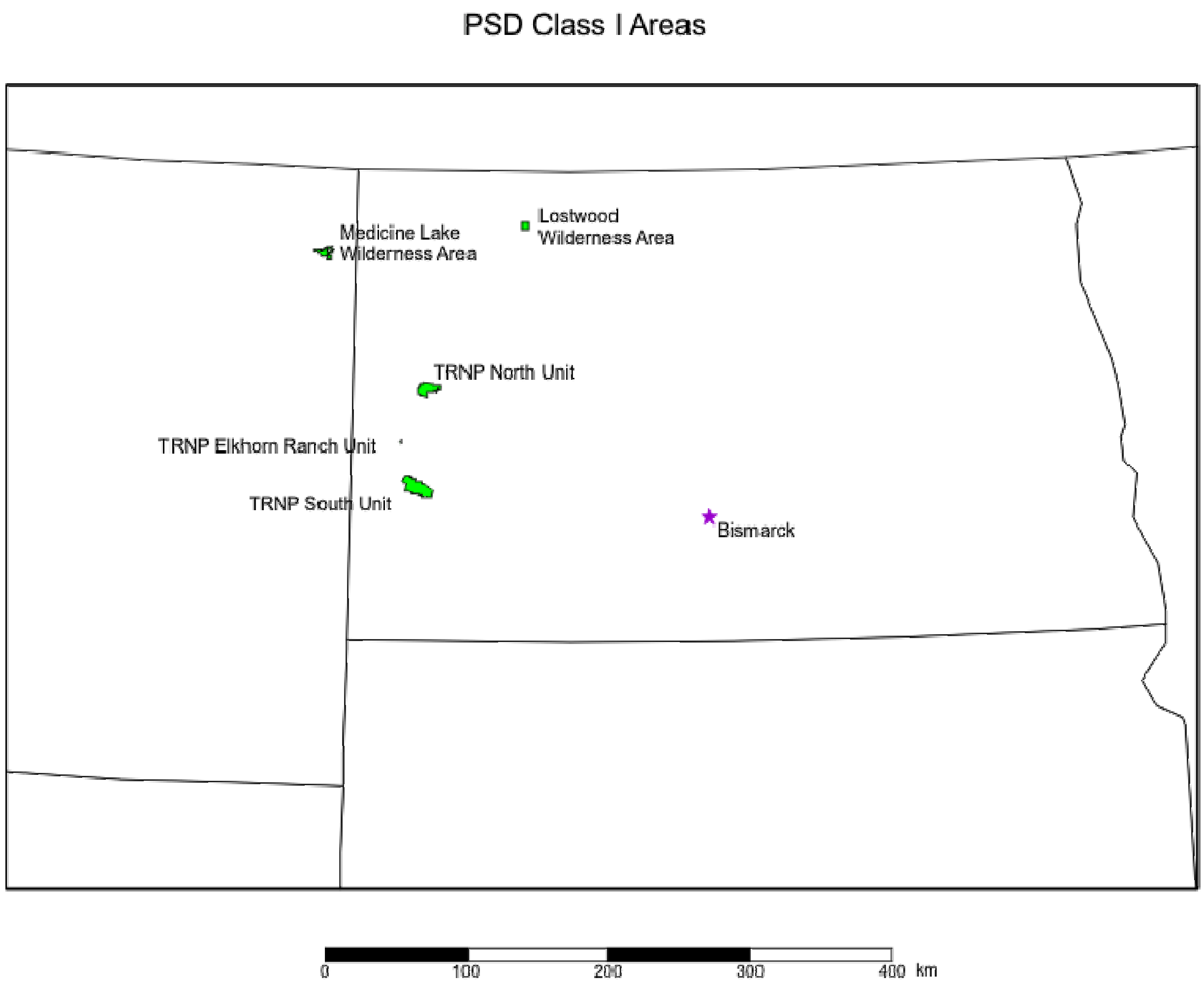
1.2 North Dakota SIP Summary

The Class I areas in North Dakota include: the Theodore Roosevelt National Park (TRNP) which consists of three separate, distinct units and the Lostwood National Wildlife Refuge Wilderness Area (LWA). The North Dakota Class I Areas are shown in Figure 1.1.

Theodore Roosevelt National Park is located within Billings and McKenzie Counties in North Dakota. The colorful badlands and Little Missouri River of western North Dakota provide the scenic backdrop to the park which memorializes the 26th president for his enduring contributions to the conservation of our nation’s resources. The park contains 70,447 acres divided among three separate units: South Unit, Elkhorn Ranch and North Unit and is managed by the National Park Service. The park is comprised of badlands, open prairie and hardwood draws that provide habitat for a wide variety of wildlife species including bison, prairie dogs, elk, deer, big horn sheep and other wildlife. The Little Missouri River passes through the three units of the park.

Lostwood National Wildlife Refuge Wilderness Area is located in Burke County in the northwestern part of the State. Created by an act of Congress in 1975, the wilderness covers an area of 5,577 acres. It is contained within Lostwood National Wilderness Refuge and is managed by the U.S. Fish and Wildlife Service. Lostwood National Wilderness Area is designed to preserve a region well known for numerous lakes and mixed grass prairie.

Figure 1.1 – Map of North Dakota Class I Areas



On March 3, 2010, the RH SIP was submitted to EPA and on April 13, 2010 EPA determined the SIP submittal was complete. Supplement No. 1 to the SIP was submitted to EPA on July 27, 2010 and Amendment No. 1 was submitted on July 28, 2010. On September 21, 2011, EPA proposed partial approval and partial disapproval of the SIP. At the same time, EPA proposed a Federal Implementation Plan (FIP) for those areas EPA determined were not approvable. On April 6, 2012, EPA finalized approval of various portions of the SIP and a FIP for those items not considered approvable. The FIP established NO_x limits for Coal Creek Station different than those the Department had proposed. However, the Coal Creek BART limits are being reconsidered. On January 2, 2013, the Department submitted supplement No. 2 to the SIP to EPA. Currently, there are two Requests for Reconsideration that EPA has not resolved. One pertains to the NO_x BART limit for the Coal Creek Station and the second pertains to the NO_x BART limits for the M.R. Young Station Units 1 and 2 and Leland Olds Station Unit 2. EPA expects to resolve these Requests for Reconsideration by the end of 2015.

The RH SIP identified both current visibility impairment and natural conditions for the 20% most impaired (worst) days and the 20% least impaired (best) days. Based on these results, the amount of visibility improvement that is required to achieve the national visibility goal and the uniform rate of progress were calculated.

Table 1.1
Improvement Necessary to Achieve Natural Conditions
(Deciviews)

Area	Baseline Least Impaired Days	Natural Least Impaired Days	Improvement Required	Baseline Most Impaired Days	Natural Most Impaired Days	Improvement Required	Uniform Rate of Progress
TRNP	7.8	3.0	4.8	17.8	7.8	10.0	2.3
LWA	8.2	2.9	5.3	19.6	8.0	11.6	2.7

In the RH SIP, it was demonstrated that the uniform rate of progress was not reasonable for establishing reasonable progress goals. Even if all North Dakota emissions of SO_x and NO_x were removed, the uniform rate of progress could not be achieved (see RH SIP, Section 8.6.3.3). The Department established reasonable progress goals based on its hybrid modeling approach for the first planning period of 16.9 dv for TRNP and 18.9 dv for LWA. However, it should be noted that based on WRAP's modeling approach, the reasonable progress goals would be 17.2 dv for TRNP and 19.1 dv for LWA (see RH SIP, Table 9.14).

Both the NDDoH's modeling approach and WRAP's modeling indicated that significant emissions reductions in North Dakota (60% for SO_2 and 25% for NO_x) would not have a significant impact ($\leq$5%) on the baseline visibility impairment for the 20% most impaired days. The reasons for this small improvement are apparent by reviewing Table 1.2. North Dakota sources contribute only a small portion of the sulfate and nitrate that cause most of the visibility impairment in the Class I Federal Areas. The reasonable progress goals established in the RH SIP were disapproved by EPA (77 FR 20944) because EPA disagreed with the NO_x BART determination for the Coal Creek Station and the NO_x reasonable progress determination for the Antelope Valley Station. The FIP for Coal Creek Station is now going through the "Reconsideration Process". The additional controls required at Antelope Valley Station by the

EPA's Federal Implementation Plan (FIP) would have virtually no effect on the amount of visibility improvement that will be achieved for the 20% most impaired days ($\leq$ 0.005 dv at TRNP and $\leq$0.01 dv at LWA). However, EPA did not establish new reasonable progress goals in their FIP for regional haze in North Dakota. Technically, there are no reasonable progress goals established for North Dakota's Class I Federal Areas. Since the FIP requirements will have a small effect on visibility impairment, the reasonable progress goals established in the RH SIP will be utilized for this report. However, the 2018 Regional Haze SIP revision will require the establishment of new Reasonable Progress goals based on regional modeling.

Table 1.2
Source Region Apportionment 20% Worst Days

Contributing Area	Class I Area			
	TRNP		LWA	
	SO_4	NO_3	SO_4	NO_3
North Dakota	21.1%	19.1%	17.9%	13.0%
Canada	28.3%	31.8%	45.9%	44.6%
Outside Domain	32.6%	17.9%	20.2%	14.0%
Montana	3.1%	15.0%	2.4%	9.3%
CENRAP	4.9%	2.5%	5.3%	5.1%
Other	10.5%	13.7%	8.3%	14.0%

In order to achieve reasonable progress toward the national visibility goal, the RH SIP relied primarily on SO_2 and NO_x reductions from existing electric generating units (EGUs). The requirements for the reductions were based on both the BART requirements in 40 CFR 51.308(e) and the reasonable progress requirements in 40 CFR 51.308(d).

Table 1.3
Emissions Reductions From the 2000-2004
Sulfur Dioxide Average

Source and Unit	2000-2004 Average Emissions Tons per Year	Baseline Level of Control % Reduction	SIP Level of Control % Reduction*	Control Device	Emissions after Controls Tons per Year**	Emissions Reduction Tons per Year**	Emission Limit
Basin Electric Power Cooperative Leland Olds Station Unit 1	16,666	0%	95%	New Wet Scrubber	1,376	15,290	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average
Basin Electric Power Cooperative Leland Olds Station Unit 2	30,828	0%	95%	New Wet Scrubber	2,530	28,298	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average
Great River Energy Coal Creek Station Unit 1	14,086	68%	95%	Modified Existing Wet Scrubber and Coal Dryer	3,781	10,305	95% reduction or 0.15 lb/10^6 Btu 30 day rolling average

Source and Unit	2000-2004 Average Emissions Tons per Year	Baseline Level of Control % Reduction	SIP Level of Control % Reduction*	Control Device	Emissions after Controls Tons per Year**	Emissions Reduction Tons per Year**	Emission Limit
Great River Energy Coal Creek Station Unit 2	12,407	68%	95%	Modified Existing Wet Scrubber and Coal Dryer	3,621	8,786	95% reduction or 0.15 $lb/10^6$ Btu 30 day rolling average
Great River Energy Stanton Station Unit 1	8,312	0%	90%	New Spray Dryer and Fabric Filter	1,179	7,133	90% reduction or 0.24 $lb/10^6$ Btu (lignite) or 0.16 $lb/10^6$ Btu (PRB) 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 1	20,148	0%	95%	New Wet Scrubber	1,007	19,141	95% reduction 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 2	12,404	65%	95%	Modified Existing Wet Scrubber	2,739	9,665	95% reduction; or 90% reduction and 0.15 $lb/10^6$ Btu 30 day rolling average
Montana Dakota Utilities R.M. Heskett Station Unit 2	2,399	0%	24%	Limestone Injection	1,826	573	70% reduction; or 0.60 $lb/10^6$ Btu 12-month rolling average
Total	117,250	----	----	----	18,059	99,198	----

* Based on the two year baseline emission rate for BART.

** Based on the average 2000-2004 operating rate and emission rates.

Table 1.4
Emissions Reductions From the 2000-2004 Nitrogen Oxides Average

Source and Unit	2000-2004 Average Emissions Tons per Year	Baseline Level of Control % Reduction	SIP Level of Control % Reduction*	Control Device	Emissions after Controls Tons per Year**	Emissions Reduction Tons per Year**	Emission Limit
Basin Electric Power Cooperative Leland Olds Station Unit 1	2,501	0%	42%	SOFA and SNCR	1,744	757	0.19 $lb/10^6$ Btu 30 day rolling average
Basin Electric Power Cooperative Leland Olds Station Unit 2	10,422	0%	54.5%	ASOFA and SNCR	5,904	4,518	0.35 $lb/10^6$ Btu 30 day rolling average
Great River Energy Coal Creek Station Unit 1	5,116	0%	30%	SOFA	4,285	831	0.17 $lb/10^6$ Btu 30 day rolling average***
Great River Energy Coal Creek Station Unit 2	5,391	0%	30%	SOFA	4,104	1,287	0.17 $lb/10^6$ Btu 30 day rolling average***

Source and Unit	2000-2004 Average Emissions Tons per Year	Baseline Level of Control % Reduction	SIP Level of Control % Reduction*	Control Device	Emissions after Controls Tons per Year**	Emissions Reduction Tons per Year**	Emission Limit
Great River Energy Stanton Station Unit 1	2,048	0%	45%	LNB, Overfire Air and SNCR	1,425	623	0.29 lb/10^6 Btu lignite coal 0.23 lb/10^6 Btu PRB coal 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 1	8,665	0%	58.1%	ASOFA and SNCR	3,857	4,808	0.36 lb/10^6 Btu 30 day rolling average
Minnkota Power Cooperative Milton R. Young Station Unit 2	14,705	0%	58.0%	ASOFA and SNCR	6,392	8,313	0.35 lb/10^6 Btu 30 day rolling average
Otter Tail Power Co. Coyote Station	13,047	0%	32%	SOFA	8,835	4,213	0.5 lb/10^6 Btu 30 day rolling average
Basin Electric Power Cooperative Antelope Valley Station Units 1 & 2	12,865	0%	50%	LNB + SOFA	6,439	6,426	0.17 lb/10^6 **** Btu 30 day rolling average
Total	74,760	----	----	----	42,985	31,776	----

* Based on the two year baseline emission rate for BART or reasonable progress.

** Based on the average 2000-2004 average operating rate.

*** EPA has issued a FIP that established an NO_x limit of 0.13 lb/10^6 Btu. The FIP is being reconsidered.

**** FIP Limit – These reductions were not included in the Regional Haze modeling conducted by WRAP or the NDDoH.

In addition to the BART and reasonable progress requirements, the RH SIP relied on Federal programs such as:

- Heavy Duty Diesel Engine Standard
- Tier 2 Tailpipe Standards
- Large Spark Ignition and Recreational Vehicle Rule
- Nonroad Diesel Rule
- Industrial Boiler MACT
- NSPS and MACT Standards for Combustion Turbines, Reciprocating and Internal Combustion Engines

The SIP also relies on several State on-going emission control programs in the North Dakota and non-SIP rules. These include the State's major and minor new source review program, fugitive dust control requirements, open burning restrictions, control requirements for sulfur dioxide and particulate matter from point sources, and State specific requirements for oil and natural gas production facilities. The list of emission control programs provided here is a summary of the RH SIP and may not be comprehensive; please refer to the final RH SIP for more details.

2. Periodic Progress

2.1 Status of Control Strategies in Regional Haze SIP (40 CFR 51.308(g))

2.1.1 BART and Reasonable Progress Sources

40 CFR 51.301(g)(1) states that the progress report shall include "A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State." EPA expects states to describe: 1) BART and reasonable progress limits for individual sources; and 2) additional control measures that the state relied on to meet the requirements of the regional haze program that were to take effect in the first planning period.

Visibility impairment in North Dakota's Class I areas is primarily due to sulfate, nitrate and organic carbon (see Table 2.1). North Dakota's Regional Haze SIP focused primarily on controlling sources of sulfur dioxide and nitrogen oxides which form sulfates and nitrates in the atmosphere. Organic carbon aerosols in North Dakota generally originate from fire (wild fire or prescribed burning) and fugitive dust sources. The Regional Haze SIP demonstrated that controls in-place for sources of fire and fugitive dust were adequate for the first planning period.

Table 2.1
Species Contribution to North Dakota Class I Areas Extinction
2000-2004
20% Worst Days

Class I Area	Pollutant Species	Extinction (Mm^{-1})	Species Contribution To Total Extinction (%)	ND Sources Contribution To Species Extinction (%) [a]
TRNP	Sulfate	17.53	35	21
	Nitrate	13.74	27	19
	OC	10.82	21	12
	EC	2.75	5	29
	PMF	0.9	2	44
	PMC	4.82	10	45
	Sea Salt	0.07	0	0
LWA	Sulfate	21.4	34	18
	Nitrate	22.94	36	13
	OC	11.05	18	23
	EC	2.84	5	35
	PMF	0.62	1	28
	PMC	3.93	6	32
	Sea Salt	0.26	0	0

[a] North Dakota contribution for sulfate and nitrate based on WRAP's tracer analysis and OC, EC, PMF, PMC and Sea Salt contribution based on WRAP's weighted emissions potential analysis.

The contribution of North Dakota sources to Class I areas in neighboring states is shown in Table 2.2. The sulfate and nitrate contribution is generally small (10% or less). The significant emissions reductions achieved at the EGUs are consistent with the Reasonable Progress Modeling conducted by WRAP and CENRAP during the original Regional Haze SIP development. The emissions reductions ultimately achieved by the EGUs in North Dakota will equal or exceed those expected when North Dakota's and surrounding states Regional Haze SIPs were developed. The emissions reductions achieved in North Dakota are expected to benefit surrounding states in meeting their Reasonable Progress goals.

Table 2.2
North Dakota
Species Contribution (%)
20% Worst Days
2000-2004

Class I Areas	Sulfate	Nitrate	OC	EC	PMF	PMC	Sea Salt
TRNP	21	19	12	29	44	45	0
LWA	18	13	23	35	28	32	0
Badlands	8	10	2	4	3	3	0
Wind Cave	8	8	1	2	4	3	0
U.L. Bend		5	1	1	1	1	0
Medicine Lake	11	7	0	15	17	16	0
Gates of the Mountains	<1	<1	<1	<1	<1	<1	0
North Absaroka	1	1	<1	<1	<1	<1	0
Voyageurs	6	9	3*	6*	15*	22*	0
Boundary Waters*	3	10	2	4	10	7	0
Isle Royale&*	2	4	1	2	6	6	0
Seney*	1	3	<1	<1	2	4	0

Based on WRAP's tracer analyses (SO_4 and NO_3) and weighted emissions potential (WEP) analyses unless otherwise noted.

* Based on CENRAP data.

Several sources have made progress toward achieving the BART limits in North Dakota. The M.R. Young Station is now in compliance with the BART SO_2, NO_x and PM limits. New wet scrubbers have been installed at the Leland Olds Station to control SO_2 and overfire air modifications at Unit 2 have reduced NO_x emissions. In addition, overfire air modifications at Coal Creek Station Unit 2 have reduced NO_x emissions. Modifications to the SO_2 scrubbers and stacks are being tested. Testing of various sorbents for SO_2 control at Stanton Station Unit 1 has been conducted. At the Antelope Valley Station, engineering and procurement efforts have started for the overfire air systems to be installed. Installation dates of 2014 for Unit 1 and 2015 for Unit 2 expected. At the Coyote Station, engineering design is just beginning on the overfire air system. At the Heskett Station, Montana Dakota Utilities expects to complete engineering design and procurement of equipment for the limestone injection system in 2015. Installation of the equipment will begin in 2016 with final compliance with the SIP limits in early 2017.

Table 2.3
BART/Reasonable Progress Status

Source	Unit	Pollutant	Applicable Requirement	BART/RP[1] Limit	Current[4] Emission Rate	Date Implemented
Antelope Valley	1	NO_x	RP (FIP)	0.17 lb/10^6 Btu	0.34 lb/10^6 Btu	
Antelope Valley	2	NO_x	RP (FIP)	0.17 lb/10^6 Btu	0.32 lb/10^6 Btu	
Leland Olds	1	SO_2 NO_x PM	BART BART BART	0.15 lb/10^6 Btu[2] 0.19 lb/10^6 Btu 0.07 lb/10^6 Btu	0.062 lb/10^6 Btu 0.23 lb/10^6 Btu 0.018 lb/10^6 Btu	6/13
Leland Olds	2	SO_2 NO_x PM	BART BART BART	0.15 lb/10^6 Btu[2] 0.35 lb/10^6 Btu 0.07 lb/10^6 Btu	0.058 lb/10^6 Btu 0.32 lb/10^6 Btu 0.019 lb/10^6 Btu	10/12
M.R. Young	1	SO_2 NO_x PM	BART BART BART	95% reduction 0.36 lb/10^6 Btu 0.03 lb/10^6 Btu	98% reduction (0.042 lb/10^6 Btu) 0.33 lb/10^6 Btu 0.010 lb/10^6 Btu	12/11 12/11 12/11
M.R. Young	2	SO_2 NO_x PM	BART BART BART	95% reduction[3] 0.35 lb/10^6 Btu 0.03 lb/10^6 Btu	0.113 lb/10^6 Btu and 94% reduction 0.33 lb/10^6 Btu 0.012 lb/10^6 Btu	12/10 12/10 12/10
Coyote		NO_x	RP	0.50 lb/10^6 Btu	0.70 lb/10^6 Btu	
Stanton	1	SO_2 NO_x PM	BART BART BART	0.16 lb/10^6 Btu 0.23 lb/10^6 Btu 0.07 lb/10^6 Btu	0.50 lb/10^6 Btu 0.23 lb/10^6 Btu 0.014 lb/10^6 Btu	
Coal Creek	1	SO_2 NO_x PM	BART BART BART	0.15 lb/10^6 Btu[2] 0.17 lb/10^6 Btu 0.07 lb/10^6 Btu	0.34 lb/10^6 Btu 0.19 lb/10^6 Btu 0.010 lb/10^6 Btu	
Coal Creek	2	SO_2 NO_x PM	BART BART BART	0.15 lb/10^6 Btu[2] 0.17 lb/10^6 Btu 0.07 lb/10^6 Btu	0.33 lb/10^6 Btu 0.15 lb/10^6 Btu 0.002 lb/10^6 Btu	
R.M. Heskett	2	SO_2	RP	0.60 lb/10^6 Btu	0.89 lb/10^6 Btu	

1 Based on a 30-day rolling average unless otherwise noted.
2 As an alternative, the source may comply with a 95% reduction requirement.
3 As an alternative, Minnkota may comply with an alternative limit of 0.15 lb/10^6 and 90% reduction.
4 Based on annual average emission rate for 2013 except for Leland Olds Unit 1 SO_2 which is based on the 4th Quarter of 2013.

The BART control requirements are to be implemented as expeditiously as possible but no later than five years after EPA approved the SIP (May 7, 2012). Therefore, different compliance dates will apply for different sources and different pollutants.

The BART limits for the M.R. Young Station Unit 1 have been included in the Title V Permit to Operate and were effective on January 1, 2012. The limits for Unit 2 were effective on January 1, 2011 except for SO_2. The BART limit for SO_2 for Unit 2 became effective February 20, 2013. The SO_2 BART limits for Leland Olds Station Unit 1 and 2 became effective on January 1, 2014.

2.1.2 Federal Programs

Heavy Duty Diesel Engine Standard (40 CFR 86, Subpart P)

This regulation, which took effect in 2007, established particulate matter, NO_x and non-methane hydrocarbon standards for new heavy duty diesel engines. The NO_x and non-methane hydrocarbon standards were phased in between 2007 and 2010. The rule also required that the sulfur in highway diesel fuel be reduced to 15 ppm (ultra-low sulfur diesel fuel). This amounted to a 97% reduction in the sulfur content. The requirements of the rule were implemented within the time frames established by the rule.

Tier 2 Tailpipe Standards (40 CFR 80, Subpart H; 40 CFR 85; 40 CFR 86)

The Tier 2 standards became effective in the 2005 model year. The rule establishes NO_x emission limits for new on-road vehicles. The Tier 2 program allows manufacturers to average NO_x emissions across their fleet in order to comply with the standard. The program has been implemented as required.

Nonroad Diesel Rule (40 CFR 89)

This rule sets standards that reduce emissions from nonroad diesel equipment including NO_x, hydrocarbons and carbon monoxide. Equipment covered by this rule includes industrial spark-ignition engines, recreational nonroad vehicles and a variety of farm and industrial equipment. These rules were effective in 2004 and fully phased in by 2012.

The nonroad diesel rule also establishes limits on the sulfur content on nonroad diesel fuel. Beginning in 2007, the rule reduced sulfur levels by 99% from previous levels. The reduction in fuel sulfur content applied to most nonroad diesel fuel in 2010 and applied to fuel used in locomotives and marine vessels starting in 2012.

Industrial Boiler MACT (40 CFR 63, Subparts JJJJJJ and DDDDD)

EPA has issued final rules for the control of emissions from industrial boilers. The final rules address emissions of particulate matter and carbon monoxide as well as hazardous air pollutants mercury and hydrogen chloride. The side benefit of the control of hydrogen chloride will be the control of sulfur dioxide emissions. For new or reconstructed facilities, the compliance date is January 31, 2013. For existing facilities, the compliance dates are generally March 21, 2014 and January 31, 2016. The NDDH is in the process of adopting both subparts. However, for the area sources subject to Subpart JJJJJJ, the NDDH will only be adopting the requirements for boilers rated at 10×10^6 Btu/hr or more.

NSPS and MACT Standards for Combustion Turbines and Internal Combustion Engines (40 CFR 60, Subparts III, JJJJ and KKKK; 40 CFR 63, Subpart YYYY)

These regulations are in effect and will primarily limit emissions of NO_x from new engines and turbines. Although the MACT standard in 40 CFR 63, Subpart YYYY limits formaldehyde emissions, the co-benefit of reducing NO_x emissions can be realized with emission controls for formaldehyde.

VOC MACT Standards

Various MACT standards have been promulgated by EPA that will limit or reduce volatile organic compound emissions as well as other visibility impairing pollutants. Table 2.3 provides a listing of MACT standards for source categories where controls are to be installed after 2002.

Table 2.4
MACT Standards

Source Category	**Subpart**	**Date Promulgated**	**Existing Source Compliance Date**	**Pollutants Affected**
Hazardous Waste Combustion (Phase I)	Parts 63 (EEE), 261 and 270	9/30/99	9/30/03	PM
Oil & Natural Gas Production	HH	6/17/99	6/17/02	VOC
Polymers and Resins III	OOO	1/20/00	1/20/03	VOC
Portland Cement Manufacturing	LLL	6/14/99	6/10/02	PM
Publically Owned Treatment Works (POTW)	VVV	10/26/99	10/26/02	VOC
Secondary Aluminum Production	RRR	3/23/00	3/24/03	PM
Combustion Sources at Kraft, Soda and Sulfate Pulp & Paper Mills (Pulp and Paper MACT II)	MM	1/21/01	1/12/04	VOC
Municipal Solid Waste Landfills	AAAA	1/16/03	1/16/04	VOC
Coke Ovens	L	10/27/93	Phased from 1995-2010	VOC
Coke Ovens: Pushing, Quenching and Battery Stacks	CCCCC	4/14/03	4/14/06	VOC
Asphalt Roofing Manufacturing and Asphalt Processing (two source categories)	LLLLL	4/29/03	5/1/06	VOC
Metal Furniture (Surface Coating)	RRRR	5/23/03	5/23/06	VOC
Printing, Coating and Dyeing of Fabrics	OOOO	5/29/03	5/29/06	VOC
Wood Building Products (Surface Coating)	QQQQ	5/28/03	5/28/06	VOC
Lime Manufacturing	AAAAA	1/5/04	1/5/07	PM, SO_2
Site Remediation TSDF	GGGGG	10/8/03	10/8/06	VOC
Iron & Steel Foundries	EEEEE	4/22/04	4/23/07	VOC
Taconite Iron Ore Processing	RRRRR	10/30/03	10/30/06	PM, SO_2
Miscellaneous Coating Manufacturing	HHHHH	12/11/03	12/11/06	VOC
Metal Can (Surface Coating)	KKKK	11/13/03	11/13/06	VOC
Plastic Parts and Products (Surface Coating)	PPPP	4/19/04	4/19/07	VOC
Miscellaneous Metal Parts and Products (Surface Coating)	MMMM	1/2/04	1/2/07	VOC
Industrial, Commercial and Institutional Boilers and Process Heaters for Major Sources	DDDDD	1/31/13	1/31/16	PM, SO_2

Source Category	Subpart	Date Promulgated	Existing Source Compliance Date	Pollutants Affected
Industrial, Commercial and Institutional Boilers and Process Heaters for Area Sources	JJJJJ	2/1/13	3/2/14	PM, SO_2
Plywood and Composite Wood Products	DDDD	7/30/04	10/1/07	VOC
Reciprocating Internal Combustion Engines	ZZZZ	6/15/04	6/15/07	NO_x, VOC
Auto and Light-Duty Truck (Surface Coating)	IIII	4/26/04	4/26/07	VOC
Wet Formed Fiberglass Mat Production	HHHH	4/11/02	4/11/05	VOC
Metal Coil (Surface Coating)	SSSS	6/10/02	6/10/05	VOC
Paper and Other Web Coating (Surface Coating)	JJJJ	12/4/02	12/4/05	VOC
Petroleum Refineries	UUU	4/11/02	4/11/05	VOC
Miscellaneous Organic Chemical Production (MON)	FFFF	11/10/03	05/10/08	VOC

2.2 Emissions Reductions from Regional Haze SIP Strategies (40 CFR 51.308(g)(2))

The Regional Haze rules require that a summary of emissions reductions achieved throughout the State through implementation of the control measures in the SIP be included in the periodic report.

Since the baseline period (2000-2004), significant reductions of sulfur dioxide, nitrogen oxides and ammonia emissions have occurred in North Dakota. The reductions can be attributed to reductions in both the point and mobile source categories. Implementation of new controls at electric generating units (EGUs) and new Federal requirements for on and off-road engines are the main reasons for the reductions. Table 2.5 shows the results of emission inventories for WRAP's 2002 Plan 02d, WRAP's 2008 West Jump project and the 2011 National Emissions Inventory (NEI). With any inventory, a change in estimation methodology or emission factors can greatly change the results. However, as shown in Table 2.5, the emission reductions at the EGUs, as measured by continuous emission monitors, are real.

Table 2.5
North Dakota Emissions
(tons)

Pollutant	2002	2008	2011	Change (2002-2011)	
				tons	%
SO_2	176,211	143,509	108,719	-67,492	-38
NO_x	229,536	164,255	178,348	-51,188	-22
OC	8,840	5,485	ND	---	---
EC	4,847	4,161	ND	---	---
PMF	61,519	60,668	89,198	+27,679	+45
PMC	360,936	353,087	273,232	-87,704	-24
NH_3	120,493	86,164	101,513	-18,980	-16
VOC	334,020	179,957	437,053	+103,033	+31

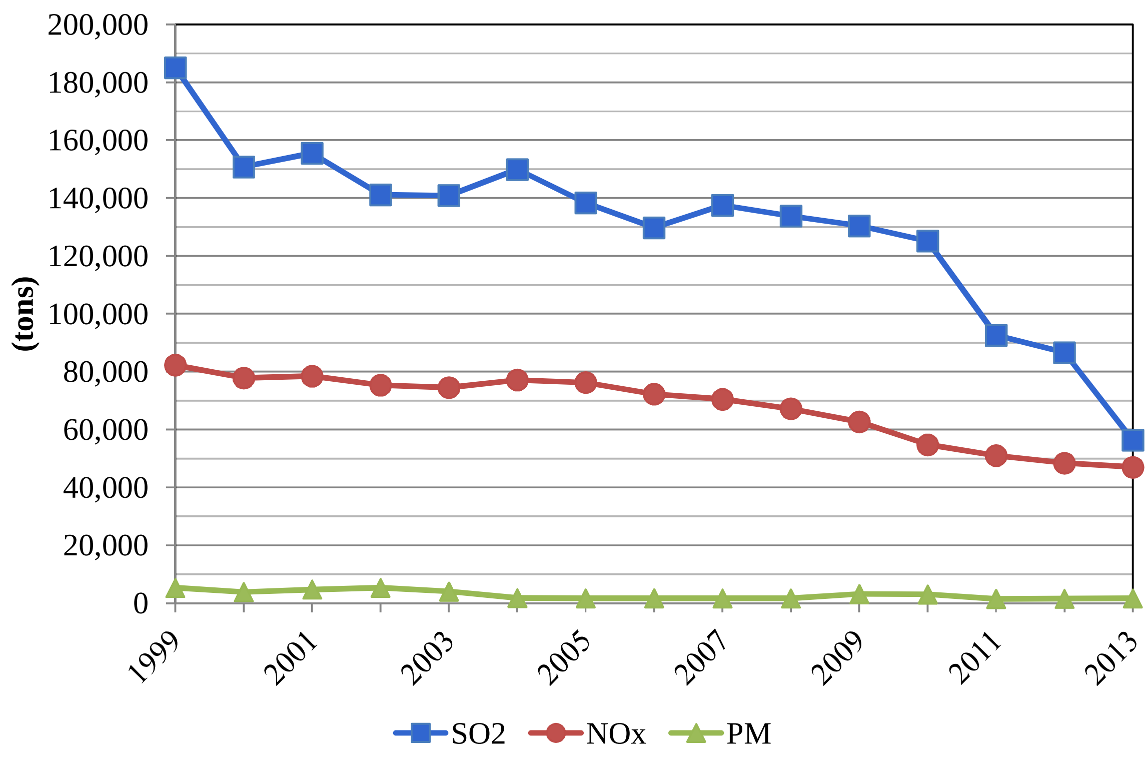
ND = no data

The increase in fine particulate mass (PMF) was primarily due to fire emissions which account for 85% of the increase. The rest of the increase was due to on-road and off-road mobile sources which were not estimated in the 2002 inventory. The increase in VOC emissions is due primarily to increases in fire, area oil and gas, and biogenic sources.

Table 2.6
North Dakota
EGU Emissions
(tons)

Pollutant	2002	2008	2013	Change (2002-2013)	
				tons	%
SO_2	141,158	133,796	56,344	-84,814	-60
NO_x	75,362	67,380	46,994	-28,368	-38
PM	5,368	1,661	1,727	-3,641	-68

Figure 2.1
North Dakota
Utility Boilers Emissions



For the sources that are subject to BART or reasonable progress requirements in the SIP, the change in emissions is as follows:

Table 2.7
BART & RP Sources
Emission Changes

Source	Unit	Pollutant	2002 Emissions (tons)	2013 Emissions (tons)	Change (tons)
Antelope Valley	1	NO_x	5,780	6,150	370
Antelope Valley	2	NO_x	5,827	5,267	-560
Leland Olds	1	SO_2	16,655	6,732	-9,923
		NO_x	2,578	1,669	-909
		PM	184	129	-55
Leland Olds	2	SO_2	30,744	890	-29,854
		NO_x	11,068	4,823	-6,245
		PM	499	283	-216
M.R. Young	1	SO_2	19,858	397	-19,461
		NO_x	8,459	3,122	-5,337
		PM	205	91	-114
M.R. Young	2	SO_2	8,707	1,498	-7,209
		NO_x	14,278	4,419	-9,859
		PM	385	158	-227
R.M. Heskett	2	SO_2	2,189	1,842	-347
Coyote		NO_x	13,039	10,914	-2,125
Stanton	1	SO_2	8,900	1,931	-6,969
		NO_x	2,312	895	-1,417
		PM	70	54	-16
Coal Creek	1	SO_2	11,910	8,242	-3,668
		NO_x	4,690	4,693	3
		PM	1,305	233	-1,072
Coal Creek	2	SO_2	12,518	7,340	-5,178
		NO_x	5,454	3,320	-2,134
		PM	1,268	42	-1,226
Totals		SO_2			-82,609
		NO_x			-28,213
		PM			-2,926

WRAP has prepared a detailed analysis of emission changes through 2008. That analysis, which is included in Appendix A, provides detailed statistics for the 2008 values found in Tables 2.4 and 2.5.

2.3 Visibility Progress (40 CFR 51.308(g)(3))

To satisfy the requirements of 40 CFR 51.308(g)(3), a state must assess the following visibility conditions and changes, which values for most impaired and least impaired days expressed in terms of 5-years average of the annual values, for each mandatory Class I Federal area within the State:

- The current visibility conditions for the most impaired and least impaired days,
- The difference between current visibility for the most impaired days and least impaired days and baseline conditions; and
- The change in visibility impairment for the most impaired and least impaired days over the past 5 years.

To assess current visibility conditions, IMPROVE data was reviewed from 2005 through 2012 (see Table 2.7). From the data, five year rolling averages (in deciviews) were calculated for both the least impaired days and the most impaired days (see Figures 2.2-2.5). In addition, detailed data regarding the various species that cause visibility impairment was mined from WRAP's "North Dakota Class I Area Monitoring Data Summary Tables and Charts" (see Appendix B) and supplemented with data for 2010, 2011 and 2012 (see Tables 2.8, 2.9a and 2.9b). Details regarding the contribution of various particulate species to light extension in the Class I area are shown in Figures 2.6 to 2.9.

Table 2.8
Visibility Conditions
(Deciviews)

Year	Class I Area	20% Least Impaired Days (Annual Avg.)	20% Least Impaired Days (5-Yr. Rolling Avg.)	20% Most Impaired Days (Annual Avg.)	20% Most Impaired Days (5-Yr. Rolling Avg.)
2000	TRNP	8.2		18.1	
	LWA	9.1		19.7	
2001	TRNP	7.8		18.0	
	LWA	8.2		20.6	
2002	TRNP	7.8		17.0	
	LWA	7.9		18.8	
2003	TRNP	7.5		18.4	
	LWA	7.9		18.6	
2004	TRNP	7.5	7.8	17.5	17.8
	LWA	7.9	8.2	20.2	19.6
2005	TRNP	6.8	7.5	17.6	17.7
	LWA	7.6	7.9	20.5	19.7
2006	TRNP	6.5	7.2	17.9	17.7
	LWA	7.8	7.8	19.6	19.5
2007	TRNP	*		*	
	LWA	8.8	8.0	19.1	19.6
2008	TRNP	6.6	7.0	17.6	17.8
	LWA	8.2	8.1	19.7	19.8
2009	TRNP	7.0	6.9	17.2	17.6
	LWA	8.4	8.2	18.9	19.6
2010	TRNP	6.3	6.6	18.8	17.8

Year	Class I Area	20% Least Impaired Days (Annual Avg.)	20% Least Impaired Days (5-Yr. Rolling Avg.)	20% Most Impaired Days (Annual Avg.)	20% Most Impaired Days (5-Yr. Rolling Avg.)
	LWA	7.4	8.1	21.3	19.7
2011	TRNP	5.7	6.4	16.4	17.6
	LWA	*	*	*	*
2012	TRNP	6.0	6.3	16.2	17.2
	LWA	*	*	*	*

* Data does not meet completeness criteria. Using the data substitution protocol developed by WRAP, the results for LWA are as follows:

