North Dakota
Regional Haze
State Implementation Plan
Periodic Progress Report

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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.

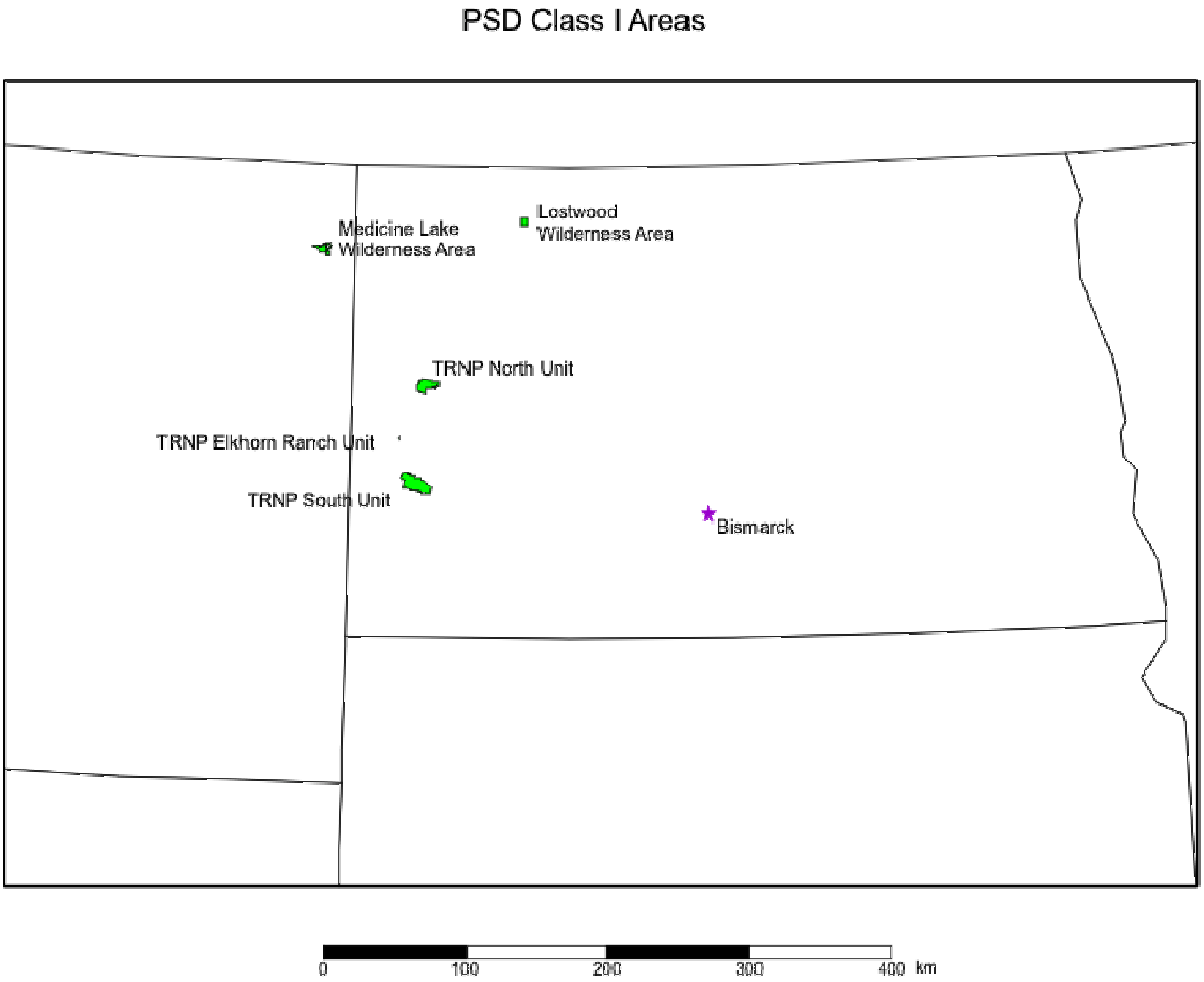
1.2 North Dakota SIP Summary

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 a small effect on the amount of visibility improvement that will be achieved for the 20% most impaired days. Modeling conducted by the Department indicated varying amounts of visibility improvement. Single source modeling indicated an improvement of 0.518 dv at TRNP and 0.356 dv for the 20% most impaired days. Cumulative modeling indicated less than 0.005 dv improvement at TRWP and less than 0.01 dv improvement at LWA. Based on IMPROVE data, the Department believes the cumulative modeling results are much more accurate.

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

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 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
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

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 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***
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	BART	0.15 lb/10^6 Btu[2]	0.062 lb/10^6 Btu	6/13
		NO_x	BART	0.19 lb/10^6 Btu	0.23 lb/10^6 Btu	
		PM	BART	0.07 lb/10^6 Btu	0.018 lb/10^6 Btu	
Leland Olds	2	SO_2	BART	0.15 lb/10^6 Btu[2]	0.058 lb/10^6 Btu	10/12
		NO_x	BART	0.35 lb/10^6 Btu	0.32 lb/10^6 Btu	
		PM	BART	0.07 lb/10^6 Btu	0.019 lb/10^6 Btu	
M.R. Young	1	SO_2	BART	95% reduction	98% reduction (0.042 lb/10^6 Btu)	12/11
		NO_x	BART	0.36 lb/10^6 Btu	0.33 lb/10^6 Btu	12/11
		PM	BART	0.03 lb/10^6 Btu	0.010 lb/10^6 Btu	12/11
M.R. Young	2	SO_2	BART	95% reduction[3]	0.113 lb/10^6 Btu and 94% reduction	12/10
		NO_x	BART	0.35 lb/10^6 Btu	0.33 lb/10^6 Btu	12/10
		PM	BART	0.03 lb/10^6 Btu	0.012 lb/10^6 Btu	12/10
Coyote		NO_x	RP	0.50 lb/10^6 Btu	0.70 lb/10^6 Btu	
Stanton	1	SO_2	BART	0.16 lb/10^6 Btu	0.50 lb/10^6 Btu	
		NO_x	BART	0.23 lb/10^6 Btu	0.23 lb/10^6 Btu	
		PM	BART	0.07 lb/10^6 Btu	0.014 lb/10^6 Btu	
Coal Creek	1	SO_2	BART	0.15 lb/10^6 Btu[2]	0.34 lb/10^6 Btu	
		NO_x	BART	0.17 lb/10^6 Btu	0.19 lb/10^6 Btu	
		PM	BART	0.07 lb/10^6 Btu	0.010 lb/10^6 Btu	
Coal Creek	2	SO_2	BART	0.15 lb/10^6 Btu[2]	0.33 lb/10^6 Btu	
		NO_x	BART	0.17 lb/10^6 Btu	0.15 lb/10^6 Btu	
		PM	BART	0.07 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

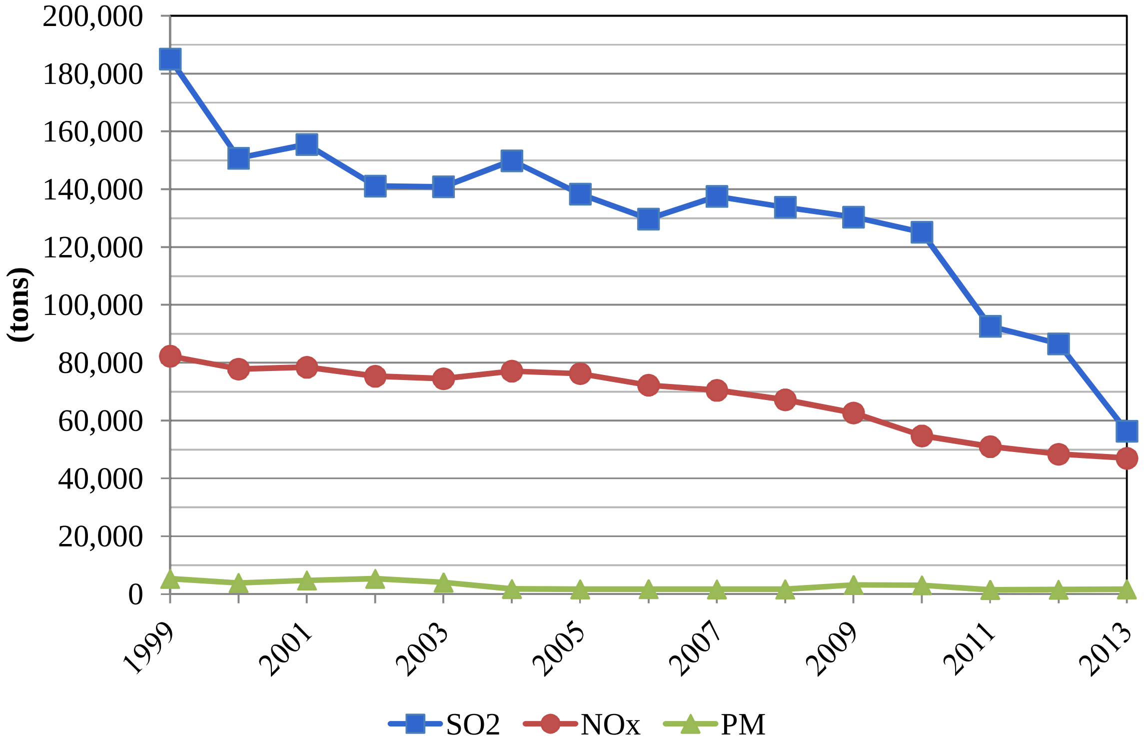
ND = no data

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.)	RPGs 20% Most Impaired Days
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	16.9
	LWA	7.9	8.2	20.2	19.6	18.9
2005	TRNP	6.8	7.5	17.6	17.7	16.9
	LWA	7.6	7.9	20.5	19.7	18.9
2006	TRNP	6.5	7.2	17.9	17.7	16.9
	LWA	7.8	7.8	19.6	19.5	18.9
2007	TRNP	*		*		16.9
	LWA	8.8	8.0	19.1	19.6	18.9
2008	TRNP	6.6	7.0	17.6	17.8	16.9
	LWA	8.2	8.1	19.7	19.8	18.9
2009	TRNP	7.0	6.9	17.2	17.6	16.9

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.)	RPGs 20% Most Impaired Days
	LWA	8.4	8.2	18.9	19.6	18.9
2010	TRNP	6.4	6.7	18.8	17.8	16.9
	LWA	7.6	8.1	21.4	19.7	18.9
2011	TRNP	5.8	6.5	16.4	17.6	16.9
	LWA	*	*	*	*	18.9
2012	TRNP	6.1	6.4	16.3	17.3	16.9
	LWA	*	*	*	*	18.9
2013	TRWP	6.5	6.4	16.0	16.9	16.9
	LWA	*	*	*	*	18.9

* 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	18.9
2012	LWA	7.6	7.8	19.4	19.5	18.9
2013	LWA	8.3	7.9	18.7	19.3	18.9

Figure 2.2
TRNP
20% Most impaired Days

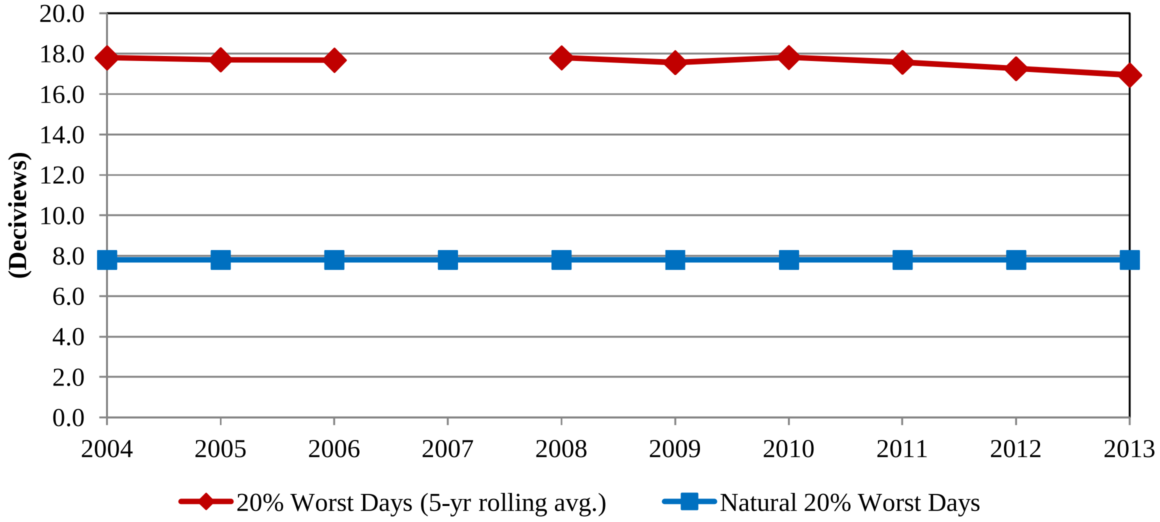


Figure 2.3
TRNP
20% Least Impaired Days

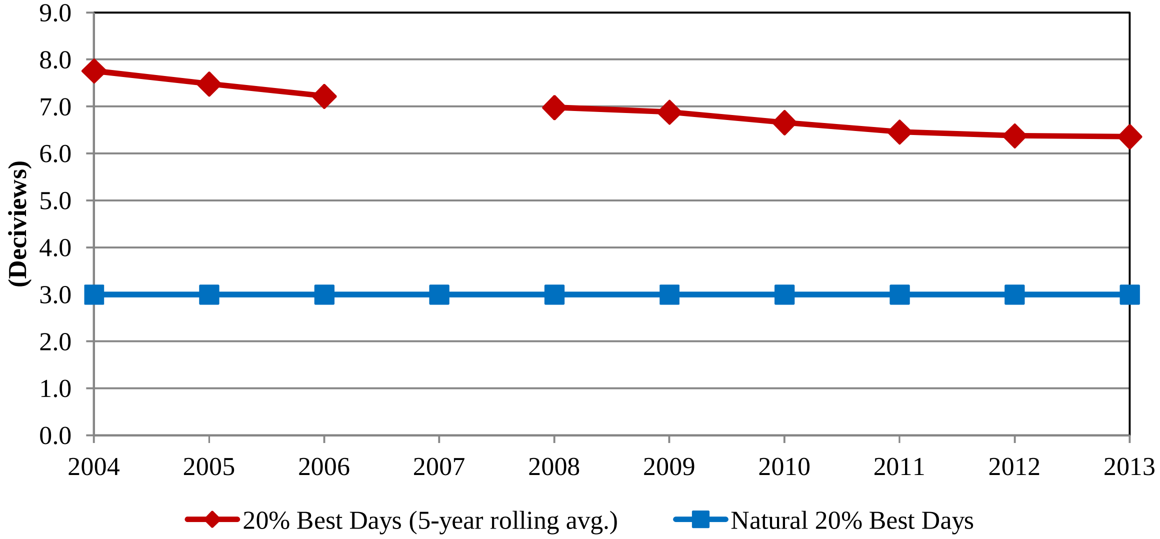


Figure 2.4
Lostwood Wilderness Area
20% Most Impaired Days

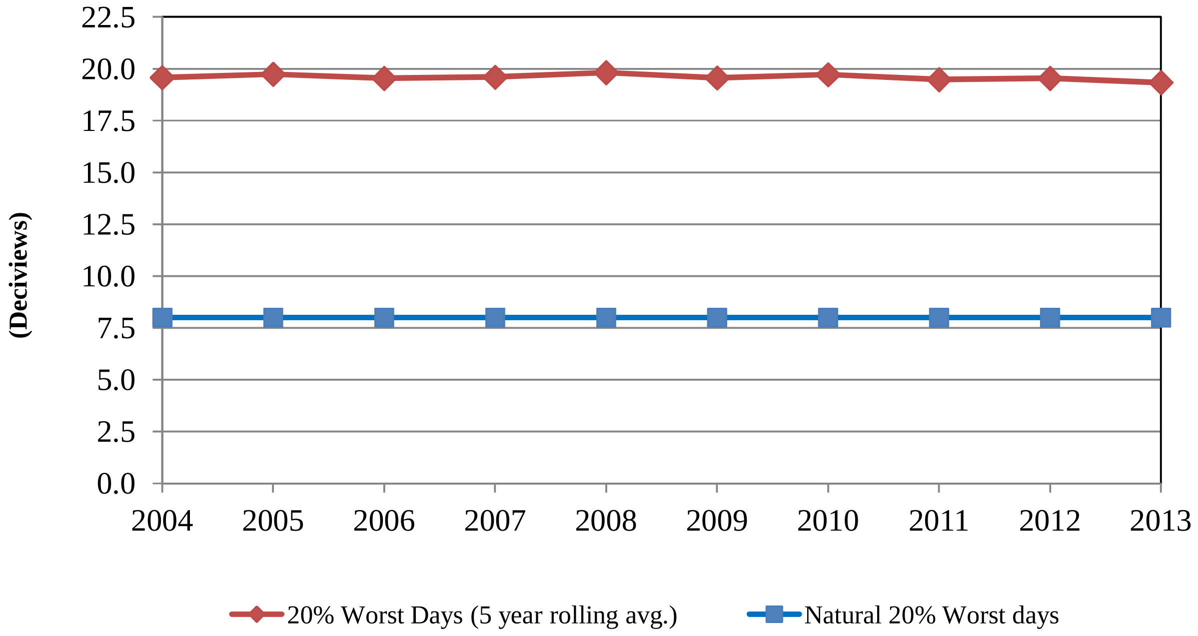


Figure 2.5
Lostwood Wilderness Area
20% Least Impaired Days

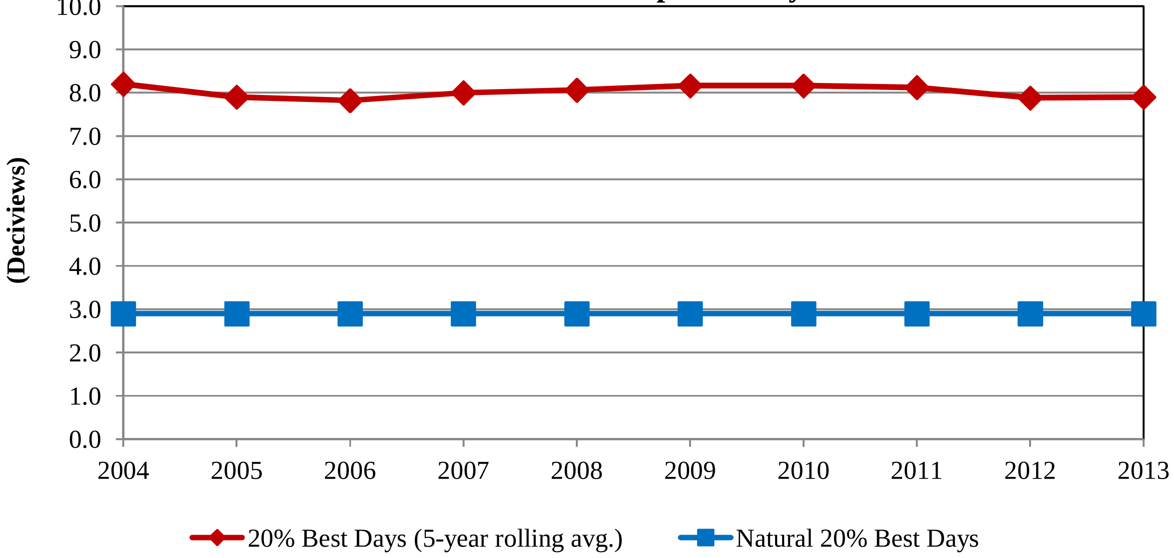


Table 2.9
Theodore Roosevelt NP
Annual Averages, Period Averages and Trends

	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	0.3	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 (change/yr.)**	**p-value**	**Baseline (B)**	**Progress (P)**	**2008-2012 (EP)**	**Difference (P -B)**	**Percent Change**	**Difference (EP -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	7.6	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

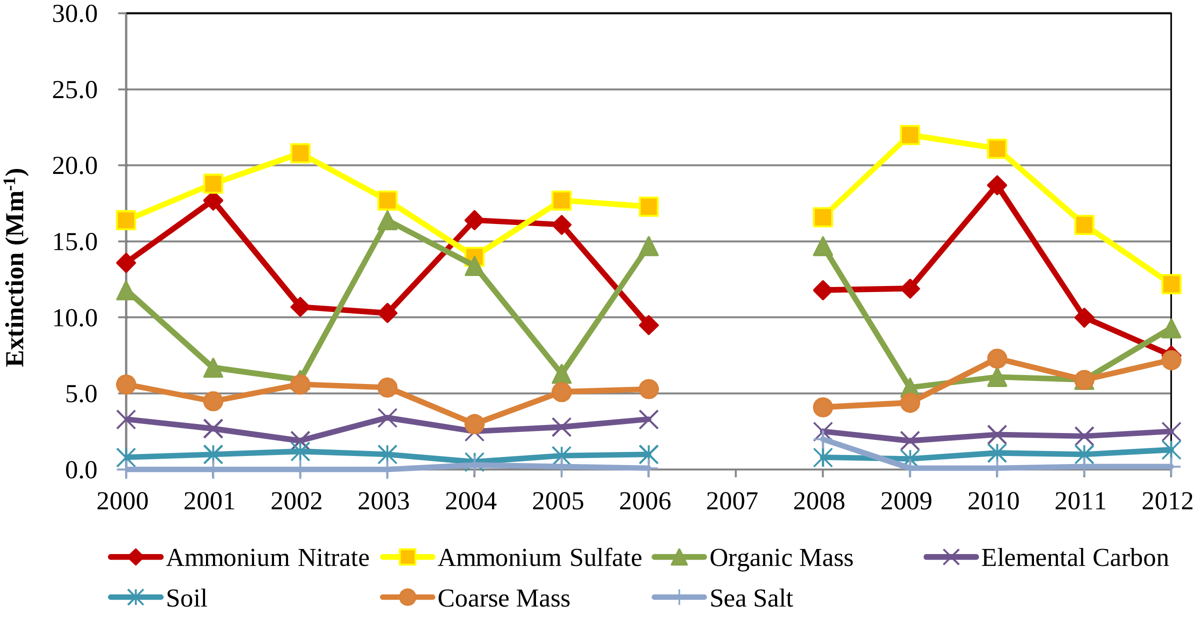


Figure 2.7
TRNP Species Contribution
20% Best Days

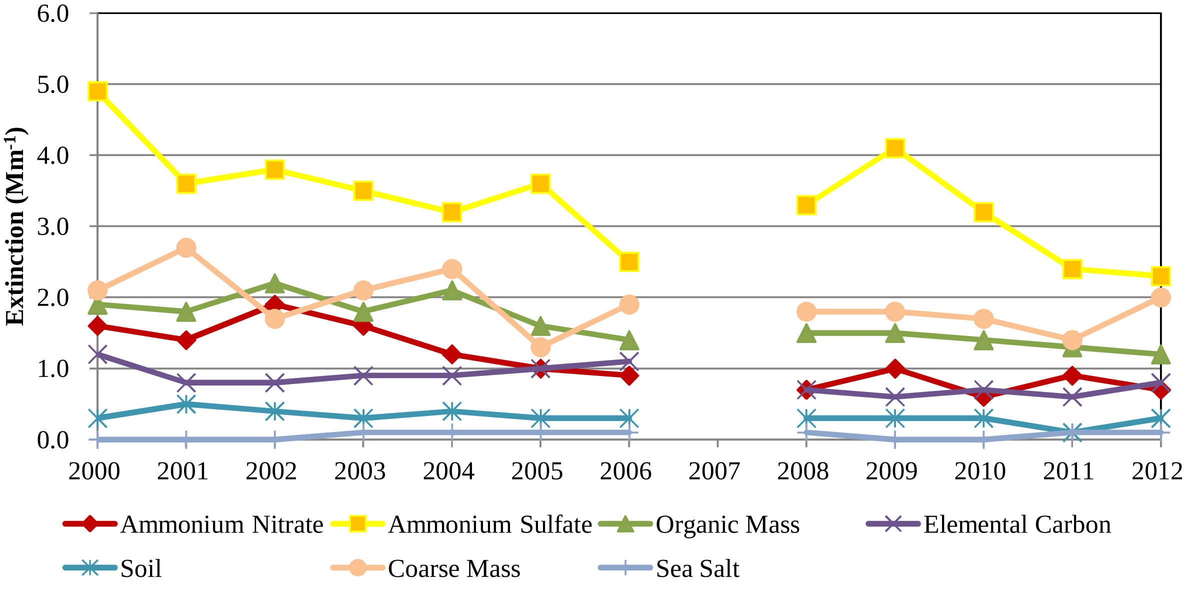


Figure 2.8
LWA Species Contribution
20% Worst Days

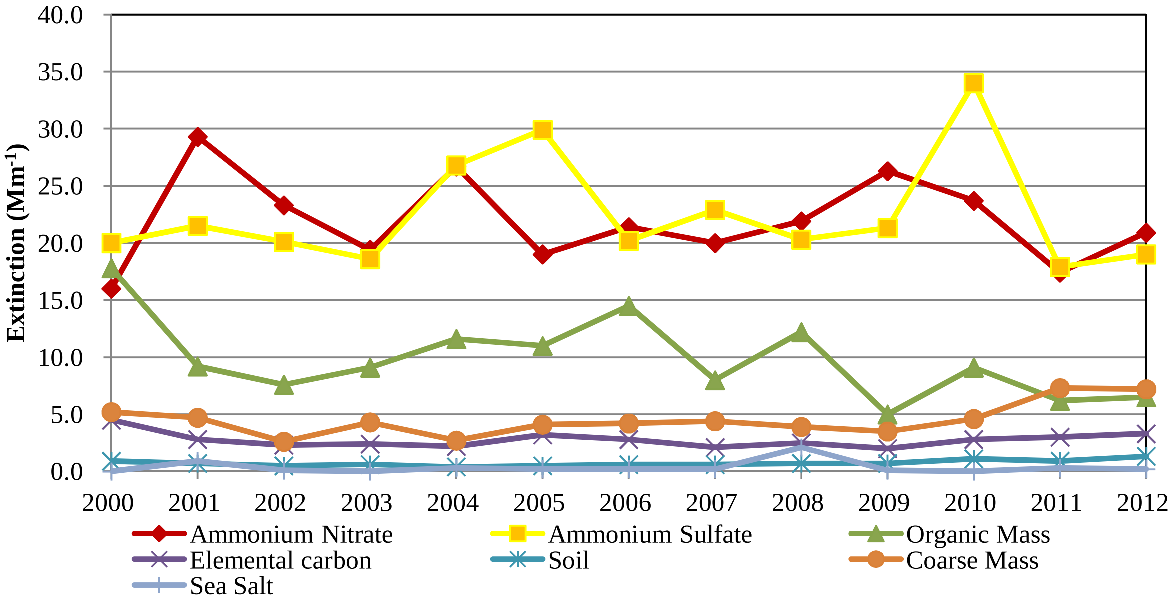


Figure 2.9
LWA Species Contribution
20% Best Days

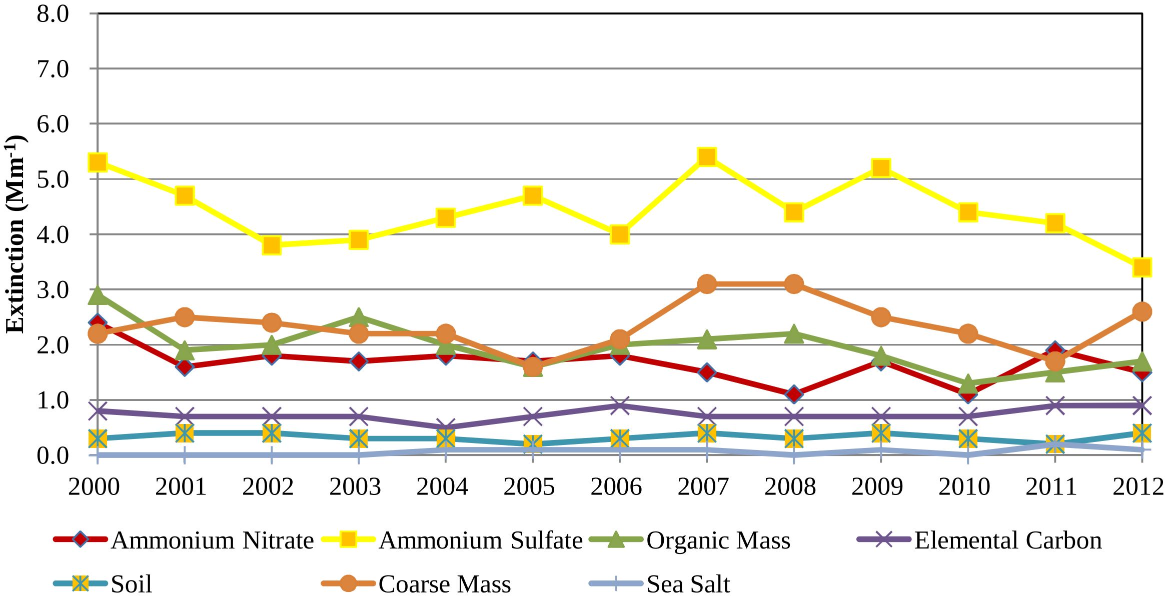


Table 2.8 and Figure 2.2 show that the reasonable progress goal for TRNP specified in the SIP (16.9 dv) has been met based on 2009-2013 data. The last three years of data indicate visibility impairment below the reasonable progress goal. During the 20% best days, the five average (2009-2013) was 6.4 deciviews compared to the baseline (2000-2004) of 7.8 deciviews.

For TRNP, 2008-2012 data was used to prepare the latest 5-year average species conditions (see Table 2.9). 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, 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 2013 was incomplete. To better evaluate the visibility at LWA, data was substituted for 2011 through 2013 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 2.8 shows the results from the data substitution. At LWA, the reasonable progress goal (18.9 dv) has been more than achieved in 2011 and 2013. The five year average for 2009-2013 was 19.3 deciviews. For the 2008-2012 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.

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[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

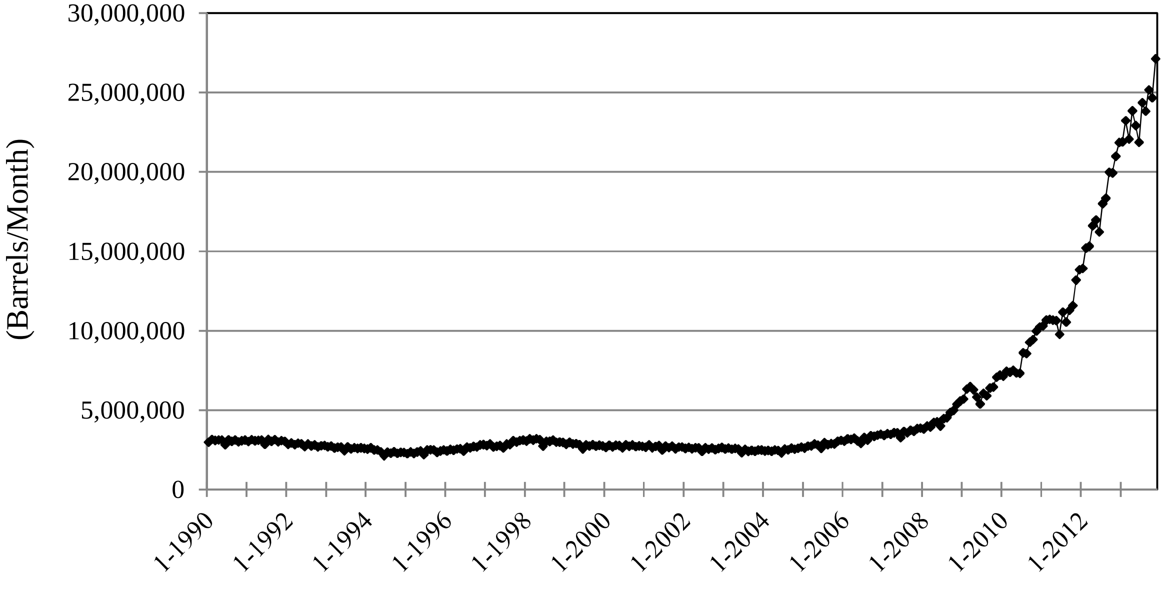

Figure 2.11
North Dakota
Natural Gas Production

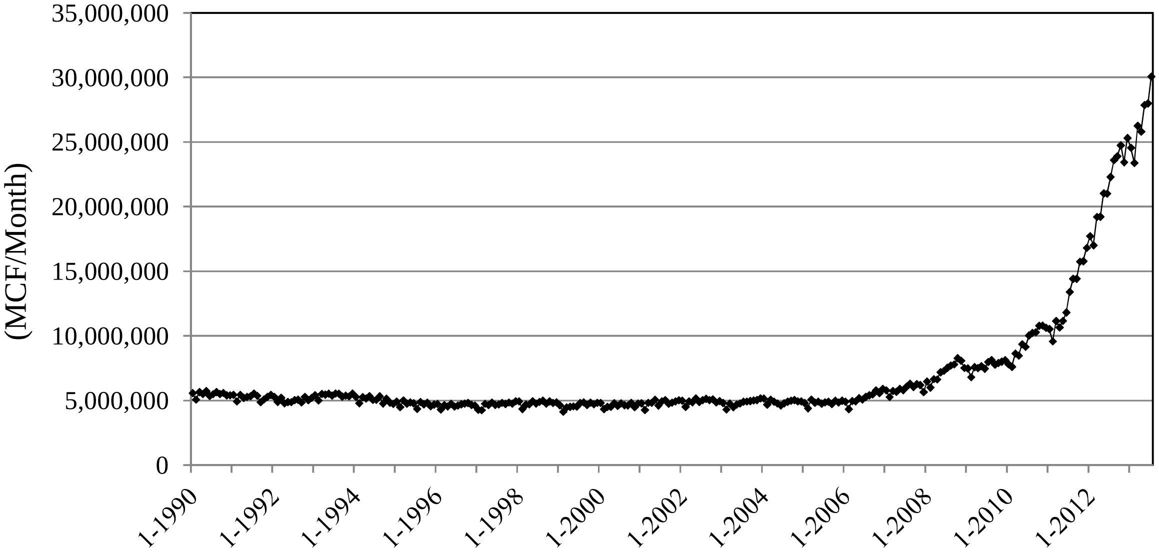

Table 2.15
Area Oil & Gas Emissions
(tons)

	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.

Visibility impairment in TRNP has decreased to the point the reasonable progress goal established in the Regional Haze SIP has been met over the last five years (see Table 2.8). At LWA, visibility degradation in two out of the last three years has been less than the reasonable progress goal. Additional reductions of sulfur dioxide and nitrogen oxides emissions are expected at North Dakota's EGUs which will decrease visibility impairment. The SIP is adequate to achieve reasonable progress toward the national visibility goal and no change to the SIP is needed at this time.

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.

As indicated in Section 2.1.1, emissions from sources in North Dakota affect a number of Class I areas outside of North Dakota. The primary pollutants that are contributed to out-of-state Class I areas are sulfates and nitrates. The SO_2 and NO_x emissions reductions at the North Dakota EGUs will help reduce visibility impact at all out-of-state Class I areas, especially those downwind. Emissions from increased oil and gas activities are primarily NO_x and VOC. These emissions are generally emitted at low elevations and produce a more localized impact. The closest out-of-state Class I area is Medicine Lake Wilderness Area (MELA). MELA is generally upwind of emission sources in North Dakota including oil and gas activity. This is a similar situation as LWA. Visiblity impairment is improving in LWA and oil and gas activity is not impeding reasonable progress toward the national visibility goal. Since MELA is upwind of North Dakota oil and gas activity, that activity is likely not impeding reasonable progress at MELA. Since the reasonable progress goals will likely be met in the North Dakota Class I areas, emissions from North Dakota will impede reasonable progress in out-of-state Class I areas.

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.”

Based on the 2011-2013 IMPROVE monitoring data TRNP and LWA, the NDDH believes the RH SIP is adequate to make reasonable progress toward the national visibility goal and no 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 reasonable progress goal at TRNP has been met based on the last five years of IMPROVE data and the goal at LWA has been achieved in two out of the last three years. The emissions reduction goals established in the RH SIP for EGUs in the state are expected to be met or exceeded.

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 entirely 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).

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[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.

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.

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

	2002		**2011**		**Change**	
Plant	**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, or exceeded, by 2018. IMPROVE monitoring data indicates the reasonable progress goal at TRNP has been met and North Dakota is well on its way to achieving the goal at LWA. 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

ENVIRONMENTAL HEALTH SECTION
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Bismarck, ND 58501-1947
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www.ndhealth.gov

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
Enc:
xc: Gail Fallon, EPA Region 8

NORTH DAKOTA
DEPARTMENT *of* HEALTH

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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

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xc: Gail Fallon, EPA Region 8

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Division of Water Quality 701.328.5210

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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,

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[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
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

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

North Dakota Department of Health
Public Notice
Regional Haze Progress Report

In accordance with 40 CFR 51.308(g), the North Dakota Department of Health, Division of Air Quality, has drafted a report on the progress made in achieving the national visibility goal of eliminating all man-made visibility impairment in the Federal Class I areas. Tentative determinations made by the Department indicate the Regional Haze State Implementation Plan (SIP) is currently adequate to achieve reasonable progress toward the national goal. The Department solicits comments on the report and its findings.

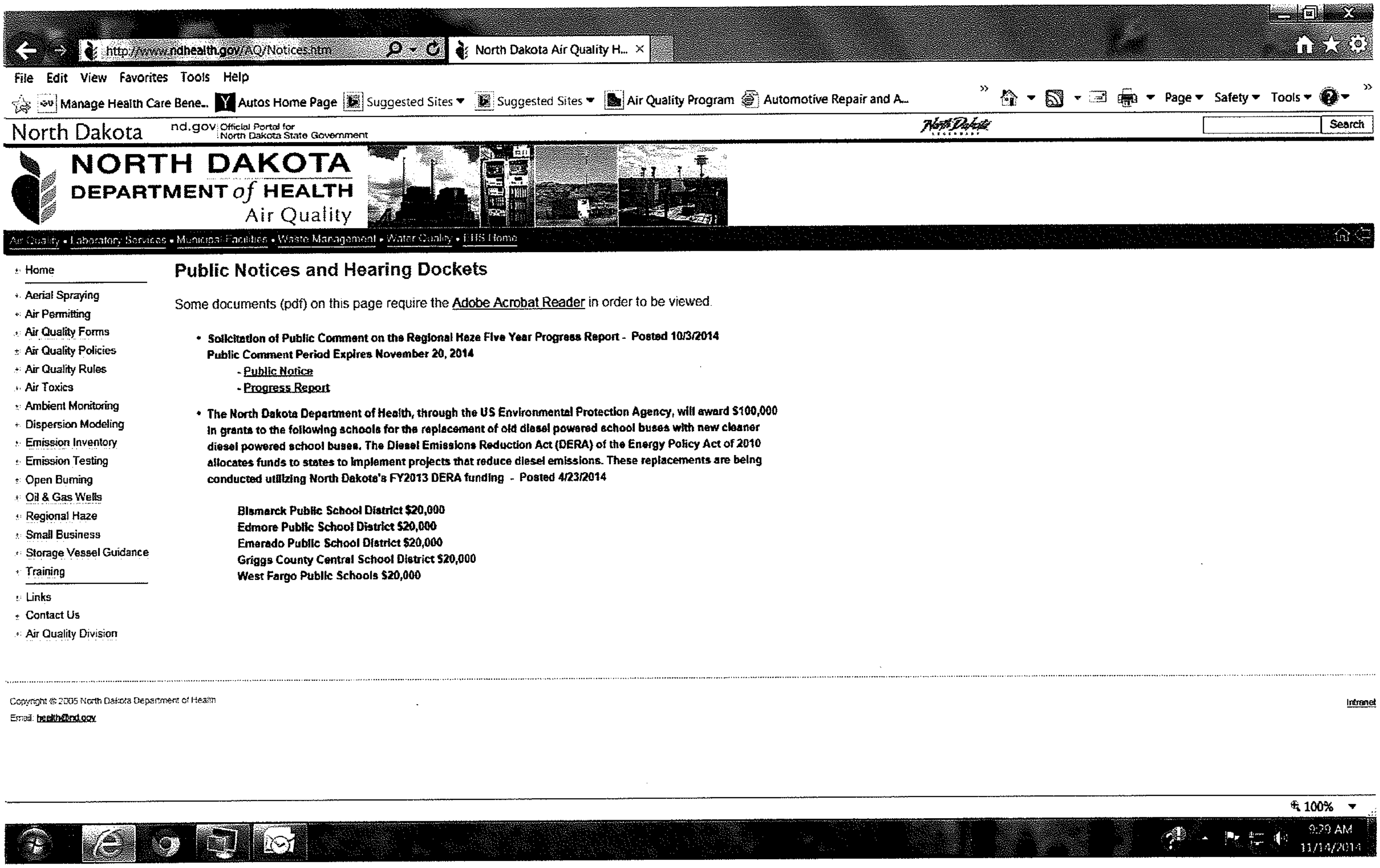
A copy of the draft report may be viewed at the Department's website at www.ndhealth.gov/AQ/Notices.htm. A hard copy of the draft report may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E. Divide Ave., Second Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from October 19 through November 19, 2014. A public hearing will be held only if there is a request from the public for a hearing. Any request for a hearing must be submitted in writing and received by the Department before the end of the comment period. If a hearing is requested, it will be held on November 21, 2014 at 9:00 a.m. CST at the Gold Seal Center's 4th floor conference room at 918 E. Divide Ave., Bismarck, North Dakota. If a public hearing is requested, the public comment period will remain open until November 28, 2014. If no requests for a public hearing are received, the announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

The National Park Service and the U.S. Forest Service have provided comments on the draft report. The comments and the Department's response to those comments can be found in section 3 of the report listed above or by contacting the Department.

If you plan to attend the requested hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above address at least three days prior to the hearing.

Dated this 1st day of October, 2014

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



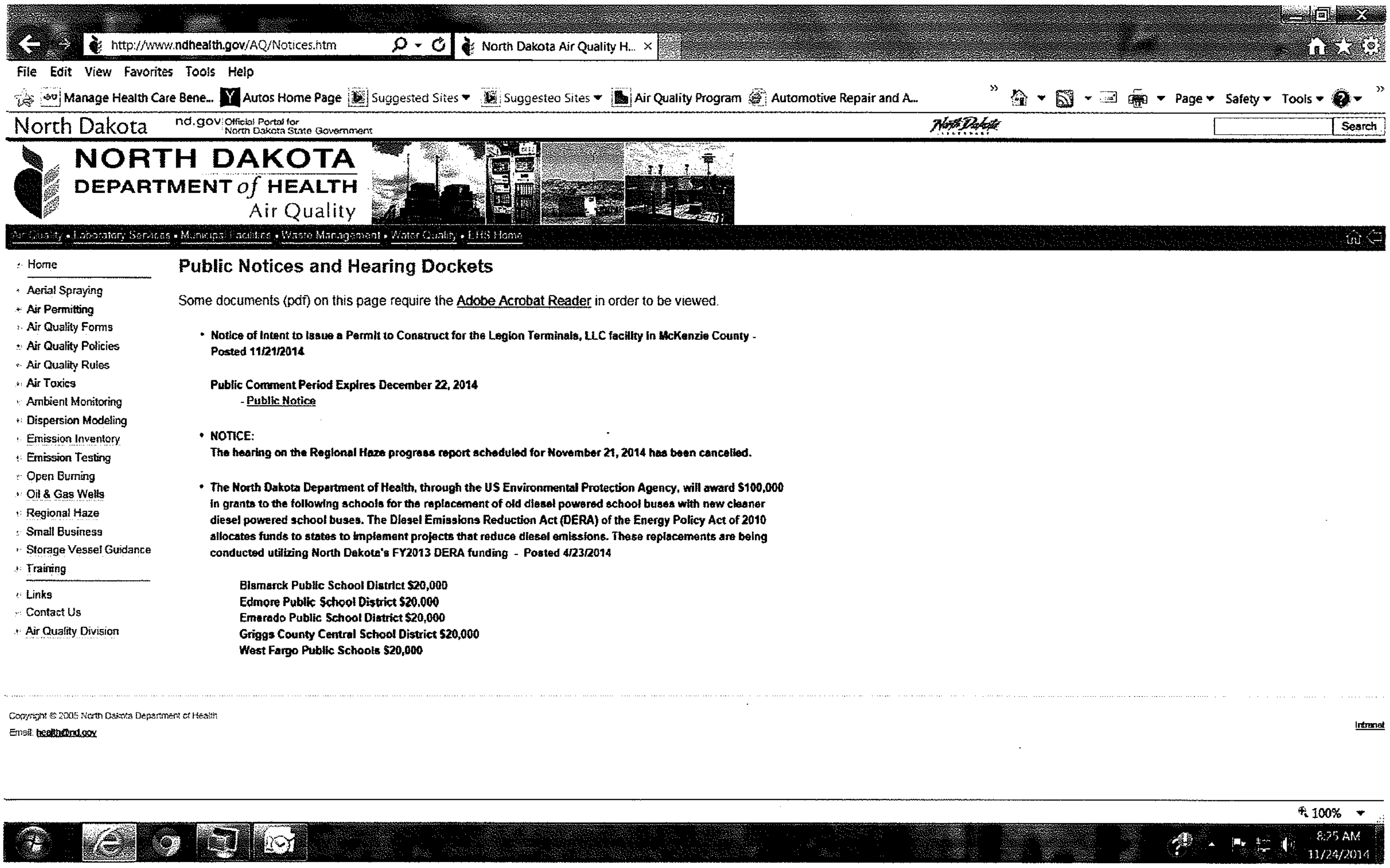
Public Notices and Hearing Dockets

Some documents (pdf) on this page require the Adobe Acrobat Reader in order to be viewed.

- **Solicitation of Public Comment on the Regional Haze Five Year Progress Report - Posted 10/3/2014**
  Public Comment Period Expires November 20, 2014
  - Public Notice
  - Progress Report
- **The North Dakota Department of Health, through the US Environmental Protection Agency, will award $100,000 in grants to the following schools for the replacement of old diesel powered school buses with new cleaner diesel powered school buses. The Diesel Emissions Reduction Act (DERA) of the Energy Policy Act of 2010 allocates funds to states to implement projects that reduce diesel emissions. These replacements are being conducted utilizing North Dakota's FY2013 DERA funding - Posted 4/23/2014**

Bismarck Public School District	**$20,000**
Edmore Public School District	**$20,000**
Emerado Public School District	**$20,000**
Griggs County Central School District	**$20,000**
West Fargo Public Schools	**$20,000**

Email: health@nd.gov



Public Notices and Hearing Dockets

Some documents (pdf) on this page require the Adobe Acrobat Reader in order to be viewed.

- **Notice of Intent to Issue a Permit to Construct for the Legion Terminals, LLC facility in McKenzie County - Posted 11/21/2014**

  Public Comment Period Expires December 22, 2014
  - Public Notice

- **NOTICE:**
  The hearing on the Regional Haze progress report scheduled for November 21, 2014 has been cancelled.

- **The North Dakota Department of Health, through the US Environmental Protection Agency, will award $100,000 in grants to the following schools for the replacement of old diesel powered school buses with new cleaner diesel powered school buses. The Diesel Emissions Reduction Act (DERA) of the Energy Policy Act of 2010 allocates funds to states to implement projects that reduce diesel emissions. These replacements are being conducted utilizing North Dakota's FY2013 DERA funding - Posted 4/23/2014**

Bismarck Public School District	**$20,000**
Edmore Public School District	**$20,000**
Emerado Public School District	**$20,000**
Griggs County Central School District	**$20,000**
West Fargo Public Schools	**$20,000**

Email: health@nd.gov

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

MEMO TO : Interested Parties

FROM : Terry L. O'Clair, P.E. TLO
Director
Division of Air Quality

RE : Regional Haze Progress Report

DATE : October 2, 2014

In accordance with 40 CFR 51.308(g), the North Dakota Department of Health has prepared a draft report on progress toward achieving the national visibility goal. The draft report may be viewed at the office of the North Dakota Department of Health, 918 E Divide Avenue, 2nd Floor, Bismarck, North Dakota or at the Department's website at www.ndhealth.gov/AQ/notices.htm. A copy of the draft report may be requested by writing the Department at the above address or calling (701)328-5188.

Also included is a notice of the public comment period and the opportunity for a public hearing. The Department welcomes any comments you or your staff may have regarding the draft report. Comments received by the close of business on November 19, 2014 will be included as part of the official record. Comments must be sent to the address listed above.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

TLO/TB:saj

North Dakota Department of Health
Public Notice
Regional Haze Progress Report

In accordance with 40 CFR 51.308(g), the North Dakota Department of Health, Division of Air Quality, has drafted a report on the progress made in achieving the national visibility goal of eliminating all man-made visibility impairment in the Federal Class I areas. Tentative determinations made by the Department indicate the Regional Haze State Implementation Plan (SIP) is currently adequate to achieve reasonable progress toward the national goal. The Department solicits comments on the report and its findings.

A copy of the draft report may be viewed at the Department's website at www.ndhealth.gov/Notices.htm. A hard copy of the draft report may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E. Divide Ave., Second Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from October 19 through November 19, 2014. A public hearing will be held only if there is a request from the public for a hearing. Any request for a hearing must be submitted in writing and received by the Department before the end of the comment period. If a hearing is requested, it will be held on November 21, 2014 at 9:00 a.m. CST at the Gold Seal Center's 4th floor conference room at 918 E. Divide Ave., Bismarck, North Dakota. If a public hearing is requested, the public comment period will remain open until November 28, 2014. If no requests for a public hearing are received, the announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

The National Park Service and the U.S. Forest Service have provided comments on the draft report. The comments and the Department's response to those comments can be found in section 3 of the report listed above or by contacting the Department.

If you plan to attend the requested hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above address at least three days prior to the hearing.

Dated this 1st day of October, 2014

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

Department of Environmental Quality
Air Quality Division
Montana State Department of
 Health & Environmental Services
Medcalf Building
P.O. Box 200901
Helena, MT 59620-0901

Division of Air Quality
Minnesota Pollution Control Agency
520 Lafayette Road
St. Paul, MN 55155

Tribal Chairman
Standing Rock Sioux Tribe
PO Box D
Fort Yates, ND 58538

Tribal Chairman
Spirit Lake Tribe
P.O. Box 359
Fort Totten, ND 58335

Administrator
Air Quality Program
South Dakota Department of
 Environment and Natural Resources
523 E Capitol Avenue
Joe Foss Building
Pierre, SD 57501

Tribal Chairman
Three Affiliated Tribes
Fort Berthold Indian Reservation
P.O. Box 460
New Town, ND 58736

Tribal Chairman
Turtle Mountain Tribe
Box 900
Belcourt, ND 58316

Chief of Policy Planning &
Permit Review Branch
National Park Service-AIR
P.O. Box 25287
Denver, CO 80225

Sisseton-Wahpeton Dakota Nation
Old Agency Box 509
Agency Village, SD 57262-0509

Chief, Branch of Air Quality
U.S. Fish & Wildlife Service
7333 W Jefferson Avenue, Ste 375
Lakewood, CO 80237-2017

Department of Environmental Quality
Air Quality Division
Montana State Department of
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Helena, MT 59620-0901

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520 Lafayette Road
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Tribal Chairman
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PO Box D
Fort Yates, ND 58538

Tribal Chairman
Spirit Lake Tribe
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Administrator
~~Natural Resources Program~~ Air Quality Program
~~Environmental Regulation Division~~
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Permit Review Branch
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P.O. Box 25287
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~~Ms. Sheila Crawford-Oliver~~
~~Water Resource Unit~~
Sisseton-Wahpeton Dakota Nation
Old Agency Box 509
Agency Village, SD 57262-0509

~~Ms. Sandra Silva~~
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service
7333 W Jefferson Avenue, Ste 375
Lakewood, CO 80237-2017

NDNA
NORTH DAKOTA NEWSPAPER ASSOCIATION

Affidavit of Publication

Colleen Park, being duly sworn, states as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of: **ND Health Department – Regional Hazen Progress Report; 1** time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of North Dakota

County of Burleigh

Subscribed and sworn to before me this 27th day of October, 2014.

Kelli Richey

KELLI RICHEY
Notary Public
State of North Dakota
My Commission Expires Oct 13, 2018

Notices

REQUEST FOR PROPOSALS

The Board of Park Commissioners of Dickinson Parks and Recreation will be accepting proposals for the food/beverage operations at the Heart River Golf Course restaurant. All proposals must be received in a sealed envelope labeled "HRGC Restaurant Proposal" by 5:00 p.m. on Monday, October 27, 2014. The lease premise shall consist of the restaurant operations at Heart River Golf Course. Each applicant shall submit a resume of their past food/liquor experience as well as a proposed business plan for their intentions to provide quality food/beverage operations at Heart River Golf Course. Applicant interviews will be conducted and final selection and lease negotiations will be contingent upon the applicants successfully obtaining the necessary license, insurance and permits. To obtain specifications or submit proposals, contact Dickinson Parks and Recreation, 2004 Fairway Street, Dickinson, ND 58601 or call 701-456-2074. Dickinson Parks and Recreation reserves the right to reject any and all bids.

PUBLICATION DATES:
Friday, October 10, 2014
Friday, October 17, 2014

(Published October 10th & 17th, 2014)

North Dakota Department of Health
Public Notice
Regional Haze Progress Report

In accordance with 40 CFR 51.308(g), the North Dakota Department of Health, Division of Air Quality, has drafted a report on the progress made in achieving the national visibility goal of eliminating all man-made visibility impairment in the Federal Class I areas. Tentative determinations made by the Department indicate the Regional Haze State Implementation Plan (SIP) is currently adequate to achieve reasonable progress toward the national goal. The Department solicits comments on the report and its findings.

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A public hearing will be held only if there is a request from the public for a hearing. Any request for a hearing must be submitted in writing and received by the Department before the end of the comment period. If a hearing is requested, it will be held on November 21, 2014 at 9:00 a.m. CST at the Gold Seal Center's 4th floor conference room at 918 E. Divide Ave., Bismarck, North Dakota. If a public hearing is requested, the public comment period will remain open until November 28, 2014. If no requests for a public hearing are received, the announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm.

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If you plan to attend the requested hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above address at least three days prior to the hearing.

Dated this 1st day of October, 2014.
Terry O'Clair, P.E.
Director
Division of Air Quality

(Published October 17, 2014)

NOTICE OF SALE

PLEASE TAKE NOTICE that the Stark County District Court entered judgment August 12, 2014, Case No. 45-2014-CV-00530, granting foreclosure to plaintiff R. Scott Page against defendant Wild Buffalo Development Corporation, in the amount of $260,930.72, with interest thereon at 7.5% after June 1, 2014.

The judgment, and the special execution issued in accordance with that judgment, directs the Stark County Sheriff to sell the property described below to satisfy the judgment, along with the sale expenses, to the extent possible from the sale proceeds.

Therefore, after publication as required by law in The Dickinson Press on October 17, October 21 and October 28, the Sheriff of Stark County will sell the real property described below to the highest bidder for cash at an auction to be held on the steps of the Stark County Courthouse, 51 3rd St. E., Dickinson, ND 58601, at 10 am, Monday, November 10, 2014.

The real property to be sold is described as: Lots 1-9, Block 26; Lots 1-21, Block 27; and Lots 18-29, Block 30; all located in the Original Plat to the City of Gladstone, Stark County, North Dakota.

DATED: October 13, 2014.
/s/ Matt Keesler
Clarence Tuhy, Stark County Sheriff, by
Deputy Matt Keesler

(Published October 17, 21 & 28, 2014)

10/17 Dickinson

OK for Payment
10/29/14
1250
Terry O'Clair

North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, North Dakota 58503
Phone: 1-701-223-6397 Fax: 1-701-223-8185

ND DEPT OF HEALTH
RECEIVED
OCT 28 2014
ACCOUNTING
TIME______

INVOICE

October 27, 2014

Order: **14103NA1** Invoice# **3613**

Attn: Tom Bachman
ND Health Department
600 E Blvd Ave Dept 301
Bismarck, North Dakota 58505-0200

Voice: Fax:

Advertiser:	**Administrative Services: Accounting**
P.O.#:	**Regional Haze Progress Report**
Brand:	
Campaign	
Amount Due:	$302.57

Please detach and return this portion with your payment

Administrative Services: Accounting Invoice# 3613 P.O.#: Regional Haze Progress Report

Run Date	*Ad Size*	*Rate Type*	*Rate*	*Color Rate*	*Total*	*Discount*	*(%)*	*Amount after Discount*	*Page*
Bismarck Tribune (Bismarck, North Dakota)									
10/17/2014	64.00	Notice A Line	$0.79		$50.56	$0.00	(0.00%)	$50.56	
	Caption: Regional Haze Progress Report								
Subtotal:	**64.00**		**$0.79**	**$0.00**	**$50.56**	**$0.00**		**$50.56**	
Dickinson Press (Dickinson, North Dakota)									
10/17/2014	63.00	Notice A Line	$0.77		$48.51	$0.00	(0.00%)	$48.51	
	Caption: Regional Haze Progress Report								
Subtotal:	**63.00**		**$0.77**	**$0.00**	**$48.51**	**$0.00**		**$48.51**	
Fargo, The Forum (Fargo, North Dakota)									
10/13/2014	64.00	Notice A Line	$0.77		$49.28	$0.00	(0.00%)	$49.28	
	Caption: Regional Haze Progress Report								
Subtotal:	**64.00**		**$0.77**	**$0.00**	**$49.28**	**$0.00**		**$49.28**	
Grand Forks Herald (Grand Forks, North Dakota)									
10/18/2014	65.00	Notice A Line	$0.72		$46.80	$0.00	(0.00%)	$46.80	
	Caption: Regional Haze Progress Report								
Subtotal:	**65.00**		**$0.72**	**$0.00**	**$46.80**	**$0.00**		**$46.80**	
Minot Daily News (Minot, North Dakota)									
10/17/2014	83.00	Notice A Line	$0.69		$57.27	$0.00	(0.00%)	$57.27	
	Caption: Regional Haze Progress Report								
Subtotal:	**83.00**		**$0.69**	**$0.00**	**$57.27**	**$0.00**		**$57.27**	
Williston Herald (Williston, North Dakota)									
10/17/2014	59.00	Notice A Line	$0.85		$50.15	$0.00	(0.00%)	$50.15	
	Caption: Regional Haze Progress Report								
Subtotal:	**59.00**		**$0.85**	**$0.00**	**$50.15**	**$0.00**		**$50.15**	

Gross Advertising	$302.57	Total Misc	$0.00	Amount Paid	$0.00
Agency Discount	$0.00	Tax	$0.00	Adjustments	$0.00
Other Discount	$0.00	Total Billed	$302.57	Payment Date	
Service Charge	$0.00	Unbilled	$0.00	Balance Due	$302.57

If you would like to pay your invoice with a credit card, please call Rhonda at 701-595-7311 or email rhondaw@ndna.com. We accept Visa, Mastercard, Discover, and AMEX. Or you can pay your bill online at www.ndna.com/billpay. Thank you!

EDF
ENVIRONMENTAL DEFENSE FUND®
Finding the ways that work

November 19, 2014

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave.
Second Floor
Bismarck, ND 58501

Via U.S. Mail and e-mail to toclair@nd.gov

Dear Director O'Clair:

In accordance with 40 CFR 51.102, Environmental Defense Fund (EDF) hereby submits written comments on the North Dakota Department of Health (NDDH), Air Quality Division's September 2014 Regional Haze Periodic Progress Report (ND Progress Report). Thank you for the opportunity to present our comments and recommendations.

EDF is a national membership organization with over one million members residing throughout the United States. EDF takes an interdisciplinary approach, crafting solutions that draw on the best scientific, economic, legal and policy ideas – to solve the world's most pressing environmental problems. Our members and staff are deeply concerned about air pollution and support reductions in harmful and visibility-impairing air pollutants. Reductions in these pollutants, as required by the federal Clean Air Act, will improve air quality, benefit public health, and preserve and enhance scenic vistas in National Parks and Wilderness Areas in North Dakota and across the country.

I. Oil and Gas Activity is Contributing to ND Regional Haze

Since the last regional haze State Implementation Plan was submitted to the U.S. Environmental Protection Agency (EPA) in 2010, North Dakota power providers reduced significantly emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X), which contribute to particulate pollution, the main component of regional haze -- from existing electric generating units. Despite these reductions from the power sector, visibility measurements in North Dakota's Class I areas, the Theodore Roosevelt National Park

(TRNP) and the Lostwood National Wildlife Refuge Wilderness Area (LWA), have not shown commensurate improvements (Figure 1 and 2).[1]

Figure 1:

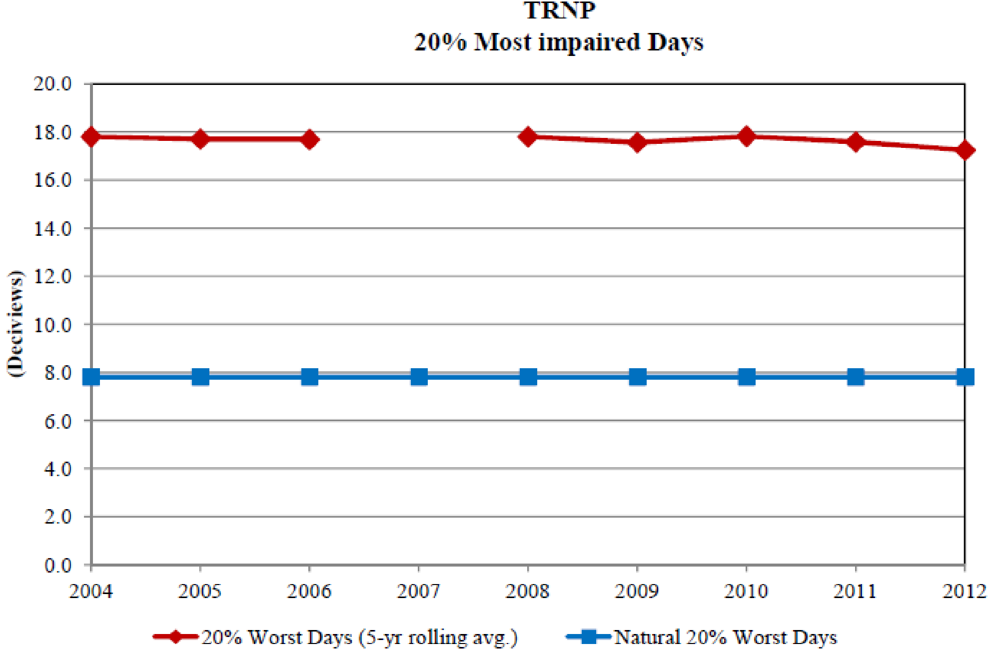
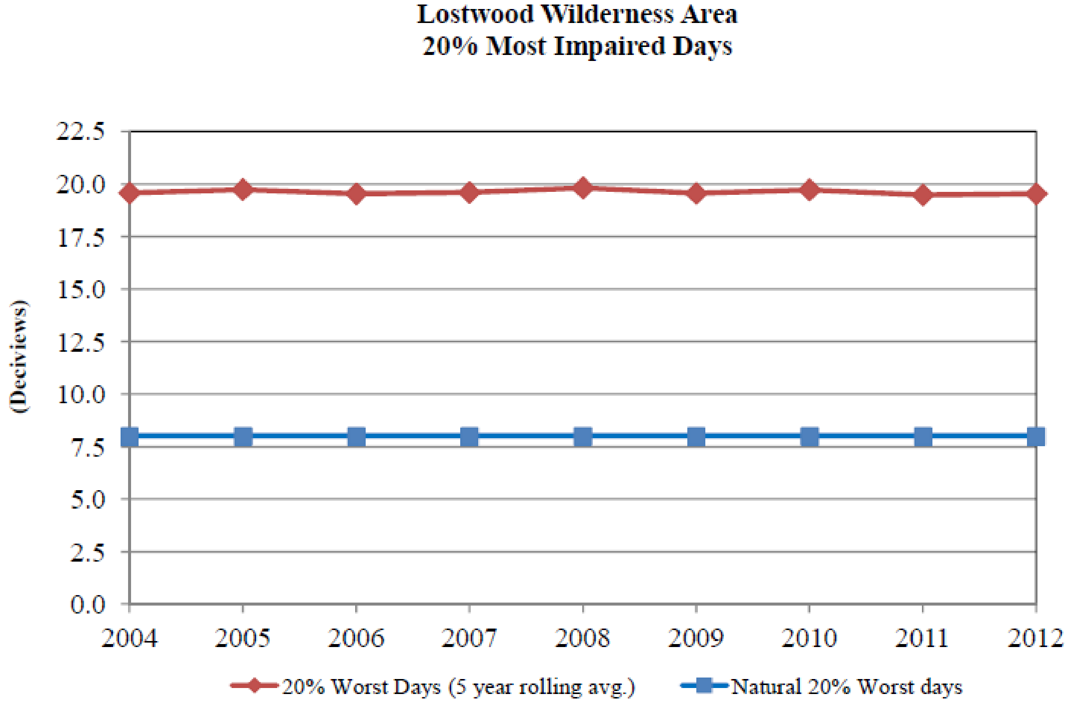


Figure 2:



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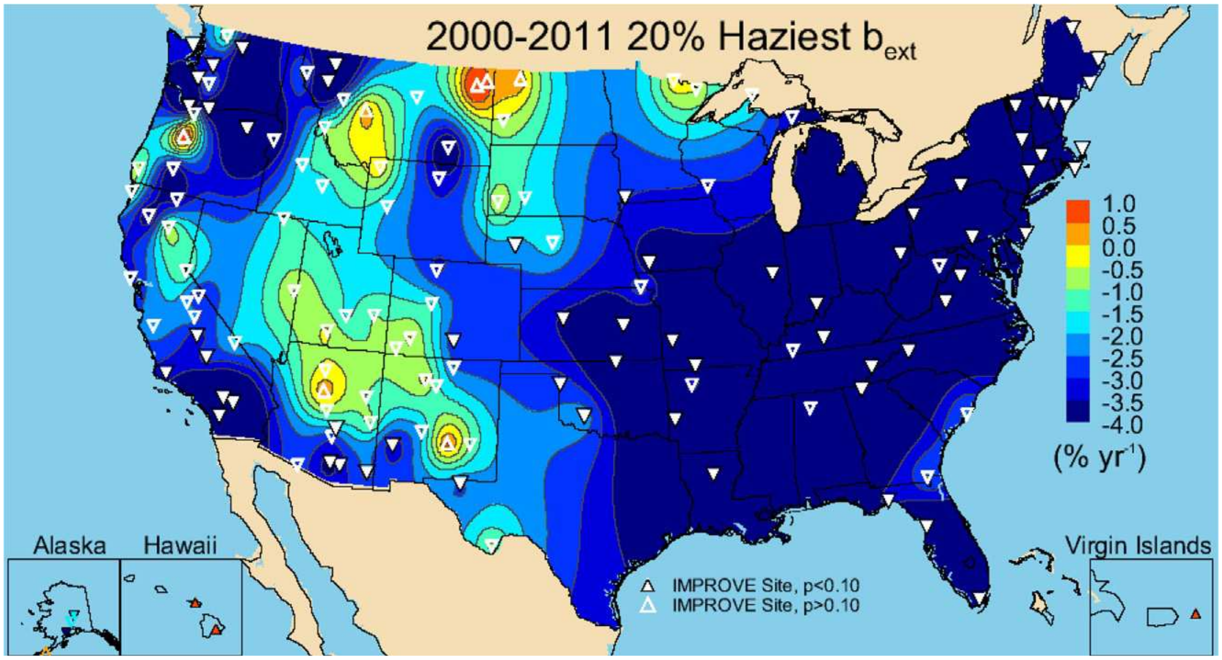
[1] NDDH Progress Report, pgs. 17, 18

In fact, data from the federal Interagency Monitoring of Protected Visual Environments (IMPROVE) network shows that haze levels at Theodore Roosevelt National Park have actually remained flat or increased since 2000, counter to national trends (Figure 3).[2]

Figure 3:



These data demonstrate that additional pollution reductions will be necessary in order for North Dakota to meet its visibility improvement goals as mandated by the federal Clean Air Act.

