North Dakota State Implementation Plan
for
Regional Haze
Supplement No. 1

A Plan for Implementing the Regional Haze Program Requirements
of
Section 308 of 40 CFR Part 51, Subpart P - Protection of Visibility

North Dakota Department of Health
Adopted: 7-28-10

Division of Air Quality
Air Pollution Control Program
North Dakota Department of Health
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APPROVAL PAGE

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North Dakota Department of Health, Environmental Health Section, Division of Air Quality.

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August 2010

North Dakota Department of Health
Division of Air Quality
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R.M. Heskett Station Unit 2

The Department has finalized a Regional Haze SIP revision. During preparation of that SIP revision, there was a disagreement as to whether R.M. Heskett Station Unit 2 was subject to the Best Available Retrofit Technology (BART) requirements. On November 25, 2009, Montana Dakota Utilities Co. (MDU), the operator of the station, supplied the NDDH a revised BART modeling protocol as necessary to complete a refined visibility impact analysis for Unit 2. The NDDH and EPA Region 8 reviewed and approved the modeling protocol in early December 2009. MDU subsequently supplied the Department a report titled "Updated BART CALPUFF Visibility Modeling Analysis for Montana-Dakota Utilities Heskett Station Unit 2," dated December 17, 2009, which set forth the refined visibility modeling analysis for R.M. Heskett Station Unit 2. The modeling report concluded that the facility will contribute less than 0.5 deciviews of visibility degradation in any Federal Class I area. The Department and EPA Region 8 reviewed the modeling and subsequently determined that R.M. Heskett Station Unit 2 is not subject to BART requirements. Because of the additional modeling and review, the NDDH was unable to timely address Unit 2 under the Reasonable Progress portion of the original SIP revision. Since the question of BART applicability has now been resolved, this SIP supplement provides an analysis of R.M. Heskett Station Unit 2 under the Reasonable Progress requirements of 40 CFR 51.308(d)(1).

R.M. Heskett Station Unit 2 consists of an atmospheric bubbling fluidized bed boiler that has a rated heat input of 916.5 x 10^6 Btu/hr. The boiler serves a single turbine/generator that can produce approximately 78 megawatts of electricity. The facility primarily burns North Dakota lignite from Westmoreland Coal Company's South Beulah Mine near Beulah, North Dakota. The unit occasionally burns subbituminous coal and tire derived fuel. The plant had initial startup in 1963 and was converted from a spread stoker combustion unit to a bubbling fluidized bed unit in 1987. Currently, the bed material in the combustion unit is made up of sand.

Table 9.5
Sources Evaluated for Additional Control

Source	Owner	Unit	Type	Capacity
Heskett Station	MDU	2	EGU	78 MWe

Table 9.6
Remaining Sources Existing Conditions

Source	Pollutant	Control Equipment	Current Emission Rate (lb/10^6 Btu)*	Current Control Eff. (%)
Heskett 2	SO_2	None	0.91	N/A
	NO_X	None	0.36	N/A

*Based on 2007-2008 data.

Table 9.7 Control Options Evaluated			
Source	**Pollutant**	**Control Considered**	**Estimated Control Eff. (%)**
Heskett 2	SO_2	WS+L.I.	96
		WS	95
		CDS+L.I.	95
		SD+L.I.	94
		CDS	92
		Spray Dryer	90
		Limestone Injection	60
	NO_x	LDSCR	70-90
		TESCR	70-90
		SNCR	30-50
		Staged Combustion	20

WS = Wet Scrubber
LI = Limestone Injection
CDS = Circulating Dry Scrubber
SD = Spray Dryer
LDSCR = Low Dust Selective Catalytic Reduction
TESCR = Tailend Selective Catalytic Reduction
SNCR = Selective Non-Catalytic Reduction

Staged combustion combined with SNCR is not technically feasible for the Unit 2 AFBC due to staged combustion decreasing the temperature of the flue gas in the upper portion of the boiler. Also, there would be space constraints with the addition of overfire air ports and adding, and appropriately spacing, the urea injection for the SNCR system.