2011	LWA	7.6	8.1	18.4	19.5
2012	LWA	7.6	7.8	19.4	19.5

Figure 2.2
TRNP
20% Most impaired Days

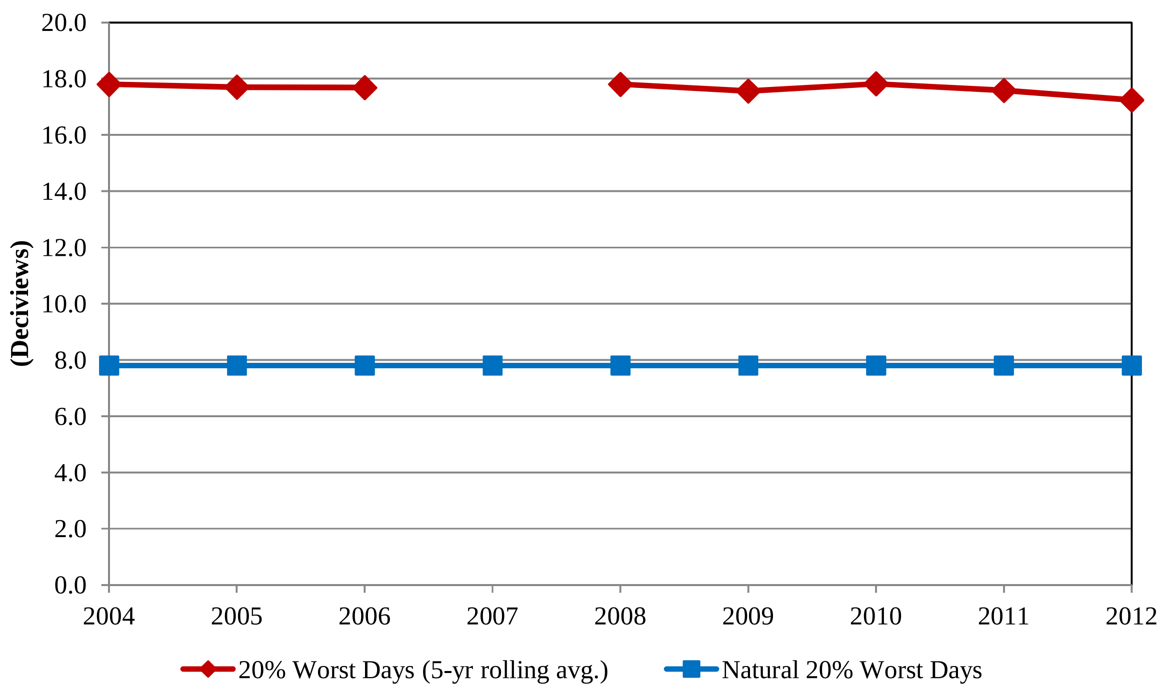


Figure 2.3
TRNP
20% Least Impaired Days

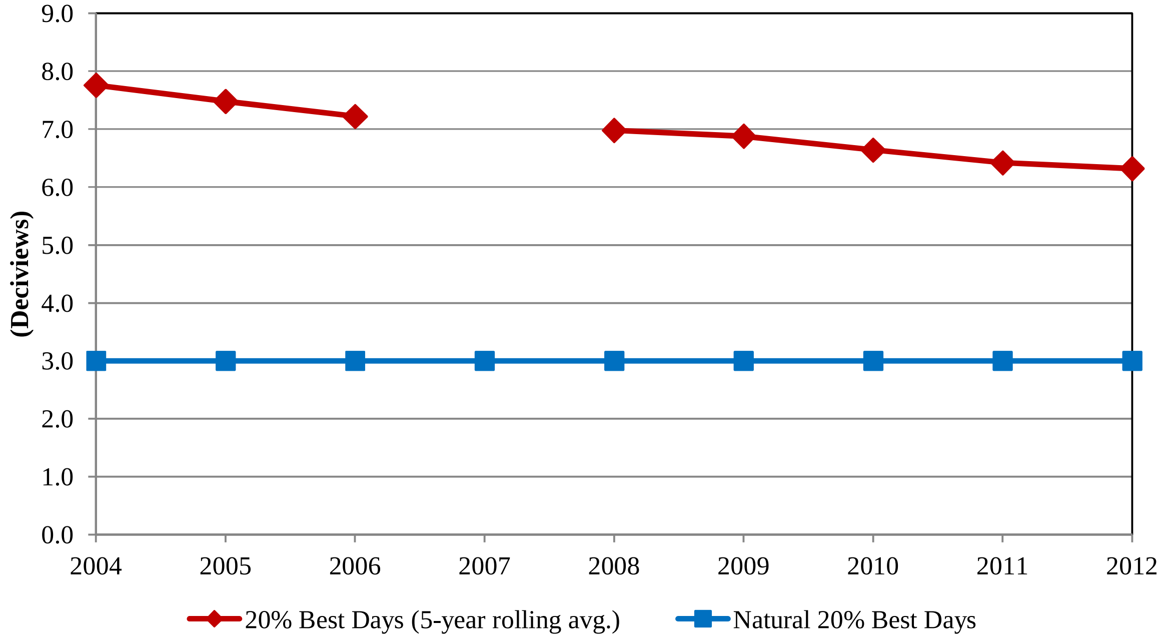


Figure 2.4
Lostwood Wilderness Area
20% Most Impaired Days

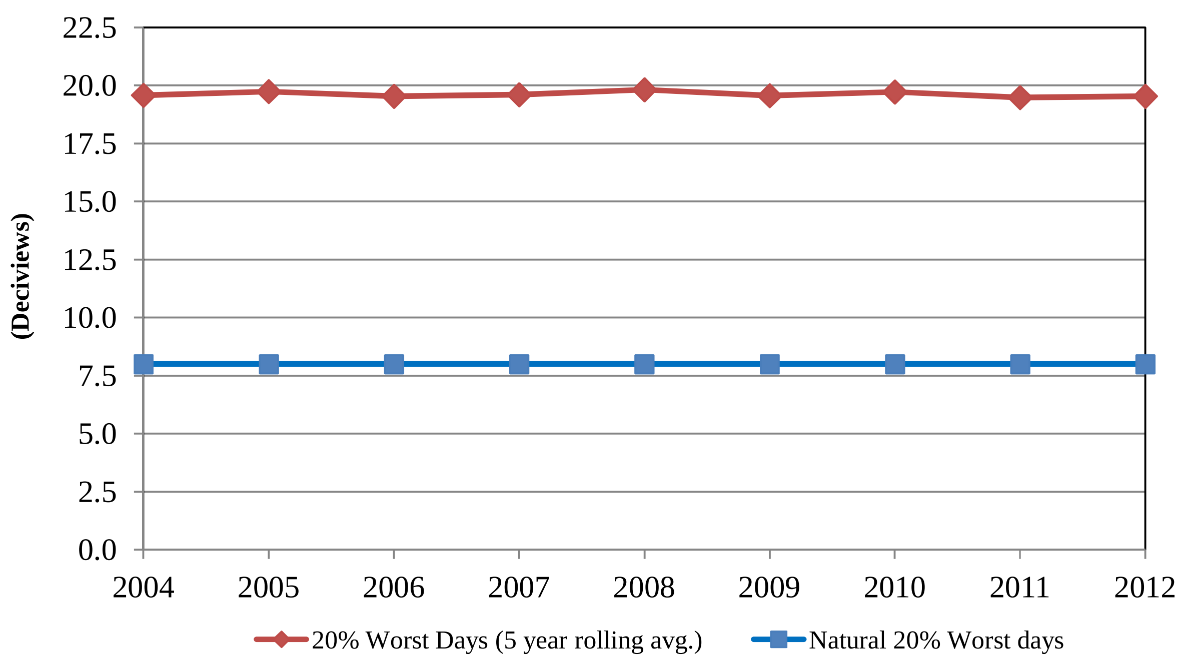


Figure 2.5
Lostwood Wilderness Area
20% Least Impaired Days

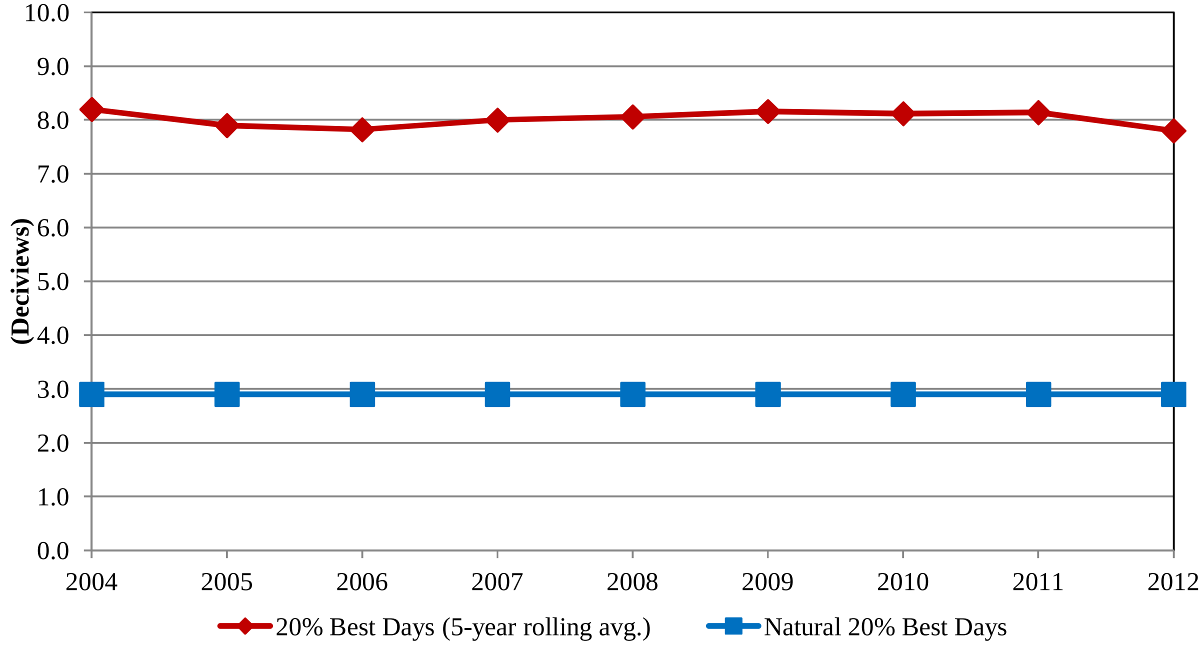


Table 2.9
Theodore Roosevelt NP
Annual Averages, Period Averages and Trends

	Baseline Period					Progress Period								Trend 2000-2009 Statistics*		Period Averages**			Baseline avg. vs. 2005 to 2009 avg.		Baseline avg. vs. 2008 to 2012 avg.	
Group	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Slope		Baseline	Progress	2008-2012	Difference	Percent	Difference	Percent
														(change/yr.)	p-value	(B)	(P)	(EP)	(P -B)	Change	(EP-B)	Change
Deciview (dv)																						
Best 20% Days	8.2	7.8	7.8	7.5	7.5	6.8	6.5	---	6.6	7.0	6.3	5.7	6.0	-0.2	0.0	7.8	6.7	6.3	-1.1	-14	-1.5	-19
Worst 20% Days	18.1	18.0	17.0	18.4	17.5	17.6	17.9	---	17.6	17.2	18.8	16.4	16.2	-0.1	0.1	17.8	17.6	17.2	-0.2	-1	-0.6	-3
All Days	12.8	12.5	11.9	12.5	11.9	11.9	12.1	---	12.0	11.6	12.1	10.9	10.9	-0.1	0.0	12.3	11.9	11.5	-0.4	-3	-0.8	-7
Total Extinction (Mm^{-1})																						
Best 20% Days	23.0	21.9	21.9	21.3	21.2	19.9	19.3	---	19.4	20.3	18.9	17.8	18.3	-0.4	0.0	21.9	19.7	18.9	-2.2	-10	-3.0	-14
Worst 20% Days	62.4	62.4	57.1	65.2	61.1	60.1	62.3	---	63.4	57.3	67.7	52.3	51.3	-0.2	0.3	61.6	60.8	58.4	-0.8	-1	-3.2	-5
All Days	38.3	37.7	35.3	37.9	35.5	35.5	36.6	---	36.7	34.4	37.3	31.9	31.8	-0.2	0.1	36.9	35.8	34.4	-1.1	-3	-2.5	-7
Ammonium Sulfate Extinction (Mm^{-1})																						
Best 20% Days	4.9	3.6	3.8	3.5	3.2	3.6	2.5	---	3.3	4.1	3.2	2.4	2.3	-0.1	0.1	3.8	3.4	3.1	-0.4	-11	-0.7	-19
Worst 20% Days	16.4	18.8	20.8	17.7	14.0	17.7	17.3	---	16.6	22.0	21.1	16.1	12.2	0.0	0.5	17.5	18.4	17.6	0.9	5	0.1	1
All Days	9.7	9.9	9.8	9.1	8.0	9.4	9.5	---	9.3	10.7	9.8	7.9	6.6	0.0	0.5	9.3	9.7	8.9	0.4	4	-0.4	-5
Ammonium Nitrate Extinction (Mm^{-1})																						
Best 20% Days	1.6	1.4	1.9	1.6	1.2	1.0	0.9	---	0.7	1.0	0.6	0.9	0.7	-0.1	0.0	1.5	0.9	0.8	-0.6	-40	-0.7	-48
Worst 20% Days	13.6	17.7	10.7	10.3	16.4	16.1	9.5	---	11.8	11.9	18.7	10.0	7.5	-0.3	0.2	13.7	12.3	12.0	-1.4	-10	-1.7	-13
All Days	5.3	6.1	5.1	5.3	5.6	4.9	4.2	---	4.9	4.6	6.4	3.8	3.5	-0.1	0.0	5.5	4.7	4.6	-0.8	-15	-0.9	-16
Particulate Organic Mass Extinction (Mm^{-1})																						
Best 20% Days	1.9	1.8	2.2	1.8	2.1	1.6	1.4	---	1.5	1.5	1.4	1.3	1.2	-0.1	0.0	2.0	1.5	1.4	-0.5	-25	-0.6	-31
Worst 20% Days	11.8	6.7	5.9	16.4	13.4	6.3	14.7	---	14.7	5.4	6.1	5.9	9.3	0.0	0.5	10.8	10.3	8.3	-0.5	-5	-2.5	-23
All Days	5.6	4.1	3.8	6.5	5.2	4.0	5.6	---	5.4	3.3	3.9	3.4	4.1	-0.1	0.3	5.0	4.6	4.0	-0.4	-8	-1.0	-20
Elemental Carbon Extinction (Mm^{-1})																						
Best 20% Days	1.2	0.8	0.8	0.9	0.9	1.0	1.1	---	0.7	0.6	0.7	0.6	0.8	0.0	0.2	0.9	0.9	0.7	0.0	0	-0.2	-24
Worst 20% Days	3.3	2.7	1.9	3.4	2.5	2.8	3.3	---	2.5	1.9	2.3	2.2	2.5	-0.1	0.2	2.7	2.6	2.3	-0.1	-4	-0.4	-16
All Days	2.1	1.7	1.4	1.9	1.5	1.9	1.9	---	1.5	1.2	1.5	1.4	1.5	-0.1	0.1	1.7	1.6	1.4	-0.1	-6	-0.3	-16
Soil Extinction (Mm^{-1})																						
Best 20% Days	0.3	0.5	0.4	0.3	0.4	0.3	0.3	---	0.3	0.3	0.3	0.1	0.3	0.0	0.0	0.4	0.3	0.3	-0.1	-25	-0.1	-35
Worst 20% Days	0.8	1.0	1.2	1.0	0.5	0.9	1.0	---	0.8	0.7	1.1	1.0	1.3	0.0	0.1	0.9	0.8	1.0	-0.1	-11	0.1	0
All Days	0.6	0.8	0.8	0.6	0.7	0.7	0.7	---	0.6	0.5	0.7	0.5	0.8	0.0	0.2	0.7	0.6	0.6	-0.1	-14	-0.1	-11
Coarse Mass Extinction (Mm-1)																						
Best 20% Days	2.1	2.7	1.7	2.1	2.4	1.3	1.9	---	1.8	1.8	1.7	1.4	2.0	0.0	0.1	2.2	1.7	1.7	-0.5	-23	-0.5	-21
Worst 20% Days	5.6	4.5	5.6	5.4	3.0	5.1	5.3	---	4.1	4.4	7.3	5.9	7.2	-0.1	0.1	4.8	4.7	5.8	-0.1	-2	1.0	20
All Days	4.0	4.0	3.3	3.4	3.4	3.5	3.6	---	3.4	3.0	3.9	3.7	4.3	-0.1	0.2	3.6	3.4	3.7	-0.2	-6	0.1	2
Sea Salt Extinction (Mm-1)																						
Best 20% Days	0.0	0.0	0.0	0.1	0.1	0.1	0.1	---	0.1	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.1		0.1	
Worst 20% Days	0.0	0.0	0.0	0.0	0.3	0.2	0.1	---	2.0	0.1	0.1	0.2	0.2	0.0	0.0	0.1	0.6	0.5	0.5	500	0.4	420
All Days	0.0	0.2	0.0	0.0	0.1	0.1	0.1	---	0.5	0.1	0.0	0.2	0.2	0.0	0.1	0.1	0.2	0.2	0.1	100	0.1	100

"---" Indicates a missing year that did not meet RHR data completeness criteria.

Table 2.10a
Lostwood Wilderness Area
Annual Averages, Period Averages and Trends

	Baseline Period					Progress Period								Trend 2000-2009 Statistics*		Period Averages**			Baseline Avg. vs. 2005-2009 Avg.		Baseline Avg. vs. 2006-2010 Avg.	
Group	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Slope		Baseline	Progress	2006-2010	Difference	Percent	Difference	Percent
														(change/yr.)	p-value	(B)	(P)	(EP)	(P -B)	Change	(EP -B)	Change
Deciview (dv)																						
Best 20% Days	9.1	8.2	7.9	7.9	7.9	7.6	7.8	8.8	8.2	8.4	7.4	---	---	0.0	0.5	8.2	8.1	8.1	-0.1	-1	-0.1	-1
Worst 20% Days	19.7	20.6	18.8	18.6	20.2	20.5	19.6	19.1	19.7	18.9	21.3	---	---	-0.1	0.3	19.6	19.6	19.7	0.0	0	0.1	1
All Days	14.1	14.0	13.0	13.1	13.0	13.2	13.3	13.3	13.9	13.3	13.8	---	---	0.0	0.4	13.4	13.4	13.5	0.0	0	0.1	1
Total Extinction (Mm^{-1})																						
Best 20% Days	25.0	22.8	22.2	22.2	22.2	21.6	22.2	24.3	23.0	23.4	21.2	---	---	0.0	0.5	22.9	22.9	22.8	0.0	0	-0.1	0
Worst 20% Days	75.3	80.2	67.6	65.6	81.7	78.9	74.8	69.3	74.5	70.0	86.5	---	---	-0.6	0.2	74.0	73.5	75.0	-0.5	-1	1.0	1
All Days	44.5	44.9	39.9	40.0	41.7	42.0	41.8	40.6	43.9	41.2	45.2	---	---	-0.1	0.4	42.2	41.9	42.5	-0.3	-1	0.3	1
Ammonium Sulfate Extinction (Mm^{-1})																						
Best 20% Days	5.3	4.7	3.8	3.9	4.3	4.7	4.0	5.4	4.4	5.2	4.4	---	---	0.1	0.3	4.4	4.8	4.7	0.4	9	0.3	6
Worst 20% Days	20.0	21.5	20.1	18.6	26.8	29.9	20.2	22.9	20.3	21.3	34.0	---	---	0.1	0.2	21.4	22.9	23.7	1.5	7	2.3	11
All Days	11.4	11.5	10.8	9.7	11.4	13.3	11.3	11.7	12.0	11.9	13.8	---	---	0.1	0.1	10.9	12.1	12.1	1.2	11	1.2	11
Ammonium Nitrate Extinction (Mm^{-1})																						
Best 20% Days	2.4	1.6	1.8	1.7	1.8	1.7	1.8	1.5	1.1	1.7	1.1	---	---	0.0	0.1	1.9	1.5	1.4	-0.4	-21	-0.5	-24
Worst 20% Days	16.0	29.3	23.3	19.4	26.7	19.0	21.4	20.0	21.9	26.3	23.7	---	---	0.4	0.4	22.9	21.7	22.7	-1.2	-5	-0.2	-1
All Days	6.7	9.8	8.4	7.8	8.6	7.1	7.6	7.4	8.6	9.1	8.6	---	---	0.1	0.4	8.3	7.9	8.3	-0.4	-5	0.0	0
Particulate Organic Mass Extinction (Mm^{-1})																						
Best 20% Days	2.9	1.9	2.0	2.5	2.0	1.6	2.0	2.1	2.2	1.8	1.3	---	---	0.0	0.2	2.3	1.9	1.9	-0.4	-17	-0.4	-18
Worst 20% Days	17.8	9.2	7.6	9.1	11.6	11.0	14.5	8.0	12.2	5.0	9.1	---	---	-0.4	0.3	11.1	10.1	9.8	-1.0	-9	-1.3	-12
All Days	8.7	5.5	4.7	5.9	5.3	5.1	6.1	4.8	5.7	3.6	5.1	---	---	-0.2	0.1	6.0	5.0	5.1	-1.0	-17	-0.9	-16
Elemental Carbon Extinction (Mm^{-1})																						
Best 20% Days	0.8	0.7	0.7	0.7	0.5	0.7	0.9	0.7	0.7	0.7	0.7	---	---	0.0	0.3	0.7	0.7	0.7	0.0	0	0.0	6
Worst 20% Days	4.5	2.8	2.3	2.4	2.2	3.2	2.8	2.1	2.5	2.0	2.8	---	---	-0.1	0.0	2.8	2.5	2.4	-0.3	-11	-0.4	-15
All Days	2.1	1.6	1.4	1.6	1.2	1.7	1.7	1.3	1.4	1.4	2.0	---	---	-0.1	0.1	1.6	1.5	1.6	-0.1	-6	0.0	-3
Soil Extinction (Mm^{-1})																						
Best 20% Days	0.3	0.4	0.4	0.3	0.3	0.2	0.3	0.4	0.3	0.4	0.3	---	---	0.0	0.3	0.3	0.3	0.3	0.0	0	0.0	0
Worst 20% Days	0.9	0.7	0.5	0.6	0.4	0.5	0.6	0.6	0.7	0.7	1.1	---	---	0.0	0.4	0.6	0.6	0.7	0.0	0	0.1	23
All Days	0.6	0.7	0.5	0.5	0.5	0.4	0.5	0.5	0.6	0.6	0.7	---	---	0.0	0.5	0.6	0.5	0.6	-0.1	-17	0.0	-3
Coarse Mass Extinction (Mm^{-1})																						
Best 20% Days	2.2	2.5	2.4	2.2	2.2	1.6	2.1	3.1	3.1	2.5	2.2	---	---	0.0	0.2	2.3	2.5	2.6	0.2	9	0.3	13
Worst 20% Days	5.2	4.7	2.6	4.3	2.7	4.1	4.2	4.4	3.9	3.5	4.6	---	---	-0.1	0.2	3.9	4.0	4.1	0.1	3	0.2	6
All Days	3.9	4.5	3.0	3.4	3.6	3.2	3.5	3.7	3.8	3.4	3.8	---	---	0.0	0.4	3.7	3.5	3.6	-0.2	-5	-0.1	-2
Sea Salt Extinction (Mm^{-1})																						
Best 20% Days	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.0	---	---	0.0	0.0	0.0	0.1	0.1	0.1		0.1	
Worst 20% Days	0.0	0.9	0.1	0.0	0.3	0.2	0.2	0.2	2.1	0.1	0.0	---	---	0.0	0.2	0.3	0.6	0.5	0.3	100	0.2	73
All Days	0.2	0.3	0.1	0.0	0.2	0.2	0.2	0.2	0.7	0.3	0.1	---	---	0.0	0.0	0.1	0.3	0.3	0.2	200	0.2	200

"---" Indicates a missing year that did not meet RHR data completeness criteria.

Table 2.10b
Lostwood Wilderness Area
Annual Average, Period Averages and Trends

	Baseline Period					Progress Period								Trend 2000-2009 Statistics*		Period Averages**			Baseline Avg. vs. 2005-2009 Avg.		Baseline Avg. vs. 2008-2012 Avg.	
Group	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Slope		Baseline	Progress	2008-2012	Difference	Percent	Difference	Percent
														(change/yr.)	p-value	(B)	(P)	(EP)	(P -B)	Change	(EP -B)	Change
Deciview (dv)																						
Best 20% Days	9.1	8.2	7.9	7.9	7.9	7.6	7.8	8.8	8.2	8.4	7.6	7.9	7.6	0.0	0.5	8.2	8.1	7.9	-0.1	-1	-0.3	-3
Worst 20% Days	19.7	20.6	18.8	18.6	20.2	20.5	19.6	19.1	19.7	18.9	18.4	18.7	19.4	-0.1	0.3	19.6	19.6	19.0	0.0	0	-0.6	-3
All Days	14.1	14.0	13.0	13.1	13.0	13.2	13.3	13.3	13.9	13.3	12.6	13.0	13.1	0.0	0.4	13.4	13.4	13.2	0.0	0	-0.2	1
Total Extinction (Mm^{-1})																						
Best 20% Days	25.0	22.8	22.2	22.2	22.2	21.6	22.2	24.3	23.0	23.4	21.2	21.5	21.5	0.0	0.5	22.9	22.9	22.1	0.0	0	-0.8	-3
Worst 20% Days	75.3	80.2	67.6	65.6	81.7	78.9	74.8	69.3	74.5	70.0	86.3	63.9	74.8	-0.6	0.2	74.0	73.5	73.9	-0.5	-1	-0.1	0
All Days	44.5	44.9	39.9	40.0	41.7	42.0	41.8	40.6	43.9	41.2	45.2	38.1	41.3	-0.1	0.4	42.2	41.9	41.9	-0.3	-1	-0.3	-1
Ammonium Sulfate Extinction (Mm^{-1})																						
Best 20% Days	5.3	4.7	3.8	3.9	4.3	4.7	4.0	5.4	4.4	5.2	4.4	4.2	3.4	0.1	0.3	4.4	4.8	4.3	0.4	9	-0.1	-2
Worst 20% Days	20.0	21.5	20.1	18.6	26.8	29.9	20.2	22.9	20.3	21.3	34.0	17.9	19.0	0.1	0.2	21.4	22.9	22.5	1.5	7	1.1	5
All Days	11.4	11.5	10.8	9.7	11.4	13.3	11.3	11.7	12.0	11.9	13.8	9.1	9.1	0.1	0.1	10.9	12.1	11.2	1.2	11	0.3	3
Ammonium Nitrate Extinction (Mm^{-1})																						
Best 20% Days	2.4	1.6	1.8	1.7	1.8	1.7	1.8	1.5	1.1	1.7	1.1	1.9	1.5	0.0	0.1	1.9	1.5	1.5	-0.4	-21	-0.4	-23
Worst 20% Days	16.0	29.3	23.3	19.4	26.7	19.0	21.4	20.0	21.9	26.3	23.7	17.4	20.9	0.4	0.4	22.9	21.7	22.0	-1.2	-5	-0.9	-4
All Days	6.7	9.8	8.4	7.8	8.6	7.1	7.6	7.4	8.6	9.1	8.6	6.6	7.4	0.1	0.4	8.3	7.9	8.1	-0.4	-5	-0.2	-3
Particulate Organic Mass Extinction (Mm^{-1})																						
Best 20% Days	2.9	1.9	2.0	2.5	2.0	1.6	2.0	2.1	2.2	1.8	1.3	1.5	1.7	0.0	0.2	2.3	1.9	1.7	-0.4	-17	-0.6	-26
Worst 20% Days	17.8	9.2	7.6	9.1	11.6	11.0	14.5	8.0	12.2	5.0	9.1	6.2	6.5	-0.4	0.3	11.1	10.1	7.8	-1.0	-9	-3.3	-30
All Days	8.7	5.5	4.7	5.9	5.3	5.1	6.1	4.8	5.7	3.6	5.1	3.8	4.0	-0.2	0.1	6.0	5.0	4.4	-1.0	-17	-1.6	-26
Elemental Carbon Extinction (Mm^{-1})																						
Best 20% Days	0.8	0.7	0.7	0.7	0.5	0.7	0.9	0.7	0.7	0.7	0.7	0.9	0.9	0.0	0.3	0.7	0.7	0.8	0.0	0	0.1	11
Worst 20% Days	4.5	2.8	2.3	2.4	2.2	3.2	2.8	2.1	2.5	2.0	2.8	3.0	3.3	-0.1	0.0	2.8	2.5	2.7	-0.3	-11	-0.1	-3
All Days	2.1	1.6	1.4	1.6	1.2	1.7	1.7	1.3	1.4	1.4	2.0	1.9	2.1	-0.1	0.1	1.6	1.5	1.8	-0.1	-6	0.2	10
Soil Extinction (Mm^{-1})																						
Best 20% Days	0.3	0.4	0.4	0.3	0.3	0.2	0.3	0.4	0.3	0.4	0.3	0.2	0.4	0.0	0.3	0.3	0.3	0.3	0.0	0	0.0	0
Worst 20% Days	0.9	0.7	0.5	0.6	0.4	0.5	0.6	0.6	0.7	0.7	1.1	0.9	1.3	0.0	0.4	0.6	0.6	0.9	0.0	0	0.3	58
All Days	0.6	0.7	0.5	0.5	0.5	0.4	0.5	0.5	0.6	0.6	0.7	0.6	1.1	0.0	0.5	0.6	0.5	0.7	-0.1	-17	0.1	20
Coarse Mass Extinction (Mm^{-1})																						
Best 20% Days	2.2	2.5	2.4	2.2	2.2	1.6	2.1	3.1	3.1	2.5	2.2	1.7	2.6	0.0	0.2	2.3	2.5	2.4	0.2	9	0.1	5
Worst 20% Days	5.2	4.7	2.6	4.3	2.7	4.1	4.2	4.4	3.9	3.5	4.6	7.3	7.2	-0.1	0.2	3.9	4.0	5.3	0.1	3	1.4	36
All Days	3.9	4.5	3.0	3.4	3.6	3.2	3.5	3.7	3.8	3.4	3.8	4.6	5.4	0.0	0.4	3.7	3.5	4.2	-0.2	-5	0.5	14
Sea Salt Extinction (Mm^{-1})																						
Best 20% Days	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.2	0.1	0.0	0.0	0.0	0.1	0.1	0.1		0.1	
Worst 20% Days	0.0	0.9	0.1	0.0	0.3	0.2	0.2	0.2	2.1	0.1	0.0	0.3	0.2	0.0	0.2	0.3	0.6	0.5	0.3	100	0.2	80
All Days	0.2	0.3	0.1	0.0	0.2	0.2	0.2	0.2	0.7	0.3	0.1	0.4	0.2	0.0	0.0	0.1	0.3	0.3	0.2	200	0.2	240

Figure 2.6
TRNP Species Contribution
20% Worst Days

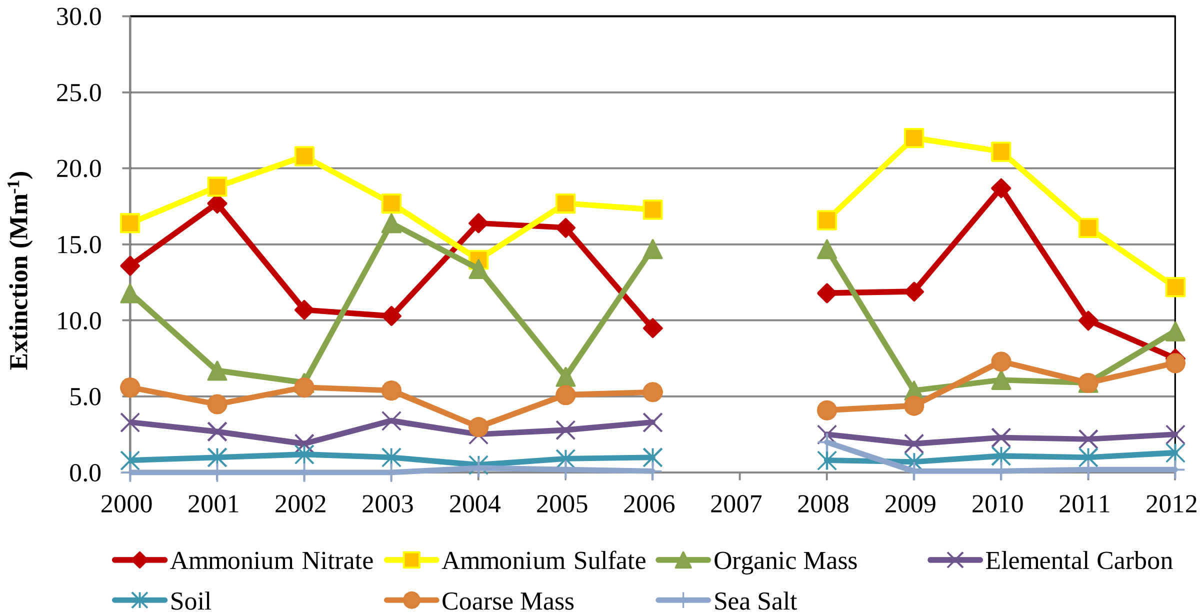


Figure 2.7
TRNP Species Contribution
20% Best Days

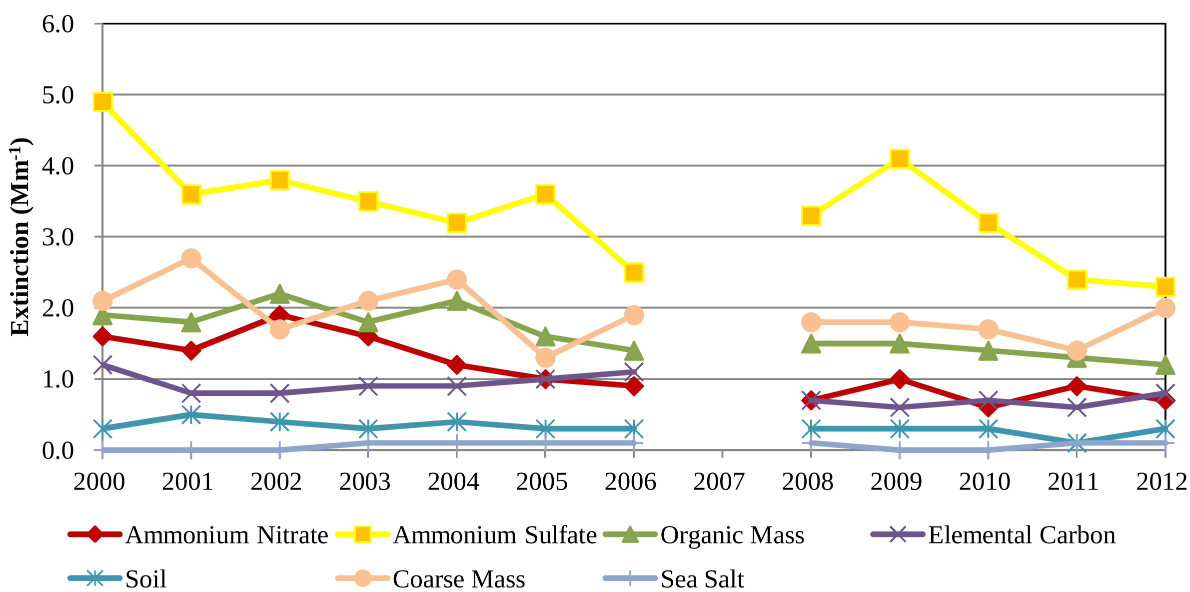


Figure 2.8
LWA Species Contribution
20% Worst Days

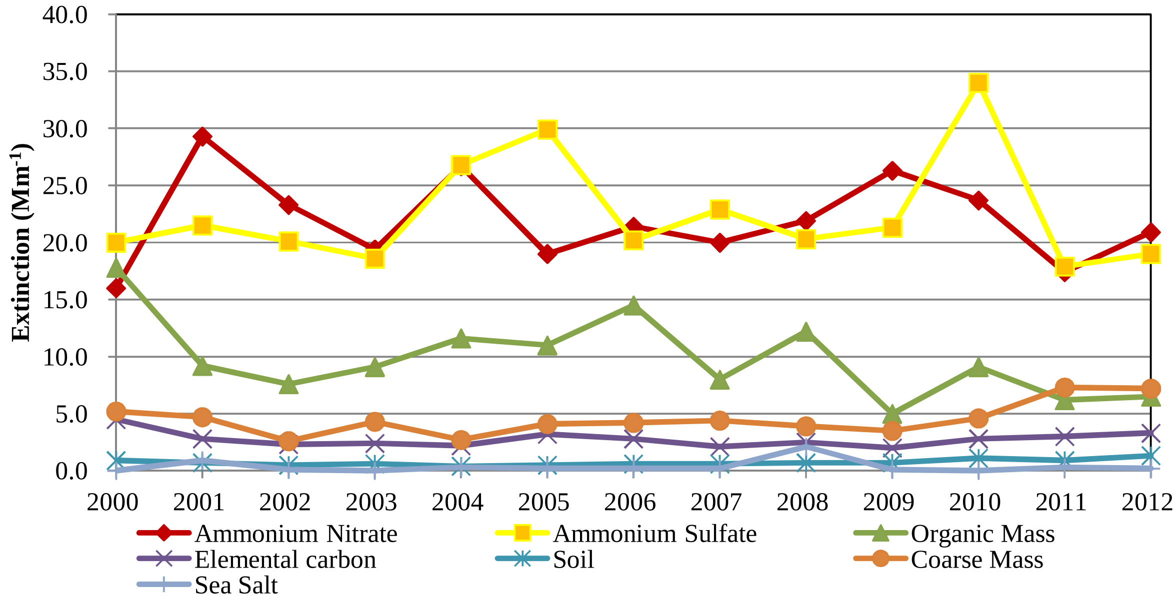
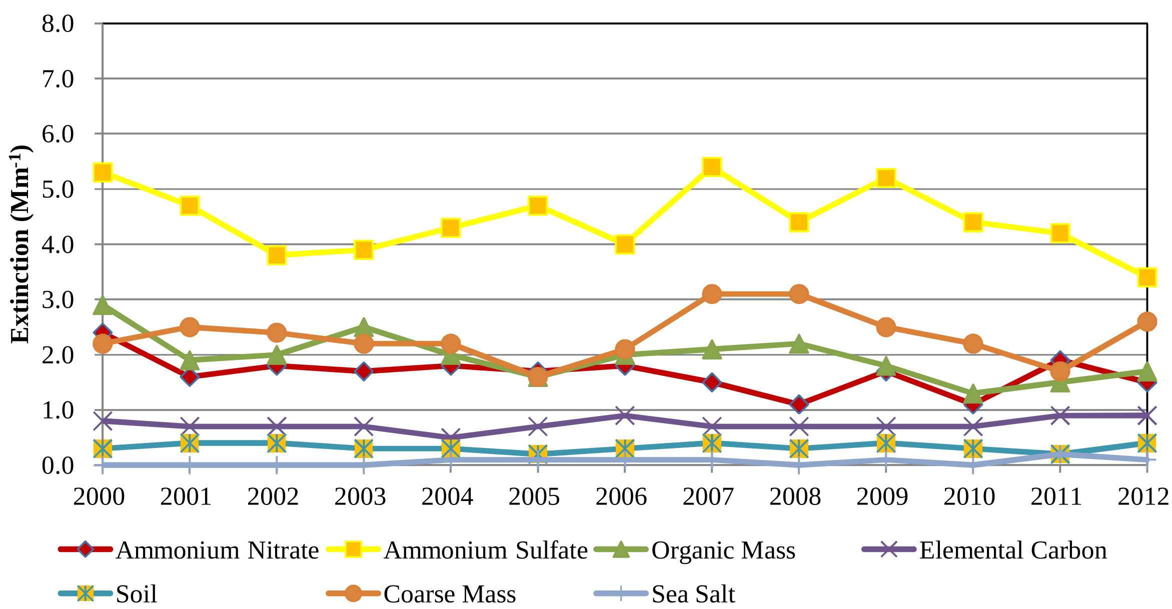


Figure 2.9
LWA Species Contribution
20% Best Days



For TRNP, 2008-2012 data was used to prepare the latest 5-year average visibility conditions. The data for TRNP indicates a slight change for the 20% most impaired days. Visibility impairment in the most impaired days, measured in deciviews for the average of the 2008-2012 period, decreased 3% from the baseline where as total extinction decreased 5%. The RH SIP identified sulfates and nitrates as the major contributors to visibility impairment in the Class I areas. Since the baseline period, sulfates during the most impaired days have increased slightly (1%) while nitrates have decreased 13%. For the 20% least impaired days, visibility impairment measured in deciviews decreased by 19% and total extinction decreased by 14%. All visibility impairing species, except sea salt, decreased during the 2008-2012 period for the least impaired days when compared against the baseline.

The data for LWA for 2011 and 2012 was incomplete. To better evaluate the visibility at LWA, data was substituted for 2011 and 2012 using the methodology in the WRAP IMPROVE data substitutions memo dated June 2011. Data from the nearby Medicine Lake IMPROVE site was used for the data substitution. Table 2.10b shows the results from the data substitution. At LWA, there was virtually no change in visibility impairment (on a deciview and total extinction basis) for the most impaired and best days for 2008-2012 period when compared to the baseline. For the most impaired days, there was an increase in sulfate, fine particulate, coarse particulate and sea salt extinction when compared to the baseline while nitrate, particulate organic mass, and elemental carbon extinction decreased. During the least impaired days for 2008-2012, elemental carbon and coarse particulate extinction increased while sulfate, nitrate and particulate organic mass extinction decreased.

2.4 Emissions Progress (40 CFR 51.308(g)(4))

This section of the Regional Haze rule requires each state to submit an analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source of activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the applicable 5-year period.

Tables 2.11, 2.12 and 2.13 provide emissions data for 2002, 2008 and 2011. The 2002 data is taken from the RH SIP (Table 6.1). The 2008 data is taken from WRAP's West Jump project which is based on the 2008 NEI. Since no data was included for oil and gas activity, data was taken from ENVIRON's Williston Basin emissions inventory for 2009.[2] The 2011 data is taken from EPA's 2011 NEI except for oil and gas sources. Because there are other more detailed oil and gas emissions inventories available than the 2011 NEI, the 2011 inventory from the Bureau of Land Management's (BLM) Resource Management Plan is provided in Table 2.15 and was utilized for Table 2.13 with the exception of SO_2. The BLM estimate of SO_2 appears to be excessive. The NEI data appears to be more accurate and was used. The BLM inventory indicates greater oil and gas emissions from North Dakota than the 2011 NEI.

An analysis of the difference between the 2002 and 2008 inventories is provided in Appendix A. Projected emissions for 2018 are shown in Table 2.14.

[2] Final Report; Development of Baseline 2009 Emissions From Oil and Gas Activity in the Williston Basin; ENVIRON International Corp.; Novata, CA; Western Energy Alliance; Denver, CO.

Table 2.11
North Dakota
2002 Emissions Inventory (tons)

	Point	All Fire	Biogenic	Area	Area O&G	On-Road Mobile	Off-Road Mobile	All Dust	Total
SO_2	157,069	540	0	5,557	4,958	812	7,246	29	176,211
NO_x	87,438	1,774	44,569	10,833	4,631	24,746	55,502	43	229,536
OC	262	3,657	0	1,466	0	231	1,034	2,190	8,840
EC	29	510	0	262	0	272	3,625	150	4,848
PMF	2,002	821	0	1,617	0	0	0	57,079	61,519
PMC	565	503	0	199	0	141	0	359,522	360,930
NH_3	518	812	0	118,398	0	732	33	0	120,493
VOC	2,086	3,849	233,561	60,455	7,740	12,814	13,515	0	334,020
Total	249,969	12,466	278,130	198,787	17,329	39,748	80,955	419,013	1,296,397

Table 2.12
North Dakota
2008 Emissions Inventory (tons)

	Point	All Fire	Biogenic	Area	Area O&G[1]	On-Road Mobile	Off-Road Mobile	All Dust	Total
SO_2	142,121	114	0	729	2,018	156	683	0	145,821
NO_X	78,252	901	9,133	16,719	10,743	23,180	34,572	0	173,500
OC	144	1,072	0	920	ND	680	794	1,874	5,484
EC	6	344	0	454	ND	994	2,337	25	4,160
PMF	122	434	0	413	405	98	54	57,932	59,458
PMC	651	207	0	99	413	1,102	109	350,919	353,500
NH_3	6,372	562	0	78,857	ND	345	29	0	86,165
VOC	3,877	1,726	118,195	21,194	307,408	10,928	11,892	0	475,220
Total	231,545	5,360	127,328	119,385	320,987	37,483	50,470	410,750	1,303,371

[1] Based on ENVIRON's "Final Report Development of Baseline 2009 Emissions from Oil and Gas Activity in the Williston Basin".

PMF and PMC emissions estimated from total PM emissions in the study and the 2011 NEI ratio.

ND = No Data

Table 2.13
North Dakota
2011 Emissions Inventory (tons)

	Point	All Fire	Biogenic	Area	Area O&G[1]	On-Road Mobile	Off-Road Mobile	All Dust	Total
SO_2	102,660	3,168	0	655	2,073	95	68	0	108,719
NO_X	61,266	7,245	32,938	18,149	25,277	21,193	31,183	0	197,251
OC	ND	ND	ND	ND	ND	ND	ND	ND	ND
EC	ND	ND	ND	ND	ND	ND	ND	ND	ND
PMF	4,006	24,243	0	1,821	859	886	2,738	55,228	89,781
PMC	1,419	8,609	0	146	16	219	95	262,739	273,243
NH_3	5,724	2,698	0	92,715	0	346	30	0	101,513
VOC	3,812	47,601	248,782	21,163	252,920	8,377	10,452	0	593,107
Total	178,887	93,564	281,720	134,649	281,145	31,116	44,566	311,205	1,363,614

ND = No data
[1] Based on the BLM Williston Basin Inventory except SO_2. NEI data was used for SO_2.

Table 2.14
North Dakota
2018 Projected Emissions (tons)

	Point	All Fire	Biogenic	Area	Area O&G [1]	On-Road Mobile	Off-Road Mobile	All Dust	Total
SO_2	59,160	337	0	5,995	6,541	81	276	33	72,423
NO_x	62,383	1,073	32,938	12,456	52,994	21,193	34,557	0	217,594
OC	248	2,647	0	1,387	ND	151	457	2,234	7,124
EC	32	449	0	267	ND	48	1,363	153	2,312
PMF	2,086	404	0	1,647	1,712	0	0	58,594	64,443
PMC	2,349	460	0	216	31	111	0	370,293	373,460
NH_3	462	379	0	118,493	875	739	47	0	120,995
VOC	2,418	2,346	233,561	69,597	369,875	3,487	8,357	0	689,641
CO	17,477	41,604	67,769	21,474	98,786	84,593	102,471	0	434,174
Total	146,615	49,699	334,268	231,532	530,814	110,403	147,528	431,307	1,982,166

[1] Based on the "Development of the 2015 Oil and Gas Emissions Projects for the Williston Basin" adjusted for an additional 2,000 wells per year except for SO_2.

2.5 Assessment of Changes Impeding Visibility Progress (40 CFR 51.308(g)(5))

This section of the RH rule requires "an assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility." The most obvious source category where emissions have increased is the oil and natural gas production sector. Beginning in 2008, development of the Bakken formation in North Dakota exploded. Figures 2.10 and 2.11 show the dramatic increase in oil and natural gas production from North Dakota wells. In January 2008 there were 3,662 producing wells. The number of producing wells increased to 5,067 in January 2011 and 9,248 in August 2013. With the increase in production, emissions increased not only from oil and gas well operations, but also from well development, local infrastructure development, increased traffic, transportation of the oil and natural gas, treatment of the gas, well maintenance, oil and condensate storage, and flaring of the natural gas when a pipeline is not available.

Figure 2.10
North Dakota
Oil Production

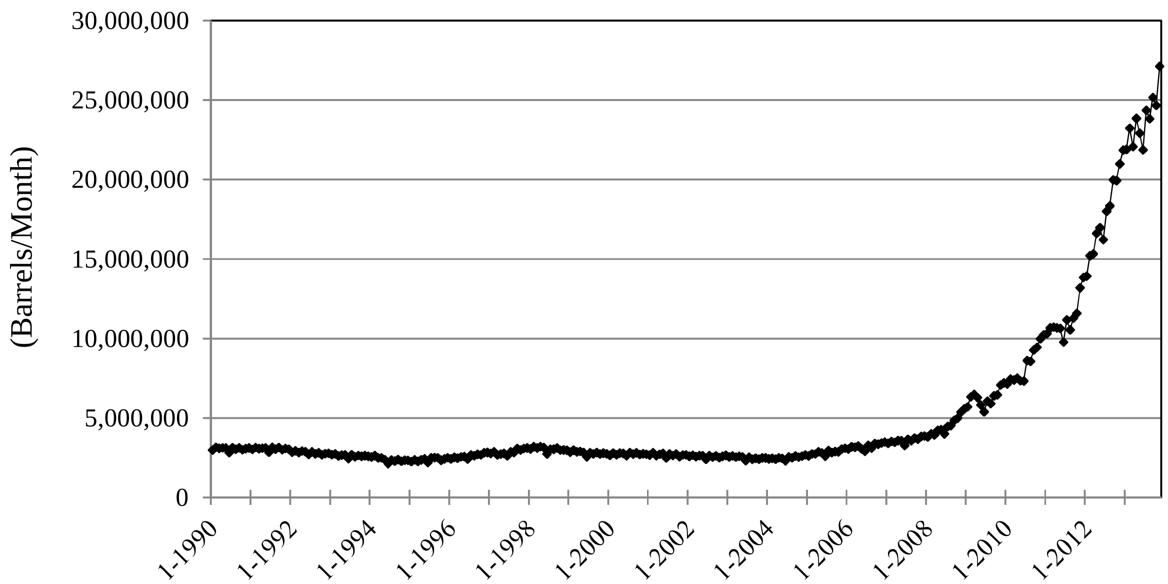


Figure 2.11
North Dakota
Natural Gas Production

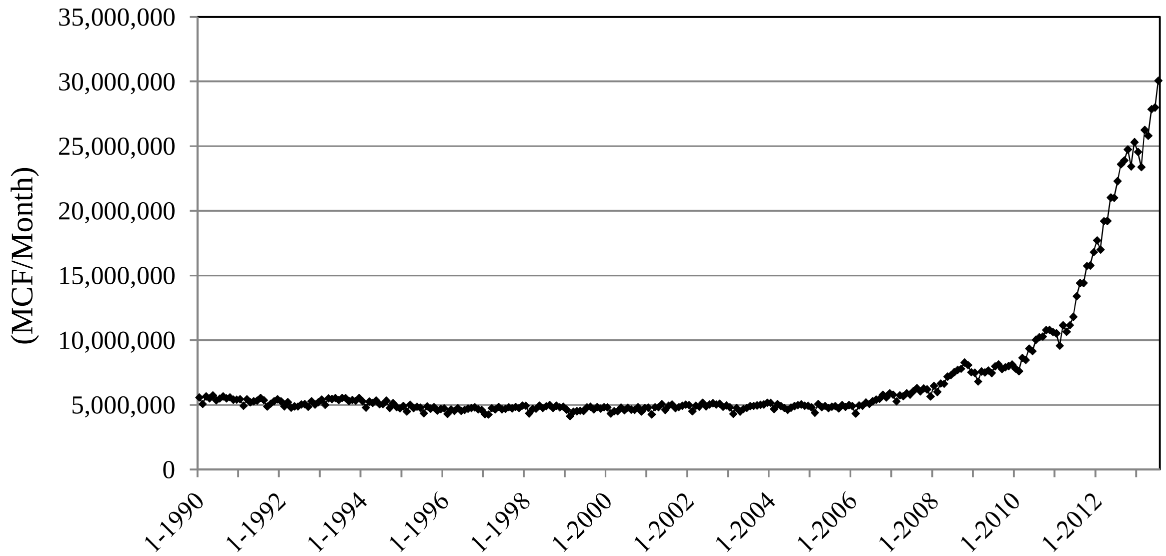


Table 2.15
Area Oil & Gas Emissions
(tons)

	SIP 2002	**ENVIRON 2009**	**NEI 2011**	**BLM 2011**
SO_2	4,958	2,081	2,073	6,269
NO_x	4,631	10,743	6,374	25,277
PMF	0	405	276	875*
PMC	0	413	281	
VOC	7,740	307,408	96,866	252,920

* The BLM inventory estimated PM_{10} emissions only.