II. Increase of Emissions from Oil & Gas Production Has Offset Power Sector Reductions

While the SO_2 and NO_X emissions reductions NDDH has put in place on electric generating units have reduced emissions that contribute to visibility-impairing air pollution[3], EDF is concerned that these gains have been almost completely overwhelmed by the increase emissions associated with the rapid expansion in oil and gas production in North Dakota. The National Park Service shares our concern that pollution from the oil and gas sector in North Dakota is "offsetting emissions reductions from other anthropogenic sources and impeding progress toward ND's visibility improvement goals."[4] This is not surprising given that the ND Progress Report itself recognizes that, over the past 5 years, "the most obvious source category where emissions have increased is the oil and natural gas production sector."[5] Therefore, we strongly endorse the National Park Service's recommendation that

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[2] Hand, *et al.*, *Widespread reductions in haze across the United States from the early 1990s through 2011*, Atmospheric Environment 94 (2014) 671–79, Fig. 4.

[3] ND Progress Report, Section 2.6.

[4] ND Progress Report, Comments of the National Park Service, p. 1 (August 26, 2014).

[5] ND Progress Report, Section 2.5.

the NDDH "begin evaluating additional controls measures for oil and gas"[6] including improved requirements on drill rigs, diesel engines and compressors in the oil and gas sector.

III. Flaring

Because of a lack of adequate infrastructure, the dramatic increase in oil and gas production has brought with it an equally dramatic increase in associated gas flaring in North Dakota. Industry, regulators and conservation-minded groups like EDF all agree that flaring nearly 30 percent of produced natural gas is unacceptable[7]. Wasting this resource undermines national energy security goals, has negative impacts on the region's air quality and represents millions of dollars of lost revenue for operators, state and local governments and mineral estate owners. In fact, in 2012, flaring resulted in the waste of around $1 billion in fuel[8] – or enough gas to heat more than a million homes.

Oil and gas flares are a significant source of both NOx and SOx in the Williston Basin of North Dakota[9]. These pollutants are particulate matter precursors and likely contribute to visibility impairment in the western portion of the state. Therefore, in addition to measures to reduce emissions from drill rigs, engines and compressors, we would also strongly encourage the state to evaluate policy reforms to reduce emissions from North Dakota's production flares.

We appreciate North Dakota's recent efforts to reduce natural gas flaring – primarily through the North Dakota Industrial Commission's (NDIC) newly adopted policies – and EDF fully supports the NDIC's stated goals of reducing the volume of flared gas, the number of wells flaring, and the time period within which flaring occurs. Strict enforcement of the NDIC's recently adopted flaring-reduction field order will help reduce emissions that can contribute to regional haze. North Dakota should consider further actions to reduce visibility-impairing pollution associated with the oil and gas sector.

IV. Rapid VOC Emissions Increase Also of Concern

The state's haze progress report notes a substantial increase by almost a third in volatile organic compound emissions from 2008-2011. It further projects these emissions to increase again by almost 60% from 2011 to 2018. Since VOC's and NOx are the main contributors to the formation of ground level ozone, we would encourage the state to

---

[6] ND Progress Report, Comments of the National Park Service, p. 5.

[7] While flaring peaked in September 2011 at 36%, the most recent reports from the North Dakota Pipeline Authority indicate operators in the state flared 24% of associated gas in September of this year.

[8] Ceres, *Flaring Up: North Dakota Natural Gas Flaring More Than Doubles in Two Years* (July 2013).

[9] ENVIRON International Corporation, *Development of Baseline 2011 and Future Year 2015 Emissions from Oil and Gas Activity in the Williston Basin* (August 2014).

consider measures to reduce both NOx and VOC emissions as well as associated emissions of hydrocarbons like methane in a proactive manner.

V. Conclusion

The rapid expansion of new oil and gas development that North Dakota has witnessed in the past decade, centered on the Bakken formation in the western part of the state, requires re-evaluation of systems, models and methods that have been used in the past but that no longer effectively ensure the responsible development of the resource. This includes ramped up efforts to reduce haze causing pollution associated with this development.

In order for North Dakota to meets its visibility goals under the federal Clean Air Act, protect its scenic vistas, and protect the health of local citizens, the NDDH should consider further efforts to reduce emissions associated with oil and gas production. This should include improved requirements on drill rigs, engines, compressors, and flares as well as broader actions to reduce hydrocarbon and methane emissions in general.

Thank you again for the opportunity to comment on the Regional Haze Progress Report and for your continued efforts to improve scenic vistas and public health in North Dakota. We look forward to working with you to carefully craft solutions to this pressing issue.

Sincerely,

Dan Grossman
Rocky Mountain Regional Director

NATIONAL PARKS CONSERVATION ASSOCIATION

EARTHJUSTICE

SIERRA CLUB
FOUNDED 1892

ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

November 19, 2014

Mr. Tom Bachman
North Dakota Department of Health
Division of Air Quality
918 E. Divide Ave., Second Floor
Bismarck, ND 58501-1947

Via email to tbachman@nd.gov

Re: Comments on the Proposed North Dakota Regional Haze State Implementation Plan Periodic Progress Report

Dear Mr. Bachmann,

National Parks Conservation Association, Sierra Club, Earthjustice, and Environmental Law and Policy Center respectfully submit respectfully the following comments regarding North Dakota's proposed Regional Haze State Implementation Plan Periodic Progress Report (hereinafter, the "Progress Report"). The Progress Report represents an important opportunity for the State to take stock of whether the haze state implementation plan ("SIP") is on track to meet the reasonable progress goals at Class I areas in North Dakota and other states. Unfortunately, the state's Class I areas have seen little or no improvement, and are not on track to meet reasonable progress goals.

As explained below, to ensure that the reasonable progress goals are achieved, and the legal requirements for a progress report are satisfied, the final Progress Report must be revised. In particular, the draft report should be revised to:

- Acknowledge that the State's plan is or may be inadequate to ensure reasonable progress due to emissions from sources within the State, in particular significantly increased emissions from oil and gas development;

- Commit to revising the implementation plan to address the plan's deficiencies within one year as required by 40 C.F.R. § 51.308(h) and including more accurate monitoring of oil and gas emissions, analysis of control options and determination to limit oil and gas emissions, analysis of the factors behind the lack of visibility progress, and analysis of any other emission reductions necessary to achieve the reasonable progress goals by 2018.

These revisions will not only ensure progress towards natural visibility conditions at our protected national parks and wilderness areas, but will also benefit public health and ecosystems by reducing emissions of damaging pollution.

I. THE CLEAN AIR ACT'S REGIONAL HAZE PROGRAM

a. Development of a Regional Haze SIP

In the 19th century, Congress had the foresight to set aside national parks so as to preserve some of the nation's most spectacular scenery. *See, e.g.*, John Copeland Nagle, The Scenic Protections of the Clean Air Act, 87 N.D. L. Rev. 571, 576 (2011). With the nation's rapid industrialization, however, these remarkable scenic views have become increasingly marred by air pollution. *See id.* at 573. Today, air pollution is "perhaps the greatest threat to national parks," and pollution all too often degrades visibility in these iconic scenic areas. *Id.*

To reduce this threat to the national parks and other treasured public lands, Congress amended the Clean Air Act in 1977 to set a "national goal" of preventing all visibility impairment caused by human activities in national parks, wilderness areas, and other "Class I" federal areas. 42 U.S.C. § 7491(a)(1). Congress again amended the Clean Air Act in 1990 to further spur reductions of regional haze after it concluded that the U.S. Environmental Protection Agency ("EPA") and the states had not made adequate progress toward reducing haze. *Id.* § 7492. The Act delegates implementation of the regional haze program to EPA. The Agency set a goal of achieving natural visibility conditions at every Class I area by 2064, and the Agency directed states to make incremental, reasonable progress toward that goal. 40 C.F.R. § 51.308(d)(1)(i)(B), (d)(1)(ii).

To achieve natural visibility conditions by 2064, the goal set forth in the Clean Air Act's implementing regulations, 40 C.F.R. §51.308(d)(1)(i)(B), the states are directed to create regional haze SIPs, which are then submitted to EPA for its review and approval. *See* 42 U.S.C. §§ 7410(a), 7491(b)(2). EPA evaluates the SIP and either approves or disapproves it in whole or in part. *Id.* § 7410(k)(3). If EPA's evaluation reveals that a SIP does not comply with the Clean Air Act, then EPA must promulgate a FIP that remedies the shortcomings. *Id.* § 7410(c)(1).

Each state's regional haze SIP must include emissions limits on sources of air pollution within the state as necessary to protect visibility at all impacted Class I areas, both inside and outside the state. *See* 42 U.S.C. § 7491(a)(4), (b)(2). The 2064 natural visibility goal is to be achieved, in part, by installing BART controls at certain fossil fuel-fired power plants and other sources. *Id.* § 7491(b)(2)(A); 40 C.F.R. § 51.308(e). BART is required at eligible sources[1] that are reasonably anticipated to cause or contribute to visibility impairment at national parks, wilderness areas, wildlife refuges and other "Class I areas" where air quality should be pristine. 42 U.S.C. § 7491(b)(2)(A). BART is an essential component of the regional haze program as it compels emissions reductions from older, disproportionately polluting sources that often have escaped control under other Clean Air Act programs. *See id.*

In addition to requiring BART, each state's regional haze SIP must also set goals, expressed in deciviews,[2] for each Class I area located within the state that will ensure reasonable progress toward achieving natural visibility conditions by 2064 (the "reasonable progress goals"). *See* 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.308(d)(1). The reasonable progress goals must provide for improvement in visibility on the most impaired days and ensure no degradation in visibility on the least impaired days over the period of the implementation plan. 40 C.F.R. § 51.308(d)(1). These goals are set after considering the anticipated visibility reductions over the planning period of the SIP from anticipated BART controls and other federal or state programs, as well as controls imposed on non-BART sources under the regional haze SIP to help achieve reasonable progress. *See, e.g.,* 76 Fed. Reg. at 58,623.

States set the level of additional reasonable progress controls based on "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected source . . . ." 40 C.F.R. § 51.308(d)(1)(i)(A); 42 U.S.C. § 7491(g)(1). With the emissions reductions anticipated from these cumulative controls in mind, the state establishes the reasonable progress goals for the period of the SIP—through 2018 in this case.

b. The Role of Five-Year Progress Reports

Every five years, states must evaluate the progress they are making in implementing the control measures included in their haze SIPs and whether they are on track to meet the visibility goals for Class I areas. 40 C.F.R. § 51.309(g). As part of these five-year progress reports, each state must assess whether its existing implementation plan is adequate to achieve its established goals for visibility improvement and emissions reductions. 40 C.F.R. § 51.308(h). To determine the adequacy of the haze plan, each state must include in its progress report the following elements:

> (1) 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;
>
> (2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (d)(10)(i)(A) of this section;

---

[1] A source is BART-eligible if it is a stationary source within one of 26 enumerated categories, was not in operation before August 7, 1962, but was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any pollutant. 42 U.S.C. § 7491(b)(2)(A), (g)(7).

[2] EPA uses the deciview as the principal metric for measuring visibility impairment. The deciview scale "expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions." 64 Fed. Reg. 35,714, 35,727 (July 1, 1999).

> (3) For each mandatory Class I Federal area within the State, an assessment of the following: the current visibility conditions for the most impaired and least impaired days; the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions; the change in visibility impairment for the most impaired and least impaired days over the past 5 years;
>
> (4) 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 or 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;
>
> (5) 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;
>
> (6) An assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals; and
>
> (7) A review of the State's visibility monitoring strategy and any modifications to the strategy as necessary.

40 C.F.R. § 51.308(g)(1)-(7). If, after considering the above elements, a state determines that its SIP is or may be inadequate to ensure reasonable progress, it must provide notification to the EPA, develop additional strategies to address the implementation plan deficiencies, collaborate with other States whose emissions may be impeding its progress, and revise the plan no later than one year from the date that the progress report was due. *Id.* § 51.308(h)(3)-(4).

II. CO-BENEFITS OF REDUCING HAZE POLLUTION

Addressing haze pollution impacting Class I areas is also about protecting public health. Haze pollutants include nitrogen oxides, sulfur dioxide, particulate matter ("PM"), ammonia, and sulfuric acid, each of which poses a threat to public health. Nitrogen oxide is a precursor to ground level ozone, which is associated with respiratory diseases, asthma attacks, and decreased lung function. In addition, nitrogen oxide reacts with ammonia, moisture, and other compounds to form particulates that can cause and worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, sulfur dioxide increases asthma symptoms, leads to increased hospital visits, and can form particulates that aggravate respiratory and heart diseases and cause premature death. Particulate matter can penetrate deep into the lungs and cause a host of health problems, such as aggravated asthma, chronic bronchitis, and heart attacks.

Reducing these pollutants will have tremendous public health benefits that far outweigh concerns associated with rising electricity rates. EPA estimated that in 2015, full implementation of the Regional Haze Rule nationally will prevent 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days. Nationally, the

Regional Haze Rule will result in health benefits valued at $8.4 to $9.8 billion annually. Investing in technologies that will reduce the pollutants that cause these asthma attacks, hospitalizations, heart attacks, emergency room visits and premature deaths is the right choice for North Dakota and the rest of the nation.

These same haze-causing emissions also harm terrestrial and aquatic plants and animals, soil health, and moving and stationary waterbodies – entire ecosystems – by contributing to acid rain, ozone formation, and nitrogen deposition. Nitrogen deposition, caused by wet and dry deposition of nitrates derived from NOx emissions, causes well known adverse impacts on ecological systems; in some places, saturation of the soil already exceeds the "critical load" the ecosystem can tolerate.[3] Acid rain causes acidification of lakes and streams and can damage certain types of trees and soils. In addition, acid rain accelerates the decay of building materials and paints, including irreplaceable buildings, statues, and sculptures that are part of our nation's cultural heritage."[4] Further, haze-causing pollutants are precursors to ozone. Ground-level ozone formation impacts plants and ecosystems by: "interfering with the ability of sensitive plants to produce and store food, making them more susceptible to certain diseases, insects, other pollutants, competition and harsh weather; damaging the leaves of trees and other plants, negatively impacting the appearance of urban vegetation, as well as vegetation in national parks and recreation areas; and reducing forest growth and crop yields, potentially impacting species diversity in ecosystems."[5]

III. CLASS I AREAS IN AND NEAR NORTH DAKOTA

Emissions from North Dakota impact at least 10 Class I areas, including Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area in North Dakota, Boundary Waters Canoe Wilderness Area and Voyageurs National Park in Minnesota, Isle Royale National Park and Seney National Wildlife Refuge Wilderness Area in Michigan, Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area in Montana, and Badlands National Park and Wind Cave National Park in South Dakota. These Class I areas preserve the region's inspiring landscapes, rare geologic formations, and diverse wildlife and vegetation. They also serve as living museums of our nation's history. Visitors from across the nation and globe are drawn to these lands and their tourist dollars benefit state and local economies.

IV. PROXIMITY OF OIL AND GAS EXPANSION TO CLASS I AREAS

The rapid expansion of oil extraction from the Bakken formation in North Dakota has catapulted the state from ninth to second in oil production nationally since 2006. The Bakken is a shale formation that underlies parts of North Dakota, Montana, and Saskatchewan. The formation was first identified in 1953, but technical advances in directional drilling and fracking led the oil industry to begin exploiting it by 2008. As a result, oil production in the state climbed dramatically from 45 million barrels in 2007 to more than 241 million barrels in 2012. The

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[3] See, e.g., discussion of impacts on Rocky Mountain National Park. http://www.nature.nps.gov/air/permits/aris/romo/impacts.cfm.

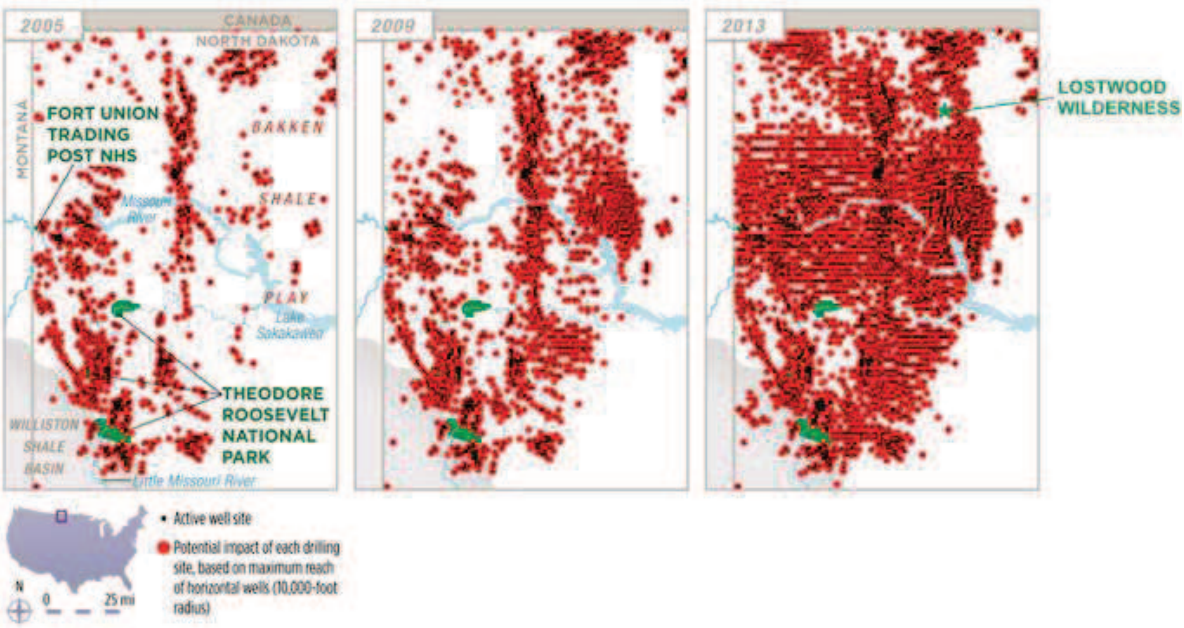
[4] http://www.epa.gov/acidrain/effects/index.html

[5] http://www.epa.gov/glo/health.html

number of producing oil wells in the state at year's end was 8,224, with 183 rigs operating. Over 70% of the state's 2012 production came from Bakken wells in Mountrail, McKenzie, Williams, and Dunn Counties.

Drilling has increased dramatically since 2006, when the State issued only 419 drilling permits. In 2011, North Dakota issued 1,927 drilling permits. In 2012, North Dakota issued 2,463 drilling permits. Estimates of total recoverable reserves vary considerably. For example, the U.S. Geological Survey estimate is between 3 and 4.3 billion barrels in North Dakota and Montana combined, whereas Continental Resources, Inc. (which is currently drilling in the Bakken) estimates 24.3 billion barrels in North Dakota's Bakken alone.

Unfortunately, this oil production occurs close to North Dakota's Class I areas. The figure below illustrates the location of Theodore Roosevelt National Park and the Lostwood Wilderness relative to well expansion in North Dakota.



At its closest, some of this development is literally within a few hundred feet from the border of Theodore Roosevelt National Park. The images below show oil and gas development along the border of the South Unit of the park.

Well pad along north boundary of South Unit of Theodore Roosevelt NP, photo (c) Chris Boyer, Kestrel Aerial Services, Inc.

3 well pads immediately adjacent to the South Unit fence (indicated by land line extending from upper left to lower right), photo (c) Chris Boyer, Kestrel Aerial Services, Inc.

V. NORTH DAKOTA'S REASONABLE PROGRESS GOALS

North Dakota's Progress Report states that:

> EPA did not establish new reasonable progress goals in their FIP for North Dakota. Technically, there are no reasonable progress goals established for North Dakota's Class I areas. (Progress Report, Section 1).

We disagree. Although we would have preferred quantified reasonable progress goals associated with EPA's FIP, EPA nonetheless was very clear that it was establishing reasonable progress goals consistent with its FIP.[6] Furthermore, in its original SIP, North Dakota committed to revising the SIP to include reasonable progress goals in connection with the progress report, stating that:

> 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 be 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(h)(4).[7]

By not planning to revise its reasonable progress goals in accordance with EPA's FIP, which certainly qualifies as an unexpected occurrence, North Dakota is reneging on its previous commitment. We request that the State quantify its revised reasonable progress goals in line with EPA's requirements. Regardless, we recognize the utility of using North Dakota's quantified reasonable progress goals, while maintaining that there are, in fact, reasonable progress goals established by EPA consistent with its FIP. Those finalized reasonable progress goals – quantified or not – are the yardstick by which progress must be measured.

VI. NORTH DAKOTA'S PROPOSED FIVE-YEAR PROGRESS REPORT MUST BE REVISED TO MEET 40 CFR 51.308(g) AND (h)

North Dakota submitted its first proposed haze plan to EPA in March 2010. As each state must submit a progress report five years after initial plan submittal, 40 C.F.R. § 51.308(g), North Dakota is required to submit its progress report by March 2015. While in general the draft Progress Report offers an important accounting of how the haze SIP is being implemented, there are a number of areas in which it should be improved. As the following sections indicate, the Progress Report should be revised to:

- Estimate emission reductions specifically associated with SIP measures;

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[6] "As part of our FIP, we are finalizing RPGs [reasonable progress goals] that are consistent with the controls we are imposing…" 77 Fed. Reg. 20,898.

[7] North Dakota State Implementation Plan for Regional Haze: A Plan for Implementing the Regional Haze Program Requirements of Section 308 of 40 CFR Part 51, Subpart P- Protection of Visibility at 213 (Feb. 24, 2010) ("ND Haze SIP") (emphasis added).

- More fully account for and provide enhanced monitoring of emissions from oil and gas activity;

- Acknowledge the likely visibility impact of increased emissions from oil and gas activity;

- Acknowledge that the State's Class I areas are not on track to meet the 2018 reasonable progress goals set by EPA;

- Determine that the existing SIP is inadequate to meet the 2018 reasonable progress goals; and

- Commit to revising the SIP within a year to ensure adequacy for meeting the 2018 reasonable progress goals.

Each of these items is discussed in detail below, in relation to the corresponding regulatory requirement.

a. EPA Checklist for 40 C.F.R § 51.308(g)(2): Does the Report Include Estimated Reduction Estimates for these Measures?

40 C.F.R § 51.308(g)(2) requires each progress report to include a "summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section." While Section 2.2 of the draft Progress Report accounts for emissions reductions achieved in North Dakota, including specifying reductions at BART/RP regulated sources (Table 2.7), it does not summarize the emissions reductions achieved through implementation of the measures contained in the North Dakota haze SIP, as required by 40 C.F.R § 51.308(g)(2). That is, the Progress Report does not distinguish between emissions reductions achieved as a result of the haze SIP versus emissions reductions achieved as a result of other enforceable requirements or voluntary measures.

The fundamental purpose of a progress report is to assess the efficacy of the haze SIP. It is difficult to render such an accounting if the State does not attempt to determine the emissions reductions required specifically by the haze SIP rather than by other programs. Accordingly, we urge the State to revise the draft Progress Report to quantify the emissions reductions achieved specifically as a result of the regional haze SIP. As EPA guidance notes, "progress reports should identify and estimate emissions reductions *to date* in visibility-impairing pollutants *from the SIP measures*." (emphasis added).[8]

For example, the emissions data in Table 2.3 make clear that some BART/RP sources (e.g. R.M. Heskett) have not yet implemented the BART/RP limits in the haze SIP. Thus, reductions attributed to the haze SIP at those sources should be zero. Likewise, it is clear that some sources (e.g. SO2 emissions at Leland Olds) have not only implemented BART/RP limits, but are achieving emission reductions well beyond those limits. In these cases, only a portion of

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[8] EPA April 2013, General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports), p. 7.

the achieved reductions are appropriately attributed to the haze SIP. This distinction is critical to determining the enforceability of the achieved reductions and hence the adequacy of the haze SIP. So too are these quantifications important for establishing a lens through which to assess adequate measures to achieve reasonable progress in the next planning period.

Some of this information is included in Tables 1.3 and 1.4. We ask that North Dakota integrate this information into Section 2.2, such that the existing and anticipated emission reductions specifically from BART/RP measures, as compared to overall reductions from the regulated sources, are clear.

b. EPA Checklist for 40 C.F.R § 51.308(g)(3): Does the report include the summaries of monitored visibility data as required by the Regional Haze Rule?

It would be helpful for North Dakota to include the uniform rate of progress and the reasonable progress goals set by its haze SIP, both in graphical and tabular form, since those are the goals by which visibility progress is measured. It would also be helpful for North Dakota to include the 5 year rolling averages of species extinction in graphical form. These depictions would more clearly illustrate the unfortunate reality that (a) North Dakota's reasonable progress goals are far from the uniform rate of progress; (b) even so, there has been little progress towards the reasonable progress goals, especially at Lostwood; and (c) in particular, despite significant decreases in SO2 from point sources, the overall level of sulfates contributing to visibility impairment has not mirrored the decrease in SO2; to the contrary, levels of visibility impairing sulfates show no decline.

c. EPA Checklist for 40 C.F.R § 51.308(g)(4): Does the report provide emissions trends across the entire inventory for a 5-year period as required by the Regional Haze Rule?

40 C.F.R § 51.308(g)(4) requires, among other things, an analysis covering the most current 5-year period "based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate." North Dakota's discussion of overall trends in emissions from EGUs from Section 2.2, along with a discussion of anticipated future emissions specific to the EGU sector, and incorporating additional anticipated BART/RP reductions, would be more appropriately situated in the section. It would also be helpful to include less aggregated emissions estimates where available (e.g. individual point sources, county level emissions, etc.) – such broken out figures would be particularly useful given the lack of progress and the need for additional analysis.

Moreover, because of the large gaps in monitoring throughout the state, the air pollution caused by oil and gas production is likely underestimated. Indeed, EPA's Inspector General recently concluded that EPA's National Emissions Inventory "likely underestimates" VOC and HAP emissions from the oil and gas sector;[9] we appreciate the inclusion of BLM estimates in

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[9] *See* EPA Office of Inspector General, (2013) EPA Needs to Improve Air Emissions Data for the Oil and Natural Gas Production Sector. Report No. 13-P-0161, at 17. Available at: http://www.epa.gov/oig/reports/2013/20130220-13-P-0161.pdf.

addition to the NEI data. However, to the extent that these estimates are still quite uncertain, we ask the State to include an enhanced monitoring and reporting plan with regard to oil and gas emissions, such that the State will have a more complete picture of these emissions for use in analysis for the 2018 planning period.

As North Dakota notes, emission increases have resulted a variety of activities and sources associated with oil and gas, including 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." (Progress Report Section 2.5). It is unclear whether all of these associated increases are included in the emission inventories documented in the Progress Report. Given the similarities between the 2018 estimates in the Progress Report and those in North Dakota's original SIP, we suspect that oil and gas associated increases may not be fully captured. We request that all of the emissions increases associated with oil and gas development – everything from flaring to traffic increases – be discussed and quantified to the extent possible in the Progress Report, and be subjected to enhanced monitoring and reporting in anticipation of the 2018 planning period.

d. EPA Checklist for 40 C.F.R § 51.308(g)(5): Does the Report include an explicit statement of whether there are anthropogenic emissions changes impeding progress?

40 C.F.R § 51.308(g)(5) obligates each progress report to include 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." EPA guidance notes that

> In Class I areas where less visibility progress has occurred, or where visibility progress is more uncertain, greater attention should be paid to evaluate whether there have been changes to expected emissions patterns in nearby states or source categories within the region that have affected progress.

Visibility progress in both of North Dakota's Class I areas has been either low or nonexistent. The most notable change in anthropogenic emissions within the state, as North Dakota notes, is the huge increase in emissions from the oil and gas sector. WRAP's emissions estimates used for the development of the haze SIP assumed an increase of 4.5 times the NOx emissions from oil and gas between the baseline and 2018. According to the emission inventories presented in the Progress Report, by 2011, a nearly 5.5 times increase had occurred – and production has roughly doubled since then. Overall, emissions of NOx from oil and gas development in North Dakota is now likely to increase more than 10 times by 2018 from baseline levels. Even more dramatically, emissions of VOCs have skyrocketed in association with oil and gas, with existing increases on the order of 30 times 2002 levels, and projected increases in 2018 on the order of 50 times 2002 levels.

The change in oil and gas emissions is a "significant change[] in anthropogenic emissions…that have limited or impeded progress in reducing pollutant emissions." Emissions associated with oil and gas development now comprise a major portion of state-wide emissions. In 2002, according to the Progress Report inventories, oil and gas NOx emissions made up 2% of statewide NOx emissions; by 2011, this increased to 13%, and by 2018, the contribution from oil and gas is projected to be 24%. For VOCs, the oil and gas sector contributed 2% of statewide emissions in 2002. By 2011, this figure was 43%, and oil and gas is projected to contribute 54% of statewide VOC emissions in 2018. Remarkably, the sector's VOC emissions are estimated to have surpassed biogenic emissions since the 2008 inventory – typically anthropogenic contributions to VOCs are significantly lower than biogenic sources.

Despite these significant increases in visibility impairing pollutants from oil and gas, and the extreme proximity of oil and gas development to Theodore Roosevelt and Lostwood, North Dakota claims the there is "no evidence that the increase in oil & gas activity is impeding progress toward the visibility goal." (Progress Report, Section 2.5). This claim is implausible. It is far more likely that the huge increases in visibility-impairing pollutants localized to the relevant Class I areas *do* have an impact on visibility than that they *don't.* We believe that the burden of proof rests with the State to demonstrate a lack of impact in the face of this obvious conclusion. Regardless, there are significant gaps in the State's logic supporting its claim, which we ask to be remedied in the final Progress Report submitted to EPA.

The State argues that a monitored decrease in particulate organic matter (POM) and nitrates, along with relatively constant ozone values, indicate that the dramatic increases in VOCs and NOx from oil and gas activity do not impede progress toward the visibility goal. This conclusion is both unlikely and premature. With regard to nitrate, decreases in nitrate extinction cannot possibly rule out the likely scenario that increases in oil and gas related NOx are at least partially offsetting decreases in NOx from point sources or out of state sources. That is, it is impossible to tell how much more nitrate extinction would have been lowered were it not for the increases in emissions from oil and gas. As noted by EPA,

> The decreases in organic mass and nitrate extinction…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.[10]

North Dakota provides little credible response to EPA and FLM concerns along these lines, instead reiterating the accurate, if largely inconclusive, fact of monitored nitrate and POM extinction reductions.

Furthermore, atmospheric chemistry is complex and non-linear. Reductions in a given pollutant do not translate directly into improvements in visibility. In particular, interactions involving VOCs and NOx, which are the major precursors to ozone, are known to be highly entangled, such that a decrease in one pollutant can lead to either an increase or decrease in ozone, depending on the circumstances. As with nitrate, it is not possible to know what ozone concentrations would exist absent the increased emissions from oil and gas, so the fact of their relatively constant values has little meaning with regard to the impacts from oil and gas to visibility. This is particularly true given both the relatively limited ozone monitoring in the Bakken area overall, and the limited data presented in the Progress Report.

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[10] EPA Comments to North Dakota, August 25, 2014.

North Dakota's Progress Report also discusses the persistent contribution of sulfates to visibility impairment at Theodore Roosevelt and Lostwood, an unexpected effect given the significant decreases in point source SO2 emissions. It is possible that the changes in oil and gas emissions may play a role in this result. A recent study notes,

> Formation of [sulfate] is chemically linked to primary emissions of sulfur dioxide (SO2) and to the abundance of atmospheric oxidants such as hydroxyl radical (OH), hydrogen peroxide (H2O2), ozone (O3), methylhydroperoxide (MHP), and peroxyacetic acid (PAA) (Seinfeld and Pandis, 1998). All of these oxidant species are formed via photochemical reactions which originate from emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC). Therefore, it is expected that variations in primary emissions of NOx and VOCs may have an effect on the amount and distribution of sulfate (Stein and Lamb, 2002).[11]

Thus, the impacts of the overall increase in VOC, and the increase in NOx from oil and gas sources, may alter the atmospheric chemistry in ways that are not immediately apparent. It is also possible that the impact of emissions from oil and gas sources, which are widespread and relatively low-lying in comparison to the tall stacks of many point sources, have a different impact on atmospheric dynamics. Regardless of the mechanism, it strains credulity to assert that the dramatic, unanticipated increase in anthropogenic visibility-impairing pollutants from sources literally next door to the Class I areas does not fit qualify as an anthropogenic change impeding progress.

Ultimately, North Dakota acknowledges that "oil and gas activity has the potential to adversely affect progress towards the national visibility goal" (Progress Report, Section 2.6), but fails to demonstrate that this probable impact does not, in fact, exist. It does include an argument about the impact of its recently enacted flaring regulations, which are a step in the right direction (discussed further below). Additionally, it includes with a misplaced promise to analyze oil and gas emissions in future SIP revisions, rather than appropriately analyzing them now (also discussed below). If oil and gas emissions clearly and definitively had no impact on visibility, neither of these would be required.

Additionally, as noted above, it is unlikely that the emission inventories capture the cumulative effect of emissions from oil and gas related activity. Our members and supporters have experienced the "oil boom" to include increased particulate matter from increased traffic (particularly heavier traffic and on unpaved scoria roads) and increased combustion emissions from residential heating and cooling needs for workers. To the extent that these local emissions are missing from the inventories, they may partly explain the continued visibility impairment at Theodore Roosevelt and Lostwood.

We also note that there has been significant variability in ammonia emissions from area sources. Like VOCs, this precursor can play a significant role in visibility impairment under specific circumstances. We encourage the State to include a more complete discussion of spatial and temporal variability in this pollutant from the State's sources, and its impact on visibility.

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[11] Stein, A.F. and Saylor, R.D. Sensitivities of sulfate aerosol formation and oxidation pathways on the chemical mechanism employed in simulations. Atmos. Chem. Phys., 12, 8567–8574, 2012. Available at http://www.atmos-chem-phys.net/12/8567/2012/acp-12-8567-2012.pdf.

Finally, 40 C.F.R § 51.308(g)(5) expressly requires an assessment of significant changes in anthropogenic emissions "within or outside the State." In order to comply with this provision, this section of the final Progress Report should include a discussion of whether there are changes in anthropogenic emissions outside of North Dakota that have impeded progress in improving visibility at Theodore Roosevelt or Lostwood.

e. EPA Checklist for 40 C.F.R § 51.308(g)(6): Does the Report include an assessment of whether the state's haze plan is on track to meet reasonable progress goals?

40 C.F.R § 51.308(g)(6) mandates an "assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals."

North Dakota's assessment intended to meet this regulatory requirement falls short. It simply reiterates that its reductions from BART/RP sources are being implemented, and that it has "no evidence" that the increases in oil and gas activity are contributing to visibility impairment.

By contrast, EPA's guidance asks states to

> …list each Class I area affected by sources in the state, as identified in the SIP. For those areas, the reports should assess qualitatively whether the emissions and visibility trends suggest any deficiencies in the SIP that will affect achievement of the reasonable progress goals for those Class I areas. In addition, there is a forward-looking component to this section, requiring a qualitative assessment of progress expected by the end of 2018…For each Class I area affected by sources in the state, the report should generally identify the "established" 2018 reasonable progress goal for the first 10-year planning period.[12]

North Dakota's assessment does not address any of these requirements. We encourage the State to include this valuable information. As EPA noted in comments to North Dakota, the State contributes significantly to visibility impairment at several out of state Class I areas, including Badlands, Wind Cave, UL Bend, Medicine Lake, Voyageurs, Boundary Waters, and Isle Royale.[13]

Of particular note is Medicine Lake. We reviewed the IMPROVE data for this Class I area in Montana near the North Dakota border. We discovered that its visibility has not improved, and in fact has ***degraded***, on the worst days since the baseline period (18.08 dv in 2008-2012 versus a baseline of 17.72). Further, the extinction from both nitrate and sulfate has increased, as has extinction from soil, coarse particulate matter, and sea salt. North Dakota's estimated contribution to species extinction at this Class I area on the worst days in the baseline

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[12] EPA April 2013, General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports), p. 16-17.

[13] EPA Comments to North Dakota, August 25, 2014.

period include 11% (sulfate), 7% (nitrate), 17% (fine particulate matter), and 16% (coarse particulate matter).[14]

Medicine Lake is also located in the Bakken formation and is impacted by the oil and gas activity in the region. It appears to exhibit a similar pattern of continued impairment as the North Dakota Class I areas. We encourage North Dakota to review data from this Class I area as well in investigating the causes of continued impairment at Theodore Roosevelt and Lostwood.

Finally, we note that any assessment of whether SIP measures are sufficient to meet established reasonable progress goals should include a discussion of enforceability. As noted above, many of the emission reductions achieved thus far, and any associated visibility improvement attained or additional impairment avoided, are not enforceable under the terms of the SIP, but are instead essentially voluntary, reversible emission reductions. We encourage the State to include information about the enforceability of its emission reductions in its assessment of the sufficiency of SIP measures.

f. EPA Checklist for 40 C.F.R § 51.308(h): Determination of Adequacy: Does the report (or the transmittal materials) provide the explicit determination required by the Regional Haze Rule?

This final step in the regulatory requirements for progress reports compels states to take one of four actions based on the information in the progress report. The first option, designed for situations where "visibility and emissions trends indicate substantial progress," allows states to declare that further revision is not needed at this time.[15] The remaining three options deal with situations where emissions – from other states, other countries, or the state itself, respectively – are or may be inadequate to ensure reasonable progress.

Contrary to North Dakota's assertion, the first situation is applicable here. Visibility trends, discussed above, indicate little to no improvement on the worst days at North Dakota's Class I areas, and degradation on the worst days at Medicine Lake, a Class I area across the border in Montana. Likewise, although point source emissions have significantly decreased, unexpected emissions from the oil and gas sector have provided a counterweight to NOx reductions and have caused a massive increase in anthropogenic VOCs.

North Dakota's Progress Report states that "there is nothing to suggest at this time that the reasonable progress goals (unapproved goals) will not be met." (Progress Report, Section 2.8). Unfortunately, in addition to the discouraging visibility and emissions trends, there is ample evidence to suggest that the reasonable progress goals will not be met. North Dakota's quantified reasonable progress goals, which are higher than the final EPA-approved goals, relied on significant reductions in extinction from sulfates which have not come to pass for reasons that the State does not understand and cannot explain. It does not make sense to conclude that such reductions will spontaneously appear by 2018. This is particularly true given that SO2 emissions

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[14] North Dakota Regional Haze SIP, Table 2.1.

[15] EPA April 2013, General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports), p. 18.

from a very localized source – oil and gas activity near the Class I areas – are projected to increase by 2018.

Likewise, North Dakota's SIP has slim plans to limit or control emissions from oil and gas activity. The State notes that such activity "may proceed at a steady or increasing rate for the next 20 years." (Progress Report, Section 2.6). Its emissions estimates from this sector in the past inspire little confidence; in the original SIP, North Dakota insisted on revising WRAP's estimates (which turned out to be low) *downward* by a factor of two.[16]

The State describes its recent flaring regulations and notes that they will reduce emissions of NOx and VOCs from oil and gas. These regulations, although an improvement on the status quo, do not in any way substitute for a complete analysis of the emission reductions feasible from oil and gas activity, and do not provide a compelling reason to believe that North Dakota's SIP is currently adequate to meet reasonable progress goals. It is unclear how effectively and enforceably this plan will translate into emission reductions. The Progress Report notes the expected impact on the flaring rate, but fails to quantify this change in terms of expected emission reductions.

Likewise the State's promise of future analysis does not negate the need for a declaration of inadequacy of the existing SIP. In its haze SIP, the State noted that,

> Given the small amount of baseline emissions and the uncertainty of the projection of future emissions, the Department proposes no additional controls for oil and gas exploration and production facilities at this time. The Department will continue to track oil and gas emissions and will take into consideration the Phase III inventory when it is available. During the mid planning period review, the Department will review oil and gas emissions and take action if necessary…
>
> 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 be 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(h)(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. [17]

The State's previous determination of no additional controls necessary for oil and gas exploration and production was premised on low baseline emissions and uncertain future emissions. Both of these have changed dramatically. Emissions from oil and gas are exponentially higher than in the baseline. Future emissions are still somewhat uncertain, but it is clear that production is not anticipated to slow down any time soon. Despite this change in circumstance and previous commitment to address unexpected changes as part of the progress

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[16] North Dakota Regional Haze SIP at pdf 129. We note that North Dakota's revision to soil contribution was likewise unwarranted.

[17] North Dakota Regional Haze SIP at pdf 211 and 232.

report process, the State has not completed a thorough analysis of oil and gas emissions and their impacts. Instead, it again proposes to kick the can further down the road.

Additionally, North Dakota's SIP is inadequate because many of the emission reductions relied on thus far are not enforceable. Where emission rates are lower than BART/RP or other state-set limits (e.g. see Table 2.3 in the Progress Report), the State should appropriately lower those limits to ensure that such reductions are enforceably retained.

North Dakota's Progress Report does not meet its obligation to demonstrate the adequacy of its SIP. Regulatory requirements set a high bar by requiring a determination of inadequacy if a plan simply "may be" inadequate to ensure reasonable progress. North Dakota's plan clearly qualifies. The final Progress Report should include a declaration that some combination of emissions from other states, other countries, and North Dakota itself are collectively causing the SIP to be inadequate to ensure reasonable progress, along with a commitment for a revision to address these deficiencies within one year as required by regulation. If it intends to complete a robust analysis of oil and gas emissions for the 2018 planning period, the State needs to begin that work as soon as possible. We offer suggestions below for considerations to include in this analysis.

VII. SUGGESTIONS FOR REVISIONS

In revising its SIP to demonstrate adequacy for meeting reasonable progress, or alternatively in anticipation of the 2018 SIP revision, North Dakota should include analysis of both emission reductions achievable from oil and gas activity, and emission reductions achievable from power plants.

a. Potential Reductions from Oil and Gas Emissions

The advent of technological advances in the oil and natural gas industry, including horizontal drilling and hydraulic fracturing, has resulted in a rapid expansion of the industry to areas previously considered inaccessible for development. Major oil and gas shale plays – which include the Bakken – are projected to produce billions of barrels of oil and trillions of cubic feet of natural gas nationwide. With this uptick in production also comes increased air pollution, and air pollution from oil wells – like those in the Bakken – are particularly harmful.

Given the substantial oil resources within North Dakota, the anticipated expanded development of these resources, and the negative environmental repercussions of unmitigated emission control, it is critical to minimize air pollution from development on these lands as much as elsewhere. While the State of North Dakota has taken preliminary steps to address the rapidly increasing development, oil wells have escaped much of the Federal regulation that has been promulgated to prevent such pollution from natural gas development.[18] With regard to well completions, North Dakota should require that operators of all wells – oil, gas, and mixed – implement the proven, economically reasonable "green completions" technologies that EPA requires, under its 2012 New Source Performance Standards, at natural gas wells.

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[18] *See* 40 C.F.R. § 60.5365 (establishing national standards of performance for "gas well affected facility[ies]" but omitting oil wells).

Low-cost controls exist today to reduce air pollution from the many sources related to oil production. Such sources include:

- Drill rigs, which can emit NOx, SO2, CO, and PM as a result of combusting diesel fuel to drive electrical generators;
- Storage vessels, which can emit VOC, methane, and hazardous air pollutants like benzene;
- Leaks, which can emit VOC and hazardous air pollutants like benzene;
- Pneumatic devices, which can emit VOC and hazardous air pollutants like benzene;
- Compressor engines, which can emit CO, NOx, SO2, PM, VOCs, methane, and hazardous air pollutants like benzene;
- Combustion emissions from flares, and other units that provide power and process steam and heat.

Moreover, particulate matter emissions within the industry occur as a result of wellpad and road construction, as well as particulate matter emissions associated with driving on those roads. As demonstrated by states like Colorado that have adopted some of these cost-effective controls, implementation of these measures is not a barrier to robust oil and gas development.

b. Potential Emission Reductions from Power Plants

The 5-year progress report provides North Dakota with a critical opportunity to revisit the appropriate controls for coal-fired power plants throughout the state, including Minnkota Power Cooperative's Milton R. Young Station ("MRYS") Units 1 and 2, Basin Electric Power Cooperative's Leland Olds Station ("LOS") Unit 2, and Otter Tail Power Company's Coyote Station. Under the prior regional haze rule, each of these units was not required to install the most effective pollution controls to limit their substantial NOx emissions. At this check-in, North Dakota should revisit the appropriate controls for these units, and require them to install and operate the best controls that will improve visibility at Theodore Roosevelt National Park and Lostwood National Wilderness Refuge Wilderness Area. At a minimum, North Dakota should use the progress report to begin collecting data that can be used in its next SIP evaluation of controls on these units.

i. Milton R. Young Station Units 1 and 2 and Leland Old Station Unit 2

MRYS and LOS are two of the polluting sources that are subject to BART requirements in North Dakota. MRYS is a two-unit, 794 MW electrical generating plant located near Center, North Dakota.[19] Unit 1, which has a capacity of 277 MW, began commercial operation in 1970, and Unit 2, which has a capacity of 517 MW, began commercial operation in 1977.[20] LOS is a 656 MW coal-fired electrical generating plant located in Stanton, North Dakota. LOS Unit 2 has

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[19] 76 Fed. Reg. at 58,589.

[20] *Id.*

a generating capacity of 440 MW, and began commercial operation in 1976.[21] MRYS Units 1 and 2 and LOS Unit 2 are major contributors to air pollution in Theodore Roosevelt National Park and Lostwood National Wilderness Refuge Wilderness Area. Reducing emissions from these plants beyond the reductions required under the first regional haze plan would help North Dakota meets its reasonable progress goals.

In the initial regional haze rule, North Dakota found that an emissions limit based on selective non-catalytic reduction ("SNCR") was the best available retrofit technology ("BART") for these plants. EPA initially rejected this determination, and found that an emission limit based on the more effective selective catalytic reduction technology ("SCR") in combination with advanced separated overfire air was BART.[22] Between the proposed and final rules, however, EPA changed its position, and affirmed the state's finding.[23] At the request of NPCA and Sierra Club, EPA is reconsidering its decision to approve North Dakota's BART determination for these units.[24] North Dakota, too, should use this 5 year progress report as an opportunity to revisit the appropriate controls at MRYS Units 1 and 2 and LOS Unit 2 to ensure that North Dakota is on track to achieve natural visibility conditions at TRNP and Lostwood by 2064.

Controlling the NOx emissions at MRYS and LOS would go a long way to reducing visibility impairing NOx emissions at TRNP and Lostwood. Of the seven BART facilities in North Dakota, MRYS and LOS are the biggest contributors to haze pollution at Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area.[25] There is substantial room to reduce their NOx emissions and improve visibility in these parks. As is shown in Table 1 below, North Dakota's own estimates from the prior regional haze rulemaking demonstrate that installing SCR at these units instead of SNCR would reduce NOx emissions by nearly 14,000 tons per year.

Table 1. Expected Emissions Reductions at MRYS Units 1 and 2 and LOS Unit 2.

Unit	**Expected Emissions SNCR (tons/year)**	**Expected Emissions SCR (tons/year)**	**Emissions Savings with SCR**
MRYS Unit 1	3,784	627	3,157[26]
MRYS Unit 2	6,630	984	5,646[27]
LOS Unit 2	5,900	900	5,000[28]
Total	**16,314**	**2,511**	**13,803**

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[21] *Id.* at 58,591-92.

[22] 76 Fed. Reg. 58,570 (proposed Sept. 21, 2011) (proposing to issue a federal implementation plan setting a NOx BART limit for MRYS Units 1 and 2 and LOS Unit 2 of 0.07 lb/MMBtu, achievable through the operation of SCR plus advanced separated overfire air).

[23] 77 Fed. Reg. 20,894 (Apr. 6, 2012) (approving the State of North Dakota's BART determinations based on less effective SNCR technology).

[24] 78 Fed. Reg. 16,452 (proposed Mar. 15, 2013).

[25] 76 Fed. Reg. at 58,583.

[26] 76 Fed. Reg. at58,606 (showing that at MYRS Unit 1, the expected NOx emissions were 3,784 tons/year, whereas with SCR the expected NOx emissions were 627 tons/year, offering a 3,157 ton per year savings).

[27] *Id.* at 58,610 (showing that at MYRS Unit 2, the expected NOx emissions were 6,630 tons/year, whereas with SCR the expected NOx emissions were 984 tons/year, offering a 5,646 tons per year savings).

[28] *Id.* at 58,614 (showing that at LOS Unit 2, the expected NOx emissions were 5,900 tons/year, whereas with SCR the expected NOx emissions were 900 tons/year, offering a 5,000 tons per year savings).

Reducing NOx emissions by nearly 14,000 tons per year would benefit North Dakota's national parks and wilderness areas. Installing SCR at MYRS Unit 1 instead of SNCR would result in 18 fewer days with reduced visibility at TRNP.[29] At MRYS Unit 2, installing SCR instead of SNCR would result in 21 fewer days of reduced visibility at TRNP.[30] And at LOS Unit 2, installing SCR instead of SNCR would result in 25 fewer days of reduced viability at TRNP.[31]

Nonetheless, under the prior regional haze rule, MRYS Units 1 and 2 and LOS Unit 2 were allowed to meet an emissions limit consistent with SNCR as BART for these units, and to forego installing SCR. However, to help achieve reasonable progress now, and to ensure that these units are emission controls that most effectively limits NOx emissions, North Dakota should require these units to install the best controls, namely SCR. As NPCA and Sierra Club have repeatedly explained, most recently in comments to EPA on its decisions to reconsider its approval of North Dakota's BART determinations for MRYS Units 1 and 2 and LOS Unit 2,[32] there is no legal reason why these units should not install SCR, and substantially reduce their NOx emissions. To justify requiring lesser controls, North Dakota has pointed to a district court decision affirming the state's determination of the best available control technology ("BACT") to resolve longstanding violations of the Clean Air Act's New Source Review provisions at the Milton R. Young plant. Although the district court upheld North Dakota's BACT determination, the district decision does not prevent North Dakota from revisiting its conclusion that SNCR is the best available control for MRYS, especially in view of the evidence that SNCR is not the best technology to control these units' NOx emissions.

Indeed, as is set forth in detail in NPCA and Sierra Club's reconsideration comments, evidence available during the prior regional haze rulemaking and newly available evidence demonstrates that in determining BART, North Dakota improperly concluded that SCR was technically infeasible at MRYS and LOS.[33] For example, catalyst vendor have explained that they would guarantee their product for use with certain SCR configurations. In noting that they would provide the guarantees, these catalyst vendors indicated that SCR is feasible on these units. Unlike North Dakota, these catalyst vendors are not concerned that the coal burned at MRYS and LOS would plug the catalyst and prevent an SCR system from operating.[34] A study of flue gas characteristics at MRYS Unit 2 confirms that the catalyst vendors are correct to conclude that SCR is feasible. The study showed that the gas stream is compatible with the use of an SCR, particularly low-dust or tail-end SCR.[35] In addition, newly available evidence confirms that SCR is technically feasible on units burning North Dakota lignite. In particular,

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[29] *Id.* at 58,610.

[30] *Id.* at 58,612.

[31] *Id.* at 58,618.

[32] June 17, 2013 Comments on Reconsideration (attached as Exhibit 1).

[33] *Id.* at 11-18.

[34] *Id.* at 12-13 (discussing statements from Johnson Matthey Catalyst and Alstom Power that various SCR configurations would be technically feasible at units burning North Dakota lignite).

[35] *Id.* at 13-14 (discussing March 2009 Microbeam study of the composition of the flue gas at MRYS Unit 2).

both modeling and actual experience operating SCR on similar lignite units show that SCR would be feasible on units that burn North Dakota lignite.[36]

Moreover, the BACT determination for MRYS never should have applied wholesale to LOS. Unlike MRYS, LOS does not fire 100% North Dakota lignite.[37] Instead, LOS burns a combination of North Dakota lignite and Powder River Basin coal.[38] This difference in fuel is important. North Dakota determined that SCR would not work at MRYS because it fired North Dakota lignite, which North Dakota found has more elements that can poison the SCR catalyst and prevent the SCR systems from removing NOx from the flue gas than Powder River Basin coal. Given the importance of coal content to North Dakota's prior determination, North Dakota should not rely on the feasibility analysis for MYRS.

Finally, even if North Dakota does not require SCR at these units, additional technologies can be used with the SNCR systems to further reduce emissions. For example, as is explained in detail in NPCA and Sierra Club's reconsideration comments, additional NOx removal technologies, such as PerNOxide or Hybrid or Advanced SCR-SNCR systems, can be used in combination with SNCR to achieve significant emissions reductions.[39] Thus, North Dakota can achieve great emissions reductions at these units by requiring use of additional controls beyond SNCR.

Given the substantial emissions reductions available if these units install SCR, and North Dakota's failure to remain on the glidepath for improving visibility, North Dakota should use this 5-year period review as an opportunity to require better controls to achieve reasonable progress. At a minimum, North Dakota should begin to collect information that it can use during the next planning period to determine the appropriate limits for these facilities. Indeed, North Dakota indicated to EPA that it would conduct a pilot study to evaluate the feasibility of SCR plants.[40] EPA expects that "the results of such a study could be used to inform further evaluation of SCR as a potential control technology when the State evaluates reasonable progress in the next planning period for regional haze. This position is supported by the State's December 20, 2011 letter from North Dakota Department of Health (NDDH), L. David Glatt, to EPA, Janet McCabe."[41]

ii. Coyote

Coyote is a 450 MW power plant located south of Beulah, North Dakota, about 112 kilometers away from Theodore Roosevelt National Park's North Unit.[42] Otter Tail Power Company, Coyote's owner, started constructing the facility in 1977, a few months after the cut-off date for BART eligibility.[43] In 2010, Coyote emitted 12,323 tons of NOx, making it the fifth

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[36] *Id.* at 14-18.
[37] *See id.* at 9 n. 14 (MRYS Units 1 and 2 burn 100% North Dakota lignite).
[38] *See id.* at 9 & nn. 15-18 (discussing the coal burned at LOS Unit 2)..
[39] *Id.* at 21-22.
[40] 77 Fed. Reg. at 20,898.
[41] *Id.*
[42] *See* 76 Fed. Reg. at 58,625 (Tables 64 and 65); *see also* ND Haze SIP, *supra* note 7, at 180 (Table 9.4).
[43] Nat'l Parks Conservation Ass'n et al. Comments on the Proposed Approval and Partial Disapproval of North Dakota Regional Haze SIP and Proposed FIP for Interstate Transport of Pollution Affecting Visibility and Regional Haze 13, Attachment 1 to Doc. No. EPA-R08-OAR-2010-0406-0213, at 13 (Nov. 21, 2011); *see also* Letter from

largest emitter of NOx in the country on a per unit basis.[44] Thus, Coyote is another candidate for additional emissions reductions to help ensure that North Dakota meets its reasonable progress goals.

Recently, in connection with an air permit, Otter Tail agreed that by the end of this regional haze planning period, or by July 31, 2018, Coyote will meet an emissions limit of 0.50 lb/mMBtu of NOx per year.[45] To meet that limit, Coyote plans to install separated overfire air controls.[46] However, as EPA explained in its review of North Dakota's March 2010 SIP, Coyote could achieve significantly greater emissions reductions if it installed more advanced controls.[47] For example, if Coyote installed advanced separated overfire air controls, it could reduce its NOx emissions by more than 1,000 tons of NOx per year over the emissions reductions expected with the 0.50 lb/mMBty emission limit.[48] Requiring an emissions limit consistent with the best available NOx control, SCR, would reduce Coyote's emissions by up to 7,000 tons per year over the 0.50 lb/mMBty emission limit.[49]

Nonetheless, at the beginning of the first regional haze planning period, EPA approved North Dakota's determination that the 0.50 lb/mMBtu emission limit was an appropriate reasonable progress limit.[50] EPA approved the reasonable progress controls for Coyote even though North Dakota was not on track to attain natural visibility conditions at its Class I areas by 2064.[51]

Richard R. Long, Director, EPA Air & Radiation Program to Gary D. Helbling, Environmental Engineer, N.D. Health Dep't, Attachment A at 1 (Apr. 17, 2001), *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/ otter.pdf.

[44] *Id.*

[45] North Dakota Regional Haze State Implementation Plant, Periodic Progress Report 7 (Table 1.4) (Sept. 2014); *see also* North Dakota State Implementation Plan for Regional Haze Amendment No. 1, Doc. No. EPA-R08-OAR-2010-0406-0026 § 10.6.1.2 (July 25, 2011).

[46] North Dakota Regional Haze State Implementation Plant, Periodic Progress Report 7 (Table 1.4) (Sept. 2014); *see also* North Dakota State Implementation Plan for Regional Haze Amendment No. 1, Doc. No. EPA-R08-OAR-2010-0406-0026 § 10.6.1.2 (July 25, 2011). Coyote has yet to update its pollution controls; in the Periodic Progress Report, North Dakota has explained that "engineering design is just beginning on the overfire air system." North Dakota Regional Haze State Implementation Plant, Periodic Progress Report 9-10 (Sept. 2014).

[47] 76 Fed. Reg. at 58,630 (explaining that EPA "d[id] not agree with the State's conclusion that no additional NOx controls are reasonable for this planning period" for Coyote); 77 Fed. Reg. at 20,899 (reaffirming EPA's "disagree[ment] with some of North Dakota's legal conclusions about the necessity of reasonable progress controls for certain sources—specifically, for Coyote Station for NOx").

[48] 76 Fed. Reg. at 58,630 (showing that with advanced separated overfire air, Coyote could reduce its annual emissions by approximately 5,223 tons over the 2000-2004 baseline; these more advanced controls would reduce Coyote's annual emissions by more than 1,000 tons per year over the reductions expected if Coyote merely installed overfire air); *id.* at 58,628 (explaining that "[f]or Coyote Sation, the State reached an agreement with the owner/operator to reduce NOx emissions by approximately 4,213 tons per year from the facility's 2000 to 2004 baseline").

[49] 76 Fed. Reg. at 58,626 (Table 67) (showing that SCR could reduce NOx emissions by between 10,446 and 11,752 tons per year over the baseline, a reduction of more than 6,000 to 7,000 tons per year over than the 4,213 annual emissions reduction expected with overfire air).

[50] 77 Fed. Reg. at 20,899.

[51] 76 Fed. Reg. at 58,630; *see also id.* at 58,628 (indicating that North Dakota estimated that under the rate of progress represented by its reasonable progress goals, it would attain natural visibility conditions in 156 years at Theodore Roosevelt National Park and 232 years at Lostwood National Wildlife Refuge Wilderness Area).

Now that North Dakota is revisiting reasonable progress in this 5-year progress report, North Dakota should revisit its conclusion that Coyote is adequately controlled under the 0.50 lb/mMBtu emission limit. As of the start of this reasonable haze planning period, North Dakota was not on track to achieve reasonable progress.[52] Nothing in the progress report suggests that North Dakota is now on track. Reducing NOx emissions from Coyote would help the state get on track to attaining reasonable progress, as the National Parks Service explained in its comments on this progress report.[53] Indeed, of all of the reasonable progress sources in North Dakota, Coyote has the greatest potential to impact visibility at North Dakota's Class I areas.[54] And, as North Dakota previously acknowledged, "[o]nce reductions are achieved from the BART sources, the Coyote Station will be the largest point source of NOx emissions in North Dakota."[55] For all of these reasons, North Dakota should require Coyote to meet more stringent emissions limits consistent with SCR in the next SIP revision. Contrary to North Dakota's assertion, SCR is feasible on units burning North Dakota lignite,[56] for all of the reasons explained in the prior section.[57] Thus, North Dakota must seize the opportunity to require additional emissions reductions to improve visibility at its national parks and wilderness areas.

Thank you for the opportunity to comment on North Dakota's Progress Report.

Sincerely,

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[52] 76 Fed. Reg. at 58,628.

[53] United States Department of Interior, National Park Service, Comment on North Dakota's Draft Regional Haze Periodic Progress Report, dated August 26, 2014, at 4 ("We also note that the 0.50 lb/mmBtu NOx 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 NOx emissions from these EGUs may partially mitigate the NOx increases from the oil & gas sector.").

[54] 76 Fed. Reg. at 58,624-25 (Table 64) (showing that Coyote has the greatest ratio of emissions relative to distance to a Class I area (the Q/d ratio) and thus the greatest potential to impact visibility at North Dakota's Class I areas of all of the reasonable progress sources).

[55] North Dakota SIP for Regional Haze, Amendment No. 1 § 10.6.1.2, Doc. No. EPA-R08-OAR-2010-0406-0026.

[56] *See* Response to FLM Comments on Periodic Progress Report at 3 (asserting that SCR controls are not feasible at Coyote in response to the Federal Land Managers comment that more must be done to reduce emissions from Coyote in the 2018 SIP)

[57] *See* pages 17-18, *supra*.

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

June 17, 2013

Submitted via regulations.gov

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Environmental Protection Agency Region 8
Mailcode 8P–AR
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Denver, CO
80202–1129

Re: Docket No. EPA-R08-OAR-2010-0406
Proposed BART Determinations for Milton R. Young and Leland Olds Stations

On behalf of the National Parks Conservation Association ("NPCA") and Sierra Club, we submit these comments on the United States Environmental Protection Agency's ("EPA") reconsideration of the Best Available Retrofit Technology ("BART") limits with respect to nitrogen oxides ("NOx") for Milton R. Young ("MRYS") and Leland Olds ("LOS") Stations, 78 Fed. Reg. 16,452 (Mar. 15, 2013). On September 11, 2011, EPA issued a well-supported proposal to issue a federal implementation plan ("FIP") setting a NOx BART limit for MRYS Units 1 and 2 and LOS Unit 2 of 0.07 lb/MMBtu, achievable through the operation of selective catalytic reduction ("SCR") plus advanced separated overfire air ("ASOFA"). 76 Fed. Reg. 58,570 (Sept. 21, 2011). However, in its final rule EPA reversed course and approved the State of North Dakota's BART determinations based on less effective selective non-catalytic reduction ("SNCR") technology. 77 Fed. Reg. 20,894 (Apr. 6, 2012). These emission limits, which EPA is now re-proposing, are nearly three times higher than the limits that MRYS and LOS could meet with SCR. EPA has not provided any reasoned justification for failing to impose BART limits based on the best available controls, which are technically feasible and cost-effective in the Agency's own estimation.

In its proposal, EPA briefly references the district court decision in *United States v. Minnkota Power Cooperative, Inc.* ("*Minnkota Power*"), and the BART Guidelines to justify its approval of North Dakota's BART determinations. However, this quasi-legal rationale for abandoning the Agency's original FIP proposal is invalid. Because the existing record and additional evidence (discussed below) confirm that SCR is BART, EPA must reject the State's BART determinations and finalize a FIP that imposes BART limits based on this best available control, as required by the Clean Air Act.

In support of these comments, we are also submitting a more detailed technical analysis prepared by Bill Powers, P.E (the "Powers Report").

I. THERE IS NO LEGITIMATE LEGAL BASIS FOR APPROVING THE STATE'S LAX BART LIMITS

In September 2011, EPA examined the five statutory factors and concluded that SCR is BART for Milton R. Young and Leland Olds. Nothing in the *Minnkota Power* decision or the BART Guidelines justifies EPA's departure from that well-supported conclusion. As EPA properly concluded, it is not bound to follow the decision in *Minnkota Power*. 78 Fed. Reg. at 16,455. Moreover, the opinion in *Minnkota Power* cannot substitute for a reasoned decision on BART by EPA. That case, which reviewed the State's determination of best available control technology ("BACT") under a deferential standard of review, did not resolve the question of what technology constitutes BART based on EPA's expert review of the record in this rulemaking. Similarly, the BACT determination at issue in *Minnkota Power* cannot substitute for a valid BART determination under the BART Guidelines where, as here, EPA is aware that BACT was not based on the best available controls to reduce emissions and address visibility impairment in Class I Areas. Finally, the district court's decision in *Minnkota Power* addressed only MRYS, and its reasoning does not apply to LOS, which burns a different coal mix than MRYS. For this reason as well, EPA could not rely on the BACT limit upheld in *Minnkota Power* to determine BART for LOS.