Table 9.8
Control Options Cost

Source	Unit	Pollutant	Control Technology	Total Annualized Cost ($)[a]	Control Efficiency (%)	Emission Rate (lb/10^6 Btu)	Emissions Reductions (tpy)	Cost Effectiveness ($/ton)
Heskett	2	SO_2	WS+L.I.	13,351,000	96	0.036	2,582	5,171
			WS	12,302,000	95	0.046	2,556	4,813
			CDS/Bag+L.I.	11,945,000[b]	95	0.046	2,556	4,673
			SD/Bag+L.I.	10,864,000	94	0.055	2,539	4,296
			CDS/Bag	10,985,000[b]	92	0.073	2,475	4,402
			SD/Bag	9,815,000	90	0.091	2,421	4,054
			L.I.	1,050,000	60	0.364	1,614	651
		NO_x	LDSCR	5,216,000	80	0.072	858	6,079
			TESCR	6,049,000[c]	80	0.072	858	7,050
			SNCR	1,424,000	33	0.241	354	4,023
			Staged Combustion	366,000	20	0.288	215	1,702

[a] Costs provided by MDU unless otherwise noted. The MDU costs were in 2006 dollars which the Department adjusted to 2009 dollars.
[b] Department estimate based on Leland Olds Unit 1.
[c] Department estimate based on cost estimate for M.R. Young Station.

Table 9.9 Visibility Improvement and Cost Effectiveness						
Source	**Pollutant**	**Control Technology**	**Emissions (TPY)**	**Visibility Improvement (dv)***	**Visibility Improvement (%)**	**Cost Effectiveness ($/dv)**
Heskett 2	SO_2	L.I.	1,076	< 0.009	< 0.05%	> 116,667,000
	NO_x	SNCR	719	< 0.009	< 0.05%	> 158,222,000
	NO_x	Staged Combustion	858	< 0.009	< 0.05%	> 40,667,000

*The Department modeled one scenario for this source – 95% SO_2 control plus 40% NO_x control. This scenario produced a 0.009 deciview improvement at TRNP and a 0.003 deciview improvement at LWA for the most impaired days.

Time Necessary for Compliance

The Department believes up to 6.5 years would be necessary for some of the control options (i.e. scrubbers and selective catalytic reduction). Other options such as SNCR and limestone injection into the boilers could be accomplished within 2-3 years depending on outage schedules.

The Department recognizes that limestone injection in the Unit 2 AFBC may potentially cause an increase in other pollutants for which a separate Permit to Construct, including a PSD permit, may be necessitated. If a related Permit to Construct is required, that permitting schedule may impact the timing of the contemplated SO_2 emissions reductions required by this Supplement.

Energy and Non-Air Impacts

All of the technologies will consume energy. However, the energy impacts would not preclude the selection of any of the technologies evaluated.

Remaining Useful Life

Table 9.10 Remaining Useful Life			
Source	**Unit**	**Startup Date**	**Estimated Remaining Useful Life (yrs)**
Heskett	2	1963	20-40

The remaining useful life of the source would not preclude the selection of any of the control options.

Reasonable Progress Goals – Required Controls for Point Sources

The costs to install a wet scrubber, circulating dry scrubber or a spray dryer, with or without limestone injection into the boiler, is considered excessive both on a dollar per ton basis and a dollar per deciview basis. The cost of limestone injection on a dollar per ton basis is reasonable; however, it provides virtually no visibility improvement (estimated at less than 0.009 deciviews) and the dollar per deciview cost effectiveness is excessive.

The Department is not aware of SCR ever being installed on a fluidized bed boiler. A HDSCR is considered technically infeasible. The cost effectiveness of LDSCR, TESCR and SNCR is considered excessive both on a dollar per ton and dollar per deciview basis. The cost effectiveness of staged combustion, on a dollar per deciview basis is considered excessive.

The Department concludes that the addition of emission controls at Heskett Unit 2 is not reasonable at this time. However, this source, as well as all other point sources, will be reevaluated during future planning periods.