The pollutant with the most significant increase is volatile organic compounds. Bakken crude (from the Bakken, Sanish and Three Forks formations) typically contains a high concentration of lighter end components which have the potential to produce increased flash and fugitive hydrocarbon emissions (flash emissions are those hydrocarbons emitted when the pressure of the crude oil is decreased or the temperature is increased). In May 2011, the Department published its "Bakken Pool Oil and Gas Production Facilities Air Pollution Control Permitting and Compliance Guidance" (see Appendix C). The guidance established the expected air pollution control requirements for oil and gas production from the Bakken formation in order to comply with NDAC 33-15-07, Control of Organic Compounds Emissions and NDAC 33-15-20, Control of Emissions from Oil and Gas Well Production Facilities. The guidance is applicable to all areas of North Dakota except tribal areas. On March 22, 2013, the Environmental Protection Agency finalized a Federal Implementation Plan (FIP) which established air pollution control requirements for oil and gas well production facilities on the Fort Berthold Indian Reservation. Both the NDDH rules and guidance and the FIP are expected to reduce emissions of volatile organic compounds.

For TRNP, particulate organic mass extinction decreased 31% in the best days from the baseline (2000-2004) to the 2008-2012 period. During the worst days, there was a 23% decrease with a 20% decrease for all days. At LWA, particulate organic mass extinction decreased 26% in the best days and 30% in the worst days. For all days, the decrease was 26%.

The increase in NO_x emissions from area oil and gas facilities is relatively small (6,000-17,000 tpy) when compared to state-wide emissions of approximately 197,000 tons in 2011. Since the baseline (2002), NO_x emissions have decreased approximately 32,000 tons per year on a statewide basis (2002 v. 2011). As shown in Table 2.9, nitrate extinction at TRNP has decreased 48% in the best days, 13% in the worst days and 16% for all days. At LWA, nitrate extinction has decreased 23% in the best days, 4% in the worst days and 3% for all days (see Table 2.10b).

Although ozone is not a visibility impairing pollutant, the increase of volatile organic compounds and nitrogen oxides emissions can cause increased ozone concentrations. The NDDH has established ozone monitoring stations at TRNP-SU, TRNP-NU, LWA and Williston, ND. The monitor data indicates that ozone design concentrations at each Class I area have remained fairly constant since the baseline period (see Appendix D). The increase in volatile organic compounds and nitrogen oxides from the oil and gas sector does not appear to be affecting ozone concentrations in the Class I areas or any part of North Dakota.

In April 2014, the North Dakota Industrial Commission (NDIC) adopted a plan to reduce natural gas flaring in the oil fields. The plan, which was effective June 1, 2014, includes:

1) A requirement that upstream producers and midstream natural gas processors and gatherers submit “Gas Capture Plans” (GCP) that will regulate currently flaring wells and future new wells. This rule requires operators to create a plan for gas capture prior to filing an application for a drilling permit with the North Dakota Industrial Commission (NDIC). Each GCP will include a location of the well and the closest pipeline and processing plant; the capacity of gathering and transport gas pipelines; the volume of gas flowing from multi-well pads; and a time period for connection of the well to a gathering pipeline.

2) Regulatory consequences for failure to comply including denial of a new permit or suspension of existing permits. In addition, operations at existing facilities may be restricted.

3) Policies to enhance Right-of-Way (ROW) access. A major obstacle for the installation of pipelines is obtaining ROW access. The plan recommends additional legislation to improve ROW access.

4) State support for infrastructure and technology development. Support would include tax credits and low interest loans for the development of pipelines, electric transmission, and other infrastructure.

5) Establishment of a “Pipeline Hotline” for reporting issues related to natural gas pipelines.

6) Midstream planning and tracking. Midstream companies would meet regularly with the NDIC to provide status reports for operation and updates.

This plan is expected to reduce the natural flaring rate of 36% of all gas produced to 15% in two years, 10% within six years and eventually to 5%. The reduced flaring is expected to reduce emissions of NO_x and VOC.

At this time, there is no evidence that the increase in oil & gas activity is impeding progress toward the visibility goal.

No other sectors appear to have increased emissions that would impede reasonable progress toward the national visibility goal.

2.6 Assessment of Current Strategy (40 CFR 51.308(g)(6))

This periodic report must contain an assessment of whether the current implementation plan elements and strategies are sufficient to enable North Dakota, or other states with mandatory Federal Class I areas affected by emissions from North Dakota, to meet all established reasonable progress goals.

North Dakota’s strategy in the RH SIP for achieving reasonable progress was based on reducing emissions of sulfur dioxide and nitrogen oxides. This was accomplished by implementing BART controls and reasonable progress controls on nine EGUs as well as the implementation of other federal emission control programs. The expected emissions reductions are currently being implemented but have not been fully achieved.

Table 2.16
North Dakota
SO_2 & NO_x Emissions
(tons)

	2002	**2011**	**Projected for 2018**
SO_2	176,211	108,719	72,423
NO_x	229,536	197,251	217,594

Sulfur dioxide emissions reductions estimated in the RH SIP have been 64% realized by the end of 2011 while NO_x emissions reductions were 88% realized. The NDDH believes the SO_2 emissions reductions estimated in the RH SIP will be met by 2018. By 2018, BART and reasonable progress controls at the EGUs alone are expected to reduce SO_2 emissions by an additional 43,500 tons from the 2011 rate. NO_x emission reductions by 2018 are expected to be greater than projected in the RH SIP. NO_x emissions in 2013 have been reduced by 28,368 tons per year from the baseline at EGUs. The RH SIP predicted a reduction of 25,350 tons per year. Additional controls at Leland Olds Station, Coal Creek Station, Stanton Station Unit 1 and Coyote Station are expected to reduce NO_x emissions well beyond the projection in the RH SIP.

As discussed in Section 2.5, oil and gas activity has the potential to adversely affect progress toward the national visibility goal. When the original RH SIP was developed, the NDDH was not aware of the rapid development that would take place. Based on information from the Oil & Gas Division of the Industrial Commission, emissions from oil & gas drilling and production were expected to peak in 2015. However, that does not appear to be the case. Development of the Bakken formation (and other formations) may proceed at a steady or increasing rate for the next 20 years. Although development of the Bakken formation has proceeded at a much faster rate than expected, there is no evidence that indicates that emissions from oil and gas development emissions are a large contributor to visibility impairment in the Class I areas (see Tables 2.9 and 2.10b). However, oil and gas development will have to be more thoroughly evaluated for the SIP revision that is due in 2018.

2.7 Review of Visibility Monitoring Strategy (40 CFR 51.308(g)(7))

This section of the Regional Haze Rule requires a review of the North Dakota's visibility monitoring strategy and any modifications to the strategy that are necessary.

The monitoring strategy is found in Section 4 of the RH SIP. The strategy depends on the IMPROVE monitoring program to collect and report aerosol monitoring data. Currently, IMPROVE monitors are operating at TRNP-SU and LWA. The TRNP-SU (THROI) IMPROVE monitor is located at the Painted Canyon Overlook in the South Unit of TRNP and is considered representative of the distinct and separate North Unit and Elkhorn Ranch Unit. The IMPROVE sites are operated by the FLMs. The IMPROVE program makes its data available to the public, states and the EPA. North Dakota will continue to support the IMPROVE program by requesting that agencies that financially support the program continue to do so.

North Dakota will continue to rely on the IMPROVE program for its monitoring strategy. The NDDH will continue to supplement the IMPROVE data with data from ambient air quality monitors that it operates at TRNP-SU, TRNP-NU and LWA. These include monitors for sulfur dioxide, nitrogen oxides, ozone, PM_{10}, $PM_{2.5}$ and a meteorological monitoring system (i.e. wind speed, direction, temperature, pressure, relative humidity, etc.). No change is needed to the monitoring strategy at this time.

2.8 Determination of Adequacy (40 CFR 51.308(h))

This section of the rules states "At the same time the State is required to submit any 5-year progress report to EPA in accordance with paragraph (g) of this section, the State must also take one of the following actions based upon the information presented in the progress report:

(1) If the State determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and emissions reductions, the State must provide to the Administrator a negative declaration that further revision of the existing implementation plan is not needed at this time.

(2) If the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another State(s) which participated in a regional planning process, the State must provide notification to the Administrator and to the other State(s) which participated in the regional planning process with the States. The State must also collaborate with the planning process for the purpose of developing additional strategies to address the plan's deficiencies.

(3) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State shall provide notification, along with available information, to the Administrator.

(4) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources within the State, the State shall revise its implementation plan to address the plan's deficiencies within one year."

The NDDH believes the RH SIP is adequate to make reasonable progress toward the national visibility goal and no substantive revisions are necessary. As indicated earlier, the reasonable progress goals established in RH SIP were disapproved by EPA; however, no other reasonable progress goals were established by EPA. The NDDH's determination that adjustments are unnecessary to the RH SIP is based on the goals established by North Dakota. The emissions reduction goals established in the RH SIP for EGUs in the state are expected to be met.

The requirements for installing BART and reasonable progress controls vary in their implementation dates up to July 2018. Most of the requirements are not effective until May 7, 2017 (5 years after EPA's effective approval date). The visibility improvement from reductions in sulfur dioxide and nitrogen oxides that are required by the RH SIP will not have shown up in the currently available IMPROVE data (current data through 2012). There is nothing to suggest at this time that the reasonable progress goals (unapproved goals) will not be met.

During the baseline period, the three species contributing most of the visibility impairment in the Class I during the 20% worst day's areas were sulfates, nitrates and organic carbon (83% at TRNP and 88% at LWA). This is also true for the 2007-2012 visibility monitoring data (65% at TRNP and 72% at LWA). At both TRNP and LWA sulfate extinction remained relatively stable while organic carbon and nitrate extinction has decreased. From the 2002 to 2011 time period sulfur dioxide emissions have decreased 39% and nitrogen oxides emissions have decreased 14%. From 2002 to 2008 (last year data is available), organic carbon emissions decreased by 38%.

The reason for the sulfate extinction remaining nearly the same as the baseline extinction (and no decrease to match the emissions decrease) is unclear. Sulfur dioxide emissions from the oil and gas operations were estimated in the Williston Basin study[3] at 2,018 tons for 2009 and 2,073 tons in the 2011 NEI compared to the 2002 estimate of 4,631 tons. The reason for the decline is reduced flaring of high H_2S gas from older wells. Although production from the Bakken formation has produced a dramatic increase in the amount of gas flared, the Bakken gas is generally sweet gas (less than 10 ppb of H_2S).

A review of surrounding state and provincial emissions does not provide the answer.

Table 2.17
State & Provincial
SO_2 & NO_x Emissions (tons)

	2002		2011[1]		Change	
	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x
North Dakota	176,211	229,536	108,719	197,251	-67,492	-32,285
Montana	51,923	243,142	29,358	161,089	-22,565	-82,052
South Dakota	22,725	146,822	17,893	107,394	-4,832	-39,428
Minnesota	160,000	485,000	74,000	168,546	-86,000	-316,454
Saskatchewan	126,528	292,539	119,289	202. 522	-7,239	-90,017
Alberta	433,394	752,966	381,295	846,978	-52,099	+94,012
British Columbia	101,990	214,914	102,170	282,607	+180	+67,693
Manitoba	398,806	142,685	142,254	78.231	-256,552	-64,454

[1] Based on 2011 NEI for states and Environment Canada data for provinces.

As pointed out in the original RH SIP (see p.55), there are three coal-fired power plants within Saskatchewan just north of the U.S./Canada border within 250 km of LWA. A review of the sulfur dioxide emissions from these plants also provides no insight to the lack of reduction in sulfate extinction.

[3] Final Report Development of Baseline 2009 Emissions From Oil and Gas Activity in the Williston Basin; Environ International Corp; Western Energy Alliance, June 25, 2013.

Table 2.18
Saskatchewan Power Plants
SO_2 and NO_x Emissions (tons)[1]

Plant	2002		2011		Change	
	SO_2	**NO_x**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Boundary Dam	47,338	18,950	43,004	18,030	-4,334	-920
Shand	15,146	6,463	11,301	4,496	-3,845	-2,618
Poplar River	47,107	12,864	47,035	15,842	-72	+2,978

[1] Data from Environment Canada

The above emissions data provide no answer to why sulfate extinction is not decreasing at TRNP and LWA. As part of the 2018 RH SIP revision, the Department will continue to study this issue and take any appropriate action.

Nitrogen oxides emissions have also decreased significantly except for the Provinces of Alberta and British Columbia. Nitrate extinction reduction at TRNP is fairly substantial (48% for the least impaired days and 13% for the most impaired days). However, at LWA nitrate extinction reduction is less pronounced (23% for the least impaired days and 3% for the most impaired days). The NDDH believes that Canadian sources are significantly influencing nitrate concentrations at LWA. As shown in 6.7 of RH SIP, Canadian sources contributed 44.6% of the nitrate at LWA. The increase in NO_x emissions in Alberta and British Columbia may offset any reductions in Saskatchewan and North Dakota.

In summary, the emission reduction goals for the BART and RP sources established in the RH SIP will be met by 2018. At this time, the Department has determined that revision of the RH SIP is unnecessary. For the 2018 RH SIP, the oil and gas industry will be thoroughly evaluated and additional controls required, if necessary.

3. Consultation with Federal Land Managers

40 CFR 51.308(i) requires a state to provide the Federal Land Managers with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on a periodic Progress Report. The NDDoH provided this opportunity to the Federal Land Managers on June 25, 2014 by providing a copy of the draft Progress Report. The report was provided to the National Park Service, U.S. Fish and Wildlife Service and the U.S. Forest Service. In addition, a copy was provided to the U.S. Environmental Protection Agency, Region 8. The National Park Service, the U.S. Forest Service and the Environmental Protection Agency provided comments.

The following items document the consultation process:

- Transmittal letters to the FLMs
- NPS Comments
- U.S. Forest Service Comments
- U.S. EPA Comments
- NDDoH Response to Comments

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

June 25, 2014

FILE

Ms. Carol McCoy
National Park Service - Air
P.O. Box 25287
Denver, CO 80225

Re: Regional Haze Five Year Progress Report

Dear Ms. McCoy:

The North Dakota Department of Health has developed a periodic progress report for the Regional Haze State Implementation Plan in accordance with 40 CFR 51.308(g) & (h). Enclosed with this letter is a CD which contains a copy of the progress report. In accordance with 40 CFR 51.308(i), the Department is providing you with the opportunity for consultation on the progress report. We ask that any comments be submitted within 60 days of receipt of this letter.

If you have any questions regarding the progress report, please feel free to contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc: Gail Fallon, EPA Region 8

NORTH DAKOTA
DEPARTMENT of HEALTH

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June 25, 2014

FILE

Ms. Sandra Silva
U.S. Fish and Wildlife Service
Branch of Air Quality
7333 West Jefferson Ave , Ste 375
Lakewood, CO 80235-2017

Re: Regional Haze Five Year Progress Report

Dear Ms. Silva:

The North Dakota Department of Health has developed a periodic progress report for the Regional Haze State Implementation Plan in accordance with 40 CFR 51.308(g) & (h). Enclosed with this letter is a CD which contains a copy of the progress report. In accordance with 40 CFR 51.308(i), the Department is providing you with the opportunity for consultation on the progress report. We ask that any comments be submitted within 60 days of receipt of this letter.

If you have any questions regarding the progress report, please feel free to contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
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xc: Gail Fallon, EPA Region 8

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June 25, 2014

FILE

Mr. Richard Periman
Deputy Forest Supervisor
U.S. Forest Service
8901 Grand Ave Place
Duluth, MN 55808-1122

Re: Regional Haze Five Year Progress Report

Dear Mr. Periman:

The North Dakota Department of Health has developed a periodic progress report for the Regional Haze State Implementation Plan in accordance with 40 CFR 51.308(g) & (h). Enclosed with this letter is a CD which contains a copy of the progress report. In accordance with 40 CFR 51.308(i), the Department is providing you with the opportunity for consultation on the progress report. We ask that any comments be submitted within 60 days of receipt of this letter.

If you have any questions regarding the progress report, please feel free to contact Tom Bachman of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc
Enc:
xc: Gail Fallon, EPA Region 8

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225-0287

TRANSMITTED VIA ELECTRONIC MAIL - NO HARDCOPY TO FOLLOW

N3615 (2350)

August 26, 2014

Terry O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

Thank you for the opportunity to review and comment on North Dakota's draft Regional Haze Periodic Progress Report. North Dakota Department of Health (NDDH) has addressed most, but not all, the requirements for the periodic progress report as outlined in 40 CFR 41.508 (g) and (h). North Dakota (ND) has made significant progress in reducing sulfur dioxide (SO_2) emissions from Electric Generating Units (EGUs) statewide. We commend these efforts by the NDDH to improve visibility in the ND Class I areas. As discussed below, we are concerned that emissions from the rapid growth in oil and gas production in North Dakota are offsetting emissions reductions from other anthropogenic sources and impeding progress toward ND's visibility improvement goals. We commend NDDH for the newly enacted requirements limiting flaring from oil production. We recommend that NDDH begin now to evaluate controls for the oil and gas area and point sources (such as replacing diesel fuel in drill rigs engines and miscellaneous engines with natural gas and/or requiring Tier 4 or post combustion controls), and potentially EGUs, in preparation for the 2018 SIP revision.

We have the following specific recommendations for revisions and additions to the draft periodic progress report.

Section 1 Background: Please summarize the regulatory actions since NDDH submitted its State Implementation Plan (SIP) to EPA in 2010. On page 4 please clarify the EPA requirements in the Federal Implementation Plan (FIP) for nitrogen oxides (NO_x) at Coal Creek Station for Best Available Retrofit Technology (BART) and at Antelope Valley Station for reasonable progress. Please clarify if all the controls in the FIP are included in Table 1.4 that summarizes EGU NO_x controls and which controls were included in the 2018 regional modeling that was used to set visibility improvement goals. Please add to Tables 1.3 and 1.4 the years that controls were installed or reference Table 2.2 to find this information.

Section 2.3: Visibility Progress: In contrast to most IMPROVE monitoring sites in the U.S., there has been no improvement in visibility on the 20% most impaired days over the past decade at the North Dakota Class I areas. Statistically, there is no change on the 20% Most Impaired Days at Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (TRNP). Please correct Figure 2.4 to show data for the 20% Most Impaired Days at LWA, not the 20% Least Impaired Days. Please illustrate the relative contributions of ammonium sulfate, ammonium nitrates, and organic carbon mass at LWA and TRNP by adding Figures J.1-1 and J.2-1 from Appendix B to the main report. Table 2.7 indicates that IMPROVE data were incomplete in 2011 and 2012. To use 2011 and 2012 data in trend analyses, data substitution methods established by the Western Regional Air Partnership (WRAP) should be applied.

Section 2.4: Emissions Reductions: EGUs in ND have reduced SO_2 emissions by 60% (84,814 tons/yr) and NO_x emissions by 38% (28,368 tons/yr) between 2002 and 2013. On page 31, NDDH indicates that additional controls at several EGUs are expected to reduce NO_x emissions beyond the projections used in the regional haze SIP. Please clarify the magnitude of these additional NO_x reductions that are expected by 2018.

The best available emissions inventory for oil and gas area sources in North Dakota is the 2011 ENVIRON inventory, sponsored jointly by the Bureau of Land Management and the WRAP, which included a 2011 base year and 2015 projections[1]. We agree with using the 2015 projections grown to 2018 in Table 2.13. We recommend in Table 2.12 that the 2011 area oil and gas inventory from the National Emissions Inventory be replaced with the 2011 ENVIRON inventory, particularly for SO_2, VOCs and NO_x, as the NEI may significantly underestimate these emissions. We recommend that more weight be given to the estimates from the 2011 ENVIRON (BLM) inventory when discussing emissions changes in the oil and gas source sector in the report.

Due to increased oil and gas development, total anthropogenic NOx emissions reported in Table 2.10 for 2002 and Table 2.13 for 2018 are unchanged, at 183,150 and 183,583 tons/yr, respectively. The contribution from oil and gas is projected to increase from 2.5% to 29% of the 2018 anthropogenic NO_x inventory.

The 2011 ENVIRON inventory found that oil and gas sources in ND emitted an estimated 6,257 tpy SO_2 in 2011 (vs. 2,073 tpy in the 2011 NEI) and will emit an estimated 13,798 tpy SO_2 in 2015. Please check the 2018 SO_2 emissions for oil and gas (6,541 tons/yr) in Table 2.13 that are based on, but lower than, the 2015 ENVIRON values.

Section 2.5 Changes Impeding Visibility Progress: When the 2009 ND Regional Haze SIP was developed, oil and gas emissions were not assumed to be a significant contributor to visibility impairment at the ND Class I areas. However, as shown in Figures 2.6 and 2.7,

[1] Development of Baseline 2011 and Future Year 2015 Emissions from Oil and Gas Activity in the Williston Basin, Final Report, ENVIRON Corp, August 2014.

beginning in 2008, oil production, and to a lesser extent, natural gas production increased exponentially in the Williston Basin. By May 2014 North Dakota crude oil production surpassed 1.0 million barrels per day (bbl/d) based on the latest data available[2]. The rapid growth in oil and gas area sources is now projected to increase NO_x emissions from 2002 to 2018 by 48,000 tons and to offset the cumulative decreases from all other anthropogenic sources in ND by 2018.

The visibility improvement goals set in the 2009 Regional Haze SIP did not include the significant increase in emissions in the Williston Basin. Table 6.3 of the ND Regional Haze SIP projects that NO_x emissions from area oil and gas sources would be 11,577 tons/yr in 2018. Table 2.13 in the progress report projects area oil and gas NO_x emissions will be 52,994 tons/yr by 2018. We conclude that the emissions increases from oil and gas may be impeding North Dakota's progress in reducing pollutant emissions and improving visibility.

NDDH discusses increased oil and gas production through 2013. Please include projections to 2018 in Figures 2.6 and 2.7 and in Table 2.14. NDDH discusses NO_x emissions growth from oil and gas by 2011, while above we point out that by 2018, oil and gas NO_x emissions increases will offset decreases from other anthropogenic sources.

Section 2.6 Assessment of Current Strategy: The oil and gas development is concentrated in the Williston Basin, comprising the western part of North Dakota and the extreme northeastern edge of Montana, and immediately surrounding the Class I areas. The vast majority of the NO_x emissions from existing development (77%) are occurring on state and private mineral estate[3], indicating that the state should play a key role in assessing and addressing emissions from these unpermitted sources.

This year the North Dakota Industrial Commission has taken steps to reduce natural gas flaring in oil fields beginning in 2015. We commend these actions and believe this is an important step towards reducing NO_x emissions in this region. Please confirm that adequate estimates of emissions from natural gas flaring are included in the ENVIRON inventories discussed in section 2.4 and estimate how emissions will change in response to this rule.

We agree with NDDH that oil and gas development will have to be more thoroughly evaluated for the regional haze SIP revision that is due in 2018. We recommend that NDDH can begin by evaluating requirements of other oil and gas producing states to determine best practices that could be adopted in North Dakota. Further, we urge NDDH to consider implementing additional controls for NOx emissions from this source sector, including (but not limited to):

- Requirements that diesel engines meet emission standards equivalent to Tier 4 engine requirements. Tier 4 engine standards limit NO_x emissions from large generator sets to 0.5 g/Hp-hr, which is roughly equivalent to a Tier 2 engine with post-combustion selective catalytic reduction technology. The standards also reduce NO_x emissions from the smaller engine classes (i.e., between 75 Hp and 750 Hp) by roughly 90% from Tier 2 levels.

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[2] Information prepared by the U.S. Energy Information Administration (EIA): http://www.eia.gov/todayinenergy/detail.cfm?id=4010 & http://www.eia.gov/todayinenergy/detail.cfm?id=17391

[3] ENVIRON, August 2014. Table ES-2.

- Where feasible, implement measures to electrify well sites and replace diesel-powered engines with electric motors.
- Where feasible and appropriate, switch from diesel-powered drill rigs and engines to natural-gas-fired drill rigs and engines.
- Require all new compressors greater than 500 Hp to meet a 0.5 g/Hp-hr NO_X limit (as is currently required in Texas and recently by New Mexico).

According to the 2011 ENVIRON inventory, drill rigs, miscellaneous engines and compressors are major sources of NO_x emissions in the Williston basin and comprise a greater percentage of the total NO_x inventory than casinghead flaring (see Table 1). Controlling emissions from each of these source types within the oil and gas fields will be important for continued improvement in NO_x emission reductions.

Table 1

Inventory Year	***Source***	***Basin-wide NOx Emissions (tpy)***	***Percent of Total Basin-wide Oil and Gas NOx Emissions***
2011	Drill Rigs	6,962	24%
	Miscellaneous Engines	4,628	16%
	Compressors	4,241	14%
2015	Drill Rigs	5,616	12%
	Miscellaneous Engines	8,364	18%
	Compressors	11,504	24%

We also recommend that NDDH consider additional NO_x controls for EGU, which NDDH projects will emit 43,000 tons of NO_x in 2018, as part of the reasonable progress analyses for the 2018 SIP revision. We continue to believe that Selective Catalytic Reduction is technically feasible for these units. We also note that the 0.50 lb/mmBtu NO_x limit for the Coyote Generating Station (and the projected 9,000 tpy emissions in 2018) is inconsistent with the 0.35 – 0.36 lb/mmBtu limits set by NDDH for the similar Leland Olds Unit #2 and Milton R. Young Units #1 & #2. Additional reductions in NO_x emissions from these EGUs may partially mitigate the NO_x increases from the oil & gas sector.

Section 2.7 Monitoring Strategy: In addition to the IMPROVE monitoring, in winter 2013 and winter 2014, National Park Service conducted special monitoring studies in TRNP, Fort Union Trading Post National Historic Site, and Medicine Lake Wilderness Area in Montana. We will share our preliminary findings with you in the coming months to use in evaluating pollutant contributions to visibility impairment in support of the 2018 regional haze SIP revision.

Section 2.8 Determination of Adequacy: NDDH has not addressed the impact of North Dakota emissions on the ability of neighboring states to meet their reasonable progress goals for 2018. In the 2009 Regional Haze SIP, NDDH determined that North Dakota emissions are reasonably anticipated to contribute to visibility impairment (contribute of more than 5 percent to light extinction) in mandatory Class I Federal areas in Minnesota (Boundary Waters Canoe Area

Wilderness Area and Voyageurs National Park), Montana (Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area), and South Dakota (Badlands National Park and Wind Cave National Park). Please discuss the implications of not reducing North Dakota NO_x emissions as projected by 2018 on the ability of neighboring states to meet their visibility improvement goals.

Conclusion: We conclude from the draft progress report that NDDH has not demonstrated that TRNP and LWA are on track to meet the visibility improvement goals set in North Dakota's 2009 Regional Haze SIP. Increases in oil and gas NO_x emissions are projected to offset NO_x emissions reductions from other anthropogenic sources. We recommend that NDDH begin evaluating additional control measures for oil and gas, and potentially EGUs, in preparation for the 2018 regional haze SIP revision.

We appreciate the opportunity to work closely with NDDH to improve visibility in our Class I national park and wilderness areas. We would like to follow up with you and your staff on the issues raised here. Please contact Pat Brewer, (303) 989-2153, with any immediate questions about our comments.

Sincerely,

Susan Johnson
Chief, Policy, Planning and Permit Review Branch

cc:
Gail Fallon, EPA Region 8
David Pohlman, NPS Midwest Region
Susan Bassett, Bureau of Land Management

USDA United States Department of Agriculture | Forest Service | Region One | Northern Region
200 East Broadway
Missoula, MT 59802

File Code: 2580
Date: JUL 15 2014

JUL 2014
Received
Air Quality

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

On June 25, 2014, The State of North Dakota submitted a draft regional haze implementation plan revision summarizing progress made toward achieving visibility improvement goals for mandatory Class I areas as outlined in the North Dakota regional haze implementation plan dated February 24, 2010. This letter acknowledges that the U.S. Department of Agriculture, Forest Service, has received and conducted a review of this report. Our comments on this report are attached. We look forward to your response required by 40 CFR 51.308(i)(3).

We appreciate the opportunity to continue working closely with the state on achieving the Clean Air Act's goal of natural visibility conditions in mandatory Class I wilderness areas and parks. For further information or if you have any questions, please contact Northern Region Air Resource Program Manager Thomas Dzomba at (406) 329-3672, or Eastern Region Air Resource Specialist Trent Wickman at (218) 626-4372.

Sincerely,

Thomas A. Schmidt (for)
FAYE L. KRUEGER
Regional Forester

cc: Brenda Halter, Bret A Anderson, Trent R Wickman

US Forest Service Technical Comments on the Regional Haze State Implementation Plan Periodic Progress Report for North Dakota

Thank you for the opportunity to review the State of North Dakota (ND) Regional Haze State Implementation Plan (SIP) Periodic Progress Report as required under Section 308(i) of the Regional Haze Rule. The US Forest Service (FS) has reviewed the report and offers the following comments. These comments primarily relate to impacts at the two Class I areas within ND, Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (THRO), which are not managed by the FS. However, the FS believes that visibility improvements at these Class I areas will also reduce impacts at more distant FS Class I areas such as the Boundary Waters Canoe Area Wilderness (BOWA) in Minnesota.

1. Figures 2.4 and 2.5 are identical. We presume one of those figures was supposed to represent the 20% worst days at LWA.

2. The FS is concerned about the increases in SO_4 extinction above baseline shown at both LWA and THRO on the 20% worst days (Tables 2.8 – 2.10). The FS acknowledges that Best Available Retrofit Technology (BART) implementation will continue until 2017, which is expected to reduce SO_2 emissions by approximately 100,000 tons. However, we remain concerned that these reductions will be offset by emissions increases from other sectors, particularly from the increased oil and gas development activity in the Bakken region.

3. We are concerned about the effect of the Bakken oil and gas boom on ND's regional haze SIP strategy and on visibility. We are unsure how accurate the emission inventories are for this sector. Nevertheless it appears that the entire projected decrease in EGU NOx (~32,000 tons) will be erased by the increase from oil and gas (see Table 2.13) along with a portion of the SO2 emissions.

4. Figures 2.6 and 2.7 show exponential increase in oil and gas production beginning in 2008. This increase was clearly unforeseen during the development of the RH SIP (see discussions at the end of section 2.6, page 31). The North Dakota Department of Health (NDDH) denies any cause and effect connection between the oil and gas-related emissions and visibility impairment. NDDH states "Although development of the Bakken formation has proceeded at a much faster rate than expected, monitoring data indicates that emissions from oil and gas development emissions are not a large contributor to visibility impairment in the Class I areas" We are not certain that this is the case.

   Hand et.al (2012) found "that for certain regions and seasons, factors other than known local and regional power plant emissions have had significant impacts on sulfate concentrations.", "Monthly mean sulfate concentrations also increased in December at many sites in the northern and central Great Plains. Beginning in 2006 concentrations increased rapidly and reached their highest values in 2010 (see Fig. 9). Hand et al. (2012b) speculated several possible causes, such as impacts from oil and gas development, transport from oil sand regions in Canada, meteorological influences, or a likely combination of all."

Hand, J. L., Gebhart, K. A., Schichtel, B. A., Malm, W.C., and Pitchford, M.L.: Particulate sulfate ion concentration and SO2 emission trends in the United States from the early 1990s through 2010, Atmos. Chem. Phys., 12, 10353–10365, 2012

Hand, J. L., Gebhart, K. A., Schichtel, B. A., and Malm, W. C.:Increasing trends in wintertime particulate sulfate and nitrate ion concentrations in the Great Plains of the United States (2000–2010), Atmos. Environ., 55, 107–110, 2012b.

At a minimum there appears to be considerable uncertainty regarding the contribution of various sources, most importantly oil and gas, to visibility impacts at the Class I areas, as stated in the ND Progress Report: "The above emissions data provide no answer to why sulfate extinction is not decreasing at TRNP and LWA. As part of the 2018 RH SIP revision, the Department will study this issue and take any appropriate action." (page 34)

5. In response to comments made by the FS on the ND SIP in 2009, ND added the following paragraph to Section 11.3 of the regional haze SIP:

   "In addition, North Dakota commits to revise the implementation plan, including the reasonable progress goals, once RH SIPs from neighboring states become available and are approved by EPA, or if the unexpected or unforeseen occurs. This would include, but not limited to, projected future emissions reductions that do not occur, are distributed differently over an alternate geographic area, or are found to be incorrect or flawed. These revisions will be made within one year as required by §51.308(d)(4). North Dakota also commits to accelerate this revision schedule if the present RH SIP is found to be significantly flawed and the 2018 reasonable progress goals cannot be reasonably attained."

   While it appears that emission reductions in ND for electric generating units (EGUs) are proceeding as planned, unforeseen increases due to oil and gas development in ND may outstrip those gains for some pollutants. Impacts from energy development in neighboring states and Canada may also be having an unforeseen impact. All of these issues point to the need to start work immediately to gain a better understanding of current and future emissions from oil and gas development in ND and the surrounding states and an assessment of their contribution to visibility impairment in the Class I Areas. The mechanisms to begin this work earlier than scheduled are outlined in 40 CFR 51.308(h).

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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Ref: 8P-AR

AUG 25 2014

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue
Bismarck, North Dakota 58501-1947

Re: EPA Region 8 Comments on Draft Regional Haze 5-Year Progress Report (FLM Consultation Version)

Dear Mr. O'Clair:

The Environmental Protection Agency has completed a preliminary review of North Dakota's July 2014 draft Regional Haze State Implementation Plan (SIP) 5-Year Progress Report, which we received as a courtesy copy of your June 25, 2014 consultation letters to the Federal Land Managers (FLMs). Our comments are detailed below.

We understand that you intend to consider all comments received on this FLM consultation version of the progress report before finalizing the documents. The final draft of the progress report, which will include a summary of the FLMs' comments and your responses, will then undergo a broader public hearing process before adoption and submission to EPA. We emphasize that we will only come to a final conclusion regarding the adequacy of North Dakota's progress report when we act on the North Dakota progress report SIP submittal, through our own public notice-and-comment rulemaking.

We acknowledge that it appears that North Dakota has addressed the reporting obligations in 40 CFR 51.308(g) and (h) and has made some progress toward improving visibility at North Dakota's Class I areas and reducing anthropogenic emissions. Additionally, we offer the following comments to strengthen the 5-Year Progress Report SIP:

1. Section 1.2, North Dakota SIP Summary, pp. 2-4: North Dakota remarks that Theodore Roosevelt National Park (TRNP) consists of three separate units. We recommend removing this language. As we and the FLMs have indicated in the past, TRNP was identified as a single national park under the Clean Air Act Amendments of 1977 (42 U.S.C. 7472); thus, there is only one mandatory federal Class I area for this park. This is relevant to any future modeling efforts. Dividing this Class I area into three units might cause slight reductions in benefits predicted when modeling the visibility effects of applying controls.

Also in this section, for purposes of the progress report, North Dakota discusses its reliance on the original reasonable progress goals from the SIP, which EPA disapproved. In support of this approach, North Dakota noted that additional controls required by the EPA's Federal Implementation Plan (FIP) would have "virtually no effect" or a "miniscule effect" on the amount of visibility improvement that will be achieved for the 20% most impaired days. But, even considering only the reasonable progress controls the FIP requires for Antelope Valley Station, North Dakota's actual progress towards achieving natural visibility conditions should be greater than that indicated by the reasonable progress goals that North Dakota originally established. Therefore, we recommend revising this section to reflect that the FIP will generally result in greater visibility benefits than the original SIP. North Dakota also noted there are technically no reasonable progress goals established for North Dakota's Class I Federal Areas. While we agree that quantified reasonable progress goals are currently lacking, we recommend that North Dakota explain that it anticipates that new modeling will be available for the 2018 planning period through efforts by the Western Regional Air Partnership.

2. Table 1.4, Emissions Reductions from the 2000-2004 Nitrogen Oxides Average, p. 6: There is a typographical error for the average 2000-2004 emissions for Milton R. Young Station Unit 1. This should be 8,665 (instead of 8.665) tons per year.

3. Section 2.1.1, BART and Reasonable Progress Sources, p. 8: For reporting the status of control strategies, 40 CFR 51.308(g)(1) requires that the report must include not only those measures being taken in the SIP for purposes of achieving visibility progress within the state, but also those measures being taken to achieve visibility progress in affected Class I areas outside the state. We recommend that North Dakota include at least a qualitative discussion in this section addressing the Class I areas outside North Dakota, and stating that measures taken to achieve visibility progress at TRNP and Lostwood Wilderness Area are also anticipated to have visibility benefits at Class I areas outside the state. Some of the out-of-state Class I areas where North Dakota has a significant contribution for one or more pollutants could be added to Table 2.1. These would include Badlands, Wind Cave, UL Bend, Medicine Lake, Voyageurs, Boundary Waters, and Isle Royale. It would also be beneficial to have a discussion in the report of any current efforts or plans for future consultation (either through the Regional Planning Organization process or separately) with other states regarding interstate transport of emissions impacting visibility at Class I areas.

4. Section 2.5, Assessment of Changes Impeding Visibility Progress, p. 27: North Dakota's characterization of the impacts of oil and gas development over the past four years on the state's regional haze SIP strategy and on visibility may be premature. The decreases in organic mass and nitrate extinction noted in Section 2.5 are only an indication that the contribution from all sources has decreased in recent years, not that oil and gas operations do not affect visibility. In particular, it is likely that the decrease in the organic mass extinction is almost entirely driven by the large contribution of wildfires in the region during the 2000-2004 baseline. Accordingly, we support North Dakota in continuing its efforts to study this issue and to take appropriate action as needed.

5. Section 2.8, Determination of Adequacy, p. 32: North Dakota notes that the sulfate extinction remained relatively stable despite sulfur dioxide emissions decreasing by 39%. We encourage the state to continue studying this issue in addition to oil and gas impacts.

We appreciate the opportunity to work with the Division of Air Quality during the review of this FLM consultation version of the draft progress report, and we look forward to continued communications during the public hearing process. If you have any questions on EPA's comments, please contact me, or your staff may contact Gail Fallon at (303) 312-6281.

Sincerely,

Carl Daly

Carl Daly, Director
Air Program

cc: Tom Bachman, NDDH
Patricia Brewer, NPS
Tim Allen, USFWS
Thomas Dzomba, USFS
John Mooney, EPA Region 5

FLM Consultation
Response to Comments

FLM Comments

Comment 1: Figures 2.4 and 2.5 are identical.

Response: Figure 2.4 has been replaced with the correct figure.

Comment 2: There is concern about an increase in sulfate (SO_4) extinction above the baseline at both the Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (TRNP) during the 20% worst days. There are concerns that any reductions of sulfur dioxide (SO_2) from Best Available Retrofit Technology (BART) will be offset by increases of SO_2 from Bakken oil activity.

Response: The modeling that was conducted as part of the original Regional Haze SIP indicated the reduction of SO_2 emissions in North Dakota would have very little effect on SO_4 extinction in LWA and TRNP. This is because of the small contribution of North Dakota sources to SO_4 concentration (see Table 1.2 of this report). As further SO_2 reductions are achieved under BART, the increase may be reversed.

The gas produced from the Bakken formation is generally sweet gas with a sulfur content of 10 ppm or less. The amount of SO_2 emissions from the Bakken oil activity was only 2,073 tons in 2011 and expected to only increase to approximately 6,000 tons in 2018. Total SO_2 reductions from the Regional Haze SIP are expected to decrease SO_2 emissions statewide by over 105,000 tons by 2018 (see Table 6.4 of RH SIP). It is expected that Bakken oil activity will have little affect on SO_4 extinction in the Class I areas.

Comment 3: It appears that NO_x emissions increases from the Bakken oil development will wipe out any decreases from EGUs.

Response: It is possible that NO_x emissions from Bakken oil activity will exceed the reductions at the EGUs. However, nitrate concentrations in LWA and TRNP are decreasing (see Tables 2.9 and 2.10b). At TRNP, nitrate extinction has decreased 13% from the baseline in the 20% worst days and 48% in the 20% best day. At LWA, nitrate extinction has decreased by 4% in the 20% worst days and 23% in the 20% best days. Bakken oil activity will be thoroughly evaluated for the 2018 RH SIP.

Comment 4: It has been found that local oil and gas production can contribute significantly to visibility impairment. The commenter is not certain that oil and gas activity in North Dakota is not a large contributor to visibility impairment at LWA and TRNP.

Response: We agree there is uncertainty regarding the contribution of Bakken oil and gas activity to visibility impairment in LWA and TRNP (and other nearby Class I areas). However, SO_2 emissions from the Bakken activity are low and nitrate concentrations are decreasing. Particulate organic mass extinction has decreased significantly despite a large increase in volatile organic compounds (VOC) emission from oil and gas sources. The commenter has provided no evidence to indicate oil and gas activity is a large contributor to visibility impairment. As indicated previously, oil and gas activity will be thoroughly evaluated for the 2018 RH SIP.

Comment 5: North Dakota needs to start early on work to understand the effect current and future emissions from oil and gas development is having on visibility impairment in the Class I areas.

Response: The NDDH has determined that the current SIP is adequate. Based on monitoring data, the increase in emissions from oil and gas activity does not currently appear to be having any significant impact on visibility. As part of the 2018 RH SIP development, oil and gas activity will be thoroughly evaluated. The recommendation to start early on this evaluation is noted.

Comment 6: The commenter would like the Department to summarize the regulatory actions since the 2010 SIP was submitted. Also, clarify the contents of EPA's FIP.

Response: Agreed. A new paragraph has been added in Section 1.2.

Comment 7: The commenter asks that it be clarified in Table 1.4 whether the EGU NO_x controls were used in the regional modeling analysis.

Response: Agreed. See footnote to Table 1.4.

Comment 8: The commenter wants the years that controls were installed at the various sources added to Tables 1.3 and 1.4.

Response: Tables 1.3 and 1.4 only address SIP and FIP requirements. The actual controls that were installed and dates installed are listed in Table 2.3.

Comment 9: The commenter would like to see graphs of the relative contributions of ammonium sulfate, ammonium nitrate and particulate organic mass to light extinction at LWA and TRNP.

Response: Four graphs with the requested data has been provided as Figures 2.6-2.9

Comment 10: The commenter suggested that the WRAP data substitution procedures be applied to 2011 and 2012 IMPROVE data for LWA.

Response: Agreed. Table 2.10b has been revised based on the WRAP IMPROVE Data Substitution memo dated June 2011. All other tables have been revised accordingly.