A. *Minnkota Power* Does Not Require EPA to Approve North Dakota's BACT Limit as BART for MRYS and LOS

EPA properly acknowledges that the decision in *Minnkota Power* does not require the Agency to adopt the State's BACT determination for MRYS as BART. *See* 78 Fed. Reg. at 16,455 ("[W]e do not view the U.S. District Court's decision regarding technical infeasibility as legally binding concerning our evaluation of the State's BART determinations at MRYS Units 1 and 2 and LOS Unit 2 . . . ."). The district court's decision has no preclusive effect for all of the reasons cited in NPCA and Sierra Club's briefs before the Eighth Circuit in the consolidated cases challenging the April 6, 2012 North Dakota regional haze rule.[1] In that litigation, and in letters opposing NPCA and Sierra Club's petition to the Agency to reconsider the NOx BART determinations for MRYS and LOS, the State of North Dakota, Minnkota Power Cooperative, Inc., Square Butte Cooperative, and Basin Electric Cooperative have argued that some form of collateral estoppel prevents EPA from undertaking its own feasibility analysis and determining NOx BART for MRYS and LOS. However, collateral estoppel is a litigation doctrine that exists to protect parties from relitigating an issue that has been actually decided by a prior court. Collateral estoppel does not apply here where the Agency is tasked with deciding an issue that has never been litigated, namely the appropriate NOx BART controls to be identified as BART for MRYS and LOS. EPA's view on this question—not the district court's—must govern, especially in view of the different evidence before EPA here.

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[1] NPCA and Sierra Club's briefs, along with other documents supporting these comments, were submitted to the Agency on a flash drive sent via Federal Express on Friday, June 14, 2013. Additional supporting documents will be uploaded to regulations.gov concurrently with these comments. An index attached to these comments explains which supporting documents were provided.

1. *EPA's BART Determination is Entitled to Deference and Evaluated Under a Different Standard of Review than that Applicable to the District Court in* Minnkota Power

EPA is not bound by the *Minnkota Power* decision given EPA's authority when making BART determinations under a FIP, [2] or ensuring that a State's submission complies with the Clean Air Act, and the deference given to those decisions. While the definition of technical feasibility is substantially the same for the BACT and BART programs, the legal standard that governed the district court's review of the North Dakota's BACT decision is not the same legal standard that applies to review of EPA's decision in promulgating a FIP or reviewing the adequacy of a state haze plan, such that the district court decision cannot govern here. [3]

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[2] It is worth noting that EPA can issue a FIP in this case without making a determination on the adequacy of North Dakota's haze plan, as the State missed the 2007 deadline for submitting a regional haze SIP. States were required to submit to EPA their proposed regional haze plans by December 17, 2007. 40 C.F.R. § 51.308(b). After North Dakota failed to submit a plan to EPA by the deadline, EPA issued a formal notice that North Dakota did not submit the required plan. 74 Fed. Reg. 2,392 (Jan. 15, 2009). Once EPA issued this finding, the Clean Air Act required EPA to issue a FIP at any time, but no later than two years after EPA found that North Dakota missed the deadline for submitting a plan revision. 42 U.S.C. § 7410(c)(1). EPA must issue a FIP unless "the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan." *Id.* § 7410(c)(1)(B). EPA's authority to issue a FIP without first taking final action on North Dakota's SIP submission was expressly recognized by the Colorado district court that entered a consent decree settling claims that EPA had unreasonably delayed issuing regional haze plans for several states, including North Dakota. *WildEarth Guardians v. Jackson*, No. 11-CV-00001, 2011 WL 4485964, at *7 n.8 (D. Colo. Sept. 27, 2011) ("In the event that final action is not taken on North Dakota's RH SIP before the schedule calls for the promulgation of a final FIP (January 26, 2012), the Court notes that it appears the EPA would nonetheless be authorized to promulgate a regional haze FIP. . . . [T]he EPA has not issued a final rulemaking approving North Dakota's RH SIP; thus, the EPA's obligation to promulgate a FIP remains. Moreover, requiring the EPA to take final action on an untimely SIP could potentially further delay the promulgation of mandatory FIPs.").

[3] For collateral estoppel (also known as issue preclusion) to apply, the issue must be the same in the original and the subsequent proceeding. *Robinette v. Jones*, 476 F.3d 585, 589 (8th Cir. 2007) (quoting *Anderson v. Genuine Parts Co*., 128 F.3d 1267, 1273 (8th Cir. 1997)). Even if the legal definition of a term is the same in two proceedings—such as the definition of technical feasibility—the legal issue is different if the burden of proof or legal standard of review differs in the two proceedings. *In re Garner*, 881 F.2d 579, 580 n.1, 582 (8th Cir. 1989) (although the elements of fraud were the same under state and federal law, the state court decision was not binding in federal court because the burden of proof in the state proceeding was the preponderance of the evidence whereas the standard under federal law was clear and convincing evidence), *rev'd sub nom Grogan v. Garner*, 498 U.S. 279, 281-82 (1991) (finding that the Eighth Circuit misinterpreted the standard for proving fraud in federal court and therefore the same standard applied in both proceedings).

In *Minnkota Power*, a consent decree established the governing standard of review, which required the district court to decide whether North Dakota's technical feasibility decision was unreasonable, resolving all questions in favor of the State. *See United States v. Minnkota Power Coop., Inc.*, 831 F. Supp. 2d 1109, 1112 (D.N.D. 2011) ("There is no dispute that the EPA bears the burden of proof as the party disputing the NOx BACT Determination."). In contrast, in this rulemaking, EPA is entitled to deference, and if the State challenged EPA's rule, it would be the State's burden to demonstrate that EPA's determination is unreasonable. Section 110 of the Clean Air Act obligates EPA to ensure that state implementation plans ("SIPs") comply with all applicable requirements of the Act, 42 U.S.C. § 7410(k), and courts defer to EPA's judgment regarding consistency with the Act. *See Mich. DEQ v. Browner*, 230 F.3d 181, 185 (6th Cir. 2000) (EPA does not have to defer to a state unless the state submits a plan that complies with the Act); *Nat'l Steel Corp. v. Gorsuch*, 700 F.2d 314, 323 (6th Cir. 1983) (EPA does not rubberstamp SIP submissions and can rely on its own data and expertise to evaluate SIPs); *Conn. Fund for the Envt., Inc. v. EPA*, 696 F.2d 169, 173, 176, 178 (2d Cir. 1982) (EPA has considerable discretion in deciding whether to approve or disapprove a SIP revision); *Kennecott Copper Corp. v. Costle*, 572 F.2d 1349, 1354 (9th Cir. 1978) (EPA is not bound by a state's determination of technical feasibility because EPA decides whether a SIP complies with the Act); *see also Michigan v. Thomas*, 805 F.2d 176, 184 (6th Cir. 1986) (upholding EPA's disapproval of a SIP revision and holding that EPA can update technology-based decisions based on new information).

In short, under the consent decree that applied in *Minnkota Power,* North Dakota was entitled to determine BACT so long as its determination was reasoned, but, here, EPA is obliged to use its technical expertise to ensure that BART limits are consistent with the Clean Air Act, and its decision in that regard is entitled to deference. This fundamental difference in the applicable standard of review means that the *Minnkota Power* decision does not have any preclusive effect on EPA, and EPA is not constrained to approve North Dakota's BACT determination as BART.

2. *EPA's BART Determination Is Based on a Different Record than the Record Before the District Court in* Minnkota Power

Further, EPA is not constrained by the district court decision given the different evidence of feasibility before EPA in this proceeding. The district court in *Minnkota Power* could not—and did not purport to—resolve for all time evolving factual questions related to the technical feasibility of air pollution controls. Importantly, the district court did not consider key evidence of technical feasibility that is before EPA in this proceeding. During the nearly 3 years that have elapsed since North Dakota's BACT decision in 2010, advancements in pollution control technologies have been made and new evidence of their feasibility is available. In particular, Johnson Matthey Catalysts ("JMC") has reiterated that it would offer a performance guarantee for SCR catalysts on units burning North Dakota lignite; the Electric Power Research Institute funded modeling that indicates tail-end SCR will work on units burning North Dakota lignite; and three units that burn Texas lignite, which is substantially similar to North Dakota lignite, have successfully installed and operated SCR systems. This new evidence is now before EPA on reconsideration, *see infra* Section II.A-B, and was not presented to the district court in *Minnkota Power.* For this reason too, the decision on BACT in *Minnkota Power* cannot bind

EPA in determining BART for MRYS and LOS, as the Agency has correctly recognized. 78 Fed. Reg. at 16,455.

B. EPA Cannot Rely on *Minnkota Power* to Determine BART

Given that *Minnkota Power* does not constrain EPA to adopt North Dakota's BACT determination as BART, it does not justify EPA's otherwise unexplained decision to do just that. EPA cannot offer a citation to *Minnkota Power* to dispense with its obligation to ensure compliance with the Clean Air Act's regional haze provisions. Fundamentally, on technical questions such as the feasibility of installing SCR to control NOx emissions from lignite-burning boilers, EPA must exercise its technical expertise in reviewing the State's determination, even if that leads EPA to conclude that a state's SIP does not comply with the Act. 42 U.S.C. § 7410(k); *Nat'l Steel*, 700 F.2d at 323. EPA's technical assessment, as set forth in its proposed rule, is that SCR is feasible at MRYS and LOS, and EPA has never suggested that this technical assessment is wrong. Nor could it reasonably do so in light of the existing record and additional evidence affirming SCR's technical feasibility. *See* Section I.A.2 above and Sections II.A and II.B below.

The district court's opinion in *Minnkota Power* simply does not justify EPA's decision to abandon its proposed FIP. The district court never addressed the key reasons why EPA originally concluded that SCR was feasible. Specifically, the district court opinion makes no mention of EPA's analysis, supported by the Microbeam report[4] and other evidence,[5] that low-dust and tail-end SCR would be feasible at MRYS and LOS. Similarly, the district court never addressed the point that placing an SCR after the ESP as in the low-dust configuration, or after both the ESP and the scrubber as in the tail-end configuration, would sufficiently remove catalyst poisons to avoid interfering with the operation of SCR catalysts. *See, e.g., Minnkota Power*, 831 F. Supp. 2d at 1121-27.

The BART Guidelines provide that "you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology has been applied previously." 70 Fed. Reg. 39,104, 39,165 (July 6, 2005), codified at 40 C.F.R. pt. 51, app. Y § (IV)(D)(2). Thus, the BART Guidelines focus the feasibility inquiry on the gas stream that leaves the boiler and enters the SCR—not on potential flue gas characteristics based on constituents of the fuel before it is fed into the boiler. The *Minnkota Power* decision never considers the characteristics of the flue gas stream after it has passed through other pollution control devices but before it would enter a low-dust or tail-end SCR. *Minnkota Power*, 831 F. Supp. 2d at 1109, 1121-27. Once those pollution control devices are accounted for, the flue gas streams at MRYS and LOS compare favorably to the flue gas streams at other units that successfully use SCR. Powers Report at 15-17. The Microbeam testing affirmatively demonstrated that upstream pollution control devices in use at MRYS removed catalyst poisons

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[4] Microbeam Technologies, Inc., Final Report: Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD (July 1, 2009), Doc. No. EPA-R08-OAR-2010-0406-0013 at 160 [hereinafter, Microbeam Report].

[5] *See, e.g.,* 76 Fed. Reg. 58,604-05 (Sept. 21, 2011).

from the flue gas before they could enter the SCR and interfere with the SCR catalyst.[6] Because the district court never addressed this evidence, EPA cannot rely on *Minnkota Power* to supply a valid justification for reversing the well-reasoned technical conclusions in its proposed rule.

Further, as discussed above, the district court did not have before it key evidence of SCR's technical feasibility that is now before EPA on reconsideration. Of particular importance is JMC's commitment to provide a catalyst vendor guarantee.[7] The district court relied heavily on the absence of vendor guarantees in upholding the State's determination of technical infeasibility. *See, e.g., Minnokota Power*, 831 F. Supp. 2d at 1123-1125, 1129. New record evidence that a vendor guarantee is in fact available makes it impossible for EPA to rely on the district court's reasoning.

Given that the district court reviewed a different factual record that did not include evidence that is now before EPA, and given that technical feasibility is inherently an evolving issue, EPA cannot fairly rely on the *Minnkota Power* decision to affirm the State's BART determinations. As EPA's own BART Guidelines make clear, technical feasibility changes over time as technologies evolve. 40 C.F.R. pt. 51, app. Y § (IV)(C).[8] Even if the BACT determination affirmed by the district court was based on best available technology that was feasible in 2010—which it was not—it does not reflect the best available technology that is feasible now.

C. The BART Guidelines Do Not Justify Approval of the State's BART Determinations

The BART Guidelines do not justify approval of North Dakota's BART determinations any more that the *Minnkota Power* decision. EPA's BART Guidelines do not permit the Agency to rely on a BACT decision where, as here, EPA's review of the evidence indicates that more stringent control technologies than BACT are available. Moreover, the BART Guidelines do not allow EPA to adopt BACT limits that are higher than presumptive BART limits unless the Agency can demonstrate that presumptive BART limits are unachievable—a demonstration that EPA cannot make with respect to MRYS and LOS. Thus, far from supporting EPA's adoption of the State's BACT limit as BART, the BART Guidelines require the Agency to finalize a FIP imposing BART limits based on SCR. *Contra* 78 Fed. Reg. at 16,454-55.

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[6] *See* Microbeam Report, *supra* note 4; 76 Fed. Reg. at 58,605; *see also* Dr. Ranajit (Ron) Sahu, Focused Comments on Proposed NOx BART Limits for Selected North Dakota Coal-Fired Power Plant Units by EPA, at 12-18 (Nov. 2011), Attachment 3 to Doc. No. EPA-R08-OAR-2010-0406-0213 [hereinafter, Sahu, Focused Comments].

[7] *See* Letter from Ken Jeffers, Senior Applications Engineer, Johnson Matthey Catalysts (JMC), to Callie Videtich, EPA (Feb. 27, 2012), Doc. No. EPA-R08-OAR-2010-0406-0322 [hereinafter, JMC Letter].

[8] For example, EPA explains that since the issuance of new source performance standards in the 1980s, new control technologies have been developed, so that "EPA no longer concludes that the NSPS level of controls automatically represent 'the best these sources can install.'" 40 C.F.R. § (IV)(D)(2) n.13.

1. *The BART Guidelines Allow Only a Recent BACT Decision Based on Best Controls to Substitute for a BART Determination*

North Dakota's BACT limit for MRYS is not a BACT limit that can substitute for required BART limits. In certain circumstances, the BART Guidelines allow EPA and state permitting agencies to rely on up-to-date technology-based limits that have been developed to meet other requirements of the Clean Air Act (*i.e.*, maximum available control technology ("MACT") limits or BACT limits) instead of conducting the usual five-factor BART analysis. *See* 40 C.F.R. pt. 51, App. Y § (IV)(C). However, the BART Guidelines do not automatically authorize reliance on a BACT limit. Where there is any indication that the BACT limit is outdated or does not reflect the best available controls, it cannot substitute for BART. Thus, the BART Guidelines state that "for *many* NSR/PSD and NSR/PSD determinations and settlement agreements," the resulting control can substitute for BART so long as there are no more cost-effective controls that would be considered the "best control." *Id.* (emphasis added); *see also id.* § (IV)(D)(1.9) (permitting an agency to skip the BART analysis only if the "source has controls already in place which are the most stringent controls available" or "if a source commits to a BART determination that consists of the most stringent controls available").[9]

Here, relying on the SNCR BACT limit to determine BART is impermissible because EPA is aware that SNCR is not the best available control. EPA has never disavowed its conclusion in the proposed rule that SCR is feasible at MRYS and LOS. *See* 76 Fed. Reg. at 58,604-05, 58,610, 58,613. Moreover, it is uncontested that SCR has the highest control efficiency of all control options. *See, e.g.*, *id.* at 58,606. Thus, SCR is indisputably the best, most stringent control, and EPA cannot settle for less under the Clean Air Act or the implementing BART Guidelines.[10]

To rely on SNCR BACT in this case would also ignore the BART-specific requirement to address visibility impairment. In determining BART, EPA, "must" consider the degree of visibility improvement that may reasonably be anticipated from the use of BART. 42 U.S.C. § 7491(g)(2). BACT, on the other hand, does not require any consideration of visibility. 42 U.S.C. § 7479(3). Given the different purposes that BACT and BART respectively are designed to serve, a BACT limit can stand in for BART only where the BACT limit is based on the most stringent available control, which necessarily will be the most effective control to reduce visibility impairing pollution. This BACT decision, which is not based on selection of the most stringent control, does not guarantee a passable level of visibility improvement or even reflect consideration of visibility improvement. For this reason too, this BACT decision is not an appropriate BART substitute under the BART Guidelines.

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[9] Outdated decisions, such as an NSPS that no longer reflects the most stringent control technologies available, cannot substitute for BART. *See* note 8, *supra*.

[10] These comments refer to SCR as providing the best controls as shorthand. As EPA proposed in its September 21, 2011 rulemaking, SCR in combination with advanced separated overfire air are the best performing combination of controls to reduce NOx emissions from MRYS and LOS. *See* 76 Fed. Reg. at 58,609, 58,612, 58,618.

2. The District Court BACT Decision Impermissibly Ignores the Presumptive BART Floor Contained in the BART Guidelines

Further, EPA cannot summarily substitute BACT for BART when the relevant BACT limit is higher than the presumptive BART floor.[11] In approving the SNCR BACT limit, EPA authorized MRYS and LOS to operate at levels that are higher than the presumptive best emission limits (the presumptive BART limits), in contravention of the requirement that the units must meet *best available* emission limits. The Guidelines provide that "presumptive BART" for *all* lignite-fired cyclone boilers is a NOx emission limit of 0.10 lb/MMBtu, based on SCR. 40 C.F.R. pt. 51, App. Y § (IV)(E)(5). EPA based this determination on a technical analysis that expressly included MRYS and LOS.[12] Notwithstanding this presumptive BART limit, EPA approved NOx BART limits of 0.35 lb/MMBtu for MRYS Unit 2 and LOS Unit 2 and 0.36 lb/MMBtu for MRYS Unit 1—limits that are over *three times* higher than the level considered feasible and cost effective for all boilers, including the North Dakota lignite-fired boiler at MRYS and LOS. The record is silent on why lax BACT limits were adopted as BART when there is a much lower presumptive BART limit prescribed in the BART Guidelines that examined these specific facilities and their allegedly unique coal.

Under the BART Guidelines, an alternative control level to the presumptive floor can only be selected based on "a careful consideration of the statutory factors." 40 C.F.R. pt. 51, app. Y § (IV)(E)(5). EPA has not provided any analysis—much less a careful consideration of the statutory factors—that justifies its failure to impose BART limits that are consistent with the presumptive BART limits. Just the opposite; when EPA analyzed the statutory factors it concluded that limits based on SCR, not SNCR, were BART. 76 Fed. Reg. at 58,604-19, 58,643.

D. The BACT Limit for MRYS Does Not Apply to LOS

Putting aside the question whether EPA could properly adopt the BACT determination as BART for MRYS—which it could not for all the reasons set forth above—the Agency has not put forward any credible explanation why the BACT limit for MRYS can establish BART for

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[11] The BART Guidelines apply to MRYS when considering the actual operation of Units 1 and 2. As EPA noted in its original proposed rule, the sum of permitted operating capacity results in a total generating capacity of at least 794 MW, which is above the 750 MW capacity threshold established by the Clean Air Act, 42 U.S.C. § 7491(b)(2), and the Regional Haze Rule, 40 C.F.R. § 51.308(e)(ii)(B). 76 Fed. Reg. at 58,596. Although LOS's total generating capacity is below the 750 MW limit, North Dakota's regional haze regulations—N.D. Admin. Code 33-15-25-03—require that facility owners or operators for whom the Guidelines are not mandatory "shall use appendix y [EPA's BART Guidelines] as guidance for preparing their best available retrofit technology determinations." *Id.* (citing N.D. Admin. Code 33-15-25). Thus, EPA's decision regarding BART for these units must be consistent with the BART Guidelines.

[12] *See* EPA, Technical Support Document: Methodology for Developing BART NOX Presumptive Limits (June 15, 2005), Doc. No. EPA-R08-OAR-2010-0406-0092; Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet (June 15, 2005), Doc. No. EPA-HQ-OAR-2002-0076-0446.

LOS. As EPA is aware, the BACT litigation in *Minnkota Power* involved MRYS only. *See Minnkota*, 831 F. Supp. 2d at 1112. Nevertheless, EPA contends that the BACT decision is applicable to LOS because "it is the same type of boiler burning North Dakota lignite coal, and North Dakota's views regarding technical infeasibility that the U.S. district court upheld in the MRYS BACT case apply to it as well." 78 Fed. Reg. at 16,455.

As set forth in detail in the attached Powers Report, EPA cannot rely upon the BACT determination for MRYS to determine BART for LOS given critical differences between the two facilities. *See* Powers Report Section III.A. LOS burns a different coal mix than MRYS, and the flue gas at LOS is accordingly different from the flue gas at MRYS.[13] More specifically, MRYS Units 1 and 2 burn 100% North Dakota lignite from the Center Mine.[14] In contrast, LOS Unit 2 burns a combination of North Dakota lignite and Powder River Basin ("PRB") coal to control the maximum as-fired sulfur, ash, and sodium content. [15] At any given time, Powder River Basin coal may comprise as much as 50% of coal burned at LOS.[16] Between 2008 and 2011, approximately 15 to 20% of the total heat input for LOS Unit 2 came from Powder River Basin coal.[17] Moreover, even the lignite burned at LOS has less of the constituents that poison catalysts than the lignite burned at MRYS.[18]

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[13] For a traditional SCR placed before the ESP and scrubber, potential catalyst poisons in the flue gas reaching the SCR inlet would not have been removed by the ESP and scrubber. Therefore, for a traditional SCR, different coal mixes would lead to significantly different flue gas streams.

[14] Dennis L. Arfmann et al., Appropriateness of Conducting Pilot Scale Testing of Selective Catalytic Reduction (SCR) Technology at Milton R. Young Station Units 1 and 2, for Use in a NOx BACT Analysis at 7 (Aug. 14, 2007), Doc. No. EPA-R08-OAR-2010-0406-0012 at 57; *see also* N.D. Dep't of Health, North Dakota State Implementation Plan for Regional Haze at 74 (Feb. 24, 2010), Doc. No. EPA-R08-OAR-2010-0406-0002.

[15] Gerry C. Snow & Gary S. Anderson, Fuel Tech's NOx Reduction and Fuel Chem Performance Improvements for Coal-Fired Steam Generators at 17, Presentation at Scientech Symposium 2012, Clearwater Beach, FL, *available at* http://famos.scientech.us/PDFs/2012_Symposium/Fuel_Tech_NOx_Reduction_Improvements.pdf; Burns & McDonnell, BART Determination Study for LOS Station Unit 1 and 2 at 5, Table 1.2-2 (Aug. 2006); *see also* N.D. Dep't of Health, North Dakota State Implementation Plan for Regional Haze at 73 (Feb. 24, 2010), Doc. No. EPA-R08-OAR-2010-0406-0002.

[16] Les Allery et al., Demonstrated Performance Improvements on Large Lignite-Fired Boiler with Targeted In-Furnace Injection Technology at 7, Presented at COAL-GEN 2010, Aug. 10-12, 2010, Pittsburg, PA, *available at* http://www.ftek.com/media/en-US/pdfs/TPP-592.pdf.

[17] United States Energy Information Administration, Annual Electric Utility Data, EIA-906/920/923 Data File, *available at* http://www.eia.gov/electricity/data/eia923/.

[18] *See* Allery et al., *supra* note 16, at 3, Table 1 (indicating the quality of the coal burned at LOS); N.D. Dep't of Health, Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2 at 18, Table 1 (June 2008) [hereinafter, Preliminary BACT Determination] (indicating the quality of coal burned at MRYS).

North Dakota's BACT decision, and the district court opinion affirming that decision, concluded that SCR is not technically feasible at MRYS because of high amounts of sodium and potassium oxides in the coal ash at MRYS. *See, e.g., Minnkota*, 831 F. Supp. 2d at 1115-16, 1122, 1125, 1126. The following table shows that LOS burns lignite and PRB coals with less sodium and potassium oxides than are present in the coal burned at MRYS.

Table 1: Chemicals Present in Coals Burned at MRYS and LOS

Coal	**Sodium oxide percentage in ash**	**Potassium oxide percentage in ash**
Lignite at MRYS, Units 1 and 2[19]	5.6	1.0
Lignite at LOS Unit 2[20]	2.94	0.73
PRB burned at LOS Unit 2[21]	1.65	0.28

Moreover, LOS Unit 2 is capable of burning up to 100% PRB coal.[22] SCR has been successfully installed at several cyclone boilers burning PRB coal[23] as well as mixtures of PRB and bituminous coals.[24] The district court decision affirming North Dakota's determination that SCR was not feasible at MRYS was premised on MRYS burning North Dakota lignite. That premise does not hold true for LOS, which routinely burns PRB coal. In short, EPA cannot assume that the district court's technical feasibility analysis for MRYS is equally applicable to LOS. Instead, EPA must conduct a separate BART analysis for LOS.

II. SCR IS TECHNICALLY FEASIBLE AND IS BART

EPA's 2011 proposed FIP properly concluded that SCR is technically feasible and is BART for MRYS and LOS. The evidence that was available in 2011 and 2012, when EPA approved the State's BART determination, as well as new evidence, confirms that EPA's initial

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[19] Preliminary BACT Determination, *supra* note 18 at 18, Table 1.

[20] *See* Allery, *supra* note 16, at 3, Table 1.

[21] *Id.*

[22] Burns & McDonnell, Technical Feasibility Assessment of NOx Control Alternatives, Appendix A1 to BART Determination Study for Leland Olds Station Unit 1 and 2 at A1-1 (Aug. 2006), *available at* http://www.ndhealth.gov/AQ/RegionalHaze/Basin%20BART%20Appendicies.pdf.

[23] Scot Pritchard et al., Catalyst Design Experience for 640 MW Cyclone Boiler Fired with 100% PRB Fuel (1997), *available at* http://www.cormetech.com/brochures/NewMadridpaper.pdf; *see also* John Cochran, CERAM Environmental, Inc., Fuel Impacts on Design and Performance of SCR Catalysts, Presented at McIlvaine "Hot Topic Hour," June 30, 2011.

[24] National Park Service compilation of cyclone boilers equipped with SCR, *available at* http://www.fws.gov/refuges/AirQuality/docs/Comments/FCPP/Appx%20A.%20Control%20Effectiveness/SCR%20CAM%20data%20and%20discussions/cyclone%20boilers%20w%20SCR.xls

finding regarding SCR was correct. On reconsideration, EPA should finalize a FIP based on the BART analysis for MRYS and LOS that EPA conducted in September 2011.

The Clean Air Act requires a state or EPA to determine BART based on a consideration of five factors, including "any existing pollution control technology in use at the source." 42 U.S.C. § 7491(g)(2). EPA interprets the statute to require consideration of the controls that existed during the baseline period, which EPA regulations define as 2000-2004.[25] 40 C.F.R. § 51.308(d)(2)(i). In both the final North Dakota regional haze rule, and in litigation over the rule, EPA has taken the correct position that pollution controls installed after the baseline period do not affect BART determinations. 77 Fed. Reg. at 20,927 ("We evaluate potential control options based on baseline conditions, not ongoing revisions to a facility after the baseline period."); *id.* at 20,918 ("[W]e note that DryFining™ was not installed until after the baseline period and was installed voluntarily, not to meet any regulatory requirement. We are not required to revisit the baseline controls or reconsider cost estimates based on voluntarily installed controls. On the contrary, there are significant issues with such an approach; it would tend to reward sources that install lesser controls in advance of a BART determination in an effort to avoid more stringent controls."); EPA, Consolidated Brief of Respondents at 83, *North Dakota v. EPA*, No. 12-1844, consolidated with No. 12-1961, 12-2331 (8th Cir. filed Dec. 4, 2012) (the statutory phrase "existing pollution control technology in use at the source" means the technology in use at the time of the baseline).

Applying this statutory framework, the record evidence before EPA confirms that SCR is technically feasible, and consideration of each of the five factors leads to the conclusion that SCR is BART. As EPA previously found in September 2011, SCR is cost-effective, would significantly improve visibility, and has no adverse environmental impacts. The remaining two factors—remaining useful life of the source and the existing controls as of the baseline—also support selecting SCR. Accordingly, SCR is BART for MRYS Units 1 and 2 and LOS Unit 2.

A. Evidence Available at the Time of the Prior BART Determination Indicates That SCR Is Technically Feasible

The evidence available during the initial rulemaking in 2012 demonstrates that SCR is technically feasible and is BART.[26] Of the evidence available during the initial rulemaking, three documents in particular demonstrate that SCR is feasible.

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[25] We are aware that North Dakota's calculations used the 2001-2005 time period to calculation the baseline for MRYS Units 1 and 2, and that in its proposal, EPA did likewise, though it adjusted the baseline in other ways. 76 Fed. Reg. at 58,606, 58,610. We believe that North Dakota and EPA should have used the 2000-2004 time period. Nonetheless, the emissions and controls were similar in the 2001-2005 and 2000-2004 time period.

[26] The record is replete with information that would, and in fact did, lead EPA in its proposed rule to rationally conclude that SCR, the most effective NOx control currently available, is technically feasible on coal plants firing North Dakota lignite. For example, the record includes:
(1) A report by Microbeam Technologies, Inc. that assessed the flue gas characteristics at Milton R. Young. *See* Microbeam Report, *supra* note 4;
(2) Information from Argillon, now JMC, regarding the parameters required to maintain its

First, JMC, a catalyst vendor, offered performance guarantees for the use of an SCR catalyst at MRYS and LOS. In a February 27, 2012 letter to EPA, JMC stated:

> JMC believes that low-dust and tail-end SCR configurations applied to North Dakota lignite fired boilers would be technically feasible. Should other RFPs [requests for proposal] occur for specific North Dakota Lignite fired facilities, JMC would be willing to offer SCR catalyst designs with reasonable operating lifetime performance guarantees for service in a low-dust or tail-end SCR configuration.[27]

EPA did not consider this evidence at the time it approved North Dakota's determination that SNCR, not SCR, was BART, but must consider this evidence now. JMC's willingness to offer a performance guarantee directly contradicts the repeated assertions that no vendor would guarantee the use of an SCR catalyst at MRYS and LOS.

Second, another catalyst vendor, Alstom Power, indicated that both traditional and tail-end SCR would work on units burning North Dakota lignite. Alstom Power wrote that:

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guarantee. Argillon, List of Toxic Agents for SINOx Systems and Catalysts *in* N.D. Dep't of Health, North Dakota State Implementation Plan for Regional Haze Part 12 of 19, Doc. No. EPA-R08-OAR-2010-0406-0013 at 314;
(3) Dr. Ranajit (Ron) Sahu's Comments, which explains the feasibility of different forms of SCR. *See* Sahu, Focused Comments, *supra* note 6;
(4) EPA Region 8's July 31, 2008 Comments on North Dakota's Preliminary NOx BACT Determination for Milton R. Young Station, including as Enclosure 1 a report by Hans Hartenstein on the Feasibility of SCR Technology for NOx Control Technology for the Milton R. Young Station. Attachment 4 to Doc. No. EPA-R08-OAR-2010-0406-0046;
(5) EPA Region 8's October 17, 2008 Response to Minnkota Power Cooperative, Inc.'s Comments on Preliminary NOx BACT Determination for Milton R. Young Station, including a as an Enclosure Remarks by Han Hartenstein. Doc. No. EPA-R08-OAR-2010-0406-0047;
(6) Dr. Phyllis Fox's Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report, which explains how to avoid catalyst deactivation. App. C to Technical Support for EPA's Proposed Rule, Doc. No. EPA-R08-OAR-2010-0406-0076; and
(7) A White Paper prepared by the Institute of Clean Air Companies ("ICAC"), NOx Control Technical Division, which includes a discussion of the feasibility of SCR on units burning a variety of lignite coals. ICAC, White Paper: Selective Catalytic Reduction (SCR) Control of NOx Emissions from Fossil Fuel-Fired Electric Power Plants at 8 (May 2009), Doc. No. EPA-R08-OAR-2010-0406-0050.

These documents, as well as other documents supporting EPA's decision, have been provided to EPA in connection with these comments and the supporting Powers Report. *See, e.g.*, *supra* note 1.

[27] JMC Letter, *supra* note 7.

> ND Lignite does create many challenges for SCRs, but even with all of those challenges, it is possible to use ND Lignite if the system is designed properly and Minnkota Power elects to pay for the increased capital and O&M costs associated with this fuel. . . . Fuels high in sodium and potassium require special selection of catalyst, but can be treated by SCR. An example of such an application would be wood and other biofuel fired boilers in Europe. While SCR catalyst life in ND lignite service is not expected to be as long as in bituminous coal service, it is expected that acceptable emissions control and maintenance requirements can be achieved. Based on experience with wood fired units, a hot side (600-750 deg F) ESP is effective in removing the fly ash compounds that result in catalyst poisoning. . . . While likely more expensive, an alternative solution to the conventional SCR, is a Tail End SCR where the SCR is located just before the stack . . . the fly ash constituents that can poison the catalyst will have been removed from the flue gas stream by the existing ESPs. . . . Designed properly, the SCR should be capable of up to 90% removal efficiencies with an associated ammonia slip below 2 ppm.[28]

In response to further information from Burns & McDonnell requesting that Alstom revisit its initial response, Alstom reiterated that a tail-end SCR would be feasible.[29]

Third, while there has been much speculation about the flue gas stream at units burning North Dakota lignite, the only study to measure the actual gas stream at MRYS or LOS demonstrated that the gas stream is compatible with the use of an SCR, particularly low-dust or tail-end SCR. In March 2009, Microbeam measured the composition of the flue gas at MRYS Unit 2.[30] The Microbeam Report found that the gas stream after the control devices contained between 2000-3000ug/m^3 of sodium and potassium.[31] These values are well within the parameters at which vendors have offered guarantees for an SCR catalyst.[32]

Moreover, the actual concentrations of alkali metals at the location of an SCR would likely be below the values reported by Microbeam. At the time of the Microbeam study on MRYS Unit 2, the unit was operating an old scrubber. MRYS Unit 2 is required to upgrade its existing wet scrubber, and MRYS Unit 1 and LOS Unit 2 are required to install new scrubbers (although MRYS Unit 1 already installed a new wet scrubber as a result of the BACT consent

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[28] Letter from Michael G. Phillips, Business Applications Manager, Alstom, to Robert Blakely, Burns and McDonnell, (May 30, 2007), Attachment 18 to Doc. No. EPA-R08-OAR-2010-0406-0295 at 30-32.

[29] Letter from Michael G. Phillips, Business Sales Manager, Alstom, to Robert Blakely, Burns and McDonnell (May 5, 2008), Attachment 18 to Doc. No. EPA-R08-OAR-2010-0406-0295 at 35-36.

[30] *See* Microbeam Report, *supra* note 4, at ES-2.

[31] This appears to be true even when calcium values are also included. *See* Powers Report at 17.

[32] *See* Powers Report at 16-17; *see also* Sahu, Focused Comments, *supra* note 6, at 13-14.

decree). 76 Fed. Reg. at 58,589, 58,591, 58,595; 77 Fed. Reg. at 20,897, 20,942. These upgraded or new scrubbers will likely remove more alkali metals than reported in the Microbeam study, which would ensure that the concentration of particulates is well within the parameters established by SCR catalyst vendors.[33]

In sum, only one study has actually measured the composition of the flue gas stream at the location where SCR would be installed. The Microbeam study confirms that values of potential catalyst poisons such as potassium and sodium oxides are well below the maximum levels at which vendors would guarantee the performance of an SCR catalyst. Indeed, JMC is willing to guarantee the performance of SCR catalysts and Alstom Power indicated that traditional or tail-end SCR would work. There is nothing in the record that contradicts this evidence.[34]

B. Newly Available Evidence Confirms that SCR Is Technically Feasible on Units Burning North Dakota Lignite

In addition to the evidence that was available at the time of the prior BART determination, newly available evidence confirms that SCR is technically feasible on units burning North Dakota lignite. In particular, both modeling and actual experience operating SCR on similar lignite units show that SCR would be feasible on units that burn North Dakota lignite.

1. SCR Has Been Successful on Similar Lignite Units

Three units in Texas that burn a type of lignite similar to North Dakota lignite have successfully installed and operated SCR systems. Oak Grove Unit 1, Oak Grove Unit 2, and Sandow Unit 4, all of which burn Texas lignite, have successfully operated SCRs since December 2009, May 2010, and April 2010, respectively.[35] Oak Grove Units 1 and 2 burn 100% Texas lignite and operate SCRs in the high-dust position to achieve an emissions limit of 0.08 lb/MMBtu.[36] Similarly, Sandow Unit 4 burns Texas lignite and operates an SCR to meet a limit of 0.08 lb/MMBtu.[37] JMC, the vendor supplying the catalyst to these three units, is the same

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[33] *See* Powers Report at 16-17.

[34] The district court in *Minnkota Power* did not consider the Microbeam study or the letters from JMC or Alstom Power. EPA cannot ignore this evidence that SCR is feasible in reliance on *Minnkota Power*.

[35] *See* Tex. Comm'n on Envtl. Quality, Permit Numbers 76474, PSD-TX-1056 (Feb. 5, 2010); Federal Operating Permit No. O54: Sandow Steam Electric Station (Mar. 12, 2010); *see also* Notice of Filing of Proposed Stipulation by the United States To Resolve Certain Alleged Violations of a Clean Air Act Consent Decree With Alcoa, Inc., 71 Fed. Reg. 67,640 (Nov. 22, 2006) (requiring "[a] commitment by TXU Sandow to install selective catalytic reduction system ("SCR") to eliminate most of the remaining NOX emissions from Sandow Unit 4").

[36] Tex. Comm'n on Envtl. Quality, Permit Numbers 76474, PSD-TX-1056 at 3-4 (Feb. 5, 2010); Construction Permit Review Analysis & Technical Review: Oak Grove Management Company LLC Permit No. 76474 at 1 (2006).

[37] Federal Operating Permit No. O54: Sandow Steam Electric Station at 10 (Mar. 12, 2010).

vendor that has offered a performance guarantee for the SCR catalyst at MRYS and LOS.[38] Texas lignite contains much higher ash content (12.6%) than North Dakota lignite (7.8%),[39] yet these three units have successfully operated SCR for over three years and have reduced NOx emissions well below the BACT limit for MRYS. *See* Powers Report at 24-25.

Under the BART Guidelines, a control is technically feasible if it is both available and applicable. 40 C.F.R. pt. 51, app. Y § (IV)(D)(2). SCR systems and the necessary catalyst to operate the system are commercially available, as demonstrated by JMC's willingness to guarantee the catalyst performance.[40] Indeed, SCR is in use at more than 250 electric generating units across the country, and has been optimized to work on a number of different types of coal.[41] SCR is also applicable because "it has been used on the same or a similar source type," 40 C.F.R. pt. 51, app. Y § (IV)(D)(2), and because it has been deployed at existing sources "with similar gas stream characteristics," namely the three units burning Texas lignite. *Id.* As SCR is both available and applicable, it is technically feasible.

2. *Recent Chemical Modeling Shows SCR Is Feasible on Units Burning Lignite Coals*

Recent modeling sponsored by the Electric Power Research Institute ("EPRI") predicts exactly what the experience of the three lignite-burning units in Texas has shown: SCR works on units burning lignite coals. EPRI is funding a study by Niska Energy Associates that uses chemical kinetic modeling to simulate the use of an SCR in the high-dust position on a unit burning North Dakota lignite, as well as other types of coal. Preliminary results from the study were presented recently at two conferences.[42] This study is explained in more detail in the attached Powers Report.

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[38] Hans Hartenstein, Feasibility of SCR Technology for NOx Control Technology for the Milton R. Young Station, Center, North Dakota at A-16 & n.30 (July 2008), Attachment 4 to Doc. No. EPA-R08-OAR-2010-0406-0046. JMC acquired Argillon in 2008. Argillon GmbH becomes Johnson Matthey and Lapp Insulators, http://www.argillon.com/.

[39] *See, e.g.,* Preliminary BACT Determination, *supra* note 18, at 18, Table 1.

[40] *See* JMC Letter, *supra* note 7.

[41] *See* EPA, Clean Air Markets Database, query coal-fired electric generating units with SCR, *available at* http://ampd.epa.gov/ampd/.

[42] Balaji Krishnakumar, Stephen Niksa &Alejandro Jimenez, Relating the Deactivation Potential of SCR Catalysts to Fuel Properties and Firing Conditions, Poster at Mega Symposium, Aug. 20-23, 2012, Baltimore, MD, *available at* http://www.mcilvainecompany.com/Universal_Power/Subscriber/PowerDescriptionLinks/Balaji%20Krishnakumar,%20Carbontxt%20-%208-23-12.pdf; Balaji Krishnakumar, Stephen Niksa & Alejandro Jimenez, Release and Transformation of Poisons Implicated in SCR Catalyst Deactivation, Remarks at Energy, Utility& Environment (EUEC) Conference, Jan. 28-30, 2013, Phoenix, AZ (information on proceedings available for purchase at http://www.euec.com/OrderEUECProceedings.aspx); *see also* Balaji Krishnakumar, remarks during McIlvaine Hot Topic Hour at 1:01:50 hrs (Aug. 23, 2012).

North Dakota expressed concern that the concentration of various chemicals, particularly calcium, potassium, and sodium, in North Dakota lignite would poison SCR catalysts. These chemicals undergo various reactions between the time the coal is burned and the flue gas would reach a high-dust (or tail-end) SCR system. Powers Report at 17-24. A certain percentage of each of these chemicals present in the coal is vaporized, then scavenged by aluminosilicates, and then sulfated. *Id.* The amount remaining as unsulfated, free oxides determines whether SCR can be successfully operated because the free oxides of calcium, sodium, and potassium can plug the catalyst pores and deactivate the catalyst. *Id.*

The compositions of the coals in this EPRI study are currently confidential. However, we were advised that the lignite sample is a "typical North Dakota lignite." The following table, adapted from the attached Powers Report, compares the concentration of free alkali oxides in the flue gases at the face of a SCR catalyst in the high dust position for a typical North Dakota lignite with a typical PRB coal. This comparison assumes typical compositions as reported in the MRYS BACT analysis for future lignites (worst case)[43] and the percentages from the above-described EPRI study, adjusted for different ash content and dust loading of the flue gas.[44]

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[43] Preliminary BACT Determination, *supra* note 18, at 18, Table 1.

[44] The dust loading of the flue gas from coal-fired cyclone units is in the range of 20% to 30% of the ash in the coal, compared with about 80% for a dry-ash pulverized coal-fired unit, simulated in the EPRI study. *See* Babcock & Wilcox, Steam: Its Generation and Use, at 10-6 (1978).

Table 2. Comparison of the Amount of Free Alkali Oxides in the Flue Gas Stream of a Lignite Unit and PRB Unit at the Inlet to a High Dust SCR[45]

Source Column	Composition A	Volatilized from Coal (% of ash emitted) Figure 1 B	Present as Aluminosilicates (% of total alkali vaporized) Figure 2 C	Remaining in Gas Phase (% of ash emitted) Note (1) D	Present as Sulfates (% of total alkali in gas phase) Figure 4 E	Present as Oxides (% of ash emitted, at catalyst) Note (2) F	Lignite Column F, Adjusted Based on Ash Content and % Emitted Note (3) G
Lignite							
Ash (% coal)	7.8						
Ash Emitted (%)	30.0						
Ca (% ash)	17.0	100	65	5.95	24	4.52	-
Na (% ash)	5.6	100	5	5.32	63	1.97	-
K (% ash)	1.0	65	37	0.41	100	0.00	-
PRB1							
Ash (% coal)	5.0						
Ash Emitted (%)	80.0						
Ca (% ash)	17.3	100	70	5.19	10	4.67	2.65
Na (% ash)	1.6	100	10	1.44	81	0.27	1.15
K (% ash)	0.5	100	18	0.41	100	0.00	0.00
TOTAL						**4.94**	**3.80**

(1) AxBx(1-C)/10,000
(2) Dx(1-E)
(3) Lignite column F x (Lignite ash/PRB ash)(Lignite Ash Emitted/PRB1 Ash Emitted)

The results indicate that 100% of the potassium in each example is sulfated, ensuring that it does not interfere with the SCR catalyst. Similarly, most of the sodium in the lignite unit is sulfated and not a threat to the SCR catalyst. Calcium oxides remain the biggest concern given the small percentage that is sulfated. However, unsulfated calcium oxides will not necessarily render the SCR inoperable. Unsulfated calcium oxides are present in greater concentrations in the flue gas from Powder River Basin coals, yet SCR has been successfully operated at several units burning PRB coal.[46] In short, the EPRI study confirms that the potential catalyst poisons present in North Dakota lignite will not prevent SCR from working at MRYS and LOS. All of the potassium and most of the sodium will be scavenged and sulfated before it reaches the SCR catalyst even in the high dust configuration. And calcium is present at levels below that the levels present in PRB coal, for which SCR systems have been successfully designed to handle calcium oxides.

The EPRI study confirms the results of the Microbeam study, which had indicated that concentrations of unsulfated, reactive calcium, sodium, and potassium oxides are below the concentrations that are known to interfere with an SCR catalyst.[47] The EPRI study shows that

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[45] The sources for the figures presented in this table appear in Table 2, on page 22, in the attached Powers Report.

[46] *See* notes 23 & 24, *supra*.

[47] *See* Microbeam Report, *supra* note 4, at ES-2; *see also* Sahu, Focused Comments, *supra* note 6, at 13-15.

the calcium, sodium, and potassium oxides are not a problem for SCR used with lignite fuel. Moreover, most of these constituents would be removed by the pollution controls—the ESPs and scrubbers—that are located prior to a low dust or tail end SCR. Thus, newly available evidence confirms what EPA has known all along: SCR is feasible at MRYS and LOS.

C. SCR is BART Based on Consideration of the Five Statutory Factors

Since SCR is technically feasible, it must be considered in the five-factor BART analysis. The BART Guidelines instruct agencies to begin with the presumptive BART emission limit, which is 0.10 lbs/MMBtu NOx for cyclone boilers burning lignite. 40 C.F.R. pt. 51, app. Y § (IV)(E)(5). An agency "may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors." *Id.* Careful consideration of the five factors indicates that EPA's original proposal is correct: BART for MRYS and LOS is SCR with a NOx emissions limit of 0.07 lbs/MMBtu.

The five statutory factors are the costs of compliance, the energy and non-air quality environmental impacts of a control, the existing pollution control technology used at the source, the remaining useful life of the source, and the anticipated visibility improvement from the control. 42 U.S.C. § 7491(g)(2). EPA previously found that SCR is cost-effective at MRYS and LOS. 76 Fed. Reg. at 58,609 (for MRYS Unit 1, SCR would cost $2,569 per ton and is cost-effective); *id.* at 58,612-13 (for MRYS Unit 2, SCR would cost $2,740 per ton and is cost-effective); *id.* at 58,619 (for LOS Unit 2, SCR would cost $1,833 per ton and is cost-effective). Further, EPA has previously found that non-air quality environmental impacts and remaining useful life did not favor selecting any particular technology and were therefore neutral factors. *Id.* at 58,609, 58,612, 58,618. The evidence regarding these two factors remains largely the same.[48]

Visibility improvement, the final factor, weighs heavily in favor of selecting SCR. EPA found visibility would improve by 3.476, 3.945, and 4.393 deciviews by installing SCR at MRYS Unit 1 and 2, and LOS Unit 2, respectively. 76 Fed. Reg. at 58,609, 58,612, 58,618. As these values represent the visibility improvement at only a single Class I area, Theodore Roosevelt National Park, they understate the total visibility improvement from installing SCR, since visibility would improve at other impacted Class I areas such as the Lostwood National Wildlife Refuge Wilderness Area in North Dakota. However, standing alone, the significant visibility improvement at Theodore Roosevelt is more than sufficient to support the conclusion that SCR is BART.

It is uncontested that SCR has the highest control efficiency, is cost-effective, and would improve visibility more than any other control options. Moreover, SCR has no significant non-air quality environmental impacts and the remaining useful life of the units does not weigh against selecting SCR. In sum, all five statutory factors point in the same direction: SCR is BART.

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[48] EPA's 2011 proposal does not mention that SNCR has greater environmental impacts than SCR because SNCR has higher rates of ammonia slip. *See* Powers Report at 9-12. Accordingly, this weighs in favor of selecting SCR.

III. THE BACT-BASED LIMITS ARE UNJUSTIFABLY WEAK

Even if it were proper to base BART on SNCR as opposed to SCR, EPA could not approve North Dakota's weak BACT limit as BART. In combination with SNCR, technologies currently in use at MRYS and LOS, namely CyClean and TIFI respectively, allow these units to achieve emission limits much lower than the BART emission limit previously approved by EPA. Moreover, additional NOx removal technologies can be used in combination with SNCR to achieve significant emissions reductions. If it were appropriate to set BART limits based on SNCR—which it is not—EPA would have to set more stringent limits based on a thorough consideration of what the most advanced SNCR systems can achieve in the way of emission reductions in combination with other controls.[49]

A. MRYS and LOS Can Achieve More Stringent Emission Limits

MRYS and LOS can currently achieve compliance with more stringent emission limits, which confirms that their BART limits are higher than they should be.

1. CyClean at Milton R. Young

In 2011, MRYS began using CyClean additives,[50] which are designed to improve cyclone boiler operations and reduce power plant emissions.[51] CyClean additives are applied to the coal before it enters the crusher to optimize combustion.[52] ADA-ES, the company that developed CyClean, claims that the system reduces NOx emissions by approximately 20%,[53] which is consistent with reports that MRYS has reduced NOx emissions by roughly 20% through the use of CyClean.[54]

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[49] As explained previously, EPA properly considers pollution controls that existed at the time of the 2000-2004 baseline in determining BART. As discussed above, a five-factor BART analysis using the 2000-2004 baseline (or the 2001-2005 baseline in the case of MRYS, *see supra* note 25) leads to selection of SCR as BART. But even if EPA were to consider pollution controls installed after the baseline in determining BART, EPA should conclude that SCR is BART and, in any case, the Agency would have to set more stringent limits than it is re-proposing.

[50] Minnkota Power Cooperative Demonstrates Lignite Innovation, Partners For Affordable Energy, http://powerofcoal.com/successstories/minnkota-power-cooperative-demonstrates-lignite-innovation/.

[51] *Id.*

[52] Refined Coal, ADA-ES, http://www.adaes.com/products-services/refined-coal/.

[53] *Id.*

[54] Minnkota Power Cooperative Demonstrates Lignite Innovation, Partners for Affordable Energy, http://powerofcoal.com/successstories/minnkota-power-cooperative-demonstrates-lignite-innovation/ ("At the Young Station, the additives have demonstrated the ability to reduce mercury emissions by 40 percent and NOx emissions by an additional 20 percent from previous levels.").

After using CyClean additives, emissions at MRYS Unit 1 were approximately 20% below the baseline emission rate of 0.84 lb/MMBtu, and the unit was achieving an emission rate of approximately 0.67 lb/MMBtu. EPA assumed that SNCR can reduce emissions by 58%. 76 Fed. Reg. at 58,598. At a removal rate of 58%, SNCR can reduce the emission rate of 0.67 lb/MMBtu by 0.39 lb/MMBtu, resulting in an emission rate of 0.28 lb/MMBtu. Performing the same calculations for MRYS Unit 2,[55] the emission limit should be no higher than 0.28 lb/MMBtu (on a 30-day rolling average), as opposed to the current limit of 0.36 lb/MMBtu.

EPA assumed that the combination of SNCR and ASOFA could reduce emissions by 58%, reducing assumed baseline emissions to the 30 day rolling average emission limits of 0.36 lb/MMBtu at Unit 1 and 0.35 lb/MMBtu at Unit 2. 76 Fed. Reg. at 58,598. Thus, in combination with the 20% CyClean reductions noted above, the appropriate 30 day rolling average emission limits for Units 1 and 2 should be no higher than 0.29 and 0.28 lb/MMBtu, respectively.[56] *See* Powers Report at 27-28.

2. TIFI at Leland Olds

In 2009, LOS Unit 2 installed Targeted in-Furnace Injection ("TIFI") to address boiler slagging and fouling.[57] The TIFI system involves mixing chemicals with a catalyst, air and water and injecting them into the furnace at targeted locations based on Computational Fluid Dynamics modeling.[58] Emissions data indicate that TIFI reduced NOx emissions from an annual average of 0.52 lb/MMBtu to approximately 0.31 lb/MMBtu by the end of 2012.[59] The emissions reductions from TIFI should be considered in the BART determination, since TIFI can achieve an additional 15-18% reduction in emissions beyond what SNCR alone can achieve. Applying the 15-18% emissions reduction from TIFI to the prior 30-day BART limit of 0.35

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[55] One can either apply the 20% emissions reductions from CyClean to the prior BART limit of 0.35 lb/MMBtu, or start from the baseline emissions of 0.79 lb/MMBtu, apply the 20% emissions reduction from CyClean, and then apply the 58% removal rate of SNCR. In both cases, the emissions limit should be no higher than 0.28 lb/MMBtu on a 30-day average.

[56] Unit 1 limit: 0.36 x (1-0.2) = 0.29

Unit 2 limit: 0.35 x (1-0.2) = 0.28

[57] Allery et al., *supra* note 16, at 12; Gerry C. Snow & Gary S. Anderson, Fuel Tech's NOx Reduction and Fuel Chem Performance Improvements for Coal-Fired Steam Generators at 17-19, Presentation at Scientech Symposium 2012, Clearwater Beach, FL, *available at* http://famos.scientech.us/PDFs/2012_Symposium/Fuel_Tech_NOx_Reduction_Improvements.pdf.

[58] Chris R. Smyrniotis & Kent W. Schulz, Recent Catalyst Development Results and the Observed Affects on NOx, CO, LOI, CO2, and Slag (July 2007), *available at* http://www.ftek.com/media/en-US/pdfs/TPP-578.pdf.

[59] *See* EPA, Clean Air Markets Database, queries for emissions and heat input data for Leland olds, *available at* http://ampd.epa.gov/ampd/QueryToolie.html.

lb/MMBtu (which reflects the use of SNCR andASOFA) yields a limit of 0.29-0.30 lb/MMBtu.[60] Accordingly, the emission limit for LOS Unit 2 should be no higher than 0.30 lb/MMBtu (on a 30-day rolling average). *See* Powers Report at 29.

B. Additional NOx Removal Systems Can Reduce Emissions Beyond the Reductions from SNCR Alone

If EPA had a valid basis for rejecting conventional SCR as BART, it would have to consider the emission reductions that SNCR can achieve in conjunction with other cost effective controls. *See* 40 C.F.R. pt. 51 App. Y, § (IV)(D)(1) ("Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant."); *id.* § pt. 51 App. Y, § (IV)(D)(3) (requiring consideration of "[c]ombinations of inherently lower-emitting processes and add-on controls"). For instance, PerNOxide could be integrated into the existing SNCR system at MRYS, also taking advantage of the plant's wet scrubbers to achieve NOx reductions greater than what the SNCR system can achieve by itself. In addition, hybrid or advanced SCR systems could be added after the SNCR, further reducing emissions beyond what SNCR alone can achieve.

1. PerNOxide

Use of PerNOxide would allow MRYS and LOS to achieve emissions limits lower than the previously approved BART limits. PerNOxide works by injecting hydrogen peroxide between the economizer and air preheater to oxidize nitrogen oxide to higher-order nitrogen oxides. Powers Report at 30-31. The nitrogen oxides are then removed by the wet scrubbers. *Id.* PerNOxide would thus work well at MRYS and LOS, given that they already have installed, or are required to install, wet scrubbers. Full-scale trials have been conducted, including on plants burning Texas lignite. *Id.* FMC, the company that has developed PerNOxide, anticipates that the technology can reduce NOx emissions by 40 to 50%, although tests with North Dakota lignite demonstrated a higher removal rate of between 45 and 60%.[61] In addition to achieving significant removal rates, PerNOxide has modest capital and maintenance costs because it uses existing ducts, a simple spray system, and inexpensive chemicals.[62]

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[60] The emissions limit should likely be lower given that the State used inappropriately high baseline emissions for LOS Unit 2. The State used baseline emissions of 0.77 lb/MMBtu (30-day average), even though the maximum 30-day average emissions were 0.71 lb/MMBtu between 2000-2010.

[61] *See* Bob Crynack & Sterling Gray, NO Oxidation and Capture with Wet and Dry Scrubbers at 39 (Apr. 27, 2012), *available at* http://environmental.fmc.com/media/resources/AirPollutionControl_workshop_presentation_final.pdf.

[62] *Id.*; Robert Crynack et al., Development of the FMC PerNOxide NOx Control Technology Using Hydrogen Peroxide at 6-7 (Oct. 26, 2011), *available at*: http://environmental.fmc.com/media/resources/AirPollutionControlTechnicalPaper.pdf.

PerNOxide can reduce NOx emissions beyond the reductions being achieved through the existing SNCR systems at MRYS and LOS. Further, the control is technically feasible, cost-effective, and would improve visibility beyond what SNCR can achieve alone.

2. Hybrid or Advanced SCR-SNCR Systems

In addition to using PerNOxide to increase the efficiency of the SNCR system, EPA could also require the addition of SCR following ASOFA/SNCR, which is referred to as a "hybrid" or "advanced" SCR system. *See* Power Report at 28. The ammonia slip from an SNCR, which is quite high and disturbingly unlimited in the instant case, could be used as reactant feed to an in-duct SCR.[63] Using the ammonia slip to operate the SCR would also improve visibility over an SNCR system standing alone. *Id.* Placing the SCR downstream of the SNCR, after NOx has already been reduced, also would allow the company to use a smaller SCR reactor and fan that would use less catalyst and require less duct modification. *Id.* The smaller catalyst volume would also reduce the potential for oxidation of SO_2 to SO_3 within the catalyst, reducing the potential for in-pore catalyst plugging by sulfation of any active alkali metals. *Id.* A hybrid SCR would significantly improve the cost effectiveness of SCR and greatly improve the NOx reduction compared with SNCR alone. *Id.* Hybrid systems such as the NOxOUT Cascade system[64] are available from Fuel Tech and have been successfully used on coal-fired boilers.[65]

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[63] Brian K. Gullett et al., NOx Removal with Combined Selective Catalytic Reduction and Selective Noncatalytic Reduction: Pilot-Scale Test Results, 44 J. Air & Waste Mgmt. Ass'n, 1188, 1189 (Oct. 1994), *available at* http://www.tandfonline.com/doi/pdf/10.1080/10473289.1994.10467313.

[64] NOxOUT Cascade, Fuel Tech, Inc., http://www.ftek.com/en-US/products/apc/noxout-cascade; *see also* V. Albanese et al., Hybridization of Urea-SNCR with SCR A Fit for the Future (Mar. 2005), *available at* http://www.ftek.com/media/en-US/pdfs/TPP-566.pdf.

[65] Kevin Dougherty, Advanced Selective Catalytic Reduction System Operating on a Coal-Fired Boiler (2013), *available at* http://www.ftek.com/media/en-US/pdfs/2013_EUEC_ASCR.pdf; Daniel P. Connell, Greenidge Multi-Pollutant Control Project, Final Report of Work Performed May 19, 2006 – October 18, 2008 (Apr. 2009), *available at* http://www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/greenidge/GreenidgeProjectFinalReport-5-27-09.pdf; Daniel P. Connell et al., The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation (Aug. 2008), *available at* http://www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/greenidge/MEGA08_Paper.pdf.

CONCLUSION

For all of the reasons set forth above, EPA cannot approve North Dakota's BART limits based on SNCR. EPA must require emissions limits based on SCR, as EPA originally proposed. At a minimum, EPA must ensure that MRYS and LOS meet the lower emission limits that are feasible and cost-effective, which are necessarily lower than the BACT-based limits that EPA is re-proposing.

Thank you for your consideration. Please feel free to contact undersigned counsel with any questions regarding these comments.

Sincerely,

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Technical Comments on Proposed NOx BART Determinations for Milton R. Young and Leland Olds Stations

as proposed in

Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze; Reconsideration, 78 Fed. Reg. 16,452 (Mar. 15, 2013)

By Bill Powers, P.E.
Powers Engineering

On behalf of
National Parks Conservation Association and Sierra Club

June 17, 2013

I. Introduction

These technical comments are provided in response to the Environmental Protection Agency's (EPA) decision to reconsider its Partial Approval of North Dakota's Regional Haze State Implementation Plan with respect to its nitrogen oxides (NOx) Best Available Retrofit Technology (BART) determination for Milton R. Young Station (MRYS) Units 1 and 2 and Leland Olds Station (LOS) Unit 2. 78 Fed. Reg. 16,452 (Mar. 15, 2013).

As set forth below, the decision in *U.S. v. Minnkota Power Cooperative, Inc.*, 831 F. Supp. 2d 1109 (D.N.D. 2011) regarding best available control technology (BACT) did not establish what BART should be and it thus should not control here. Information available at the time of EPA's original decision, as well as newly available information, confirms that selective catalytic reduction (SCR) technology is BART for NOx. EPA has taken the position that pollution controls installed after the 2000-2004 baseline are not considered in a BART determination, and in keeping with that position, the record supports selecting SCR as BART for NOx. If the agency were to depart from that position and consider pollution controls installed after the baseline period, hybrid SCR systems would represent BART. Finally, even if EPA rejects SCR and affirms selective non-catalytic reduction (SNCR) technology as BART, the NOx emission limit based on SNCR should be lowered.

These comments are organized as follows. Section II provides background information on the BACT and BART determinations for NOx. Section III explains why the BACT decision does not fulfill the BART requirements for either MRYS or LOS. As LOS fires different types of coal than MRYS, the conclusions in the BACT decision regarding the feasibility of controls at MRYS are not applicable to LOS. Furthermore, the BACT decision does not represent BART because it contains an emissions limit higher than presumptive BART, and EPA has not conducted a five-factor BART analysis justifying an emission limit above presumptive BART.

Section IV explains why SCR is technically feasible and is BART for NOx. Letters from Johnson Matthey guarantee the performance of SCR catalysts at MRYS and LOS, and Alstom Power indicated SCR would work at the units. Further, catalyst reaction modeling sponsored by the Electric Power Research Institute demonstrates that the flue gas stream at MRYS and LOS would not prevent successful operation of SCR systems. And three units that burn Texas lignite, which is similar to North Dakota lignite, have successfully operated SCR systems over the last several years, further supporting the conclusion that units burning North Dakota lignite can successfully operate SCR systems.

Section V explains that the BACT NOx limits adopted as BART do not establish what existing pollution controls are capable of achieving now or with upgrades. Importantly, existing controls remove pollutants from the flue gas stream, which alleviates concerns about catalyst poisons interfering with the operation of the SCR system. In addition, available technologies, such as perNOxide™ and NOxOUT, are either already installed or can be added on to the existing pollution controls, reducing

NOx emissions beyond what SNCR alone can achieve. Finally, should EPA identify SNCR as BART—which is unjustified based on the evidence before the agency—EPA must require lower NOx emission limits that reflect the reductions that the full suite of existing controls can actually achieve.

II. Background

The National Parks Conservation Association (NPCA) and Sierra Club petitioned EPA in June 2012 to reconsider its Partial Approval of North Dakota's Regional Haze State Implementation Plan with respect to its NOx BART determination for MRYS Units 1 and 2 and LOS Unit 2. In response, EPA is proposing to affirm its prior approval of the NOx BART emission limits for MRYS and LOS. 78 Fed. Reg. 16,452 (Mar. 15, 2013). In its proposed affirmation, EPA has provided no further basis for abandoning its initial BART proposal at 76 Fed. Reg. 58,570 (Sept. 21, 2011). These technical comments further explain why EPA's initial proposal to require the use of SCR technology in combination with advanced separated overfire air (ASOFA) to reduce NOx emissions to 0.07 lb/MMBtu as BART for MRYS and LOS was correct.

In November 2010, North Dakota determined that BACT for NOx emissions was 0.36 lb/MMBtu for MRYS Unit 1 and 0.35 lb/MMBtu for MRYS Unit 2 on a 30-day rolling average basis. Separate pounds per hour limits applied during startup and shutdown.[1] This determination was made under the Clean Air Act's Prevention of Significant Deterioration (PSD) provisions as opposed to the Regional Haze provisions at issue in this case.

This state NOx BACT determination served as the basis for North Dakota's State Implementation Plan (SIP) for NOx BART for MRYS and LOS Unit 2. In a series of SIP submittals to EPA between March and July 2010, North Dakota determined NOx BART to be emission limits of 0.36 lb/MMBtu for MRYS Unit 1; 0.35 lb/MMBtu for MRYS Unit 2; and 0.35 lb/MMBtu for LOS Unit 2, based on the use of SNCR plus ASOFA. 76 Fed. Reg. at 58,598, Table 26.

EPA disagreed with North Dakota's Consent Decree NOx BACT determination, as well as its subsequent NOx BART determination based on the same reasoning. Thus, pursuant to the terms of a consent decree that EPA had previously negotiated with the State, EPA challenged the BACT determination in federal district court in North Dakota.

As to BART, EPA prepared an independent and exhaustive NOx BART analysis for MRYS Units 1 and 2 and LOS Unit 2, correcting the errors in North Dakota's submittals. EPA published its revised NOx BART determinations in a proposed rulemaking on September 21, 2011. 76 Fed. Reg. 58,570. This revised analysis concluded that NOx BART for these units is 0.07 lb/MMBtu (30-day rolling average),

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[1] N.D. Dep't of Health, Findings of Fact for Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, at 12-13 (Nov. 2010), Doc. No. EPA-R08-OAR-2010-0406-0069 ("Findings of Fact").

achieved using either low-dust or tail-end SCR and ASOFA. No exemptions were allowed for startups or shutdown. 76 Fed. Reg. at 58,647.