The estimated amount of improvement from operating limestone injection and staged combustion at Heskett Station Unit 2 is 0.006 deciviews improvement at TRNP and 0.002 deciviews at LWA at a capital cost of 5.8 million dollars and an annualized cost of 1.4 million dollars. Combining these controls with the controls considered for the other Reasonable Progress sources, the combined capital cost is 249 million dollars with an annualized cost of 69 million dollars. The combined cost effectiveness is over 616 million dollars per deciview at LWA and over 1.92 billion dollars per deciview at TRNP. For all sources evaluated individually and cumulatively, the cost ($/dv) is considered excessive. Therefore, no additional controls are proposed for the non-BART sources during this planning period.

10.6.1.3 R.M. Heskett Station Unit 2

In Section 9.5.1, it was concluded that requiring additional air pollution controls at R.M. Heskett Station Unit 2 was not reasonable. However, the Department and Montana-Dakota Utilities has reached an agreement whereby limestone injection into the boiler will commence within five years after EPA approves the Permit to Construct for Heskett Unit 2 as part of this Regional Haze SIP. A Permit to Construct will be issued and is included in Appendix A.2.4. The Permit to Construct requires at least 70% control of the potential SO_2 (coal-to-stack) or no more than 0.60 lb/10^6 Btu (12-month rolling average) emission rate. This will be a 34% reduction from the 2007-2008 baseline emission rate or a 573 ton reduction from the 2000-2004 average emission rate.

Although MDU and the Department have agreed to a reduction of SO_2 emissions at Heskett Station Unit 2, this source will be reevaluated for additional air pollution controls during future planning periods.

Supplementary
Cost Information

Cost Estimates

In order to estimate the cost of various control options for R.M. Heskett Unit 2, the Department used data provided by Montana Dakota Utilities (MDU), CUECOST Model output, calculations using EPA's Air Pollution Control Cost Manual, and data from other in-state BART analyses. MDU had drafted a BART analysis for this facility and provided cost excerpts for several technologies (copy attached). The costs were estimated using 2006 dollars, so the Department adjusted those costs to 2009 dollars using the Marshall and Swift Equipment cost index for the electric power industry. The Marshall and Swift Equipment cost index has increased approximately 13% from first quarter 2006 to fourth quarter 2009 (1219.2 to 1377.3).

To verify the costs, the CUECOST model was run. The CUECOST model provides costs in 1998 dollars so adjustment had to be made to have an apples-to-apples comparison. To adjust the CUECOST capital cost results, the Department reviewed available data from several cost indexes to arrive at an average value.

Index	**1998 Index**	**Date of Available Data**	**Recent Index**	**Percent Increase**
Engineering News – Record Construction C.I.	5920	1/10	8660	46%
Chemical Engineering Plant C.I.	390	2/09	532	36%
Marshall and Swift Equipment Cost C.I.	1062	11/09	1377	30%
Consumer Price Index	162.2	10/09	216.2	33%
			Avg.	36%

Due to limited data on the increase of operation and maintenance costs, a 36% increase was also applied to O&M costs.

For the circulating dry scrubber (CDS), data from the Leland Olds Unit 1 BART analysis was used. This data suggested a 12% higher annualized cost for a CDS/baghouse than a spray dryer/baghouse. For the various technologies, the estimated annualized costs from the various sources in 2009 dollars were:

Technology	**MDU**	**CUECOST**	**Control Cost Manual**
Wet Scrubber	$12,302,000	$11,154,000	
SD/Baghouse	$9,815,000	$12,212,000	
SNCR	$1,424,000	$603,000	$645,000

The MDU cost estimate for a wet scrubber is approximately 10% higher than the CUECOST model estimate and the spray dryer cost is approximately 20% less than the CUECOST model.

Since these values are within the range of accuracy of the CUECOST model and EPA's Air Pollution Control Cost Manual of ±30%, the MDU costs were used.