Comment 11: The commenter asks that the additional amount of NO_x reductions that will be achieved by 2018 be quantified.

Response: The exact amount of additional reductions is unknown. Full controls have not been installed at Leland Olds Station, Coyote Station, Antelope Valley Station or Stanton Station. NO_x emissions from the EGU's could (depending on utilization of the units) decrease by another 9,000 tons per year.

Comment 12: The commenter recommended that the 2011 emissions inventory for oil and gas sources in Table 2.12 (now Table 2.13) utilize the BLM's inventory.

Response: The NDDH agrees except for SO_2. As Environ (the BLM contractor) has pointed out, there is a lot of uncertainty in the SO_2 numbers because of the concentration of sulfur in the Bakken gas. The NDDH believes Environ has overestimated the SO_2 emissions because they overestimated the sulfur content of the Bakken gas. The NDDH believes the average sulfur content in the gas is around 10 ppm. We believe Environ's January 2014 estimate and the 2011 NEI estimate are more accurate.

Comment 13: The commenter would like the NDDH to change the SO_2 emissions estimate in Table 2.13 (now Table 2.14) to match the BLM estimate.

Response: See response to Comment 12.

Comment 14: The commenter would like Figures 2.6 and 2.7 and Table 2.14 be revised to include projections for 2018.

Response: Emissions estimates for 2018 for oil and gas are included in Table 2.13 (now Table 2.14) based on the BLM inventory (with adjustments for SO_2). The purpose of Table 2.14 (now table 2.15) is to show the difference between the various estimates of emissions that have been made, not to project future emissions. The purpose of Figures 2.6 and 2.7 is to show when the expansion of oil and gas development began and to graphically show the rapid expansion of the industry. Any projection to 2018 is speculative and may mislead the reader because of flaring controls established by the North Dakota Industrial Commission and the NDDH policy for controlling emissions from Bakken wells. The important data element is emissions projected to 2018 which is included in Table 2.13 (now Table 2.14).

Comment 15: The commenter recommended additional controls for EGUs for the 2018 SIP. The commenter believes SCR is technically feasible for Coyote Station, M.R. Young Station Units 1 and 2 and Leland Olds Unit 2 (cyclone boilers). The commenter noted that the "Reasonable Progress" NO_x limit for Coyote Station is greater than the BART limits for M.R.Young Station Units 1 and 2 and Leland Olds Station Unit 2.

Response: SCR has been shown to be not technically feasible for cyclone boilers that burn North Dakota lignite (see Amendment No 1 to RH SIP). The determination that SCR is not technically feasible was upheld by the U.S. District Court for the District of North Dakota, Southwestern Division (Case No: 1:06-cv-035, Dec. 12, 2011). Until additional information is supplied that proves the technical feasibility of SCR for these units, the NDDH considers SCR technically infeasible.

In Section 9.5.1 of the RH SIP, it was determined that additional NO_x controls on Coyote Station were not warranted under the "Reasonable Progress" portion of the SIP. The NDDH negotiated additional NO_x controls with the operators of the Coyote Station. Although the NO_x emissions limit is greater than the limit for M.R.Young 1 and 2 and Leland Olds 2, the reductions are greater than required by the "Reasonable Progress" analysis. Coyote Station will be reevaluated for the 2018 RH SIP and additional controls required if warranted.

Comment 16: NDDH has not addressed the impact of emissions on the ability of neighboring station to meet the reasonable progress goals.

Response: A paragraph has been added to Section 2.1.1 which addresses this issue.

Comment 17: The commenter recommends that NDDH begin evaluating control measures for oil and gas, and potentially EGUs, in preparation for the 2018 regional haze SIP revision.

Response: The recommendation is noted.

<u>EPA Comments</u> (that are different from FLM comments)

Comment 18: The commenter recommends that NDDH remove the statement that TRNP consists of three separate units.

Response: The NDDH disagrees with this comment. North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The Department considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observed features in another unit.

Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The NDDH has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The NPS has assigned the units three different names, the South Unit, the North Unit and the Elkhorn Ranch Unit.

Comment 19: EPA would like the Department to revise Section 1.2 to indicate the FIP will result in greater visibility improvement than the original SIP. The commenter also recommended that the report indicate that NDDH anticipates new modeling for the 2018 SIP which will establish Reasonable Progress goals.

Response: The actual amount of visibility improvement expected from the FIP for Antelope Valley Station has been included in the discussion as well as a statement regarding 2018 modeling. Improvements from the FIP for Coal Creek Station were not included since it is being reconsidered.

Comment 20: There is a typo in Table 1.4

Response: Agreed. Table 1.4 has been revised.

Comment 21: The NDDH's assessment that oil and gas activity is not adversely affecting visibility may be premature. Reductions at other sources may be offsetting the effects of oil and gas sources.

Response: Based on the data that is available for this report, there is no evidence that demonstrates that oil and gas emissions are adversely affecting visibility. The language in this section has been revised.

Comment 22: EPA encourages the state to continue investigating the reasons sulfate extinction is not decreasing and oil and gas impacts.

Response: The recommendation is noted.

4. Public Hearing Record

- Public Notice
- Notice of Interested Parties
- Affidavit of Publication
- Invoice of Publication
- Public Comments
- Response to Public Comments

Appendix A

State and Class I Area Summaries

6.0 STATE AND CLASS I AREA SUMMARIES

As described in Section 2.0, each state is required to submit progress reports at interim points between submittals of Regional Haze Rule (RHR) State Implementation Plans (SIPs), which assess progress towards visibility improvement goals in each state's mandatory Federal Class I areas (CIAs). Data summaries for each CIA in each Western Regional Air Partnership (WRAP) state, which address Regional Haze Rule (RHR) requirements for visibility measurements and emissions inventories are provided in this section. These summaries are intended to provide individual states with the technical information they need to determine if current RHR implementation plan elements and strategies are sufficient to meet all established reasonable progress goals, as defined in their respective initial RHR implementation plans.

6.10 NORTH DAKOTA

The goal of the RHR is to ensure that visibility on the 20% most impaired, or worst, days continues to improve at each Federal Class I area (CIA), and that visibility on the 20% least impaired, or best, days does not get worse, as measured at representative Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites. North Dakota has 2 mandatory Federal CIAs, which are depicted in Figure 6.10-1 and listed in Table 6.10-1, along with the associated IMPROVE monitor locations.

This section addresses differences between the 2000-2004 baseline and 2005-2009 period, for both monitored data and emission inventory estimates. Monitored data are presented for the 20% most impaired, or worst, days and for the 20% least impaired, or best, days, as per Regional Haze Rule (RHR) requirements. Annual average trend statistics for the 2000-2009 10-year period are also presented here to support assessments of changes in each monitored species that contributes to visibility impairment. Some of the highlights regarding these comparisons are listed below, and more detailed state specific information is provided in monitoring and emissions sub-sections that follow.

- For the best days, the 5-year average deciview metric decreased at both the THRO1 and LOST1 sites.
- For the worst days, the 5-year average deciview metric decreased at the THRO1 site and remained the same at the LOST1 site.
- Both sites showed decreases in ammonium nitrate, which is consistent with emission inventories showing decreases in mobile and point source NO_X emissions.
- Both sites showed increases in 5-year average ammonium sulfate, and the LOST1 showed a statistically significant increasing annual trend. This was not consistent with a comparison of emissions inventories and summaries of annual EGU emissions which showed decreased SO_2 due to point and area sources. Increases in ammonium sulfate were also observed at the nearby MELA1 site in Montana. Both of these sites are near the Canadian border, so it is possible that international emissions affected these measurements.
- Both sites showed decreases in particulate organic mass, and emission inventories indicated that these measurements are largely due to fire impacts, which are highly variable from year-to-year.

Figure 6.10-1. Map Depicting Federal CIAs and Representative IMPROVE Monitors in North Dakota.

Table 6.10-1
North Dakota CIAs and Representative IMPROVE Monitors

Class I Area	Representative IMPROVE Site	Latitude	Longitude	Elevation (m)
Lostwood WA	LOST1	48.64	-102.40	696
Theodore Roosevelt NP	THRO1	46.89	-103.38	852

6.10.1 Monitoring Data

This section addresses RHR regulatory requirements for monitored data as measured by IMPROVE monitors representing Federal CIAs in North Dakota. These summaries are supported by regional data presented in Section 4.0 and by more detailed site specific tables and charts in Appendix J.

As described in Section 3.1, regional haze progress in Federal CIAs is tracked using calculations based on speciated aerosol mass as collected by IMPROVE monitors. The RHR calls for tracking haze in units of deciviews (dv), where the deciview metric was designed to be linearly associated with human perception of visibility. In a pristine atmosphere, the deciview metric is near zero, and a one deciview change is approximately equivalent to a 10% change in cumulative species extinction. To better understand visibility conditions, summaries here include both the deciview metric, and the apportionment of haze into extinction due to the various measured species in units of inverse megameters (Mm^{-1}).

6.10.1.1 Current Conditions

This section addresses the regulatory question, ***what are the current visibility conditions for the most impaired and least impaired days (40 CFR 51.308 (g)(3)(i))?*** RHR guidance specifies that 5-year averages be calculated over successive 5-year periods, i.e. 2000-2004, 2005-2009, 2010-2014, etc.[1] Current visibility conditions are represented here as the most recent successive 5-year average period available, or the 2005-2009 period average, although the most recent IMPROVE monitoring data currently available includes 2010 data.

Tables 6.10-2 and 6.10-3 present the calculated deciview values for current conditions at each site, along with the percent contribution to extinction from each aerosol species for the 20% most impaired, or worst, and 20% least impaired, or best, days for each of the Federal CIA IMPROVE monitors in North Dakota. Figure 6.10-2 presents 5-year average extinction for the current progress period for both the 20% most impaired and 20% least impaired days. Note that the percentages in the tables consider only the aerosol species which contribute to extinction, while the charts also show Rayleigh, or scattering due to background gases in the atmosphere.

Specific observations for the current visibility conditions on the 20% most impaired days are as follows:

- The largest contributors to aerosol extinction at North Dakota sites were ammonium sulfate, ammonium nitrate and particulate organic mass.

Specific observations for the current visibility conditions on the 20% least impaired days are as follows:

- The aerosol contribution to total extinction on the best days was less than Rayleigh, or the background scattering that would occur in clear air.
- For both North Dakota sites, ammonium sulfate was the largest contributor to the non-Rayleigh aerosol species of extinction

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[1] EPA's September 2003 *Guidance for Tracking Progress Under the Regional Haze Rule* specifies that progress is tracked against the 2000-2004 baseline period using corresponding averages over successive 5-year periods, i.e. 2005-2009, 2010-2014, etc. (See page 4-2 in the Guidance document.)

Table 6.10-2
North Dakota Class I Area IMPROVE Sites
Current Visibility Conditions
2005-2009 Progress Period, 20% Most Impaired Days

Site	Deciviews (dv)	Percent Contribution to Aerosol Extinction by Species (Excludes Rayleigh) (% of Mm^{-1}) and Rank*						
		Ammonium Sulfate	**Ammonium Nitrate**	**Particulate Organic Mass**	**Elemental Carbon**	**Soil**	**Coarse Mass**	**Sea Salt**
LOST1	19.6	**37% (1)**	35% (2)	16% (3)	4% (5)	1% (6)	6% (4)	1% (7)
THRO1	17.6	**37% (1)**	25% (2)	21% (3)	5% (5)	2% (6)	9% (4)	1% (7)

*Highest aerosol species contribution per site is highlighted in bold.

Table 6.10-3
North Dakota Class I Area IMPROVE Sites
Current Visibility Conditions
2005-2009 Progress Period, 20% Least Impaired Days

Site	Deciviews (dv)	Percent Contribution to Aerosol Extinction by Species (Excludes Rayleigh) (% of Mm^{-1}) and Rank*						
		Ammonium Sulfate	**Ammonium Nitrate**	**Particulate Organic Mass**	**Elemental Carbon**	**Soil**	**Coarse Mass**	**Sea Salt**
LOST1	8.1	**40% (1)**	13% (4)	16% (3)	6% (5)	3% (6)	21% (2)	1% (7)
THRO1	6.7	**39% (1)**	11% (4)	17% (3)	10% (5)	3% (6)	20% (2)	1% (7)

*Highest aerosol species contribution per site is highlighted in bold.

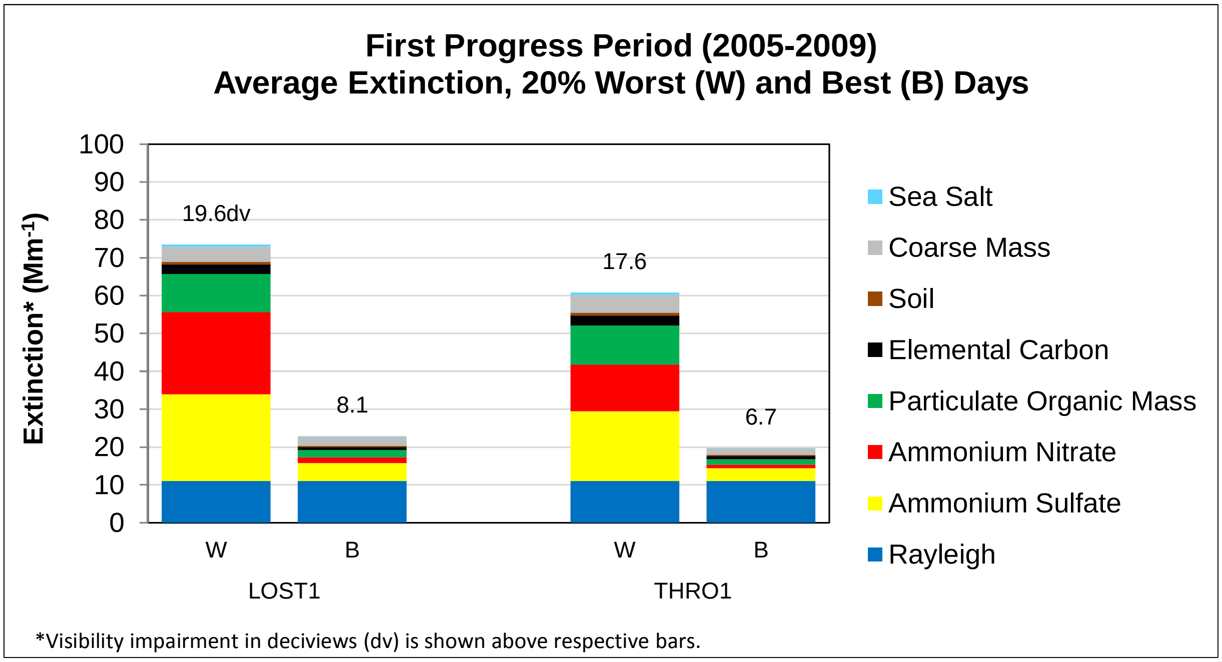

Figure 6.10-2. Average Extinction for Current Progress Period (2005-2009) for the Worst (Most Impaired) and Best (Least Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

6.10.1.2 Differences between Current and Baseline Conditions

This section addresses the regulatory question, ***what is the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions (40 CFR 51.308 (g)(3)(ii))?*** Included here are comparisons between the 5-year average baseline conditions (2000-2004) and current progress period extinction (2005-2009).

Table 6.10-4 presents the differences between the 2000-2004 baseline period average extinction and the 2005-2009 progress period average for each site in North Dakota for the 20% most impaired days, and Table 6.10-5 presents similar data for the least impaired days. Averages that increased are depicted in red text and averages that decreased in blue.

Figure 6.10-3 presents the 5-year average extinction for the baseline and current progress period averages for the worst days and Figure 6.10-4 presents the differences in averages by aerosol species, with increases represented above the zero line and decreases below the zero line. Figures 6.10-5 and 6.10-6 present similar plots for the best days.

For the 20% most impaired days, the 5-year average deciview metric decreased between the 2000-2004 and 2005-2009 periods at the THRO1 site and remained the same at the LOST1 site. Notable differences for individual species averages were as follows:

- Ammonium nitrate, particulate organic mass, and elemental carbon averages decreased at both sites.
- Ammonium sulfate and sea salt averages increased at both sites.

Table 6.10-4
North Dakota Class I Area IMPROVE Sites
Difference in Aerosol Extinction by Species
2000-2004 Baseline Period to 2005-2009 Progress Period
20% Most Impaired Days

Site	Deciview (dv)			Change in Extinction by Species (Mm^{-1})*						
	2000-04 Baseline Period	2005-09 Progress Period	Change in dv*	Amm. Sulfate	Amm. Nitrate	POM	EC	Soil	CM	Sea Salt
LOST1	19.6	19.6	0.0	+1.5	-1.2	-0.9	-0.3	0.0	+0.1	+0.3
THRO1	17.8	17.6	-0.2	+0.9	-1.4	-0.5	-0.1	-0.1	-0.1	+0.5

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction and values in blue indicate decreases.

Table 6.10-5
North Dakota Class I Area IMPROVE Sites
Difference in Aerosol Extinction by Species
2000-2004 Baseline Period to 2005-2009 Progress Period
20% Least Impaired Days

Site	Deciview (dv)			Change in Extinction by Species (Mm^{-1})*						
	2000-04 Baseline Period	2005-09 Progress Period	Change in dv*	Amm. Sulfate	Amm. Nitrate	POM	EC	Soil	CM	Sea Salt
LOST1	8.2	8.1	-0.1	+0.4	-0.3	-0.3	0.0	0.0	+0.2	+0.1
THRO1	7.8	6.7	-1.1	-0.4	-0.6	-0.5	-0.1	-0.1	-0.5	0.0

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction and values in blue indicate decreases.

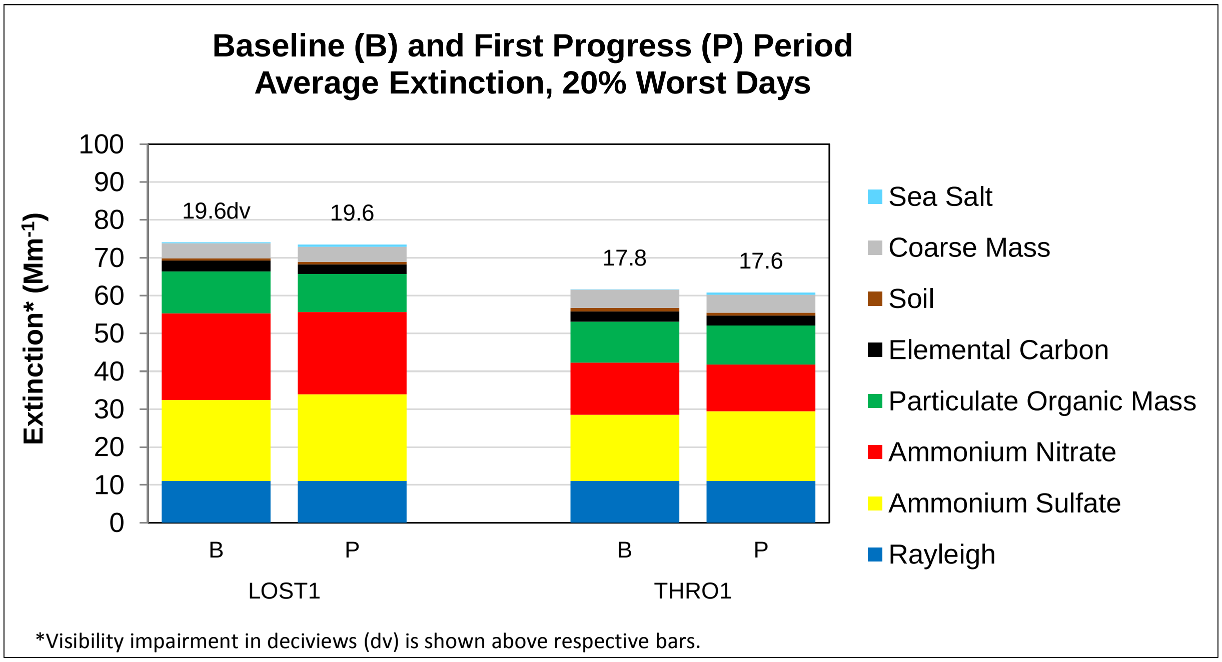

Figure 6.10-3. Average Extinction for Baseline and Progress Period Extinction for Worst (Most Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

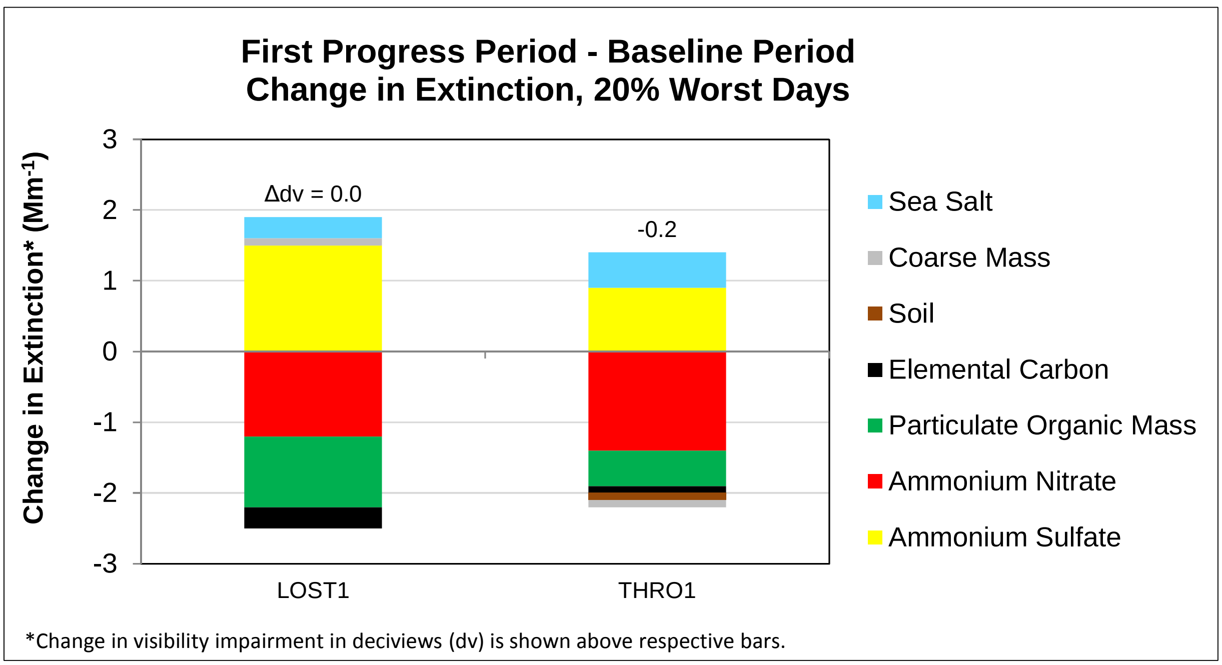

Figure 6.10-4. Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Worst (Most Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

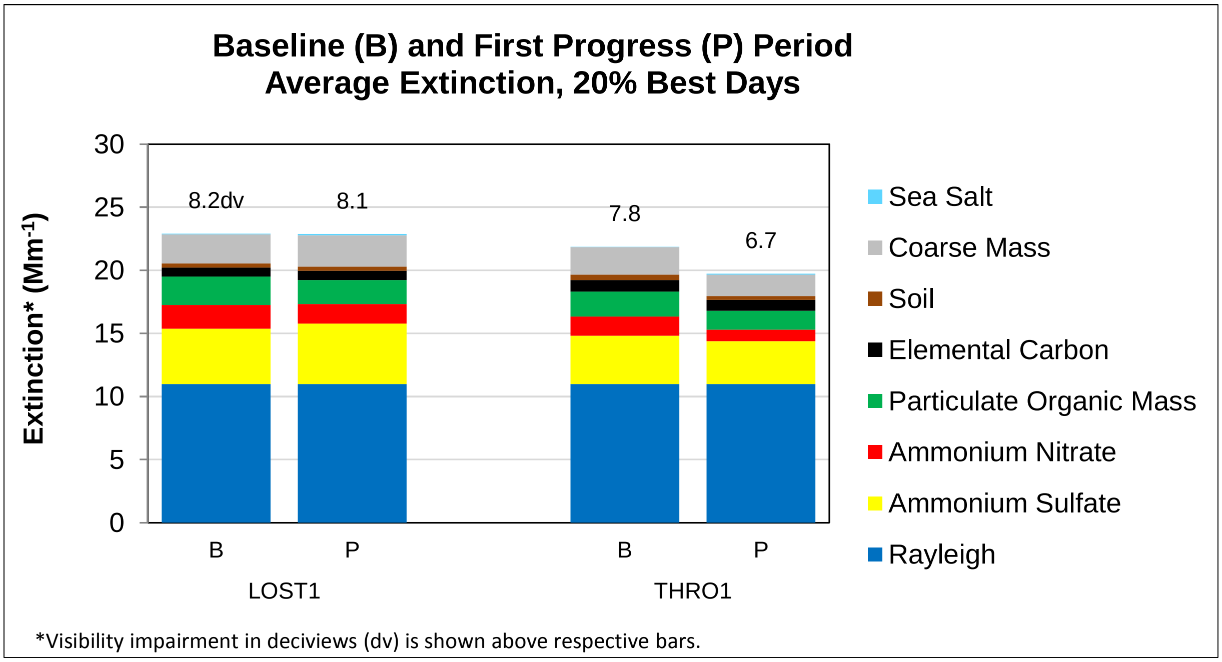

Figure 6.10-5. Average Extinction for Baseline and Progress Period Extinction for Best (Least Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

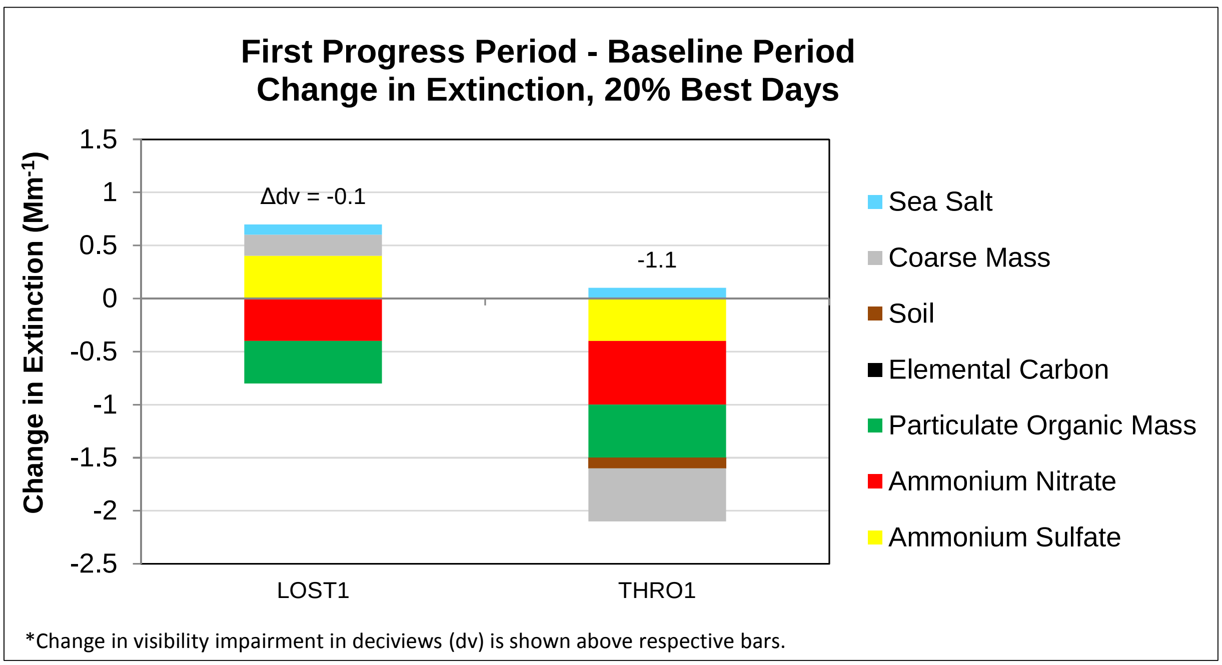

Figure 6.10-6. Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Best (Least Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

6.10.1.3 Changes in Visibility Impairment

This section addresses the regulatory question, ***what is the change in visibility impairment for the most impaired and least impaired days over the past 5 years (40 CFR 51.308 (g)(3)(iii))?*** Included here are changes in visibility impairment as characterized by annual average trend statistics, and some general observations regarding local and regional events and outliers on a daily and annual basis that affected the current 5-year progress period. The regulatory requirement asks for a description of changes over the past 5-year period, but trend analysis is better suited to longer periods of time, so trends for the entire 10-year planning period are presented here.

Trend statistics for the years 2000-2009 for each species at each site in North Dakota are summarized in Table 6.10-6, and regional trends were presented earlier in Section 4.1.1.[2] Only trends for aerosol species trends with p-value statistics less than 0.15 (85% confidence level) are presented in the table here, with increasing slopes in red and decreasing slopes in blue.[3] In some cases, trends may show decreasing tendencies while the difference between the 5-year averages do not (or vice versa), as discussed in Section 3.1.2.2. In these cases, the 5-year average for the best and worst days is the important metric for RHR regulatory purposes, but trend statistics may be of value to understand and address visibility impairment issues for planning purposes.

For each site, a more comprehensive list of all trends for all species, including the associated p-values, is provided in Appendix J. Additionally, this appendix includes plots depicting 5-year, annual, monthly, and daily average extinction for each site. These plots are intended to provide a fairly comprehensive compilation of reference information for individual states to investigate local and regional events and outliers that may have influenced changes in visibility impairment as tracked using the 5-year deciview metrics. Note that similar summary products are also available from the WRAP TSS website (http://vista.cira.colostate.edu/tss/). Some general observations regarding changes in visibility impairment at sites in North Dakota are as follows:

- For ammonium sulfate, the 5-year average for the worst days increased at both North Dakota sites, and showed an increasing annual average trend at the LOST1 site.
- For ammonium nitrate, the 5-year average for the worst days decreased at both North Dakota sites, and showed a decreasing annual average trend at the THRO1 site.
- Elemental carbon and particulate organic mass showed decreasing annual average trends at both sites.

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[2] Annual trends were calculated for the years 2000-2009, with a trend defined as the slope derived using Theil statistics. Trends derived from Theil statistics are useful in analyzing changes in air quality data because these statistics can show the overall tendency of measurements over long periods of time, while minimizing the effects of year-to-year fluctuations which are common in air quality data. Theil statistics are also used in EPA's National Air EPA's National Air Quality Trends Reports (http://www.epa.gov/airtrends/) and the IMPROVE program trend reports (http://vista.cira.colostate.edu/improve/Publications/improve_reports.htm)

[3] The significance of the trend is represented with p-values calculated using Mann-Kendall trend statistics. Determining a significance level helps to distinguish random variability in data from a real tendency to increase or decrease over time, where lower p-values indicate higher confidence levels in the computed slopes.

Table 6.10-6
North Dakota Class I Area IMPROVE Sites
Change in Aerosol Extinction by Species
2000-2009 Annual Average Trends

Site	Group	Annual Trend* (Mm^{-1}/year)						
		Ammonium Sulfate	**Ammonium Nitrate**	**Particulate Organic Mass**	**Elemental Carbon**	**Soil**	**Coarse Mass**	**Sea Salt**
LOST1	20% Best	--	0.0	--	--	--	--	0.0
	20% Worst	--	--	--	**-0.1**	--	**-0.1**	--
	All Days	**0.1**	--	**-0.2**	**-0.1**	--	--	0.0
THRO1	20% Best	**-0.1**	**-0.1**	**-0.1**	--	0.0	0.0	0.0
	20% Worst	--	--	--	--	0.0	**-0.1**	0.0
	All Days	--	**-0.1**	--	**-0.1**	--	--	0.0

*(--) Indicates statistically insignificant trend (<85% confidence level). Annual averages and complete trend statistics for all significance levels are included for each site in Appendix J.

6.10.2 Emissions Data

Included here are summaries depicting differences between two emission inventory years that are used to represent the 5-year baseline and current progress periods. The baseline period is represented using a 2002 inventory developed by the WRAP for use in the initial WRAP state SIPs, and the progress period is represented by a 2008 inventory which leverages recent WRAP inventory work for modeling efforts, as referenced in Section 3.2.1. For reference, Table 6.10-7 lists the major emitted pollutants inventoried, the related aerosol species, some of the major sources for each pollutant, and some notes regarding implications of these pollutants. Differences between these baseline and progress period inventories, and a separate summary of annual emissions from electrical generating units (EGUs), are presented in this section.

Table 6.10-7
North Dakota
Pollutants, Aerosol Species, and Major Sources

Emitted Pollutant	Related Aerosol	Major Sources	Notes
Sulfur Dioxide (SO_2)	Ammonium Sulfate	Point Sources; On- and Off-Road Mobile Source	SO_2 emissions are generally associated with anthropogenic sources such as coal-burning power plants, other industrial sources such and refineries and cement plants, and both on- and off-road diesel engines.
Oxides of Nitrogen (NO_X)	Ammonium Nitrate	On- and Off-Road Mobile Sources; Point Sources; Area Sources	NO_X emissions are generally associated with anthropogenic sources. Common sources include virtually all combustion activities, especially those involving cars, trucks, power plants, and other industrial processes.
Ammonia (NH_3)	Ammonium Sulfate and Ammonium Nitrate	Area Sources; On-Road Mobile Sources	Gaseous NH_3 has implications in particle formation because it can form particulate ammonium. Ammonium is not directly measured by the IMPROVE program, but affects formation potential of ammonium sulfate and ammonium nitrate. All measured nitrate and sulfate is assumed to be associated with ammonium for IMPROVE reporting purposes.
Volatile Organic Compounds (VOCs)	Particulate Organic Mass (POM)	Biogenic Emissions; Vehicle Emissions; Area Sources	VOCs are gaseous emissions of carbon compounds, which are often converted to POM through chemical reactions in the atmosphere. Estimates for biogenic emissions of VOCs have undergone significant updates since 2002, so changes reported here are more reflective of methodology changes than actual changes in emissions (see Section 3.2.1).
Primary Organic Aerosol (POA)	POM	Wildfires; Area Sources	POA represents organic aerosols that are emitted directly as particles, as opposed to gases. Wildfires in the west generally dominate POA emissions, and large wildfire events are generally sporadic and highly variable from year-to-year.
Elemental Carbon (EC)	EC	Wildfires; On- and Off-Road Mobile Sources	Large EC events are often associated with large POM events during wildfires. Other sources include both on- and off-road diesel engines.
Fine soil	Soil	Windblown Dust; Fugitive Dust; Road Dust; Area Sources	Fine soil is reported here as the crustal or soil components of $PM_{2.5}$.
Coarse Mass (PMC)	Coarse Mass	Windblown Dust; Fugitive Dust	Coarse mass is reported by the IMPROVE Network as the difference between PM_{10} and $PM_{2.5}$ mass measurements. Coarse mass is not separated by species in the same way that $PM_{2.5}$ is speciated, but these measurements are generally associated with crustal components. Similar to crustal $PM_{2.5}$, natural windblown dust is often the largest contributor to PMC.

6.10.2.1 Changes in Emissions

This section addresses the regulatory question, ***what is the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State (40 CFR 51.308 (g)(4))?*** For these summaries, emissions during the baseline years are represented using a 2002 inventory, which was developed with support from the WRAP for use in the original RHR SIP strategy development (termed plan02d). Differences between inventories are represented as the difference between the 2002 inventory, and a 2008 inventory which leverages recent inventory development work performed by the WRAP for the WestJumpAQMS and $DEASCO_3$ modeling projects (termed WestJump2008). Note that the comparisons of differences between inventories does not necessarily reflect a change in emissions, as a number of methodology changes and enhancements have occurred between development of the individual inventories, as referenced in Section 3.2.1. Inventories for all major visibility impairing pollutants are presented for major source categories, and categorized as either anthropogenic or natural emissions. State-wide inventories totals and differences are presented here, and inventory totals on a county level basis are available on the WRAP Technical Support System website (http://vista.cira.colostate.edu/tss/).

Table 6.10-8 and Figure 6.10-7 present the differences between the 2002 and 2008 sulfur dioxide (SO_2) inventories by source category. Tables 6.10-9 and Figure 6.10-8 present data for oxides of nitrogen (NO_X), and subsequent tables and figures (Tables 6.10-10 through 6.10-15 and Figures 6.10-9 through 6.10-14) present data for ammonia (NH_3), volatile organic compounds (VOCs), primary organic aerosol (POA), elemental carbon (EC), fine soil, and coarse mass. Inventory totals on a county level basis will be made available on the WRAP TSS website (http://vista.cira.colostate.edu/tss/). General observations regarding emissions inventory comparisons are listed below.

- Largest differences for point source inventories were decreases in SO_2 and NO_X, and increases in NH_3 and VOCs. Note that decreases in SO_2 and NO_X for point sources are consistent with the summary of annual EGU emissions as included in Section 6.10.2.2.
- Area source inventories showed decreases in SO_2, NH_3, and VOCs, with increases in NO_X. These changes may be due to a combination of population changes and differences in methodologies used to estimate these emissions, as referenced in Section 3.2.1. One methodology change was the reclassification of some off-road mobile sources (such as some types of marine vessels and locomotives) into the area source category in 2008, which may have contributed to increases in area source inventory totals, but decreases in off-road mobile totals.
- On-road mobile source inventory comparisons showed decreases in most parameters, especially NO_X and VOCs, with slight increases in POA, EC, and coarse mass. Reductions in NO_X and VOC are likely influenced by federal and state emissions standards that have already been implemented. The increases in POA, EC, and coarse mass occurred in all of the WRAP states for on-road mobile inventories, regardless of reductions in NO_2 and VOCs, indicating that these increases were likely due use of different on-road models, as referenced in Section 3.2.1.

- Off-road mobile source inventories showed decreases in NO_X, SO_2, and VOCs, and increases in fine soil and coarse mass, which was consistent with most contiguous WRAP states. These differences were likely due to a combination of actual changes in source contributions and methodology differences, as referenced in Section 3.2.1. As noted previously, one major methodology difference was the reclassification of some off-road mobile sources (such as some types of marine vessels and locomotives) into the area source category in 2008, which may have contributed to decreases in the off-road inventory totals, but increases in area source totals.
- For most parameters, especially POAs, VOCs, and EC, fire emission inventory estimates decreased. Note that these differences are not necessarily reflective of changes in monitored data, as the baseline period is represented by an average of 2000-2004 fire emissions, and the progress period is represented only by the fires that occurred in 2008, as referenced in Section 3.2.1.
- Comparisons between VOC inventories showed large decreases in biogenic emissions, which was consistent with other contiguous WRAP states. Estimates for biogenic emissions of VOCs have undergone significant updates since 2002, so changes reported here are more reflective of methodology changes than actual changes in emissions, as referenced in Section 3.2.1.
- Fine soil and coarse mass decreased for the windblown dust inventory comparisons, and increased for the combined fugitive/road dust inventories. Large variability in changes in windblown dust was observed for the contiguous WRAP states, which was likely due in large part to enhancements in dust inventory methodology, as referenced in Section 3.2.1, rather than changes in actual emissions.

Table 6.10-8
North Dakota
Sulfur Dioxide Emissions by Category

Source Category	Sulfur Dioxide Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	156,668	142,121	-14,547
Area	5,389	729	-4,660
On-Road Mobile	771	156	-615
Off-Road Mobile	6,828	683	-6,144
Area Oil and Gas	358	0	-358
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	268	107	-162
Total Anthropogenic	**170,283**	**143,796**	**-26,486 (-16%)**
Natural Sources			
Natural Fire	195	7	-188
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	**195**	**7**	**-188 (-97%)**
All Sources			
Total Emissions	**170,477**	**143,803**	**-26,674 (-16%)**

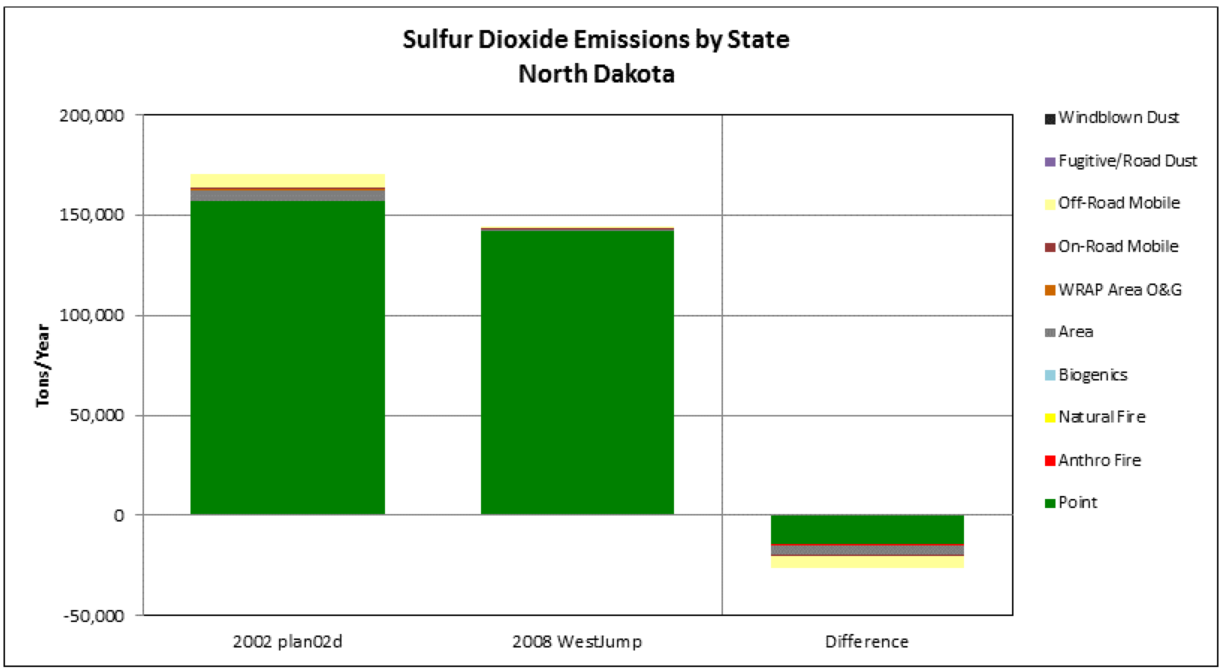


Figure 6.10-7. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Sulfur Dioxide by Source Category for North Dakota.

Table 6.10-9
North Dakota
Nitrogen Oxide Emissions by Category

Source Category	Oxides of Nitrogen Emissions (tons/year)		
	2002 (Plan02d)	**2008 (WestJump2008)**	**Difference (Percent Change)**
Anthropogenic Sources			
Point	87,425	78,252	-9,173
Area	10,826	16,719	5,892
On-Road Mobile	24,746	23,180	-1,566
Off-Road Mobile	55,502	34,572	-20,930
Area Oil and Gas	4,631	0	-4,631
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	995	854	-140
Total Anthropogenic	**184,125**	**153,577**	**-30,548 (-17%)**
Natural Sources			
Natural Fire	766	47	-720
Biogenic	44,569	9,133	-35,436
Wind Blown Dust	0	0	0
Total Natural	**45,335**	**9,180**	**-36,156 (-80%)**
All Sources			
Total Emissions	**229,460**	**162,757**	**-66,703 (-29%)**

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

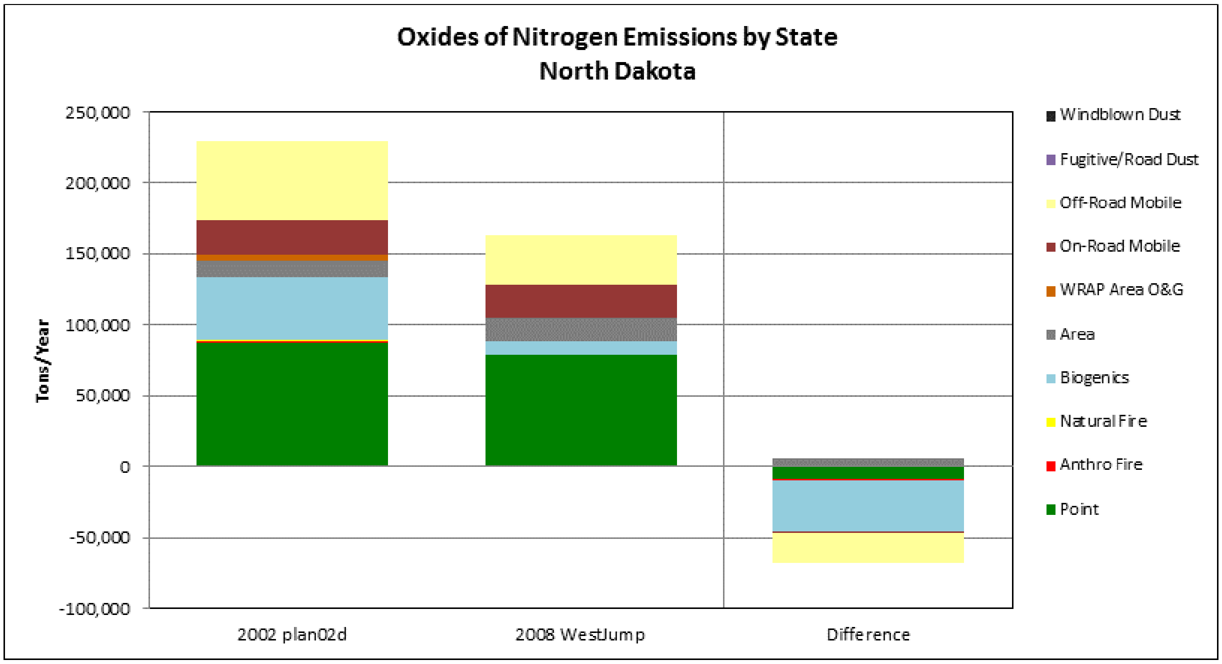


Figure 6.10-8. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Oxides of Nitrogen by Source Category for North Dakota.