On December 21, 2011, the North Dakota District Court rejected EPA's challenge to the state's NOx BACT determination for MRYS. Affording the state substantial deference under the standard of review set forth in the Consent Decree, the Court concluded that North Dakota had a "reasonable" basis for finding that SCR was not technically feasible for reducing NOx at MRYS and upheld North Dakota's determination that SNCR and SOFA are BACT. *Minnkota Power*, 831 F. Supp. 2d at 1121-30. The Court expressly did not rule on the question of whether EPA could reasonably determine that BART was SNCR, as the question of what constitutes BART for MRYS or LOS was not before the Court.

A few months after the decision in *Minnkota Power*, on April 6, 2012, EPA abandoned its previous determination of BART for both MRYS and LOS. 77 Fed. Reg. at 20,897-98. EPA approved the state's proposed BART limits stating that it would be improper to do otherwise in light of the District Court decision, and it further relied on the BART Guidelines to assume that the BACT determination could substitute for a new BART determination. *Id.*

EPA based its initial BART determinations on its conclusion that SCR was a feasible, cost-effective control technology that would provide significant additional visibility benefits compared to SNCR. 76 Fed. Reg. at 58,609-10, 58,612-13, 58,618-19. In addition, EPA found that North Dakota improperly calculated the cost of compliance and improperly assessed visibility improvements. *Id.* at 58,599-58,602. In its final rule, EPA did not suggest that its previous conclusions regarding the feasibility of SCR, its cost, and its ability to improve visibility were wrong. Instead, the Agency briefly referenced the *Minnkota Power* decision and the BART guidelines, neither of which provides a sound basis for approving SNCR as BART. 77 Fed. Reg. at 20,897. As noted above, the *Minnkota Power* decision did not address BART, and to the extent it addressed the question of technical feasibility, it expressly deferred to the state's views as reasonable without rejecting EPA's analysis as incorrect. *See Minnkota Power*, 831 F. Supp. 2d at 1121-30.

With respect to the BART Guidelines, EPA stated that the criteria for determining whether a control technology is "technically infeasible" are substantially the same for BART and BACT and that the BART Guidelines therefore generally allow states to rely on a BACT determination to determine BART, "unless new technologies have become available or best control levels for recent retrofits have become more stringent." 77 Fed. Reg. at 20,897. As to LOS, EPA stated, without support, that "[i]t is the same type of boiler burning North Dakota lignite coal, and North Dakota's views regarding technical infeasibility that the U.S. District Court upheld in the MRYS BACT case apply to it as well." *Id*. at 20,898. As is documented below, none of these arguments justifies the selection of SNCR as opposed to SCR as BART for either MRYS or LOS.

NPCA and Sierra Club petitioned EPA to reconsider the MRYS and LOS NOx BART determinations because EPA had not provided the public with an opportunity to comment on the rationale for its approval of the North Dakota BART proposal. EPA granted the petition and has now proposed to reaffirm its final rule approving North Dakota's NOx BART determinations of 0.36 lb/MMBtu for MRYS Unit 1 and 0.35 lb/MMBtu for MRYS Unit 2 and LOS Unit 2, based on SNCR plus ASOFA. 78 Fed. Reg. at 16,454-55. The affirmation fails to provide any further justification or factual basis for approving these limits beyond the brief explanation provided in the final rule.

The sections below discuss the reasons why it is inappropriate to adopt the state's BACT determination as BART for either MRYS and LOS, and how EPA must determine BART moving forward.

III. The District Court BACT Decision Does Not Establish BART for MRYS or LOS

A. LOS Is Distinguishable from MRYS

EPA reversed its NOx BART determinations for both MRYS and LOS Unit 2 based on a North Dakota BACT determination for MRYS. EPA extrapolated this BACT determination to LOS Unit 2, stating without factual support: "While LOS Unit 2 was not the subject of the BACT determination, the same reasoning that applies to MRYS Units 1 and 2 also applies to LOS Unit 2. It is the same type of boiler burning North Dakota lignite coal, and North Dakota's views regarding technical infeasibility that the U.S. District Court upheld in the MRYS BACT case apply to it as well." 78 Fed. Reg. at 16,455; *see also* 77 Fed. Reg. at 20,898. This is incorrect because LOS does not burn the same type of fuel as MRYS and fuel type was the primary basis used to eliminate SCR in the MRYS BACT determination. Further, many of the assumptions made in the MRYS BACT determination do not apply to LOS Unit 2.

Fuel quality, or the burning of 100% North Dakota lignite, was the key reason North Dakota concluded that SCR was technically infeasible. However, MRYS and LOS burn different fuels. MRYS Units 1 and 2 burn 100% North Dakota lignite from the Center Mine, adjacent to the facility.[2] LOS Unit 2 burns a blend of North Dakota lignite and Powder River Basin (PRB) coal to control the maximum as-fired sulfur, ash, and sodium content.[3] LOS operators frequently adjust PRB blend ratios from 0% to as high

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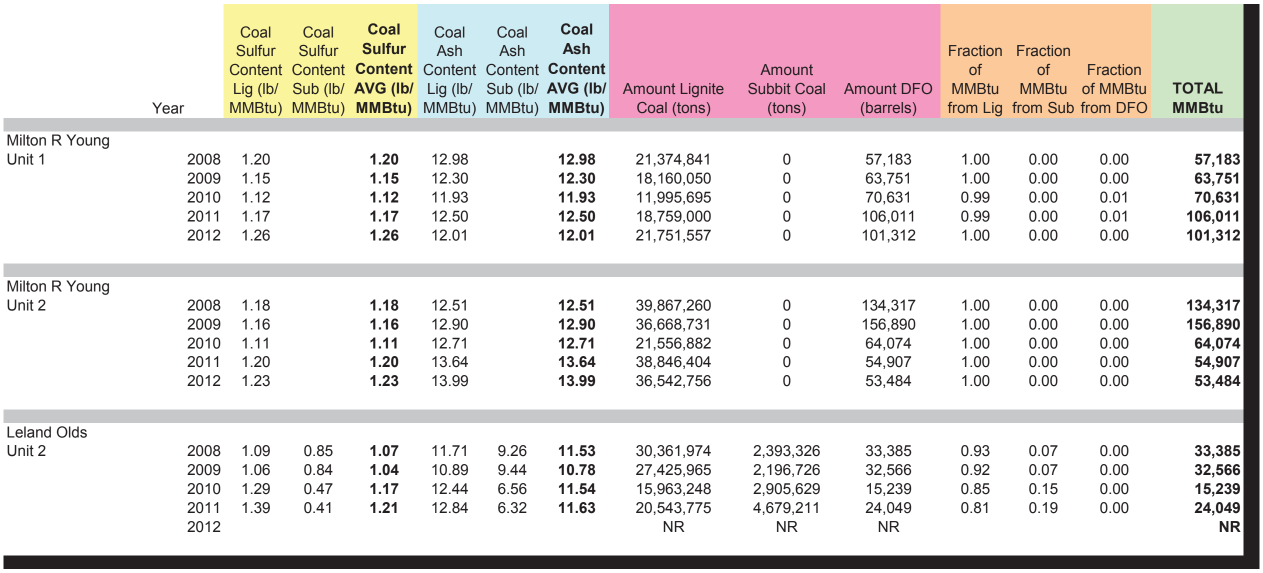
[2] Dennis L. Arfmann et al., Appropriateness of Conducting Pilot Scale Testing of Selective Catalytic Reduction (SCR) Technology at Milton R. Young Station Units 1 and 2, for Use in a NOx BACT Analysis at 7 (Aug. 14, 2007), Doc. No. EPA-R08-OAR-2010-0406-0012 at 57; Findings of Fact, *supra* note 1, at 2.

[3] Gerry C. Snow & Gary S. Anderson, Fuel Tech's NOx Reduction and Fuel Chem Performance Improvements for Coal-Fired Steam Generators at 17, Presentation at Scientech Symposium 2012, Clearwater Beach, FL, *available at* http://famos.scientech.us/PDFs/2012_Symposium/Fuel_Tech_NOx_Reduction_Improvements.pdf; Burns & McDonnell, BART Determination Study for Leland Olds Station Unit 1 and 2, Final Draft at 5 (Aug. 2006), *available at* http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Appendix%20C/L

as 50%.[4] Between 2008 and 2011, LOS Unit 2 burned between 2 and 5 million tons per year of PRB coal, amounting to approximately 15% to 20% of the total heat input to the units. MRYS Units 1 and 2 do not burn any PRB coal. *See* EIA coal data[5] summarized in Table 1. As coal quality was one of the key factors used to reject SCR at MRYS Units 1 and 2,[6] EPA should revisit its conclusion that SCR is infeasible at LOS Unit 2 based on the BACT determination for MRYS, which burns 100% lignite.

Table 1. Comparison of Coal Burned at MRYS Units 1 and 2 and LOS Unit 2



	Year	Coal Sulfur Content Lig (lb/ MMBtu)	Coal Sulfur Content Sub (lb/ MMBtu)	**Coal Sulfur Content AVG (lb/ MMBtu)**	Coal Ash Content Lig (lb/ MMBtu)	Coal Ash Content Sub (lb/ MMBtu)	**Coal Ash Content AVG (lb/ MMBtu)**	Amount Lignite Coal (tons)	Amount Subbit Coal (tons)	Amount DFO (barrels)	Fraction of MMBtu from Lig	Fraction of MMBtu from Sub	Fraction of MMBtu from DFO	**TOTAL MMBtu**
Milton R Young														
Unit 1	2008	1.20		**1.20**	12.98		**12.98**	21,374,841	0	57,183	1.00	0.00	0.00	**57,183**
	2009	1.15		**1.15**	12.30		**12.30**	18,160,050	0	63,751	1.00	0.00	0.00	**63,751**
	2010	1.12		**1.12**	11.93		**11.93**	11,995,695	0	70,631	0.99	0.00	0.01	**70,631**
	2011	1.17		**1.17**	12.50		**12.50**	18,759,000	0	106,011	0.99	0.00	0.01	**106,011**
	2012	1.26		**1.26**	12.01		**12.01**	21,751,557	0	101,312	1.00	0.00	0.00	**101,312**
Milton R Young														
Unit 2	2008	1.18		**1.18**	12.51		**12.51**	39,867,260	0	134,317	1.00	0.00	0.00	**134,317**
	2009	1.16		**1.16**	12.90		**12.90**	36,668,731	0	156,890	1.00	0.00	0.00	**156,890**
	2010	1.11		**1.11**	12.71		**12.71**	21,556,882	0	64,074	1.00	0.00	0.00	**64,074**
	2011	1.20		**1.20**	13.64		**13.64**	38,846,404	0	54,907	1.00	0.00	0.00	**54,907**
	2012	1.23		**1.23**	13.99		**13.99**	36,542,756	0	53,484	1.00	0.00	0.00	**53,484**
Leland Olds														
Unit 2	2008	1.09	0.85	**1.07**	11.71	9.26	**11.53**	30,361,974	2,393,326	33,385	0.93	0.07	0.00	**33,385**
	2009	1.06	0.84	**1.04**	10.89	9.44	**10.78**	27,425,965	2,196,726	32,566	0.92	0.07	0.00	**32,566**
	2010	1.29	0.47	**1.17**	12.44	6.56	**11.54**	15,963,248	2,905,629	15,239	0.85	0.15	0.00	**15,239**
	2011	1.39	0.41	**1.21**	12.84	6.32	**11.63**	20,543,775	4,679,211	24,049	0.81	0.19	0.00	**24,049**
	2012							NR	NR	NR				**NR**

Further, the quality of the lignite burned at LOS Unit 2 is different in significant ways from the quality of the lignite burned at MRYS. North Dakota argued that SCR was not feasible due to high quantities of sodium and potassium oxides in the MRYS lignite ash.[7] LOS Unit 2 lignite has much less sodium oxide in its ash (2.94%) compared to MRYS (5.6%) and LOS further blends its lower sodium oxide value down using PRB coal, which has even lower amounts of sodium oxide (1.65%). LOS Unit 2 lignite also has much less potassium oxide in its ash (0.73%) compared to MRYS (1.0%) and further blends this down using PRB coal, which has even lower amounts of potassium oxide

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OS/Basin%20LOS%20BART%20Report.pdf; *see also* N.D. Dep't of Health, North Dakota State Implementation Plan for Regional Haze at 73 (Feb. 24, 2010), Doc. No. EPA-R08-OAR-2010-0406-0002.

[4] Les Allery et al., Demonstrated Performance Improvements on Large Lignite-Fired Boiler with Targeted In-Furnace Injection Technology™ at 7, Presented at COAL-GEN 2010, Aug. 10-12, 2010, Pittsburg, PA, *available at* http://www.ftek.com/media/en-US/pdfs/TPP-592.pdf.

[5] U.S. Energy Information Administration, Annual Electric Utility Data, EIA-906/920/923 Data File, *available at* http://www.eia.gov/electricity/data/eia923/.

[6] Findings of Fact, *supra* note 1, at 7-10.

[7] Findings of Fact, *supra* note 1, at 7.

(0.28%).[8] Because elevated levels of sodium and potassium oxides in MRYS ash were the principal basis North Dakota used to reject SCR as technically infeasible at MRYS, North Dakota's feasibility analysis for MRYS should not apply to LOS.[9]

Moreover, it has previously been acknowledged that it is feasible to convert LOS Unit 2 to fire up to 100% PRB coal.[10] Rail service and unloading facilities are installed at the site, so the additional operational and capital costs to bring in larger quantities of PRB coal would be modest. SCR is being successfully used to control NOx emissions from cyclone boilers firing 100% PRB,[11] as well as various blends of PRB and bituminous coals,[12] thus eliminating the SCR feasibility issue that the State raised in connection with MRYS. This option was not pursued in the prior BART analysis because, alone, it would not significantly lower NOx impacts. However, this previous analysis failed to recognize that switching the coal source would mitigate the alleged SCR catalyst impacts (many SCRs are being successfully used on PRB-fired boilers, including cyclone boilers), thus increasing the achievable NOx reduction. Thus, a fuel switch was never properly evaluated in the record.

Finally, LOS Unit 2 was equipped with Targeted In-Furnace Injection (TIFI) to control boiler slagging and fouling and reduce NOx in January 2009. This control was not present at MRYS and was not considered in any of the various BACT or BART determinations. Given this difference between the two plants, EPA cannot merely rely on the limits at MRYS for LOS. Use of TIFI at LOS is discussed further elsewhere in these comments. *See infra* Section V.C.

In summary, LOS Unit 2 is dissimilar in important ways to MRYS, and it is inappropriate to extrapolate the MRYS BACT determination to LOS. EPA should revisit its decision as to the feasibility of SCR at LOS Unit 2 based on the fact that it co-fires PRB and lignite with lesser amounts of alleged catalyst poisons; has been increasing the amount of PRB that it fires over time; can be modified to fire even greater quantities of PRB coal, up to 100%, completely eliminating the lignite fuel quality claims; and, unlike MRYS, is equipped with TIFI to reduce slagging and NOx emissions.

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[8] LOS coal quality data from Allery et al., *supra* note 4, at 3, Table 1. MRYS coal quality data from N.D. Dep't of Health, Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2 at 18, Table 1 (June 2008) ("Preliminary BACT Determination").

[9] Findings of Fact, *supra* note 1, at 7-10.

[10] Burns & McDonnell, Technical Feasibility Assessment of NOx Control Alternatives, Appendix A1 to BART Determination Study for Leland Olds Station Unit 1 and 2 at A1-1 (Aug. 2006), *available at* http://www.ndhealth.gov/AQ/RegionalHaze/Basin%20BART%20Appendicies.pdf.

[11] Scot Pritchard et al. Catalyst Design Experience for 640 MW Cyclone Boiler Fired with 100% PRB Fuel (1997), *available at* http://www.cormetech.com/brochures/NewMadridpaper.pdf; *see also* John Cochran, CERAM Environmental, Inc., Fuel Impacts on Design and Performance of SCR Catalysts, Presented at McIlvaine "Hot Topic Hour," June 30, 2011.

[12] *See* NPS compilation of cyclone boilers equipped with SCR, *available at* http://www.fws.gov/refuges/AirQuality/docs/Comments/FCPP/Appx%20A.%20Control%20Effectiveness/SCR%20CAM%20data%20and%20discussions/cyclone%20boilers%20w%20SCR.xls.

B. The BACT Decision Did Not Determine BART for MRYS or LOS

EPA states in its proposal to affirm the BACT-based BART limits for MRYS and LOS that "[o]ur BART Guidelines indicate that recent BACT determinations generally may be considered BART without further analysis." 78 Fed. Reg. at 16,455. Thus, EPA contends that "we are not acting arbitrarily or capriciously, or unreasonably, in determining that the State's selection of SNCR plus ASOFA . . . is reasonable and should be approved." *Id.* Further, EPA notes that: "As a general rule, the selection of a recent BACT level as BART is the equivalent of selecting the most stringent level of control, and consideration of the five statutory BART factors becomes unnecessary." *Id.*

This overlooks the fact that the BACT decision at issue here was not based on the most stringent level of control achievable. The BART Guidelines do not allow EPA to rely on a BACT determination that does not reflect the best available controls. Given EPA's own analysis demonstrating that SCR is feasible and cost-effective, relying on BACT to identify less effective controls as BART is impermissible.

EPA's independent analyses concluded that BART for NOx at MRYS is ASOFA plus SCR, not ASOFA plus SNCR, which is a much less effective NOx control combination. The record amply supports this conclusion. Further, new technologies have been installed at all of the subject units that were neither considered in the North Dakota BACT determination nor in EPA's current proposal to approve the State's weak BART limits.

C. Proposed BART Is Higher than the Presumptive NOx BART Limit

Under the BART Guidelines that EPA relies on for its assumption that "BACT equals BART," EPA should not have accepted a BACT determination that is less than the presumptive BART floor.[13] In so doing, EPA authorized MRYS and LOS to operate at levels that are less than the predetermined best levels of controls, in contravention of the requirement that the units meet BART emission limits.

The Guidelines conclude that presumptive BART for all lignite-fired cyclone boilers greater than 200 MW located at 750 MW power plants is a NOx emission limit of 0.10 lb/MMBtu, based on SCR. 40 C.F.R. Pt. 51, App. Y § IV(E)(5). The NOx BART limits proposed by EPA using its "BART equals BACT" argument range from 0.35

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[13] The BART Guidelines apply to MRYS when considering the actual operation of Units 1 and 2. As EPA noted in its original proposed rule, the sum of permitted operating capacity results in a total generating capacity of at least 794 MW, which is above the 750 MW capacity threshold established by the Clean Air Act, 42 U.S.C. § 7491(b)(2), and the Regional Haze Rule, 40 C.F.R. § 51.308(e)(ii)(B). 76 Fed. Reg. at 58,596. Although LOS's total generating capacity is below the 750 MW limit, North Dakota's regional haze regulations require that facility owners or operators for whom the guidelines are not mandatory "shall use appendix y (the guidelines) as guidance for preparing their best available retrofit technology determinations." N.D. Admin. Code 33-15-25-03; *see also* 76 Fed. Reg. at 58,596.

lb/MMBtu for MRYS Unit 2 and LOS Unit 2 to 0.36 lb/MMBtu for MRYS Unit 1, or over THREE times higher than the level considered feasible and cost effective. 78 Fed. Reg. at 16,455 & n.6. ***EPA specifically evaluated the use of SCR on both MRYS and LOS in determining the presumptive NOx BART level and found it feasible and cost effective***.[14] The BART Guidelines state:

> Because of the relatively high NOx emission rates of cyclone units, SCR is more cost-effective than the use of current combustion control technology for these units. The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NOx rates of 0.10 lb/mmbtu. As a result, we are establishing a presumptive NOx limit of 0.10 lb/mmbtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants.

40 C.F.R. Pt. 51, App. Y § IV(E)(5).

This presumptive determination has not been refuted by EPA in this case. The supporting documentation for the presumptive NOx limit specifically analyzed and found feasible the use of SCR on the MRYS and LOS cyclone boilers firing North Dakota lignite.[15] The record is silent on why the presumptive BART limit provided in the BART Guidelines—*examining these specific facilities and their "unique" coal*—does not trump a much more lax BACT determination for the same sources under a separate statutory provision. This presumptive determination sets the starting point or the floor for a BART determination for MRYS and LOS. In other words, BART for these units should be no higher than 0.10 lb/MMBtu, and certainly not three times higher as proposed by EPA in this rulemaking, absent a credible demonstration that compliance with presumptive BART limits is inappropriate.

Under the BART Guidelines, an alternative control level different from this presumptive level can only be selected based on "a careful consideration of the statutory factors." 40 C.F.R. Pt. 51, App. Y § IV(E)(5); *see also* 70 Fed. Reg. 39,104, 39,130-31 (July 6, 2005) ("We agree with commenters who asserted that the method for assessing BART controls for existing sources should consider all of the statutory factors."). The record in this case contains no analysis of the BART statutory factors to support substituting a NOx BART limit three times higher than the presumptive level, let alone a careful consideration of the statutory factors.

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[14] *See* EPA, Technical Support Document: Methodology for Developing BART NOX Presumptive Limits (June 15, 2005), Doc. No. EPA-R08-OAR-2010-0406-0092; Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet (June 15, 2005), Doc. No. EPA-HQ-OAR-2002-0076-0446.

[15] *See* EPA, Technical Support Document: Methodology for Developing BART NOX Presumptive Limits (June 15, 2005), Doc. No. EPA-R08-OAR-2010-0406-0092; Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet (June 15, 2005), Doc. No. EPA-HQ-OAR-2002-0076-0446.

1. BACT Does Not Reflect Consideration of Visibility

Under the Clean Air Act, EPA, in determining BART, "shall" consider the degree of visibility improvement which may reasonably be anticipated from the use of BART while BACT does not require any consideration of visibility. *Compare* 42 U.S.C. § 7491(g)(2) *with id.* §§ 7479(3), 7475. The BACT decision, which is not based on selection of the most stringent control, does not guarantee visibility improvement or even reflect consideration of the issue, and so it cannot substitute for BART.

Visibility is the *raison d'etre* for BART, and it is an important consideration in this case as EPA is proposing to conclude that NOx BART is satisfied by ASOFA/SNCR, which emits FIVE times more NOx than ASOFA/SCR and THREE times more NOx than the presumptive level. Thus, ASOFA/SNCR results in greater adverse visibility impacts than ASOFA/SCR.

Further, SNCR works by injecting ammonia into the hot flue gases. While both SCR and SNCR are similar in that they oxidize NOx entrained in the flue gas to form to molecular nitrogen (N_2) and water vapor (H_2O) using ammonia (NH_3) or urea ($(NH_2)_2CO$) as a reagent, much more ammonia is required for SNCR than for SCR to achieve similar reductions for the reasons explained below. This results in more severe visibility and other non-air quality impacts for SNCR than for SCR.

The SNCR reaction is not efficient as it does not use a catalyst, so more ammonia slips through and is emitted into the atmosphere than with SCR.[16] While SCR also emits ammonia, the amount is much smaller.[17] A recent study by Black & Veatch, for example, found that

> Even with best efforts (multiple levels of injection, conscientious operator attention, etc.), ammonia slip emissions from SNCR systems will be highly variable during load changes. This can result in excess or inadequate reagent injection, the increased potential for exceeding allowable NOx emission limits, or increased ammonia slip with associated air heater pluggage and fly ash contamination. SNCR processes typically require three to eight times the theoretical amount of reagent to achieve NOx reductions as compared to SCR systems causing a significant economic consideration. The increased reagent consumption is due to reagent thermal decomposition, varying temperature, and the lack of a true

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[16] California Air Resources Board, Compliance Assistance Technical Manual Series: Stationary Source Air Pollution Control Devices and Techniques, Section 310: Selective Non-Catalytic Reduction Control Theory and Design (2011).

[17] The relative amounts of ammonia slip for a given NOx control efficiency can be determined from the algorithms in the EPA Cost Control Manual. EPA, EPA Air Pollution Control Cost Manual Section 4.2, Chapters 1 & 2 (2002).

> steady-state controlled environment, which tends to increase ammonia slip emissions.[18]

Ammonia and urea-based SNCR processes require three or four times as much reagent as SCR systems to achieve similar NOx reductions.[19]

Modern SNCR technologies typically have an ammonia slip of 5 to 10 parts per million (ppm). In contrast, SCR technologies are typically designed with a 2 ppm ammonia slip.[20] For example, the San Juan Generating Station Federal Implementation Plan ("FIP") requires design of the NOx control system with a 2 ppm ammonia slip.[21] The North Dakota BART determination does not set any ammonia slip limit, allowing unlimited amounts of ammonia to be emitted to accommodate fluctuations in boiler operation, which is a well known problem with SNCRs. Because SNCR performance is very sensitive to temperature and flue gas temperatures are generally set to meet steam generation requirements, they are not always ideal for the SNCR process. When suitable conditions are not available, more ammonia must be injected to compensate. The California Air Resources Board (CARB) notes that "[v]ariations in the flue gas temperature make the design and operation of an SNCR system more difficult…" and "… SNCR requires especially efficient temperature and NOx monitoring and diligent operator oversight."[22] Thus, more ammonia slips out of an SNCR than out of an SCR. This degrades visibility and creates other non-air quality environmental impacts.[23]

The contribution of ammonia slip to visibility degradation was not considered in the either the BACT or BART determinations for MRYS and LOS, nor was this slipped ammonia included in any of the BART visibility analyses. A complete BART determination based on SNCR should include an evaluation of the impact of ammonia on visibility and a limit on the amount of ammonia slip to assure that visibility improvement is achieved. As set forth above, rejecting the presumptive NOx BART limit of 0.10 lb/MMBtu must be based on a careful consideration of the all of the BART statutory factors, and the record does not contain the required analysis of visibility improvement.

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[18] Black & Veatch, Platte River Power Authority Rawhide Energy Station: Rawhide NOx Reduction Study at 2-2 (Jan. 2009).

[19] IEA Clean Coal Centre, Selective Non-Catalytic Reduction (SNCR) For NOx Control, http://www.iea-coal.org.uk/site/2010/database-section/ccts/selective-non-catalytic-reduction-sncr-for-nox-control.

[20] *See* EPA, Identification of (and Responses to) Potential Effects of SCR and Wet Scrubbers on Submicron Particulate Emissions and Plume Characteristics at 36 (Aug. 2004).

[21] 76 Fed. Reg. 52,388, 52,439 (Aug. 22, 2011).

[22] California Air Resources Board, *supra* note 16, at § 310.4.1.

[23] EPA, Air Pollution Control Technology Fact Sheet, Name of Technology: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-031 at 1-2, *available at* http://www.epa.gov/ttn/catc/dir1/fsncr.pdf; 72 Fed. Reg. 20,586, 20,591 (Apr. 25, 2007); David L. Read and Alvaro A. Linero, Bioenergy Project Permitting in Florida at 11 (2011), *available at* http://www.dep.state.fl.us/air/emission/innovative_technology/503_2.pdf.

2. EPA Did Not Consider Non-Air Quality Benefits in Rejecting Presumptive BART

Another important statutory factor that must be considered to reject the presumptive BART limit is non-air quality environmental impacts. The non-air quality impacts of ammonia used in the SNCR are highly significant compared with those from SCR absent an aggressive limit on ammonia slip. While the April 6, 2012, rulemaking asserts for Coal Creek Station that the same ammonia slip levels can be achieved for both SCR and SNCR (2 ppm), 77 Fed. Reg. at 20,920, in general, this is not true,[24] particularly when the NOx limit is not accompanied by an ammonia slip limit, no continuous ammonia monitoring is required, and no requirement to optimize operation is specified as BART. These impacts alone should have led to the rejection of SNCR as BART. The record fails to disclose a significant class of adverse impacts associated with SNCR that would be mitigated with SCR.

The non-air quality impacts of ammonia use in an SNCR, compared to an SCR, depend in part on the form in which the ammonia arrives at the plant—urea, anhydrous or aqueous. The North Dakota BART determination does not require any specific form, allowing the worst case—anhydrous—to be used.

The impacts of transporting, storing and using ammonia in an SNCR include public health impacts from breathing more ammonia fumes emitted at the stack;[25] public health impacts from breathing more ammonia-based fine PM2.5 particulates;[26] public health impacts from accidental releases of ammonia during transport, storage and use;[27] adsorption of ammonia on flyash, which may affect disposal or reuse of the ash;[28]

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[24] Institute of Clean Air Companies, White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions (Feb. 2008).

[25] Agency for Toxic Substances and Disease Registry, Toxicological Profile for Ammonia (Sept. 2004), *available at* http://www.atsdr.cdc.gov/ToxProfiles/tp126.pdf.

[26] 72 Fed. Reg. at 20,589 (April 25, 2007) ("The main precursor gases associated with fine particle formation are SO2, NOx, volatile organic compounds (VOC), and ammonia."); *id.* at 20,586 ("The EPA established air quality standards for PM2.5 based evidence from numerous health studies demonstrating that serious health effects are associated with exposures to elevated levels of PM2.5..."). For a detailed discussion of health effects of PM2.5, see 62 Fed. Reg. 38,652 (July 18, 1997).

[27] Ammonia transportation and storage risks are routinely evaluated in EIRs, EISs, and power plant licensing proceedings before State and Federal regulatory agencies. *See, e.g.*, CH2M HILL, Transportation of Ammonia Risk Analysis, Appendix 5.5C to Application for Certification for the Carlsbad Energy Center Project (Aug. 28, 2007), *available at* http://www.energy.ca.gov/sitingcases/carlsbad/documents/applicant/afc/CECP_Volume%202-Appendices/Appendix%205.5C_Transportation%20of%20Ammonia%20Risk%20Analysis.pdf.

[28] *See*, *e.g.,* EPA, Air Pollution Control Technology Fact Sheet, Name of Technology: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-031 at 1, *available at* http://www.epa.gov/ttn/catc/dir1/fsncr.pdf; EPA, Air Pollution Control Technology Fact Sheet, Name of Technology: Selective Catalytic Reduction (SCR), EPA-452/F-03-032 at 1, http://www.epa.gov/ttn/catc/dir1/fscr.pdf.

ammonia odor; [29] impairment of visibility from secondary PM2.5 in the atmosphere that is not included in the visibility modeling and which offsets the claimed visibility improvement by SNCR compared to SCR; acid deposition; and eutrophication of waterways.[30]

These impacts, part of the non-air quality statutory factor that must be evaluated to reject a presumptive limit, were not considered or disclosed to the public. These impacts are much more severe with SNCR than SCR as much more ammonia is used and released. These impacts support setting the BART NOx limit no lower than the presumptive NOx BART limit. Although unreacted ammonia slip is emitted from both SNCR and SCR, it is emitted in the greatest amounts per unit of NOx reduction by SNCR, which is proposed as the BART technology to replace the presumptive BART technology, SCR. Thus, EPA should have considered this statutory factor, non-air quality impacts, before rejecting the presumptive BART limit, which is based on SCR.

Both of these statutory factors—visibility improvements and non-air-quality impacts—argue for rejecting SNCR as a replacement for a NOx BART limit of 0.10 lb/MMBtu or lower, based on SCR.

D. The Record Contains No Demonstration of Technical Infeasibility for Low Dust or Tail End SCR

EPA correctly concluded in its proposed rule that low-dust and tail-end SCR are technically feasible in for both MRYS and LOS. EPA notes that "[f]or BART, EPA's criteria for determining whether a control option is technically infeasible are substantially the same as the criteria used for determining technical infeasibility in the BACT context." 78 Fed. Reg. at 16,455. The BART Guidelines indicate that "you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously." 40 C.F.R. Pt. 51, App. Y § IV(D)(2). This is the same criterion used in PSD feasibility determinations. However, the North Dakota BACT determination that EPA relies on did not make this required gas stream comparison.

The record underlying the BACT determination does not contain a comparison of the physical and chemical characteristics of the gas stream at the location of a low-dust or tail-end SCR at MRYS or LOS Unit 2 with gas streams at the location of an SCR in any

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[29] Lamar Larrimore, Effects of Ammonia from Post-combustion NOx Control on Ash Handling and Use, Effects on Utilization Applications, 47 Fuel Chemistry Division Preprints 832, 833 (2002), *available at* http://www.anl.gov/PCS/acsfuel/preprint%20archive/Files/47_2_Boston_10-02_0241.pdf .

[30] Committee on the Environment and Natural Resources Air Quality Research Subcommittee, Atmospheric Ammonia: Sources and Fate: A Review of Ongoing Federal Research and Future Needs at 1, 8-9 (June 2000), *available at* http://www.esrl.noaa.gov/csd/AQRS/reports/ammonia.pdf; National Atmospheric Emissions Inventory, Acidification and Eutrophication, http://naei.defra.gov.uk/overview/issues?issue_id=7.

other application. Rather, the record is based on coal and ash composition[31] and speculation as to their impacts on the SCR catalyst. However, control devices are located between the boiler outlet and a low-dust or tail-end SCR at both MRYS and LOS. These control devices remove significant amounts of the pollutants of concern,[32] altering the physical and chemical characteristics of the gas stream. This renders conclusions based on coal and ash irrelevant as to the required finding on gas stream composition. There is no valid basis in the BACT record or subsequent BART record for an infeasibility determination for SCR as there is no one-on-one comparison of gas stream composition.

IV. EPA Must Identify SCR as BART

As EPA initially found, SCR is the most stringent control and is BART. The points discussed below corroborate EPA's original view that SCR is feasible and should be required as BART.

A. Catalyst Vendors Will Offer Guarantees

Consultants to Minnkota[33] and the U.S. Department of Justice[34] sought SCR information from various catalyst vendors. The Findings of Fact supporting North Dakota's BACT determination stressed the fact that two of these vendors, CERAM and HTI, "refused to provide a catalyst life guarantee for MRYS which burns North Dakota lignite."[35] However, these Findings unfairly describe the record and fail to note potential motives of these two vendors.[36]

Further, the Findings of Fact fail to disclose that another catalyst vendor, Johnson Matthey Catalysts, was willing to offer a performance guarantee, and Alstom Power was willing to move forward with the project. Johnson Matthey Catalysts offered to guarantee SCR at MRYS without qualification.

Johnson Matthey Catalysts (then Argillon) did not respond to Minnkota's 2007 request for information, but did respond positively to the U.S. DOJ's query and subsequently wrote EPA on February 27, 2012, after the close of public comments on November 21, 2011, but before EPA's final rulemaking on April 6, 2012, to clarify its

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[31] *See, e.g.,* Preliminary BACT Determination, *supra* note 8, at 15-27.

[32] Microbeam Technologies, Inc., Final Report: Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD at 28 (July 1, 2009), Doc. No. EPA-R08-OAR-2010-0406-0013 at 190.

[33] Minnkota Power Coop., Inc., & Square Butte Elec. Coop., Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility: North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2 (May 8, 2008), Attachment 18 to Doc. No. EPA-R08-OAR-2010-0406-0295.

[34] Hans Hartenstein, Feasibility of SCR Technology for NOx Control Technology for the Milton R. Young Station, Center, North Dakota at A-57 to A-66 (July 2008), Attachment 4 to Doc. No. EPA-R08-OAR-2010-0406-0046.

[35] Findings of Fact, *supra* note 1, at 8.

[36] *See* EPA, Comments on NDDH Preliminary BACT Determination at 7-8 (July 31, 2008), Attachment 4 to Doc. No. EPA-R08-OAR-2010-0406-0046 at 90-91.

position, which had been mischaracterized in the BACT proceedings before the North Dakota District Court. Johnson Matthey Catalysts wrote:

> JMC believes that low-dust and tail-end SCR configurations applied to North Dakota lignite fired boilers would be technically feasible. Should other RFPs [requests for proposal] occur for specific North Dakota Lignite fired facilities, JMC would be willing to offer SCR catalyst designs with reasonable operating lifetime performance guarantees for service in a low-dust or tail-end SCR configuration.[37]

EPA, in its March 15, 2013 proposal to affirm its NOx BART determination for MRYS and LOS Unit 2, does not disclose the fact that SCR on North Dakota lignite is considered to be technically feasible by one of the major SCR catalyst vendors. This fact demonstrates that the North Dakota BACT determination does not represent the best controlled NOx level.

A second vendor, Alstom Power, also confirmed its willingness to assist any project to install SCR. Alstom Power wrote in response to Burns and McDonnell's request for SCR information at MRYS:

> ND Lignite does create many challenges for SCRs, but even with all of those challenges, it is possible to use ND Lignite if the system is designed properly and Minnkota Power elects to pay for the increased capital and O&M costs associated with this fuel. . . . Fuels high in sodium and potassium require special selection of catalyst, but can be treated by SCR. An example of such an application would be wood and other biofuel fired boilers in Europe. While SCR catalyst life in ND lignite service is not expected to be as long as in bituminous coal service, it is expected that acceptable emissions control and maintenance requirements can be achieved. Based on experience with wood fired units, a hot side (600-750 deg F) ESP is effective in removing the fly ash compounds that result in catalyst poisoning. . . .While likely more expensive, an alternative solution to the conventional SCR, is a Tail End SCR where the SCR is located just before the stack . . . the fly ash constituents that can poison the catalyst will have been removed from the flue gas stream by the existing ESPs. . . . Designed properly, the SCR should be capable of up to 90% removal efficiencies with an associated ammonia slip below 2 ppm. [38]

Alstom Power offered preliminary pricing information and closed by noting: "In summary, it is possible to design and operate an SCR on this fuel if required, but doing so

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[37] Letter from Ken Jeffers, Sr Applications Engineer, Johnson Matthey Catalysts, to Callie Videtich, EPA (Feb. 27, 2012), Attachment 2 to Doc. No. EPA-R08-OAR-2010-0406-0322.

[38] Letter from Michael G. Phillips, Business Applications Manager, Alstom, to Robert Blakely, Burns and McDonnell (May 30, 2007), Attachment 18 to Doc. No. EPA-R08-OAR-2010-0406-0295 at 30-32.

is not without challenges and can be very costly depending on which approach you may choose to pursue."[39]

In response to further information from Burns & McDonnell requesting that Alstom revisit its initial response, Alstom conceded that "some R&D, custom engineering, and likely a pilot testing program" would be required for a "traditional SCR," but stuck to its guns as to a tail-end SCR, the location proposed by EPA as BART.[40]

B. SCR Can Work on Boilers Firing North Dakota Lignite

The North Dakota BACT determination that EPA is proposing to rely on concluded that all forms of SCR, including low-dust and tail-end SCR, were technically infeasible due to the unique chemical composition of the gases from burning North Dakota lignite in cyclone boilers. However, as discussed elsewhere, this determination never compared the actual flue gas composition of gases from burning North Dakota lignite in cyclone boilers with the flue gases from any other source, the test specifically required by the BART Guidelines. Further, recent research and other information indicate the North Dakota BACT determination was fundamentally flawed and should not be adopted for BART purposes.

The North Dakota BACT analysis argues that the combined sum of oxides of sodium (Na_2O), calcium (CaO), magnesium (MgO), and potassium (K_2O) in North Dakota lignite are present in double the amount found in other low rank coals, such as PRB.[41] These constituents are alleged to plug and foul the SCR catalyst, rendering SCR technically infeasible under BACT. However, these conclusions were based on speculation from lignite coal and ash composition and pilot-scale tests using widely discredited slip stream reactors.[42] The pilot-testing, for example, predicted that SCR catalyst would deactivate rapidly at the PRB-fired Baldwin Energy Complex, but subsequent full-scale SCR installations did not experience the problems anticipated by the slipstream test.[43] As noted elsewhere in these comments, the composition of the fuel is not the correct metric to consider in evaluating technical feasibility, but rather the composition of the gas at the catalyst. This is the test that must be used to satisfy the BART feasibility criterion.

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[39] *Id.* at 32.

[40] Letter from Michael G. Phillips, Business Applications Manager, Alstom, to Robert Blakely, Burns and McDonnell (May 5, 2008), Attachment 18 to Doc. No. EPA-R08-OAR-2010-0406-0295 at 35-36.

[41] *See, e.g.*, Preliminary BACT Determination, *supra* note 8, at 30-31; Findings of Fact, *supra* note 1, at 7.

[42] *See, e.g.*, Phyllis Fox, Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report at 13-16 (Mar. 2011).

[43] Rob James and Peter Spinney, Boiler Optimization and SCR Systems: Reducing NOx, Managing Tradeoffs, Power Engineering 102, 102-108 (July 2008), *available at* http://www.neuco.net/pdfs/0807PE102-109f11_FINAL.pdf.

Comments submitted in support of EPA's initial BART proposal (that were not addressed in the final rule) demonstrate that when looking at the gas composition, which is the correct inquiry to determine technical feasibility, it becomes apparent that the claimed plugging and fouling is not a genuine issue. Further, recent reaction modeling confirms that North Dakota lignite flue gases should not "plug and foul" SCR catalyst any more than PRB, a similar low-rank coal that does not preclude the effective use of SCR. Thus, EPA cannot rely on the North Dakota BACT determinations to establish BART for MRYS and LOS Unit 2.

1. Prior Comments on Proposed BART Limit Achieved with ASOFA/SCR

Dr. Ron Sahu filed comments supporting EPA's September 21, 2011, BART proposal requiring low-dust or tail-end SCR on MRYS Units 1 and 2 and LOS Unit 2 on behalf of NPCA.[44] Dr. Sahu observed that a low-dust or tail-end SCR would come after the particulate control device (ESPs) and SO_2 scrubbers.[45] These devices remove significant amounts of the alleged catalyst poisons, which are present in the flue gas as particulates. Thus, any evaluation of plugging and poisoning potential to reject SCR as technically infeasible should consider the composition of the flue gas when it comes into contact with the catalyst, not the composition of the lignite before it is burned in the boiler and not the ash that is created and subsequently removed. Comparison of flue gas compositions is the test required in the BART Guidelines to establish technical feasibility.[46]

Dr. Sahu noted that the record contains one responsive test, conducted in March 2009 at MRYS Unit 2 by Microbeam Technologies that measured the composition of the flue gases after these control devices.[47] This test took place over a four day period. Over this period, the unit was burning North Dakota lignite with as-received ash content of 7.73% to 7.89% and sodium oxide content of 7.22% to 7.57%.[48] The sodium values are high compared to values historically burned at MRYS (4.4%) and values projected to be burned in the future (5.6%).[49] Sodium is the principal constituent alleged to set North Dakota lignite apart from all other fuels where SCR has been used. Thus, this test is a worst-case condition for catalyst fouling.

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[44] Dr. Ranajit (Ron) Sahu, Focused Comments on Proposed NOx BART Limits for Selected North Dakota Coal-Fired Power Plant Units by EPA (Nov. 2011), Attachment 3 to Doc. No. EPA-R08-OAR-2010-0406-0213.

[45] *Id.* at 4, 9.

[46] "In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously." 40 C.F.R. Pt. 51, App. Y § IV(D)(2).

[47] Microbeam Technologies, *supra* note 32.

[48] *Id.* at 10, Table 7.

[49] Preliminary BACT Determination, *supra* note 8, at 18, Table 1.

The Microbeam report concluded that "[t]he particulate [exiting the scrubber] consisted mainly of sodium, potassium, and sulfur. The total quantity of sodium and potassium exiting [the control devices] was between 2000 to 3000 ug/dscm."[50] Dr. Sahu compared this with the value reported to be acceptable for SCR catalyst. The vendor information states: "To keep our guarantee the following values (maximal concentrations of catalyst poisons in the exhaust gas) must be strictly respected: alkali metals: maximum 5mg/m^3 wet."[51] Thus, Dr. Sahu concluded that "the post-ESP flue gas contains alkali poisons in concentrations that are less than half or around half of what would be of concern to the SCR catalyst."[52]

The actual concentration of alkali metals at the location of a tail-end SCR would be even lower than reported in the Microbeam study. This study found very little overall removal of submicron (<1 micron) particulate across the existing MRYS Unit 2 wet scrubber. However, this scrubber is old and inefficient. The North Dakota BART determination requires that a new wet scrubber be installed on LOS Unit 2 and MRYS Unit 1 and an upgrade of the existing wet scrubber on MRYS Unit 2, to meet 95% SO2 control. 76 Fed. Reg. at 58,595, Table 21. This would further reduce potential SCR catalyst poisons. Further, a proper BART NOx determination should evaluate the ESP to upgrade its ability to remove catalyst poisons. This was not done for MRYS or LOS Unit 2.

Dr. Sahu's comparison of levels of catalyst poisons in gases from MRYS with levels found to be acceptable in other SCR installations is exactly the type of test that is required under both the BACT and BART Guidelines to reject a widely used technology such as SCR as technically infeasible. The only responsive SCR feasibility test in the record is the test conducted by Microbeam and discussed by Dr. Sahu. This test stands unrebutted in the record and demonstrates that EPA should not rely on the BACT limit to reject SCR as BART.

2. Catalyst Reaction Modeling

SCR has not yet been used to control NOx from any boiler that fires North Dakota lignite. This is the case as no new North Dakota lignite-fired boilers have been built since SCR was first used on coal-fired boilers in the early 1990s, likely due to the lack of demand for electricity in the local area and well-documented slagging problems from burning these coals.[53] The last North Dakota lignite-fired boiler started up in 1978. Thus, absence of experience does not indicate infeasibility, but simply lack of any regulatory requirement.

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[50] Microbeam Technologies, *supra* note 32, at 30.

[51] Sahu, *supra* note 44, at 14. Johnson Matthey acquired Argillon in 2008.

[52] *Id.* The Microbeam report does not include exact values for the calcium component of the particulate; however, review of the included graphs indicates that the total alkali loading would still fall below vendor thresholds.

[53] H.H. Schobert, Lignites of North America, ch. 11 (1995); Everett A. Sondreal and George A. Wiltsee, Low-Rank Coal: Its Present and Future Role in the United States, 9 Ann. Rev. Energy 473, 488 (1984).

The BART Guidelines anticipate this situation and lay out a procedure to determine whether a technology could be applied. If the technology is "available" and "applicable," it is technically feasible. SCR is clearly available. It is "applicable" in a new situation if the physical and chemical characteristics of the gas stream in the new application are similar to those of existing applications. 40 C.F.R. Pt. 51, App. Y § IV(D)(2). As explained elsewhere, this determination is only made in comments submitted by Dr. Sahu, based on actual measurements at one of the subject plants, but not addressed by EPA.

The comparative composition of gas streams generated by different coals as they relate to SCR catalyst performance has also been recently addressed using chemical kinetic modeling. This approach simulates chemical reactions that occur during combustion and at downstream points, based on the composition of the fuel and combustion conditions. The following summarizes work published to date, which is based on a pulverized coal-fired boiler with the SCR catalyst in the high-dust position. This is the worst case for SCR, as pulverized boilers generate three to four times more fly ash than cyclone boilers, and the high dust position has substantially higher concentrations of all pollutants of concern than the low-dust and tail-end positions initially proposed by EPA and supported by commenters. We summarize this existing work below.

The Electric Power Research Institute ("EPRI") is sponsoring a program entitled "Equilibrium Characteristics of SCR Poisons" at Niska Energy Associates in California. This work is simulating catalyst fouling using chemical kinetic modeling. Preliminary results from this work have recently been reported at the 2012 Mega Symposium and at the Energy, Utility and Environment Conference ("EUEC") in January 2013 for an SCR located in the high dust position at a pulverized coal fired boiler burning a typical North Dakota lignite, several PRB coals, several bituminous coals, a northern Appalachian coal, and a wood blend. [54]

As shown in Figure 1, these simulations indicate that all of the calcium and sodium and over 60% of the potassium are vaporized (vap) from a typical North Dakota lignite fired in a conventional pulverized coal fired boiler. Similar amounts of these elements are also vaporized from PRB coals, except potassium. Greater amounts would be vaporized in cyclone boilers as temperatures are higher.

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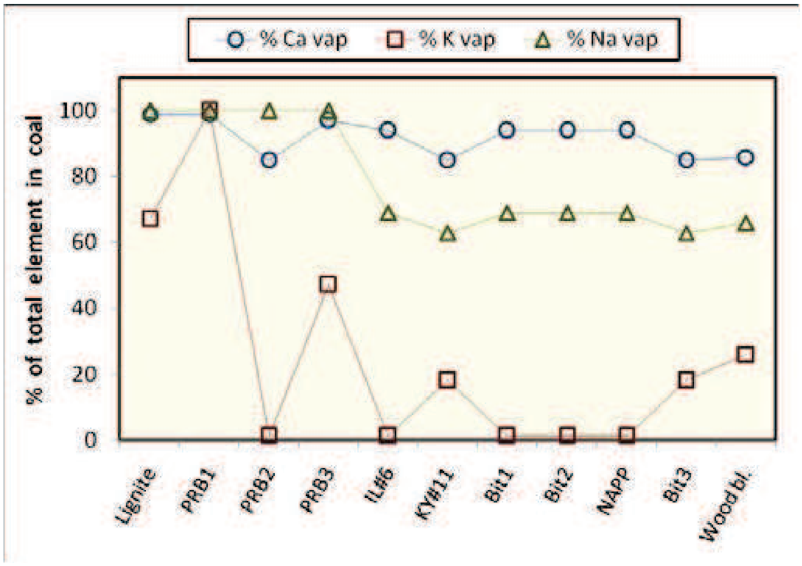
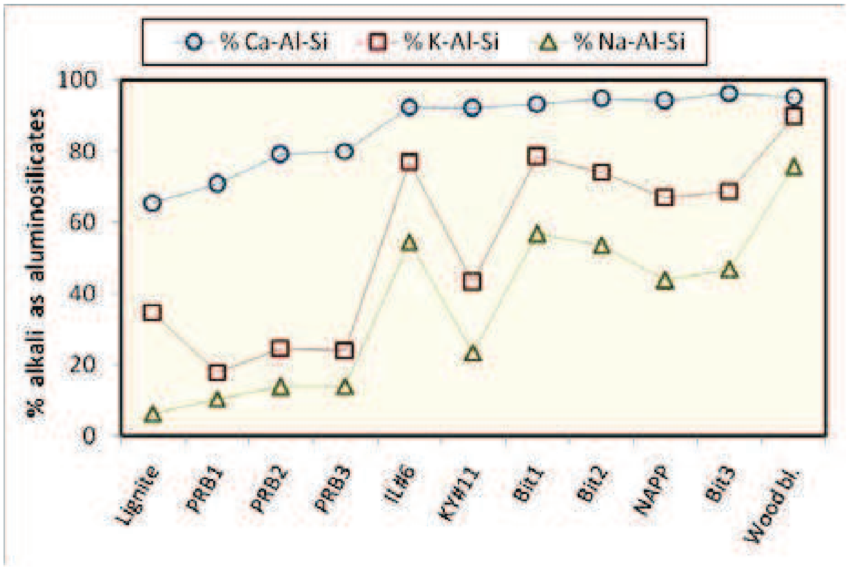
[54] *See* Balaji Krishnakumar, Stephen Niksa & Alejandro Jimenez, Relating the Deactivation Potential of SCR Catalysts to Fuel Properties and Firing Conditions (2012) (poster at 2012 Mega Symposium), *available at* http://www.mcilvainecompany.com/Universal_Power/Subscriber/PowerDescriptionLinks/Balaji%20Krishnakumar,%20Carbontxt%20-%208-23-12.pdf ("Krishnakumar, Deactivation Potential"); Balaji Krishnakumar, Stephen Niksa & Alejandro Jimenez, Release and Transformation of Poisons Implicated in SCR Catalyst Deactivation, Remarks at EUEC Conference, Jan. 28-30, 2013, Phoenix, AZ (information on proceedings available for purchase at http://www.euec.com/OrderEUECProceedings.aspx); *see also* Balaji Krishnakumar, remarks during McIlvaine Hot Topic Hour at 1:01:50 hrs (Aug. 23, 2012) ("Krishnakumar Remarks").

Figure 1.[55]



Some of the vaporized metals are scavenged by aluminosilicates, which converts them into particulates that can be removed by downstream particulate control devices. In low rank coals, calcium strongly competes with sodium and potassium for the aluminosilicates. As shown in Figure 2, for North Dakota lignite, about 60% of the calcium, 40% of the potassium, but very little of the sodium are scavenged by aluminosilicates and thus easily removed by an ESP.

Figure 2.[56]



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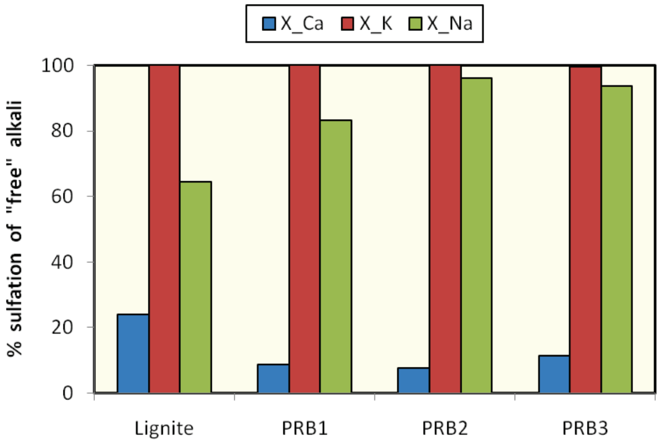
[55] Krishnakumar, Deactivation Potential, *supra* note 54.

[56] *Id.*

The alkali metals that are not scavenged by aluminosilicates are either sulfated or are present as "free" oxides. The "free" oxides are responsible for catalyst fouling while the sulfated forms do not foul the catalyst. In low rank coals, most of the potassium and sodium not scavenged by the aluminosilicates are sulfated, while only about 20% of the calcium is sulfated[57] before the SCR inlet at the high dust position. In the North Dakota lignite sample, about 22% of the calcium, 60% of the sodium, and 100% of potassium are sulfated before reaching the SCR catalyst in the high dust SCR position. The degree of sulfation should increase at the low-dust and tail-end positions of the catalyst compared to these high-dust simulations for a pulverized coal fired boiler as the flue gas temperatures decline with distance from the boiler. The majority of the sulfation takes place in the 400 to 800°C window, between the boiler exit and the ESP.

Figure 3 shows the percent of the unscavenged metals that are sulfated. These sulfated forms do not deactivate the catalyst. Only unsulfated, reactive calcium, sodium, and potassium oxides form sulfates in the catalyst pores. If reactive oxides, such as CaO, Na_2O, NaOH or KOH, reach the catalyst, they react with sulfates within the catalyst pores and expand rapidly, much like popcorn, plugging the internal pores and deactivating the catalyst. Thus, the amount of reactive oxides of alkali metals that reach the catalyst determine how much in-pore catalyst deactivation occurs.[58] The only study to address the amount of alkali oxides reaching the catalyst in the low-dust and tail-end positions, the Microbeam study, indicates that the concentrations are below levels known to poison SCR catalyst.[59]

Figure 3.[60]



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[57] The "free" metal oxide is the fraction released from coal that is not scavenged by aluminosilicates. The percent sulfated is a percentage of the "free" metal oxide.

[58] Krishnakumar, Deactivation Potential, *supra* note 54; *see also* Krishnakumar Remarks, *supra* note 54.

[59] Sahu, *supra* note 44, at 14.

[60] Krishnakumar, Deactivation Potential, *supra* note 54.

This figure shows that most of the unscavenged sodium (60%), the alleged major catalyst poison, is in the wrong chemical form to poison the catalyst, even when the catalyst is located in the worst-case position, at the boiler outlet. Moreover, most of the sulfated and unsulfated forms of these alkali metals would be removed in the ESPs and scrubbers at MRYS and LOS Unit 2 and would never reach an SCR catalyst in a low-dust or tail-end position, as demonstrated in the Microbeam study discussed elsewhere in these comments.[61] The amount of these alkali metals reaching the low-dust and tail-end positions could be further reduced by upgrading the existing ESPs and will be further reduced by the new/upgraded scrubbers. These options (upgraded ESPs and scrubbers) were not considered in any of the analyses of SCR feasibility in the record.

This research refutes claims that these alkali metals would foul SCR catalyst. Fouling would not occur as the subject alkali metals are in the wrong chemical form to poison SCR catalyst. This highlights the problem of basing a catalyst BART/BACT feasibility determination on coal and ash composition, rather than gas composition at the catalyst face, the test explicitly required by the BART Guidelines. The North Dakota BACT determination that EPA relies on to establish BART is based only on coal and ash composition and thus is fundamentally flawed.

Table 2 below suggests that calcium is a bigger issue for both lignite and PRB coals than sodium, as very little of the calcium is sulfated and it is present at high concentrations in both coals. In fact, PRB coals typically have more CaO in their ash than North Dakota lignite, and more calcium than sodium, suggesting that catalyst fouling would be a more significant issue for PRB coals, where SCR is already widely used, than for lignites. Calcium fouling at PRB-fired units is understood and is mitigated by catalyst design, including use of large pitch, soot blowers, and special catalyst formulations.

The EPRI research evaluates the potential for SCR catalyst poisoning when the catalyst is in the high dust position, at the boiler exit where catalyst poisons are present in the highest concentrations. This is the worst case for catalyst poisoning. The September 2011 draft FIP proposed locating the catalyst in the low-dust (after the ESP) or cold-side (after the scrubber) positions, where the concentration of alleged contaminants are much lower than in EPRI's study.

We extrapolated the EPRI study results to determine the relative SCR poisoning potential of a catalyst in the high dust position for PRB coals compared to North Dakota lignite. We made this comparison because SCR has been successfully used on many PRB-fired boilers, including cyclone-PRB-fired units. This PRB experience is reviewed below, after our extrapolation from the EPRI work.

The compositions of the coals in the EPRI study are currently confidential. However, we were advised that the lignite sample is a "typical North Dakota lignite."

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[61] Microbeam Technologies, *supra* note 32; *see also* D.G. Shannon and L.O. Fine, Cation Solubilities of Lignite Fly Ashes, 8 Env. Sci. & Tech 1026, 1026-1028 (1974).

Table 2 compares the concentration of free alkali oxides in the flue gases at the face of a SCR catalyst in the high dust position for a typical North Dakota lignite with a typical PRB coal. This comparison assumes typical compositions as reported in the MRYS BACT analysis for future lignites (worst case)[62] and the percentages from the above-described EPRI study, adjusted for different ash content and dust loading of the flue gas.[63] The EPRI study simulated three PRB coals. We selected PRB1 as a worst case for our calculations in Table 2. Our results are essentially the same, regardless of which PRB sample is used.

Table 2.

	Composition		**Volatilized from Coal (% of ash emitted)**	**Present as Aluminosilicates (% of total alkali vaporized)**	**Remaining in Gas Phase (% of ash emitted)**	**Present as Sulfates (% of total alkali in gas phase)**	**Present as Oxides (% of ash emitted, at catalyst)**	**Lignite Column F, Adjusted Based on Ash Content and % Emitted**
Source	Source		Figure 1	Figure 2	Note (1)	Figure 4	Note (2)	Note (3)
Column		A	B	C	D	E	F	G
Lignite								
Ash (% coal)	fn 62	7.8						
Ash Emitted (%)	fn 63	30.0						
Ca (% ash)	fn 62	17.0	100	65	5.95	24	4.52	-
Na (% ash)	fn 62	5.6	100	5	5.32	63	1.97	-
K (% ash)	fn 62	1.0	65	37	0.41	100	0.00	-
PRB1								
Ash (% coal)	fn 62	5.0						
Ash Emitted (%)	fn 63	80.0						
Ca (% ash)	fn 62	17.3	100	70	5.19	10	4.67	2.65
Na (% ash)	fn 62	1.6	100	10	1.44	81	0.27	1.15
K (% ash)	fn 62	0.5	100	18	0.41	100	0.00	0.00
TOTAL							**4.94**	**3.80**

(1) AxBx(1-C)/10,000
(2) Dx(1-E)
(3) Lignite column F x (Lignite ash/PRB ash)(Lignite Ash Emitted/PRB1 Ash Emitted)

This extrapolation from the EPRI modeling demonstrates that calcium oxides are the main constituents of concern in both coals, not sodium oxides as widely argued in the record. The calcium oxides are present at much higher concentrations (4.52% for lignite and 4.67% for PRB) than sodium oxides (1.97% for lignited and 0.27% for PRB) in the emitted ashes from both coals at the SCR catalyst in the high dust position. This position is the worst-case for SCR. The September 21, 2011, FIP proposed to locate the SCR after either the electrostatic precipitator or scrubber, which would significantly reduce the concentration of these alkali oxides, compared to the estimates in Table 2. 76 Fed. Reg. at 58,605-07.

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[62] Preliminary BACT Determination, *supra* note 8, at 18, Table 1.

[63] The dust loading of the flue gas from coal-fired cyclone units is in the range of 20 to 30% of the ash in the coal, compared with about 80% for a dry-ash pulverized coal-fired unit, simulated in the EPRI study. *See* Babcock & Wilcox, Steam: Its Generation and Use at 10-6 (1978).

Sodium oxides, on the other hand, are present in much lower concentrations in the emitted ashes of both coals at the catalyst (1.97% for lignite and 0.27% for PRB). While more sodium oxide is present in lignite ashes than in PRB ashes, the amount is small, on the order of only 2% of the emitted ash and when expressed on a whole coal basis, less than 0.1%.[64] Further, at the low-dust or tail-end catalyst position, these amounts would be even lower, as demonstrated by the Microbeam study.

However, despite higher ash content in lignite, larger amounts of PRB ash arrive at the catalyst face because 80% to 90% of the PRB coal ash is emitted as fly ash while only 30% to 50% of the lignite ash is emitted. To account for the differences in ash content and ash emitted, and to provide a direct comparison between the two situations, Column G of Table 2 adjusts the percent of alkali oxides in the emitted lignite ash at the face of the catalyst. After adjustment and summing, the percent of the three alkali metal oxides in the emitted ash is higher for PRB (4.94%) than for lignite (3.80%). This suggests the SCR poisoning potential of PRB is similar to or greater than the poisoning potential of lignite, in the high dust position, which represents a worst case.

SCR has been widely (and successfully) used on PRB-fired units. Most of these units are pulverized coal-fired boilers. Pulverized coal-fired boilers present a worst-case fouling situation as they generate three to four times more fly ash than cyclone boilers, where the ash ends up as slag. The lower ash loading in cyclone-fired units minimizes catalyst erosion and plugging, as compared to pulverized coal applications.

Metal oxide deactivation of SCR catalyst used on PRB-fired cyclone and pulverized coal-fired boilers has been studied and solved. High-dust SCR has been widely and successfully used to remove NOx from PRB flue gases, including from many PRB-fired cyclone boilers. Fouling from calcium and sodium oxides is readily taken into consideration in the design of SCRs for PRB- and other coal-fired units.[65]

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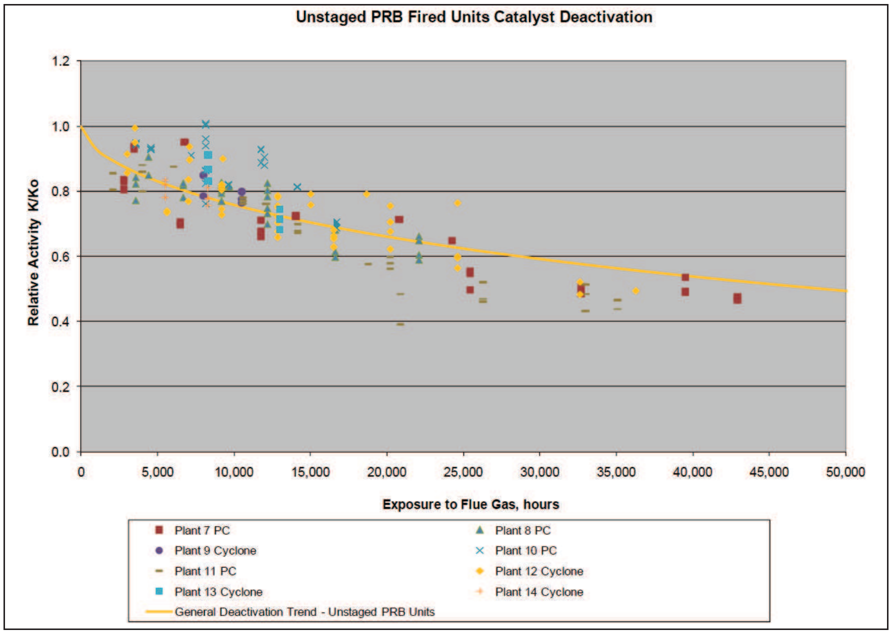
[64] Present as oxides, expressed as % of coal calculated from Table 2 as: Fx(Ash %)x(Ash % Emitted)/10,000.

[65] *See* Cochran, *supra* note 11.

Figure 4: Deactivation rates of typical PRB-fired units[66]



The subject poisons are water soluble and can be controlled by periodic catalyst washing, a technique used on many PRB-fired boilers. The SCR system can be designed to take deactivation into account, for example, by using large pitch, special catalyst formulations, and soot blowing. Fuel composition is simply not an issue for a properly designed SCR on a cyclone boiler firing North Dakota lignite.

In sum, this equilibrium modeling suggests that an SCR treating lignite flue gases in the low-dust or tail-end positions should experience similar or less catalyst deactivation from free alkali metals than PRB coals where SCR has been successfully used for many years. Potassium will never be an issue for either lignite or PRB, contrary to claims in the record, because it will be scavenged and sulfated completely before it reaches the catalyst. Calcium appears to be the alkali of greatest concern for both lignite and PRB. Calcium is not significantly sulfated in either lignite or PRB before arriving at the catalyst and is present in relatively high amounts in both coals. Thus, any free calcium that makes it through the ESP could deactivate the catalyst, but in amounts that can be controlled to acceptable levels using standard design—a fact that is well-established based on the successful use of SCR at PRB coal-burning boilers.

3. Successful Use of SCR at Texas Lignite Plants Affirms Feasibility of SCR at MRYS and LOS

At the time the BACT determination was made, there was very little experience with SCR on lignite coals in the U.S. At that time, three SCRs had just started operating on lignite-fired units–Oak Grove Units 1 and 2 and Sandow Unit 4, all in Texas. The

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[66] *Id.* at 21.