For SNCR, the MDU cost is 2.4 times the CUECOST model. The Department reviewed BART cost estimates from other small power plants to determine which estimate was appropriate. Based on the results below, the MDU estimate of annualized cost appears to be reasonable.

Source	**Size (MWe)**	**Installed Cost ($)**	**Installed Cost ($/KW)**	**Annualized Cost ($)**	**Annualized Cost ($/KW)**
Heskett 2	78	4,056,700	52	1,424,000	18.26
Stanton 1	160	8,390,000	52	2,700,000	16.88
North Shore #2	75	4,020,000	54	1,810,000	24.13
J.E. Corette	154	3,279,000	21	1,303,471	8.46
Taconite Harbor #3	79	2,154,000	27	1,260,000	15.95
Average			41		16.74

For low dust SCR, MDU used a capital cost factor of $250/kw. This falls in the mid range of SCR costs as ERG reported for a high dust SCR at the PGE Boardman Plant. Estimates for Leland Olds 2 and Minnkota 1 and 2 range from approximately $335 - $700/kw for a low dust SCR. ERG, in their analysis for the Boardman plant also indicated that SCR costs have rapidly escalated since 2004. ERG also notes that they believe the CUECOST model does not accurately predict installed costs for major construction projects such as SCR. The Department also believes EPA's Air Pollution Control Cost Manual does not accurately estimate SCR costs. Therefore, MDU's cost estimate was used in this analysis although the estimate appears to be low based on the other estimates and ERG's analysis.

Montana Dakota Utilities

Cost Estimates

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

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(701) 222-7900

FEB 2010
Received
Air Quality

February 3, 2010

Mr. Tom Bachman
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Re: Montana-Dakota Utilities Co. – R.M. Heskett Station Unit 2
Best Available Retrofit Technology (BART) Emissions Control Summary

Dear Mr. Bachman:

In response to your recent request for additional information related to regional haze impacts for Heskett Station's Unit 2, please find enclosed a summary of relevant materials related to SO_2 and NOx BART controls that were historically evaluated for Unit 2.

In anticipation of potential regional haze regulatory impacts to Unit 2, Montana-Dakota Utilities Co. (Montana-Dakota) conducted a BART control evaluation in late 2005 and early 2006 that remained in draft form. The complete draft evaluation is rather lengthy. Recognizing your familiarity with the various control technology descriptions and impacts from reviewing BART analyses for North Dakota utilities, Montana-Dakota has excerpted information directly relevant to the SO_2 and NOx emissions control evaluation at Unit 2 and has provided this information in Attachment A. Minor corrections and updates have been made to the excerpted 2006 draft report; however, the cost data have not been updated. Additional detail related to the background of the evaluation and conclusions may be provided upon request.

We understand that the North Dakota Department of Health may use this information in part to assess Unit 2 under the reasonable progress goals in its Regional Haze SIP. In doing so, please appreciate that the 2006 analysis may not reflect current regional haze policies. Nevertheless, it provides a useful site-specific technical evaluation.

Also recognizing that the control cost information may have changed since the evaluation was completed in first quarter 2006, Montana-Dakota has provided for reference a cost index table for the electrical power industry. The values shown below are from the Marshall and Swift Equipment Cost Index and compare the cost between first quarter 2006 and fourth quarter 2009. The Vatavuk Air Pollution Control Cost Indexes (VAPCCI) was discontinued by EPA a few years ago. In lieu of a site-specific cost update for the technically feasible emission controls, the Marshall and Swift index provides a reasonable general estimate of the change in cost of equipment.

Marshall and Swift Equipment Cost Index – Electrical Power Industry

Year	Quarter	Index
2006	Q1	1219.2
2009	Q4	1377.3

If you have any questions about this submittal or require additional information to complete your analysis, please contact me at 701-222-7844.