Table 6.10-10
North Dakota
Ammonia Emissions by Category

Source Category	Ammonia Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	518	6,372	5,854
Area	118,398	78,857	-39,542
On-Road Mobile	732	345	-387
Off-Road Mobile	33	29	-4
Area Oil and Gas	0	0	0
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	619	529	-90
Total Anthropogenic	**120,300**	**86,131**	**-34,169 (-28%)**
Natural Sources			
Natural Fire	193	33	-160
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	**193**	**33**	**-160 (-83%)**
All Sources			
Total Emissions	**120,493**	**86,164**	**-34,329 (-28%)**

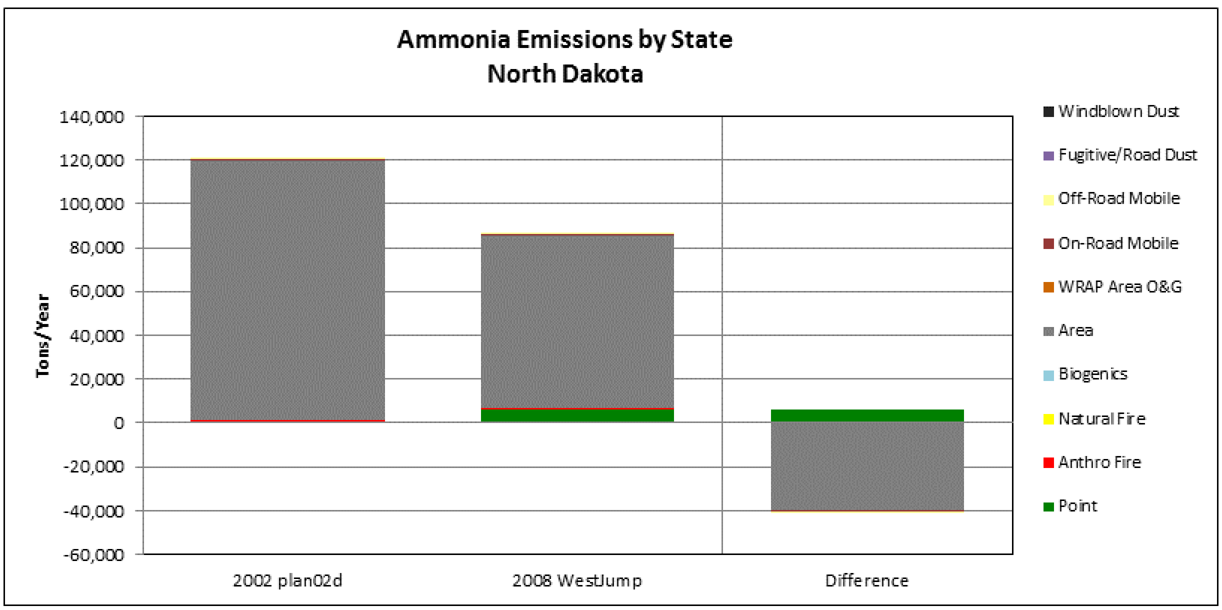


Figure 6.10-9. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Ammonia by Source Category for North Dakota.

Table 6.10-11
North Dakota
Volatile Organic Compound Emissions by Category

Source Category	Volatile Organic Compound Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	2,086	3,877	1,791
Area	60,455	21,194	-39,262
On-Road Mobile	12,814	10,928	-1,885
Off-Road Mobile	13,515	11,892	-1,623
Area Oil and Gas	7,740	0	-7,740
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	2,148	1,674	-474
Total Anthropogenic	**98,758**	**49,566**	**-49,192 (-50%)**
Natural Sources			
Natural Fire	1,701	52	-1,649
Biogenic	233,561	118,195	-115,366
Wind Blown Dust	0	0	0
Total Natural	**235,262**	**118,247**	**-117,015 (-50%)**
All Sources			
Total Emissions	**334,020**	**167,813**	**-166,207 (-50%)**

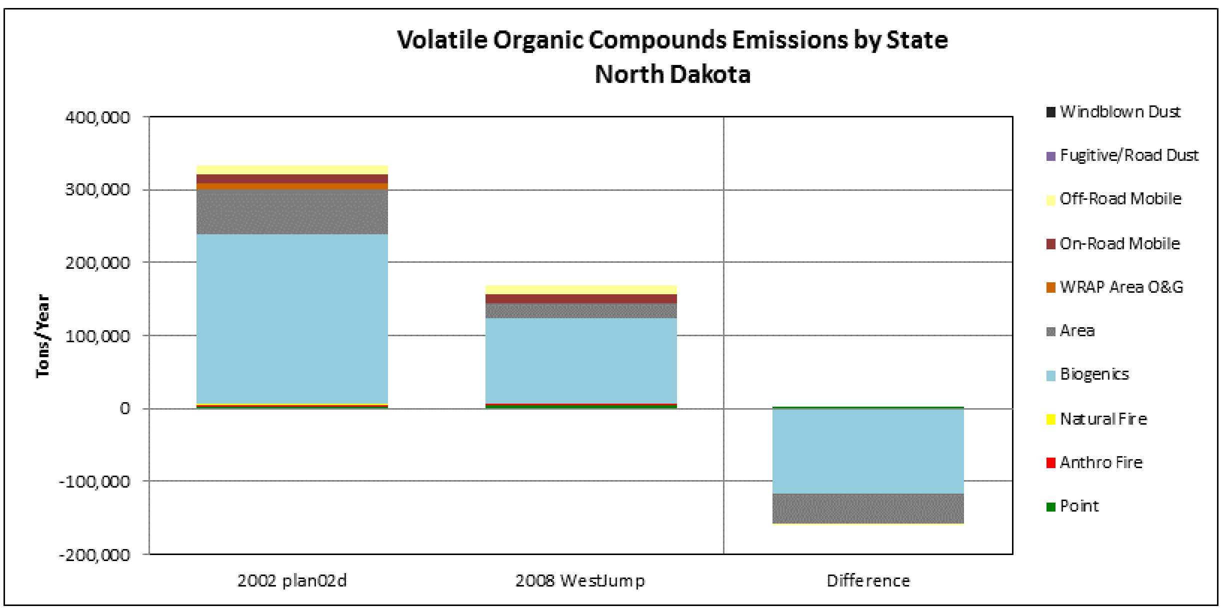


Figure 6.10-10. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Volatile Organic Compounds by Source Category for North Dakota.

Table 6.10-12
North Dakota
Primary Organic Aerosol Emissions by Category

Source Category	Primary Organic Aerosol Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point*	262	144	-118
Area	1,466	920	-546
On-Road Mobile	231	680	449
Off-Road Mobile	1,034	794	-240
Area Oil and Gas	0	0	0
Fugitive and Road Dust	2,190	1,874	-316
Anthropogenic Fire	1,443	990	-452
Total Anthropogenic	**6,626**	**5,402**	**-1,223 (-18%)**
Natural Sources			
Natural Fire	2,214	82	-2,132
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	**2,214**	**82**	**-2,132 (-96%)**
All Sources			
Total Emissions	**8,840**	**5,485**	**-3,355 (-38%)**

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (http://vista.cira.colostate.edu/tss/).

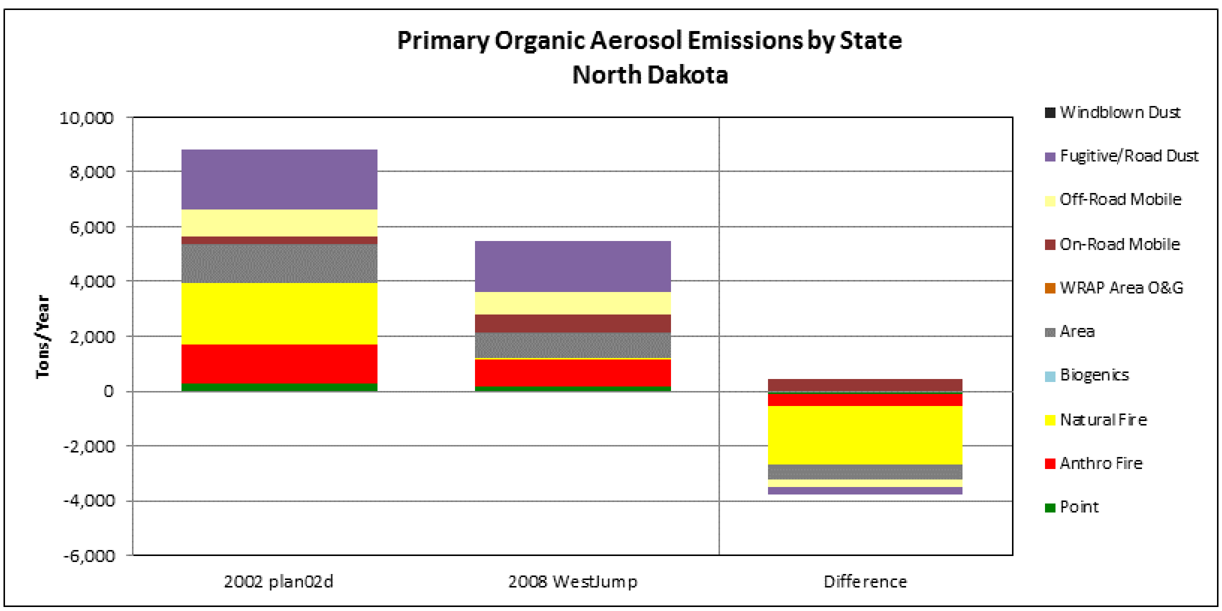


Figure 6.10-11. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Primary Organic Aerosol by Source Category for North Dakota.

Table 6.10-13
North Dakota
Elemental Carbon Emissions by Category

Source Category	Elemental Carbon Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point*	29	6	-23
Area	262	454	192
On-Road Mobile	272	994	722
Off-Road Mobile	3,625	2,337	-1,288
Area Oil and Gas	0	0	0
Fugitive and Road Dust	150	25	-124
Anthropogenic Fire	86	307	221
Total Anthropogenic	**4,423**	**4,124**	**-299 (-7%)**
Natural Sources			
Natural Fire	423	37	-387
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	**423**	**37**	**-387 (-91%)**
All Sources			
Total Emissions	**4,847**	**4,161**	**-686 (-14%)**

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (http://vista.cira.colostate.edu/tss/).

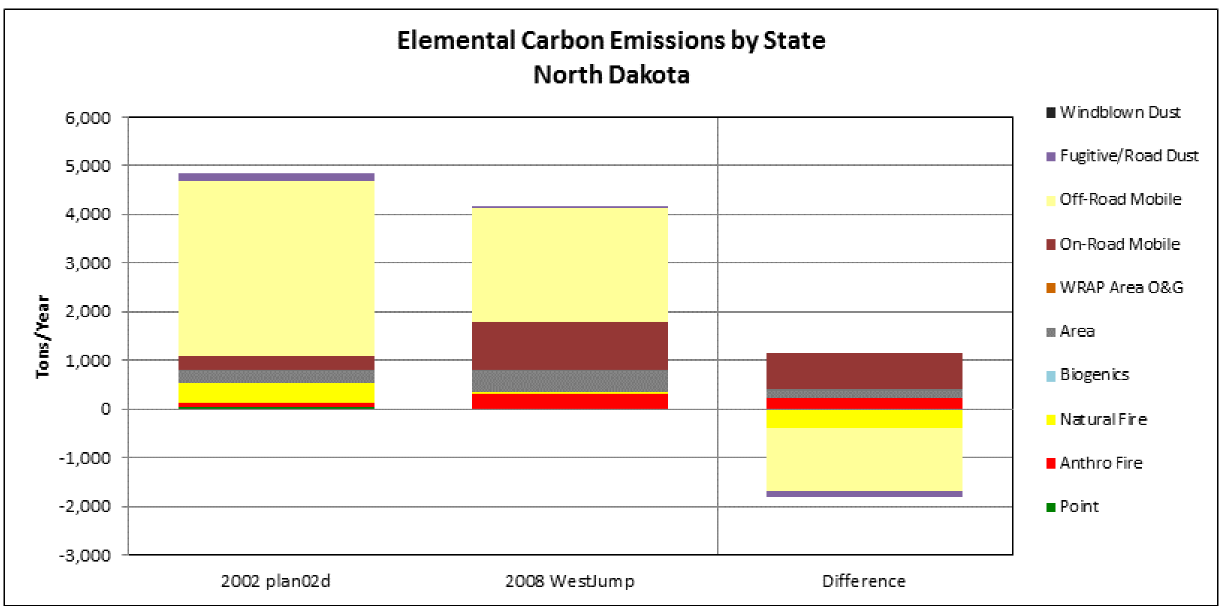


Figure 6.10-12. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Elemental Carbon by Source Category for North Dakota.

Table 6.10-14
North Dakota
Fine Soil Emissions by Category

Source Category	Fine Soil Emissions (tons/year)		
	2002 (Plan02d)	**2008 (WestJump2008)**	**Difference (Percent Change)**
	Anthropogenic Sources		
Point*	2,002	122	-1,880
Area	1,617	413	-1,204
On-Road Mobile	149	98	-52
Off-Road Mobile	0	54	54
Area Oil and Gas	0	0	0
Fugitive and Road Dust	39,440	42,148	2,708
Anthropogenic Fire	596	403	-194
Total Anthropogenic	**43,805**	**43,237**	**-567 (-1%)**
	Natural Sources		
Natural Fire	225	31	-194
Biogenic	0	0	0
Wind Blown Dust	17,639	15,784	-1,855
Total Natural	**17,864**	**15,815**	**-2,049 (-11%)**
	All Sources		
Total Emissions	**61,669**	**59,052**	**-2,617 (-4%)**

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (http://vista.cira.colostate.edu/tss/).

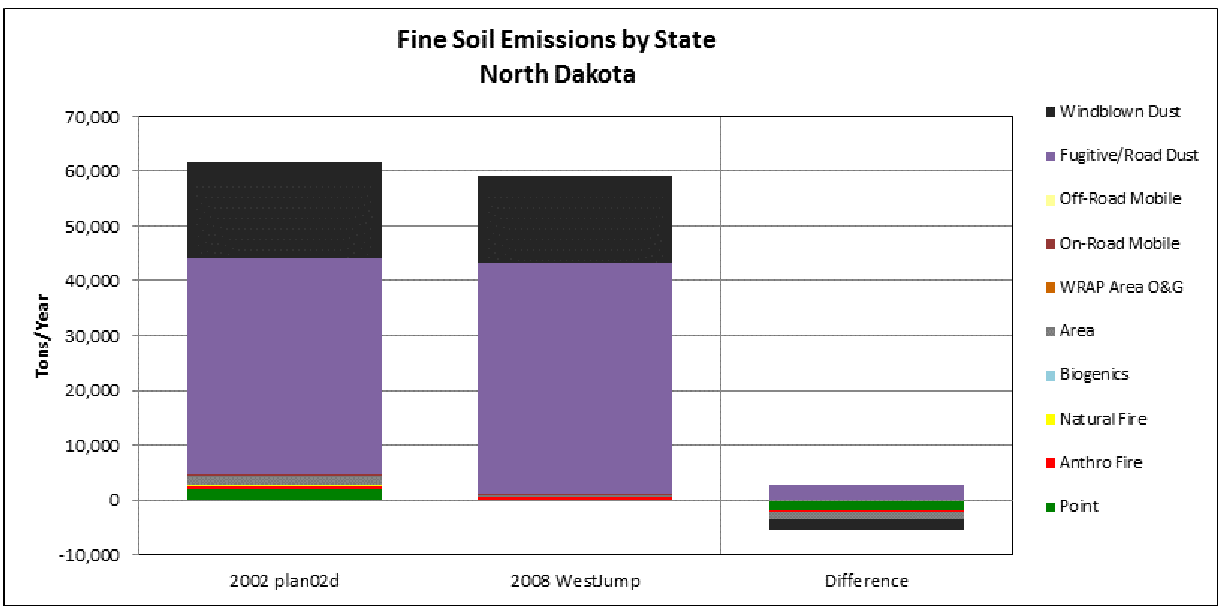


Figure 6.10-13. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Fine Soil by Source Category for North Dakota.

Table 6.10-15
North Dakota
Coarse Mass Emissions by Category

Source Category	Coarse Mass Emissions (tons/year)		
	2002 (Plan02d)	**2008 (WestJump2008)**	**Difference (Percent Change)**
Anthropogenic Sources			
Point*	565	651	86
Area	199	99	-100
On-Road Mobile	141	1,102	961
Off-Road Mobile	0	109	109
Area Oil and Gas	0	0	0
Fugitive and Road Dust	200,777	208,858	8,081
Anthropogenic Fire	62	191	129
Total Anthropogenic	**201,743**	**211,010**	**9,267 (5%)**
Natural Sources			
Natural Fire	441	16	-425
Biogenic	0	0	0
Wind Blown Dust	158,752	142,061	-16,691
Total Natural	**159,193**	**142,077**	**-17,116 (-11%)**
All Sources			
Total Emissions	**360,936**	**353,087**	**-7,849 (-2%)**

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (http://vista.cira.colostate.edu/tss/).

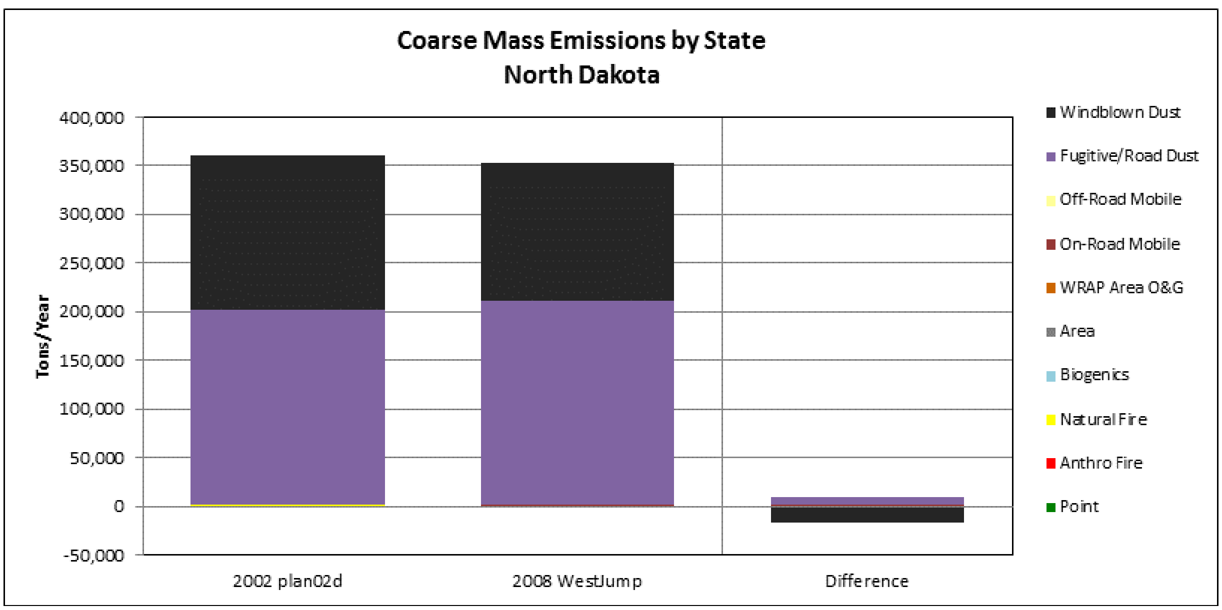


Figure 6.10-14. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Coarse Mass by Source Category for North Dakota.

6.10.2.2 EGU Summary

As described in previous sections, differences between the baseline and progress period inventories presented here do not necessarily represent changes in actual emissions because numerous updates in inventory methodologies have occurred between the development of the separate inventories. Also, the 2002 baseline and 2008 progress period inventories represent only annual snapshots of emissions estimates, which may not be representative of entire 5-year monitoring periods compared. To better account for year-to-year changes in emissions, annual emission totals for North Dakota electrical generating units (EGU) are presented here. EGU emissions are some of the more consistently reported emissions, as tracked in EPA's Air Markets Program Database for permitted Title V facilities in the state (http://ampd.epa.gov/ampd/). RHR implementation plans are required to pay specific attention to certain major stationary sources, including EGUs, built between 1962 and 1977.

Figure 6.10-17 presents a sum of annual NO_X and SO_2 emissions as reported for North Dakota EGU sources between 1996 and 2010. While these types of facilities are targeted for controls in state regional haze SIPs, it should be noted that many of the controls planned for EGUs in the WRAP states had not taken place yet in 2010, while other controls separate from the RHR may have been implemented. The chart shows periods of decline for both SO_2 and NO_X. The chart shows a fairly steady decline for both SO_2 and NO_X emissions in recent years.

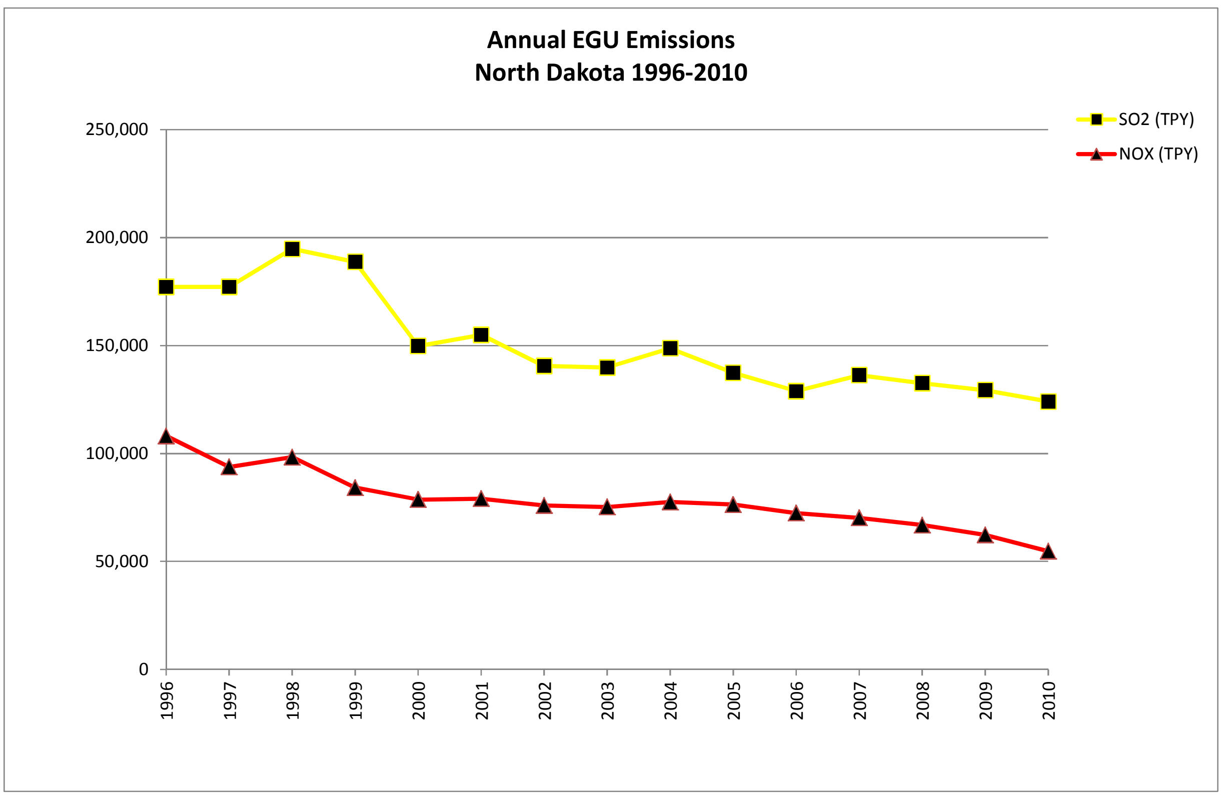


Figure 6.10-17. Sum of EGU Emissions of SO_2 and NO_X reported between 1996 and 2010 for North Dakota.

Appendix B

North Dakota
Class I Area Visibility Monitoring Data Summary
Tables and Charts

APPENDIX J:

North Dakota Class I Area Monitoring Data Summary Tables and Charts

Includes the following subsections:

Subsection	IMPROVE Monitor	Class I Area(s) Represented
J.1	LOST1	Lostwood WA
J.2	THRO1	Theodore Roosevelt NP

J.1. LOSTWOOD WA (LOST1)

The following tables and figures are presented in this section for the Lostwood WA represented by the LOST1 IMPROVE Monitor:

- **Table J.1-1: Annual Averages, 5-Year Period Averages, and Trends:** Table of averages and other metrics for the 20% least impaired days, the 20% most impaired days, and all sampled days is presented.

- **Figure J.1-1: Annual and 5-Year Period Averages for the 20% Most Impaired Visibility Days:** Line graphs depicting annual and period averages by component are presented.

- **Figure J.1-2: Annual and 5-Year Period Averages for the 20% Least Impaired Visibility Days:** Line graphs depicting annual and period averages by component are presented.

- **Figure J.1-3: 20% Most Impaired Visibility Days:** Pie charts depicting period averages and stacked bar charts depicting annual averages by component for the 20% most impaired days are presented.

- **Figure J.1-4: 20% Least Impaired Visibility Days:** Pie charts depicting period averages and stacked bar charts depicting annual averages by component are presented.

- **Figure J.1-5: 2000-2004 Monthly Average Aerosol Extinction, All Monitored Days:** Line graphs depicting monthly averages by year and component for the baseline period are presented.

- **Figure J.1-6: 2005-2009 Monthly Average Aerosol Extinction, All Monitored Days:** Line graphs depicting monthly averages by year and component for the progress period are presented.

- **Figure J.1-7: 2000-2004 Progress Period Extinction, All Sampled Days:** Stacked bar charts depicting daily averages by year and component for the baseline period are presented.

- **Figure J.1-8: 2000-2004 Progress Period Extinction, All Sampled Days**: Stacked bar charts depicting daily averages by year and component for the progress period are presented.

Table J.1-1
Lostwood WA, ND (LOST1 Site)
Annual Averages, 5-Year Period Averages and Trends

Group	Baseline Period					Progress Period						2000-2009 Trend Statistics*		Period Averages**			
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Slope (change/yr.)	p-value	Baseline (B)	Progress (P)	Difference (P -B)	Percent Change
Deciview (dv)																	
Best 20% Days	9.1	8.2	7.9	7.9	7.9	7.6	7.8	8.8	8.2	8.4	7.4	0.0	0.5	8.2	8.1	-0.1	-1%
Worst 20% Days	19.7	20.6	18.8	18.6	20.2	20.5	19.6	19.1	19.7	18.9	21.3	-0.1	0.3	19.6	19.6	0.0	0%
All Days	14.1	14.0	13.0	13.1	13.0	13.2	13.3	13.3	13.9	13.3	13.8	0.0	0.4	13.4	13.4	0.0	0%
Total Extinction (Mm-1)																	
Best 20% Days	25.0	22.8	22.2	22.2	22.2	21.6	22.2	24.3	23.0	23.4	21.2	0.0	0.5	22.9	22.9	0.0	0%
Worst 20% Days	75.3	80.2	67.6	65.6	81.7	78.9	74.8	69.3	74.5	70.0	86.3	-0.6	0.2	74.0	73.5	-0.5	-1%
All Days	44.5	44.9	39.9	40.0	41.7	42.0	41.8	40.6	43.9	41.2	45.2	-0.1	0.4	42.2	41.9	-0.3	-1%
Ammonium Sulfate Extinction (Mm-1)																	
Best 20% Days	5.3	4.7	3.8	3.9	4.3	4.7	4.0	5.4	4.4	5.2	4.4	0.1	0.3	4.4	4.8	0.4	9%
Worst 20% Days	20.0	21.5	20.1	18.6	26.8	29.9	20.2	22.9	20.3	21.3	34.0	0.1	0.2	21.4	22.9	1.5	7%
All Days	11.4	11.5	10.8	9.7	11.4	13.3	11.3	11.7	12.0	11.9	13.8	0.1	0.1	10.9	12.1	1.2	11%
Ammonium Nitrate Extinction (Mm-1)																	
Best 20% Days	2.4	1.6	1.8	1.7	1.8	1.7	1.8	1.5	1.1	1.7	1.1	0.0	0.1	1.9	1.5	-0.4	-21%
Worst 20% Days	16.0	29.3	23.3	19.4	26.7	19.0	21.4	20.0	21.9	26.3	23.7	0.4	0.4	22.9	21.7	-1.2	-5%
All Days	6.7	9.8	8.4	7.8	8.6	7.1	7.6	7.4	8.6	9.1	8.6	0.1	0.4	8.3	7.9	-0.4	-5%
Particulate Organic Mass Extinction (Mm-1)																	
Best 20% Days	2.9	1.9	2.0	2.5	2.0	1.6	2.0	2.1	2.2	1.8	1.3	0.0	0.2	2.3	1.9	-0.4	-17%
Worst 20% Days	17.8	9.2	7.6	9.1	11.6	11.0	14.5	8.0	12.2	5.0	9.1	-0.4	0.3	11.1	10.1	-1.0	-9%
All Days	8.7	5.5	4.7	5.9	5.3	5.1	6.1	4.8	5.7	3.6	5.1	-0.2	0.1	6.0	5.0	-1.0	-17%
Elemental Carbon Extinction (Mm-1)																	
Best 20% Days	0.8	0.7	0.7	0.7	0.5	0.7	0.9	0.7	0.7	0.7	0.7	0.0	0.3	0.7	0.7	0.0	0%
Worst 20% Days	4.5	2.8	2.3	2.4	2.2	3.2	2.8	2.1	2.5	2.0	2.8	-0.1	0.0	2.8	2.5	-0.3	-11%
All Days	2.1	1.6	1.4	1.6	1.2	1.7	1.7	1.3	1.4	1.4	2.0	-0.1	0.1	1.6	1.5	-0.1	-6%
Soil Extinction (Mm-1)																	
Best 20% Days	0.3	0.4	0.4	0.3	0.3	0.2	0.3	0.4	0.3	0.4	0.3	0.0	0.3	0.3	0.3	0.0	0%
Worst 20% Days	0.9	0.7	0.5	0.6	0.4	0.5	0.6	0.6	0.7	0.7	1.1	0.0	0.4	0.6	0.6	0.0	0%
All Days	0.6	0.7	0.5	0.5	0.5	0.4	0.5	0.5	0.6	0.6	0.7	0.0	0.5	0.6	0.5	-0.1	-17%
Coarse Mass Extinction (Mm-1)																	
Best 20% Days	2.2	2.5	2.4	2.2	2.2	1.6	2.1	3.1	3.1	2.5	2.2	0.0	0.2	2.3	2.5	0.2	9%
Worst 20% Days	5.2	4.7	2.6	4.3	2.7	4.1	4.2	4.4	3.9	3.5	4.6	-0.1	0.2	3.9	4.0	0.1	3%
All Days	3.9	4.5	3.0	3.4	3.6	3.2	3.5	3.7	3.8	3.4	3.8	0.0	0.4	3.7	3.5	-0.2	-5%
Sea Salt Extinction (Mm-1)																	
Best 20% Days	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0%
Worst 20% Days	0.0	0.9	0.1	0.0	0.3	0.2	0.2	0.2	2.1	0.1	0.0	0.0	0.2	0.3	0.6	0.3	100%
All Days	0.2	0.3	0.1	0.0	0.2	0.2	0.2	0.2	0.7	0.3	0.1	0.0	0.0	0.1	0.3	0.2	>100%

*Values highlighted in blue (red) indicate statistically significant decreasing (increasing) annual trend. Significance is measured at the 85% confidence level (p-value ≤0.15).
**Values highlighted in blue indicate a decrease in the 5-year average, values highlighted in red indicate an increase.
"---" Indicates a missing year that did not meet RHR data completeness criteria.

Figure J.1-1
Lostwood WA, ND (LOST1 Site)
Annual and 5-Year Period Averages
20% Most Impaired Visibility Days

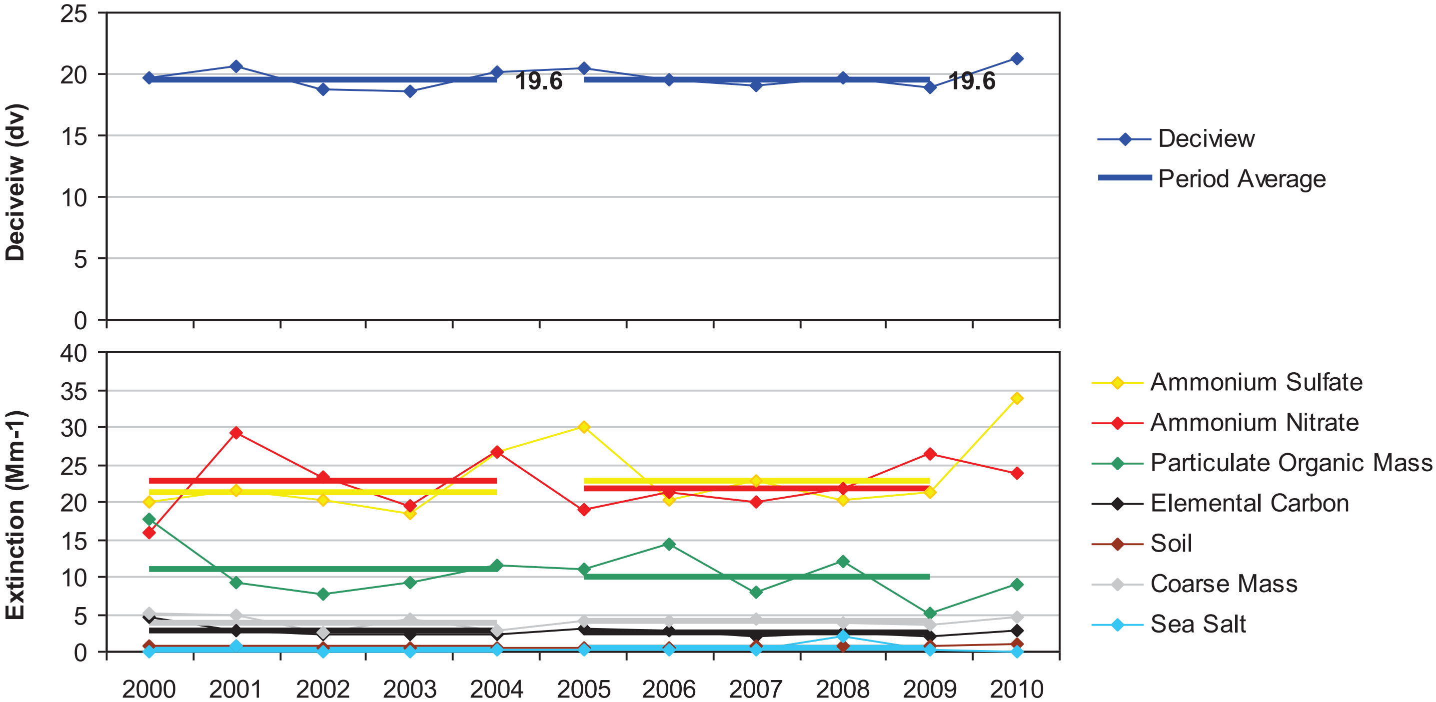


Figure J.1-2
Lostwood WA, ND (LOST1 Site)
Annual and 5-Year Period Averages
20% Least Impaired Visibility Days

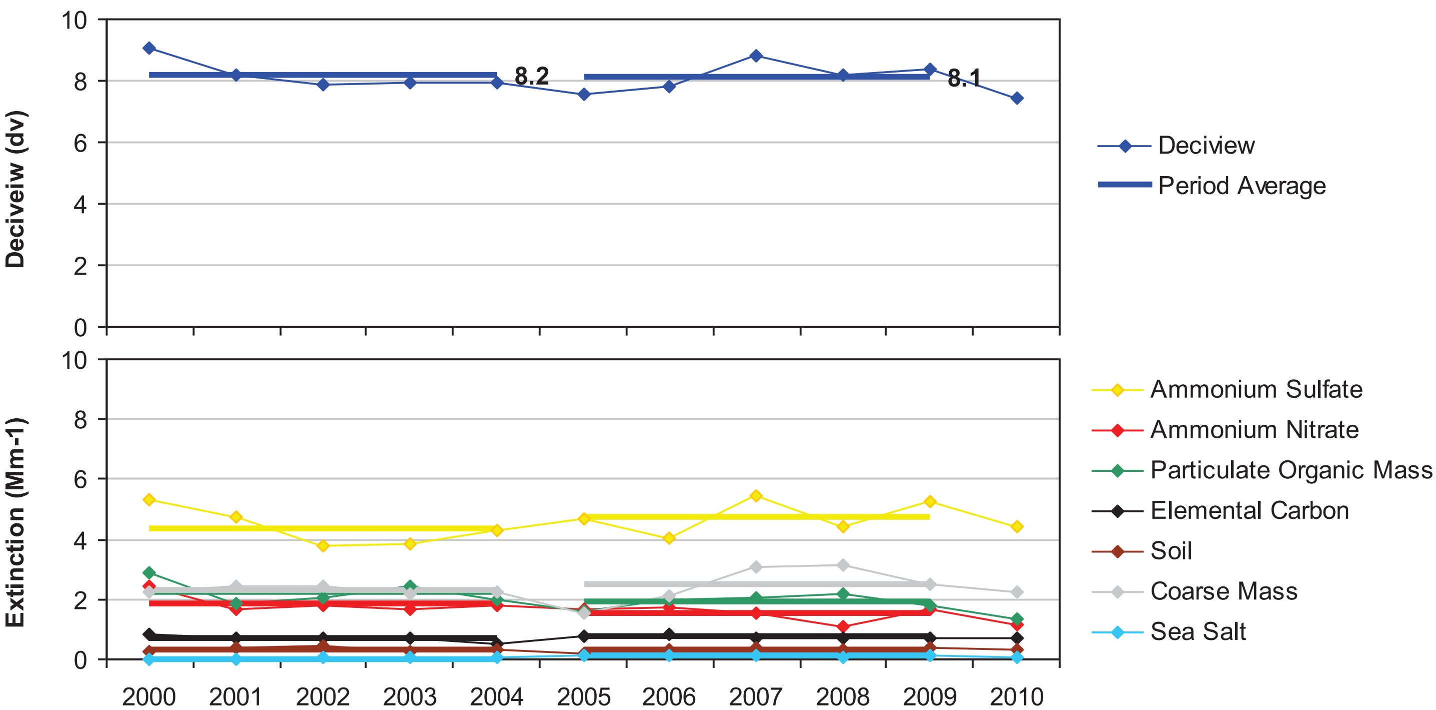


Figure J.1-3
Lostwood WA, ND (LOST1 Site)
20% Most Impaired Visibility Days

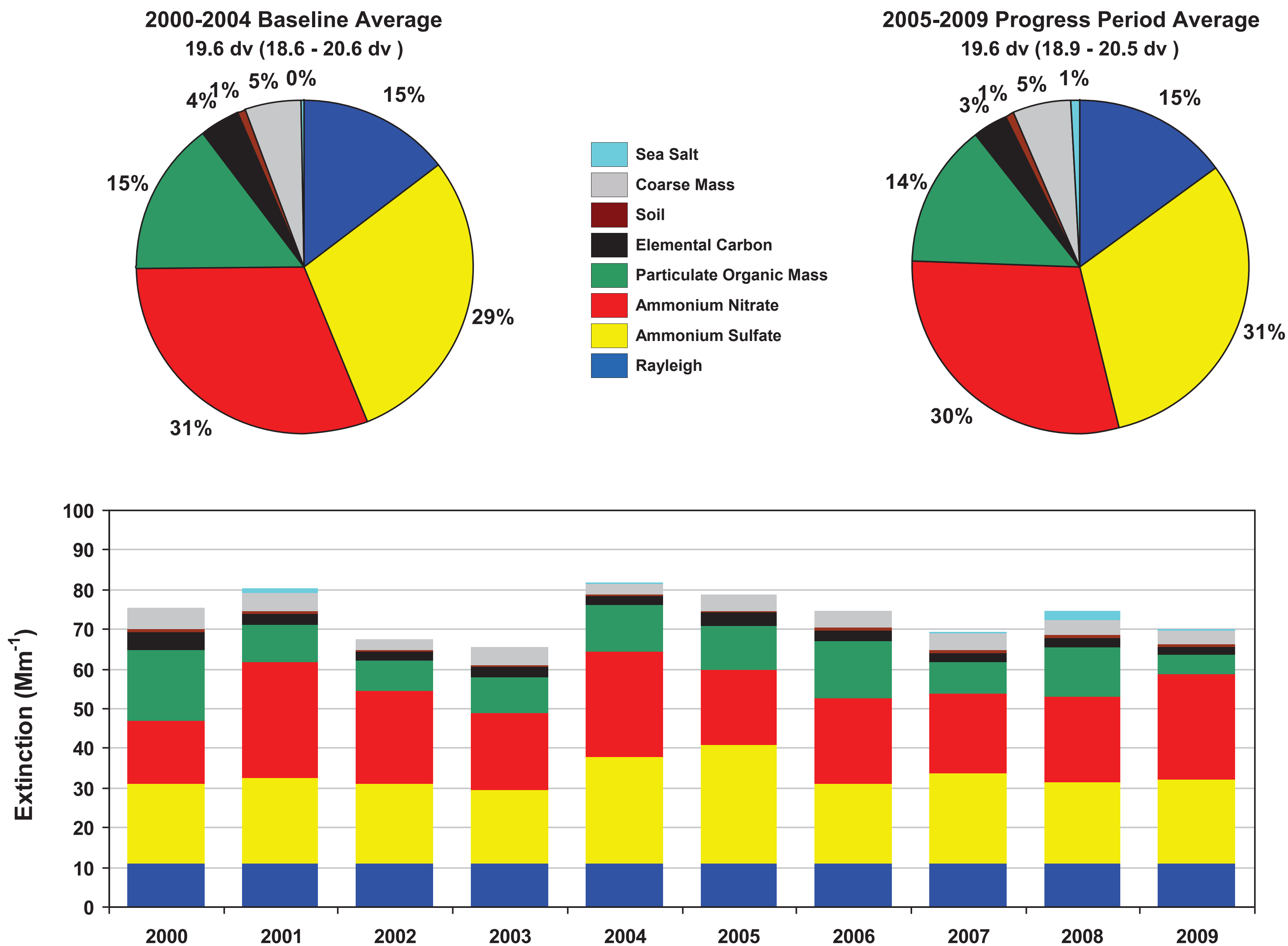


Figure J.1-4
Lostwood WA, ND (LOST1 Site)
20% Least Impaired Visibility Days

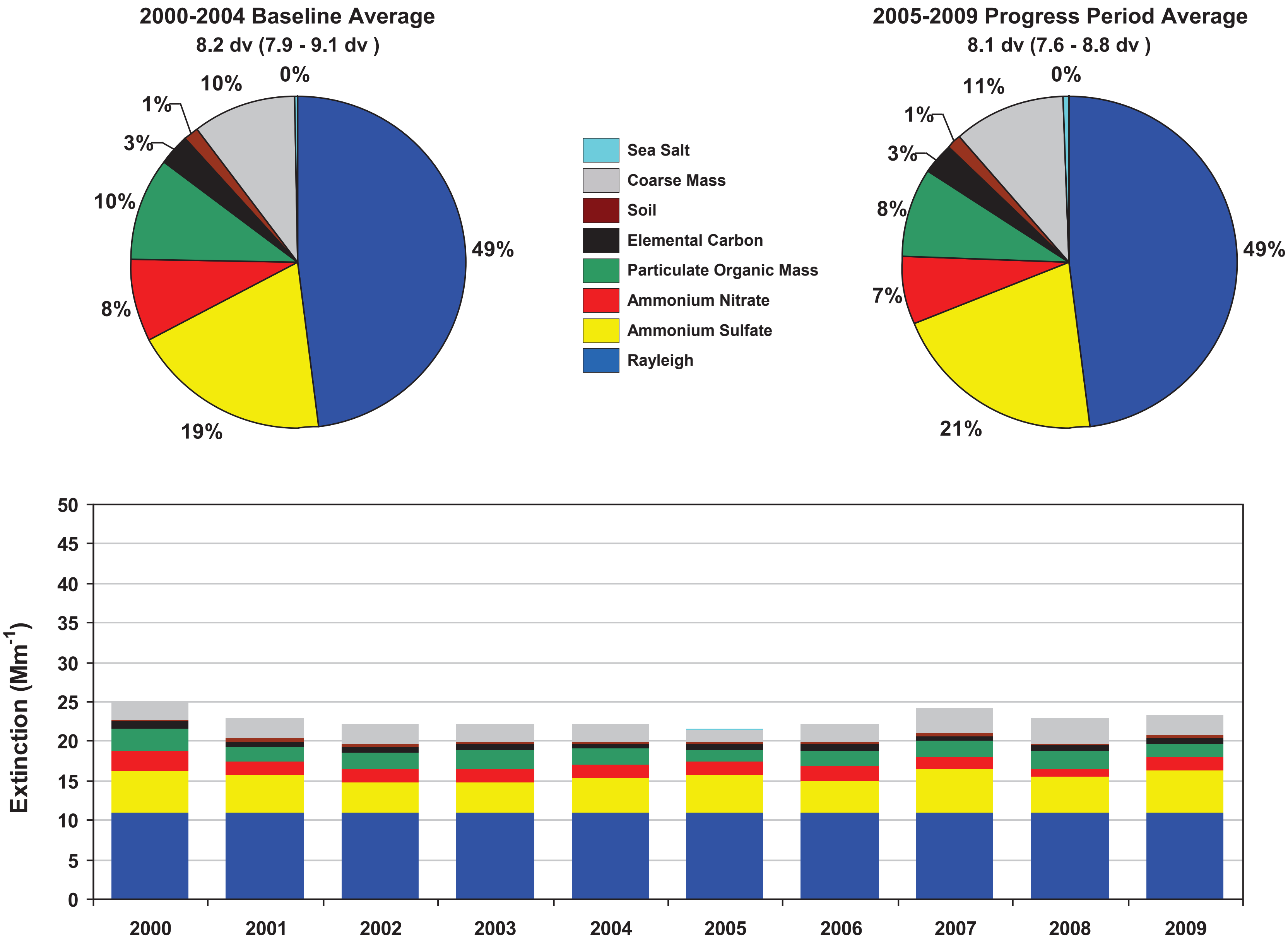


Figure J.1-5
Lostwood WA, ND (LOST1 Site)
2000-2004 Monthly Average Aerosol Extinction, All Monitored Days