SCR on Oak Grove Unit 1 had been in operation since December 2009 (10 months), the SCR on Unit 2 since May 2010 (6 months), and the SCR on Sandow Unit 4 since April 2010 (7 months).[67] None had operated for the full guaranteed lifetime of the catalyst.

Since then, about three years of SCR operating experience has been gained at these lignite-fired units, exceeding catalyst guaranteed lifetime. There have been no catalyst problems attributable to burning lignite. These units are meeting NOx emission limits that are substantially lower than proposed as BART for MRYS and LOS Unit 2. Oak Grove burns 100% Texas lignite and controls NOx with an SCR in the high dust position to 0.08 lb/MMBtu, required as BACT.[68] Sandow Unit 4 similarly uses SCR to control NOx to 0.080 lb/MMBtu.[69] This information should be considered by EPA in reconsidering BART for MRYS and LOS Unit 2. The catalyst for two of these SCRs was supplied by Johnson Matthey Catalysts[70], who has written a letter, discussed in Section IV.A. of these comments, indicating Johnson Matthey Catalysts would guarantee SCR on North Dakota lignite with standard industry performance and lifetime catalyst guarantees.[71]

The fact that these plants burn lignite from Texas rather than from North Dakota is immaterial. There is nothing unique about North Dakota lignite that would justify a separate source classification for purposes of establishing either BACT or BART for NOx emissions. While it is true that North Dakota lignite contains more sodium in its ash than PRB coal, Texas lignite contains much higher ash content (12.6%) than North Dakota lignite (7.8%).[72] In fact, every coal is unique and the catalyst must be specially formulated and the SCR system designed to address each case. We are not aware of any situation where SCR failed because the catalyst vendor could not design for specific coal and ash conditions.

There is no rational basis in the record for carving out a North Dakota lignite exception for NOx BART or BACT based on state lines, particularly given EPA's presumptive BART limit for lignite fired cyclone boilers. Thus, EPA bears a substantial burden to support its rejection of SCR here as BART just because there are no other "North Dakota lignite" fired plants that use SCR. SCR in fact is being successfully used

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[67] *See* Tex. Comm'n on Envtl. Quality, Permit Numbers 76474, PSD-TX-1056 (Feb. 5, 2010); Federal Operating Permit No. O54: Sandow Steam Electric Station (Mar. 12, 2010); Notice of Filing of Proposed Stipulation by the United States To Resolve Certain Alleged Violations of a Clean Air Act Consent Decree With Alcoa, Inc., 71 Fed. Reg. 67,640 (Nov. 22, 2006) (requiring "[a] commitment by TXU Sandow to install selective catalytic reduction system ("SCR") to eliminate most of the remaining NOX emissions from Sandow Unit 4").

[68] Tex. Comm'n on Envtl. Quality, Permit Numbers 76474, PSD-TX-1056 at 3-4, (Feb. 5, 2010); Construction Permit Review Analysis & Technical Review: Oak Grove Management Company LLC Permit No. 76474 at 1 (2006).

[69] Federal Operating Permit No. O54: Sandow Steam Electric Station at 10 (Mar. 12, 2010).

[70] Hartenstein, *supra* note 34, at A-16 & n.30. Johnson Matthey acquired Argillon in 2008.

[71] *See, e.g.,* Letter from Jeffers, *supra* note 37.

[72] Preliminary BACT Determination, *supra* note 8, at 18, Table 1.

in the US and elsewhere on "lignite" fired plants and on other low rank coals, burned in both pulverized coal fired and cyclone boilers. As EPA aptly noted in its responses to comments on the NOx NSPS for electric generating units, the reason there are no SCRs on North Dakota lignite-fired cyclone boilers is that none have been built since 1986, before the era when SCR was widely available.[73] Thus, absence does not demonstrate infeasibility.

V. Controls Short of SCR Could Achieve Greater Emissions Reductions than EPA is Proposing to Require

If EPA does not select SCR as BART—which would be unjustified—at a minimum, it must require an emission lower than the BACT emission limit. Feasible controls used in combination with SNCR, including CyClean at MRYS and TIFI at LOS, would allow for MRYS and LOS to achieve greater emission reductions than required by the BACT limits, further supporting the conclusion that EPA cannot adopt the BACT decision as BART. In addition, MRYS and LOS could optimize an SNCR system with other NOx removal technologies.

A. CyClean at MRYS

CyClean is ADA-ES's patented refined coal technology that enhances combustion and reduces emissions when coal is burned in cyclone boilers. The process uses a simple storage and conveying system to add a cost-effective granular additive after the coal leaves the crusher house, evenly distributing it before combustion. Two components are added directly to the coal belt just prior to the crusher: Cyclean A, a fluxing additive to improve cyclone bottom-slag flow and Cyclean B, a liquid additive that changes elemental mercury to a form that can be captured as a particulate. This technology has been installed at and is in full-time operation at 14 coal-fired boilers and is reported to reduce NOx emissions by more than 20%.[74] CyClean was not identified or considered in any of the subject BACT or BART determinations.

Most cyclone-fired boilers have switched from their design fuel, typically bituminous coal, to PRB coal, a low-rank fuel similar to lignite. This switch was done to reduce SO_2 emissions, lower NOx levels, and reduce fuel costs. Cyclone boilers were designed for high sulfur Midwestern bituminous coal. Switching to PRB has caused some problems that can be alleviated with CyClean including:

- Slag layer in cyclone barrel is too thin for good combustion
- "Eyebrows" of slag build up in cyclone
- Slag freezes in the "monkey hole" and won't tap easily
- More coal burns in suspension and increases flyash loading
- Incomplete combustion raises LOI in flyash
- Less bottom ash produced

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[73] 71 Fed. Reg. 9,866, 9,870 (Feb. 27, 2006).

[74] Refined Coal, ADA-ES, http://www.adaes.com/products-services/refined-coal/ (last visited June 7, 2013)

- Must blend in bituminous “kicker” coal to unclog slag tap
- Only one or two PRB coals are “acceptable” fuels
- Unit cannot operate at lower load levels without slag tap freeze-up.[75]

These problems are also common at lignite-fired cyclone boilers. CyClean was implemented at MRYS in 2011 to improve cyclone boiler operations and reduce emissions. It has been demonstrated to reduce NOx emissions by 20% at MRYS.[76]

EPA has not considered whether the effectiveness of CyClean could be improved or whether it could be used in combination with other NOx control options to increase overall NOx removal or affect SCR performance.

Further, the patents on CyClean suggest that it may improve the exhaust gas quality, reducing or eliminating some of the SCR catalyst fouling issues used by North Dakota to reject SCR as BACT. The additive, for example, results in reduced entrained particles in the flue gas.[77] Thus, the SCR catalyst fouling claims relied on to reject SCR in North Dakota’s BACT analysis should be revisited by EPA in light of the fact that CyClean was already in use at MRYS when it made its BART determination assuming BACT equals BART.

B. SOFA/SNCR at MRYS

If EPA does not select SCR as BART, EPA should consider reducing emission limits beyond those based on SOFA/SNCR at MRYS based on existing technologies in place, and feasible updates. For example, the utilization of CyClean means that MRYS’s limits based on SOFA/SNCR should be lower. As CyClean reduces NOx emissions by 20% by improving combustion, the SOFA/SNCR system no longer has to operate at the assumed BART NOx control efficiency of 58%. *See* 76 Fed. Reg. at 58,598, Table 26. Thus, it does not represent the “degree of reduction achievable through the application of the best system of continuous emission reduction,” as explicitly required by the definition of BART. 40 C.F.R. § 51.301. Assuming CyClean is removing at least 20% of the NOx, ASOFA/SNCR can operate at only 47% to 48% efficiency and still meet the NOx BART emission limits.[78]

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[75] McIlvaine, ADA-ES CyClean System for Cyclone-fired Boilers Firing PRB Coal, FGD and DeNOx Newsletter No. 411 (July 2012).

[76] Minnkota Power Cooperative Demonstrates Lignite Innovation, Partners for Affordable Energy, http://powerofcoal.com/successstories/minnkota-power-cooperative-demonstrates-lignite-innovation/ (last visited June 7, 2013).

[77] Kenneth E. Baldrey et al., Additives for Mercury Oxidation in Coal-fired Power Plants, U.S. Patent 8,293,196 (May 14, 2013), http://patft.uspto.gov/netacgi/nph-Parser?Sect1=PTO2&Sect2=HITOFF&p=1&u=%2Fnetahtml%2FPTO%2Fsearch-bool.html&r=1&f=G&l=50&co1=AND&d=PTXT&s1=8124036&OS=8124036&RS=8124036.

[78] For MRYS Unit 1, the assumed NOx baseline is 0.36 lb/MMBtu/(1-0.581) = 0.86 lb/MMBtu. 76 Fed. Reg. at 58,598, Table 26. Assuming 20% NOx control by CyClean, the revised baseline is (0.86 lb/MMBtu)(0.8) = 0.69 lb/MMBtu. The NOx control efficiency for ASOFA/SNCR to reach 0.36 lb/MMBtu is thus 1-(0.36/0.69) = 48%.

EPA assumed that the combination of SNCR + ASOFA could reduce emissions by 58%, reducing assumed baseline emissions to the 30 day rolling average emission limits of 0.36 lb/MMBtu at Unit 1 and 0.35 lb/MMBtu at Unit 2. 76 Fed. Reg. at 58,598. Thus, in combination with the 20% CyClean reductions noted above, the appropriate 30 day rolling average emission limits for Units 1 and 2 should be no higher than 0.29 and 0.28 lb/MMBtu, respectively.[79]

Further, given it is possible to consider the addition of SCR following ASOFA/SNCR, which is referred to as a "hybrid" or "advanced" SCR system. The ammonia slip from an SNCR, which is quite high and unlimited in the instant case, could be beneficially used in an in-duct SCR.[80] One of the key problems with SNCR taken alone is the high ammonia slip, which offsets some of the visibility improvement achieved by reducing NOx, one of the key BART statutory factors not considered in the underlying BACT determination.

However, in a hybrid SNCR-SCR system, the ammonia slip from the SNCR can be used as reactant feed to the SCR. As the upstream SNCR achieves significant NOx reductions, the downstream SCR, the more expensive component, can be downsized, including less catalyst, a smaller SCR reactor, less duct modification, catalyst, and fan. The smaller catalyst volume would also reduce the potential for oxidation of SO_2 to SO_3 within the catalyst, reducing the potential for in-pore catalyst plugging by sulfation of any active alkali metals. This arrangement would significantly improve the cost effectiveness of SCR and greatly improve the NOx reduction, compared with EPA's selected NOx BART control technology. This arrangement is offered, for example, by Fuel Tech, as the NOxOUT Cascade system[81] and has been successfully used on coal-fired boilers.[82]

Finally, as discussed in Section V.D. below, PerNOxide™ could improve on the performance of ASOFA/SNCR and further reduce the emission limit applicable as BART.

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[79] Unit 1 limit: 0.36 x (1-0.2) = 0.29
Unit 2 limit: 0.35 x (1-0.2) = 0.28

[80] Brian K. Gullett et al., NOx Removal with Combined Selective Catalytic Reduction and Selective Noncatalytic Reduction: Pilot-Scale Test Results, 44 J. Air & Waste Mgmt. Ass'n 1188, 1189 (Oct. 1994), *available at* http://www.tandfonline.com/doi/pdf/10.1080/10473289.1994.10467313.

[81] NOxOUT Cascade, Fuel Tech, Inc., http://www.ftek.com/en-US/products/apc/noxout-cascade (last visited June 7, 2013); *see also* V. Albanese et al., Hybridization of Urea-SNCR with SCR: A Fit for the Future (Mar. 2005), *available at* http://www.ftek.com/media/en-US/pdfs/TPP-566.pdf.

[82] Kevin Dougherty, Advanced Selective Catalytic Reduction System Operating on a Coal-Fired Boiler (2013), *available at* http://www.ftek.com/media/en-US/pdfs/2013_EUEC_ASCR.pdf; Daniel P. Connell, Greenidge Multi-Pollutant Control Project, Final Report of Work Performed May 19, 2006 – October 18, 2008 (Apr. 2009), *available at* http://www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/greenidge/GreenidgeProjectFinalReport-5-27-09.pdf; Daniel P. Connell et al., The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation (Aug. 2008), *available at* http://www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/greenidge/MEGA08_Paper.pdf

C. TIFI at LOS Unit 2

LOS Unit 2 uses a chemical additive system to control slagging problems from burning low rank coals and overfire air. The additive system, like CyClean at MRYS, also reduces NOx. LOS Unit 2 installed Targeted In-Furnace Injection (TIFI) to control boiler slagging and fouling in January 2009. In November 2009, new retrofit overfire air (OFA) ports were installed and TIFI was upgraded. The OFA ports were subsequently required as part of the BART determination. The TIFI system involves mixing chemicals with a catalyst, air and water and injecting them into the furnace at targeted locations based on Computational Fluid Dynamics modeling.[83]

The CEMS data reported by the facility indicates TIFI/OFA reduced NOx emissions from an average of 0.52 lb/MMBtu in 2008 to an average of 0.31 lb/MMBtu or by 40%, from November 5, 2009, when the OFA ports were installed and TIFI was upgraded, through the end of 2012.[84] The rolling 30-day average over this period met the BART limit of 0.35 lb/MMBtu (startups and shutdown subject to separate limit) based on 54.5% NOx control achieved using ASOFA/SNCR. 76 Fed. Reg. at 58,598, Table 26. The vendor reported a 15% to 18% decrease in NOx emissions due to increased furnace cleanliness and improved heat transfer from TIFI plus a further 30% to 40% reduction in NOx due to the overfire air ports.[85]

Indeed, in combination with the OFA installed later in 2009, EPA emissions data indicate that TIFI reduced NOx emissions from an annual average of 0.52 lb/MMBtu to approximately 0.31 lb/MMBtu by the end of 2012.[86] Applying the 15-18% emissions reduction from TIFI to the prior 30 day BART limit of 0.35 lb/MMBtu, which reflects the use of SNCR + ASOFA, yields a revised limit of 0.29-0.30 lb/MMBtu. Accordingly, the emission limit for LOS Unit 2 should be no higher than 0.30 lb/MMBtu (on a 30-day rolling average).[87] Thus, with TIFI, LOS Unit 2 can operate at the BACT NOx limit without SNCR. Thus, with TIFI, LOS Unit 2 can operate at the BACT NOx limit without SNCR.

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[83] Chris R. Smyrniotis & Kent W. Schulz, Recent Catalyst Development Results and the Observed Affects on NOx, CO, LOI, CO2, and Slag at 1 (July 2007), *available at* http://www.ftek.com/media/en-US/pdfs/TPP-578.pdf.

[84] EPA, Air Markets Program Data, *available at* http://ampd.epa.gov/ampd/.

[85] Allery et al., *supra* note 4, at 12.

[86] *See* EPA, Clean Air Markets Database, queries for emissions and heat input data for Leland Olds, *available at* http://ampd.epa.gov/ampd/QueryToolie.html.

[87] The emissions limit should likely be lower given that the State and EPA appear to have used an inappropriately high baseline for LOS Unit 2. The stated reductions of 54.5% from SNCR + ASOFA and the associated BART limit of 0.35 lb/MMBtu together imply a 30-day average baseline of 0.77 lb/MMBtu (0.35/(1-0.545) = 0.77), referenced most explicitly in LOS' August 2006 BART Determination Study (p. ES-3). However, EPA emissions data indicate that the maximum 30 day average during the baseline period – indeed, from 2000 through 2010 – was 0.71 lb/MMBtu.

D. PerNOxide^{TM}

PerNOxide is another feasible technology option to improve on the performance of ASOFA/SNCR at MRYS and LOS. This technology is a two-step process. Hydrogen peroxide is injected between the economizer and air preheater to oxidize nitrogen oxide (NO) in flue gas to NO2 and higher-order oxides. These oxides are then removed in downstream wet scrubbers, such as those installed on MRYS and LOS. It is applicable to all types of coal-fired boilers and coals. Pilot tests indicate that about 5,000 to 8,000 mg/L of dissolved sulfite is necessary to maximize NOx capture. This level is only available in sodium-based scrubbers, but can be produced by adding sodium as sodium carbonate or trona to lime or limestone inhibited oxidation scrubbers. It thus would be particularly attractive on the MRS units in combination with the existing SNCR system, as they are equipped with new (Unit 1) or newly upgraded (Unit 2) wet lime scrubbers, designed to achieve >95% SO2 removal.

At the current time, research and development is complete and FMC is actively seeking host sites for another full-scale demonstration site. FMC expects PerNOxide to be fully commercial by the end of 2013. Four full-scale trials have been conducted to date, including on a Texas lignite plant. There are no commercial installations yet, but talks are underway with several large western coal plants, including one fired on North Dakota lignite. FMC believes that they can achieve 40% to 50% NOx reduction, but they have not yet offered a commercial guarantee.[88]

PerNOxide offers higher NOx removal efficiencies than SNCR, lower capital and maintenance costs than SCR, and operational flexibility.[89] It uses existing ducts, a simple spray system, and economical chemistry, allowing significant NOx reduction without large capital investment. It can be easily integrated with an existing SNCR system to enhance NOx removal or to address high ammonia slip. Tests with North Dakota lignite demonstrated NOx removal efficiencies of 45% to 60% at N_2O_2/NOx molar ratios of 2.0 to 3.0.[90]

This technology was not commercially available at the time of the BACT or BART determinations but will be in the near term. This is precisely the type of new technologies that "would lead to cost-effective increases in the level of control" that should be evaluated when relying on a BACT determination under a separate statute. 40 C.F.R. Pt. 51, App. Y § IV(C). This technology could be easily integrated with the

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[88] Personal communications with Nathan Miller, Air Quality Analyst, NPCA.

[89] Bob Crynack & Sterling Gray, NO Oxidation and Capture with Wet and Dry Scrubbers (Apr. 27, 2012) *available at* http://environmental.fmc.com/media/resources/AirPollutionControl_workshop_presentation_final.pdf; Robert Crynack et al., Development of the FMC PerNOxide NOx Control Technology Using Hydrogen Peroxide (Oct. 26, 2011), *available at* http://environmental.fmc.com/media/resources/AirPollutionControlTechnicalPaper.pdf.

[90] Crynack & Gray, *supra* note 89, at 39.

existing SNCR system to increase overall NOx removal. We encourage EPA to consider this new technology.

VI. Conclusion

Evidence available at the time of EPA’s prior BART determinations, as well as new evidence, confirms that SCR is technically feasible and is BART for MRYS 1 and 2 and LOS 2. If EPA does not select SCR as BART—which would be unjustified and unsupported by the record—EPA should establish emissions limits below the prior limits based on SNCR.

Attachment A

Resume of Bill Powers, P.E.

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Thirty years of experience in:

- Power plant air emission control system and cooling system assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

POWER PLANT EMISSION CONTROL AND COOLING SYSTEM CONVERSION ASSESSMENTS

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NOx and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^{o}F and 13 ^{o}F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^{o}F and 13 ^{o}F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^{o}F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate.

Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Kentucky Coal-Fired Power Plant – Pulverized Coal vs IGCC. Expert witness in Sierra Club lawsuit against Peabody Coal Company's plan to construct a 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that Integrated Gasification Combined Cycle (IGCC) is a superior method for producing power from coal, from environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost competitive with pulverized coal.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Utility Boiler – Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Expert witness in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County. Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District. Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling. Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "\$/kwh" and "\$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^{o}F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ±1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Bay Area Smart Energy 2020 Plan . Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County. Report is available online at: http://pacificenvironment.org/-1-87.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support. Report at: http://www.etechinternational.org/new_pdfs/smartenergy/52008_SmE2020_2nd.pdf

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the

San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ^{o}F and 20 ^{o}F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ^{o}F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM_{10} RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10} control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ±1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

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PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B

Index of Documents Submitted in Support of Technical Comments on Proposed NOx BART Determinations for Milton R. Young and Leland Olds Stations

Index of Documents Submitted in Support of Technical Comments on Proposed NOx BART Determinations for Milton R. Young and Leland Olds Stations

I. Documents Provided on Flash Drive Submitted on June 14, 2013

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2. Dennis L. Arfmann et al., Appropriateness of Conducting Pilot Scale Testing of Selective Catalytic Reduction (SCR) Technology at Milton R. Young Station Units 1 and 2, for Use in a NOx BACT Analysis (Aug. 14, 2007), Doc. No. EPA-R08-OAR-2010-0406-0012
3. Gerry C. Snow & Gary S. Anderson, Fuel Tech's NOx Reduction and Fuel Chem Performance Improvements for Coal-Fired Steam Generators, Presentation at Scientech Symposium 2012, Clearwater Beach, FL
4. Burns & McDonnell, BART Determination Study for Leland Olds Station Unit 1 and 2, Final Draft (Aug. 2006)
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46. Minnkota Power Cooperative Demonstrates Lignite Innovation, Partners for Affordable Energy, http://powerofcoal.com/successstories/minnkota-power-cooperative-demonstrates-lignite-innovation/

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48. Brian K. Gullett et al., NOx Removal with Combined Selective Catalytic Reduction and Selective Noncatalytic Reduction: Pilot-Scale Test Results, 44 J. Air & Waste Mgmt. Ass'n 1188 (Oct. 1994)

49. NOxOUT Cascade, Fuel Tech, Inc., http://www.ftek.com/en-US/products/apc/noxout-cascade

50. V. Albanese et al., Hybridization of Urea-SNCR with SCR: A Fit for the Future (Mar. 2005)

51. Kevin Dougherty, Advanced Selective Catalytic Reduction System Operating on a Coal-Fired Boiler (2013)

52. Daniel P. Connell, Greenidge Multi-Pollutant Control Project, Final Report of Work Performed May 19, 2006 – October 18, 2008 (Apr. 2009)

53. Daniel P. Connell et al., The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation (Aug. 2008)

54. Chris R. Smyrniotis & Kent W. Schulz, Recent Catalyst Development Results and the Observed Affects on NOx, CO, LOI, CO2, and Slag (July 2007)

55. Bob Crynack & Sterling Gray, NO Oxidation and Capture with Wet and Dry Scrubbers (Apr. 27, 2012)

56/57. Robert Crynack et al., Development of the FMC PerNOxide NOx Control Technology Using Hydrogen Peroxide (Oct. 26, 2011)

II. Documents Uploaded as Attachments on regulations.gov on June 17, 2013

1. Black & Veatch, Platte River Power Authority Rawhide Energy Station: Rawhide NOx Reduction Study a (Jan. 2009)
2. Tex. Comm'n on Envtl. Quality, Permit Numbers 76474, PSD-TX-1056 (Feb. 5, 2010)
3. Federal Operating Permit No. O54: Sandow Steam Electric Station (Mar. 12, 2010)

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NOV 19 2014

Ref: 8P-AR

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
(Public Comment Version)

Dear Mr. O'Clair:

The Environmental Protection Agency has completed a preliminary review of North Dakota's September 2014 draft Regional Haze State Implementation Plan (SIP) 5-Year Progress Report. Our comments are below.

We understand that you intend to consider all comments received on this public comment version of the progress report before finalizing the document. Please note 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). Thank you for revising the document to address many of the comments in our August 25, 2014 letter. However, three issues we raised in that letter remain unresolved:

1. Section 1.2, North Dakota SIP Summary: North Dakota remarks that Theodore Roosevelt National Park (TRNP) consists of three separate units. We recommend removing this language. As we and the federal land managers 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.

2. Section 1.2, North Dakota SIP Summary: 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, with some revised language, that additional controls required by the EPA's Federal Implementation Plan (FIP) would have a "small 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 further revising this section to reflect that the FIP will generally result in greater visibility benefits than the original SIP and to reference visibility benefits from the installation of combustion controls at Antelope Valley Station consistent with CALPUFF modeling North Dakota performed for this source in addition to the state's hybrid modeling results.

3. Section 2.8, Determination of Adequacy: We encourage the state, as it prepares the next regional haze SIP revision, to continue investigating the reasons sulfate extinction is not decreasing, and to further study oil and gas impacts.

We appreciate the opportunity to work with the North Dakota Division of Air Quality during the review of this public comment 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

Response to Comments

Regional Haze

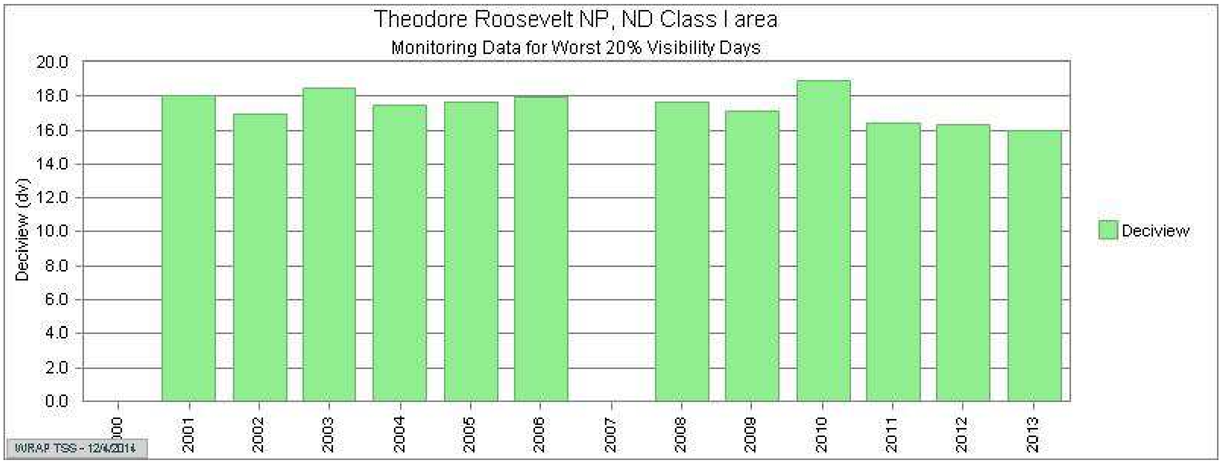
Five Year Progress Report

January 2015

Comment 1: The SIP is inadequate to achieve reasonable progress towards the national visibility goal because of increased oil and gas activities in western North Dakota. The SIP must be revised.

Response: The NDDH disagrees with this comment. Emissions reductions from the sources affected by the SIP essentially began in 2011. Since that time, a new scrubber at the M.R. Young Station (MRYS) Unit 1 has come on line and the Unit 2 scrubber has been updated. In addition, SNCR and advanced separated overfire air (SOFA) has been put in place and operated on both units. At Leland Olds Station (LOS), two new scrubbers for sulfur dioxide have been placed into service and reduction of nitrogen oxides has occurred.

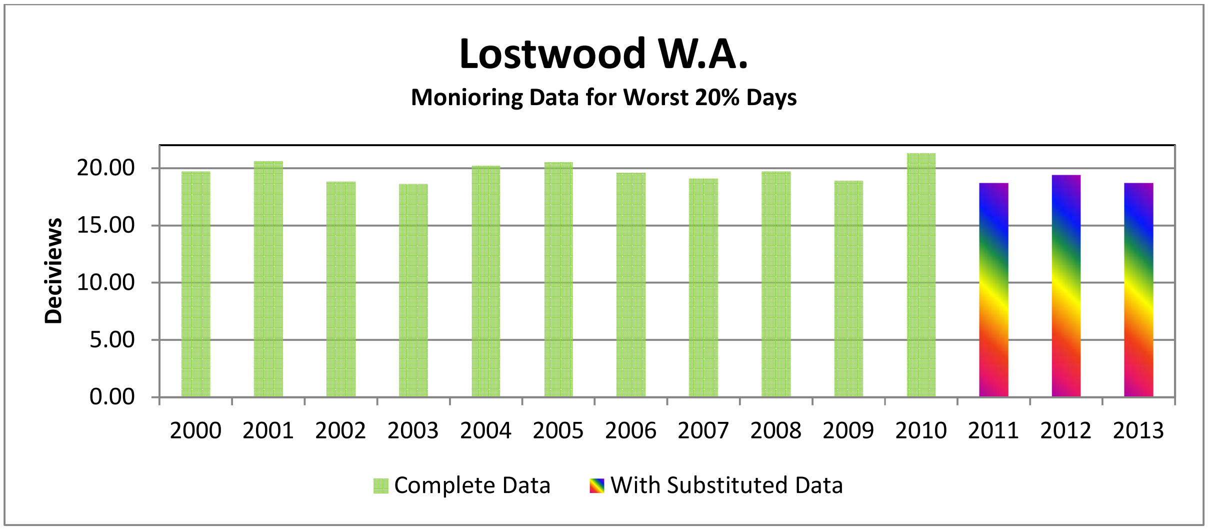
When this Progress Report (RP) was being developed, IMPROVE data were available up through 2012. Since that time, 2013 IMPROVE data have become available. The data for the last three years (2011-2013) indicate that the emissions reductions already achieved have lowered visibility impairment in the 20% worst days at Theodore Roosevelt National Park (TRNP) to levels below the Reasonable Progress Goal (RPG) specified in the SIP (16.9 dv). In fact, the latest five year (2009-2-013) average impairment in deciviews is 16.9 dv, the same as the RPG.



Site	Method	Year	N	Deciview
THRO1	NIA	2001	22	18
THRO1	NIA	2002	19	17
THRO1	NIA	2003	21	18.4
THRO1	NIA	2004	23	17.5
THRO1	NIA	2005	24	17.6
THRO1	NIA	2006	22	17.9
THRO1	NIA	2008	24	17.6
THRO1	NIA	2009	24	17.2
THRO1	NIA	2010	24	18.9
THRO1	NIA	2011	23	16.4
THRO1	NIA	2012	24	16.3
THRO1	NIA	2013	21	16

It is clear that increased oil and gas activity is not impeding progress toward the RPG at TRNP since the RPG has already been achieved.

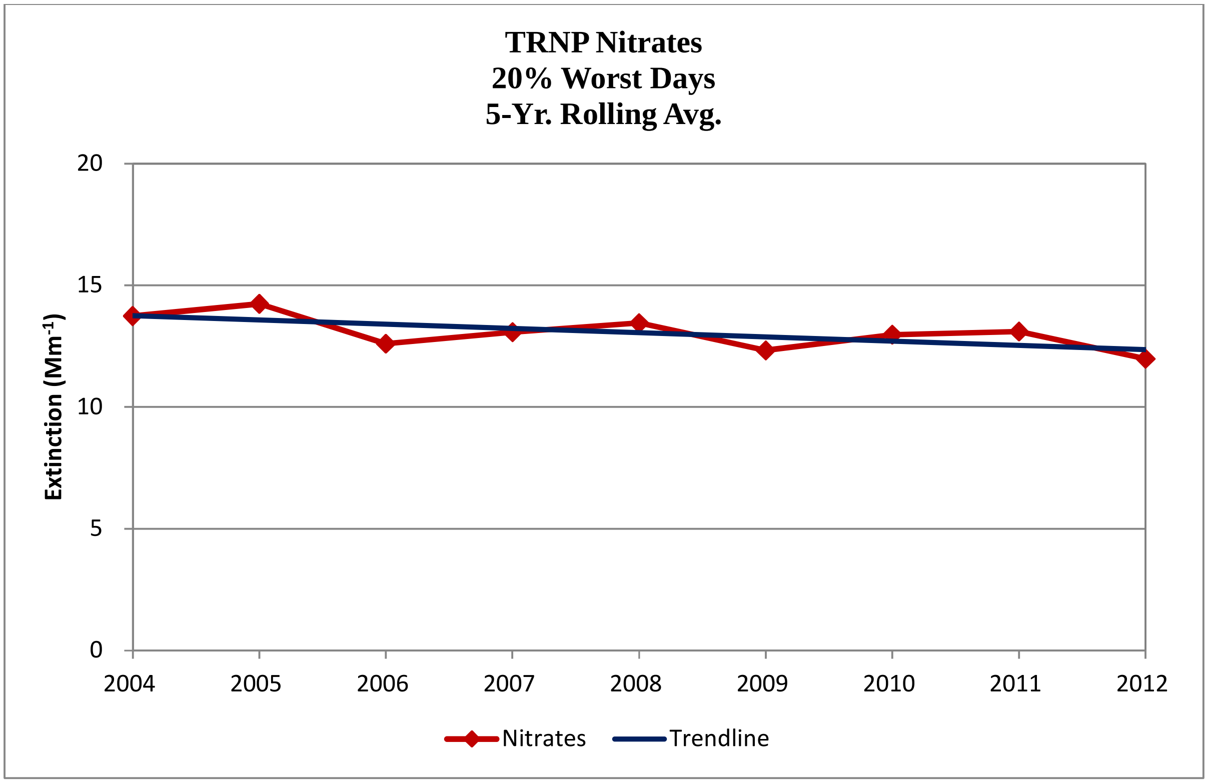
The IMPROVE data for 2011-2013 for the Lostwood Wilderness Area (LWA) are considered incomplete due to missing data. However, the Department has used the Western Regional Air Partnership (WRAP) substitution protocol for the LWA data and substituted Medicine Lake (MELA) IMPROVE data. The MELA IMPROVE site is located approximately 90 miles west of the LWA IMPROVE site near oil field activities. From the data (mostly LWA IMPROVE data and some substituted MELA IMPROVE data), the NDDH has generated visibility impairment values (dv) for those three years. The data indicate that the impairment was 18.4 dv in 2011, 19.4 dv in 2012 and 18.7 dv in 2013 compared the RH SIP RPG of 18.9 dv. The average of the 2011 to 2013 period is 18.9 dv (same as the RPG) with a five year average of 19.4 dv.

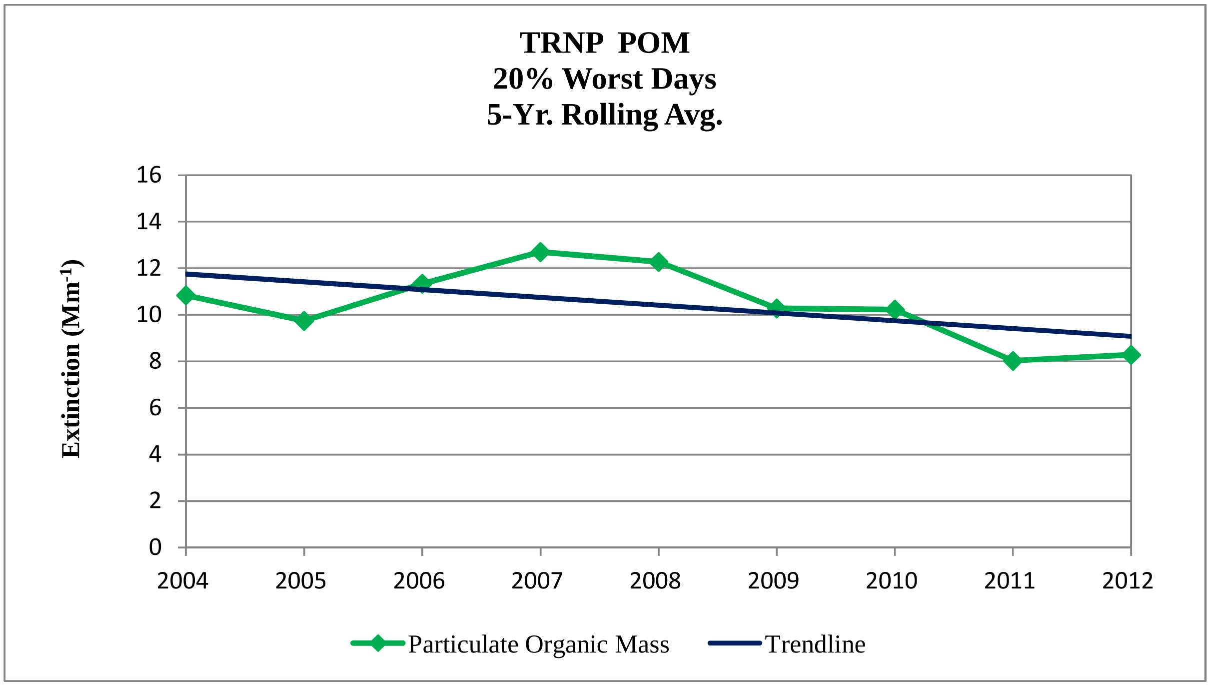


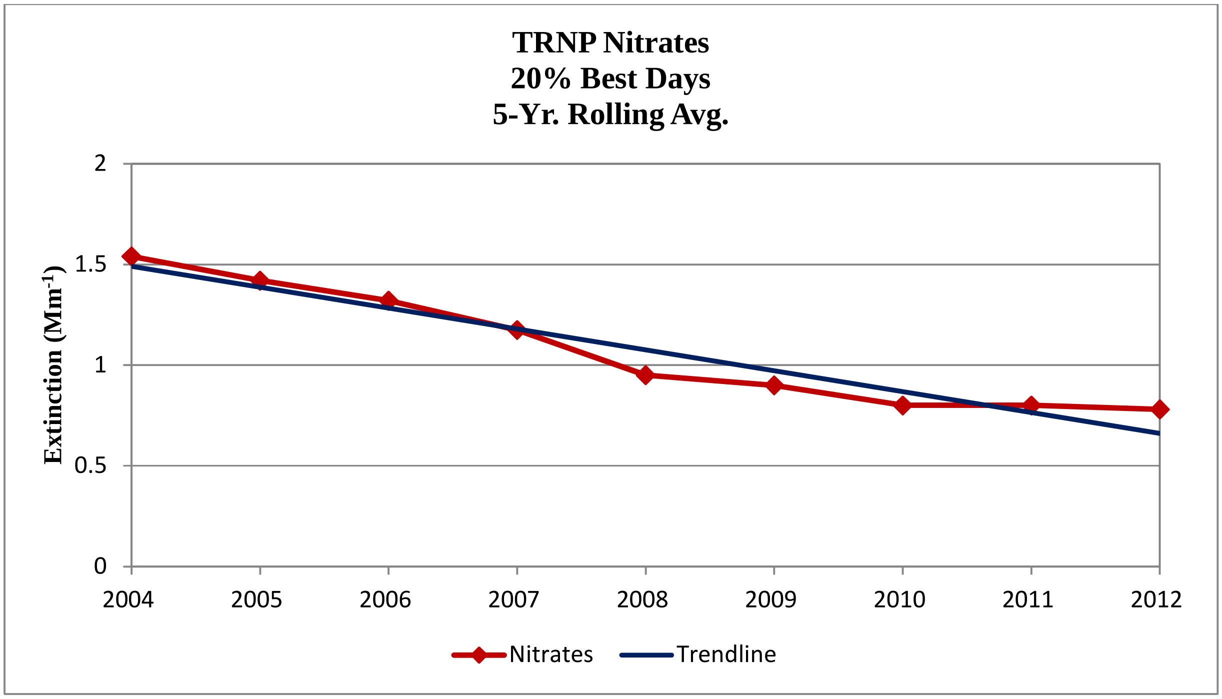
Site	Year	Deciviews
Lost1	2000	19.7
Lost1	2001	20.6
Lost1	2002	18.8
Lost1	2003	18.6
Lost1	2004	20.2
Lost1	2005	20.5
Lost1	2006	19.6
Lost1	2007	19.1
Lost1	2008	19.7
Lost1	2009	18.9
Lost1	2010	21.4
Lost1	2011	18.4
Lost1	2012	19.4
Lost1	2013	18.7

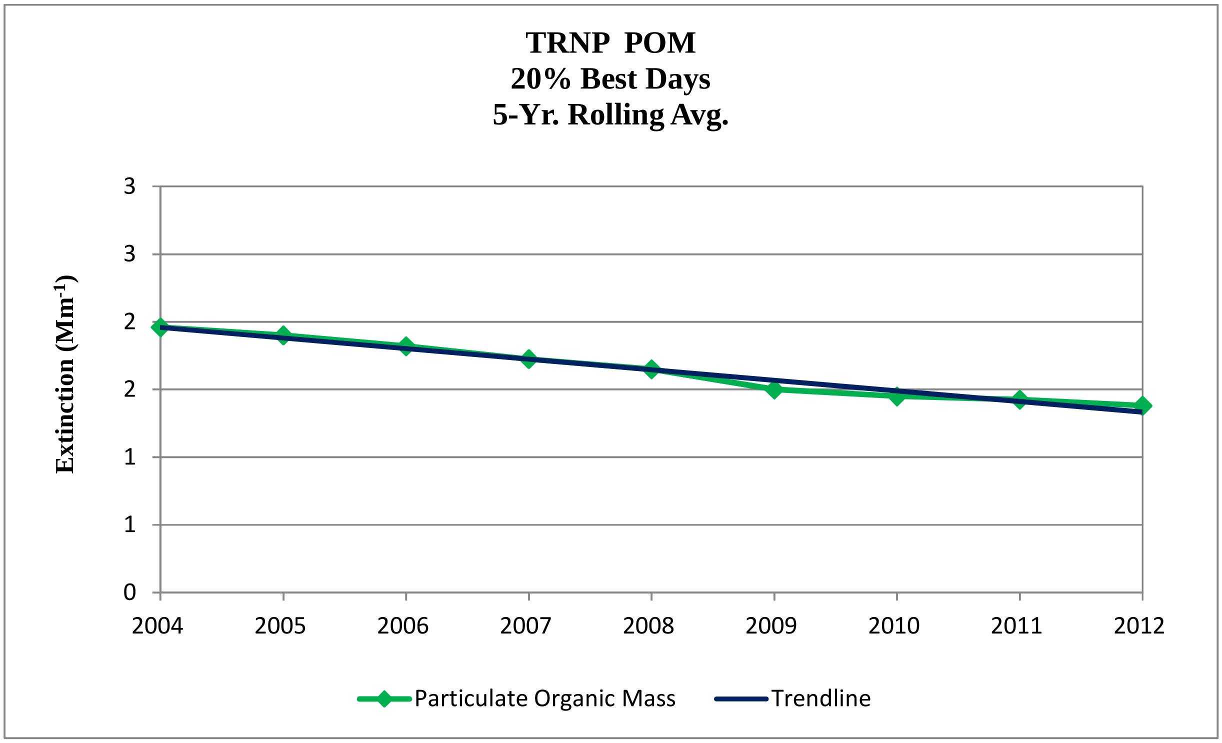
Nitrogen Oxides and VOC Emissions From Oil and Gas Activity

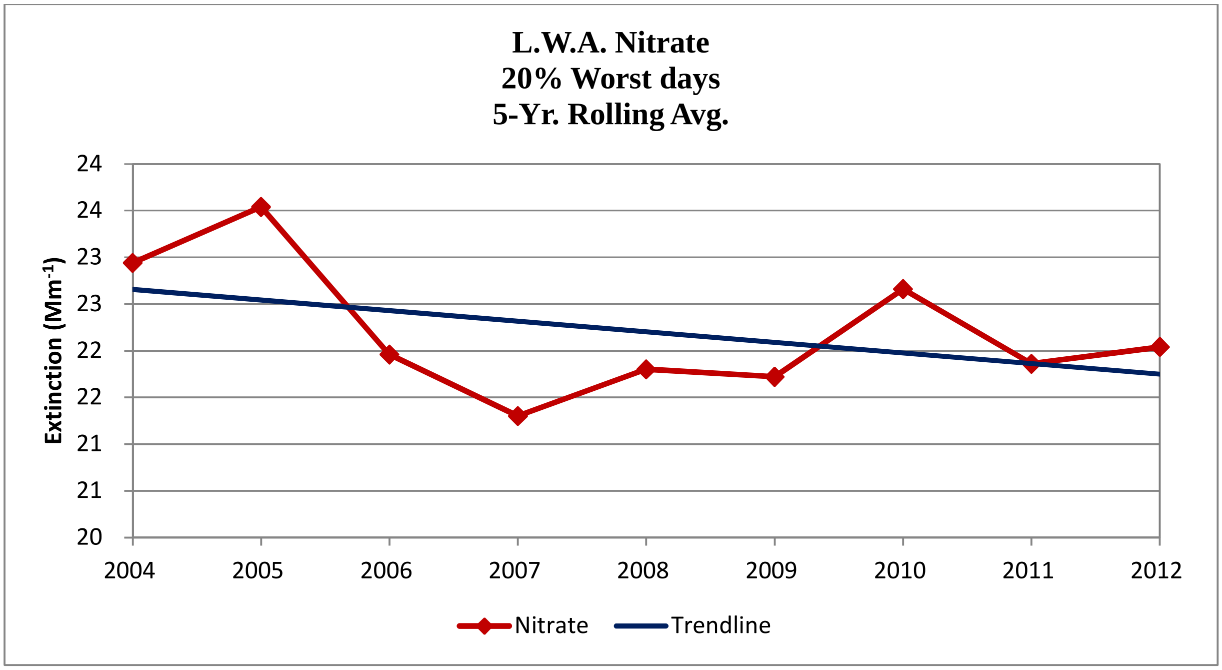
The primary emissions from oil and gas activity are nitrogen oxides and volatile organic compounds. These emissions are precursors of ammonium nitrate (nitrate) and particulate organic mass, or material (POM). As suggested by a commenter, the NDDH has evaluated the five year rolling averages of the extinction caused by nitrates and particulate organic mass at TRNP and LWA. The following graphs show that the five year rolling averages for nitrates and POM are declining despite increasing oil and gas activity.

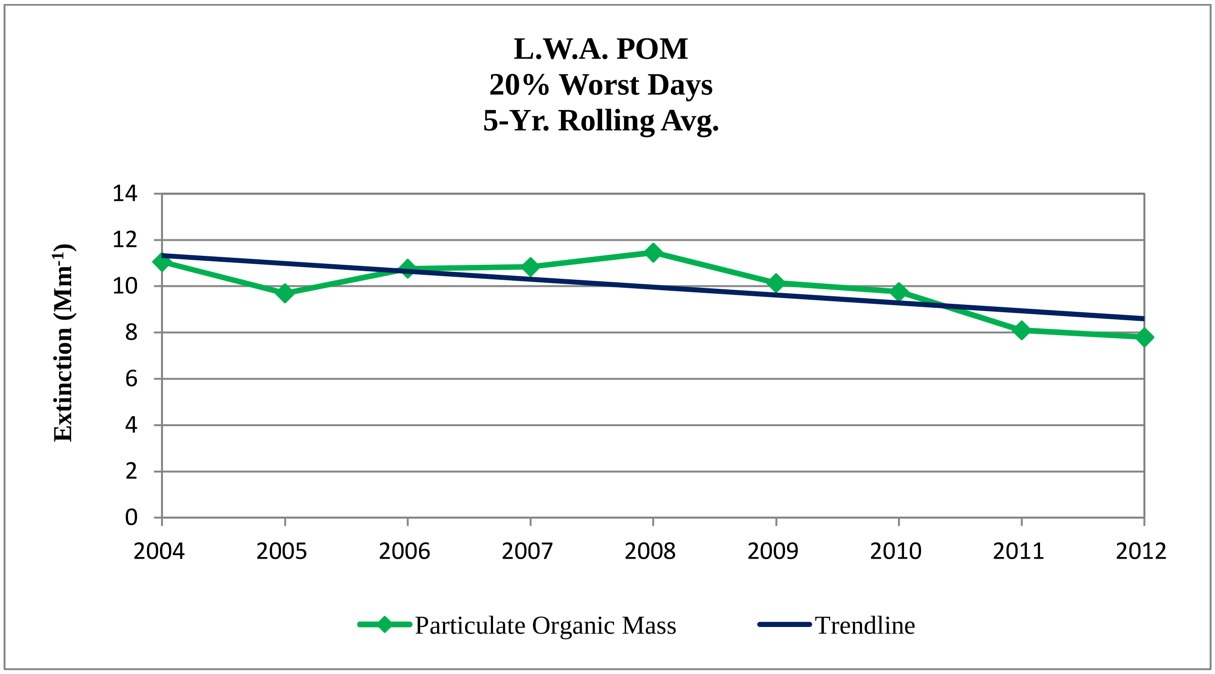


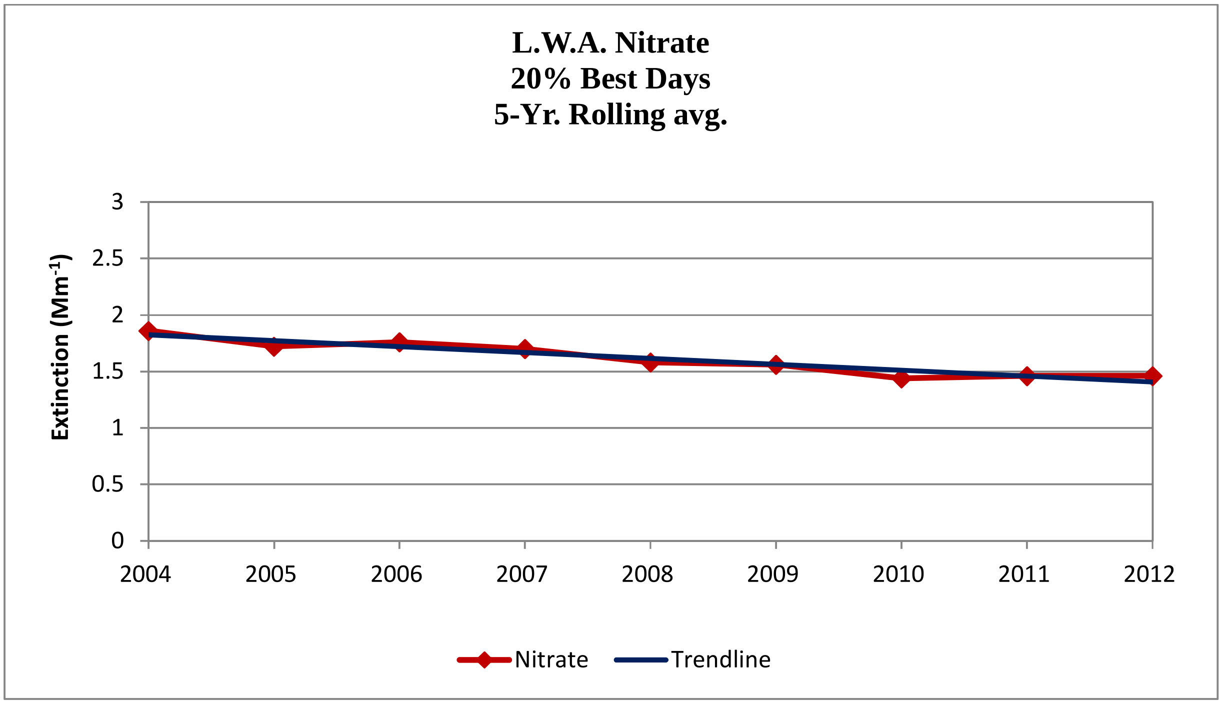

TRNP POM
20% Worst Days
5-Yr. Rolling Avg.
Extinction (Mm^{-1})
16
14
12
10
8
6
4
2
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
Particulate Organic Mass
Trendline

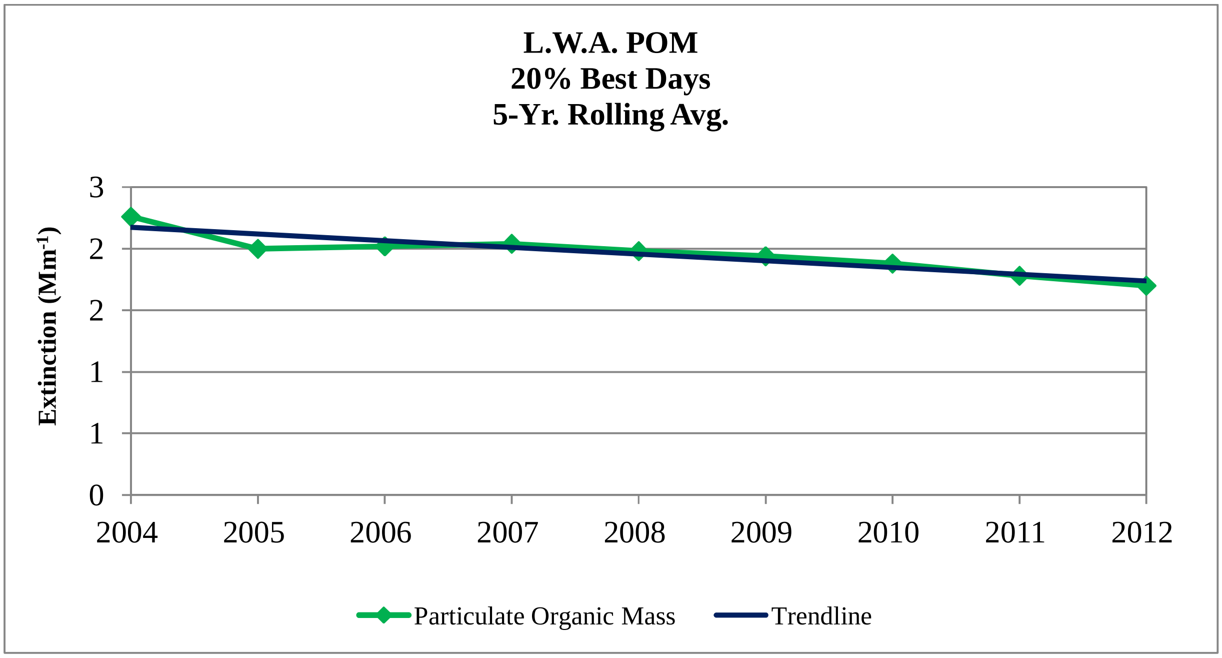

TRNP Nitrates
20% Best Days
5-Yr. Rolling Avg.
Extinction (Mm^{-1})
2
1.5
1
0.5
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
Nitrates
Trendline


TRNP POM
20% Best Days
5-Yr. Rolling Avg.
Extinction (Mm^{-1})
3
3
2
2
1
1
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
Particulate Organic Mass
Trendline


L.W.A. Nitrate
20% Worst days
5-Yr. Rolling Avg.
Extinction (Mm^{-1})
24
24
23
23
22
22
21
21
20
2004
2005
2006
2007
2008
2009
2010
2011
2012
Nitrate
Trendline


L.W.A. POM
20% Worst Days
5-Yr. Rolling Avg.
Extinction (Mm^{-1})
14
12
10
8
6
4
2
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
Particulate Organic Mass
Trendline


L.W.A. Nitrate
20% Best Days
5-Yr. Rolling avg.
Extinction (Mm^{-1})
3
2.5
2
1.5
1
0.5
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
Nitrate
Trendline



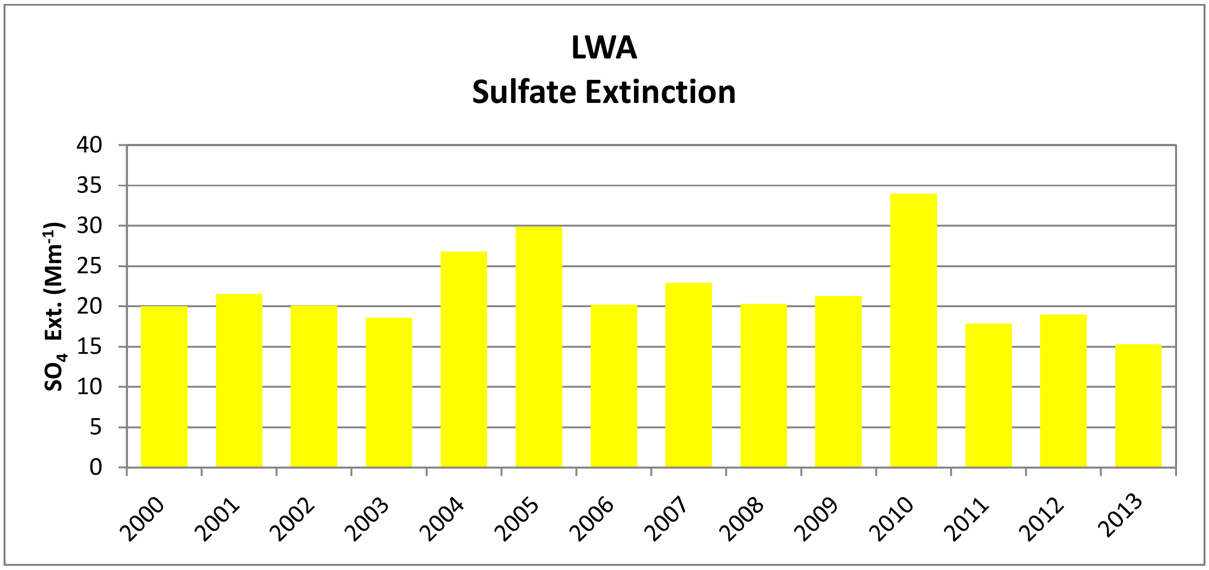
In addition to the emissions reductions already achieved, additional nitrogen oxides reductions will be achieved at the Antelope Valley Station, Coyote Station, Leland Olds Station, Coal Creek Station and Stanton Station Unit 1. The additional reductions could total 9,000 tons per year. The argument that reductions in visibility impairing pollutants would have been greater absent the increase in oil and gas production activities is speculative. There is no way of knowing whether this is true or not given the available data. The main criteria is whether reductions are on pace to achieve the RPGs in the SIP – which they are.

Although the NDDH has not required specific reductions for the oil and gas industry based on this the Progress Report, the industry has been required to reduce flaring activities by mandates imposed by the ND Industrial Commission. In addition, the NDDH has taken action, through global settlements with major oil producing companies, to decrease VOC emissions from numerous sources throughout the oil producing area.

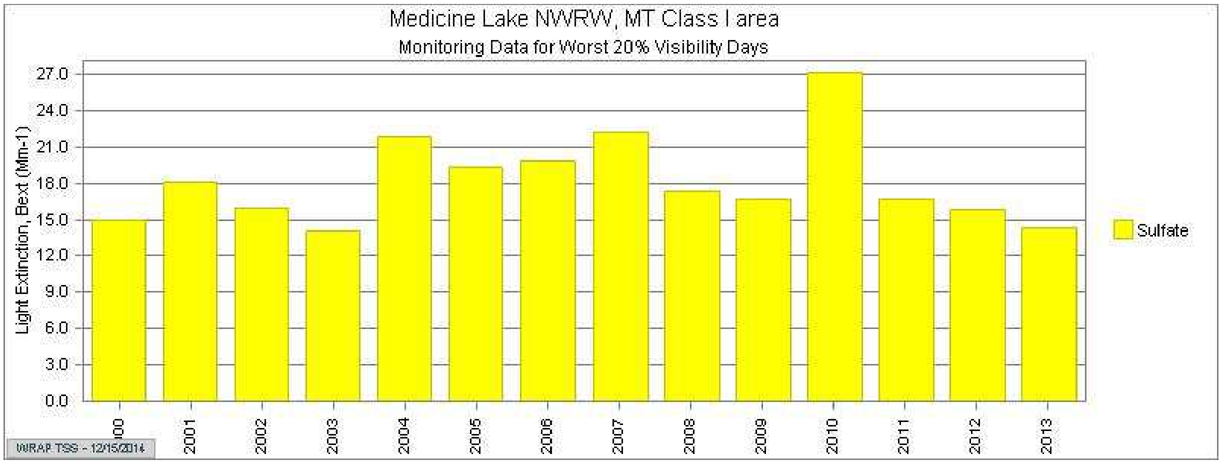
The NDDH believes there is no reason to require additional nitrogen oxides or volatile organic compound emissions control at this time. IMPROVE data indicates oil and gas activity is not impeding reasonable progress toward the national visibility goal.

Sulfate Extinction

The IMPROVE sulfate data for LWA has been further reviewed as suggested by a commenter. Although five year averages of sulfate extinction shows little progress, the data for the last three years (2011-2013) suggest that sulfate extinction is decreasing, which coincides with sulfur dioxide emissions reductions at North Dakota EGUs. Since the Progress Report occurs prior to all emissions reductions being implemented, additional reduction of sulfate extinction may be achieved by the end of the planning period - 2018.



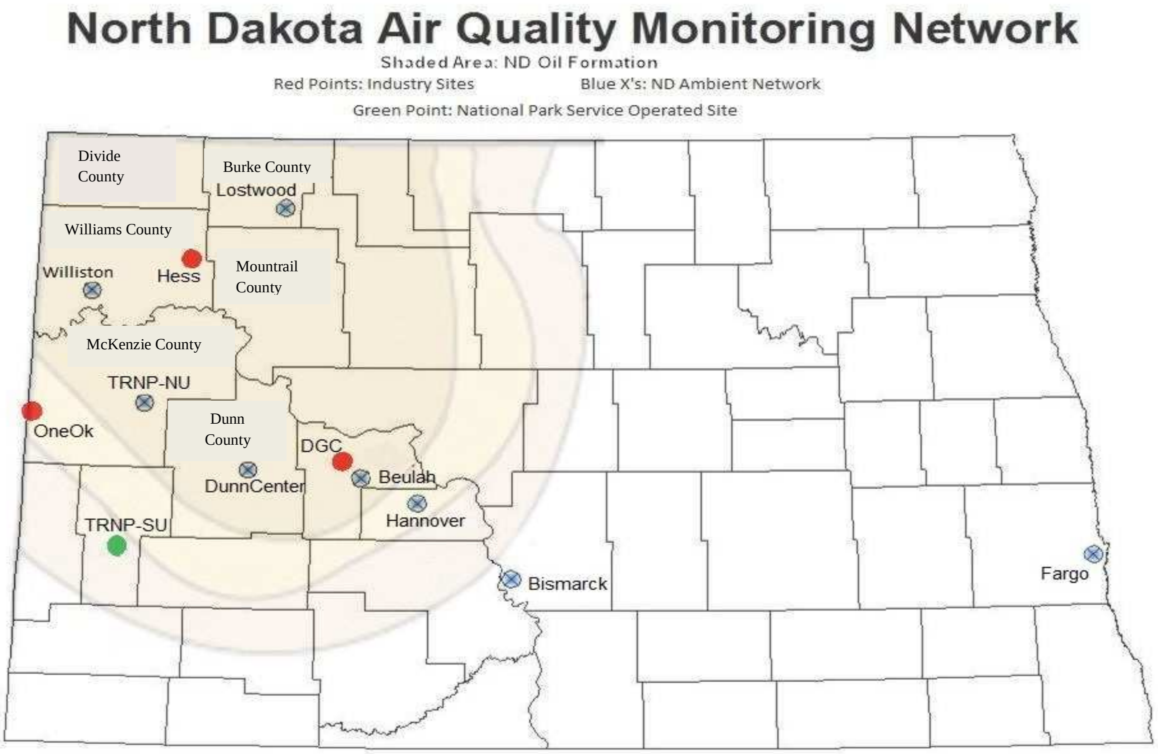
The NDDH has also investigated sulfate extinction at Medicine Lake Wilderness Area (MELA) in Montana. 2010-2013 IMPROVE data also suggests that sulfate extinction has been decreasing at MELA in the last three years at shown below. Again, this reduction in sulfate extinction occurs at the same time as sulfur dioxide emissions reductions were occurring in North Dakota.



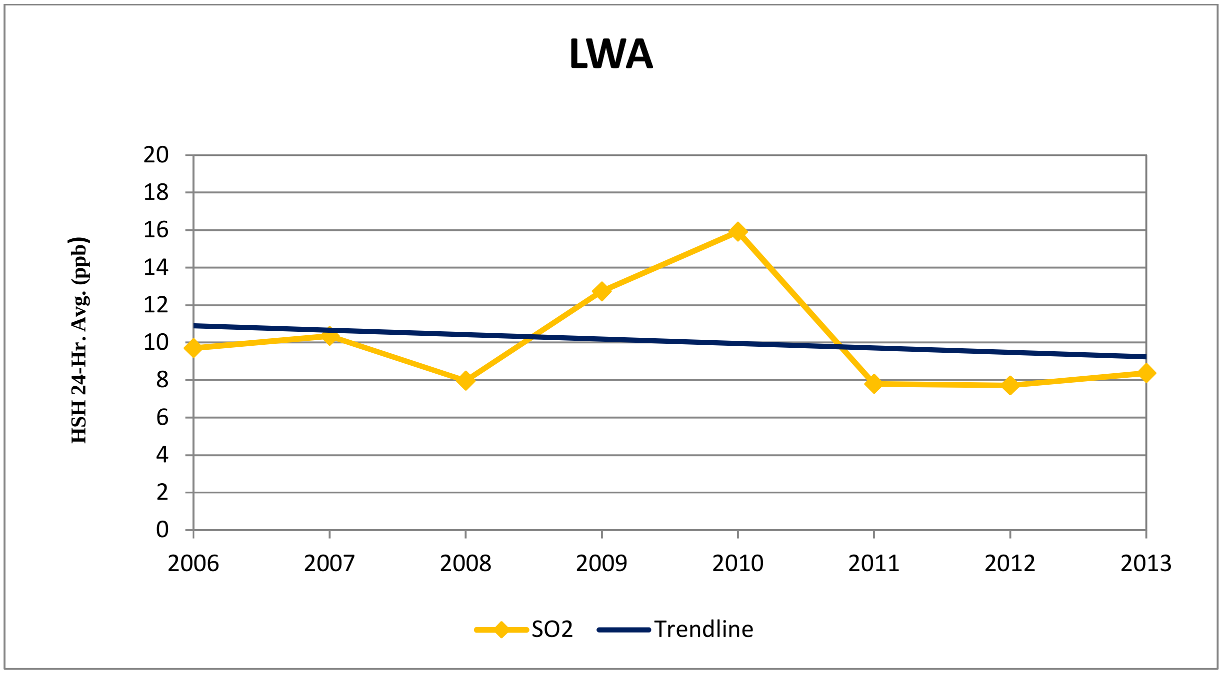
Sulfur Dioxide

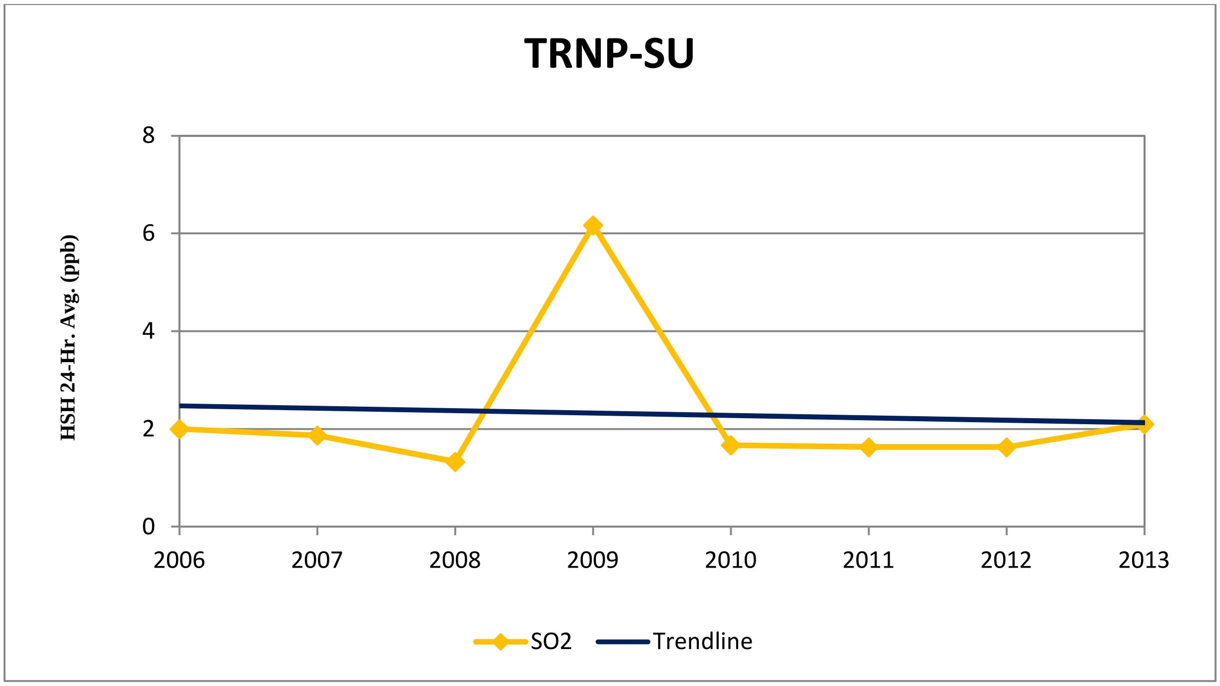
The Periodic Progress Report indicated that the five year average of sulfate extinction at LWA was not decreasing and the reasons are a mystery (see Section 2.8 of the report). The gas produced by the Bakken/Three Forks/Sanish formations is generally very low in sulfur. As part of the NDDH’s oil well registration system, a gas analysis is submitted for each well that is put into production. Attachment A provides several of these gas analyses which verify the low sulfur content.