Sincerely,

Kenneth H. Hangler

for Ms. Abbie Krebsbach
Environmental Manager – Power Production

Enc.

cc: Alan Welte, Generation Manager
Tony Stroh, R. M. Heskett Station Manager
Joel Trinkle, Barr Engineering Company

Attachment A

Excerpts from 2006 BART Evaluation at R.M. Heskett Station Unit 2

Excerpted R.M. Heskett Station Unit 2 (Main Boiler) Draft BART Analysis from May 2006

Prepared for Montana-Dakota Utilities Co. by
Sargent & Lundy and Barr Engineering Company

1.0 BART ANALYSIS FOR MAIN BOILER SULFUR DIOXIDE (SO_2)

Sulfur emissions from coal combustion consist primarily of SO_2, with a much lower quantity of SO_3 and gaseous sulfates. These compounds form as the organic and pyretic sulfur in the coal is oxidized during the combustion process. For permitting and design purposes, it is assumed that 100% of the fuel sulfur will convert to SO_2 during the combustion process, and that 1% of the uncontrolled SO_2 will oxidize to SO_3 within the fluidized combustion bed.

The generation of SO_2 is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. Heskett Unit 2 uses North Dakota lignite or a blend of lignite and Power River Basin (PRB) coal as its fuel source. Table 1-1 provides a summary of the lignite used at Heskett Unit 2, including the heating value and sulfur content.

Table 1-1
Fuel Characteristics

Characteristic	Unit	North Dakota Lignite	
		Average	Maximum
Heating Value	Btu/lb	6,892	7,061
Sulfur Content	%	0.74	1.02
Potential SO_2 Emission Rate	lb/MMBtu	2.15	2.89

1.1 Step 1: Identify Available Retrofit SO_2 Control Options

Several techniques can be used to reduce SO_2 emissions from coal combustion sources. SO_2 control techniques can be divided into pre-combustion strategies, combustion techniques, and post-combustion controls. SO_2 control options identified for potential application with at Heskett Unit 2 are listed in Table 1-2.

Table 1-2
SO_2 Control Options with Potential Application to a Lignite/PRB Fired AFBC Boiler

Pre-Combustion Controls
Fuel Switching
Fuel Washing and Benefication
Combustion Controls
Atmospheric Fluidized Bed Combustion (AFBC) Technology with Limestone Injection
Post-Combustion SO_2 Control Technologies
Wet Flue Gas Desulfurization
Wet Lime Flue Gas Desulfurization
Wet Limestone Flue Gas Desulfurization
Dry Flue Gas Desulfurization
Ash Reinjection Systems
Spray Dryer Absorber
Circulating Dry Scrubber
Dry Sorbent Injection

1.2 Step 2: Eliminate Technically Infeasible Retrofit Options

Results of Step 2 of the SO_2 BART Analysis (technical feasibility analysis of potential SO_2 control technologies) are summarized in Table 1-3.

Table 1-3
Technical Feasibility of Potential SO_2 Control Technologies

Control Technology	Approx. SO_2 Concentration in Flue Gas (ppmvd @3% O_2)	In Service on Existing AFBC Boilers Yes	In Service on Existing AFBC Boilers No	In Service on Other Combustion Sources?	Technically Feasible for Heskett Unit 2?
Fuel Switching	--	--	--	AFBCs have been designed to burn a variety of fuels.	No. Fuel switching would require significant boiler modifications and would not significantly reduce controlled SO_2 emissions from Heskett Unit 2.
Coal Washing	--		X	Washing has not been used on coal burned in AFBCs.	No. Washed coal has not been used in AFBC boilers, and will not significantly reduce controlled SO_2 emissions from Heskett Unit 2.
Coal Processing	--		X	Processed coal has been demonstrated in PC boilers.	No. Processed coal has not been demonstrated on a long-term basis in AFBC boilers, and is not commercially available as a retrofit technology.