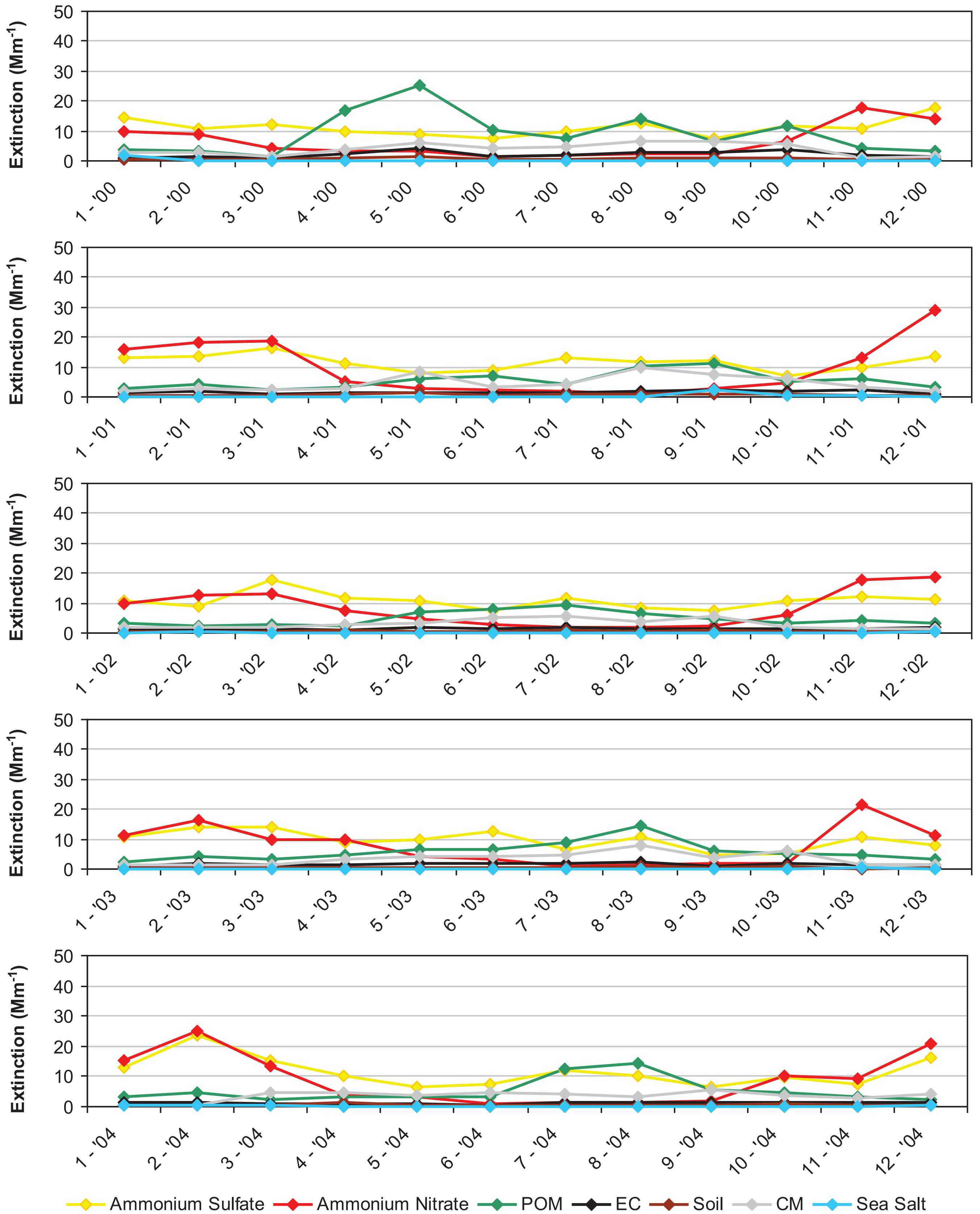


Figure J.1-6
Lostwood WA, ND (LOST1 Site)
2005-2009 Monthly Average Aerosol Extinction, All Monitored Days

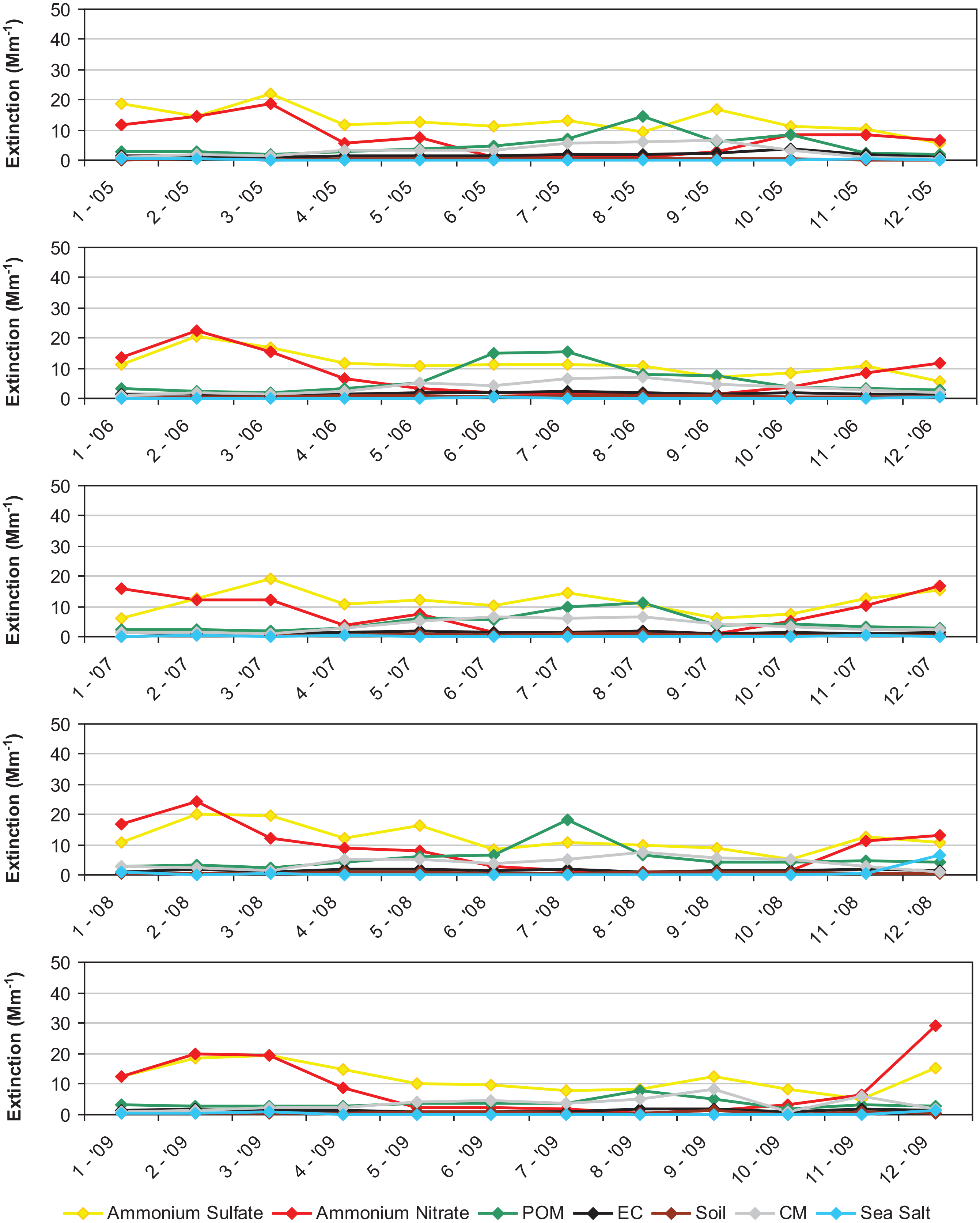


Figure J.1-7
Lostwood WA, ND (LOST1 Site)
2000-2004 Progress Period Extinction, All Sampled Days

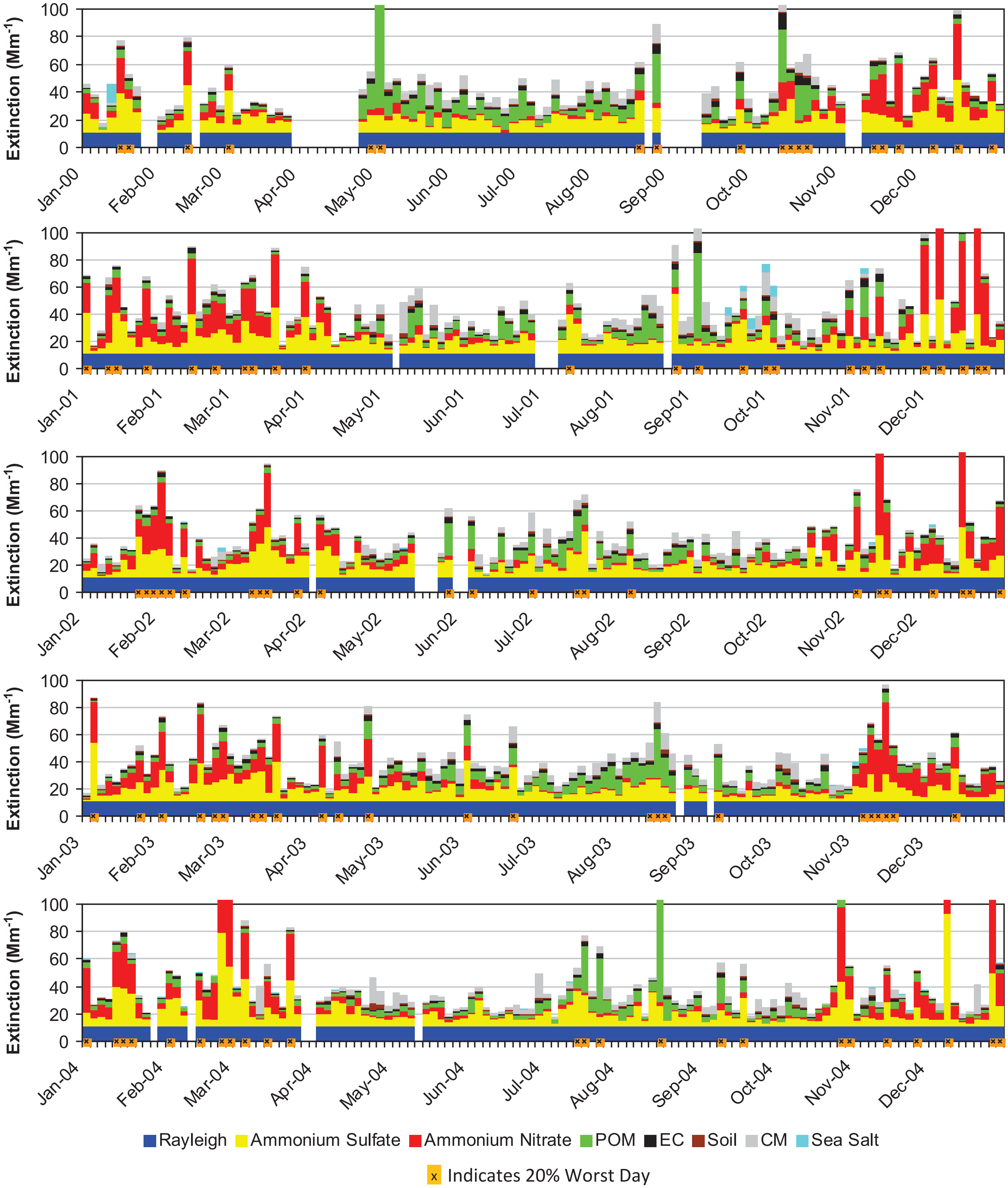
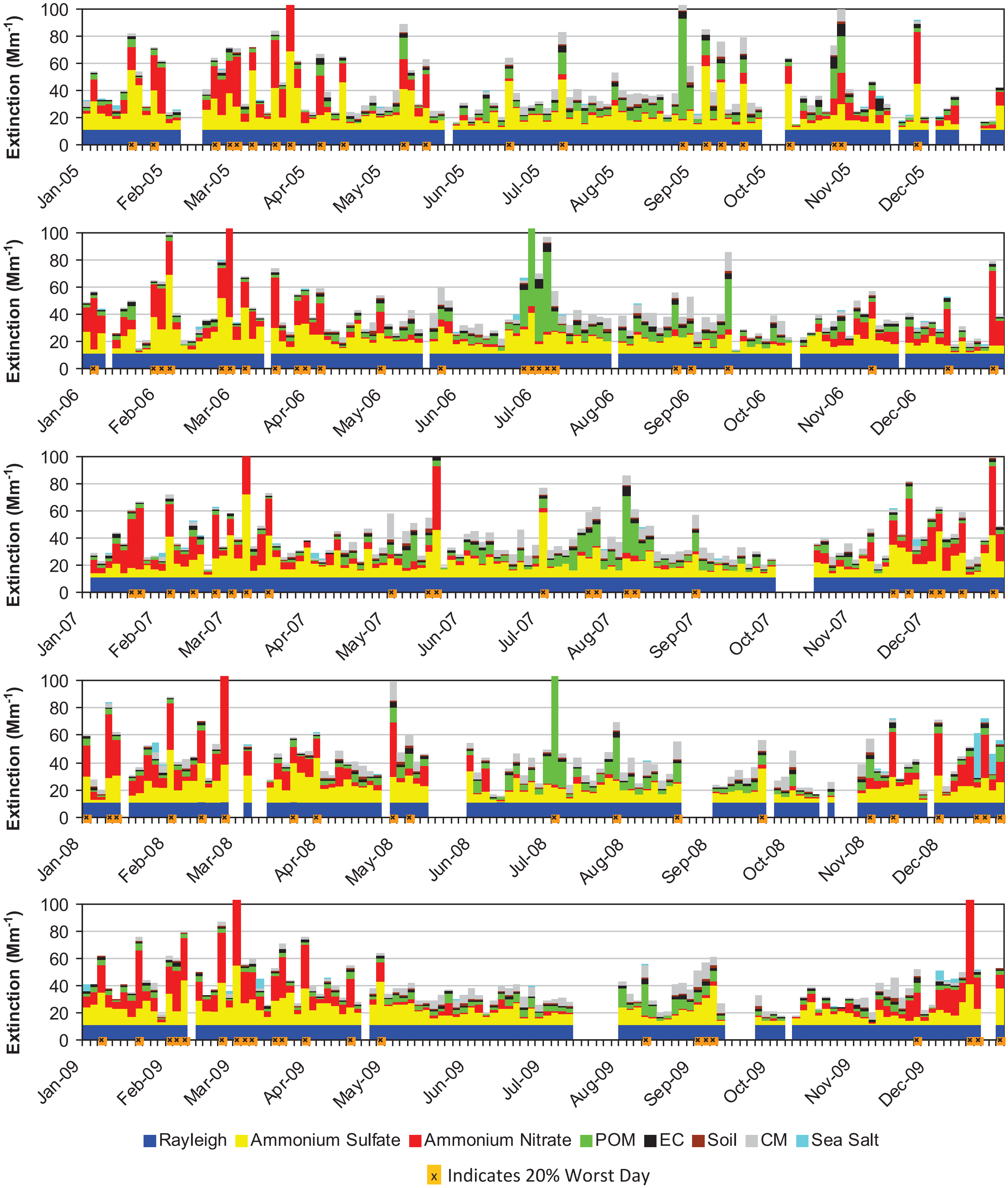


Figure J.1-8
Lostwood WA, ND (LOST1 Site)
2005-2009 Progress Period Extinction, All Sampled Days



J.2. THEODORE ROOSEVELT NP (THRO1)

The following tables and figures are presented in this section for the Theodore Roosevelt NP represented by the THRO1 IMPROVE Monitor:

- **Table J.2-1: Annual Averages, 5-Year Period Averages, and Trends:** Table of averages and other metrics for the 20% least impaired days, the 20% most impaired days, and all sampled days is presented.

- **Figure J.2-1: Annual and 5-Year Period Averages for the 20% Most Impaired Visibility Days:** Line graphs depicting annual and period averages by component are presented.

- **Figure J.2-2: Annual and 5-Year Period Averages for the 20% Least Impaired Visibility Days:** Line graphs depicting annual and period averages by component are presented.

- **Figure J.2-3: 20% Most Impaired Visibility Days:** Pie charts depicting period averages and stacked bar charts depicting annual averages by component for the 20% most impaired days are presented.

- **Figure J.2-4: 20% Least Impaired Visibility Days:** Pie charts depicting period averages and stacked bar charts depicting annual averages by component are presented.

- **Figure J.2-5: 2000-2004 Monthly Average Aerosol Extinction, All Monitored Days:** Line graphs depicting monthly averages by year and component for the baseline period are presented.

- **Figure J.2-6: 2005-2009 Monthly Average Aerosol Extinction, All Monitored Days:** Line graphs depicting monthly averages by year and component for the progress period are presented.

- **Figure J.2-7: 2000-2004 Progress Period Extinction, All Sampled Days:** Stacked bar charts depicting daily averages by year and component for the baseline period are presented.

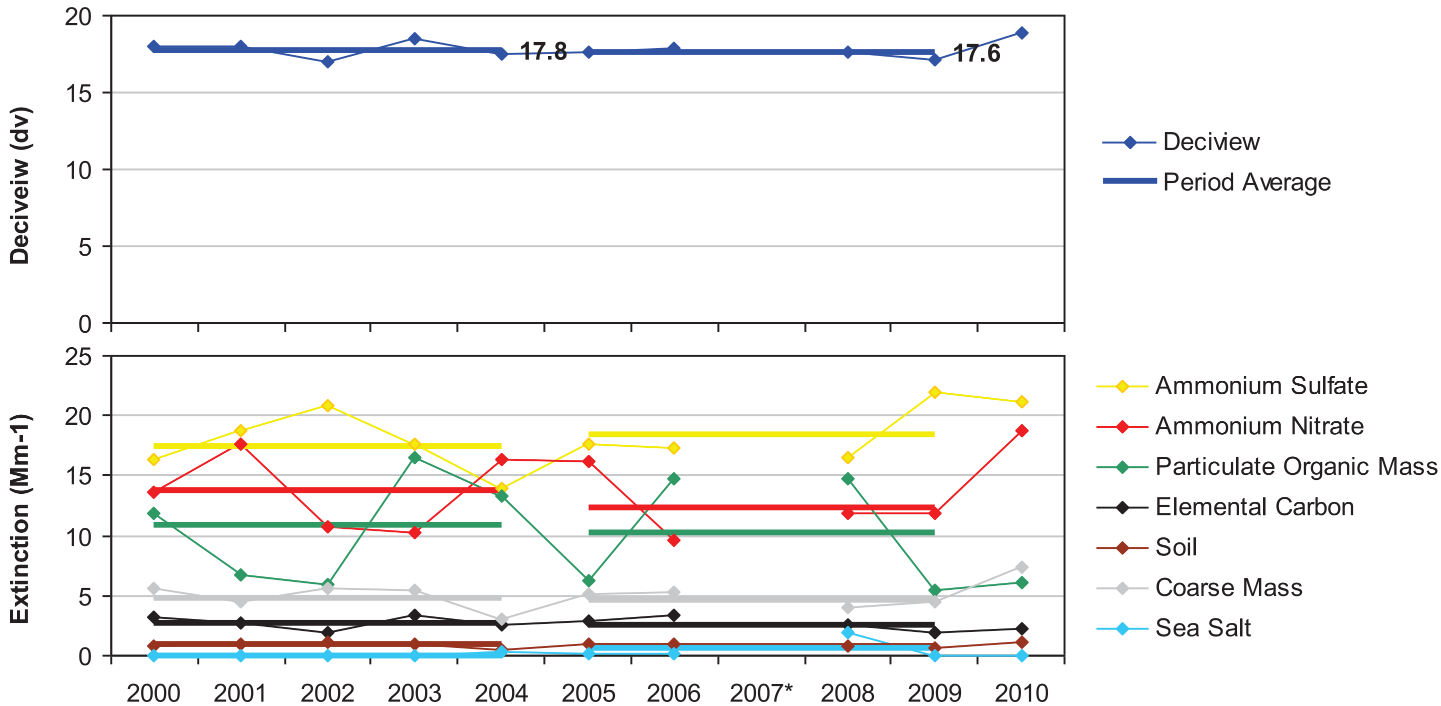
- **Figure J.2-8: 2000-2004 Progress Period Extinction, All Sampled Days**: Stacked bar charts depicting daily averages by year and component for the progress period are presented.

Table J.2-1
Theodore Roosevelt NP, ND (THRO1 Site)
Annual Averages, 5-Year Period Averages and Trends

Group	Baseline Period					Progress Period						2000-2009 Trend Statistics*		Period Averages**			
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Slope (change/yr.)	p-value	Baseline (B)	Progress (P)	Difference (P -B)	Percent Change
Deciview (dv)																	
Best 20% Days	8.2	7.8	7.8	7.5	7.5	6.8	6.5	---	6.6	7.0	6.3	-0.2	0.0	7.8	6.7	-1.1	-14%
Worst 20% Days	18.1	18.0	17.0	18.4	17.5	17.6	17.9	---	17.6	17.2	18.8	-0.1	0.1	17.8	17.6	-0.2	-1%
All Days	12.8	12.5	11.9	12.5	11.9	11.9	12.1	---	12.0	11.6	12.1	-0.1	0.0	12.3	11.9	-0.4	-3%
Total Extinction (Mm-1)																	
Best 20% Days	23.0	21.9	21.9	21.3	21.2	19.9	19.3	---	19.4	20.3	18.9	-0.4	0.0	21.9	19.7	-2.2	-10%
Worst 20% Days	62.4	62.4	57.1	65.2	61.1	60.1	62.3	---	63.4	57.3	67.7	-0.2	0.3	61.6	60.8	-0.8	-1%
All Days	38.3	37.7	35.3	37.9	35.5	35.5	36.6	---	36.7	34.4	37.3	-0.2	0.1	36.9	35.8	-1.1	-3%
Ammonium Sulfate Extinction (Mm-1)																	
Best 20% Days	4.9	3.6	3.8	3.5	3.2	3.6	2.5	---	3.3	4.1	3.2	-0.1	0.1	3.8	3.4	-0.4	-11%
Worst 20% Days	16.4	18.8	20.8	17.7	14.0	17.7	17.3	---	16.6	22.0	21.1	0.0	0.5	17.5	18.4	0.9	5%
All Days	9.7	9.9	9.8	9.1	8.0	9.4	9.5	---	9.3	10.7	9.8	0.0	0.5	9.3	9.7	0.4	4%
Ammonium Nitrate Extinction (Mm-1)																	
Best 20% Days	1.6	1.4	1.9	1.6	1.2	1.0	0.9	---	0.7	1.0	0.6	-0.1	0.0	1.5	0.9	-0.6	-40%
Worst 20% Days	13.6	17.7	10.7	10.3	16.4	16.1	9.5	---	11.8	11.9	18.7	-0.3	0.2	13.7	12.3	-1.4	-10%
All Days	5.3	6.1	5.1	5.3	5.6	4.9	4.2	---	4.9	4.6	6.4	-0.1	0.0	5.5	4.7	-0.8	-15%
Particulate Organic Mass Extinction (Mm-1)																	
Best 20% Days	1.9	1.8	2.2	1.8	2.1	1.6	1.4	---	1.5	1.5	1.4	-0.1	0.0	2.0	1.5	-0.5	-25%
Worst 20% Days	11.8	6.7	5.9	16.4	13.4	6.3	14.7	---	14.7	5.4	6.1	0.0	0.5	10.8	10.3	-0.5	-5%
All Days	5.6	4.1	3.8	6.5	5.2	4.0	5.6	---	5.4	3.3	3.9	-0.1	0.3	5.0	4.6	-0.4	-8%
Elemental Carbon Extinction (Mm-1)																	
Best 20% Days	1.2	0.8	0.8	0.9	0.9	1.0	1.1	---	0.7	0.6	0.7	0.0	0.2	0.9	0.9	0.0	0%
Worst 20% Days	3.3	2.7	1.9	3.4	2.5	2.8	3.3	---	2.5	1.9	2.3	-0.1	0.2	2.7	2.6	-0.1	-4%
All Days	2.1	1.7	1.4	1.9	1.5	1.9	1.9	---	1.5	1.2	1.5	-0.1	0.1	1.7	1.6	-0.1	-6%
Soil Extinction (Mm-1)																	
Best 20% Days	0.3	0.5	0.4	0.3	0.4	0.3	0.3	---	0.3	0.3	0.3	0.0	0.0	0.4	0.3	-0.1	-25%
Worst 20% Days	0.8	1.0	1.2	1.0	0.5	0.9	1.0	---	0.8	0.7	1.1	0.0	0.1	0.9	0.8	-0.1	-11%
All Days	0.6	0.8	0.8	0.6	0.7	0.7	0.7	---	0.6	0.5	0.7	0.0	0.2	0.7	0.6	-0.1	-14%
Coarse Mass Extinction (Mm-1)																	
Best 20% Days	2.1	2.7	1.7	2.1	2.4	1.3	1.9	---	1.8	1.8	1.7	0.0	0.1	2.2	1.7	-0.5	-23%
Worst 20% Days	5.6	4.5	5.6	5.4	3.0	5.1	5.3	---	4.1	4.4	7.3	-0.1	0.1	4.8	4.7	-0.1	-2%
All Days	4.0	4.0	3.3	3.4	3.4	3.5	3.6	---	3.4	3.0	3.9	-0.1	0.2	3.6	3.4	-0.2	-6%
Sea Salt Extinction (Mm-1)																	
Best 20% Days	0.0	0.0	0.0	0.1	0.1	0.1	0.1	---	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0%
Worst 20% Days	0.0	0.0	0.0	0.0	0.3	0.2	0.1	---	2.0	0.1	0.1	0.0	0.0	0.1	0.6	0.5	>100%
All Days	0.0	0.2	0.0	0.0	0.1	0.1	0.1	---	0.5	0.1	0.0	0.0	0.1	0.1	0.2	0.1	100%

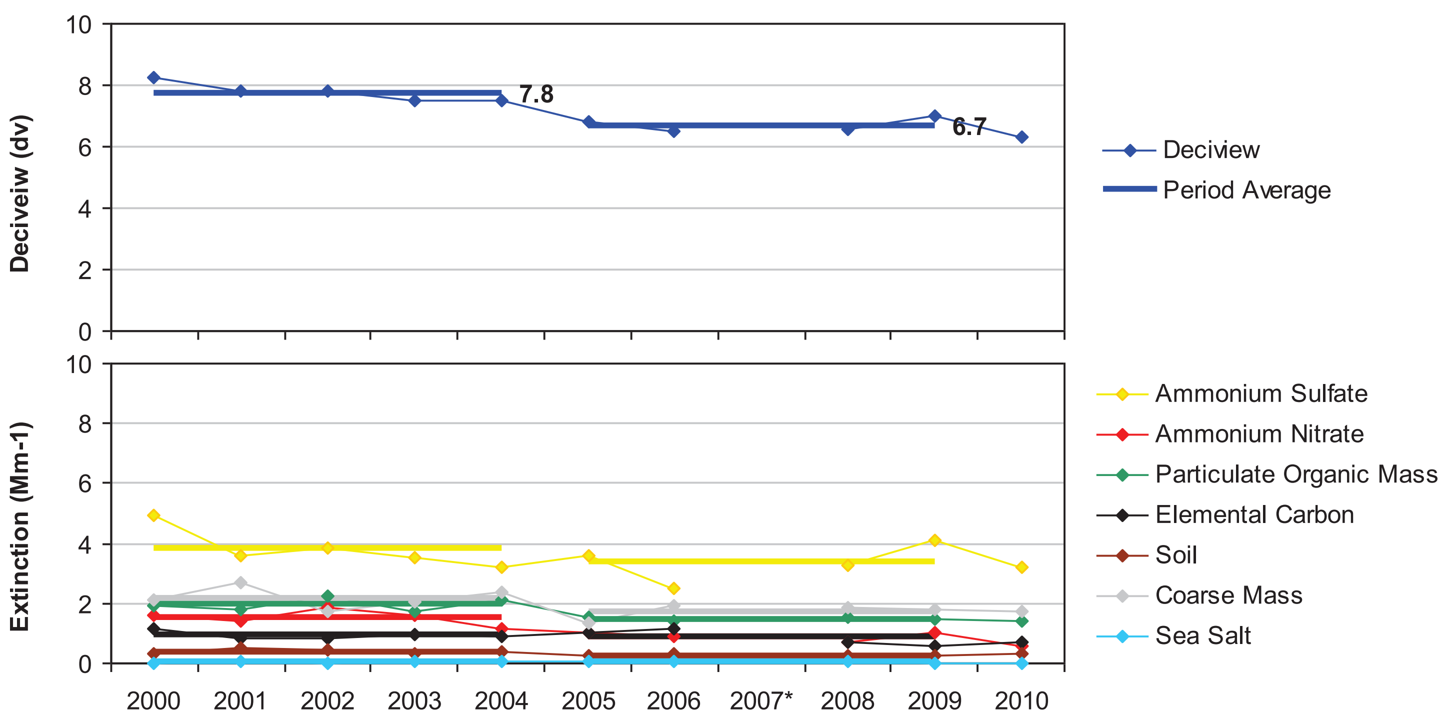
*Values highlighted in blue (red) indicate statistically significant decreasing (increasing) annual trend. Significance is measured at the 85% confidence level (p-value ≤0.15).
**Values highlighted in blue indicate a decrease in the 5-year average, values highlighted in red indicate an increase.
"---" Indicates a missing year that did not meet RHR data completeness criteria.

Figure J.2-1
Theodore Roosevelt NP, ND (THRO1 Site)
Annual and 5-Year Period Averages
20% Most Impaired Visibility Days



*Missing years did not meet RHR data completeness criteria.

Figure J.2-2
Theodore Roosevelt NP, ND (THRO1 Site)
Annual and 5-Year Period Averages
20% Least Impaired Visibility Days

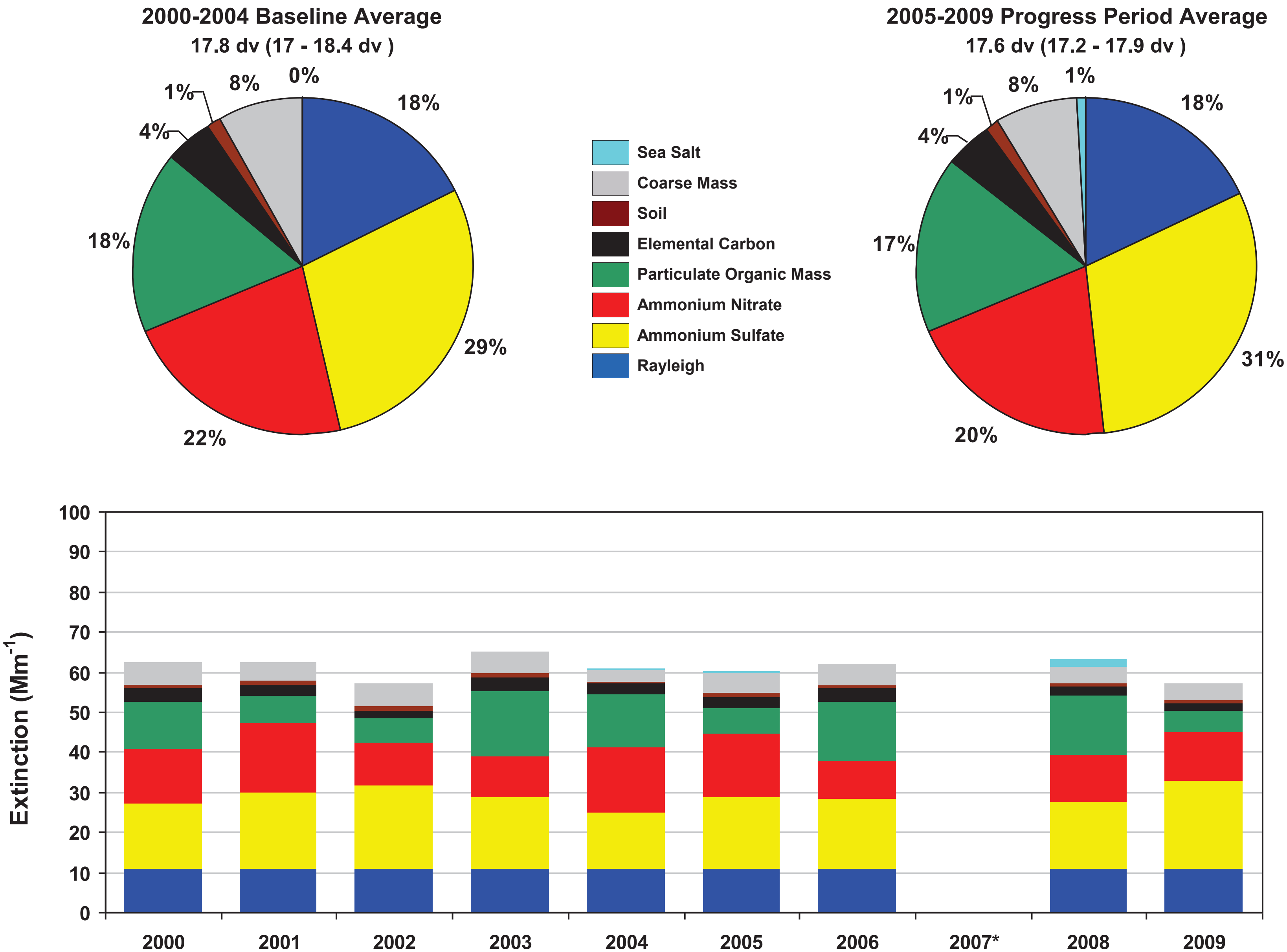


*Missing years did not meet RHR data completeness criteria.

Figure J.2-3

Theodore Roosevelt NP, ND (THRO1 Site)

20% Most Impaired Visibility Days

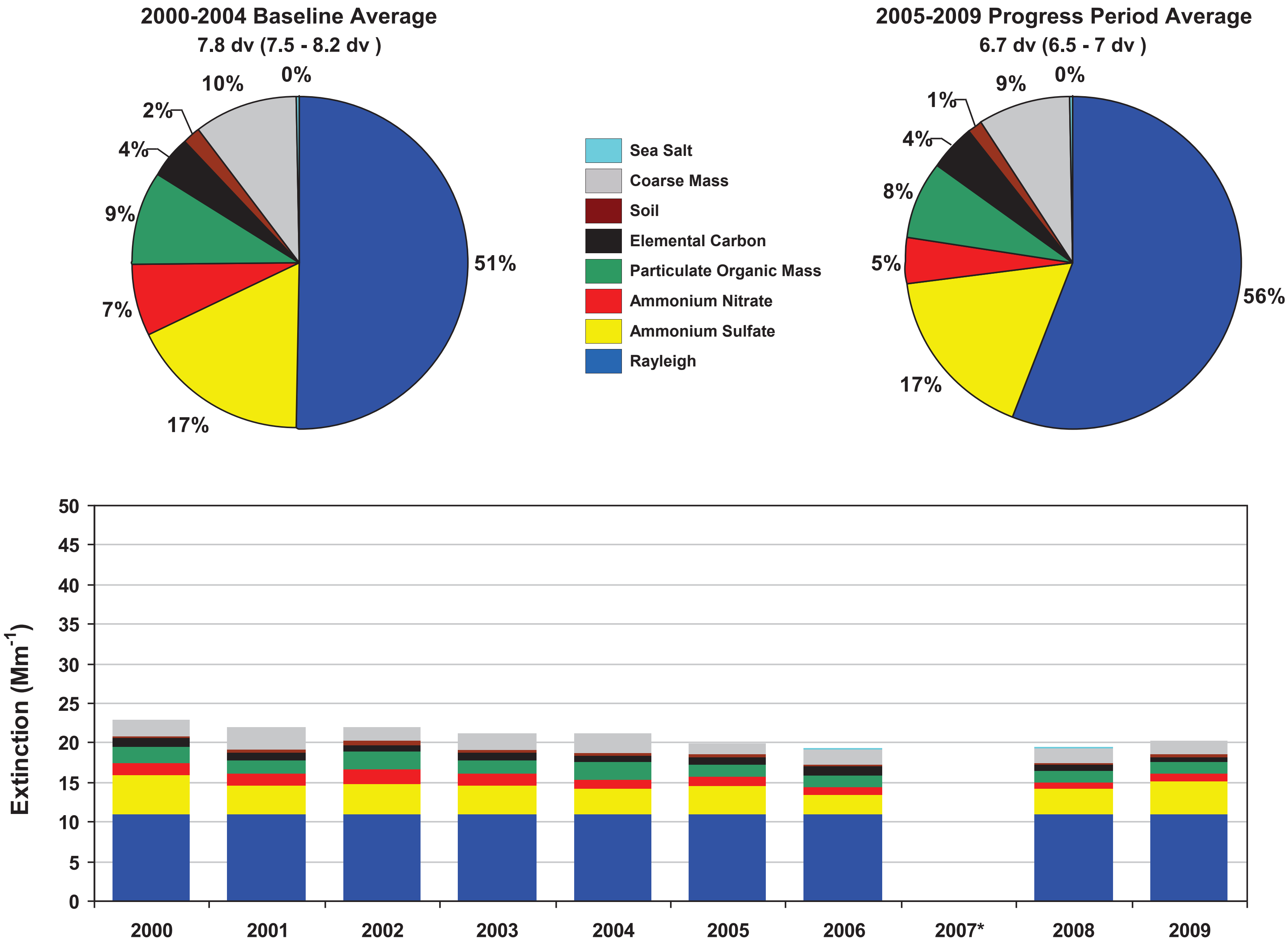


*Missing years did not meet RHR data completeness criteria. Only complete years are included in 5-year average pie charts.

Figure J.2-4

Theodore Roosevelt NP, ND (THRO1 Site)

20% Least Impaired Visibility Days



*Missing years did not meet RHR data completeness criteria. Only complete years are included in 5-year average pie charts.

Figure J.2-5
Theodore Roosevelt NP, ND (THRO1 Site)
2000-2004 Monthly Average Aerosol Extinction, All Monitored Days

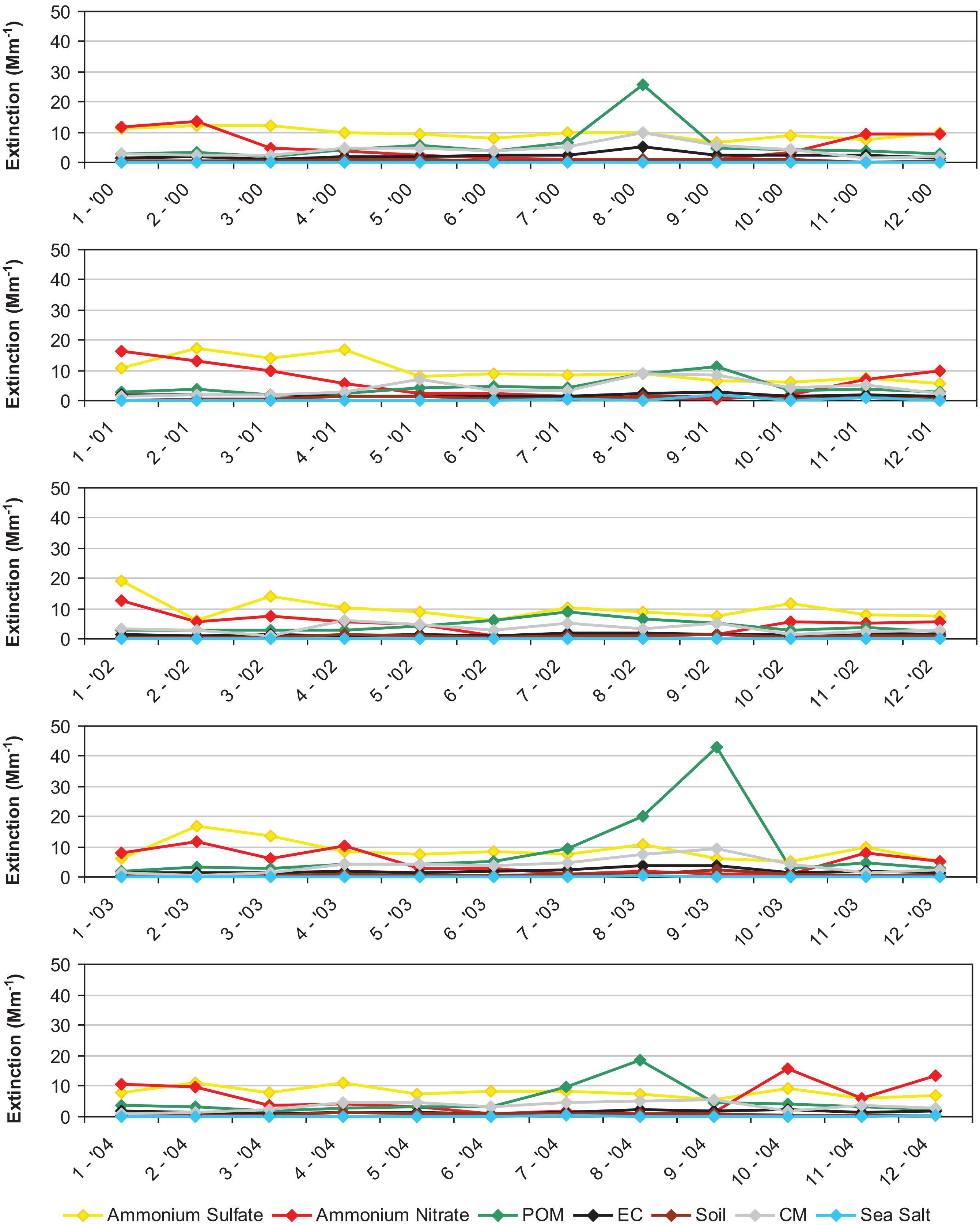
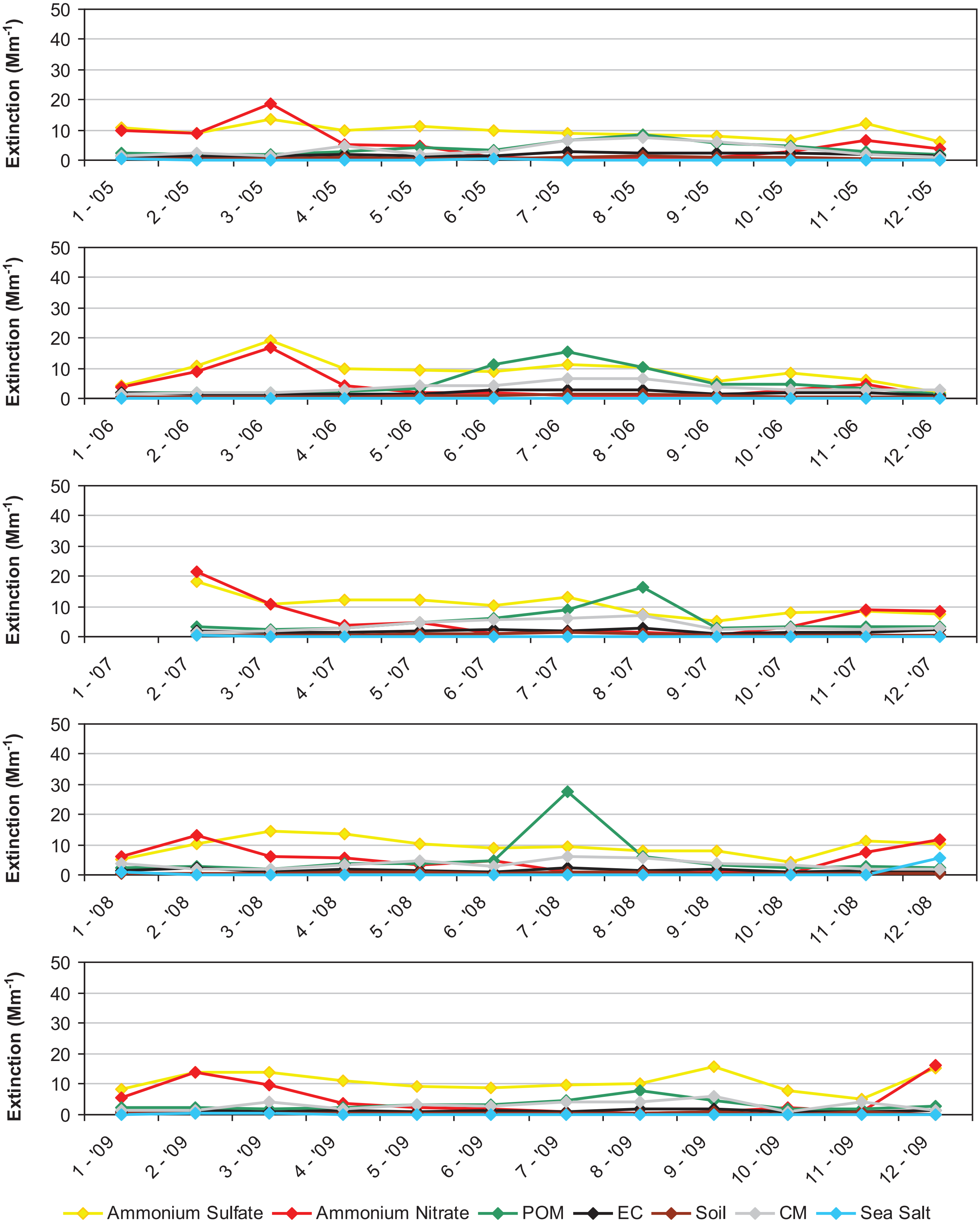


Figure J.2-6
Theodore Roosevelt NP, ND (THRO1 Site)
2005-2009 Monthly Average Aerosol Extinction, All Monitored Days



*Note that monthly averages for the year 2007 are shown here, but this year did not meet RHR data completeness criteria.