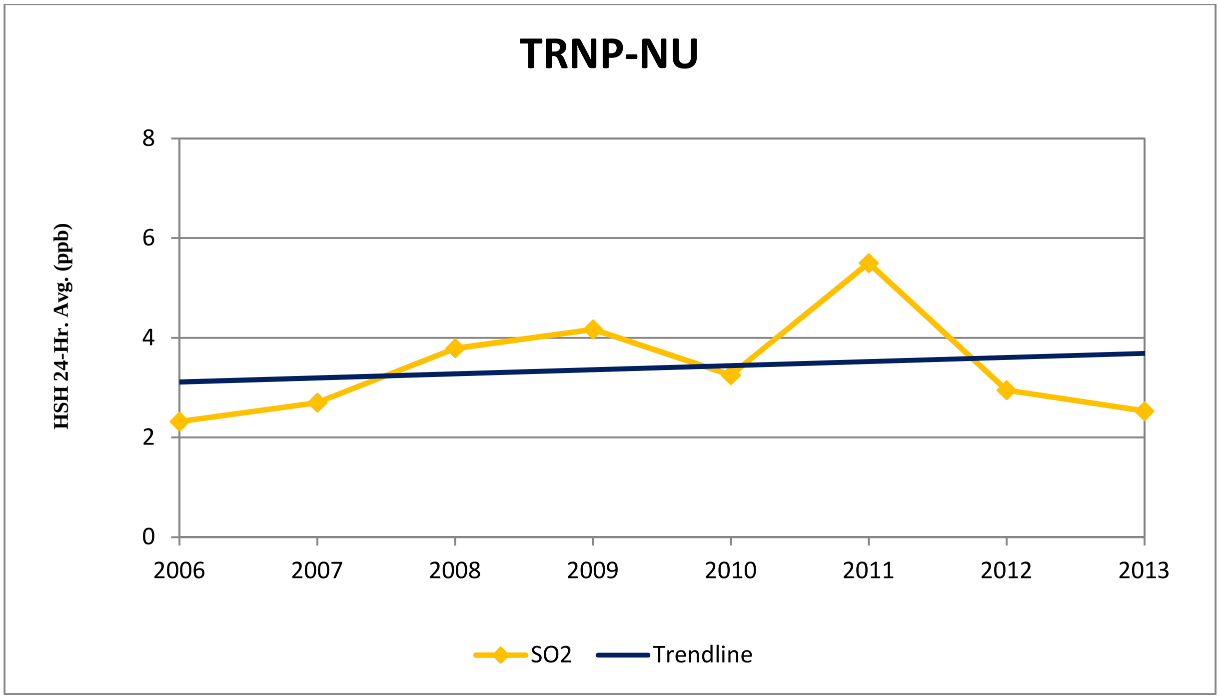
The primary oil activity in North Dakota takes place in Williams, Mountrail, McKenzie and Dunn counties. The following map shows the location of the NDDH’s ambient monitoring sites with respect to the oil production formations.



The NDDH evaluated the 24-hour average (second high) sulfur dioxide concentrations at LWA and found that in the last three years the concentration is actually less than it was in 2006, before the oil and gas production activity developed in western North Dakota. The same decline is evident at TRNP-SU. Although this trend may not be evident at TRNP-NU, the last two years has shown a marked decrease in concentration at this site. The decline in SO_2 concentrations is also consistent with the sulfate decreases for 2011-2013 shown above. The decreases in sulfur dioxide concentration may be attributable to BART controls already installed on North Dakota sources. Emissions of sulfur dioxide from oil and gas activity do not appear to be contributing significantly to the very low concentrations of SO_2 in the Class I Federal areas. Based on this data, it appears that oil and gas activities would also not be a large contributor to sulfate concentrations in the Class I areas.

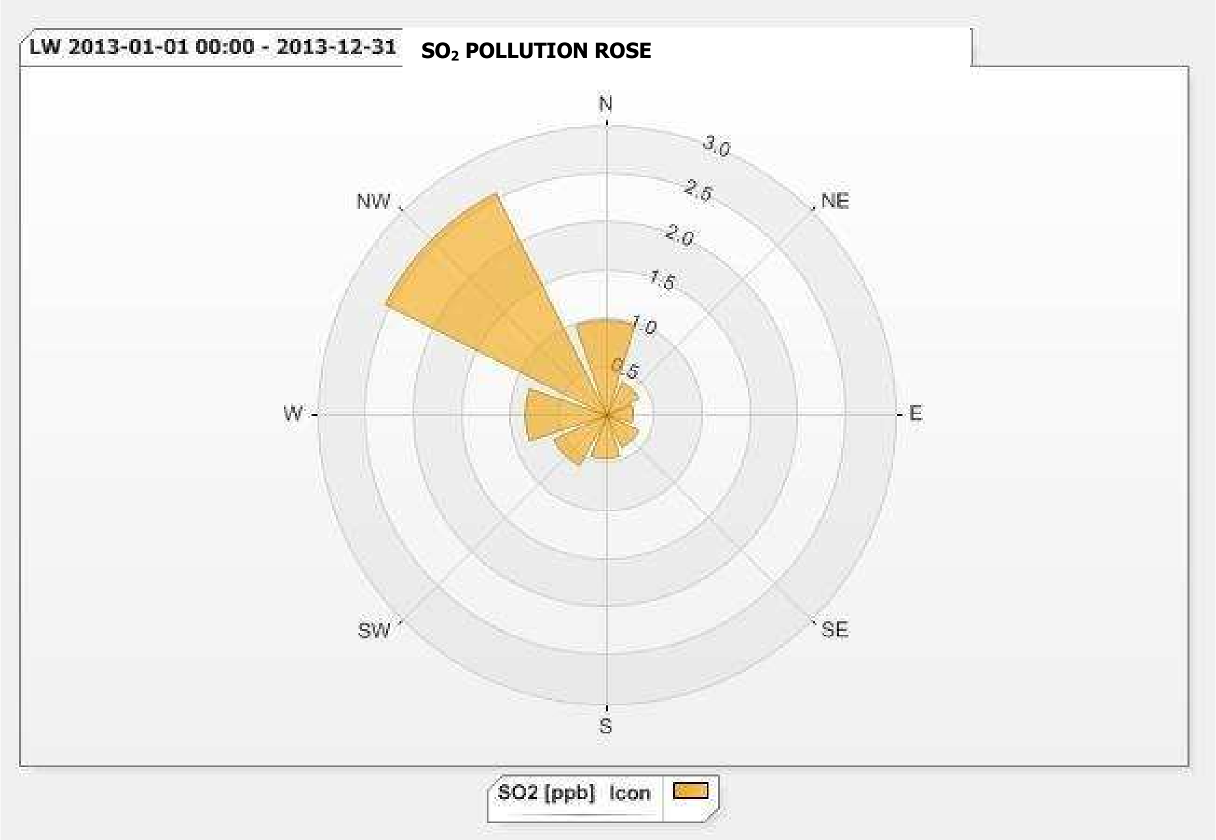






Additional sulfur dioxide emissions reductions, beyond those already achieved, are required by the SIP at the Coal Creek Station, Stanton Station Unit 1 and the R.M. Heskett Station Unit 2. The NDDH sees no reason to require additional sulfur dioxide controls on power plants or oil and gas activities at this time.

The NDDH has further investigated the sulfate concentrations in LWA. The following SO_2 pollution rose from monitoring data at LWA show the huge influence of sources located in Canada to the north and west-northwest of LWA on SO_2 concentrations. The pollution rose also shows the small influence from the sources in the North Dakota oil and gas areas located to the south and southwest of LWA as well as the North Dakota power plants located to the southeast. SO_2 and sulfate concentrations in LWA appear to be significantly influenced by SO_2 emissions from Canadian sources located just across the border in Saskatchewan (e.g. Boundary Dam, Shand and Poplar River power plants). The SO_2 emissions from Canadian sources may make further reductions of sulfate extinction at LWA difficult.



Summary:

In summary, the RPG at TRNP has been met on a five year average. The RPG at LWA has been more than met in two out of the last three years. Additional BART and Reasonable Progress emissions reduction requirements in the current SIP will further reduce visibility impairment in TRNP and LWA. The current SIP is adequate to meet the RPGs the NDDH established in the SIP for both TRNP and LWA.

The Periodic Progress Report has been updated to include the 2013 visibility impairment data on a deciview basis.

Comment 2: The commenter takes exception to the NDDH statement that Theodore Roosevelt National Park (TRNP) consists of three separate units for modeling purposes. The commenter recommends that this language be removed since the Clean Air Act Amendments of 1977 identify TRNP as a single national park.

Response: The NDDH disagrees with the comment for the following reasons:

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 observe 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. The following is taken the National Park Service's website at http://www.nps.gov/thro/planyourvisit/directions.htm -- **The park is comprised of three areas: South Unit, North Unit and Elkhorn Ranch Unit."** [emphasis added]

G. The NPS has recently announced plans to establish an IMPROVE monitoring site at TRNP-NU. This indicates that the NPS thinks, for visibility impairment purposes, that the North Unit is distinct from the South Unit where a current IMPROVE site operates.

Comment 3: The commenter recommends that NDDH further revise the Progress Report in Section 1.2 to include the results for Antelope Valley Station based on the single source modeling that the NDDH conducted when it evaluated the benefits of Low NO_x burners (LNB) and separated overfire air (SOFA) versus installation of SCR at Leland Olds Station.

Response: LNB+SOFA are expected to reduce NO_x emissions at AVS by a maximum of 6,400 tons per year. The single source modeling indicated that LNB+SOFA changes would produce an improvement of about 0.518 dv at TRNP and 0.356 dv at LWA (see Attachment B). The NDDH's cumulative modeling analysis indicated the LNB+SOFA at AVS would produce 0.01 dv or less improvement at TRNP and LWA (see table 9.9 of SIP). To date (2013), 82,609 tons per year of sulfur dioxide and 28,213 tons per year of NO_x reductions at the power plants from the baseline have produced visibility improvement results which are consistent with the NDDH's cumulative modeling (see Response to Comment 1). It is very unlikely the LNB+SOFA at AVS will produce the reductions in visibility impairment estimated using single source modeling. However, the single source modeling results will be added to the discussion.

Comment 4: Several commenters recommended the NDDH continue to investigate the reasons for sulfate extinction not decreasing and further study oil and gas impacts.

Response: Agreed. As part of the Regional Haze SIP revision for the next planning period, the NDDH will evaluate these items.

Comment 5: The commenter indicated that North Dakota should consider further action to reduce visibility impairing pollutants as well as VOC from the oil and gas sector.

Response: As shown in the Progress Report and Response to Comment 1, oil and gas sector emissions are not impeding reasonable progress toward the national visibility goal. Although VOC emissions can cause an increase in ground level ozone, monitoring data at TRNP-NU, LWA and TRNP-SU shown ozone concentrations, at worst, are remaining constant and there is some indication that concentrations may be decreasing (see graph in Appendix D to this Progress Report). There is no need to address these emissions at this time. The NDDH will further evaluate emissions from the oil and gas sector when it updates its SIP for the next planning period.

Comment 6: The commenter disagrees with the NDDH's statement that EPA did not establish Reasonable Progress Goals in its FIP. The Commenter quotes EPA's statement "As part of our FIP, we are finalizing RPGs that are consistent with the controls we are imposing …"

Response: 40 CRF 51.308(d)(1) states "For each mandatory Class I Federal area located in the State, the State must establish goals **(expressed in deciviews)** *[emphasis added]* that provide for reasonable progress towards achieving natural visibility conditions." EPA did not establish deciview value based RPGs in their FIP as required by rule. In addition, EPA disapproved the RPGs (deciview values) established in the original SIP (see table 9.14). The NDDH stands by its statement that EPA has not established RPGs and no approved RPGs, on a deciview basis, exist.

Comment 7: The commenter believes that the NDDH must revise its RPGs in the SIP based on a commitment in the SIP that states:

> *"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 be limited to, projected future emissions* ***reductions*** [emphasis added] *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(h)(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."*

Response: The NDDH disagrees with this comment. The neighboring states of Minnesota and Montana do not have fully approved SIP/FIP and/or are under legal challenge. Therefore, the first requirement of this commitment does not obligate any changes at this time. The future emissions **reductions** that were predicted by the SIP are occurring as outlined in the SIP and on schedule. In fact, emissions reductions may actually be greater than the SIP projected. Therefore, no change is needed based on the second part of the commitment. The third part of the commitment indicates that the NDDH will accelerate the revision schedule if the present RH SIP is found to be significantly flawed or the 2018 RPGs cannot be reasonably attained. As shown in the Progress Report and Response to Comment 1, the SIP is adequate and the RPGs will likely be attained. No change is necessary because of the third part of the commitment.

Comment 8: The commenter believes that the Progress Report must separate out emissions reductions that are directly attributable to SIP requirements versus other programs.

Response: The NDDH disagrees. 40 CFR 51.308(g)(2) requires a summary of the emissions reductions that are achieved through the implementation plan measures for achieving reasonable progress. The SIP measures for achieving reasonable progress include BART requirements and Reasonable Progress measures which include emissions reductions due to "ongoing air pollution control programs" (see Section 10.6.1 of the SIP). These ongoing air pollution control measures include the Acid Rain Program, MACT standards including the Mercury and Air Toxics Standards (MATS), New Source Performance Standards, Ambient Air Quality Standards, as well as other state and federal rules. Emissions reductions beyond what is required by the Regional Haze (RH) permits (Appendix D of the SIP) that are attributable to "ongoing air pollution control programs" all count towards achieving reasonable progress. The IMPROVE monitoring data that forms the basis for determining whether Reasonable Progress is achieved cannot separate out visibility improvement that is achieved by BART versus MATS or the Acid Rain program or any other rule.

The RH permit requires Basin Electric Power Cooperative (BEPC) to achieve an emission limit of 0.15 lb/10^6 Btu at the Leland Olds Station (BEPC is allowed to average between units). This limit was effective January 1, 2014. In 2013, the average SO_2 emission rate for the station was 0.34 lb/10^6 Btu. Therefore, the station had not achieved full compliance with the RH permit in 2013. Regarding the emissions reduction of sulfur dioxide at Leland Olds Station Unit 2 that exceeds the BART requirements, these reductions may be due to the Acid Rain program (sale or transfer of allowances) or the MATS rules or other rules which is directly attributable to "ongoing air pollution control programs". In any case, BART required the scrubber that is achieving these reductions.

At R.M. Heskett Station Unit 2, the RH Permit requires Montana Dakota Utilities Co. (MDU) to achieve an emission limit of 0.50 lb/10^6 Btu by May 7, 2017. In 2013, the average SO_2 emission rate at this unit was 0.89 lb/10^6 Btu. Although the requirements of the RH permit have not been fully implemented, MDU has been working on achieving that compliance. Whether the reduction in SO_2 emissions at Unit 2 are directly attributable to the RH permit or other "ongoing air pollution control programs" is immaterial since the reductions will help achieve reasonable progress towards the national visibility goal.

The NDDH believes the emissions reduction calculations are consistent with the SIP requirements which include "ongoing air pollution control programs". No changes to the Progress Report were made based on this comment.

Comment 9: The commenter believes that most of the reductions shown in the Progress Report are not enforceable.

Response: The NDDH disagrees. The primary source of emission reductions is the EGUs with the main reductions at the M.R. Young Station and the Leland Olds Station. All of the sources listed in Table 2.7, with the exception of Antelope Valley Station, have federally enforceable RH permits which establish limits for sulfur dioxide and/or nitrogen oxides (AVS is required to reduce NO_x emissions under a FIP). M.R. Young Station is under a Consent Decree which established long past compliance dates for these same reductions and the requirements are included in their Title V Permit to Operate. The SO_2 reduction requirements for Leland Olds Station have been incorporated into their Title V Permit to operate with a compliance date that has passed. Other reductions, such as those from mobile sources, are mainly the result of EPA rules on engine emissions and fuel quality which are both federally enforceable. The NDDH also has a number of regulations that are federally enforceable that limits emissions at other point sources, as well as fire and dust emissions.

Comment 10: The commenter suggested the report include the uniform rate of progress and reasonable progress goals in tabular and graphic form. The commenter also wants the five year rolling averages of the species extinction included in the report.

Response: The uniform rate of progress is a meaningless metric since it cannot be met even if all sources of sulfur dioxide and nitrogen oxides are eliminated in North Dakota (see Section 8.6.3.3 of the SIP). The uniform rate of progress is listed in table 1.1 of this report. The reasonable progress goals are discussed on page 4 of this report. They have also been added to Table 2.8. The five year averages of species extinction for the baseline period (2000-2004), progress period (2005-2009) and for the current period (2008-2012) are included in Tables 2.9 and 2.10b. In addition, the Response to Comment 1 also includes graphs of the 5-year rolling averages for nitrates and particulate organic mass (POM).

Comment 11: The commenter would like emissions estimates broken down on a less aggregated basis (i.e. individual point sources, county level, etc.). The commenter wants an enhanced monitoring and reporting plan for oil and gas emissions included in the state plan. The commenter states "Given the similarities between the 2018 estimates in the Progress Report and those in North Dakota's original SIP, we suspect that oil and gas associated emissions may not be fully captured."

Response: Tables 2.11, 2.12, 2.13 and 2.14 break down the emissions estimates into eight different categories including a specific category for oil and gas. This is consistent with the emissions estimates provided in the RH SIP. In addition, Tables 2.6 and 2.7 and Figure 2.1 provide emissions specific to EGUs (the largest emitters in the "point source" category). Additional breakdown of emissions would not provide any additional useful information.

An enhanced monitoring and reporting system for oil and gas emissions will not be necessary. The WRAP has been working with EPA to refine the oil and gas tool that is used to estimate oil and gas emissions for the NEI. The WRAP is supplying information from the BLM's Williston Basin emissions inventory for use in EPA's oil and gas tool. This is the best information that is available. Requiring another reporting system would be a duplication of the NEI effort and is unnecessary at this time because oil and gas activities are not impeding reasonable progress toward the national visibility goal.

The 2018 emissions inventory for oil and gas activity in the original RH SIP is not similar to the 2018 inventory in Progress Report. The inventories are as follows:

	RH SIP Inventory (tons)	Progress Report Inventory(tons)
SO_2	4,200	6,541
NO_x	11,577	52,994
OC	0	ND
EC	0	ND
PMF	0	1,712
PMC	0	31
NH_3	0	875
VOC	17,968	369,875
CO	172	98,786
Total	33,917	530,814

The NDDH believes all emissions from oil and gas activities have been accounted for in the 2011 inventory and the 2018 projection of emissions in the Progress Report. The BLM inventory included all sources of emissions except mobile sources. This includes flaring activity, drilling, hydraulic fracturing (fracking) and production. The point source inventory includes compressor stations, gas processing plants, etc. that are required to have a permit. The NEI includes mobile sources in two categories – "on-road mobile" and "off-road mobile". This includes mobile sources from the oil and gas producing counties. The NEI and BLM inventories were used to prepare the 2018 emissions projections for oil and gas activity in the Progress Report.

Comment 12: The commenter notes that there has been significant variability in ammonia emissions from area sources. The commenter encourages the NDDH to include a more detailed discussion of the spatial and temporal variability of ammonia and its impact on visibility.

Response: The NDDH operates two ammonia monitoring stations – at Beulah and at LWA. The LWA site was established in 2009. As such, data from this site was not available for the original RH SIP. However, data from the LWA monitoring site indicates ammonia concentrations very similar to those at the Beulah site (see Attachment E). The monthly ammonia average concentrations at LWA (see Attachment E) are very similar to those used in the NDDH's modeling for the RH SIP (see Table 8.5). The NDDH believes it has appropriately captured the spatial and temporal variations of ammonia in the RH SIP by using data from the Beulah site. For the SIP revision for the next planning period, ammonia monitoring data will be available from both the Beulah and LWA sites.

Comment 13: The commenter indicates the Progress report must address whether emissions in North Dakota are impeding "reasonable progress" in out-of-state Class I areas.

Response: A paragraph has been added to section 2.6 of the Progress Report that addresses out-of-state Class I areas. The primary visibility impairing pollutants that are contributed to out-of-state Class I areas are sulfates and nitrates. As indicated in the Progress Report, North Dakota EGUs have dramatically reduced SO_2 and NO_x emissions. This should help out-of-state Class I areas, especially more distant Class I areas, make progress towards the national visibility goal. The emissions from increased oil and gas activities are generally low level emissions and would be expected to impact Class I areas that are closer. As shown in the Response to Comment 1, emissions from oil and gas activity are not impeding reasonable progress in the North Dakota Class I areas and should not impede out-of-state Class I areas.

Comment 14: The commenter indicated that additional emissions controls should be required for: a) Oil and gas drilling and production operations; b) NO_x reductions at M.R. Young Station and Leland Olds Station Unit 2; and c) NO_x reductions at the Coyote Station.

Response: The NDDH disagrees.

a) As shown in the Progress Report and the Response to Comment 1, oil and gas drilling and productions activities are not impeding reasonable progress toward the national visibility goal. There is no need to require more emissions control. The NDDH will further evaluate oil and gas emissions when it develops a SIP revision for the next planning period.

b) The NDDH has determined that selective catalytic reduction (SCR), for both BACT and BART purposes, is not technically feasible for MRYS or L.O. Unit 2 (see Amendment 1 to the RH SIP). The BACT determination for MRYS was upheld by the United States District Court for the District of North Dakota Southwestern Division, Case No. 1:06-cv-034, decided December 11, 2011. The EPA has also determined that NO_x BART for these units is selective non-catalytic reduction (SNCR), not SCR (see 78 FR 16452).

The commenter suggests that the fuel is different at L.O. Unit 2 than at MRYS because they also combust subbituminous coal. The amount of subbituminous coal burned at L.O. Unit 2 is very small. In 2012, it was 14% of the total coal burned and in 2013 it was only 8%. This small amount of subbituminous coal will not alter the flue gas characteristics enough to make SCR technically feasible.

The Johnson-Mathey reported guarantee for SCR has been addressed in the NDDH's comment on EPA's proposed reconsideration of the NO_x BART for MRYS and L.O. Unit 2 (see Attachment C). This guarantee was based on an estimate of the flue gas characteristics at MRYS, provided by an EPA contractor, which was at the low end of the range of what is expected. CERAM Environmental and Haldor Topsoe also agreed to supply a guarantee based on this estimate of the constituents until they found out the source in question was MRYS - after which they withdrew their guarantee.

The commenter has provided no new information that changes the NDDH's determination that SCR is not technically feasible at each of these units. The RPGs are expected to be met; therefore, no additional NO_x emissions control is required at these units at this time.

c) The Coyote Station also utilizes a cyclone boiler similar to the ones at MRYS and L.O. Unit 2. The lignite that is combusted at the Coyote Station contains soluble sodium and potassium in concentrations equal to or greater than the lignite combusted at MRYS and L.O. Unit 2 (see Attachment D). Therefore, SCR is also not technically feasible for this unit. The commenter has provided no information that would indicate that SCR is technically feasible.

The NDDH evaluated this unit for additional emissions controls as part of the original RH SIP. It was determined that additional controls were not warranted; however, the operators of the unit agreed to reduce NO_x emissions to 0.50 lb/10^6 Btu. Since the RH SIP is adequate to achieve reasonable progress toward the national visibility goal, no additional controls are required at this time. The source will be reevaluated for the SIP revision required for the next planning period.

Attachment A
Bakken Gas Analyses

Aspen Consulting & Testing Inc.

Natural Gas Analysis Report

Client: Continental Resources
Analysis Date: 10/24/2013
Well name: Oscar 2-24H
Cylinder ID: ASPEN 10
County: Williams
State: ND

Sampled By: Kellen Sullivan
Method: GPA 2261-00
Field: Tioga North
Sampled on Site: 10/22/2013
Tap Point: Sales
Temp. & Pressure: 89.4 F / 74.1 psi

COMPONENT	MOLE %	SPC GRAVITY	GPM	GROSS BTU CONTENT
Nitrogen	3.397	0.033	0.000	0.000
Methane	53.599	0.297	0.000	541.346
Carbon Dioxide	0.260	0.004	0.000	0.000
Ethane	22.229	0.231	5.943	393.380
Water	0.000	0.000	0.000	0.000
Propane	13.387	0.204	3.687	336.821
Iso-Butane	0.691	0.014	0.226	22.473
n-Butane	4.472	0.090	1.410	145.901
Iso-Pentane	0.850	0.021	0.311	34.001
n-Pentane	0.164	0.004	0.059	6.557
Hexanes	0.194	0.006	0.080	9.249
		Extended Analysis		
Heptanes	0.077	0.003	0.035	4.228
Octanes	0.050	0.002	0.025	3.103
Nonanes	0.057	0.003	0.032	4.021
Decanes	0.163	0.008	0.100	12.626
BTEX	0.410			
Hydrogen Sulfide	0.000	0.000	0.000	0.021
	100.000			

Total Gross BTU/ft^3 @ 14.73 psia and 60 F		METHOD
Dry:	1514	GPA 2172-09
Wet:	1487	GPA 2172-09
Total GPM:	11.909	GPA 2172-09
Compressibility Factor:	0.9941	GPA 2172-09
Specific Gravity (Air =1.000):	0.918	GPA 2172-09

Remarks: On-site H_2S using GPR-7100 H_2S Portable Analyzer = **4.2 ppm**

NOTATION: ALL CALCULATIONS PERFORMED USING PHYSICAL CONSTANTS FROM GPA 2145-09, THE TABLES OF PHYSICAL CONSTANTS FOR HYDROCARBONS AND OTHER COMPOUNDS OF INTEREST TO THE NATURAL GAS INDUSTRY.

Aspen Consulting & Testing
2285 Deerfield Lane, Helena, Montana 59601 Phone: (406) 457-5188 Fax: (406) 449-7072 www.aspentesting.com

est

ASTRO-CHEM LAB, INC.

Williston, North Dakota 58802-0972
P.O. Box 972

Phone: (701) 572-7355

NATURAL GAS ANALYSIS

NY Triangle Petroleum

DATE OF ANALYSIS 9-9-13

E State 1H

ATE SAMPLED 9-6-13

TEMPERATURE 125. °F

AMPLE SOURCE

PRESSURE 74 PSI

AMPLE NUMBER G-13-6107

SAMPLED BY TA

YPE OF ANALYSIS GAS

ANALYSIS BY BK

ORMATION

INTERVAL

OCATION SECTION TOWNSHIP RANGE

ISTRIBUTION Distribution List

COMPONENT	MOLE %	GPM
Nitrogen	1.80	0.000
Methane	51.37	0.000
Carbon Dioxide	0.42	0.000
Ethane	21.35	5.700
H2S	0.00	0.000
Propane	14.41	3.951
i-Butane	1.68	0.548
n-Butane	5.04	1.582
i-Pentane	0.94	0.342
n-Pentane	1.32	0.475
Hexanes+	1.67	0.731
Oxygen/Argon	0.00	0.000
Total	100.00	13.330

ALCULATED SPECIFIC GRAVITY 0.9968 (Air =1.0000)

ALCULATED GROSS BTU/ft^3 1634 (Saturated) 1663 (Dry) at 14.73 psi and 60°F

EMARKS On-Site H2S = 0 ppm by JW Energy

ASTRO-CHEM LAB, INC.

4102 2nd Ave. West
Williston, North Dakota 58802-0972
P.O. Box 972
Phone: (701) 572-7355

NATURAL GAS ANALYSIS

COMPANY	Whiting Oil & Gas	**DATE OF ANALYSIS**	8-22-13
LEASE	Moen 41-26-2		
DATE SAMPLED	8-21-13	**TEMPERATURE**	95 °F
SAMPLE SOURCE		**PRESSURE**	60 PSI
SAMPLE NUMBER	G-13-5657	**SAMPLED BY**	
TYPE OF ANALYSIS	GAS	**ANALYSIS BY**	BK
FORMATION		**INTERVAL**	

LOCATION **SECTION** **TOWNSHIP** **RANGE**

DISTRIBUTION Scott Chelgren

COMPONENT	MOLE %	GPM
Nitrogen	1.53	0.000
Methane	58.59	0.000
Carbon Dioxide	0.52	0.000
Ethane	19.04	5.084
H2S	0.00	0.000
Propane	11.20	3.071
i-Butane	1.42	0.463
n-Butane	4.00	1.256
i-Pentane	0.79	0.287
n-Pentane	1.13	0.407
Hexanes+	1.78	0.779
Oxygen/Argon	0.00	0.000
Total	100.00	11.347

CALCULATED SPECIFIC GRAVITY 0.9302 (Air =1.0000)

CALCULATED GROSS BTU/ft³ 1534 (Saturated) 1561 (Dry) at 14.73 psi and 60°F

REMARKS

4102 2nd Ave. West

ASTRO-CHEM LAB, INC.

Williston, North Dakota 58802-0972

P.O. Box 972

Phone: (701) 572-7355

NATURAL GAS ANALYSIS

COMPANY Whiting Oil & Gas

DATE OF ANALYSIS 8-20-13

LEASE Tescher State 11-25 PH

DATE SAMPLED 8-16-13

TEMPERATURE 100 °F

SAMPLE SOURCE

PRESSURE 26 PSI

SAMPLE NUMBER G-13-5536

SAMPLED BY

TYPE OF ANALYSIS GAS

ANALYSIS BY BK

FORMATION

INTERVAL

LOCATION **SECTION** **TOWNSHIP** **RANGE**

DISTRIBUTION Scott Chelgren

COMPONENT	MOLE %	GPM
Nitrogen	5.36	0.000
Methane	49.80	0.000
Carbon Dioxide	0.39	0.000
Ethane	17.88	4.774
H2S	0.00	0.000
Propane	14.01	3.842
i-Butane	1.95	0.636
n-Butane	5.49	1.723
i-Pentane	1.22	0.444
n-Pentane	1.52	0.547
Hexanes+	2.38	1.042
Oxygen/Argon	0.00	0.000
Total	100.00	13.008

CALCULATED SPECIFIC GRAVITY 1.0278 (Air =1.0000)

CALCULATED GROSS BTU/ft³ 1624 (Saturated) 1653 (Dry) at 14.73 psi and 60°F

REMARKS

ASTRO-CHEM LAB, INC.

2nd Ave. West
Williston, North Dakota 58802-0972
P.O. Box 972
Phone: (701) 572-7355

NATURAL GAS ANALYSIS

MPANY Whiting Oil & Gas

DATE OF ANALYSIS 8-22-13

ASE Voll 14-32-1

TE SAMPLED 8-21-13

TEMPERATURE 105 °F

MPLE SOURCE

PRESSURE 30 PSI

MPLE NUMBER G-13-5651

SAMPLED BY

PE OF ANALYSIS GAS

ANALYSIS BY BK

RMATION

INTERVAL

CATION SECTION TOWNSHIP RANGE

STRIBUTION Scott Chelgren

COMPONENT	MOLE %	GPM
Nitrogen	2.19	0.000
Methane	48.87	0.000
Carbon Dioxide	0.50	0.000
Ethane	20.47	5.465
H2S	0.00	0.000
Propane	13.98	3.833
i-Butane	1.82	0.593
n-Butane	5.78	1.814
i-Pentane	1.31	0.477
n-Pentane	1.93	0.695
Hexanes+	3.15	1.379
Oxygen/Argon	0.00	0.000
Total	100.00	14.257

CULATED SPECIFIC GRAVITY 1.0599 (Air =1.0000)

CULATED GROSS BTU/ft^3 1722 (Saturated) 1753 (Dry) at 14.73 psi and 60°F

MARKS

Sathe Analytical Laboratory, Inc.

301 West 2nd Street
PO Box 1527
Williston, ND 58802-1527
701-572-3632

Gas Analysis Report

Lab No: G-13-1425

Operator:	Newfield Production Company	Date:	10/29/2013
Well No:	Anderson Federal 3H	Location:	not listed
Field:	not listed	Formation:	Bakken
County:	McKenzie	Interval:	production
State:	North Dakota	Sample Source:	Treater 08/21/13

Component	Mole %	GPM	Specific Gravity	Gross BTU Content
Nitrogen	2.250	0.000	0.022	0.000
Methane	55.990	0.000	0.310	565.331
Carbon Dioxide	1.021	0.000	0.016	0.000
Ethane	20.598	5.500	0.214	364.337
Hydrogen Sulfide	0.000	0.000	0.000	0.000
Propane	11.048	3.029	0.168	278.133
Iso-Butane	1.321	0.431	0.027	42.968
Butane	4.080	1.281	0.082	133.094
Iso-Pentane	0.933	0.339	0.023	37.323
Pentane	1.138	0.410	0.028	45.629
Hexanes +	1.621	0.710	0.048	77.127
	100.000			

BTU 14.73 PSIA and 60F
DRY = 1544
WET = 1526

Propane Plus GPM = 6.200
I-Pentane Plus GPM = 1.459
Specific Gravity Composite Stream = 0.938
Total Gross BTU Content = 1543.94
Total Acid Gas Mole % = 1.021
Compressibility Factor = 0.9939
VOC Weight Fraction = 0.404
H2S Mole Fraction = 0.000
H2S Weight Fraction = 0.000

REMARKS: No detectable H2S was present in the sample analyzed.

DISTRIBUTION:

DATE RECEIVED: 08/23/2013

ASTRO-CHEM LAB, INC.

4102 2nd Ave. West
Williston, North Dakota 58802-0972
P.O. Box 972
Phone: (701) 572-7355

NATURAL GAS ANALYSIS

OMPANY Whiting Oil & Gas
DATE OF ANALYSIS 5-3-13
EASE Sondrol 11-3 TFH
ATE SAMPLED 5-1-13
TEMPERATURE 100 °F
AMPLE SOURCE
PRESSURE 20 PSI
AMPLE NUMBER G-13-2790
SAMPLED BY
PE OF ANALYSIS GAS
ANALYSIS BY BK
RMATION
INTERVAL
OCATION SECTION TOWNSHIP RANGE
STRIBUTION Scott Chelgren

COMPONENT	MOLE %	GPM
Nitrogen	0.96	0.000
Methane	56.62	0.000
Carbon Dioxide	0.52	0.000
Ethane	20.49	5.471
H2S	0.00	0.000
Propane	11.56	3.170
i-Butane	1.52	0.495
n-Butane	3.80	1.193
i-Pentane	0.86	0.313
n-Pentane	1.35	0.486
Hexanes+	2.32	1.016
Oxygen/Argon	0.00	0.000
Total	100.00	12.144

LCULATED SPECIFIC GRAVITY 0.9562 (Air =1.0000)

LCULATED GROSS BTU/ft³ 1583 (Saturated) 1611 (Dry) at 14.73 psi and 60°F

MARKS

Attachment B
AVS Modeling Results

Thodore Roosevelt National Park
Calpuff 24-hr Delta Deciview*
98th Percentile

	2000	2001	2002	3-yr Average
AVS Base Case	1.508	2.083	2.581	
AVS LNBSOFA	1.240	1.551	1.827	
AVS Improvement (Base - LNBSOFA)	0.268	0.532	0.754	0.518
LOS Unit 2 SNCR	0.468	0.486	0.828	
LOS Unit 2 SCR	0.197	0.238	0.335	
LOS Unit 2 Improvement (SNCR - SCR)	0.271	0.248	0.493	0.337

Lostwood Wilderness Area
Calpuff 24-hr Delta Deciview*
98th Percentile

	2000	2001	2002	3-yr Average
AVS Base Case	1.313	1.523	1.497	
AVS LNBSOFA	0.984	1.185	1.097	
AVS Improvement (Base - LNBSOFA)	0.329	0.338	0.400	0.356
LOS Unit 2 SNCR	0.328	0.572	0.495	
LOS Unit 2 SCR	0.136	0.260	0.215	
LOS Unit 2 Improvement (SNCR-SCR)	0.192	0.312	0.280	0.261

* Based on single-source BART type modeling,
new Improve Equation,
annual average natural background.

NDDH 1/6/2011

Attachment C
BART Reconsideration 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 14, 2013

FILE

Mr. Carl Daly (8P-AR)
Director, Air Program
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Docket ID No. EPA-R08-0AR-2010-0406 – Comments on Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze; Reconsideration

Dear Mr. Daly:

The North Dakota Department of Health (Department) respectfully submits these comments on the U.S. Environmental Protection Agency's above-noted proposal to reaffirm its approval of North Dakota's Best Available Retrofit Technology (BART) determinations for nitrogen oxides (NO_x) at the M.R. Young Station (MRYS) and Leland Olds Station (LOS) Unit 2 contained in North Dakota's State Implementation Plan (SIP) for Regional Haze. EPA's proposal comes as a result of granting the National Parks Conservation Association's (NPCA) petition requesting that EPA reconsider its approval of North Dakota's BART determinations for MRYS and LOS Unit 2. North Dakota's BART determination for these units was that BART is selective non-catalytic reduction (SNCR) plus advance separated over fire air (ASOFA) and not selective catalytic reduction (SCR). As set forth below, the Department agrees with EPA's proposal to reaffirm its approval of the Department's BART determinations for these units.

Background

In 2006, EPA and North Dakota filed a joint complaint against Minnkota and Square Butte Power Cooperative which alleged Minnkota violated provisions of the Clean Air Act and North Dakota's State Implementation Plan as a result of unauthorized major modifications at MRYS, including failing to install Best Available Control Technology (BACT) (Case No. 1:06-cv-034). Under a Consent Decree entered by the U.S. District Court for the District of North Dakota, the parties agreed that North Dakota would determine BACT at MRYS by December 31, 2010. After a four year review, two public comment periods, numerous communications with EPA and its consultants, and public input from industry, environmental groups, Federal Land Managers, and EPA, in November 2010 the Department determined that SCR was not technically feasible and that BACT at MRYS was SNCR.

Environmental Health Section Chief's Office 701.328.5150	Division of Air Quality 701.328.5188	Division of Municipal Facilities 701.328.5211	Division of Waste Management 701.328.5166	Division of Water Quality 701.328.5210

The Department's BACT determination for MRYS is supported by an extensive administrative record. The complete Minnkota Administrative Record is submitted with and incorporated herein to the Department's comments. The Department's findings and conclusions in support of its determination that SCR is not technically feasible at MRYS is stated in the Department's Findings of Fact (see Administrative Record at Exhibit 240). Among the Department's findings why SCR is not technically feasible at MRYS are:

1. A lack of vendor guarantees for SCR at MRYS;
2 The flue gas characteristics of North Dakota lignite are different from any other source category where SCR has been applied;
3. The lack of any experience in the SCR industry dealing with flue gas characteristics similar to those at MRYS; and
4. The only pilot scale testing on a cyclone boiler that burns North Dakota lignite indicated major problems for the successful use of the technology.

MRYS operates a cyclone boiler that is fueled by North Dakota lignite. As the Administrative Record shows, North Dakota lignite is different from any other fuel used where SCR has been applied. CERAM Environmental (CERAM), a leading SCR catalyst supplier, has indicated that there is no experience in the SCR industry with the level and form of sodium found in North Dakota lignite (see Administrative Record Exhibits 221 and 223). Haldor Topsoe, Inc, (HTI), another catalyst vendor, indicated that SCR may not be a viable option for the control of NO_x (see Administrative Record Exhibit 223). Both CERAM and HTI indicated they would not provide a catalyst life guarantee for tail-end SCR (TESCR) or low-dust SCR (LDSCR) (see Administrative Record Exhibit 221). Both vendors have indicated they have provided catalyst life guarantees for other lignite (including Texas lignite), subbituminous coals, European brown coals, and biomass (see Administrative Record Exhibit 238). Accordingly, after careful research and analysis, the Department concluded that due to the characteristics of North Dakota lignite, coupled with the design features unique to cyclone boilers, SCR technologies were not technically feasible at MRYS for the control of NO_x.

Despite North Dakota's extensive analysis of what is BACT at MRYS, EPA disagreed with North Dakota's BACT determination. Under the terms of the 2006 Consent Decree, EPA challenged North Dakota's BACT determination in the U.S. District Court for the District of North Dakota arguing that North Dakota's BACT Determination was "not reasonable." On December 21, 2011, the District Court issued an Order upholding North Dakota's selection of SNCR as BACT for MRYS, finding that North Dakota's conclusion that SCR technologies for MRYS are not technically feasible was reasonable. See *U.S. v. Minnkota Power Coop., Inc.*, 831 F. Supp. 2d 1109 (D.N.D. 2011). EPA did not appeal the District Court's Order.

The Department Correctly Determined BART For MRYS And LOS

The Department May Look To Its Recent BACT Determination When Making A BART Determination

In preparing its Regional Haze SIP, North Dakota looked to its BACT determination for MRYS when making the BART determinations for MRYS and LOS. While a BACT determination is separate from a BART determination, NDDH properly relied on its BACT determination for MRYS when making its BART determinations for MRYS and LOS. The criteria for determining technical feasibility under BACT and BART are nearly identical. A technology must be both commercially available and applicable to the source under review for it to be technically feasible. (see Administrative Record Exhibits 221 and 223). In the BACT process for MRYS, the Department determined that SCR (high-dust SCR, LDSCR or TESCR) is neither commercially available nor applicable to a cyclone boiler that combusts North Dakota lignite (see Administrative Record Exhibits 240 and 241).

Pursuant to EPA's BART Guidelines, states like North Dakota may rely upon a recent BACT determination for purposes of selecting BART when no changes to applicable technologies have occurred. Using a BACT determination as BART meets the requirements of the Clean Air Act because as EPA states in its BART guidelines, "the selection of a recent BACT level as BART is the equivalent of selecting the most stringent level of control, [so] consideration of the five statutory BART factors becomes unnecessary." 77 Fed. Reg. at 20897.

The Department Properly Determined That The LOS Unit 2 Shares The Same Physical And Operating Characteristics As MRYS

The BACT determination for MRYS is directly applicable to the BART determination for LOS Unit 2 because of the cyclone firing and the use of North Dakota lignite. LOS Unit 2 is a cyclone fired boiler similar to Unit 2 at MRYS. LOS Unit 2 is of similar size (440 MWe vs 477 MWe, respectively) and similar age (1975 vs 1977 respectively). LOS Unit 2 is primarily fired on North Dakota lignite with a small amount of subbituminous coal combusted. Data reported for LOS Unit 2 from the last 10 years indicates that the percentage (by weight) of subbituminous coal burned varied from 6.5 % to 16.5% with an average of 11.3% (see Attachment 1). The small amount of subbituminous coal combusted will not significantly change the flue gas characteristics at LOS Unit 2.[1]

The Department Properly Determined That SCR Is Not Technically Feasible At MRYS Or LOS Due To Their Unique Design Characteristics

The Department properly concluded that the high amount of soluble sodium and potassium from lignite can cause rapid deactivation of the SCR catalyst. Rapid deactivation of the SCR is not merely a cost factor when determining BACT or BART, it will preclude the successful operation of an SCR system. Specifically, were SCR to be installed at MRYS or LOS the SCR catalyst would have to be replaced at least every few months if not days. LOS Unit 2 is a baseload unit which operates for years between major outages. Taking LOS Unit 2 down to replace the SCR

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[1] At EPA's May 15, 2013 public hearing in Bismarck North Dakota on this proposed rule, a representative of the NPCA commented that LOS also burns subbituminous coal and not just North Dakota lignite. NPCA's comment was designed to call into question the Department's reasonable determination that SCR is not technically feasible when operated on cyclone boilers that burn North Dakota lignite.

catalyst every few days or months is not consistent with the sustainable operation of LOS Unit 2 or the successful operation of an SCR.

EPA Guidelines for both BACT and BART recognize that "successful" operation must occur for a technology to be technically feasible. To date, the Department is aware of no vendor that will guarantee any amount of catalyst life or successful operation of the SCR system operating on North Dakota lignite. As stated in the BART Guidelines, poor reliability and adverse side effects on the rest of the facility are issues that make a technology technically infeasible (70 Fed. Reg. 39165). Since SCR is not commercially available or applicable, the Department properly concluded that it is not technically feasible and does not represent BACT or BART.

In July 2011, North Dakota submitted Amendment No. 1 to its Regional Haze SIP to EPA, which added information obtained and produced as part of the BACT determination for MRYS in support of North Dakota's BART determinations for MRYS and LOS.

In its September 2011 Proposed Rule approving in part and disapproving in part North Dakota's Regional Haze SIP, EPA initially proposed disapproving the NDDH's MRYS and LOS BART determinations for the same reasons EPA's disapproved of NDDH's BACT determination for MRYS. However, upon the District Court's decision that the NDDH's BACT determination that SCR is technically not feasible at MRYS was reasonable, EPA withdrew its proposed disapproval of NDDH's BART determinations for MRYS and LOS. In its Final Rule, EPA approved the BART determinations for both MRYS and LOS.

No Commentator Has Submitted Any New Information Or Data That Would Change North Dakota's BART Determination For MRYS Or LOS Or EPA's Approval Of The BART Determinations

The Sierra Club, NPCA and the National Park Service have indicated they believe SCR will work in the tail-end or low dust position. They believe the electrostatic precipitator and wet scrubber will remove the submicron aerosols of sodium and potassium that prevents the successful operation of an SCR system (*See Docket ID: EPA-R08-OAR-2010-0406-0382).*

The comments submitted by the Sierra Club, NPCA and National Park Service do not change the conclusion of CERAM and HTI that TESCR and LDSCR may have major problems operating on cyclone boilers fueled by North Dakota lignite which indicates SCR is not technically feasible (see Administrative Record Exhibits 221 and 223). In addition, Minnkota has demonstrated that the electrostatic precipitator and wet scrubber used with SCR technologies will not sufficiently reduce the submicron sodium and potassium aerosols that cause rapid catalyst deactivation (see Administrative Record Exhibit 234, p.21-80). After reviewing this documentation on the flue gas characteristics after the electrostatic precipitator and after the wet scrubber, neither CERAM nor HTI would provide a catalyst life guarantee.

A late comment submitted by Mr. Ken Jeffers of Johnson Matthey Catalysts, LLC to EPA's Proposed Rule approving in part and disapproving in part North Dakota's Regional Haze SIP suggests that Johnson Matthey will provide a catalyst life guarantee for LDSCR or TESCR at

MRYS (*See Docket ID: EPA-R08-OAR-2010-0406-0322).* Johnson Matthey's indication of a catalyst life guarantee is based on a Request for Proposals (RFP) provided by Evonik Energy Services, LLC (Evonik). The Department has properly determined that Evonik's RFP did not accurately portray the flue gas characteristics at MRYS (see Administrative Record Exhibit 241, p.12 and Exhibit 240, p. 9, item 15). Johnson Matthey's statements should not be given any weight since they are based upon an inaccurate description of the flue gas characteristics at MRYS. Unless Johnson Matthey signs a contract with a catalyst life guarantee, which it has not done, its statements are little more than an opinion based upon false assumptions. Johnson Matthey did not respond to Minnkota's RFP for LDSCR or TESCR.

In conclusion, the Department has determined that SCR (HDSCR, LDSCR and TESCR) is not technically feasible for either MRYS or LOS Unit 2. EPA should reaffirm its approval of the Department's BART determinations for MRYS and LOS because:

1. It gives proper consideration to the Department's determination that BART is represented by SNCR plus ASOFA.

2. The proposed action properly acknowledges and defers to the U.S. District Court decision in the Minnkota BACT case; and

3. The Minnkota Administrative Record clearly supports the action.

If you have any questions, please contact Tom Bachman of my staff at (701)328-5188.

Respectfully,

Terry O'Clair

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

TLO/TB:saj
xc: Dave Glatt, Chief, Env. Health Section
Maggie Olson, Asst. Attorney General
Paul Seby, Special Asst. Attorney General

ATTACHMENT 1
LELAND OLDS UNIT 2
COAL USAGE

Year	Lignite (tons)	Subbituminous (tons)	Total Coal (tons)	% Lignite	% Subbituminous
2012	1,561,567	264,680	1,826,247	85.5	14.5
2011	1,537,283	284,307	1,821,590	84.4	15.6
2010	1,831,851	249,782	2,081,633	88.0	12.0
2009	1,973,492	151,665	2,125,157	92.9	7.1
2008	2,248,564	158,444	2,407,008	93.4	6.6
2007	2,628,787	318,832	2,947,619	89.2	10.8
2006	1,628,385	258,579	1,886,964	86.3	13.7
2005	2,158,125	427,477	2,585,602	83.5	16.5
2004	2,383,852	166,512	2,550,364	93.5	6.5
2003	1,785,218	246,224	2,031,442	87.9	12.1
Total	19,737,124	2,526,502	22,263,626	88.7	11.3

Attachment D
Coyote Station
Coal Analysis

FUEL BURNING EQUIPMENT USED FOR INDIRECT HEATING
ANNUAL EMISSION INVENTORY REPORT

NORTH DAKOTA DEPARTMENT OF HEALTH
DIVISION OF AIR QUALITY
SFN 8536 (11-10)

GENERAL

Name of Firm or Organization Otter Tail Power Company	Permit to Operate Number T5-F84011	Year of Emissions **2012**	
Mailing Address P.O. Box 496	City Fergus Falls	State MN	Zip Code 56538-0496
Facility Name Coyote Station	Facility Location 6240 13th Street SW Beulah, ND 58523	Emission Unit Number EUI 1	

EQUIPMENT INFORMATION

Manufacturer of Unit Babcock & Wilcox	Model Number RBC 48/CY	Maximum Heat Input (Btu/hr) 5,800 Million Btu/hr
Boiler Type: ☐ Pulverized Tangential ☒ **Cyclone** ☐ Spreader Stoker ☐ Pulverized Wall Fired ☐ Fluidized Bed ☐ Other	Electricity Generated (MWe)* **2,439,798.77**	Actual Hours of Operation **6,393.51**

*Electric utility only.

FUELS USED		Primary Fuel	Standby Fuel	Other Fuel
Type (ex. lignite, natural gas, LPG No. 2 fuel oil, No. 6 fuel oil. etc.)		Lignite	No. 2 Fuel Oil	Used Oil
Quantity of Fuel per Year (Specify Units: ex. ton, gal, cu.ft., etc.)		1,824,595 tons	297,910 gallons	2,990 gallons
Percent Ash (Coal Only)	Maximum Minimum Average	8.98% 7.56% 8.15% (Expected Range 7.0% to 13.0%)	---	---
Percent Sulfur	Maximum Minimum Average	1.26% 0.72% 0.79% (Expected Range 0.7% to 1.5%)	0.0015% (estimate)	0.0015% (estimate)
Btu per Unit (Specify lb, ton, gal, etc.)	Maximum Minimum Average	7104 Btu/lb 6912 Btu/lb 7012 Btu/lb (Expected Range 6500 to 7200 Btu/lb)	140,000 Btu/gal	140,000 Btu/gal
Percent Sodium in Coal Ash Average		5.60% (Expected Range 2.0% to 7.0%)	---	---

TOTAL STACK EMISSIONS (USE THE TABLE ABOVE FOR SINGLE FUEL USAGE; USE OTHER SIDE IF MULTIPLE FUELS ARE USED AND THEN SUMMARIZE THE TOTAL EMISSIONS PER YEAR ON THE FOLLOWING TABLE.)

Air Contaminant **	Emission Factor (Include Units)	Emission Factor Source (Include Test Date if Applicable)	Tons
Particulate – Total			121.54
PM_{10} (Particulate < 10 microns)			115.46
$PM_{2.5}$ (Particulate < 2.5 microns)	0.07 tons/PM Total tons	EPA PM Calculator for PM2.5	8.51
Sulfur Dioxide			10,639.60
Nitrogen Oxides			9,943.50
Carbon Monoxide			548.13
Total Organic Compounds: Nonmethane			63.89
Mercury***			0.07
Ammonia***			27.37

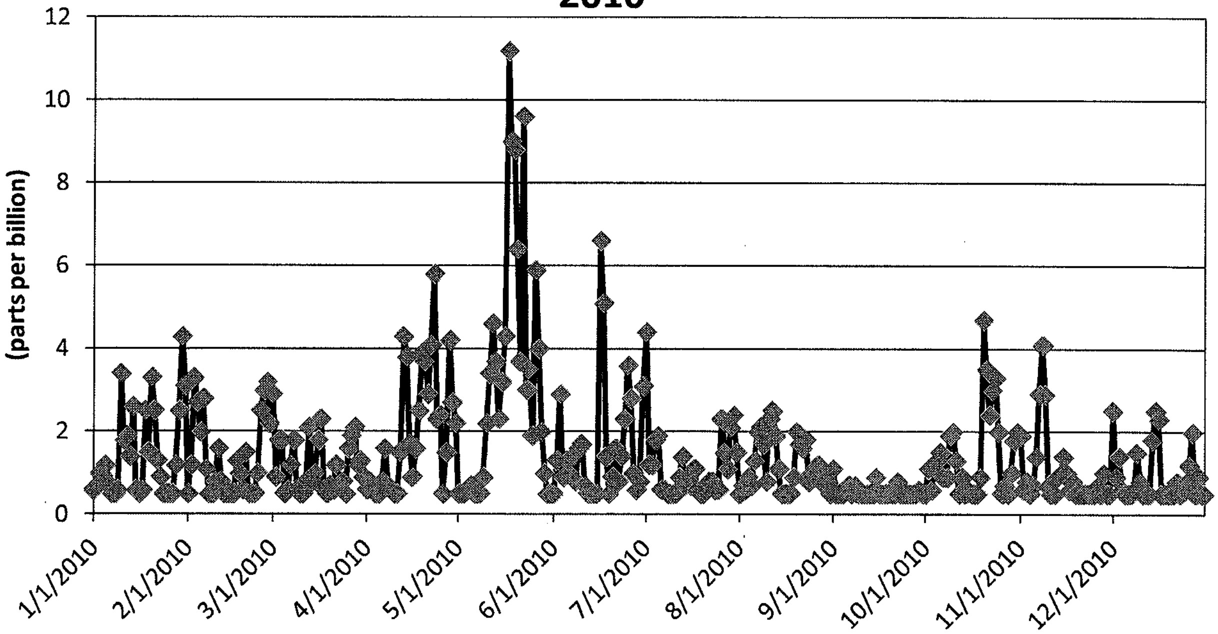
**Submit SFN 19839 for Hazardous Air Pollutants if applicable.
***Title V units only.

I declare under the penalties of perjury that this report has been examined by me and to the best of my knowledge is a true, correct and complete report.

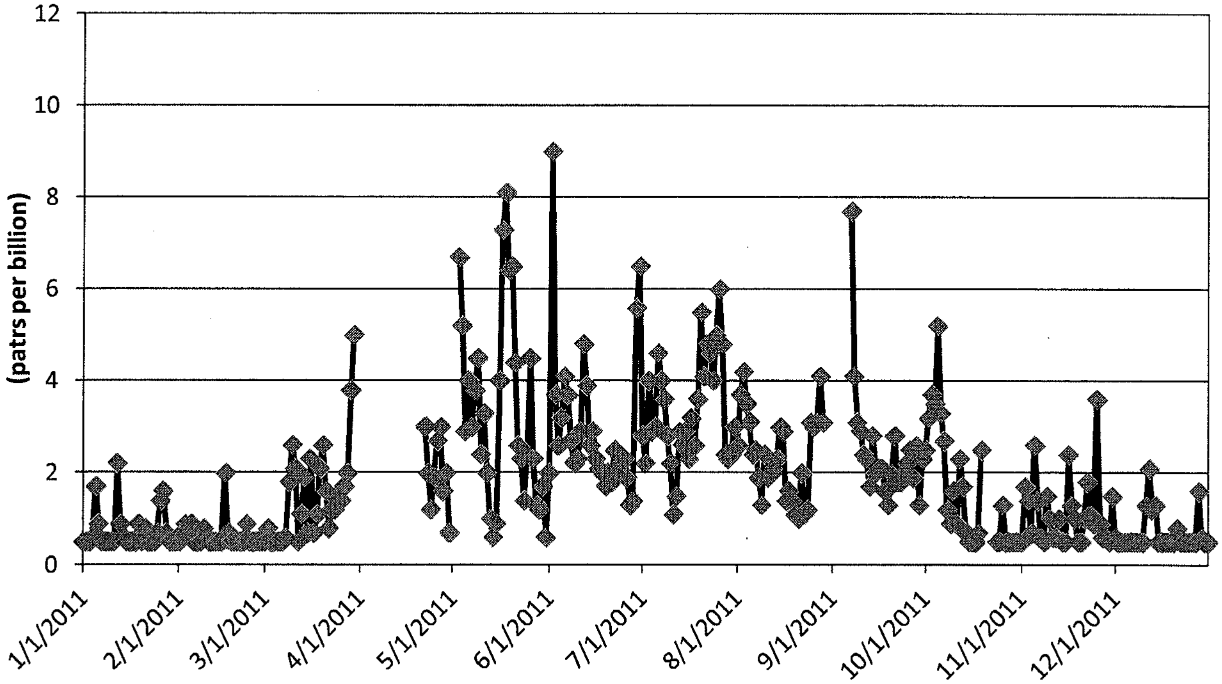
Print Name of Person Submitting Report Mark Thoma	Title Manager, Environmental Services	Email mthoma@otpco.com
Signature Mark Thoma	Telephone Number (218) 739-8526	Date 1/30/13

Return completed form to:
North Dakota Department of Health
Division of Air Quality
918 E Divide, 2nd Floor
Bismarck, ND 58501-1947
Telephone: (701)328-5188

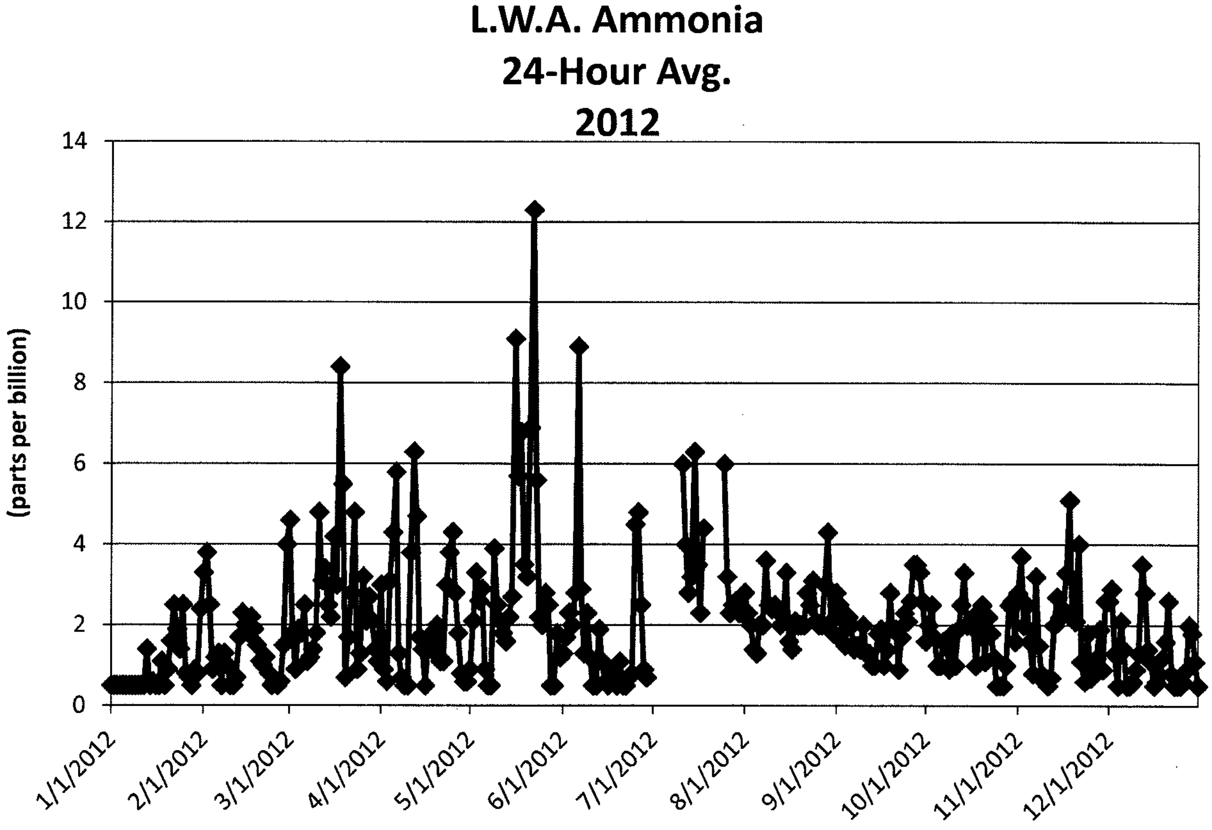
Attachment E
LWA Ammonia Data



L.W.A. Ammonia
24-Hr. Avg.
2010



L.W.A. Ammonia
24-Hour Avg.
2011


L.W.A. Ammonia
24-Hour Avg.
2012
(parts per billion)
14
12
10
8
6
4
2
0
1/1/2012
2/1/2012
3/1/2012
4/1/2012
5/1/2012
6/1/2012
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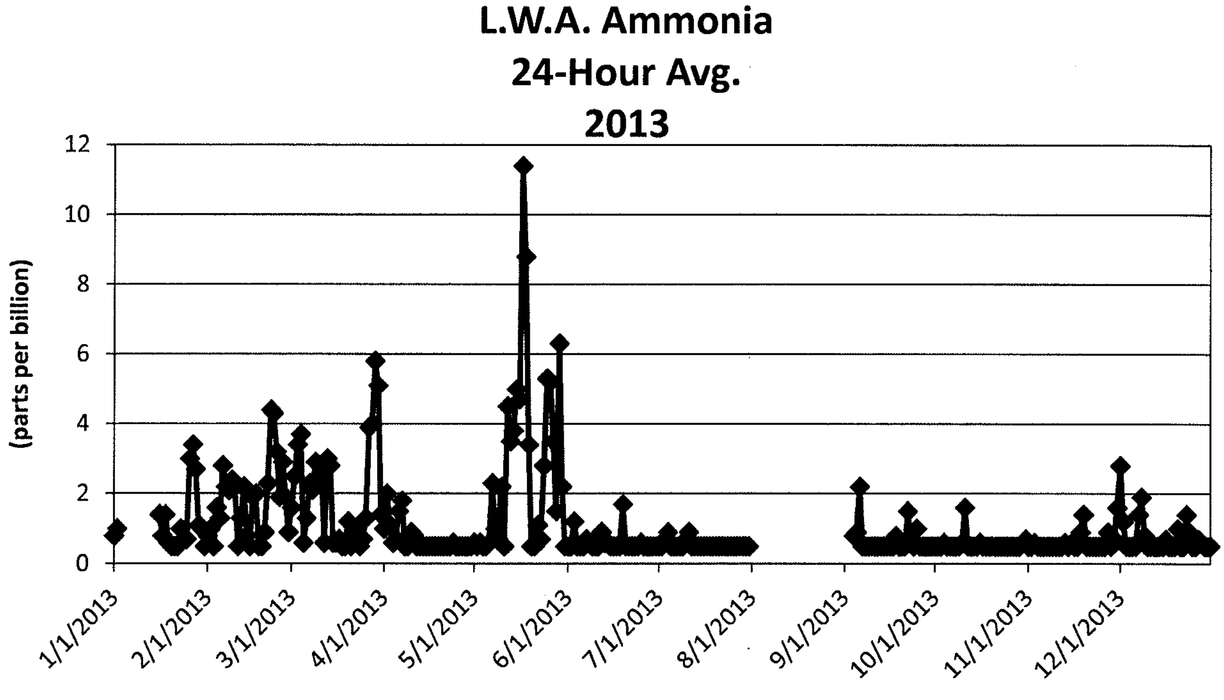
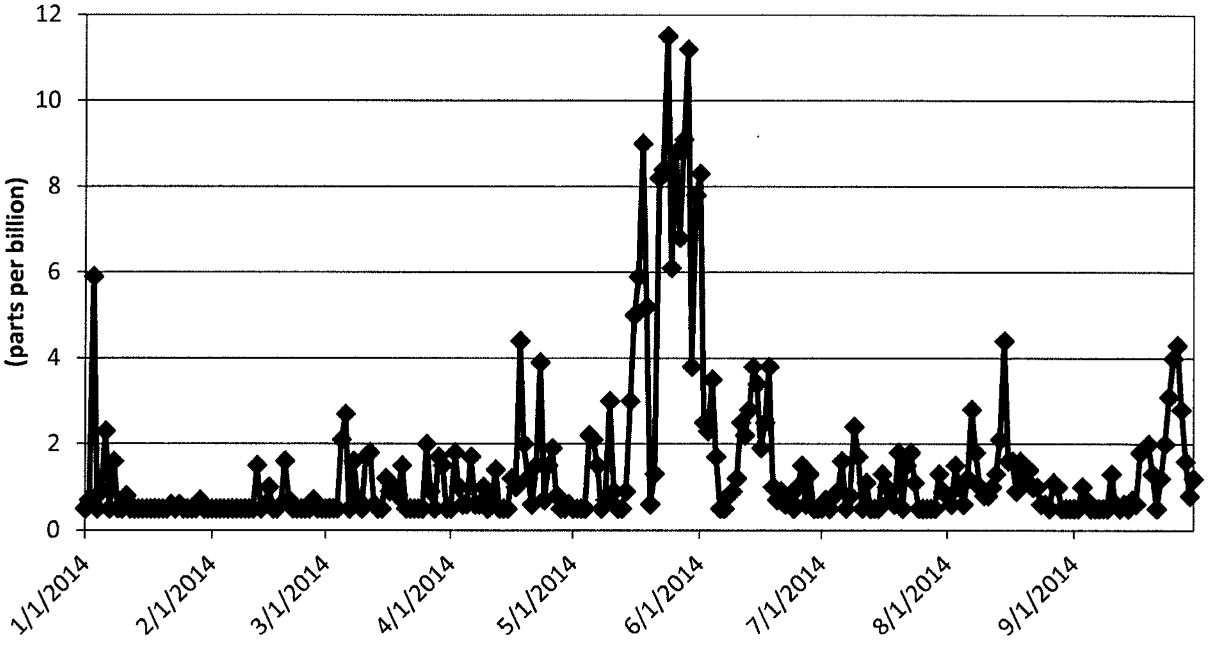
11/1/2012
12/1/2012


L.W.A. Ammonia
24-Hour Avg.
2013
(parts per billion)
12
10
8
6
4
2
0
1/1/2013
2/1/2013
3/1/2013
4/1/2013
5/1/2013
6/1/2013
7/1/2013
8/1/2013
9/1/2013
10/1/2013
11/1/2013
12/1/2013

L.W.A. Ammonia
24-Hour Avg.
2014



LWA
Monthly Average Ammonia
(ppb)

	2009	2010	2011	2012	2013	2014		Avg.
January	1.06	1.44	0.73	0.90	1.20	0.81		**1.02**
February	1.32	1.34	0.64	1.47	1.78	0.61		**1.19**
March	2.41	1.18	1.47	2.61	1.96	0.97		**1.77**
April	1.78	2.01	2.01	2.19	0.70	0.97		**1.61**
May	2.17	3.33	3.36	3.13	2.75	4.08		**3.14**
June	1.37	1.62	3.01	1.75	0.60	1.83		**1.70**
July		1.14	3.35	3.58	0.54	0.92		**1.91**
August		1.17	2.38	2.31		1.20		**1.77**
September		0.57	2.47	1.96	0.67	1.28		**1.39**
October		1.37	1.59	1.66	0.55			**1.29**
November	1.40	1.00	1.11	1.94	0.61			**1.21**
December	1.18	0.93	0.68	1.29	0.75			**0.97**
Annual Average	**1.59**	**1.43**	**1.90**	**2.07**	**1.10**	**1.41**		**1.58**

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.