Control Technology	Approx. SO_2 Concentration in Flue Gas (ppmvd @3% O_2)	In Service on Existing AFBC Boilers Yes	In Service on Existing AFBC Boilers No	In Service on Other Combustion Sources?	Technically Feasible for Heskett Unit 2?
AFBC Boiler with Limestone Addition (1.5 to 2.0 Ca/S ratio)	approx. 180	X			Yes. Heskett Unit 2 currently uses sand to sustain the combustion bed. The boiler and associated material handling systems could be modified to utilize limestone.
AFBC + Wet FGD	approx. 50		X	Wet FGD has been used on coal-fired PC boilers.	Yes, however, no commercial experience or operating history, and question about commercial availability.
AFBC + Dry FGD (Spray Dry Absorber)	approx. 60	X			Yes, however limited commercial experience.
AFBC + Dry Sorbent Injection	>60		X		No, not technically practical on a AFBC boiler because of the unreacted lime concentration already in the flue gas.
AFBC + Circulating Dry Scrubber	approx. 60		X	CDS control systems are in use on a limited number of coal-fired units.	Yes, however limited commercial experience.

1.3 Step 3: Evaluate Control Effectiveness of Technically Feasible Technologies

The control effectiveness of each technically feasible retrofit technology was discussed in Step 2. The effectiveness of each retrofit technology identified as being technically feasible for SO_2 control are presented in Table 1-4 in descending order of control efficiency.

Table 1-4
Summary of Technically Feasible
Main Boiler SO_2 Control Technologies

Control Technology	SO_2 Emission Rate (lb/MMBtu)	% Reduction from Maximum Uncontrolled Case(1)
AFBC with Limestone Addition plus Wet FGD	0.10	95%
AFBC with Limestone Addition plus Dry FGD (SDA or CDS)	0.12	94%
AFBC with Limestone Addition	0.35	83.3%
AFBC with Sand	0.862	60%
Potential Uncontrolled SO_2 (baseline)	2.10	

(1) Overall reduction efficiency takes into account SO_2 reduction in the AFBC and the post-combustion control system, and is based on an average uncontrolled SO_2 emission rate of 2.10 lb/MMBtu.

1.4 Step 4: Evaluate Impacts and Document the Results

Step 4 of the BART determination requires an evaluation of the economic, energy, and non-air-quality environmental impacts of each technically feasible retrofit technology. This evaluation should take into consideration the remaining useful life of the unit. Table 1-5 presents the capital costs and annual operating costs associated with building and operating each control system. A summary of the Step 4 economic and environmental BART impact analysis is provided in Table 1-6.

Table 1-5
SO_2 Emission Control System
Cost Summary

Control Technology	Total Capital Investment ($)	Total Capital Investment ($/kW-net)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
AFBC with Limestone Addition plus Wet FGD(1)	$56,501,000	$723	$5,333,000	$6,482,600	$11,815,600
AFBC with Limestone Addition plus Dry FGD(2)	$46,017,600	$588	$4,334,000	$5,270,800	$9,614,800
AFBC with Limestone Addition	$3,780,000	$48	$356,800	$572,200	$929,000

(1) Wet FGD capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the FGD absorber tower, recycle pumps, induced draft fans, significant modifications to the existing stack, limestone receiving, limestone addition to the boiler, and FGD sludge handling systems.

(2) Dry FGD capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the reaction vessel, induced draft fans, reactant injection system, stack modifications, lime handling system and solid waste handling system. Dry FGD capital costs also include costs associated with a fabric filter baghouse because particulate control is needed after the dry FGD and it would be impractical to fit the dry FGD system between the boiler and existing ESP control system.

Table 1-6
Summary of BART Impact Analysis

Control Technology	Emissions (tpy)	Emission Reduction (tpy)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Environmental Impacts
AFBC with Limestone Injection plus Wet FGD	341	2,600	$11,815,600	$4,540	$12,760	Increased PM emissions and increased acid gas emissions, including sulfuric acid mist. Increased water use and wastewater treatment/ discharge.
AFBC with Limestone Injection plus Dry FGD	409	2,532	$9,614,800	$3,800	$11,060	Increased water use, and increased PM emissions from handling lime reagent.
AFBC with Limestone Injection	1,194	1,747	$929,000	$530	--	Potential increase in PM emissions from limestone handling, potential impacts to fly ash resistivity and effectiveness of the ESP control system, and potential impacts to the existing solid waste management/disposal system.
AFBC with Sand (baseline)	2,941	--	--	--	--	Baseline
Potential Uncontrolled SO_2	7,165	--	--	--	--	