Figure J.2-7
Theodore Roosevelt NP, ND (THRO1 Site)
2000-2004 Progress Period Extinction, All Sampled Days

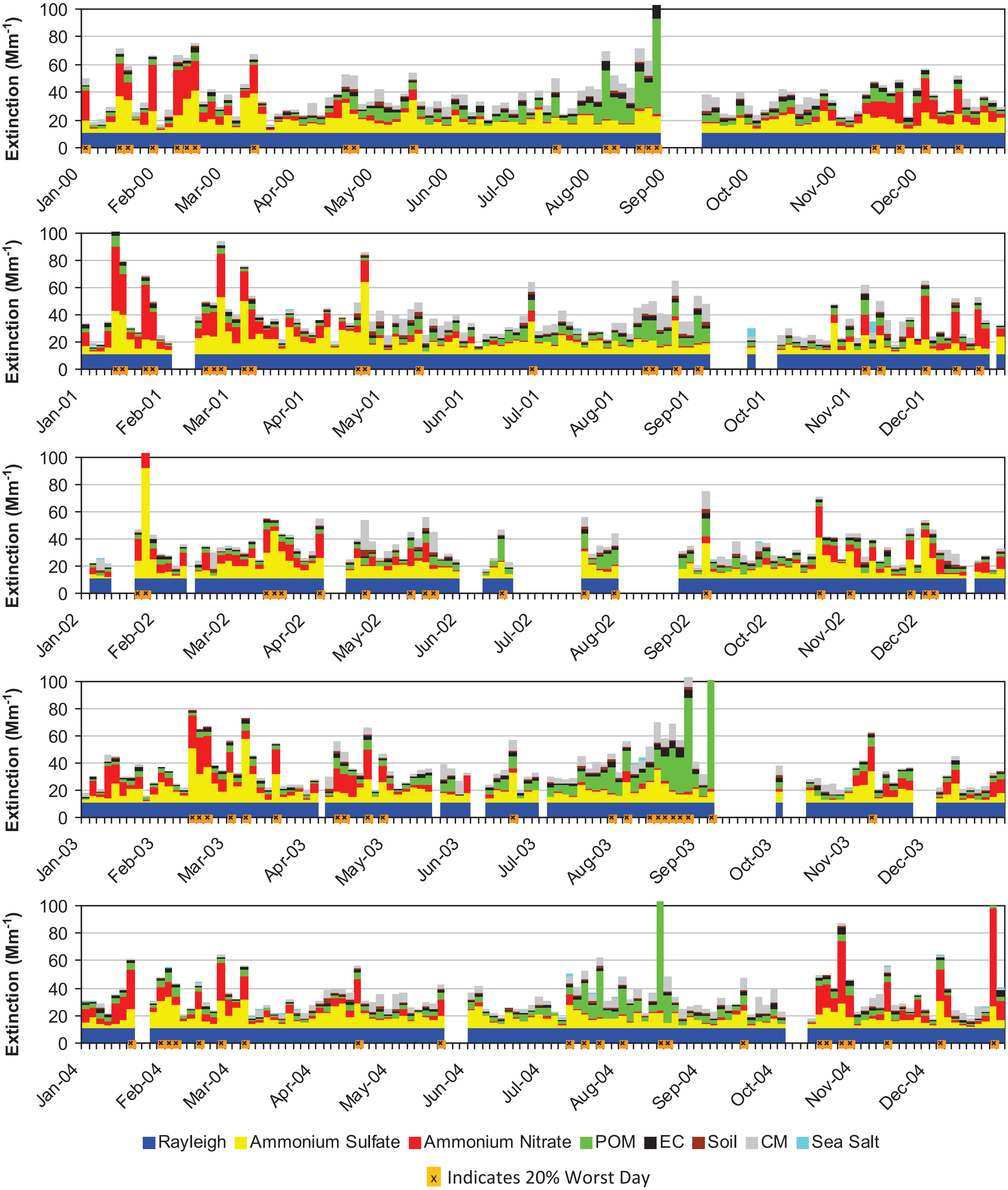
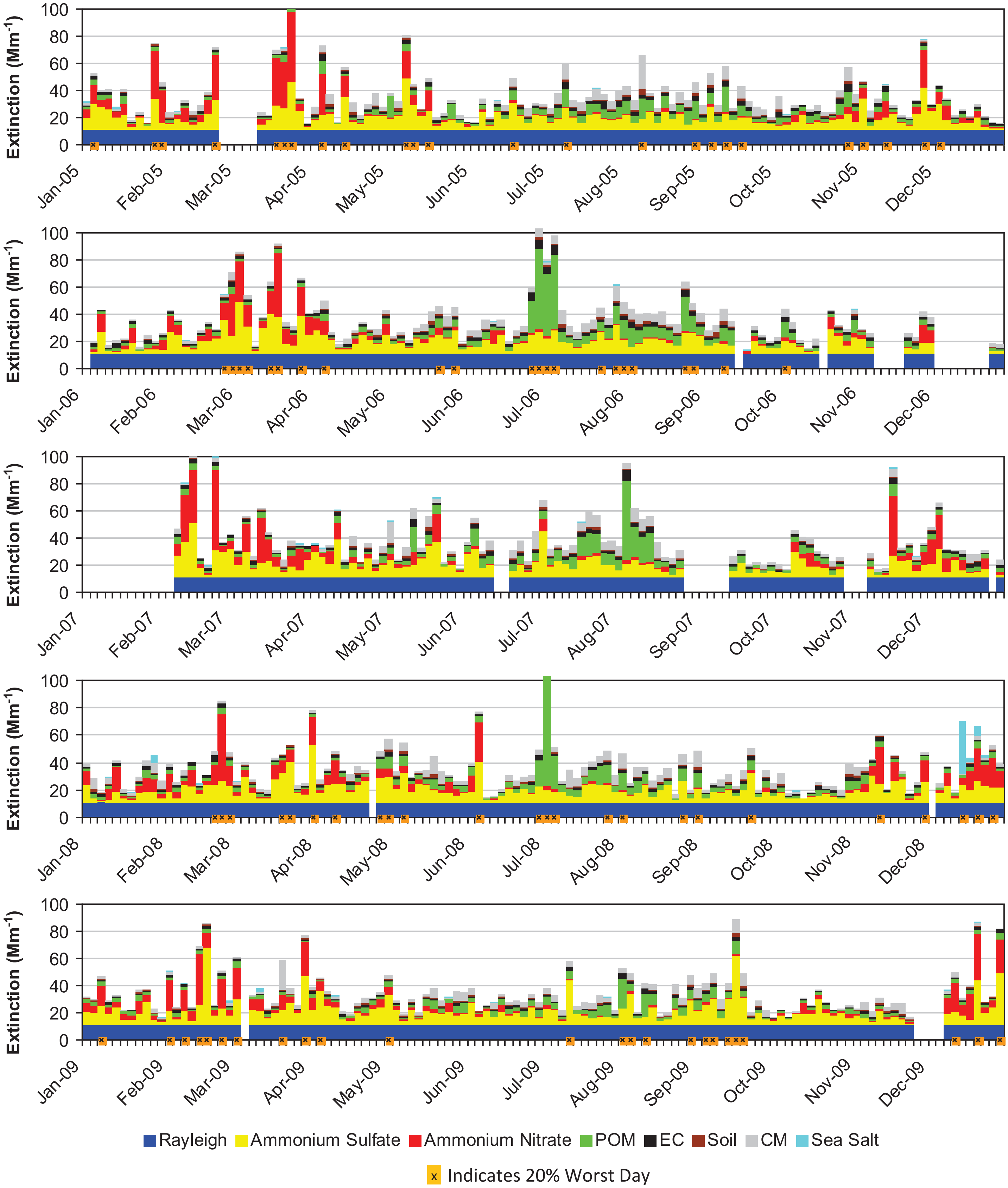


Figure J.2-8
Theodore Roosevelt NP, ND (THRO1 Site)
2005-2009 Progress Period Extinction, All Sampled Days



*Note that daily averages for the year 2007 are shown here, but this year did not meet RHR data completeness criteria.

Appendix C

Bakken Pool Oil & Gas Production Facilities Air Pollution Control Permitting & Compliance Guidance

Bakken Pool

Oil and Gas Production Facilities

Air Pollution Control
Permitting & Compliance Guidance

North Dakota Department of Health

Division of Air Quality

Effective Date May 2, 2011

Table of Contents

APPENDICES

1. ACRONYMS AND ABBREVIATIONS

AP-42 EPA Publication AP-42, Compilation of Air Pollutant Emission Factors (5th Edition)
Bakken Pool Oil from Bakken, Three Forks, and Sanish Formations
bbl barrel
BOPD barrels of oil per day
BTEX benzene/toluene/ethyl-benzene/xylenes
Btu British thermal unit
Btu/hr Btu per hour
CO carbon monoxide
DRE destruction and removal efficiency
EF emission factor
EPA Environmental Protection Agency
gpm gallons per minute
H_2S hydrogen sulfide
HAP hazardous air pollutants
hp horsepower
lb pound
lb/lb-mole pound per pound mole
LACT Lease Automatic Custody Transfer
MMBtu one million Btu
MMscf one million standard cubic feet (scf × 10^6)
MMscfd = 1,000,000 scf per day
Mscf one thousand standard cubic feet (scf × 1000)
Mscfd = 1000 SCF per day
NDDoH North Dakota Department of Health
NESHAP National Emission Standards for Hazardous Air Pollutants
NOx nitrogen oxides
NSCR Non-Selective Catalytic Reduction
NSPS New Source Performance Standards
O&G Oil and Gas
PSD Prevention of Significant Deterioration
psig pounds per square inch gauge
psia pounds per square inch absolute
PTE potential to emit
RICE reciprocating internal combustion engine
scf standard cubic foot
scf/bbl standard cubic foot per barrel
SO_2 sulfur dioxide
S/W/B standing/working/breathing losses
TEG tri-ethylene glycol
Title V Title V of the Clean Air Act Amendments of 1990
TOC total organic compounds
TPY tons per year
VOC volatile organic compounds

2. BACKGROUND

A. Introduction

The creation of this guidance document (Guidance) was a coordinated effort between the North Dakota Department of Health (NDDoH) and the Bakken VOC Task Force, which is comprised of an Emission Factor Committee and an Emission Control Committee.

This Guidance provides an approach that may be used by Bakken Pool Oil and Gas (O&G) production facility owners/operators to demonstrate compliance with the applicable North Dakota Air Pollution Control Rules (including, but not limited to the requirements established by Chapters 33-15-07 and 33-15-20, N.D. Admin. Code). This Guidance provides owners and operators of Bakken Pool O&G production facilities that have the potential to emit air pollutants below the major source thresholds (minor Bakken Pool O&G production facilities) with an alternative to obtaining North Dakota air pollution control permits. Owners and operators of minor Bakken Pool O&G production facilities may still choose to apply for facility-specific air pollution control permits. The NDDoH will consider those applications on a case-by-case basis.

It should be noted that emissions associated with the exploration and production of O&G resources cannot be predicted with any degree of precision or accuracy until after it is determined the oil or gas well will actually produce and site specific production data are collected and known. Therefore, unlike other stationary sources for which projected emissions upon startup can be estimated in advance for purposes of pre-construction air permitting, emissions from O&G exploration and production facilities are only known post-construction and completion. This situation is unique to O&G exploration and production facilities and, therefore, requires a practical regulatory response. To accommodate this reality, the NDDoH has tailored its O&G registration process and this Guidance to allow for the start-up of new exploration and production facilities, and the modification of existing facilities, to occur prior to requiring the submittal of the appropriate O&G Registration Packet, provided the owners/operators of such facilities meet certain emission control requirements that have been established within this Guidance document. This represents a rational and practical regulatory response to operational realities posed by O&G exploration and production operations.

Control requirements have been established within this Guidance for tank emissions and emissions from dehydration units, treater flares and pneumatic pumps. Emissions from other sources such as pneumatic controllers, truck loading, etc. are also included in this Guidance.

Nothing in this Guidance is intended to relieve owners and operators of Bakken Pool O&G production facilities of the responsibility to comply with all State and Federal environmental laws and rules. Owners and operators of Bakken Pool O&G production facilities with the potential to emit at or above major source thresholds must follow the normal permitting processes established in Chapters 33-15-14 and 33-15-15 of the North Dakota Air Pollution Control Rules.

B. **Unique Issues with Bakken Pool VOCs**

Crude oil from the Bakken Pool (defined as wells in the Bakken, Sanish and Three Forks formations) typically contains a high amount of lighter end components which have the potential to produce increased volumes of flash emissions. Because of this, customary correlations such as API's E&P Tanks and Vasquez-Beggs do not work well for estimating flash vapors in the Bakken, potentially overestimating and underestimating emissions.

Recognizing the need to predict tank emissions at Bakken Pool O&G production facilities, the NDDoH and industry collaborated and formed the Bakken VOC Task Force. The Task Force included the Emission Factor Committee and the Emission Control Committee.

The Emission Factor Committee's goal was to gather direct measurement data collected by various owners/operators within the Bakken Pool and establish an emission factor that could be used to predict tank emissions from producing Bakken Pool formation wells.

The Emission Control Committee's goal was to evaluate available emission control technologies and to recommend the best emission control for different emission scenarios.

The findings of both Committees were used as a platform to create this Guidance for Bakken Pool O&G production facilities. The data from the Bakken VOC Task Force that was used to create the default values for Bakken Pool O&G production facilities were submitted and revised by NDDoH and are available for public review upon request. Use of the Bakken default values to calculate VOC emissions is expected to result in a conservatively high estimate of VOC emissions. As an alternative to using the Bakken default values, site-specific data can be used to estimate emissions. In the vast majority of cases, the use of site-specific data instead of the Bakken default values is expected to result in lower calculated VOC emissions.

As mentioned above, Bakken Pool O&G production facilities are different from other O&G production facilities in North Dakota because of the higher potential for flash emissions. This Guidance was created to provide a consistent and more accurate approach for calculating emissions from the Bakken Pool O&G production facilities. While all producing wells in the State will need to have a registration form filed with NDDoH (see Appendix A) and emissions calculations performed, it is not expected that non-Bakken Pool O&G production facilities will require emission controls for tank emissions to the same extent as Bakken Pool production facilities.

Although the Guidance is applicable to Bakken Pool O&G production facilities, the Emission Calculation Workbook may also be used for non-Bakken Pool O&G production facilities; however, it should be noted that some of the default values in the Workbook are specific to Bakken Pool O&G production facilities. When applying the Workbook to non-Bakken Pool O&G production facilities, the user should review the Workbook to ensure that the values are appropriate for the production facility being evaluated.

C. Applicability

All Bakken Pool O&G production facilities (excluding those facilities on Tribal Land) within the State of North Dakota that emit regulated air contaminants into the atmosphere are subject to the requirements discussed in this Guidance and are required to submit either a new or an updated O&G registration packet to NDDoH.

Each Bakken Pool O&G production facility owner or operator will receive a letter detailing instructions on well information submissions. The following summarizes the content of the submissions.

Existing Bakken Pool O&G production facilities are those where the first date of production occurred on or before June 1, 2011. Owners/operators that have previously submitted registration forms will be required to submit the worksheet detailing well information such as controls, calculations and dates. The NDDoH will supply a blank worksheet to perform the calculations that contains all required fields. Each owner/operator must submit the spreadsheet information to the NDDoH by December 1, 2011 (note that the worksheet is in lieu of a new registration).

All owners/operators of existing Bakken Pool O&G production facilities that have not previously filed a registration form must submit a new registration packet to NDDoH by no later December 1, 2011 or within 90 days after the first date of production, whichever is later. These registrations will include information on each well, including all prior controls, in the worksheet (supplied by the NDDoH).

New Bakken Pool production facilities are those where the first date of production occurs after June 1, 2011. The owner/operator of a new Bakken Pool O&G production facility must submit a registration packet to NDDoH within 90 days after the first date of production.

D. Potential to Emit (PTE) Action Levels

Based on the total facility-wide emissions, there are three different registration/permit action levels that will require varying submittals for Bakken Pool O&G production facilities, regardless of location. All new and previously unregistered Bakken Pool O&G production facilities must register with the NDDoH as provided in the Applicability section above. The owner/operator of previously registered Bakken Pool O&G production facilities need only submit a summary spreadsheet as outlined in the Applicability section above. The flowchart below can be used to determine the action/actions an owner/operator needs to take depending on the potential to emit of the Bakken Pool O&G production facility.

Action Flowchart

VOC, CO, NOx <100 TPY & Combined HAP <25 TPY & Single HAP <10 TPY

- Submit Registration Packet within 90 days after the first date of production (new well) or by 12/1/11 (for existing wells)
- No further action

→

VOC, CO, NOx $\geq$100 TPY or Combined HAP $\geq$25 TPY or Single HAP $\geq$10 TPY

- Submit Registration Packet within 90 days after the first date of production (new well) or by 12/1/11 (for existing wells)
- A Permit to Construct is required
- Submit Title V Application within 365 days of the first date of production

→

VOC, CO, NOx $\geq$250 TPY

- Requires a PSD Application and Permit
- PSD is a pre-construction permit
- Contact the NDDoH for further guidance

E. **Registration Only**

If a Bakken Pool O&G production facility has a potential to emit (PTE) $\leq$100 TPY of any criteria pollutant, $\leq$25 TPY of combined HAP and $\leq$10 TPY of any single HAP, the owner/operator only needs to submit a completed registration packet for that facility within 90 days after the first date of production for new production facilities or by December 1, 2011 (whichever is later). No further action is required. See example forms in Appendices A and B.

F. **Permit to Construct and Title V Operating Permit (Major Source)**

If a Bakken Pool O&G production facility has a PTE $\geq$100 TPY of any criteria pollutant, $\geq$25 TPY of combined HAP or $\geq$10 TPY of a single HAP, the facility is required to obtain a Permit to Construct and a Title V permit as required by Chapter 33-15-14. Although the O&G production facility is subject to permitting requirements, a registration packet is still required to be submitted within 90 days after the first date of production. These permitting requirements are beyond the scope of this Guidance, but more information on the permitting process can be obtained from the NDDoH website at: http://www.ndhealth.gov/AQ/AirPermitting.htm.

G. Prevention of Significant Deterioration (PSD)

A Bakken Pool O&G production facility that either emits, or has the PTE, $\geq$250 tons per year of any air contaminant regulated under North Dakota Century Code Chapter 23-25 (or $\geq$100,000 tons per year of greenhouse gases), as determined by the NDDoH, must comply with the permitting requirements of Chapter 33-15-15 (Prevention of Significant Deterioration of Air Quality).

The PSD permit is a pre-construction permit. A facility cannot construct until a permit application has been filed and the permit has been issued. The PSD permitting process is a complicated, time-consuming process that is beyond the scope of this Guidance. More information on the PSD permitting process can be obtained from the NDDoH website at: http://www.ndhealth.gov/AQ/AirPermitting.htm.

H. Potential to Emit

The federal regulations define "potential to emit" as: "The maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of fuel combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable."

Chapter 33-15-07 of the North Dakota Air Pollution Control Rules states, "No person may cause or permit the emission of organic compounds gases, vapors.....unless these gases and vapors are burned by flares or an equally effective control device as approved by the Department. Chapter 33-15-07 has been approved by the EPA as part of the North Dakota State Implementation Plan and as a result, is federally enforceable. Therefore, for an oil and gas production facility, the PTE of VOCs and the associated HAPs is calculated post-controls. Please refer to Appendix C for approved control devices. This Guidance is intended to assist O&G owners/operators demonstrate compliance with Chapter 33-15-07.

I. New Source Performance Standards (NSPS) and Maximum Available Control Technology (MACT) Applicability

Equipment at Bakken Pool O&G production facilities may be subject to rules and regulations under 40 CFR Parts 60 and 63. These federal regulations are beyond the scope of this document. It is the owner/operator's responsibility to determine if equipment is subject to these federal regulations. A summary of numerous Federal rules that may apply to Bakken Pool O&G production facilities is located at: www.ndhealth.gov/AQ/OilAndGasWells.htm.

J. Regulated Air Pollutant Sources

When registering a Bakken Pool O&G production facility, all emission sources at that particular facility must be considered to determine source status (major or minor source). Generally, the following are the most common emission sources and the type of regulated air pollutants they may emit at a typical Bakken Pool O&G production facility:

- Oil/Condensate Tanks – VOC, HAP, H_2S (NOx, CO, SO_2 when controlled)
- Produced Water Tanks – VOC, HAP, H_2S (NOx, CO, SO_2 when controlled)
- Treater Flares – VOC, HAP, NOx, CO, H_2S, SO_2
- Heaters/Burners – VOC, HAP, NOx, CO, SO_2
- Truck Loading – VOC, HAP
- RICE Engines – VOC, HAP, NOx, CO
- Pneumatic Pumps – VOC, HAP
- Pneumatic Controllers – VOC, HAP
- Fugitives – VOC, HAP

K. Control of Bakken Pool O&G Production Facility VOC Emissions

Based on historical information from Bakken Pool O&G production facilities, flashing emissions from the production tanks may be significant. Acceptable VOC emission control systems or devices are discussed in Appendix C. The control requirements for emissions from production tanks are outlined in Appendix D of this document.

L. Greenhouse Gas (GHG) Emissions

It is the responsibility of each owner/operator to determine the applicability of GHG emissions inventory reporting and permitting rules to their facilities and to comply with the rules. If multiple wells are drilled from a single pad, GHG emissions from all wells may need to be aggregated (see Multi Well Pad Statement below).

M. Multi Well Pad Statement

When multiple wells are drilled from a single pad, it may be necessary to aggregate all emission sources at the multiple well production facility and additional permitting requirements may apply (Title V, PSD, etc.), which are beyond the scope of this document. Questions regarding permitting requirements for multi-well production facilities should be addressed to Craig Thorstenson of the Division of Air Quality at 701-328-5188 or cthorstenson@nd.gov.

3. FORM COMPLETION

A. Oil & Gas Facility Registration Process

Within 90 days after the first date of production or recompletion of any Bakken Pool O&G production facility, the following documents (registration packet) must be submitted to the NDDoH for the facility:

Registration Packet Contents

1) A completed Oil/Gas Registration Form (AP-114)
2) A gas analysis of any gas produced from the well
3) The first 2 pages (Input and Emission Summary) of a completed Oil and Gas Facility Emission Calculation Workbook

The Registration packet, (forms and examples found at: http://www.ndhealth.gov/AQ/OilAndGasWells.htm), which includes the above three items, must be sent to the following address:

North Dakota Department of Health
Division of Air Quality
918 E Divide Ave, 2nd Floor
Bismarck, ND 58501-1947

B. Emission Calculation Workbook

The Emission Calculation Workbook can be downloaded from the NDDoH O&G website in Excel format. The workbook will serve two functions: it will provide a simple way of calculating facility-wide emissions, as well as insuring that all owner/operators are calculating emissions in a consistent manner that meets the requirements of NDDoH.

The Oil & Gas Facility Emission Calculation Workbook contains the following 10 tabs:

- **Input** – The necessary data to perform the required calculations are entered here (required to be submitted in Registration Packet).
- **RICE Input** – The necessary data to perform the required calculations for RICE are entered here (required to be submitted in Registration Packet).
- **Emission Summary** – The calculated emissions are summarized by source and pollutant here (required to be submitted in Registration Packet).
- **Oil/Condensate Tanks** – The tank vapor emissions are calculated here.
- **Treater Flare** – The treater flare emissions are calculated here.
- **Treater Burner** – The treater burner emissions are calculated here.
- **Truck Loading** – The truck loading emissions are calculated here.
- **RICE** – The RICE emissions are calculated here.
- **Pneumatic Pump** – The pneumatic pump emissions are calculated here.
- **Pneumatic Controllers** –The pneumatic controller emissions are calculated here.

C. Emission Calculation Workbook Instructions

The Emission Calculation Workbook can be completed in three steps: Calculating production numbers, calculating glycol dehydrator emissions using GRI-GLYCalc (if applicable) and entering data into the Emission Calculation Workbook.

Step 1

Thirty days after the first date of production or recompletion of a Bakken Pool O&G production facility, the average daily production for the facility needs to be calculated. Once calculated, this production data will need to be entered into the Emission Calculation Workbook in order to perform the required emission calculations.

Step 2

If the facility has a glycol dehydrator in operation, the NDDoH recommends using GRI-GLYCalc V4 or higher to calculate the emissions. Other programs may be used upon approval from the NDDoH.

Step 3

Complete the entire Emission Calculation Workbook per the detailed instructions below:

Data Input

Facility and Registration Information: Lines 1-3

Line 1: Enter the name of the facility and the well number.

Line 2: Enter the first date of production or date of recompletion of the facility.

Line 3: Enter the date that the registration packet is submitted to the NDDoH.

Production Data: Lines 4-8

Line 4: New wells: enter the average daily production in BOPD, based on the first 30 days of production, excluding any days the well was not operating during that period of time. Existing wells: enter the average daily production in BOPD, based on the most recent 30 days of production, excluding any days the well was not operating during that period of time.

Line 5: New wells: enter the average daily production of gas in Mscf per day, based on the first 30 days of production, excluding any days the well was not operating during that period of time. Existing wells: enter the average daily production in Mscf, based on the most recent 30 days of production, excluding any days the well was not operating during that period of time.

Line 6: New wells: enter 0.6 on this line. This equates to an 80% decline in production from the well during the first year of production. If the expected decline rate is less than 80%, then the expected decline rate should be used. Existing wells: in most situations, a decline factor may not be used for an existing well; therefore, enter 1 on this line. The Department will accept a decline factor other than 0.6 or 1 in the following instance: an actual decline factor (based on well production) must be submitted for each well that is producing for less than one year before June 1, 2011. Wells that have produced for more than one year before June 1, 2011 must use a decline factor of 1. See Appendix E for an explanation of the decline factor and how it relates to an 80% decline in production during the first year of production.

Line 7: No input required. This is the projected first year average daily oil production rate (BOPD). This is automatically calculated by multiplying the average daily rate entered on Line 3 by the decline factor entered on Line 5.

Line 8: No input required. This is the projected first year average daily gas production rate (Mscfd). This is automatically calculated by multiplying the average daily rate entered on Line 4, by the decline factor entered on Line 5.

Oil/Condensate Tank Data: Lines 9-19

Line 9: Using the drop down box, select the appropriate flash gas method used for determining the tank vapor emission factor (scf/bbl).

- Default Bakken EF
- Site Specific Direct Measurement
- Representative Average (This average can be established from direct measurements from a minimum of six different wells within the same field and operating under similar parameters; however, it requires a case-by-case review and approval by the NDDoH prior to submitting the registration packet).

Line 10: Enter the scf/bbl EF based on the method chosen on Line 8.

- Default Bakken EF: If site specific data is not available, the default Bakken EF of 97.91 scf/bbl should be used.
- Direct Measurement: If site specific direct measurements have been taken, enter the measured scf/bbl EF determined from taking the direct measurement.
- Representative average: Enter the representative average scf/bbl approved by the NDDoH.

Line 11: No input required. This is a calculated value determined by multiplying the adjusted BOPD value on Line 6, by the scf/bbl entered in Line 9.

Line 12: Enter the lower heating value (Btu/scf) of tank vapors. If site specific data is not available, use the Bakken default value of 2000.

Line 13: Enter the molecular weight of the tank vapors in pounds per pound-mole (lb/lb-mole). If site specific data is not available, use the Bakken default value of 45.19.

Line 14: Enter the VOC weight fraction of the tank vapor gas (C3+). If site specific data is not available, use the Bakken default value of 79.8%.

Line 15: Enter the HAP weight fraction of the tank vapor gas. If site specific data is not available, use the Bakken default value of 2.26%. A complete list of HAPs is located at http://www.epa.gov/ttn/atw/orig189.html.

Line 16: Enter the H_2S weight percent of the tank vapors.

Line 17: Enter the H_2S mole percent of the tank vapors.

Line 18: Use the drop down menu to select the type of device used to destruct tank vapors from the following options:

- Vapor Recovery Unit or Oil Stabilizer
- Enclosed Smokeless Combustor
- Utility Flare or Other 98% DRE Device
- Ground Pit Flare or other 90% DRE device

Line 19: No input required. This is a fixed destruction efficiency based on the control type selected on Line 17.

- Vapor Recovery Unit or Oil Stabilizer = 99% DRE
- Enclosed Smokeless Combustor = 98% DRE
- Utility Flare or Other 98% DRE Device = 98% DRE
- Ground Pit Flare or other 90% DRE device = 90% DRE

Treater Gas Data: Lines 20-29

Line 20: Enter the site specific Btu/scf of the wellstream gas.

Line 21: Enter the average molecular weight of the wellstream gas in lb/lb-mole.

Line 22: If it is necessary to convert specific gravity to molecular weight, enter the specific gravity of the wellstream gas.

Line 23: This is the calculated molecular weight of the wellstream gas based on the specific gravity entered on Line 22. Enter this value on Line 21.

Line 24: Enter the VOC weight fraction of the wellstream gas (C3+). Note that this is the weight percent, not the mole percent of the gas.

Line 25: Enter the HAP weight fraction of the wellstream gas. Note that this is the weight percent, not the mole percent of the gas. A complete list of HAPs is located at http://www.epa.gov/ttn/atw/orig189.html.

Line 26: Enter the H_2S weight percent of the wellstream gas.

Line 27: Enter the H_2S mole percent of the wellstream gas.

Line 28: Use the drop down menu to select the type of device used to destruct the wellstream gas from the following options:

- Enclosed Smokeless Combustor
- Utility Flare or other 98% DRE Device

- Ground Pit Flare or other 90% DRE device
- Connected to Sales Line

Line 29: No input required. This is a fixed destruction efficiency based on the control type selected on Line 25.

- Enclosed Smokeless Combustor = 98% DRE
- Utility Flare or Other 98% DRE Device = 98% DRE
- Ground Pit Flare or other 90% DRE device = 90% DRE
- Connected to Sales Line = 100% DRE

Treater Burner(s) Data: Lines 30-31

Line 30: Enter the total burner rating for the treater burner(s) in Btu/hr. If there are multiple burners at the facility, enter the total heat input of all burners.

Line 31: The burner(s) is/are assumed to operate 8,760 hours per year.

Truck Loading Data: Lines 32-38

Line 32: Use the drop down menu to choose the appropriate oil sales method. If oil is sold through a Lease Automatic Custody Transfer, no input values are required in Lines 30-35.

Line 33: Use the drop down list to choose the appropriate mode of operation. The saturation factor will automatically be selected based on mode of operation.

Line 34: Enter the molecular weight of tank vapors, lb/lb-mole. If no site specific data is available, please refer to Table 2 on the Truck Loading tab.

Line 35: Enter the true vapor pressure of liquid loaded, pounds per square inch absolute (psia). If no site specific data is available, please refer to Table 2 on the Truck Loading tab.

Line 36: Temperature of bulk liquid loaded in degrees Fahrenheit. If no site specific data is available, use an estimated average annual temperature.

Line 37: Enter the load rate of liquid loaded in barrels per hour.

Line 38: Enter the time (in hours) it takes to loadout one load.

Pneumatic Pumps Data: Lines 39-43

Line 39: Enter the number of pneumatic pumps at the facility.

Line 40: Enter the hours each pump is in operation annually. For winter months only, enter 4380 hours.

Line 41: Enter the pneumatic source consumption rate from manufacturer's data (scf/min).

Line 42: Use the drop down menu to choose the appropriate emission control type.

Line 43: No input required. Control efficiency is automatically calculated based on control type selected on Line 55.

Pneumatic Controllers Data: Lines 44-45

Line 44: Enter the number of pneumatic controllers at facility.

Line 45: Enter the average bleed rate of device (scf/hr).

Glycol Dehydrator Data: Lines 46-47

Line 46: Enter the TPY of VOC emissions calculated in GRI-GLYCalc V4 software. (If no glycol
dehydrator is installed, enter 0).

Line 47: Enter the TPY of HAP emissions calculated in GRI-GLYCalc V4 software. (If no glycol dehydrator is installed, enter 0).

<u>RICE Data Input</u>: Lines 1-97

Line 1: Enter the number of engines to be installed at the production facility.

RICE Engine #1: Lines 2-9

Line 2: Engine is assumed to operate 8,760 hours per year.

Line 3: Enter the manufacturer's maximum hp rating.

Line 4: Enter the manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).

Line 5: Enter the manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).

Line 6: Enter the manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for volatile organic compounds (VOC).

Line 7: Enter the NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc.) obtained from manufacturer data or actual test results.

Line 8: Enter the CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc.) obtained from manufacturer data or actual test results.

Line 9: Enter the VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc.) obtained from manufacturer data or actual test results.

Repeat the above input instructions for line 2 through 9 for each additional engine at the facility.

4. EMISSION SOURCE DETAILS

A. Oil/Condensate Tanks

Vapors containing regulated pollutants are released from solution in hydrocarbon liquids as the liquids are transferred from higher to lower pressure, such as from a separator to an atmospheric storage tank. These vapors are called flashing losses.

Vapors escaping from hydrocarbon liquids while they are stored in atmospheric tanks are called standing/working/breathing (S/W/B) losses. Standing losses are essentially evaporation losses. Working losses are those caused by decreased tank vapor space occurring as the tank is filled. Breathing losses are those promoted by ambient changes such as increased air temperatures.

As used in this Guidance, the term, tank emissions include all S/W/B losses and flashing emissions together.

B. Calculating Tank Emissions

Tank emissions are calculated using the Oil & Gas Facility Emission Calculation Workbook. The workbook calculates the tank emissions by using either an actual direct measurement (scf/bbl) taken by the owner/operator, a representative average or by using the default Bakken Pool emission factor of 97.91 scf/bbl described below. In addition to the scf/bbl value, the workbook uses the molecular weight, lower heating value of the fuel and the VOC and HAP weight fractions of the tank vapors to calculate the tank vapor emissions.

C. Bakken Pool Tank Vapor Emission Factor

In conjunction with the NDDoH, a VOC Emission Factor Committee was formed in 2010 to determine an emission factor that could be used for the Bakken Pool crude when calculating tank vapor emissions.

The VOC Emission Factor Committee consisted of representatives from various O&G companies, as well as several environmental consultants. After reviewing the data from 89 direct measurements taken by several owner/operators within Mountrail County, the average emission factor of all measurements taken was 55.26 scf/bbl.

Many of the facilities could actually have emissions which are considerably higher than the average emission factor. Therefore, to better represent some of the higher emitting facilities and to avoid underestimating emissions, the 90^{th} percentile (97.91 scf/bbl) will be utilized. If an owner/operator does not have direct measurement data to support a site specific emission factor, or an NDDoH pre-approved average scf/bbl emission factor established from direct measurements taken from a minimum of 6 different locations operating under similar parameters (representative sample), the owner/operator must use the default value of 97.91 scf/bbl.

D. <u>Tank Emissions Control Threshold</u>

Tank emissions require control in accordance with Appendix D of this document.

E. <u>Tank Emissions Control Requirements</u>

Emission control requirements for tank emissions are outlined in Appendix D of this document. Also see Appendix C for a list of acceptable control systems or devices.

F. <u>Produced Water Tanks</u>

At sites where tank emissions must be controlled by at least 90%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 90% within 60-days after the first date of production. See Appendix C for a list of acceptable control systems or devices.

G. <u>Glycol Dehydrators</u>

Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. "Lean" TEG contacts the wet gas and absorbs water. The TEG is then considered "rich." As the rich TEG is passed through a reboiler and a flash separator (if installed) for regeneration, steam containing hydrocarbon vapors are released. These are then vented from the dehydration unit flash separator and/or reboiler still vent.

H. <u>Calculating Glycol Dehydrator Emissions</u>

The NDDoH recommends using GRI-GLYCalc V4.0 or higher to determine potential uncontrolled VOC and HAP emissions from the process vents of the dehydration unit associated with the projected (decline factor applied) first year average daily gas production rate. Other emission calculation programs may be used upon approval from the NDDoH.

After running the program, print a copy of the report and include it with the Registration Packet submittal. The estimated VOC and HAP emission values also must be entered on Line 59 & Line 60 on the Input Tab of the Emission Calculation Spreadsheet.

I. <u>Glycol Dehydrator Control Threshold</u>

Emissions that meet or exceed the following thresholds require the still vent vapors be routed to a control device: $\geq$ 5.0 TPY of any combination of HAPs, or $\geq$ 15.0 TPY any combination of VOCs.

J. **Glycol Dehydrator Control Requirements**

The following control systems or devices are accepted by the NDDoH for glycol dehydrator emissions:

1) An enclosed, smokeless combustion device or flare that is designed and operated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98% by weight.
2) Any other control device (e.g. condenser or ground pit flare) or configuration that can be demonstrated to reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 90% by weight.
3) Glycol dehydrator emission controls may be removed after one year of operation provided emissions have declined to <15 TPY VOC and <5 TPY HAP. An updated GRI-GLYCalc run with new calculations must be submitted to the NDDoH with a request for control removal. No controls may be removed prior to obtaining written approval from the NDDoH.

K. **Glycol Dehydrator Federal Regulations**

A Federal regulation (40 CFR 63, Subpart HH) may be applicable to glycol dehydrators located at Bakken Pool O&G production facilities. This regulation is beyond the scope of this document, but listed below is a brief summary of the regulation:

40 CFR 63, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Gas Production Facilities

This federal regulation applies to all Bakken Pool O&G production facilities that are major and area sources of HAPs with the following exceptions:

1) A facility that exclusively processes, stores or transfers black oil.
2) A major source prior to the point of custody transfer with a facility-wide annual average natural gas throughput < 18.4 thousand cubic meters/day and a facility-wide annual hydrocarbon liquid throughput < 37,700 liters/day.

L. **Calculating Treater Gas Flare Emissions**

The treater flare emissions are calculated within the Oil & Gas Facility Emission Calculation Workbook using the following:

1) The projected first year average daily gas production rate. This is automatically calculated by multiplying the average daily rate entered on Line 1, by the decline factor entered on Line 3.
2) VOC & HAP weight fraction of gas
3) H_2S mole percent of treater gas
4) Lower heating value of gas
5) Average molecular weight of gas

6) NOx & CO emissions are based on AP-42 emission factors for industrial flares.

M. Control Requirements for Treater Gas

Treater gas must be routed to a gas gathering pipeline as soon as practicable in accordance with the North Dakota Industrial Commission requirements. When a pipeline is not available, treater gas is required to be routed to a control system or device. See Appendix C for a list of acceptable control systems or devices. That stated, the current opportunities to capture and transmit treater gas emissions necessitates the intermittent, or otherwise, use of combustion devices.

N. Natural Gas Fired Heaters & Burners

Some of the byproducts of natural gas combustion in process heaters, boilers, burners, etc. are regulated air pollutants. NOx, CO, VOC, HAP & SO_2 emissions from process unit heaters are calculated within the Oil & Gas Facility Emission Calculation Workbook using the emission factors (EF) below from EPA AP-42, Tables 1.4-1, 1.4-2 and 1.4-3:

Table 1.4-1 Emission Factors from Natural Gas Combustion (Excerpt from AP-42, Tables 1.4-1, 1.4-2 and 1.4-3)

Pollutant	Natural Gas EF*
NOx	100 lb/MMscf
CO	84 lb/MMscf
VOC	5.5 lb/MMscf
HAPS	1.89 lb/MMscf

*Based on an average heating value of 1020 Btu/scf of natural gas.

O. Truck Loading

When oil and condensate are loaded into tank trucks, the hydrocarbon vapors released from the tanker lines, as the truck is filling, contain regulated air pollutants. VOC emissions from loading oil or condensate into tank trucks are calculated within the Workbook by using the following formula with data from AP-42 tables.

$LL = 12.46 \times S \times P \times M/T$

Where: LL = loading loss, pound per 1,000 gallons of liquid loaded (lb/1000 gal)

S = a saturation factor (See Table 5.2-1 below)
P = true vapor pressure of liquid loaded (psia)
M = molecular weight of tank vapors (lb/lb-mol)
T = temperature of bulk liquid loaded (°R) (°R = °F + 460)
"S" values are obtained from Table 5.2-1.
"M" and "P" values are obtained from Table 7.1-2.

Table 5.2-1 Saturation (S) Factors for Calculating Petroleum Liquid Loading Losses (Excerpt from AP-42, Table 5.2-1)

Cargo Carrier	Mode of Operation*	S Factor
Tank Truck and Rail Tank Cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00

* Splash loading is not permitted in accordance with NDAC 33-15-07.

Table below may be used to provide the "P" and "M" values for the above equation:

Table 7.1-2 Properties of Selected Petroleum Liquids (Excerpt from AP-42, Table 7.1-2)

Petroleum Liquid	Vapor MW at 60 F M_V(lb/lb-mole)	Condensed Vapor Density at 60F W_{VC}(lb/gal)	Liquid Density at 60F W_L(lb/gal)	True Vapor Pressure, P_{va} (psi) at various temperatures in F						
				40	50	60	70	80	90	100
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7

P. **Truck Loading Control Requirements**

Bakken Pool O&G production facilities are not required to route emissions displaced from truck loading activities to a control system or device due to safety concerns. However, the owner/operator shall follow any operating and/or construction requirements established in Chapters 33-15-07 and 33-15-20 of the North Dakota Air Pollution Control Rules.