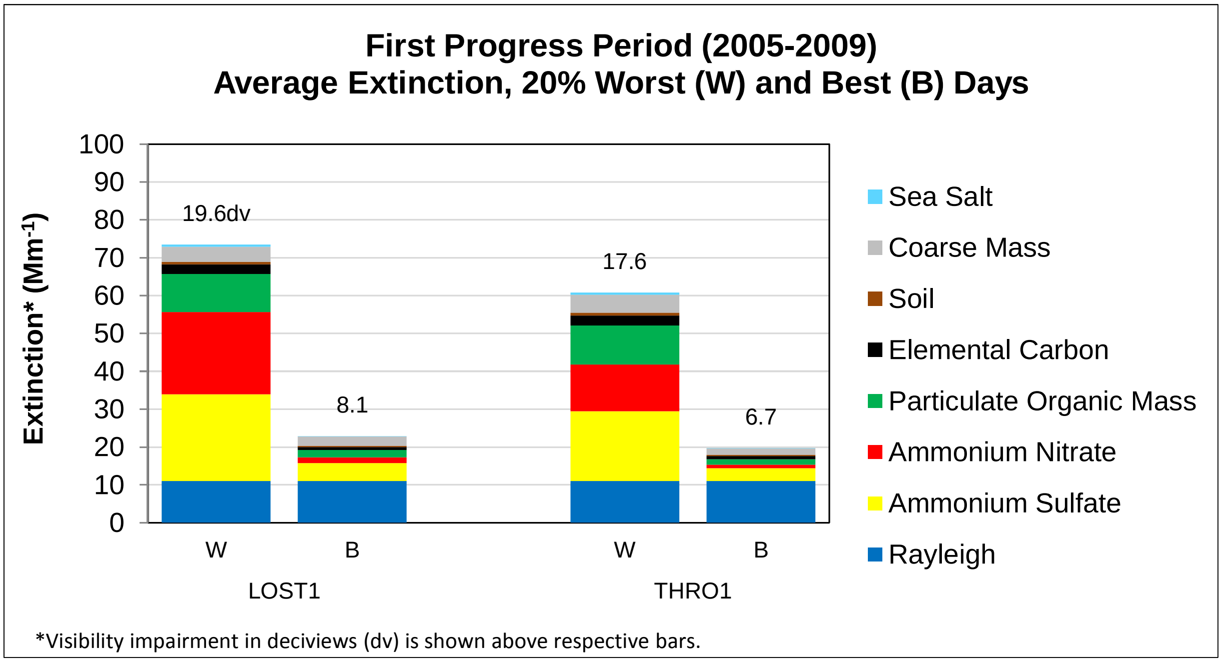

Figure 6.10-2. Average Extinction for Current Progress Period (2005-2009) for the Worst (Most Impaired) and Best (Least Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

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.

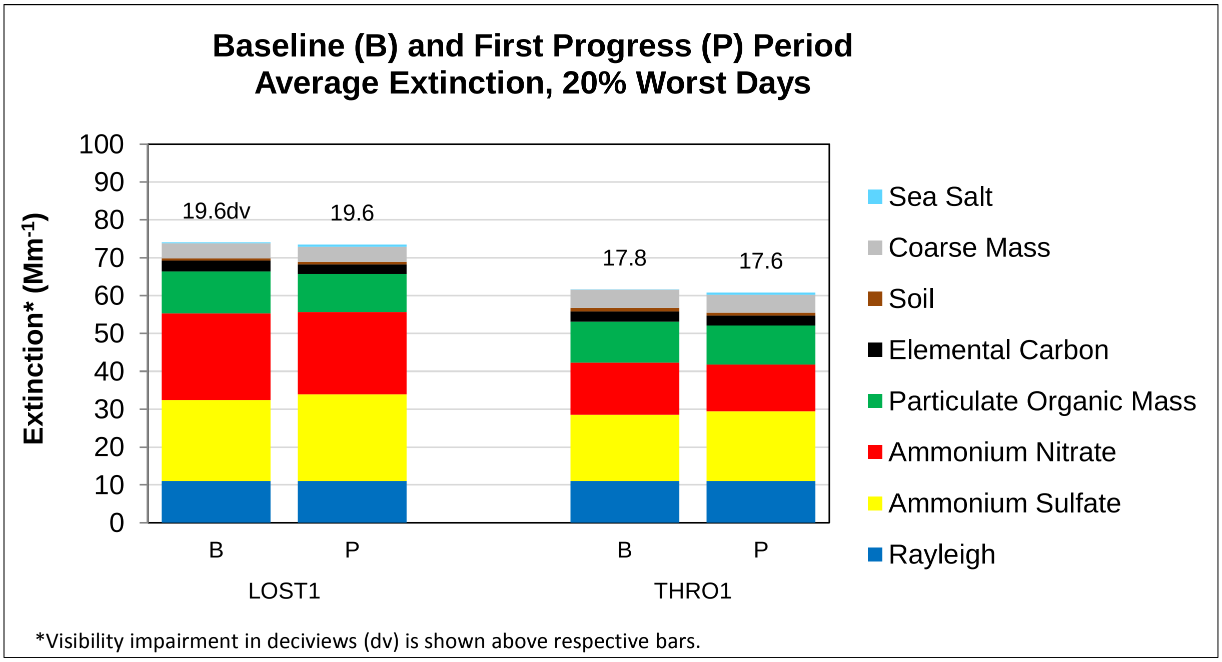

Figure 6.10-3. Average Extinction for Baseline and Progress Period Extinction for Worst (Most Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

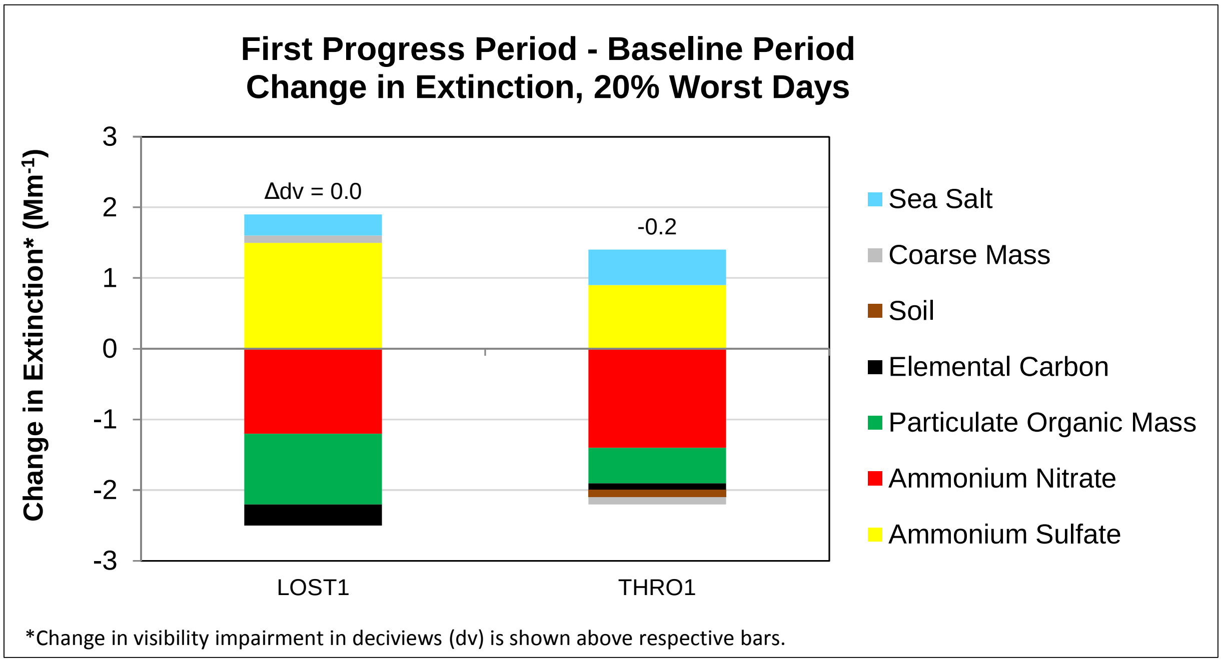

Figure 6.10-4. Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Worst (Most Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

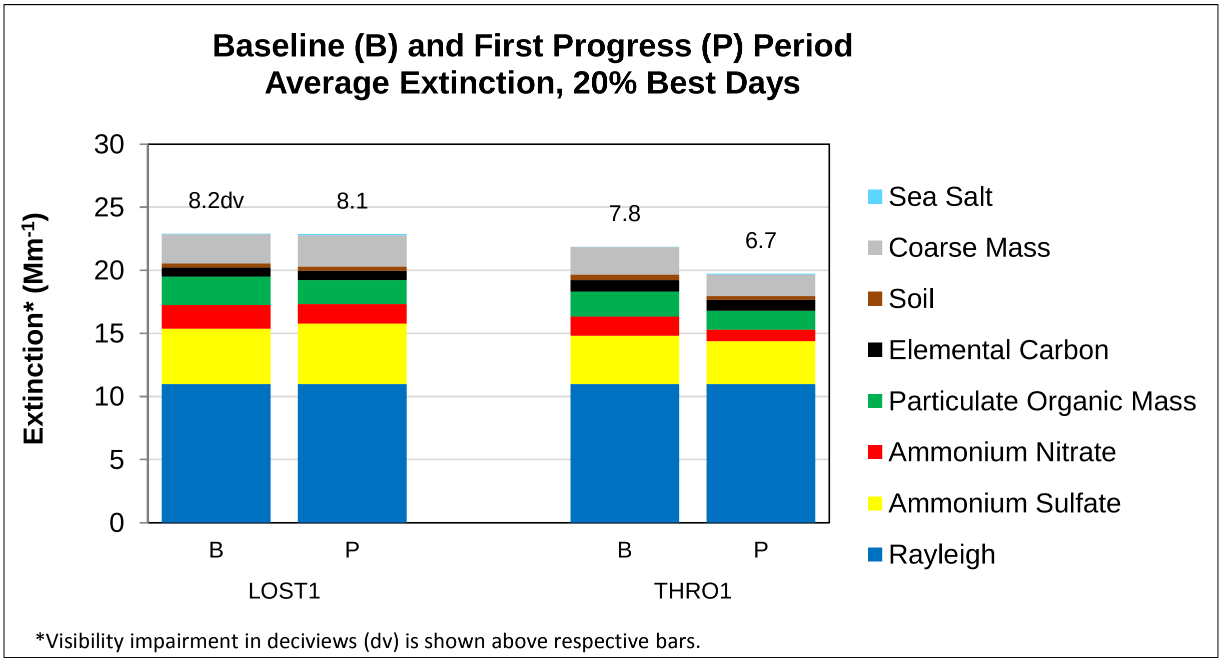

Figure 6.10-5. Average Extinction for Baseline and Progress Period Extinction for Best (Least Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

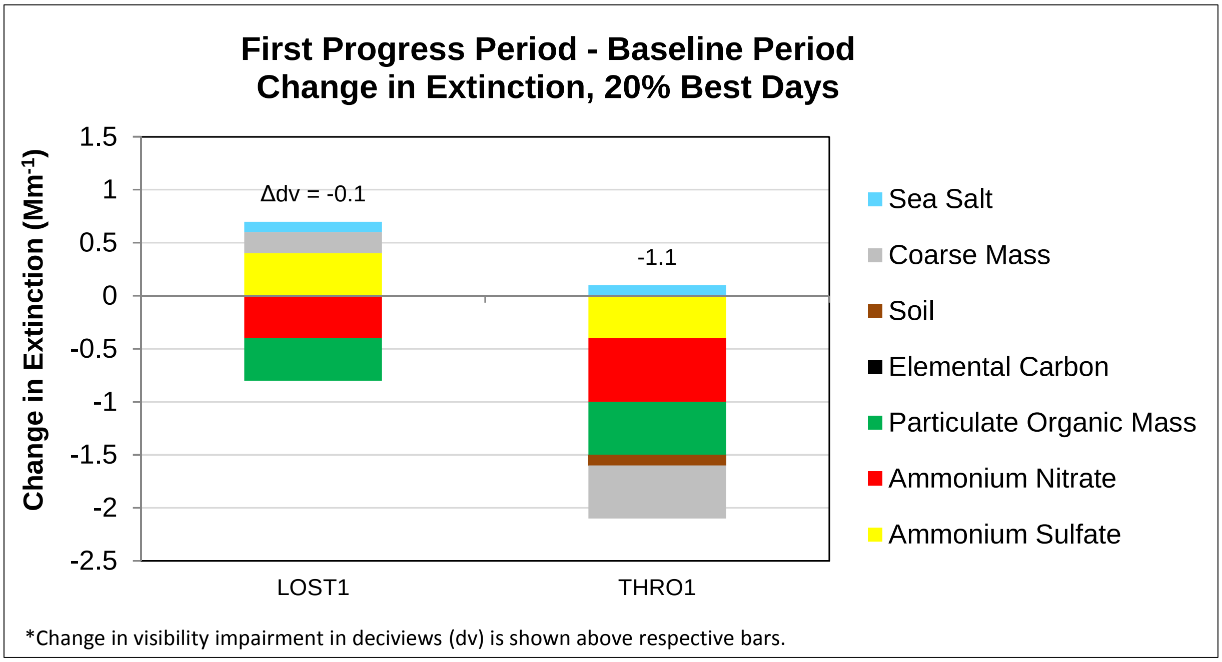

Figure 6.10-6. Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Best (Least Impaired) Days Measured at North Dakota Class I Area IMPROVE Sites.

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%)**

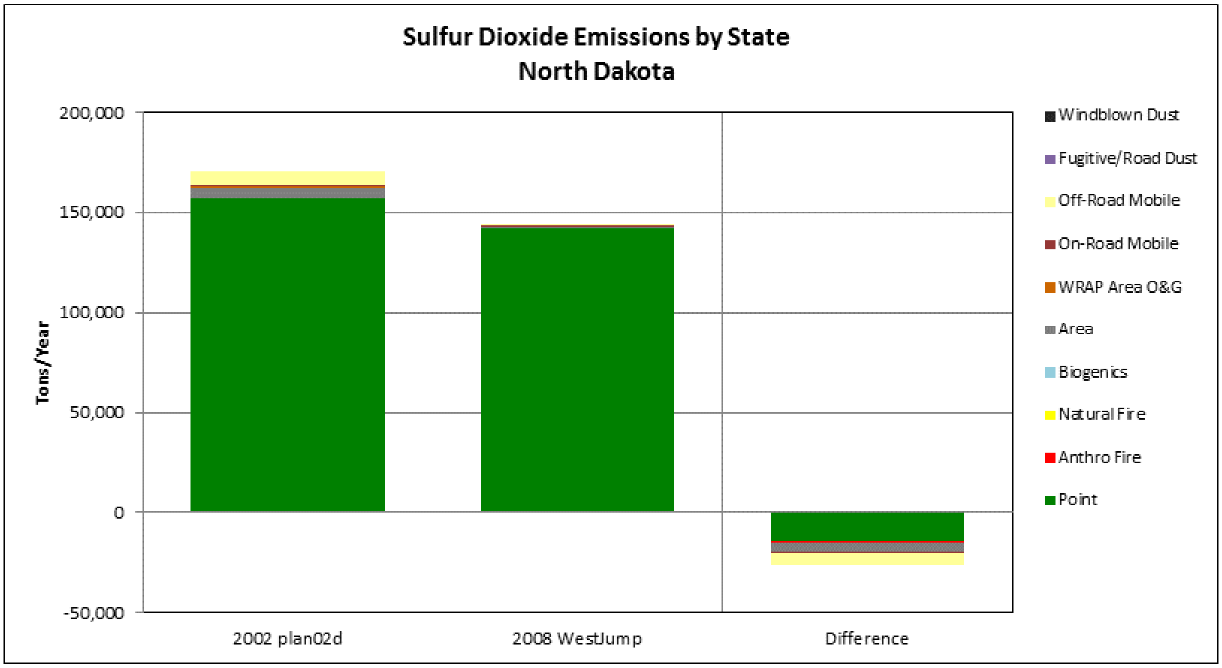


Figure 6.10-7. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Sulfur Dioxide by Source Category for North Dakota.

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.

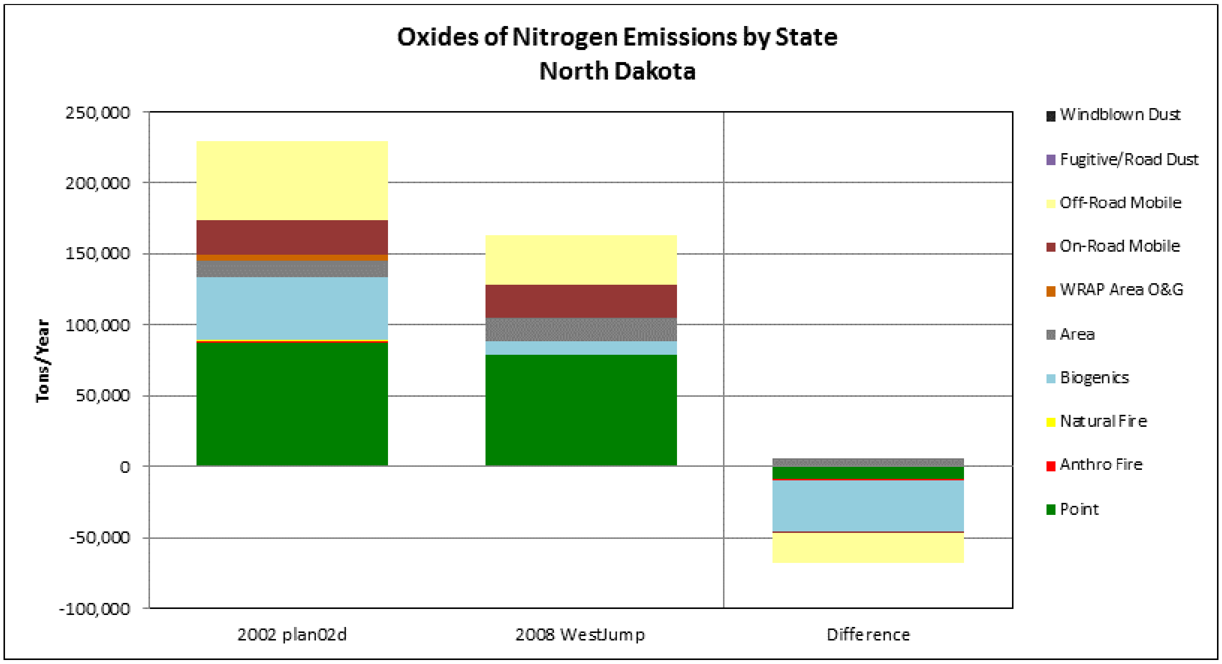


Figure 6.10-8. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Oxides of Nitrogen by Source Category for North Dakota.

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%)**

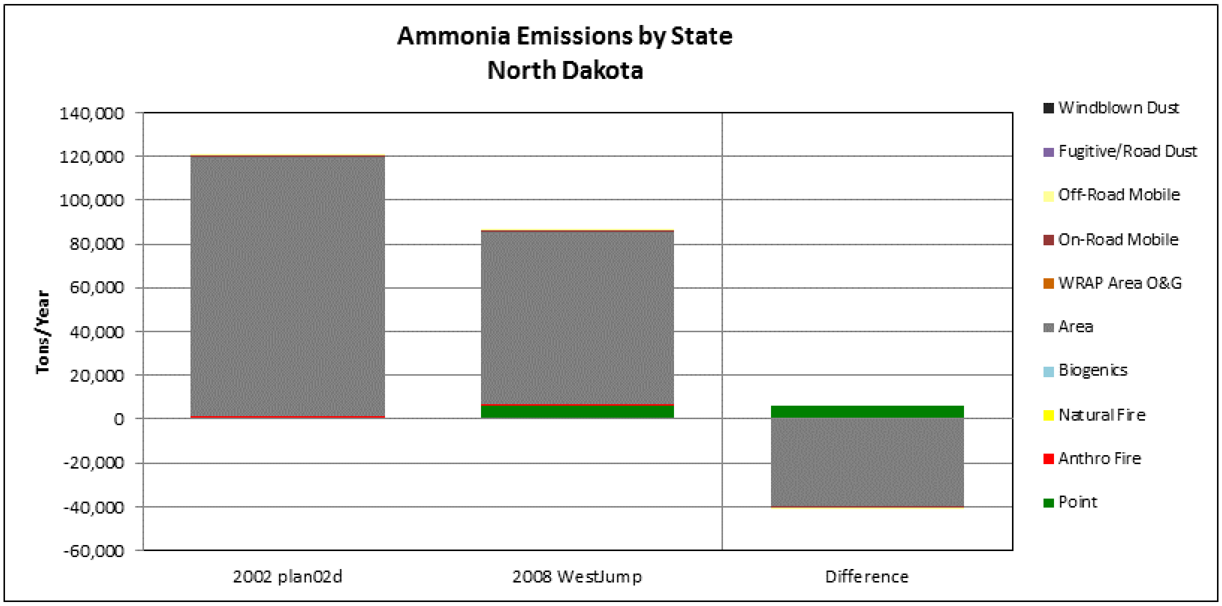


Figure 6.10-9. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Ammonia by Source Category for North Dakota.

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%)**

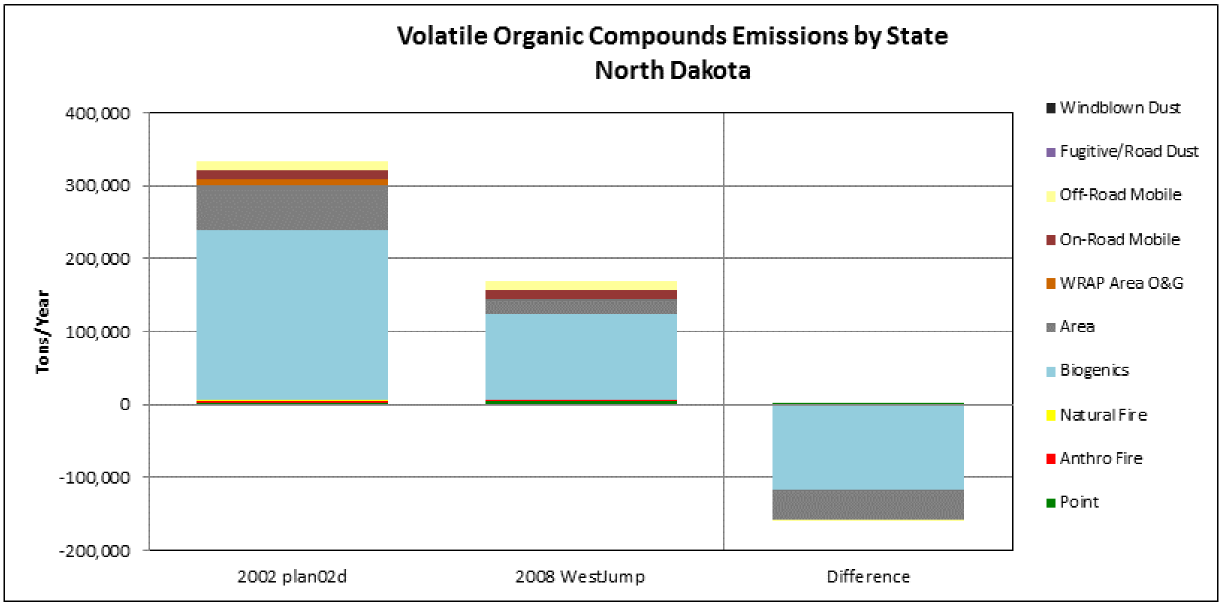


Figure 6.10-10. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Volatile Organic Compounds by Source Category for North Dakota.

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/).

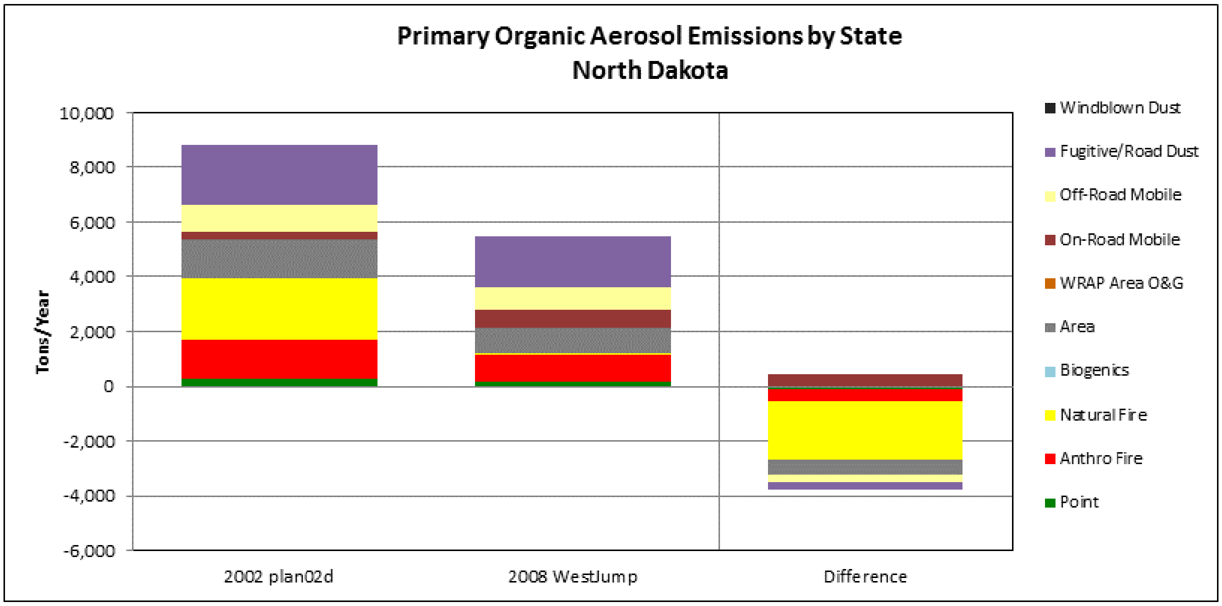


Figure 6.10-11. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Primary Organic Aerosol by Source Category for North Dakota.

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/).

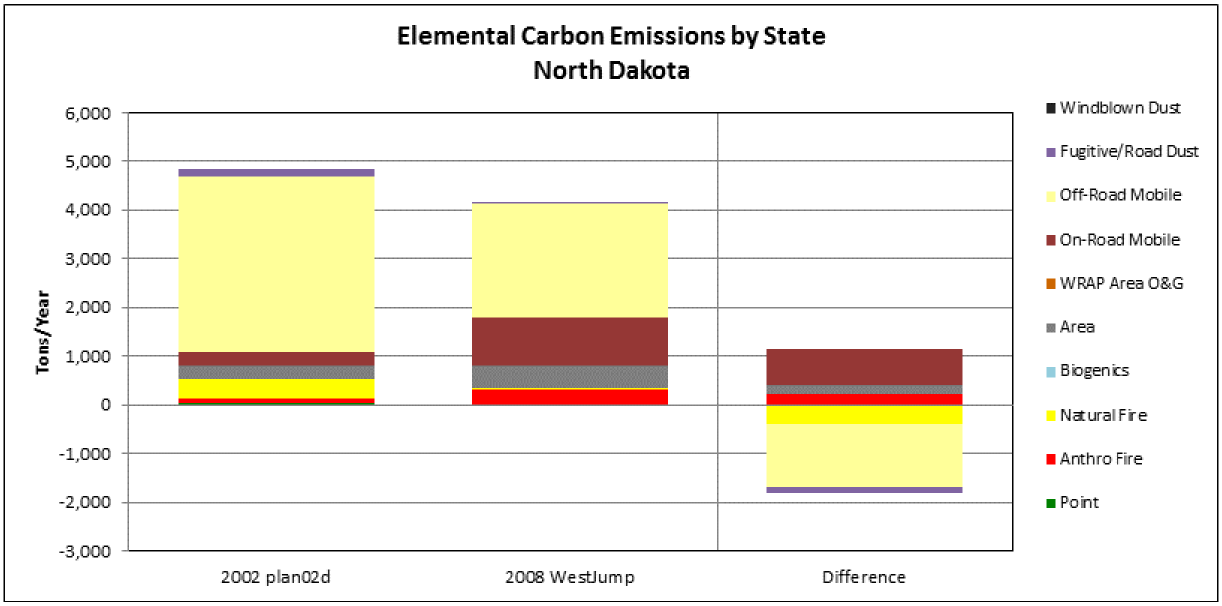


Figure 6.10-12. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Elemental Carbon by Source Category for North Dakota.

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/).

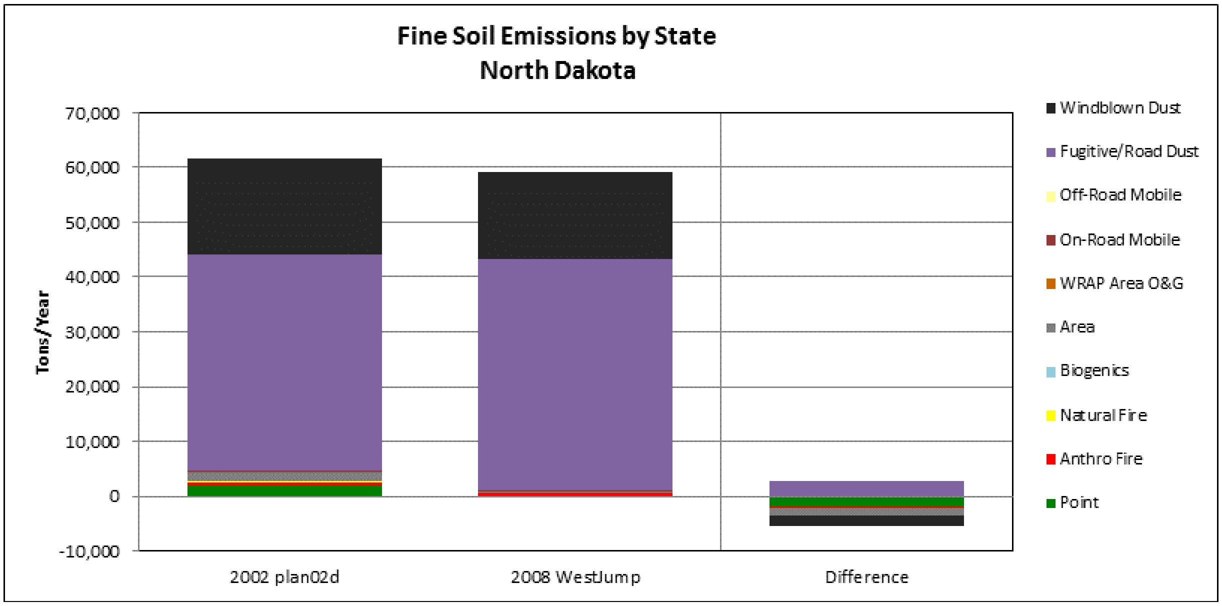


Figure 6.10-13. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Fine Soil by Source Category for North Dakota.

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/).

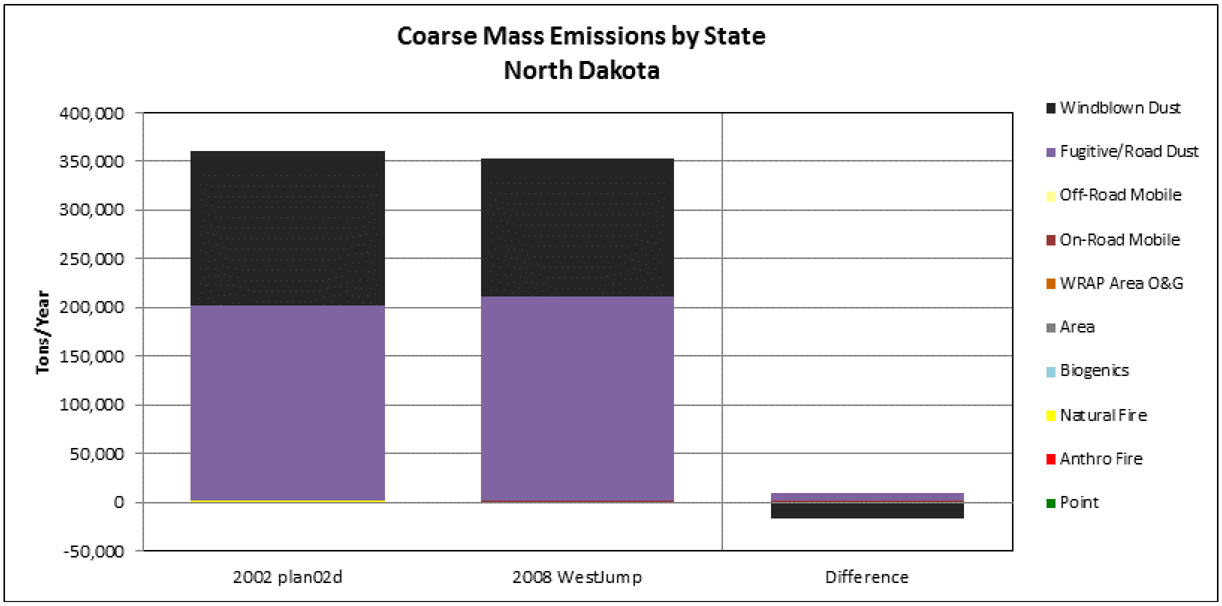


Figure 6.10-14. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Coarse Mass by Source Category for North Dakota.

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.

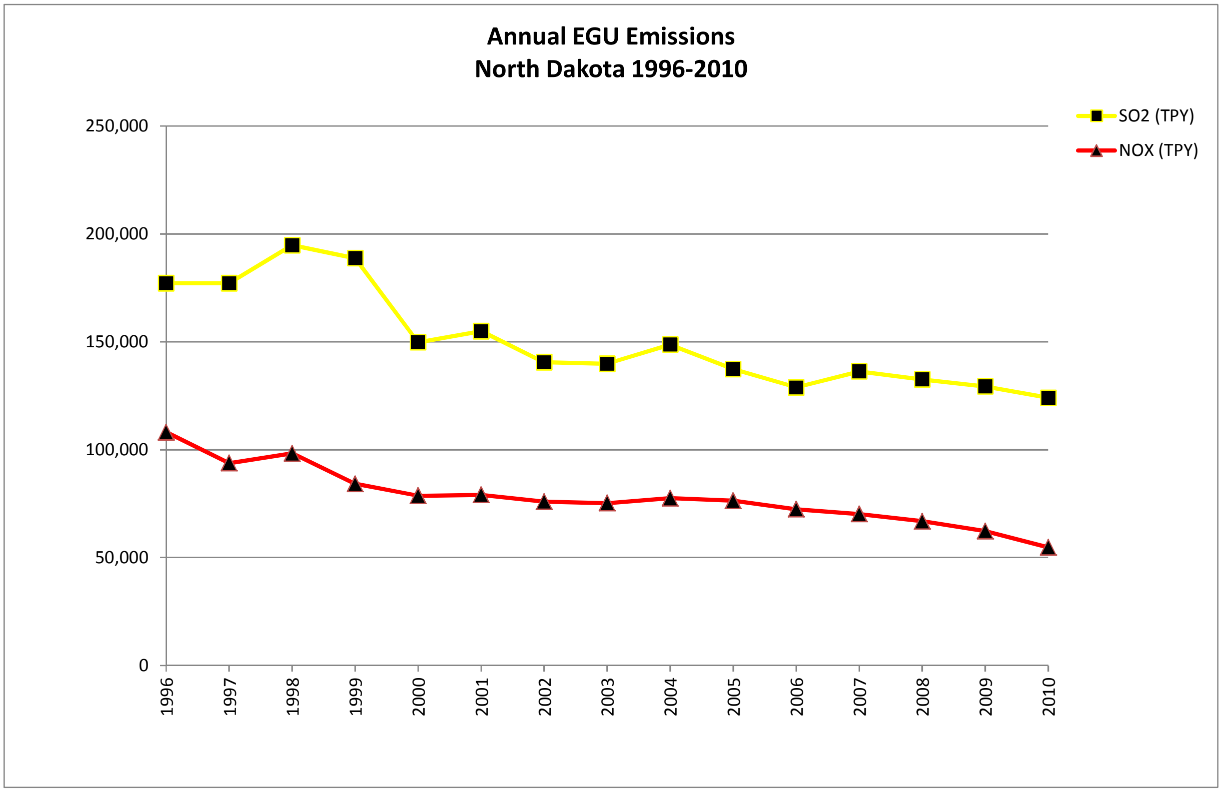


Figure 6.10-17. Sum of EGU Emissions of SO_2 and NO_X reported between 1996 and 2010 for North Dakota.

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

	Baseline Period					Progress Period						2000-2009 Trend Statistics*		Period Averages**			
Group	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

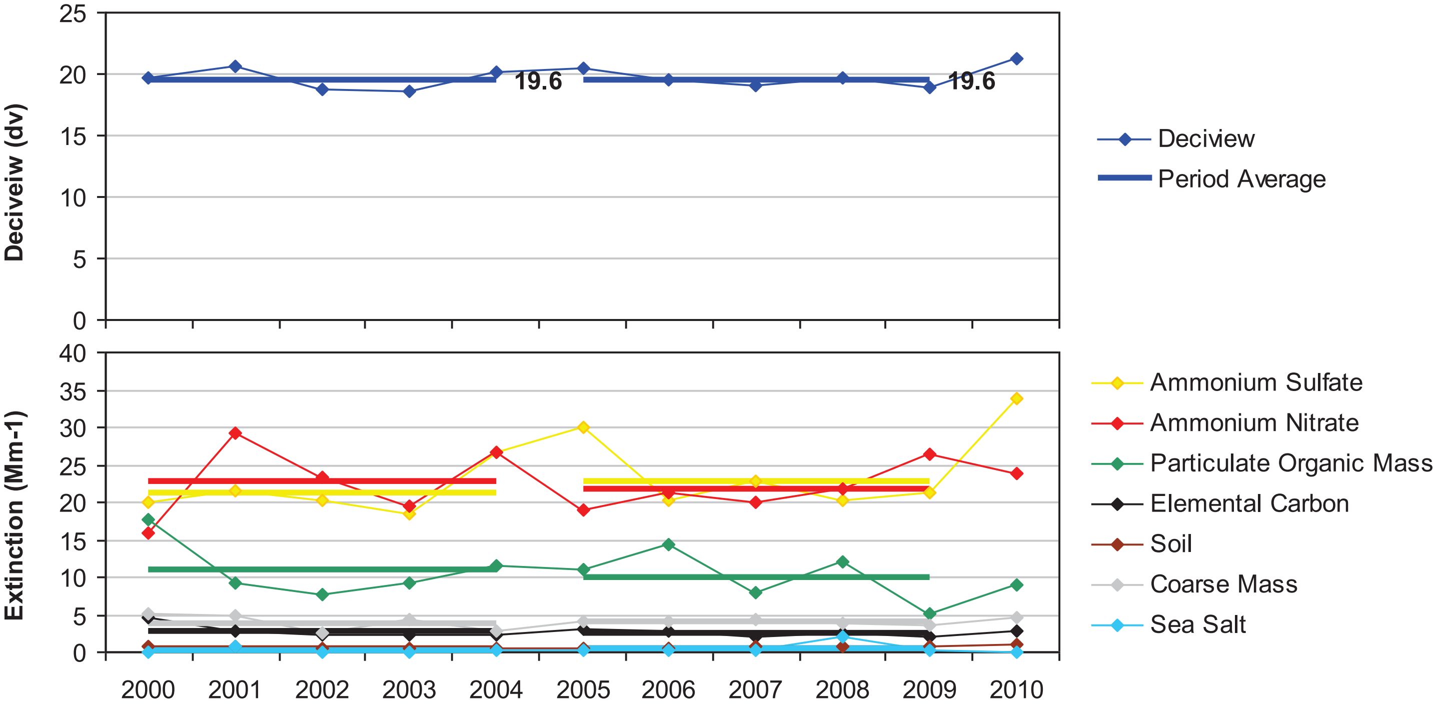


Figure J.1-2
Lostwood WA, ND (LOST1 Site)
Annual and 5-Year Period Averages
20% Least Impaired Visibility Days

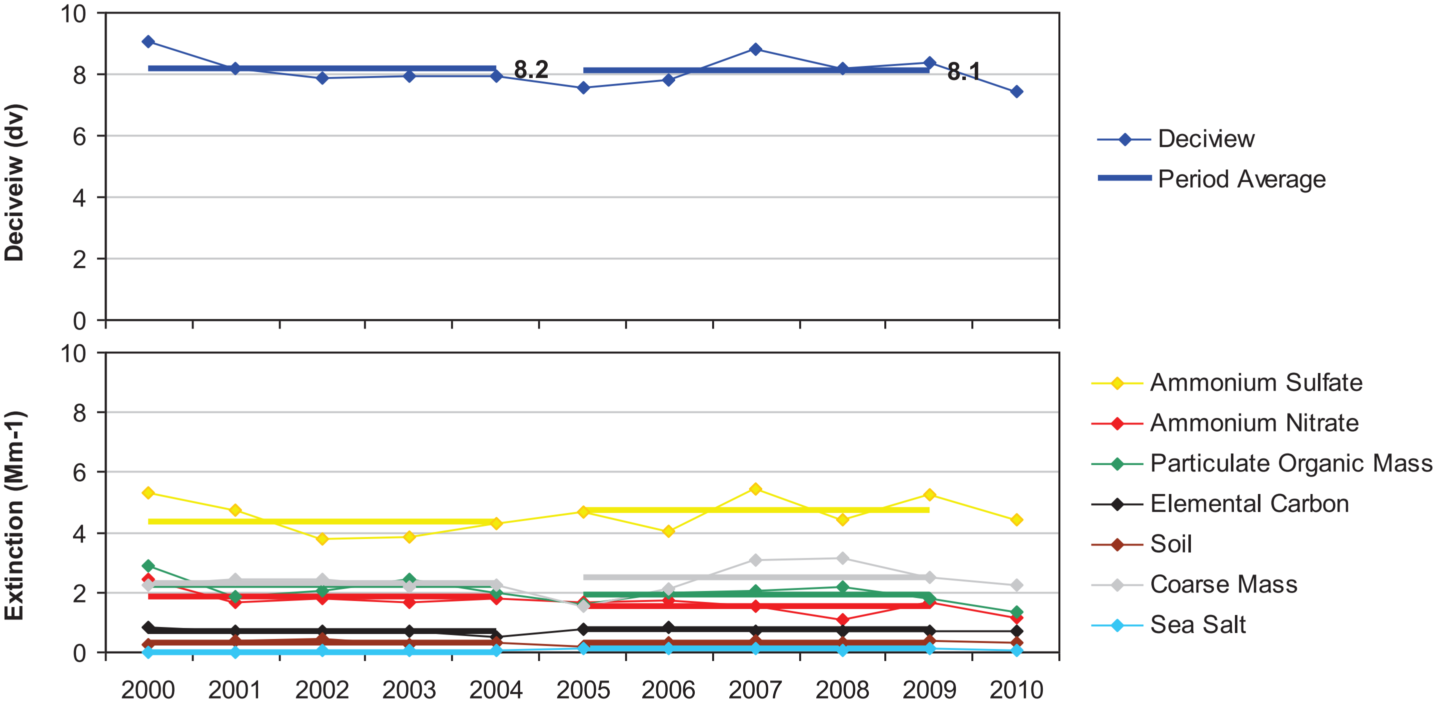


Figure J.1-3
Lostwood WA, ND (LOST1 Site)
20% Most Impaired Visibility Days

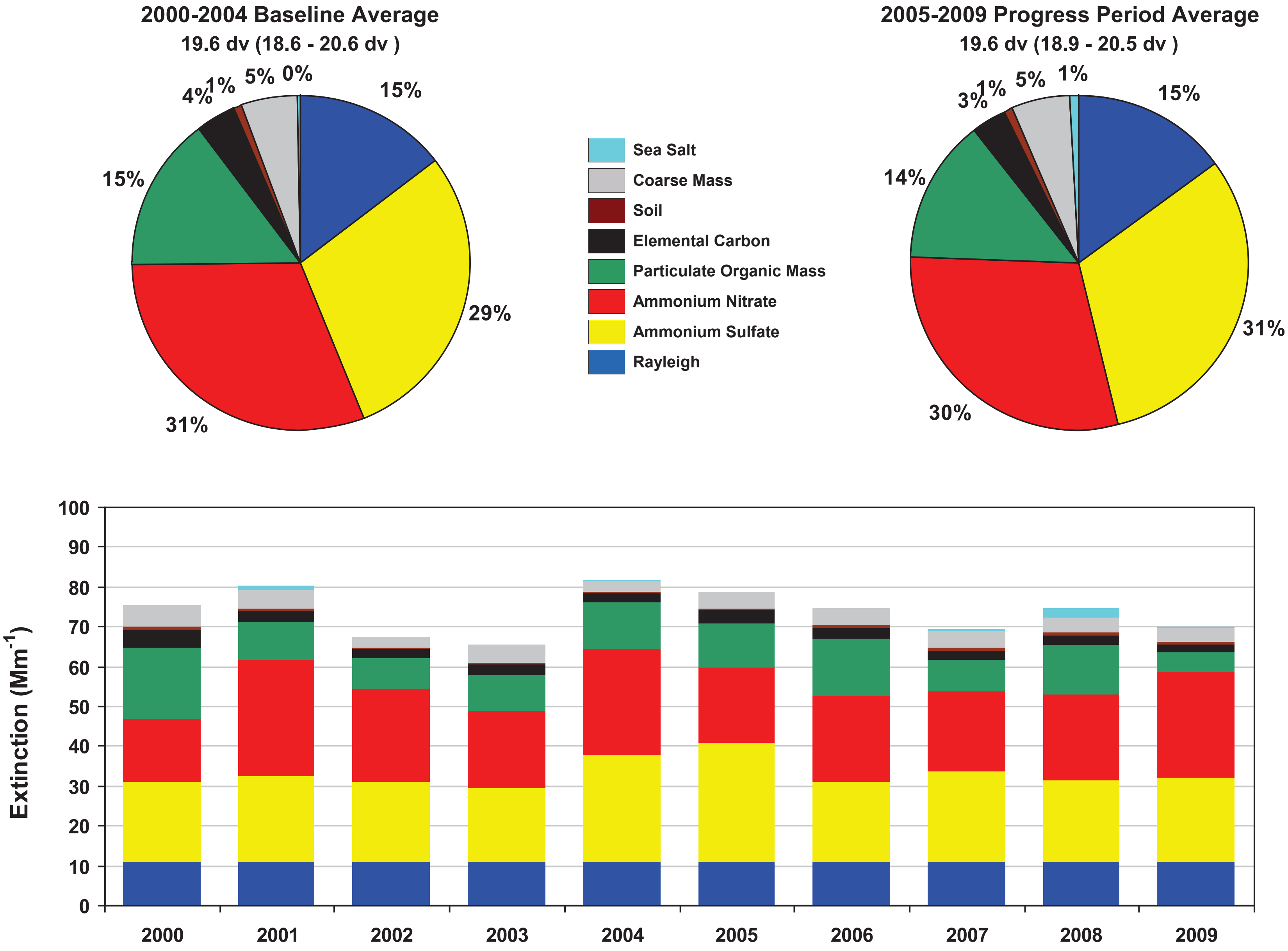
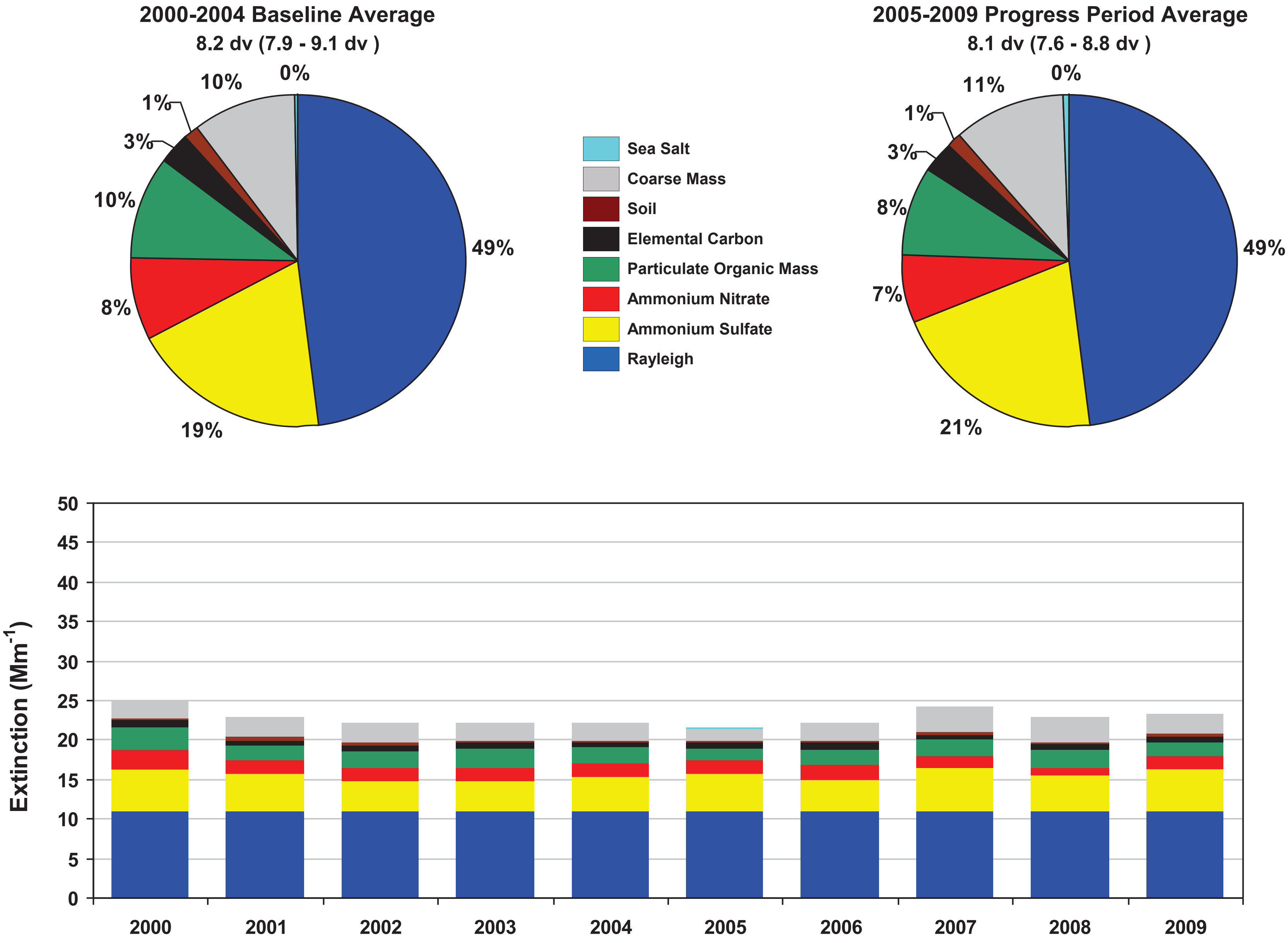


Figure J.1-4
Lostwood WA, ND (LOST1 Site)
20% Least Impaired Visibility Days



2000-2004 Baseline Average
8.2 dv (7.9 - 9.1 dv)

2005-2009 Progress Period Average
8.1 dv (7.6 - 8.8 dv)

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

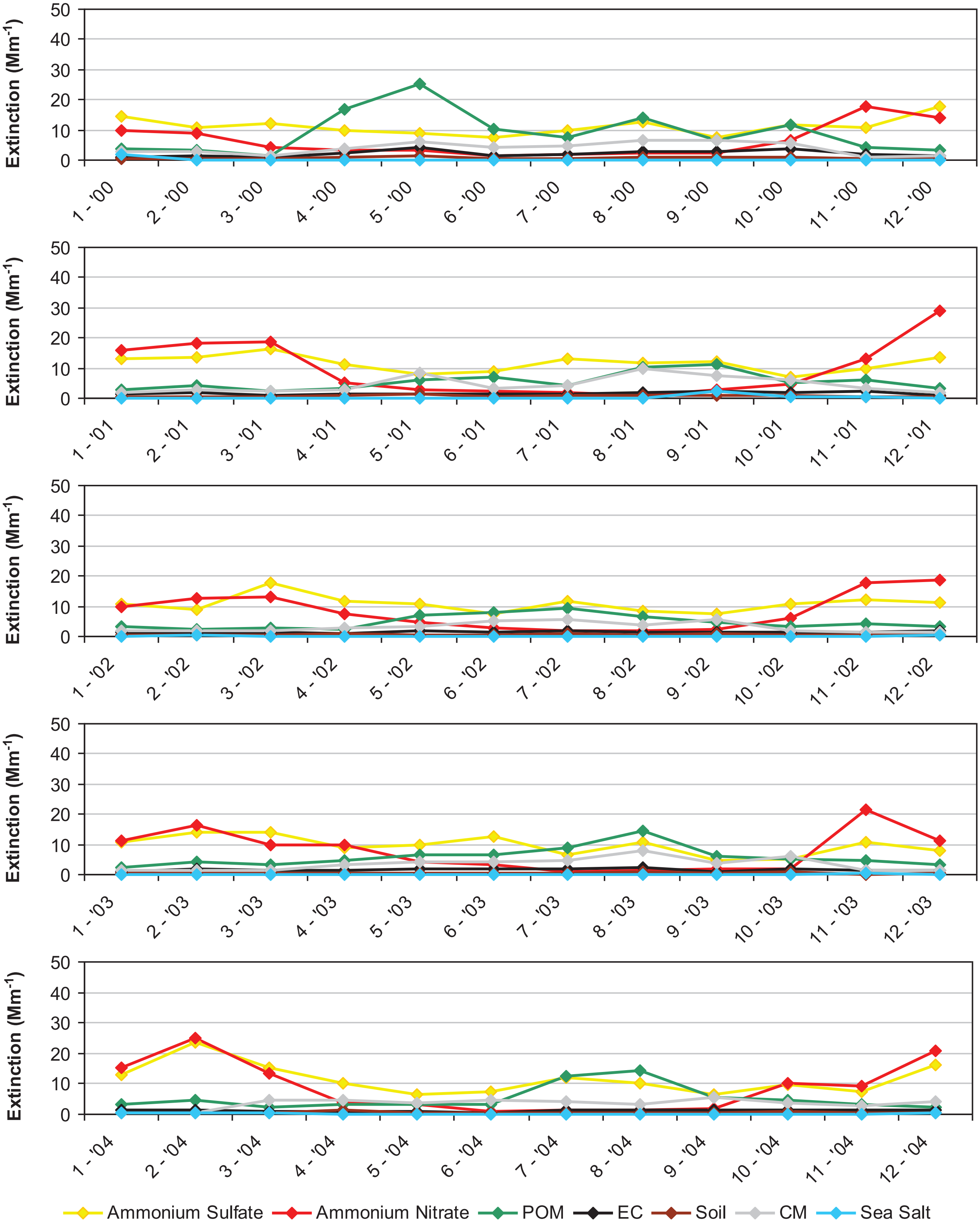


Figure J.1-6
Lostwood WA, ND (LOST1 Site)
2005-2009 Monthly Average Aerosol Extinction, All Monitored Days

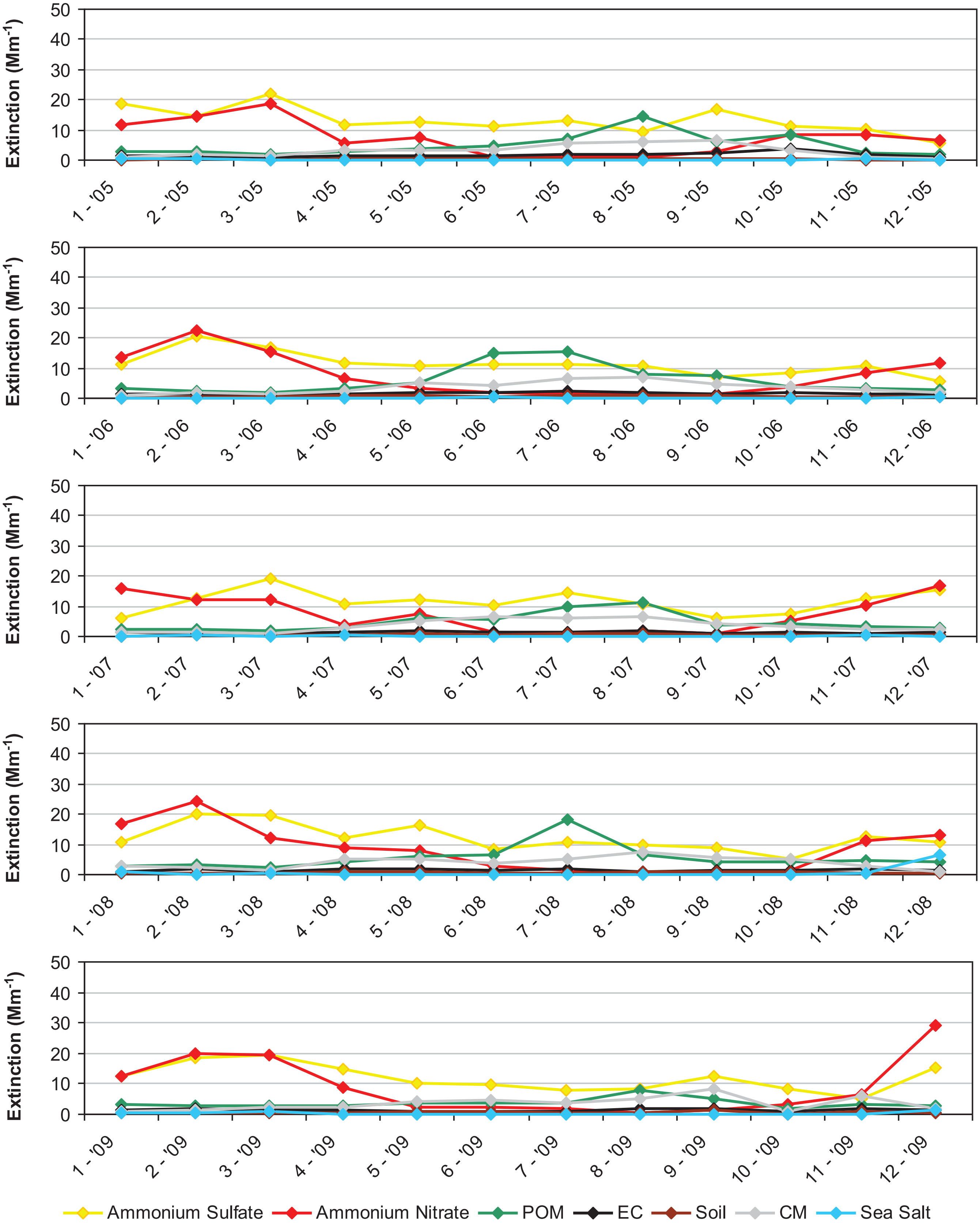


Figure J.1-7
Lostwood WA, ND (LOST1 Site)
2000-2004 Progress Period Extinction, All Sampled Days

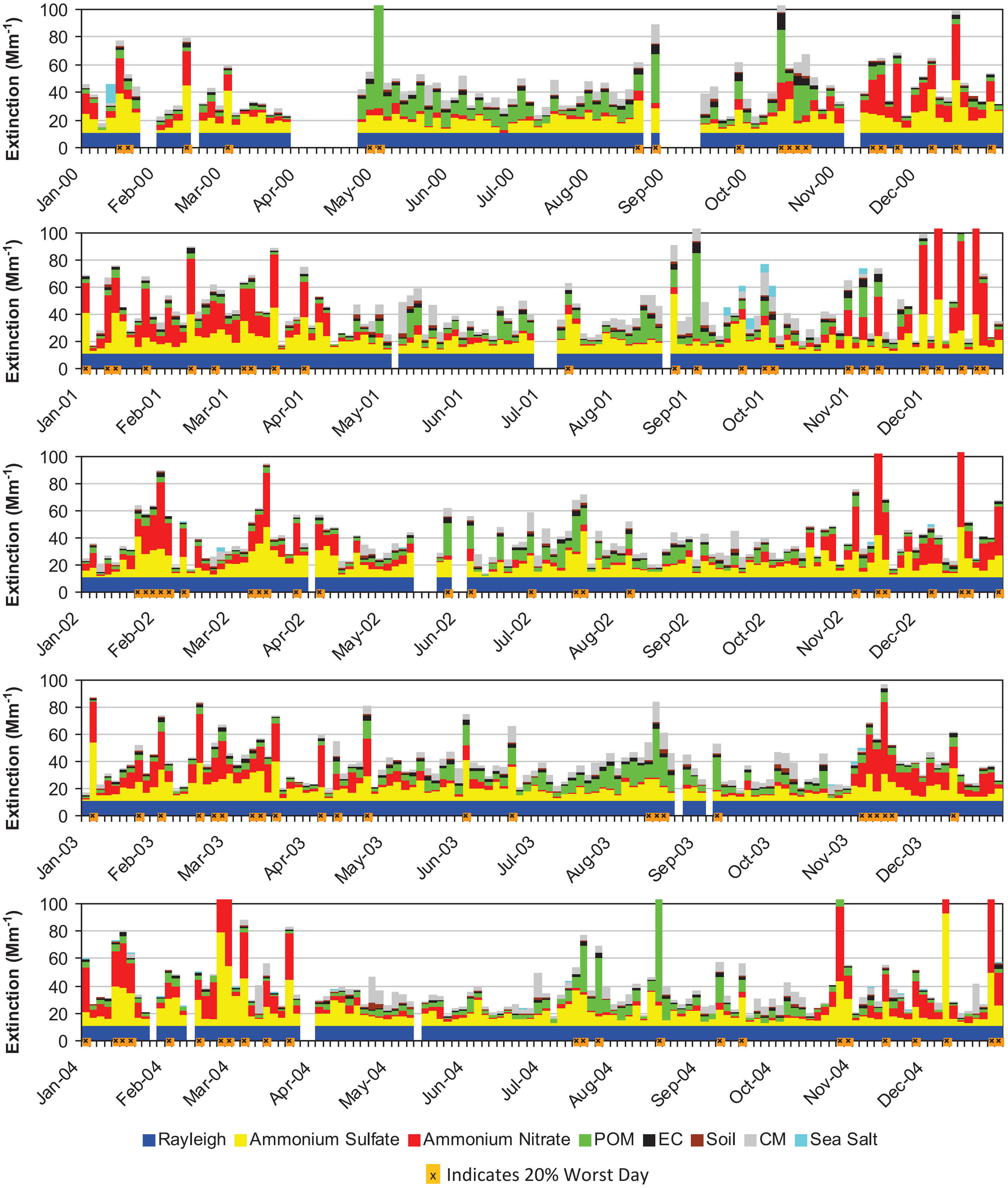
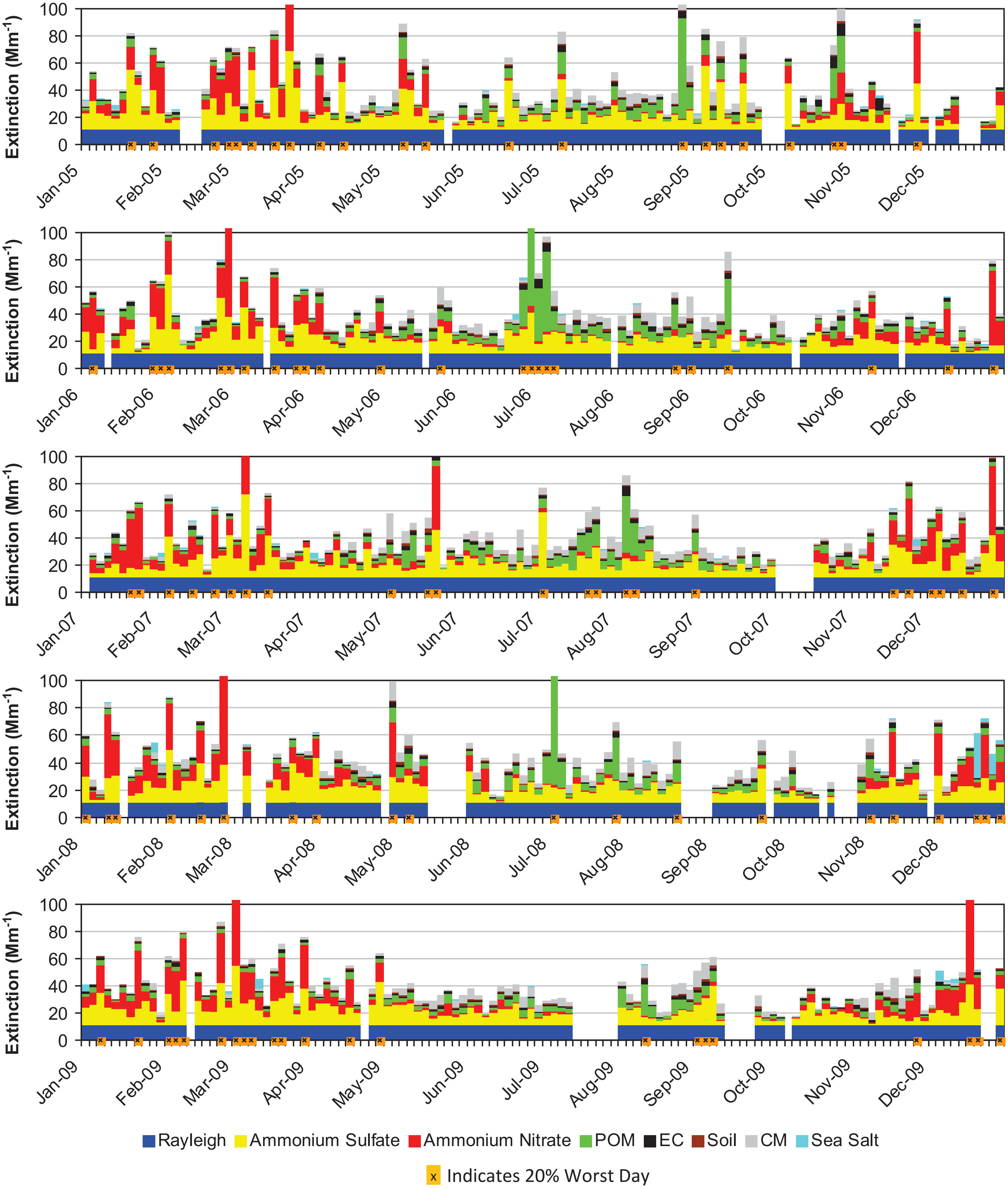


Figure J.1-8
Lostwood WA, ND (LOST1 Site)
2005-2009 Progress Period Extinction, All Sampled Days



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.