Q. **Reciprocating Internal Combustion Engines (RICE)**

The emission calculation workbook requires g/bhp-hr values for VOC, NOx and CO in order to perform calculations for any particular engine. Those values may be obtained in three different manners and are listed below in order of preference.

Engine Emission Factor in Order of Preference

1) Actual Stack Test
2) Manufacturer's Engine Data
3) AP-42 Values

While any of the three emission factors are acceptable by the NDDoH, actual test data from a particular engine, is usually the most accurate and preferred method. When test data is not readily available, manufacturer data for that particular engine model is the next best emission factor to be used. If neither test data, nor manufacturer data is available, AP-42 values should be used.

R. RICE Control Requirements

The NDDoH does not require any specific air pollution control equipment for RICE; however, the RICE must be in compliance with all State and Federal Rules and Regulations.

S. Federal Regulations for RICE

There are several Federal regulations that may be applicable to RICE located at Bakken Pool O&G production facilities. These regulations are beyond the scope of this document, but listed below is a brief summary of the Federal regulations that may be applicable. These regulations can be found at the following: http://ecfr.gpoaccess.gov.

40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines: Applies to any compression-ignition internal combustion engine where construction is commenced after July 11, 2005 and the engine is manufactured after April 1, 2006.

40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines: Applies to any spark-ignition internal combustion engine where construction is commenced after June 12, 2006 and the engine is manufactured:

- After July 1, 2007 for engines > 500 hp
- After January 1, 2008 for lean-burn engines 500 < hp < 1350
- After July 1, 2008 for engines < 500 hp
- After January 1, 2009 for emergency engines

40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines: Applies to any (new, existing, modified and reconstructed) RICE located at a major source or an area source of HAPs.

T. Pneumatic Pumps

If a pneumatic pump uses natural gas as the motive gas, the pump will release VOC and HAP emissions each time it strokes since all motive gas is vented by the pump. The Workbook calculates emissions from the pump based on the following:

1) Manufacturer's information regarding gas usage (scf/hr)
2) The VOC & HAP weight fraction of the motive gas
3) Molecular weight of motive gas
4) Hours of operation

U. Pneumatic Pump Control Requirements

Bakken Pool O&G production facilities are required to control pneumatic pumps that use natural gas as the motive gas, if the PTE of VOCs from the pneumatic pump is >5 TPY per pump.

V. Pneumatic Controllers

If a pneumatic controller uses natural gas as the motive gas, the device will release VOC and HAP emissions each time it operates. The Workbook calculates emissions from the pump based on the following:

1) Manufacturer's information regarding gas usage (scf/hr)
2) The VOC & HAP weight fraction of the motive gas
3) Molecular weight of motive gas
4) Hours of operation

W. Pneumatic Controller Control Requirements

Bakken Pool O&G production facilities are not required to install add-on controls for emissions from these types of devices.

5. EFFECTIVE DATE

This policy is effective on the date shown below. This policy does not supersede any applicable state or federal rule, regulation or law.

Any questions about this document should be directed to:

North Dakota Department of Health
Division of Air Quality
918 E Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947
Phone: 701-328-5188

This document is available at: http://www.ndheath.gov/aq

Approved: Terry O'Clair   Date: May 2, 2011

Terry L. O'Clair, P.E.
Director
Division of Air Quality
North Dakota Department of Health

APPENDIX A

Oil & Gas Production Facility Registration Form

Following is a copy of the NDDoH Oil/Gas Production Facility Registration Form (AP-114) which must be submitted as part of the registration packet within 90 days after the first date of production of a Bakken Pool O&G production facility. The form can be downloaded from the NDDoH website (http://www.ndhealth.gov/AQ/OilAndGasWells.htm) and is available in both Word and PDF formats. Also required is a copy of the gas analysis for the well and the first three pages of the Emission Calculation Workbook.

OIL/GAS PRODUCTION FACILITY REGISTRATION
NORTH DAKOTA DEPARTMENT OF HEALTH
DIVISION OF AIR QUALITY
SFN 14334 (2-11)

GENERAL

Type of Report ☐Initial ☐Amended		Well Status ☐Initial Completion ☐Recompletion		
Name of Owner/Operator				
Official to Contact on Air Pollution Matters	Email address	Title	Telephone Number	
Name of Applicant		Title	Telephone Number	
Mailing Address		City	State	Zip Code

FACILITY DATA

Well(s) Name	Producing Pool	Field Name
Legal Description of Well Site Surface Location 1/4 1/4, Section , Twp. N., Rge. W	Permit Number	Date of Completion/Recompletion
Location of Treater ☐On-site * ☐At Central Tank Battery, Specify Location 1/4 1/4, Section , Twp. N, Rge. W		
Location of Storage Tanks ☐On-site * ☐At Central Tank Battery, Specify Location 1/4 1/4, Section , Twp. N, Rge. W		
Location of Flare ☐On-site * ☐At Central Tank Battery, Specify Location 1/4 1/4, Section , Twp. N, Rge. W		
Other Air Pollution Equipment (e.g., Internal Combustion Engines @ x HP - compressors, generators, etc., whose collective HP rating exceeds 500 HP), Specify:		

* The emissions for the entire facility must be included in the section titled "EMISSIONS". Include well name and file number in the section titled "COMMENTS" on any additional well(s) using the central tank battery.

GAS INFORMATION

Gas/Oil Ratio (cf/bbl)	Date of GOR	H2S Content in Gas "ATTACH GAS ANALYSIS" ppm or mole % (1% = 10,000 ppm)
Disposition of Gas (check all that apply) ☐Flared, Estimate Amount Mcf/day ☐Sold to		☐Used on Lease, Estimate Amount Mcf/day ☐Currently Flared Scheduled to be Tied-in To By

EQUIPMENT

Flare System ☐Equipped with Automatic Ignitor ☐Equipped with Continuous Pilot, Specify Pilot Fuel		Flare Stack Height Above Ground Feet
STORAGE TANKS		
Number of Saltwater	Number of Oil	Estimate Total Amount of Gas Generated From Storage Tanks Mcf/day with ppm H2S
Tank Gas Emissions Are: ☐Controlled by Vapor Recovery Unit ☐Burned by Flare (Include Amount of SO2 Produced in "EMISSIONS" Section) ☐Burned by Treater (Include Amount of SO2 Produced in "EMISSIONS" Section)		☐Vented to Atmosphere ☐Other, Specify
TREATER		
Treater Fuel	If Sour ppm H2S	Treater Stack Height Above Ground Feet

SFN 14334 (2-11) Page 2

EMISSIONS

Annual Total S Emissions (Note: For facilities comp/recomp prior to 7/1/87, if Total S is 10 T/yr or greater, registration must be submitted. All facilities comp/recomp on or after 7/1/87 must submit registration.)

S = (Flared + Lease Use + Vented) (mole % H2S) (0.00042)

Mcf/Day	*	% H2S	*	Days/Year	*	0.00042	=	Tons/year (total S)

Annual Total SO2 Emissions (Note: This calculation is necessary to determine if prevention of significant deterioration (PSD) or Title V permitting is required.)

SO2 (tons/year) = (Flared + Lease Use) (mole % H2S) (days operation/year) (0.00084)

Mcf/Day	*	% H2S	*	Days/Year	*	0.00084	=	Tons/year (SO2)

If SO2 > 100 tons/year, additional permitting is required.

Annual Total VOC Emissions

VOC Emissions: tons/year (uncontrolled) tons/year (controlled)

COMMENTS

Certification of Truth, Accuracy and Completeness

As an authorized company representative, I certify that to the best of my knowledge the information contained in this Oil/Gas Production Facility form and additional sheets is true, accurate and complete.

Signature of Applicant	Date
X	

ND Department of Health
Division of Air Quality
918 E Divide, 2nd Floor
Bismarck, ND 58501-1947

Telephone: (701)328-5188
Fax: (701)328-5185

APPENDIX B

Oil & Gas Production Facility Emission Calculation Workbook Screenshots

The following pages represent screenshots of the Emission Calculation Workbook. The workbook is available for download from the NDDoH website in Excel format at: (http://www.ndhealth.gov/AQ/OilAndGasWells.htm

The workbook is intended to provide an easy way for owner/operators to calculate emissions for a Bakken Pool O&G production facility. With all owner/operators using the same emission workbook, it will help ensure that all emissions are calculated in a consistent manner from one owner/operator to another. It will also assist the NDDoH in tracking statewide emissions from Bakken Pool O&G production facilities.

Please note: the only Emission Calculation Workbook pages required in the Registration Packet are the Input Data Page, RICE Input Data Page and the Emission Summary Page (applies to all submittals).

INPUT DATA PAGE

NORTH DAKOTA
DEPARTMENT of HEALTH

GREEN = Requires input
RED = No input required. This is a calculated value.

	Facility Information		
Line 1	North Dakota Well #1		Name of the facility and the well number.
Line 2	1/13/2011		First date of production or the date of modification of the facility.
Line 3	3/12/2011		Date registration packet is submitted to the NDDoH.

	Production Data		Description
Line 4	BOPD	240	Average daily production in barrels of oil per day (BOPD), based on the first 30 days of production.
Line 5	Mscfd	150	Average daily production of gas in Mscf per day, based on the first 30 days of production.
Line 6	Decline Factor	0.6	Expected decline factor for the first year of operation. Enter the default value 0.6; anything lower needs prior approval from the NDDoH.
Line 7	Adjusted BOPD	144	This is the calculated BOPD expected to be produced using the above entered decline factor.
Line 8	Adjusted Treater Gas (Mscfd)	90	This is the calculated mcfd of gas the well is expected to produce using the above entered decline factor.

	Oil/Condensate Tank Data		Description
Line 9	Flash Gas Method: Default Bakken EF		Use the drop down menu to choose the appropriate flash gas method.
Line 10	Bakken EF scf/bbl	97.91	The scf/bbl from direct measurement or representative sample. If specific data is not available, use the Bakken default of 97.91.
Line 11	Estimated Tank Vapors (scfd)	14099.04	This is the estimated scfd of tank vapors based on the following: adjusted BOPD multiplied by the scf/bbl entered on Line 9.
Line 12	Lower Heating Value	2000	Lower heating value (Btu/scf) of tank vapors. If site specific data is not available, use the Bakken default value of 2000.
Line 13	Molecular Weight	45.19	Molecular weight of the tank vapors in pounds per pound-mole (lb/lb-mole). If site specific data is not available, use the Bakken default value of 45.19.
Line 14	VOC%	79.80%	VOC weight fraction of the tank vapor gas (C3+). If site specific data is not available, use the Bakken default value of 79.8%.
Line 15	HAP%	2.26%	HAP weight fraction of the tank vapor gas. If site specific data is not available, use the Bakken default value of 2.26%.
Line 16	H_2S weight %	0.000%	H_2S weight percent of the tank vapor gas.
Line 17	H_2S mole %	0.000%	H_2S mole percent of the tank vapor gas.
Line 18	Vapor Recovery Unit or Oil Stabilizer		Use the drop down menu to choose the appropriate emission control type.
Line 19	Control Destruction Efficiency	99%	Control efficiency of any applicable controls. This is a fixed number based on control type.

	Treater Gas Data		Description
Line 20	Btu/scf	1500	Btu/scf of wellstream gas.
Line 21	Molecular Weight	28.96	Average molecular weight of the wellstream gas in lb/lb-mole.
Line 22	Specific Gravity	1	If necessary to convert specific gravity to molecular weight, enter the specific gravity of the wellstream gas.
Line 23	Calculated Molecular Weight	28.96	This is the calculated molecular weight based on the specific gravity entered above. Please enter this number on Line 21.
Line 24	VOC%	32.00%	VOC weight fraction of the wellstream gas (Note: Weight%, not Mole%).
Line 25	HAP%	0.50%	HAP weight fraction of the wellstream gas. (Note: Weight%, not Mole%).
Line 26	H_2S weight %	0.000%	H_2S weight percent of the wellstream gas
Line 27	H_2S mole %	0.000%	H_2S mole percent of the wellstream gas
Line 28	Connected to sales line		Use the drop down menu to choose the appropriate emission control type.
Line 29	Control Destruction Efficiency	100%	Control efficiency of any applicable controls (combustor, pit flare, utility flare, etc).

	Treater Burner(s)		Description
Line 30	Total Btu/hr	500,000	Total burner rating for the heater treater burner(s) in btu/hr. If there are multiple burners, add the total heat input together.
Line 31	Hours of Operation	8,760	The burner(s) is/are assumed to operate 8,760 hours per year.

	Truck Loading		Description
Line 32	Oil is hauled by truck		Use the drop down menu to choose the appropriate oil sales method. If oil is sold through a LACT, no input values are required in Lines 30-35.
Line 33	Submerged loading: dedicated vapor balance service	1	Use the drop down list to choose the appropriate mode of operation. The saturation factor will automatically be selected based on mode of operation.
Line 34	Molecular Weight	50.00	Molecular weight of tank vapors in lb/lb-mole If no site specific data is available, please refer to Table 2 on the Truck Loading tab.
Line 35	Vapor Pressure	2.30	True vapor pressure of liquid loaded, pounds per square inch absolute (psia) If no site specific data is available, please refer to Table 2 on the Truck Loading tab.
Line 36	Temperature	50.00	Temperature of bulk liquid loaded in Farenheit. If no site specific data is available, use an estimated average annual temperature.
Line 37	Load Rate (bbl/hr)	180	Load rate of liquid loaded in barrels per hour.
Line 38	Load Time (hrs)	1.00	The time it takes to loadout one load (hrs).

	Pneumatic Pumps		Description
Line 39	Number of Pneumatic Pumps	2	Number of pneumatic pumps at facility.
Line 40	Hours of Operation	4380	Hours the pump is in operation annually. For winter months only, please enter 4380 hours.
Line 41	scf/min	0.50	Pneumatic source consumption rate as per manufacturer data (scf/min).
Line 42	Routed exhaust back into closed loop system		Use the drop down menu to choose the appropriate emission control type.
Line 43	Control Efficiency	100%	Control efficiency of any applicable controls (combustor, routing exhaust to fuel supply, VRU, etc).

	Pneumatic Controllers		Description
Line 44	Number of Pneumatic Controllers	10	Number of pneumatic controllers at facility.
Line 45	Bleed rate (scf/hr)	0.00	Average bleed rate of device (scf/hr).

	Glycol Dehydrator		Description
Line 46	VOC (TPY)	10.00	VOC emissions calculated in GRI-GLYCalc software (if no glycol dehydrator enter 0).
Line 47	HAP (TPY)	6.00	HAP emissions calculated in GRI-GLYCalc software (if no glycol dehydrator enter 0).

RICE INPUT DATA PAGE

Line 1	**Number of Engines**	2	Enter the number of engines that will be installed at the production facility.

	RICE Engine #1		Description
Line 2	Hours of Operation	8760	Engine is assumed to operate 8,760 hours per year.
Line 3	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 4	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 5	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 6	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 7	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 8	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 9	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #2		Description
Line 10	Hours of Operation	8760	Engine is assumed to operate 8,760 hours per year.
Line 11	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 12	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 13	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 14	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 15	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 16	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 17	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #3		Description
Line 18	Hours of Operation	0	Engine is assumed to operate 8,760 hours per year.
Line 19	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 20	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 21	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 22	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 23	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 24	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 25	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #4		Description
Line 26	Hours of Operation	0	Engine is assumed to operate 8,760 hours per year.
Line 27	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 28	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 29	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 30	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 31	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 32	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 33	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

	RICE Engine #5		Description
Line 34	Hours of Operation	0	Engine is assumed to operate 8,760 hours per year.
Line 35	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 36	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) for nitrogen oxides (NOx).
Line 37	CO g/hp-hr	5	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for carbon monoxide (CO).
Line 38	VOC g/hp-hr	4	Manufacturer's emission factor, actual test results or AP-42 factor in g/hp-hr for total organic compounds (TOC or THC).
Line 39	NOx Control Efficiency	90%	NOx control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 40	CO Control Efficiency	75%	CO control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.
Line 41	VOC Control Efficiency	70%	VOC control efficiency of any applicable controls (NSCR catalyst, AFRC, etc) obtained from manufacturer data or actual test results.

EMISSION SUMMARY PAGE

Facility:
North Dakota Well #1

Emission Summary
North Dakota Department of Health*
*The NDDH PTE is post-control

Emission Source	PTE (TPY)					
	VOC	HAP	NOx	CO	H_2S	SO_2
Oil/Condensate Tanks	2.05	0.14	0.35	1.90	N/A	N/A
Treater Flare	0.00	0.00	0.00	0.00	0.00	0.00
Treater Burner	0.01	0.00	0.21	0.18	N/A	N/A
RICE Engine	2.32	NA	1.93	2.41		
Truck Loading	2.23	NA				
Pneumatic Pump	0.00	0.00				
Pneumatic Controllers	0.00	0.00				
Glycol Dehydrator	10.00	6.00				
Totals (TPY)	**16.62**	**6.15**	**2.50**	**4.50**	**0.00**	**0.00**

Emission Control Requirements

Emission Source	Controls Required	Initial Control Installation Deadline	Additional Control Installation Deadline
Oil/Condensate Tanks	YES	1/13/2011	NA
Treater	YES	1/13/2011	
Pneumatic Pump	NO	NA	
Glycol Dehydrator	YES	1/13/2011	

Document/Permit Requirements*

Document/ Permit Required	YES/NO	Due Date
Registration Packet	YES	4/13/2011
Title V Permit	NO	NA
PSD Permit	NO	NA

*Owners and operators of O&G facilities with the potential to emit at or above major source thresholds must adequately control emissions or follow the normal permitting process established in Chapters 33-15-14 and 33-15-15 of the North Dakota Air Pollution Control Rules.

OIL/CONDENSATE TANKS

North Dakota Well #1

Tanks

Flare Gas Volume	14,099 scf/day
Lower Heating Value	2000 Btu/scf
Molecular Weight	42 lb/lb-mole
VOC wt Fraction	72.00%
HAP wt Fraction	5.00%

Controlled emissions are calculated based on a 99% destruction efficiency of the VOC gas.

VOC:	587 scf/hr	x	1/379 scf/lb-mole	x	42 lb/lb-mole	x	72.00%	x	99%	=	0.47 lb/hr
	0.47 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	99%	=	2.05 TPY		
HAP	587 scf/hr	x	1/379 scf/lb-mole	x	42 lb/lb-mole	x	5.00%	x	99%	=	0.03 lb/hr
	0.03 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	99%	=	0.14 TPY		
NOx:	587 scf/hr	x	2,000 Btu/scf	x	1 MMBtu/1,000,000 Btu	x	0.068 lb/MMBtu	=	0.08 lb/hr		
	0.08 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	=	0.35 TPY				
CO:	587 scf/hr	x	2,000 Btu/scf	x	1 MMBtu/1,000,000 Btu	x	0.370 lb/MMBtu	=	0.43 lb/hr		
	0.43 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	=	1.90 TPY				

NOx & CO emission factors are from AP-42 Table 13.5-1
(Emission Factors for Flare Operations).

TREATER FLARE

North Dakota Well #1

Treater Flare

Flare Gas Volume	90,000 scfd
Lower Heating Value	1500 Btu/scf
Avg. Molecular Weight	28.96 lb/lb-mole
VOC wt fraction	32.00%
HAP wt fraction	0.50%

Controlled emissions are calculated based on 100% destruction efficiency of the VOC gas.

VOC:	3,750 scf/hr	x	1/379 scf/lb-mole	x	28.96 lb/lb-mole	x	32.00%	x	100%	= 0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%			= 0.00 TPY
HAP	3,750 scf/hr	x	1/379 scf/lb-mole	x	28.96 lb/lb-mole	x	0.50%	x	100%	= 0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%			= 0.00 TPY
H_2S	3,750 scf/hr	x	1/379 scf/lb-mole	x	28.96 lb/lb-mole	x	0.00%	x	100%	= 0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%			= 0.00 TPY
SO_2	3,750 scf/hr	x	1/379 scf/lb-mole	x	64 lb/lb-mole	x	0.00%	x	100%	= 0.00 lb/hr
	0.00 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb	x	100%			= 0.00 TPY
NOx:	3,750 scf/hr	x	1,500 Btu/scf	x	1 Mmbtu/1,000,000 Btu	x	0.068 lb/MMB			= 0.38 lb/hr
	0.38 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb					= 1.68 / 0.00 TPY
CO:	3,750 scf/hr	x	1,500 Btu/scf	x	1 Mmbtu/1,000,000 Btu	x	0.370 lb/MMB			= 2.08 lb/hr
	2.08 lb/hr	x	8760 hr/yr	x	1 ton/2000 lb					= 9.12 / 0.00 TPY

NOx & CO emission factors are from AP-42 Table 13.5-1
(Emission Factors for Flare Operations).

TREATER BURNER

North Dakota Well #1

Heater Treater Burner

Burner Rating 500,000 Btu/hr

NOx:	0.10 lb/MMBtu	x	0.50 MMBtu/hr			=	0.05 lb/hr
	0.0490 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	0.21 TPY
CO:	0.08 lb/MMBtu	x	0.50 MMBtu/hr			=	0.04 lb/hr
	0.04 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	0.18 TPY
VOC:	0.01 lb/MMBtu	x	0.50 MMBtu/hr			=	0.00 lb/hr
	0.00 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	0.01 TPY
HAP:	0.002 lb/MMBtu	x	0.50 MMBtu/hr			=	0.00 lb/hr
	0.00 lb/hr	x	8,760 hr/yr	x	1 ton / 2000 lb	=	0.00 TPY

NOx, CO & VOC Emission Factors are from AP-42 Table 1.4-1 and 1.4-2 (Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion).

0.21	NOx TPY
0.18	CO TPY
0.01	VOC TPY
0.00	HAP TPY

TRUCK LOADING

North Dakota Well #1

Truck Loadout Emission Calculation

		Saturation Factor (S)		Vapor Pressure (P)		Molecular Weight (MW)		Temp + 460		Load Loss lb/1000 gal
12.46	x	0.60	x	2.30	x	50.00	/	510.00	=	1.69

LL lb/1,000 gal		Truck Load Rate bbl/hr		Load Time hrs		gal/bbl		Emissions lb/hr
1.69	x	180.00	/	1.00	x	42.00	=	12.78

LL lb/1,000 gal		Annual bbl/yr		gal/bbl		lb/ton		Emissions TPY VOC	C3+ VOC
1.69	x	438000.00	x	42.00	/	2000.00	=	15.54	11.19

Uncontrolled	Control %		VOC Emissions TPY
11.19	0.00	1.00	11.19

(EPA AP-42 Values) Table 1 below is required to supply the saturation factor variable in the above equation.

Cargo Carrier	Mode of Operation	S Factor
Tank Trucks and Rail Tank Cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00

(EPA AP-42 Values) Table 2 below may be used to provide the vapor pressure and molecular weight values for the above equation.

Petroleum Liquid	Vapor MW at 60F Mv(lb/lb-mole)	Condensed Vapor Density at 60F Wvc(lb/gal	Liquid Density at 60F W1(lb/gal)	True Vapor Pressure, Pva (psi) at various temperatures in F						
				40	50	60	70	80	90	100
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4	4.8	5.7

RICE

North Dakota Well #1

Reciprocating Engine Emissions

ENGINE #1

100 MAX HP | 90% NOx DRE | 75% CO DRE | 70% VOC DRE

NOx:	10.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	2.20 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	=	0.97 NOx TPY
CO:	5.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	1.10 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	=	1.21 CO TPY
VOC:	4.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	0.88 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	=	1.16 VOC TPY

ENGINE #2

100 MAX HP | 90% NOx DRE | 75% CO DRE | 70% VOC DRE

NOx:	10.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	x	2.20 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	=	0.97 NOx TPY
CO	5.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	x	1.10 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	=	1.21 CO TPY
VOC	4.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	x	0.88 lb/hr	x	8760 hr/yr	x	1 ton / 2000lb	=	1.16 VOC TPY

ENGINE #3

100 MAX HP | 90% NOx DRE | 75% CO DRE | 70% VOC DRE

NOx:	10.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	2.20 lb/hr	x	0 hr/yr	x	1 ton / 2000lb	=	0.00 NOx TPY
CO:	5.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	1.10 lb/hr	x	0 hr/yr	x	1 ton / 2000lb	=	0.00 CO TPY
VOC:	4.00 g/HP-HR	x	100 HP	x	1 lb / 453.6 grams	=	0.88 lb/hr	x	0 hr/yr	x	1 ton / 2000lb	=	0.00 VOC TPY

PNEUMATIC PUMPS

North Dakota Well #1

Emissions from Pneumatic Pumps

Emissions (lb/hr) = PSCR (scf/min) x (60 min/1hr) x (1/379 scf/lb-mole) x (VOC wt. Fraction)
Emissions (TPY) = (lb/hr VOC) x (8760 hr/yr) x (1 ton/2000)

Where:
PSCR = Pneumatic Source Consumption Rate (scf/min), as per manufacturers literature
Gas MW = Supply Gas Average Molecular Weight (lb/lb-mole)

							Supply Gas MW		VOC wt fraction			
0.5 scfm/min	*	60 min/1 hr	*	1/379 scf/lb-mole	x		28.96	x	32.00%	=	0.73 lb/hr VOC Uncontrolled
				lbs/hr			Hours (winter months)				
				0.73	x		4380	x	2000 lbs/ton	=	3.20 TPY VOC Uncontrolled
							Supply Gas MW		HAP wt fraction		
0.5 scfm/min	*	60 min/1 hr	*	1/379 scf/lb-mole	x		28.96	x	0.50%	=	0.01 lb/hr HAP Uncontrolled
				lbs/hr			Hours (winter months)				
				0.01	x		4380	x	2000 lbs/ton	=	0.04 TPY HAP Uncontrolled

Control Efficiency	100%	
Number of Pumps	2	
Total Controlled Emissions	0.00	TPY VOC
Total Controlled Emissions	0.00	TPY HAP

PNEUMATIC CONTROLLERS

North Dakota Well #1

Emissions from Pneumatic Controllers

Emissions (lb/hr) = PSCR (scf/hr) x (1/379 scf/lb-mole) x (VOC wt. Fraction)
Emissions (TPY) = (lb/hr VOC) x (8760 hr/yr) x (1 ton/2000)

Where:

PSCR = Pneumatic Source Consumption Rate (scf/min), as per manufacturers literature
Gas MW = Supply Gas Average Molecular Weight (lb/lb-mole)

						Supply Gas MW		VOC wt fraction			
0 scf/hr	x	60 min/1 hr	x	1/379 scf/lb-mole	x	28.96	x	32.00%	=	0.00	lb/hr VOC
				lbs/hr		Hours (winter months)					
				0.00	x	0	x	2000 lbs/ton	=	0.00	TPY VOC
						Supply Gas MW		HAP wt fraction			
0 scf/hr	x	60 min/1 hr	x	1/379 scf/lb-mole	x	28.96	x	0.50%	=	0.00	lb/hr HAP
				lbs/hr		Hours (winter months)					
				0.00	x	0	x	2000 lbs/ton	=	0.0	TPY HAP

APPENDIX C

NDDoH ACCEPTABLE CONTROL SYSTEMS OR DEVICES

The following VOC control systems or devices are accepted by the NDDoH:

1. A ground pit flare (including, but not limited to pit flares, shop built flares or other similar oilfield type flares) or other 90% or greater DRE device. If a ground pit flare is utilized, the NDDoH will allow a 90% DRE to be assumed. This is considered the minimum level of control for tank and treater gas emissions.

2. A vapor recovery unit or oil stabilizer that is designed and operated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 99% by weight. (Caution: a vapor recovery unit and oil stabilizer is used only to control tank emissions.)

3. An enclosed, smokeless combustion device or utility flare that is designed and operated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98% by weight. A utility flare is any flare that is designed and operated in accordance with the requirements of NDAC 33-15-12-02, Subpart A 60.18 (40 CFR 60.18). Requirements of 40 CFR 60.18 include, but are not limited to the following:

   - Flare shall be designed and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours;
   - Flare shall be operated with a flame present at all times;
   - An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) and the maximum tip velocity specifications in paragraph (c)(4) <u>or</u> adhering to the requirements in (c)(3)(i);
   - Flares used to comply with this section shall be steam-assisted, air-assisted or nonassisted;
   - Owners/operators of flares shall monitor the control devices to ensure that they are operated and maintained in conformance with their designs;
   - Flares shall be operated at all times when emissions may be vented to them;
   - Method 22 of Appendix A shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation is 2 hours and shall be used according to Method 22;
   - The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. Daily checks by an operator to verify the existence of a visible flame or to verify proper operation of the igniter may be used in lieu of a physical device.

4. Control devices other than those listed above may be utilized upon approval from the NDDoH.

For safety and air pollution control purposes on all wells: each flare must be equipped and operated with an automatic ignitor or a continuous burning pilot, which must be maintained in good working order as outlined in NDAC 33-15-07-02. This is required even if the flare is used for emergency purposes only. Flares operating with automatic pilot systems are not required to operate with thermocouples.

Each combustion device must be installed with a thermocouple or any other equivalent device approved by the NDDoH designed to ensure the presence of a pilot on the device. Additionally, a continuous burning pilot is required if this department determines that an automatic ignition system is ineffective due to production characteristics.

Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device must be maintained and operated during any time a well is producing such that the emissions are controlled as outlined in Appendix D.

The owner/operator shall maintain and operate all air pollution control equipment in accordance with the manufacturer's recommendations and in a manner consistent with good air pollution control practice for minimizing emissions. All reasonable precautions shall be taken by the owner/operator to prevent and/or minimize opacity from the operation of the flare or combustion device. A properly operating flare should be virtually free of opacity and a minimum of a visual check of a flare for opacity should be done whenever an operator is on site. Improperly operating equipment should be thoroughly inspected and if necessary, repaired as soon as possible. Compliance with opacity requirements will be based on applicable EPA Reference Methods.

The Department acknowledges that emission control equipment under an operating and maintenance plan will be off-line during routine maintenance and does not expect redundant equipment to be installed unless the uncontrolled emissions during that time cause the Bakken Pool O&G production facility emissions to exceed Title V or PSD thresholds.

APPENDIX D

CONTROL REQUIREMENTS FOR TANK EMISSIONS

The following procedure must be followed to determine the level of control required for tank emissions from Bakken Pool O&G production facilities:

1. For production facilities where the first date of production occurred after June 1, 2011, tank emissions must be controlled by a ground pit flare (including, but not limited to pit flares, shop built flares or other similar oilfield type flares) or other control device that achieves at least a 90% DRE for VOCs upon startup of the facility.

2. For production facilities where the first date of production occurred after June 1, 2011, the owner/operator must calculate the VOC potential to emit (PTE) from tank emissions within 90 days after the first date of production and control VOC emissions as outlined in 2.a and 2.b below. For production facilities where the first date of production occurred on or before June 1, 2011, the owner/operator must calculate the VOC PTE from tank emissions by September 1, 2011 and control VOC emissions as outlined in 2.a and 2.b below.

   a. If the PTE for VOC tank emissions is less than 20 tons/year, then a minimum of a ground pit flare (or other control device that achieves at least a 90% DRE for VOCs) is required to control VOC tank emissions.

   b. If the PTE for VOC tank emissions is greater than or equal to 20 tons/year, then a control device that achieves at least a 98% DRE for VOCs must be installed and operated.

3. It is possible that the PTE for VOC tank emissions will initially be calculated to equal or exceed 20 tons/year (which requires a control device with at least a 98% DRE for VOCs), but future calculations may result in a PTE for VOC tank emissions below 20 tons/year (which requires at least a ground pit flare or other control device that achieves at least a 90% DRE for VOCs). In this case, the owner/operator may replace the 98% DRE control device with a 90% DRE control device after receiving written approval from NDDoH. A revised well registration packet shall be submitted to the NDDoH prior to the replacement of the control device.

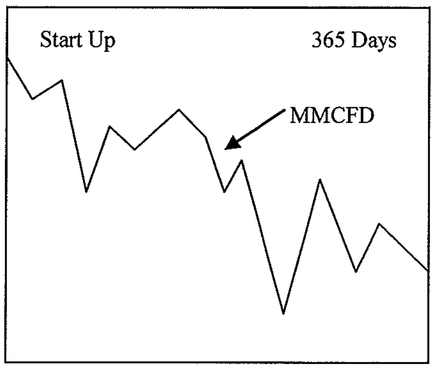
4. At a minimum, tank emissions must be controlled by a ground pit flare (or other control device that achieves at least a 90% DRE for VOCs). In the event of a breakdown of any control equipment used to control tank emissions, the control equipment must be repaired in a timely manner.

APPENDIX E

The Basis for the 0.6 Factor and How it Relates to 80% Decline in Production for the First Year

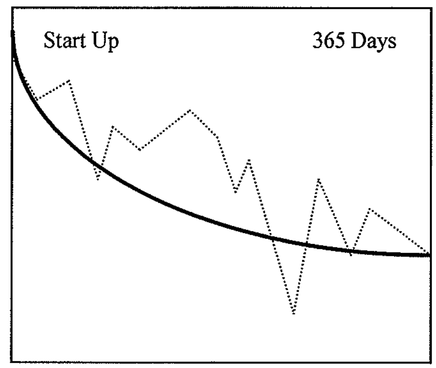
The first year daily production rates are represented by the jagged line in **BOX 1**. The area under the line represents the total actual production volume for the first year. It is difficult to calculate the total volume under the jagged line so it is smoothed out in **BOX 2** using statistical methods.

BOX 1



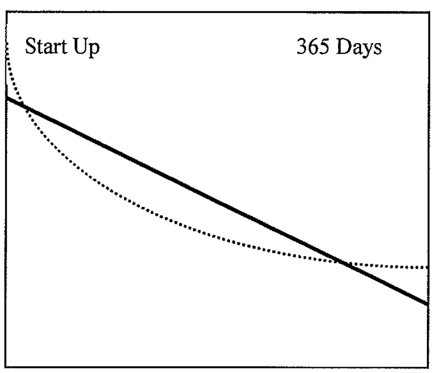
Actual production during the first year is represented by the area under the jagged line which ultimately turns out to be ~730 MMCF.

BOX 2



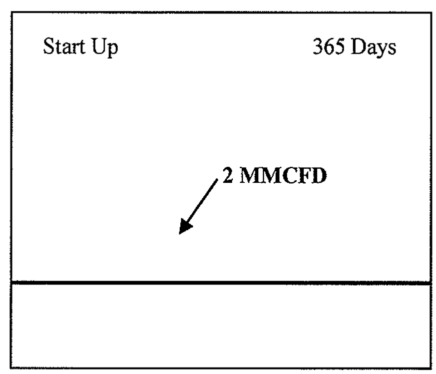
The jagged line representing daily production is "smoothed" out using statistical methods.

BOX 3



The "smoothed" curve in BOX 2 is "straightened" out using mathematical methods.

BOX 4



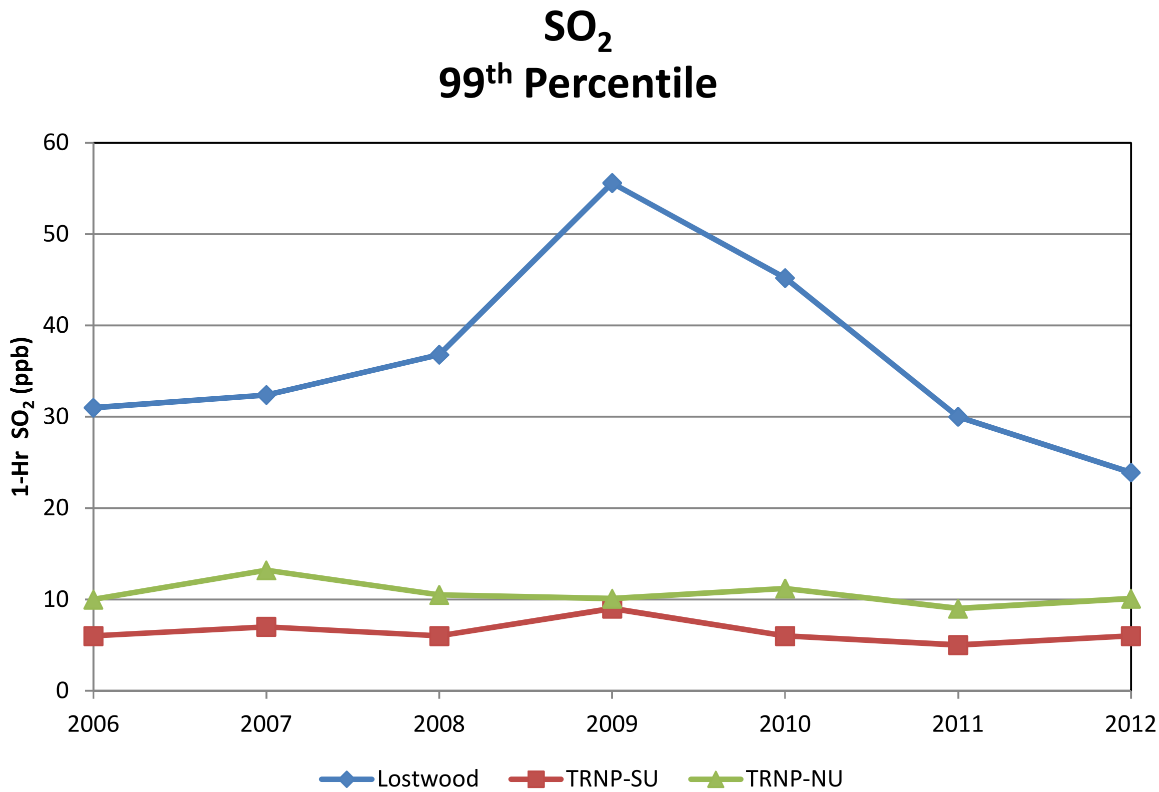
Leveled" out, projected daily gas production rate vs. time
Total projected production for the first year is represented by the area under the straight line
2 MMCFD x 365 days = 730 MMCF

The smoothed curve is straightened out in **BOX 3**, and then leveled out in **BOX 4**. Now the production for the first year is represented by the area under the line in **BOX 4** which is easily calculated. Production curves from a large sampling of wells indicate the average well declines by 80% during the first year. That 80% decline is represented by the level line in **BOX 4** after the first 30-day average production rate is multiplied by 0.6.

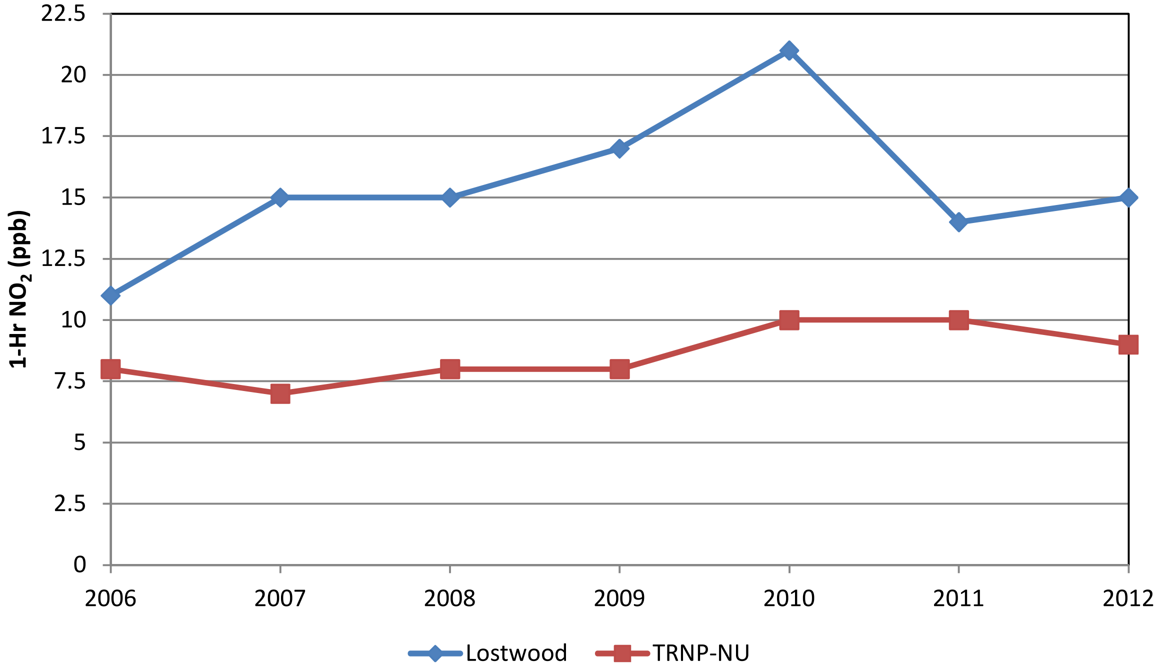
Example: For the first month the well makes an average 3.333 MMCFD. With 80% decline during the first year, the well will make 0.667 MMCFD at the end of the first year (3.333 – 0.8(3.333) = 0.667). Then the average daily production rate over 365 days is (3.33 + 0.667)/2 = 2.0 MMCFD which is the same as 3.333 x 0.6 = 2.0 MMCFD.

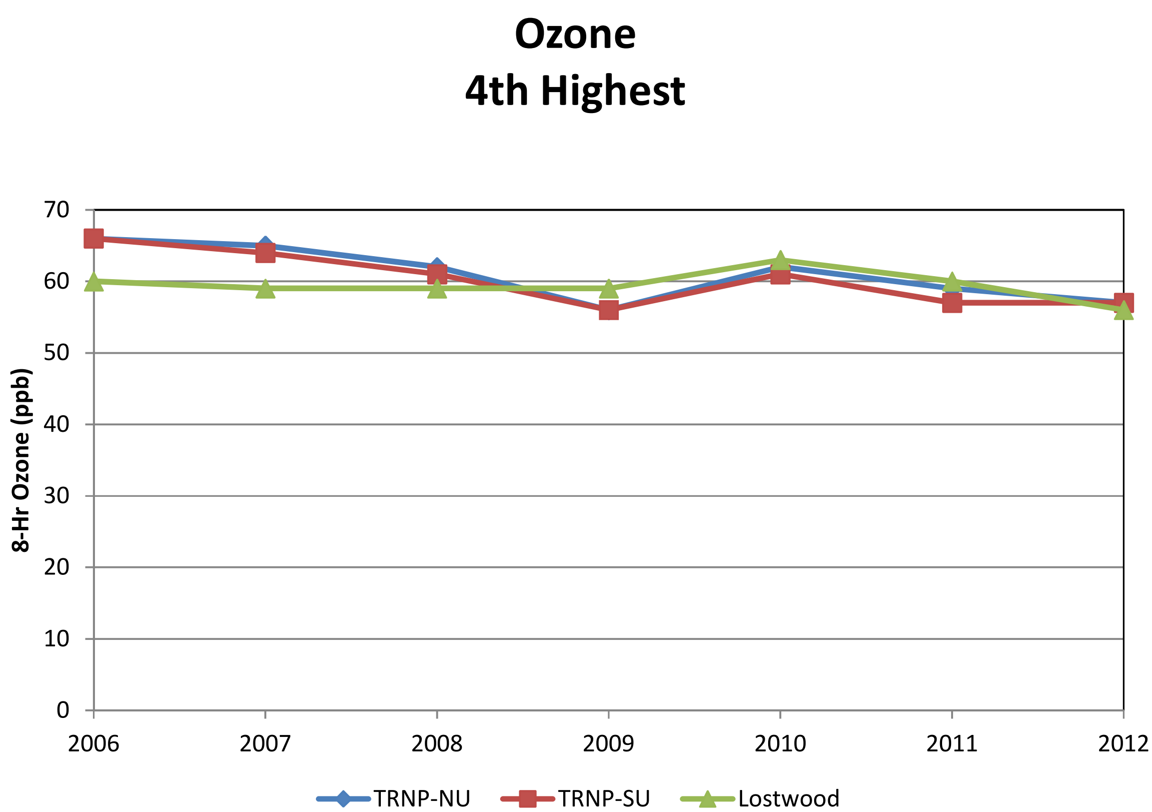
Appendix D

North Dakota Ambient
Air Quality Monitoring
Data Summary for Class I Areas


SO2
99th Percentile
1-Hr SO2 (ppb)
60
50
40
30
20
10
0
2006
2007
2008
2009
2010
2011
2012
Lostwood
TRNP-SU
TRNP-NU

NO_2
98th Percentile




Ozone
4th Highest
8-Hr Ozone (ppb)
70
60
50
40
30
20
10
0
2006
2007
2008
2009
2010
2011
2012
TRNP-NU
TRNP-SU
Lostwood