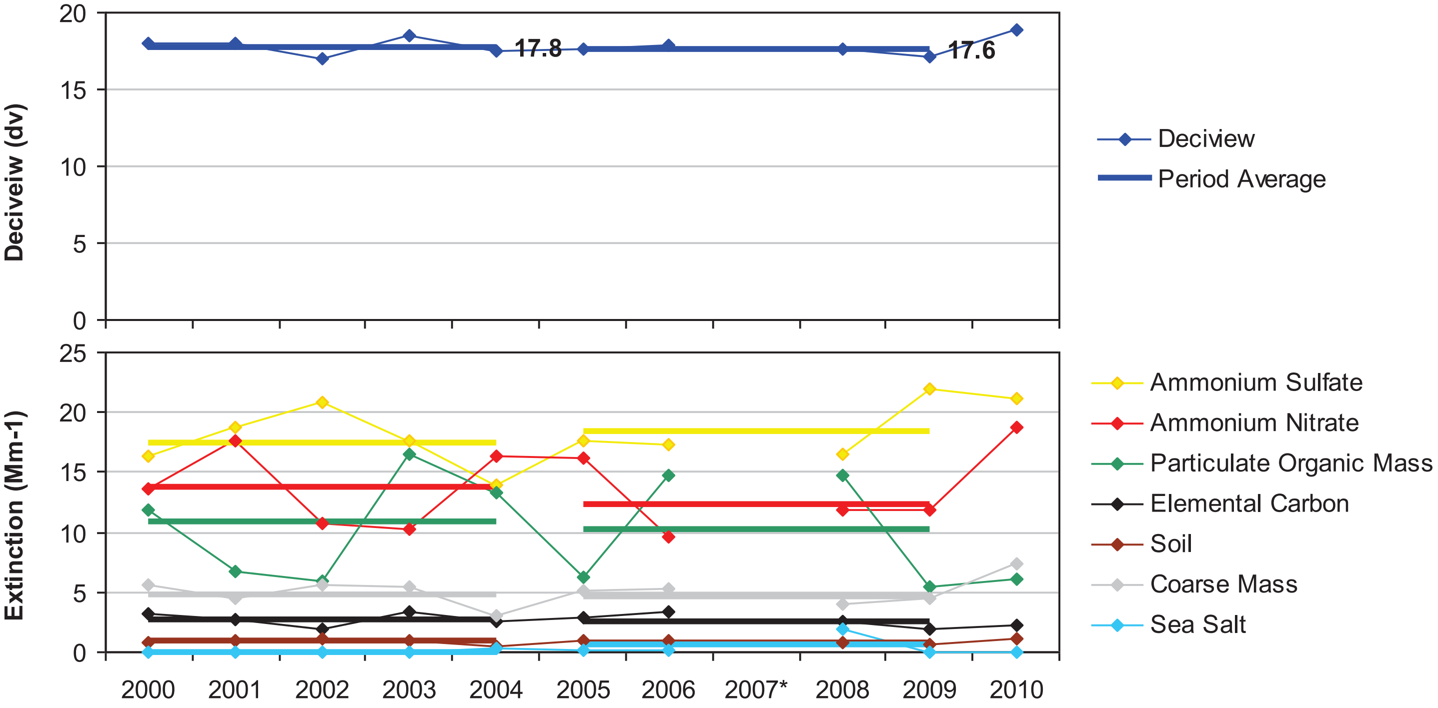
- **Figure J.2-8: 2000-2004 Progress Period Extinction, All Sampled Days**: Stacked bar charts depicting daily averages by year and component for the progress period are presented.

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%

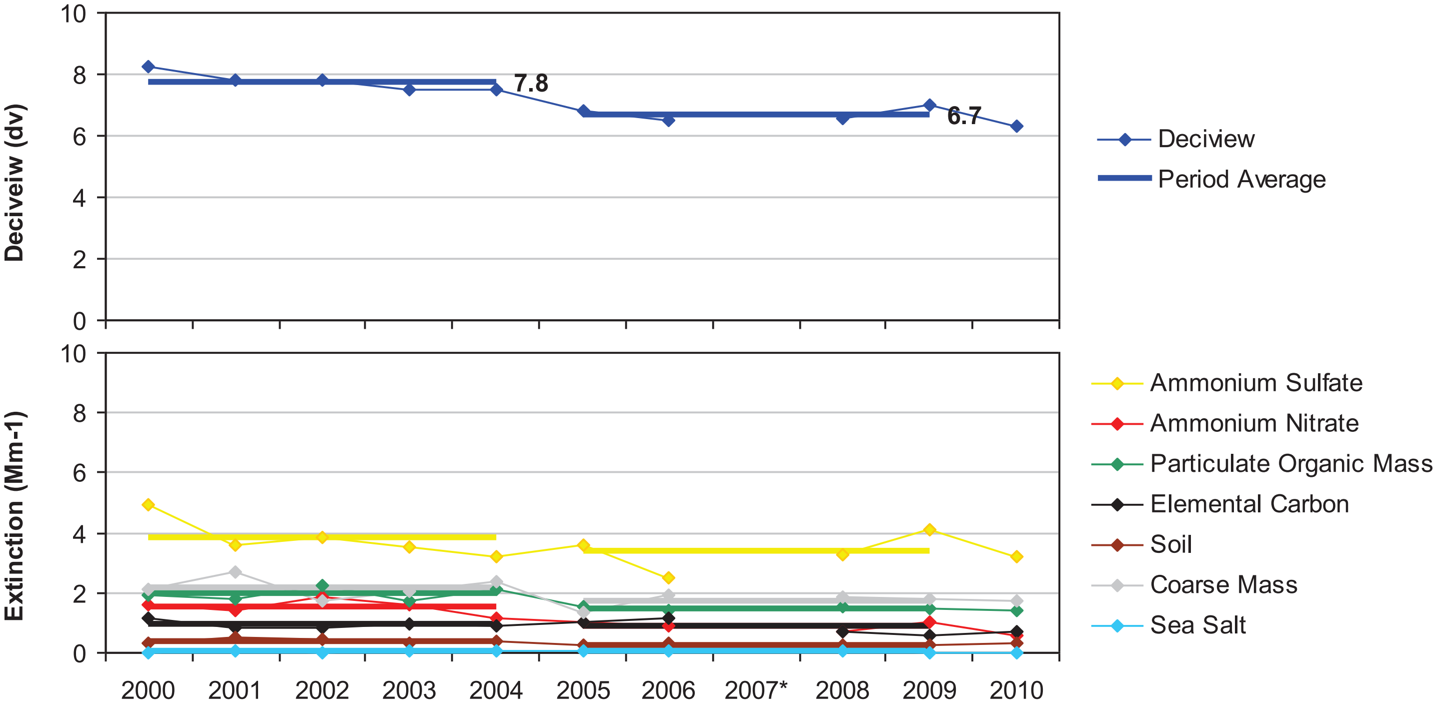
*Values highlighted in blue (red) indicate statistically significant decreasing (increasing) annual trend. Significance is measured at the 85% confidence level (p-value ≤0.15).
**Values highlighted in blue indicate a decrease in the 5-year average, values highlighted in red indicate an increase.
"---" 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

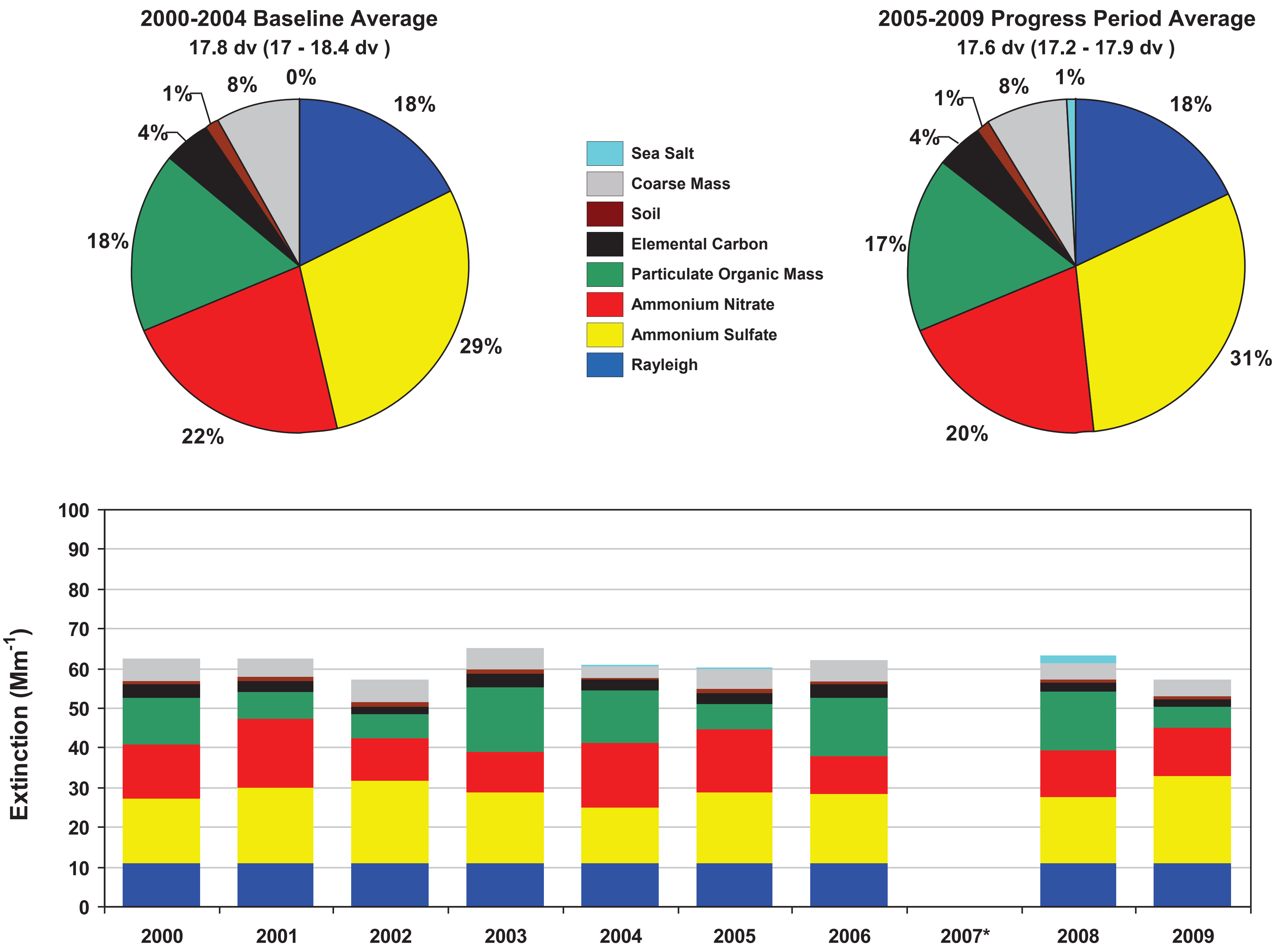


*Missing years did not meet RHR data completeness criteria.

Figure J.2-3

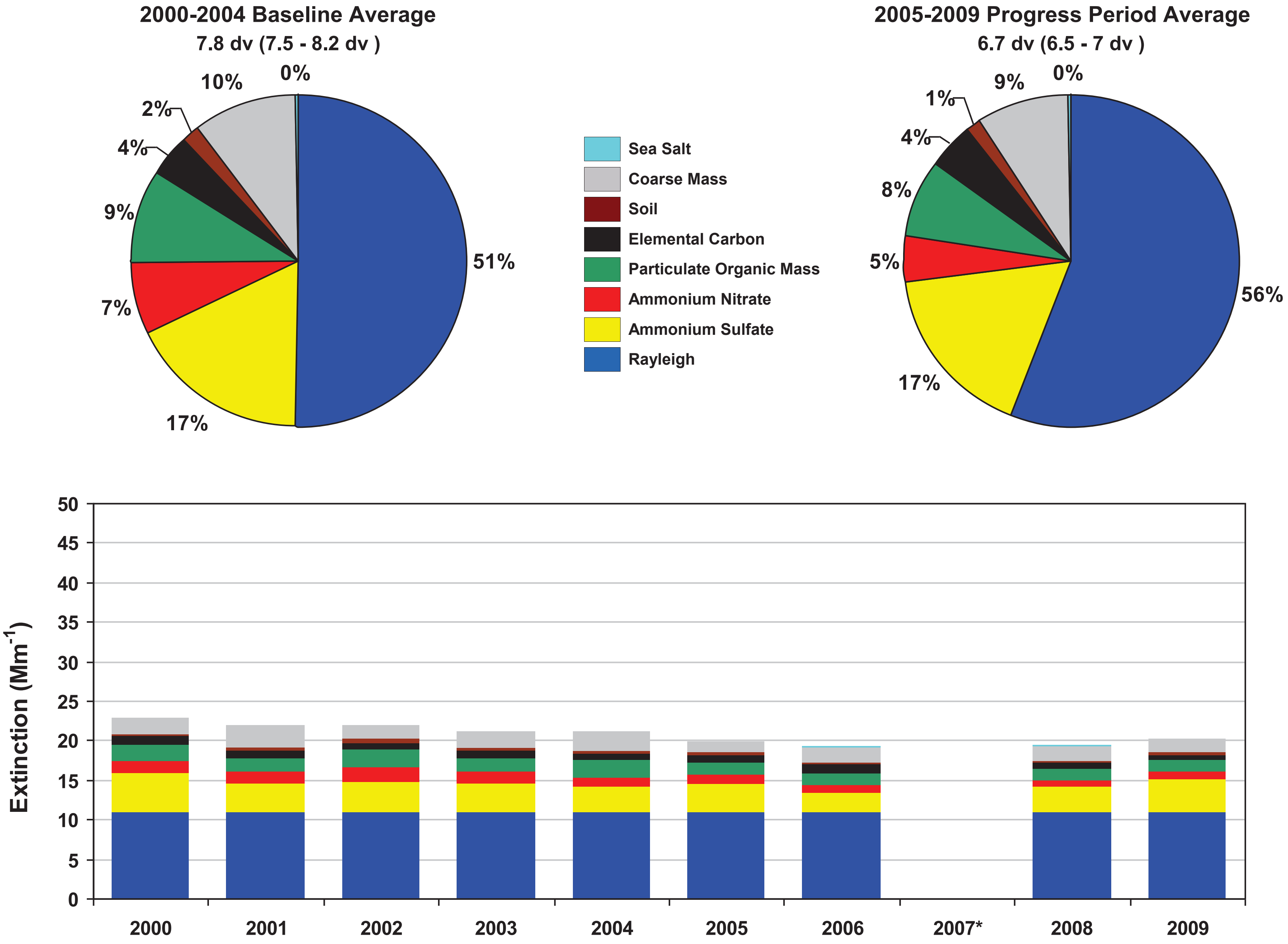
Theodore Roosevelt NP, ND (THRO1 Site)

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

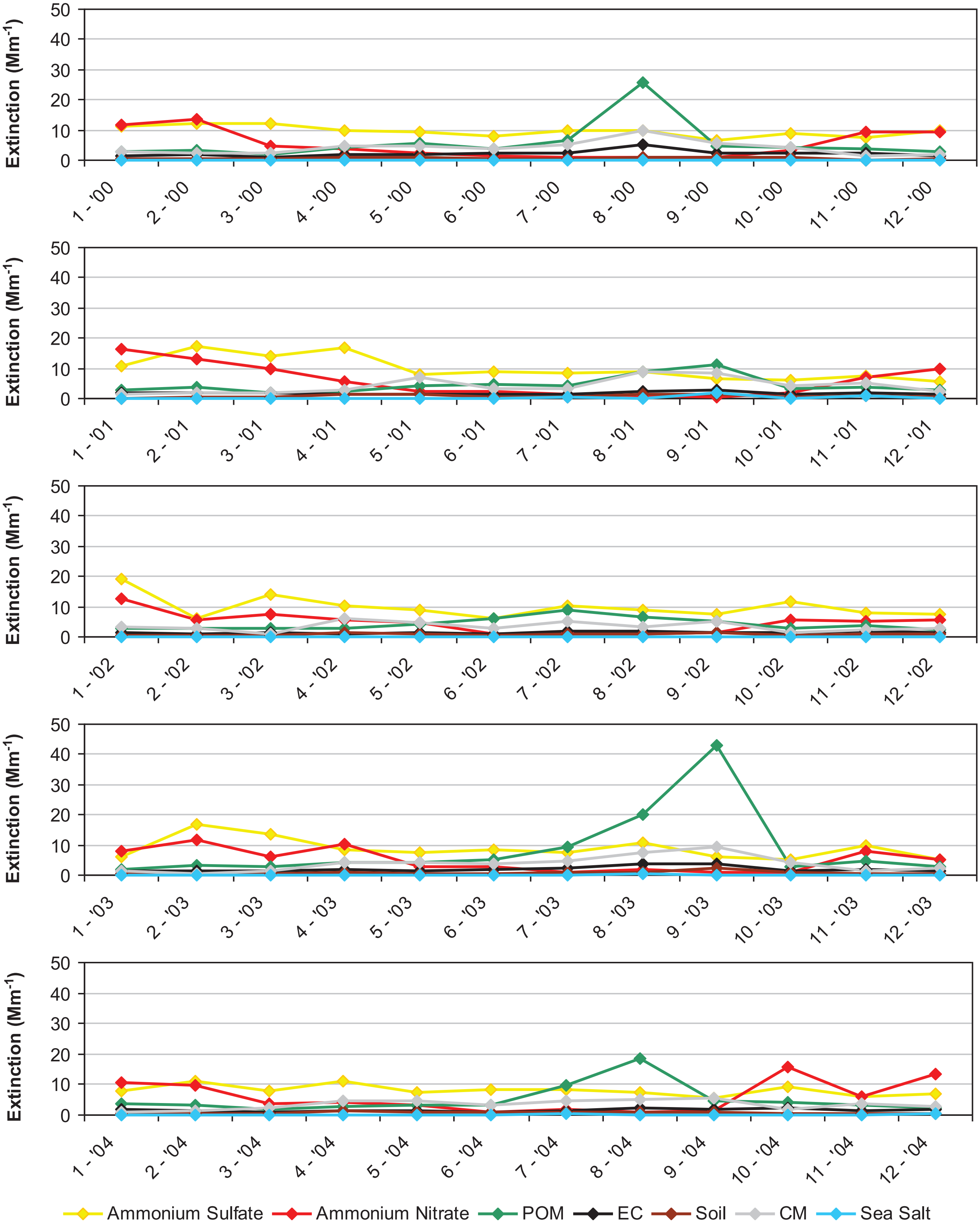
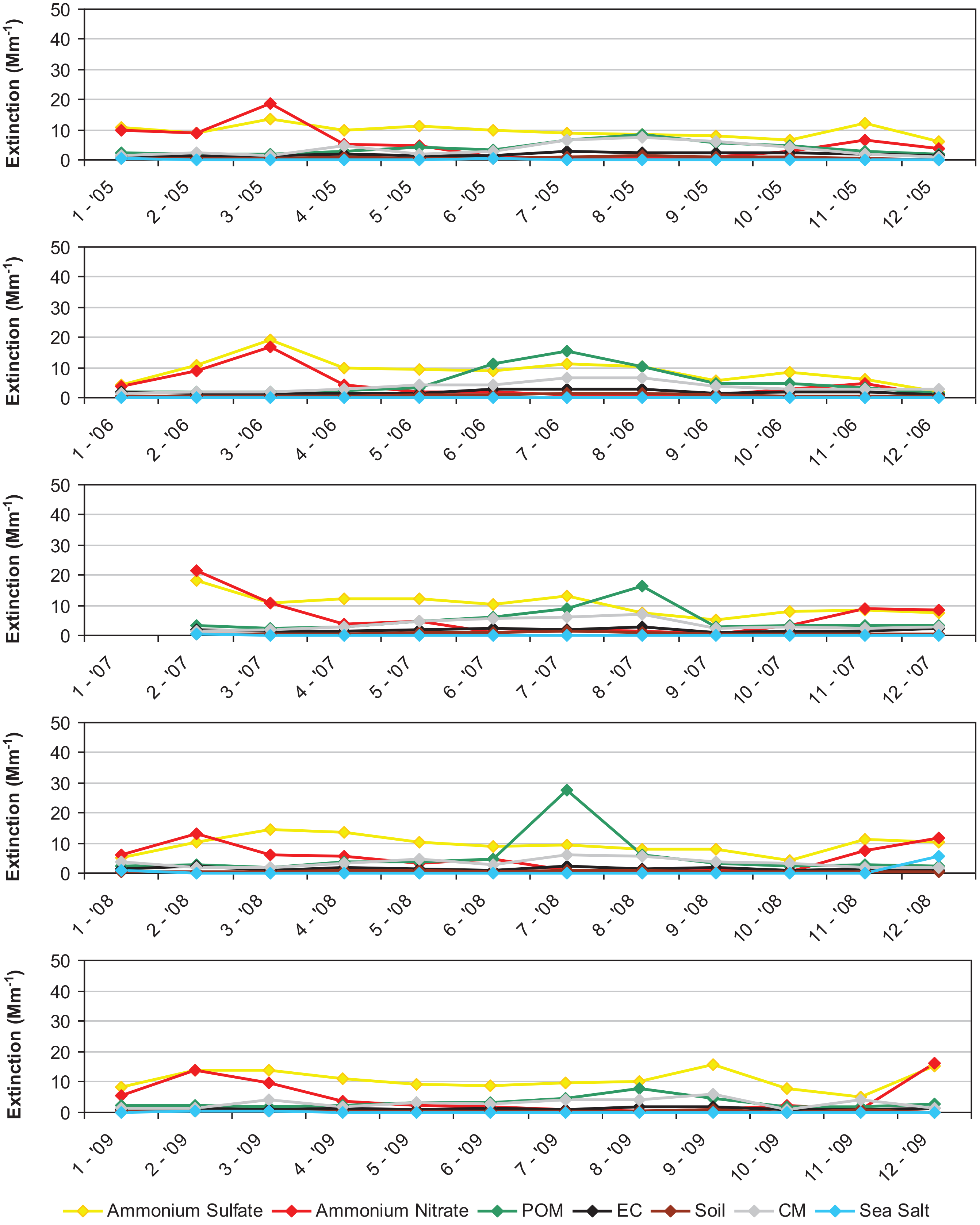


Figure J.2-6
Theodore Roosevelt NP, ND (THRO1 Site)
2005-2009 Monthly Average Aerosol Extinction, All Monitored Days



*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

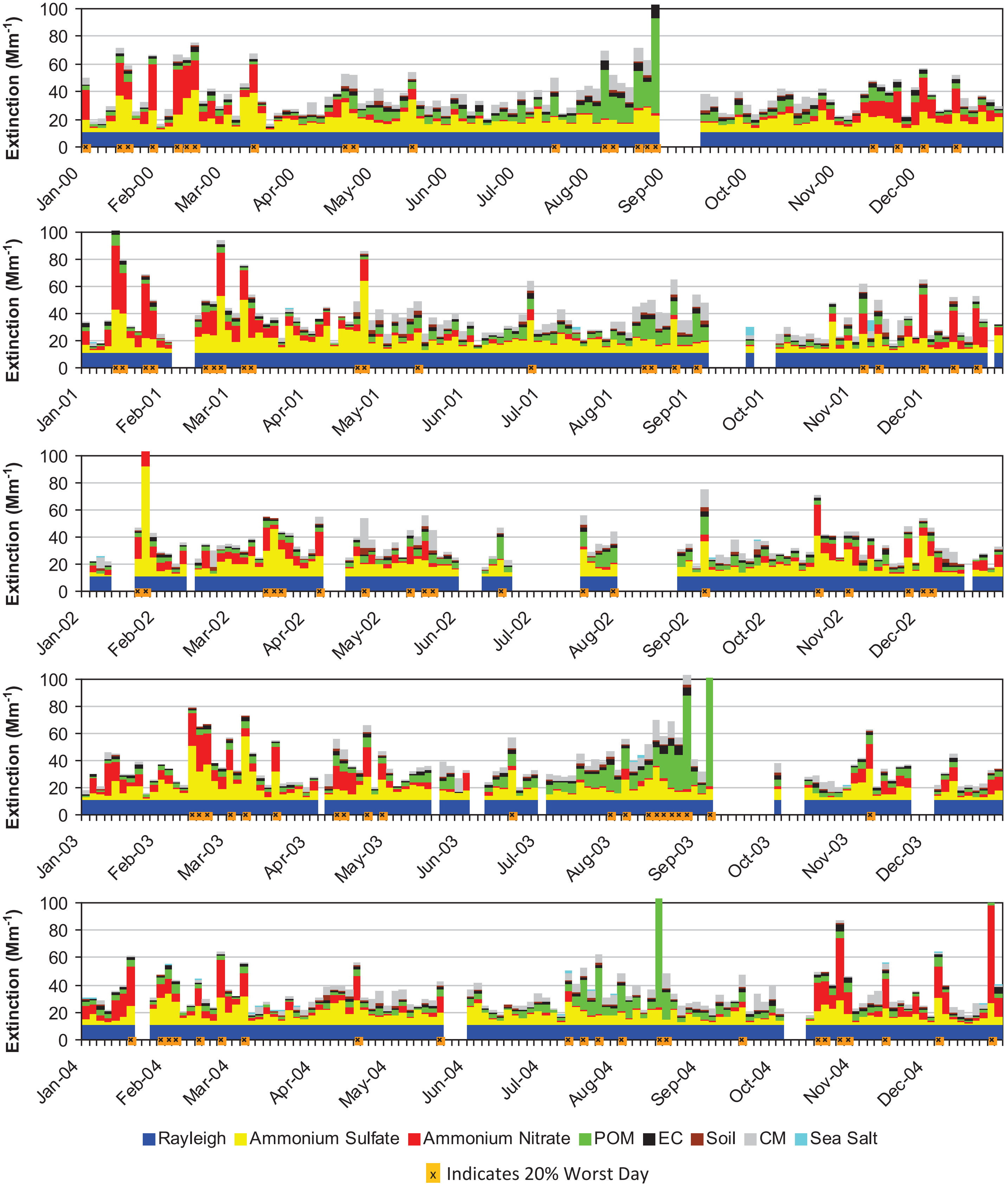
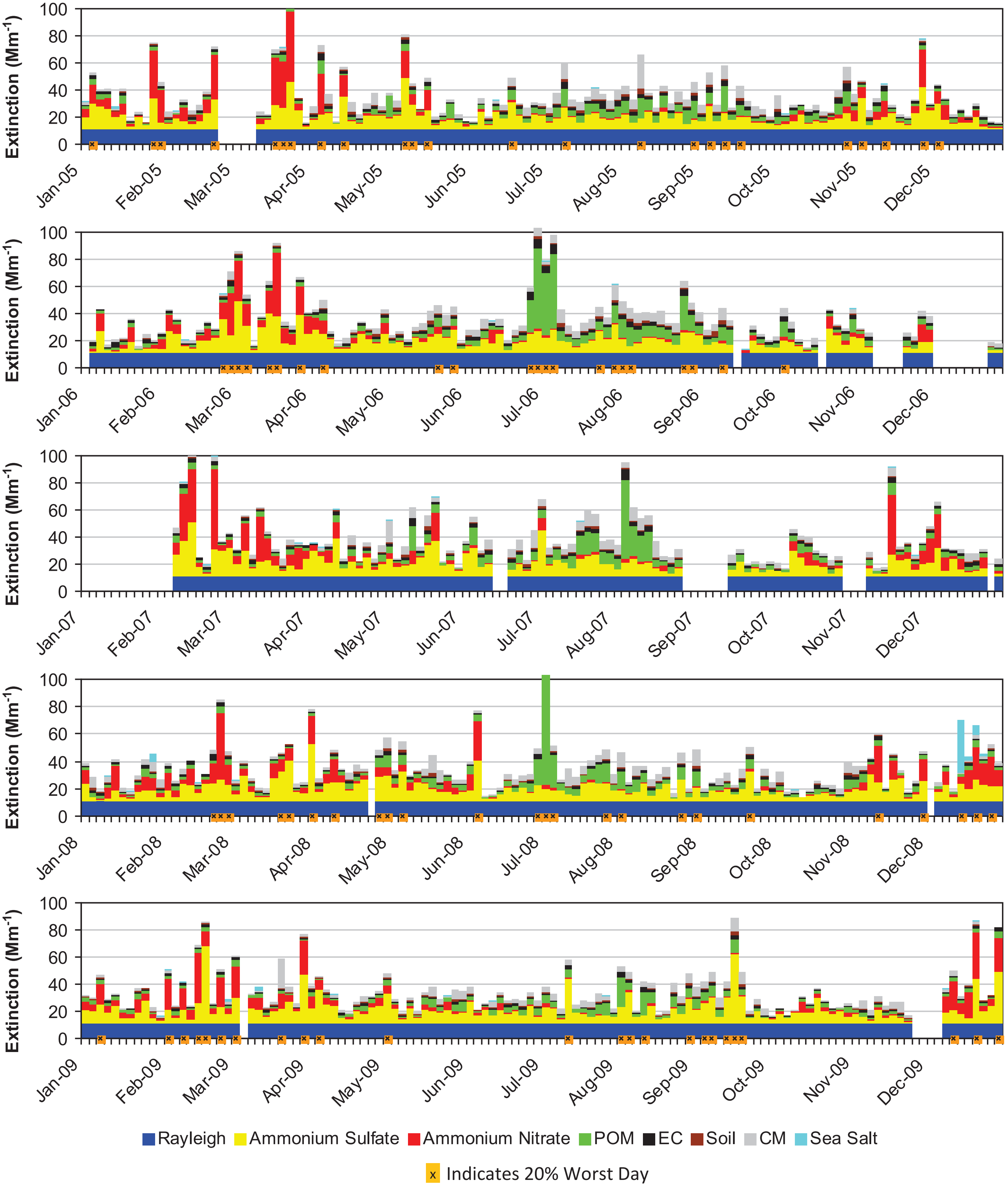


Figure J.2-8
Theodore Roosevelt NP, ND (THRO1 Site)
2005-2009 Progress Period Extinction, All Sampled Days



*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

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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).

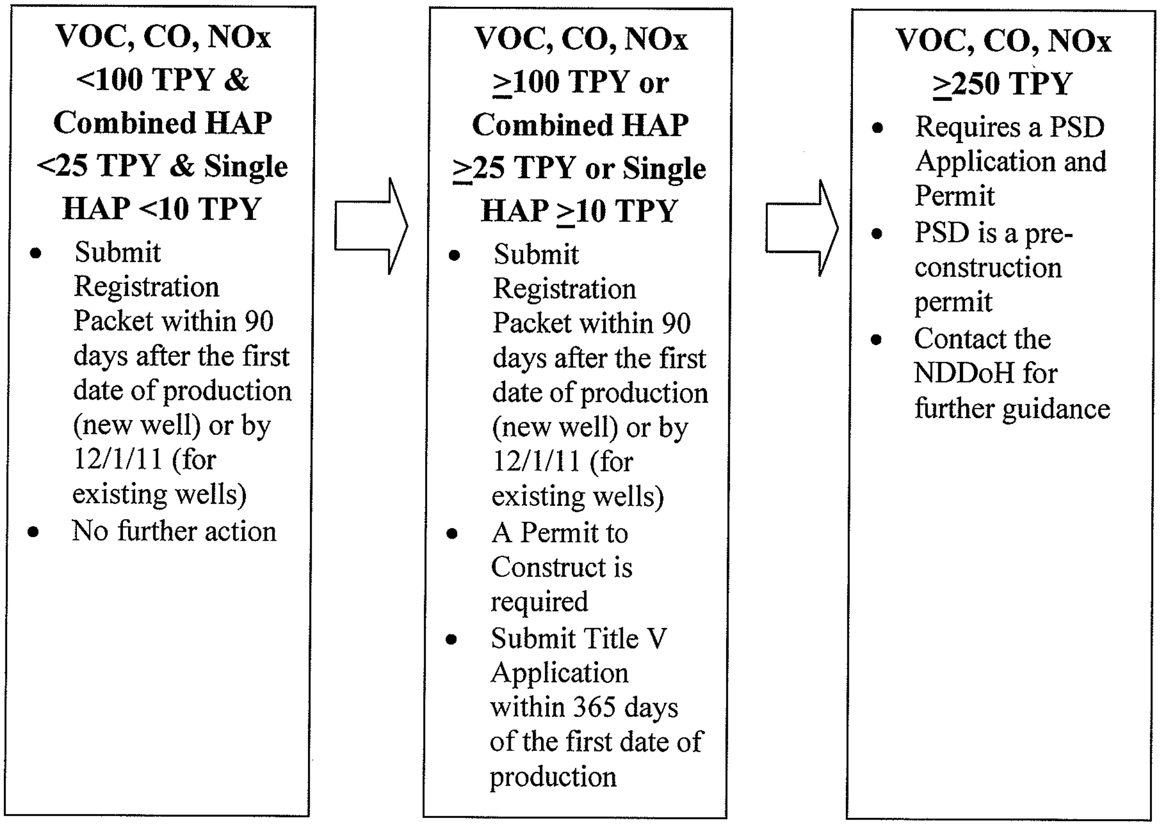
All owners/operators of existing Bakken Pool O&G production facilities that have not previously filed a registration form must submit a new registration packet to NDDoH by no later December 1, 2011 or within 90 days after the first date of production, whichever is later. These registrations will include 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



E. Registration Only

If a Bakken Pool O&G production facility has a potential to emit (PTE) ≤100 TPY of any criteria pollutant, ≤25 TPY of combined HAP and ≤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 ≥100 TPY of any criteria pollutant, ≥25 TPY of combined HAP or ≥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, ≥250 tons per year of any air contaminant regulated under North Dakota Century Code Chapter 23-25 (or ≥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 90th 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. **Tank Emissions Control Threshold**

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

E. **Tank Emissions Control Requirements**

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. **Produced Water Tanks**

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. **Glycol Dehydrators**

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. **Calculating Glycol Dehydrator Emissions**

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. **Glycol Dehydrator Control Threshold**

Emissions that meet or exceed the following thresholds require the still vent vapors be routed to a control device: ≥ 5.0 TPY of any combination of HAPs, or ≥ 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

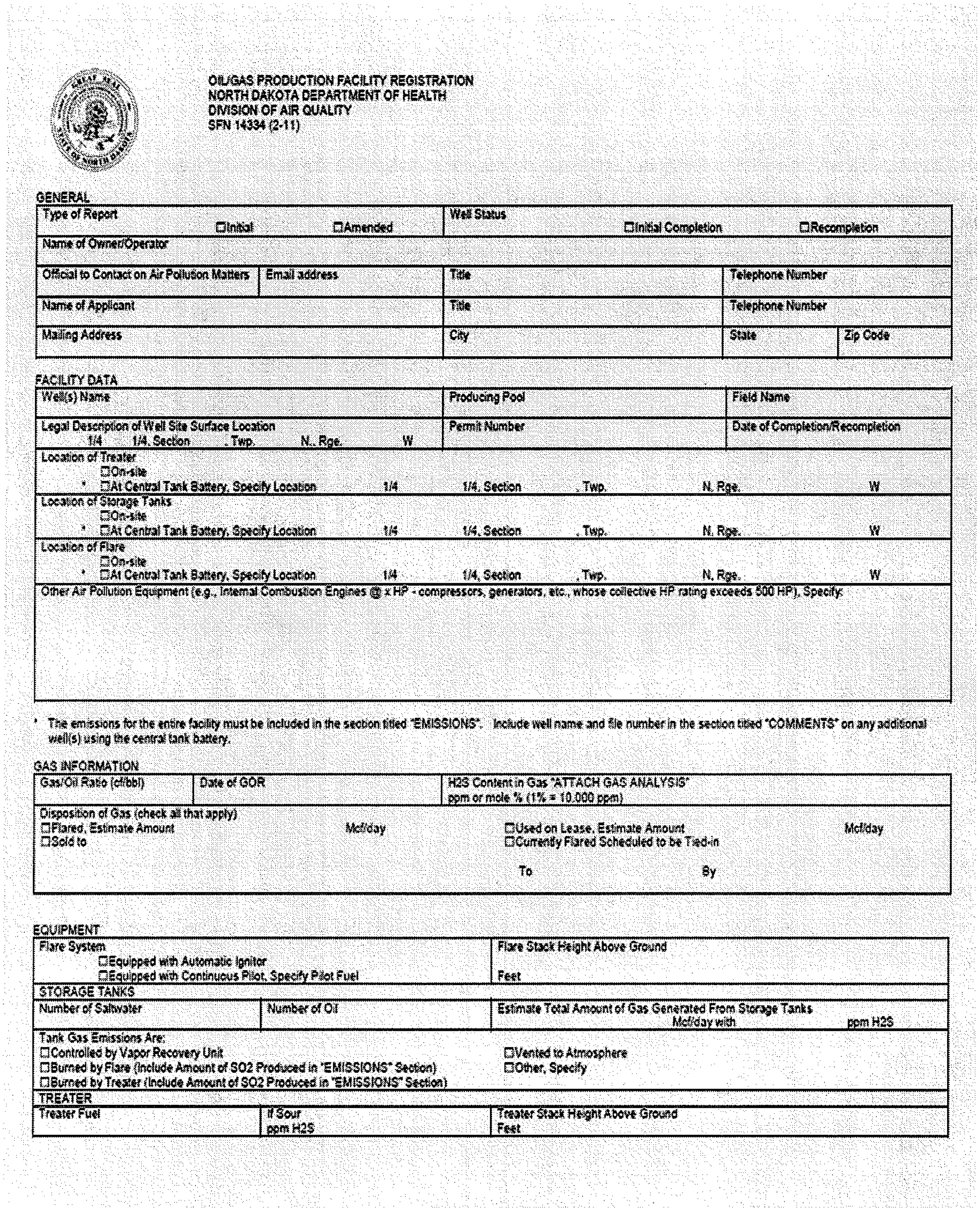
Terry L. O'Clair, P.E.
Director
Division of Air Quality
North Dakota Department of Health

Date: May 2, 2011

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

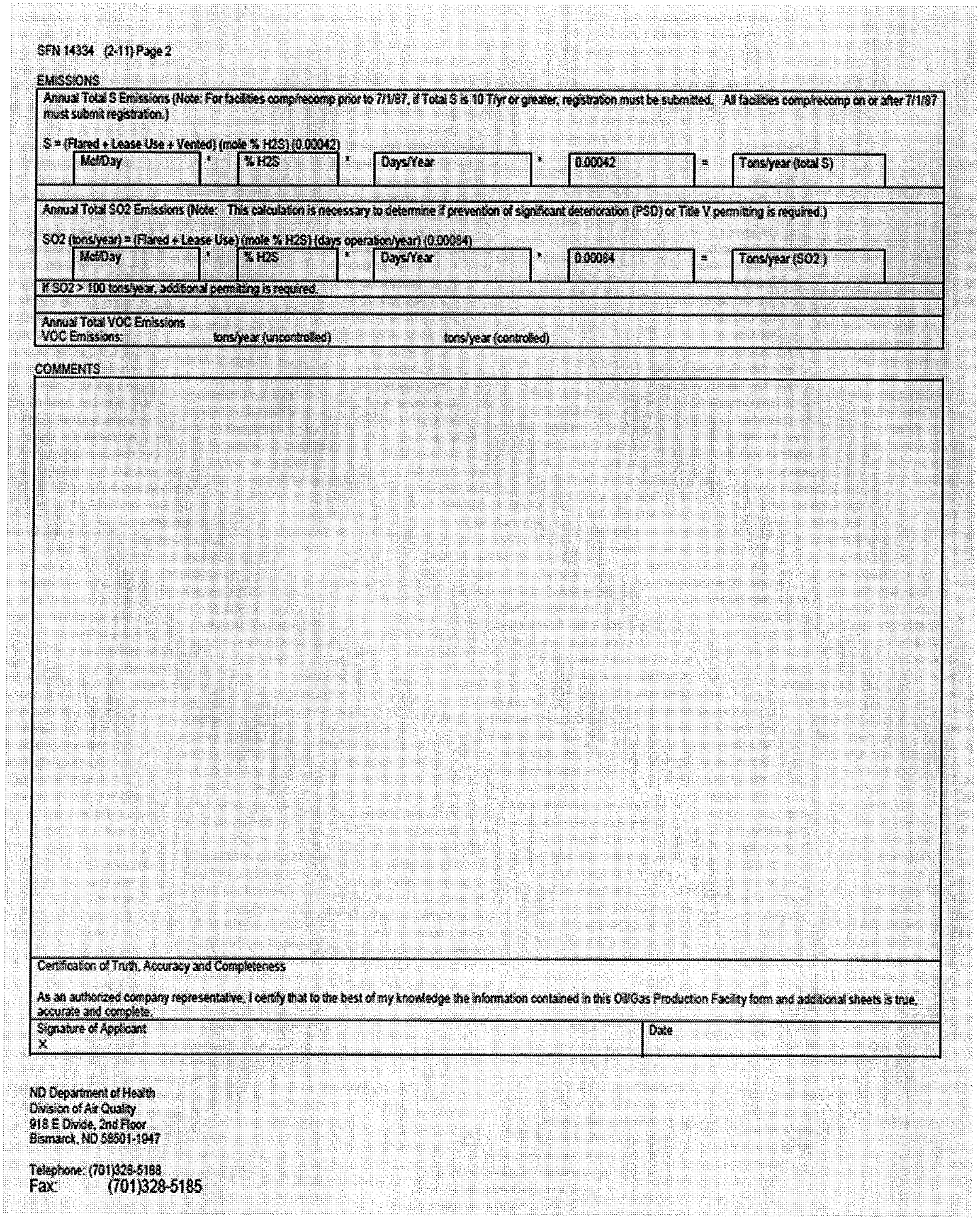
STORAGE TANKS

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



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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 X	Date

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.

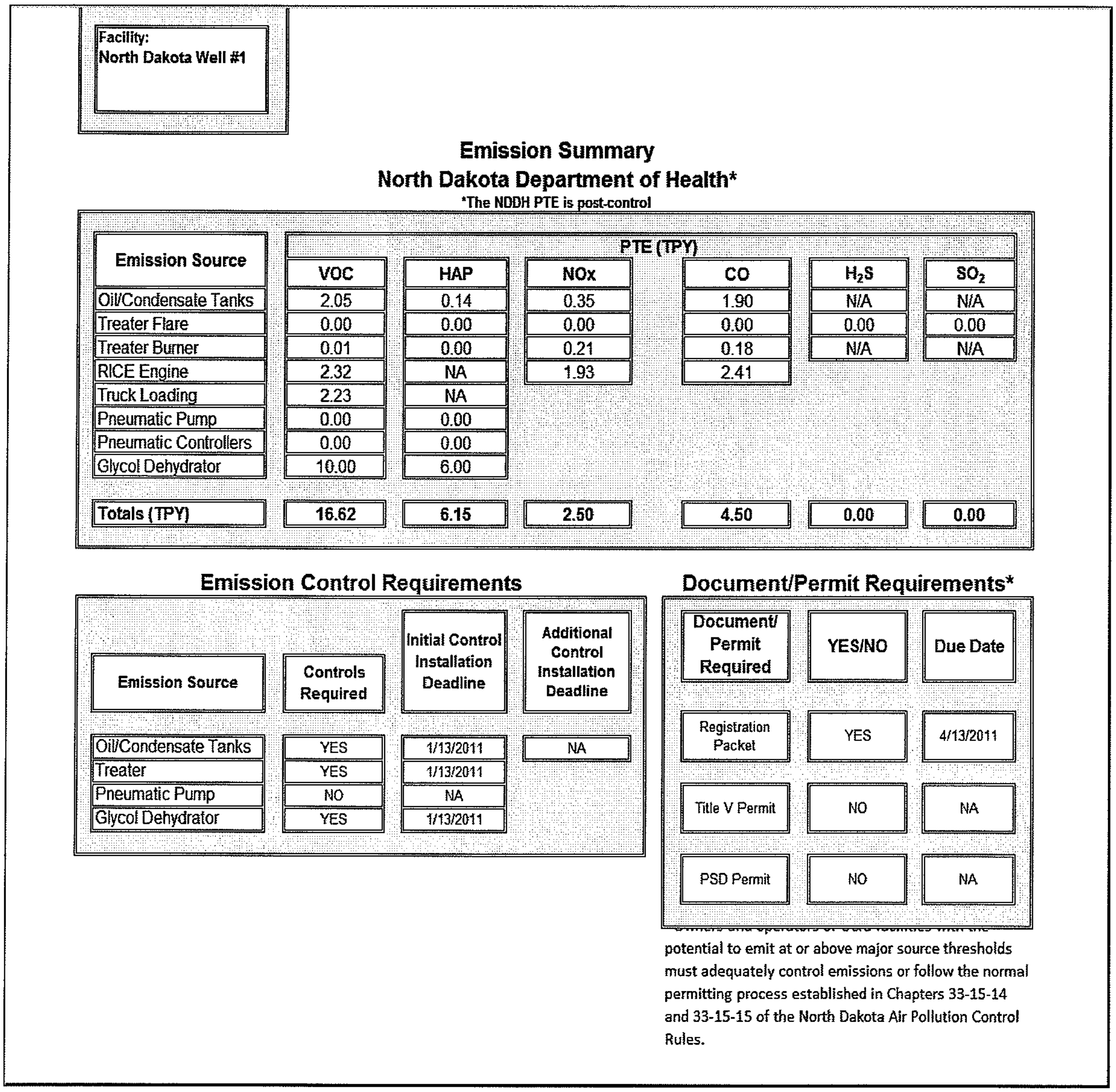
	RICE Engine #2		**Description**
Line 10	Hours of Operation	8760	Engine is assumed to operate 8,760 hours per year.
Line 11	Maximum HP Rating	100	Manufacturer's maximum hp rating.
Line 12	NOx g/hp-hr	10	Manufacturer's emission factor, actual test results or AP-42 factor in grams per horsepower hour (g/hp-hr) 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

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

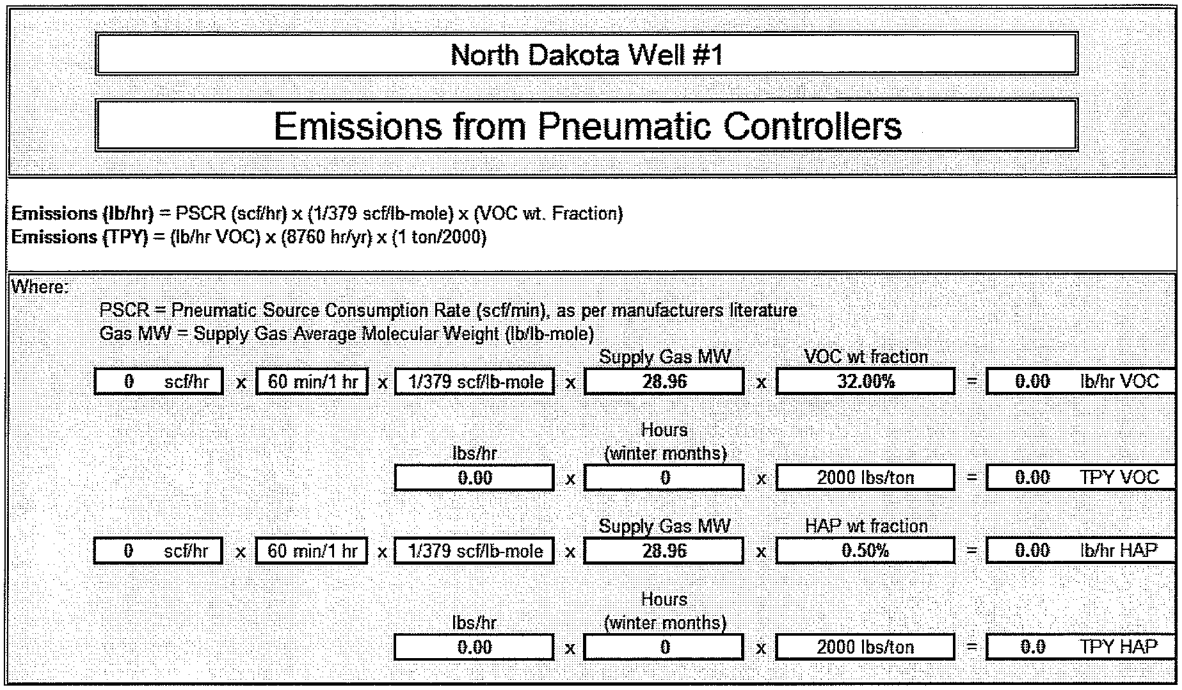
Emissions (lb/hr) = PSCR (scf/min) x (60 min/1hr) x (1/379 scf/lb-mole) x (VOC wt. Fraction)
Emissions (TPY) = (lb/hr VOC) x (8760 hr/yr) x (1 ton/2000)

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		x		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.

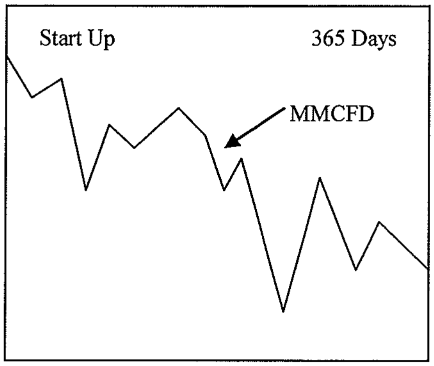
4. At a minimum, tank emissions must be controlled by a ground pit flare (or other control device that achieves at least a 90% DRE for VOCs). In the event of a breakdown of any control equipment used to control tank emissions, the control equipment must be repaired in a timely manner.

APPENDIX E

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

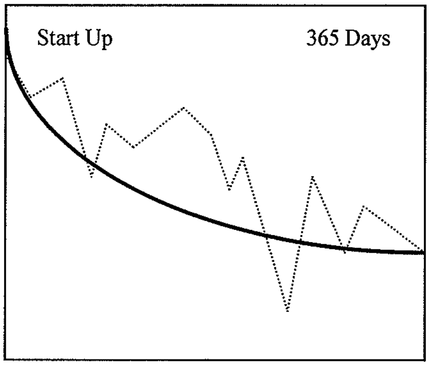
The first year daily production rates are represented by the jagged line in **BOX 1**. The area under the line represents the total actual production volume for the first year. It is difficult to calculate the total volume under the jagged line so it is smoothed out in **BOX 2** using statistical methods.

BOX 1



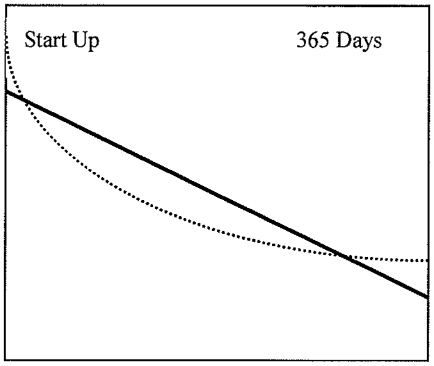
Actual production during the first year is represented by the area under the jagged line which ultimately turns out to be ~730 MMCF.

BOX 2



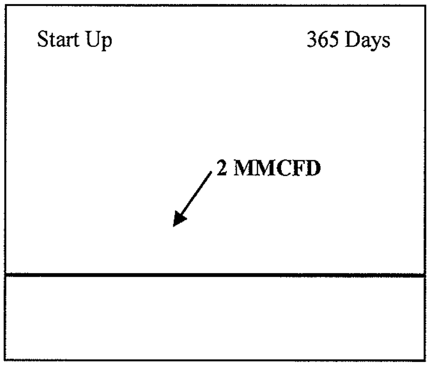
The jagged line representing daily production is "smoothed" out using statistical methods.

BOX 3



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

BOX 4



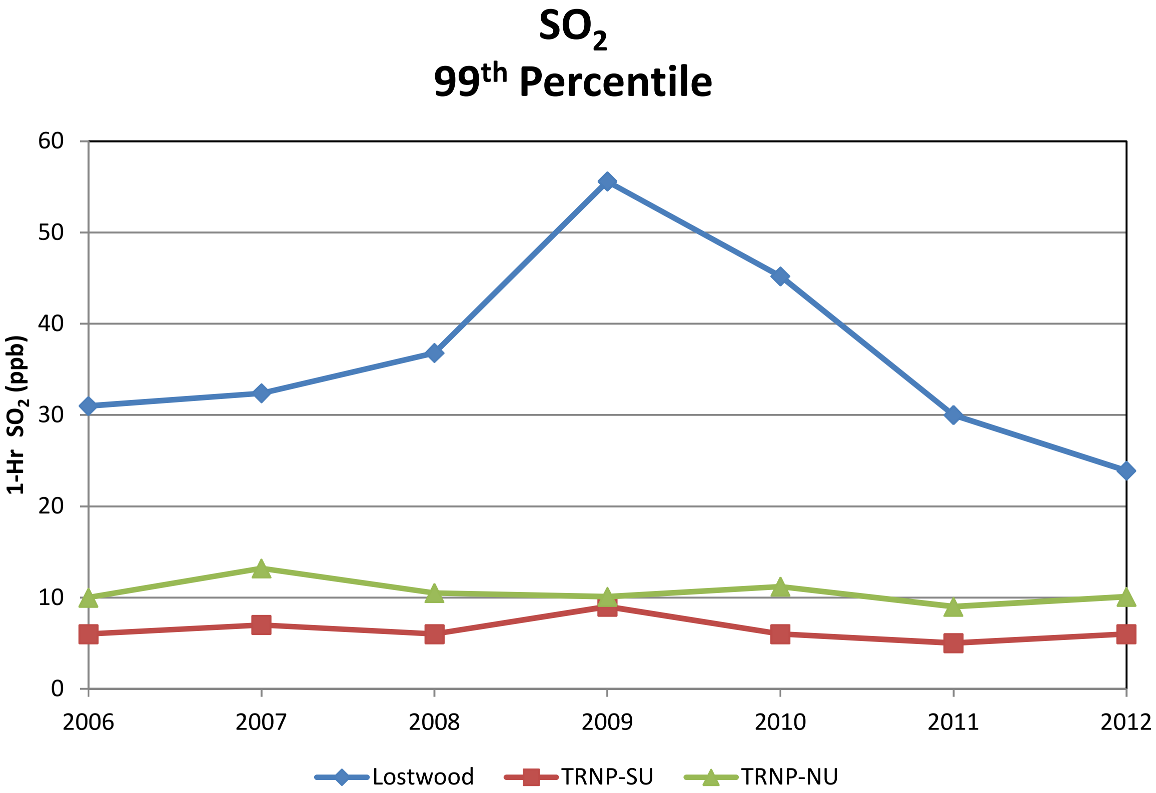
Leveled" out, projected daily gas production rate vs. time
Total projected production for the first year is represented by the area under the straight line
2 MMCFD x 365 days = 730 MMCF

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.

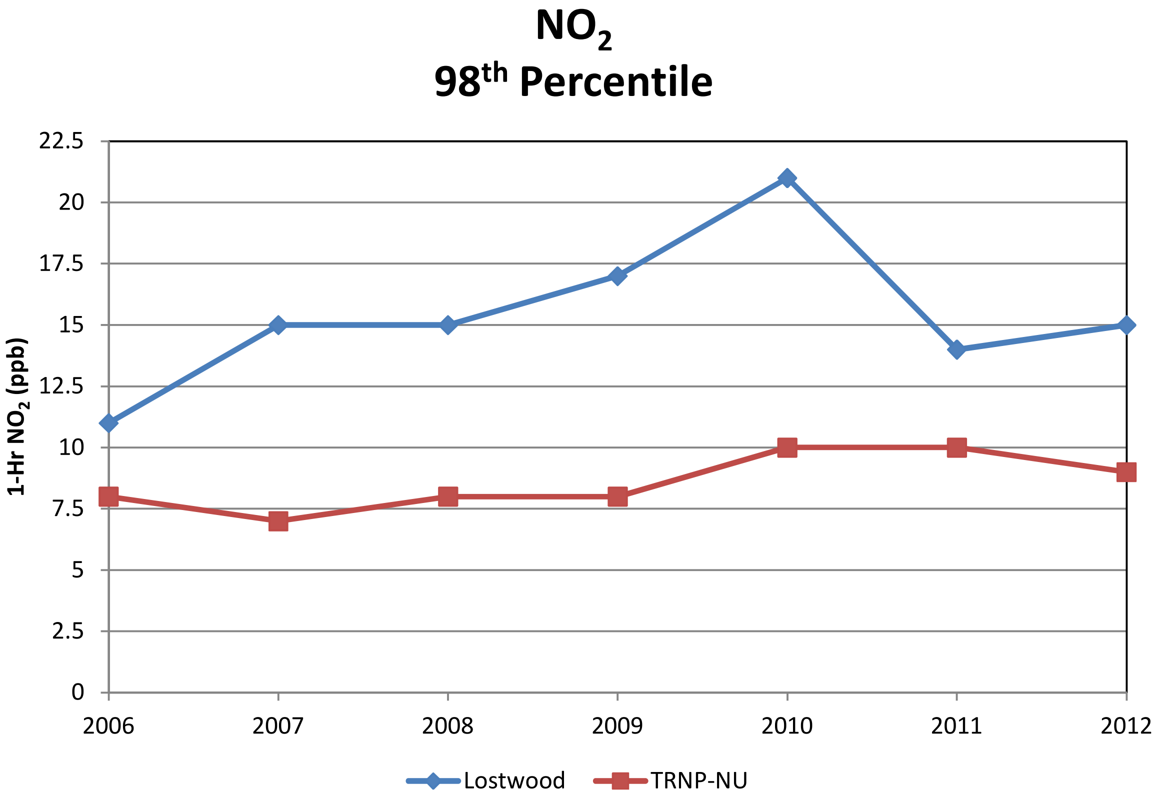
Example: For the first month the well makes an average 3.333 MMCFD. With 80% decline during the first year, the well will make 0.667 MMCFD at the end of the first year (3.333 – 0.8(3.333) = 0.667). Then the average daily production rate over 365 days is (3.33 + 0.667)/2 = 2.0 MMCFD which is the same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

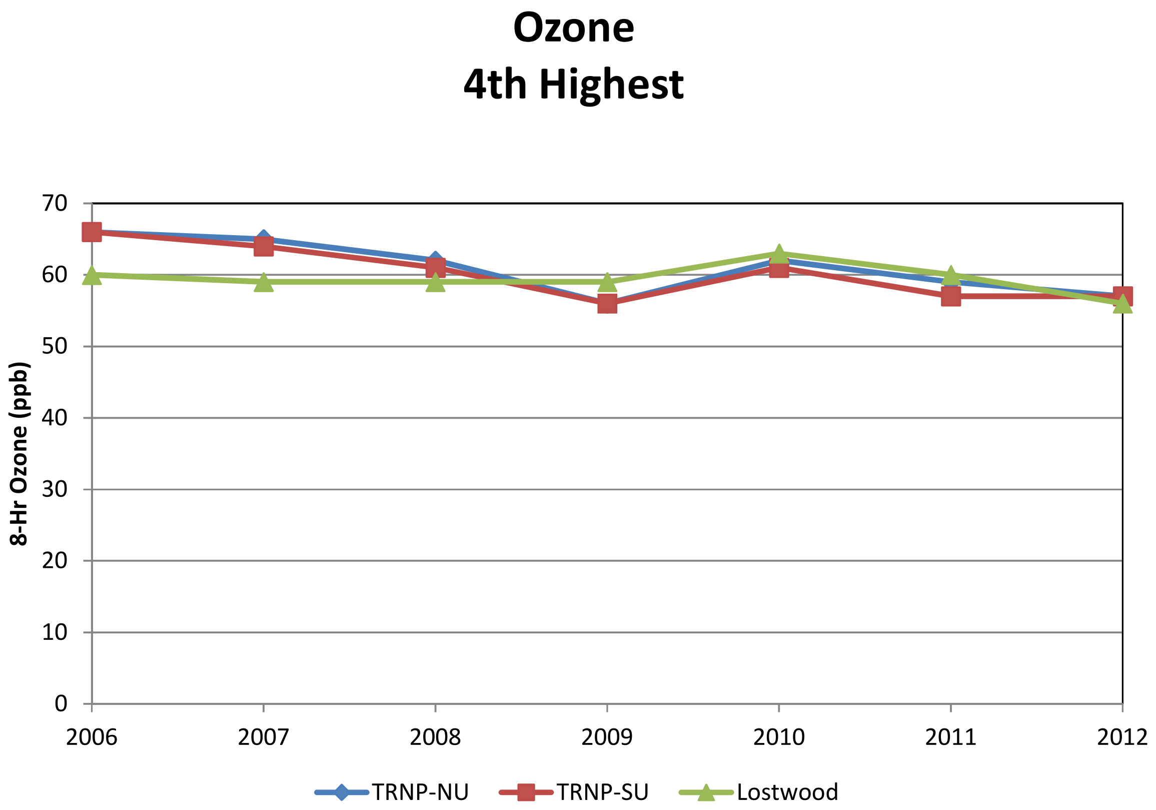
Appendix D

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



SO_2
99th Percentile
1-Hr SO_2 (ppb)
60
50
40
30
20
10
0
2006
2007
2008
2009
2010
2011
2012
Lostwood
TRNP-SU
TRNP-NU


NO$_2$
98th Percentile
1-Hr NO$_2$ (ppb)
22.5
20
17.5
15
12.5
10
7.5
5
2.5
0
2006
2007
2008
2009
2010
2011
2012
Lostwood
TRNP-NU


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