2.0 BART ANALYSIS FOR NITROGEN OXIDES (NO_x)

The formation of NO_x is determined by the interaction of chemical and physical processes occurring primarily within the combustion zone of the boilers. There are two principal forms of NO_x designated as "thermal" NO_x and "fuel" NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature, post-flame region of the combustion zone. The major factors influencing thermal NO_x formation are temperature, the concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and residence time within the combustion zone. Fuel NO_x is formed by the oxidation of nitrogen in the fuel.

2.1 Step 1: Identify Available Retrofit NOx Control Options

Potential NO_x retrofit control options were identified based on a review of available technical information. Retrofit control options with potential application to Heskett Unit 2 are listed in Table 2-1.

Table 2-1
List of Potentially Available Retrofit NOx Control Options

Control Technology
Combustion Controls
Fluidized Bed Combustion (existing)
Staged Combustion
Low NO_x Burners
Flue Gas Recirculation (FGR)
Burner Tempering (Water Injection)
Post-Combustion Controls
Selective Non-catalytic Reduction (SNCR)
SNCR with Staged Combustion
Selective Catalytic Reduction (SCR) High-Dust SCR Low-Dust SCR
Innovative Control Technologies
Rotating Over-fire Air (ROFA)
Boosted Over-fire Air (BOFA)
ROFA + SNCR (Rotamix™)
NOxStar™
Exxon Thermal DeNOx™
Pahlman Process
Wet NO_x Scrubbing LOTOx™

2.2 Step 2: Eliminate Technically Infeasible Retrofit Options

Retrofit NO_x control technologies can be divided into two general categories: (1) combustion controls, and (2) post-combustion controls. Combustion controls reduce the amount of NO_x that is generated in the boiler, while post-combustion controls remove NO_x from the boiler exhaust gas. Retrofit control technologies identified in Step 1 were evaluated for technical feasibility, including availability and applicability, for Heskett Unit 2. The results of Step 2 of the NOx BART determination (technical feasibility analysis of potential NOx retrofit control technologies) are summarized in Table 2-2.

Table 2-2
Technical Feasibility of Potential NOx Retrofit Control Technologies

Control Technology	Approx. NO_x Controlled NOx Emission Rate (ppmvd @3% O_2)	In Service on Existing AFBC Boilers Yes	In Service on Existing AFBC Boilers No	In Service on Other Combustion Sources?	Technically Feasible for Heskett Unit 2?
Atmospheric Fluidized Bed (AFBC) Combustion	225 – 235 (0.326 lb/MMBtu)	X		na	yes
AFBC with Additional Staged Combustion	180 – 190 (0.26 lb/MMBtu)	X		na	yes
Low NOx Burners	--		X	Not applicable to AFBC boilers	No, combustion takes place within the fluidized bed in an AFBC.
Flue Gas Recirculation	--		X	Not applicable to AFBC boilers	Ineffective because of the low combustion temperature in an AFBC boiler.
Burner Tempering	--		X	Not applicable to AFBC boilers	No, low combustion temperatures within fluidized bed.
AFBC + SNCR	150 – 160 (0.22 lb/MMBtu)	X			yes
AFBC with Staged Combustion + SNCR	--		X	May be applicable to PC units	Not technically feasible for Heskett Unit 2. Temperature window needed for SNCR is not available within boiler.
AFBC + High Dust SCR	--		X	SCR control systems have been installed on PC boilers	No. Technical limitations including rapid catalyst deactivation. Not demonstrated in practice on an AFBC.
AFBC + Low Dust SCR	50 – 60 (0.08 lb/MMBtu)		X	SCR control systems have been installed on PC boilers	Yes, but not demonstrated in practice. Requires flue gas re-heat. May not be commercially available.
Boosted Overfire Air (BOFA) and Rotating Overfire Air (ROFA)	--		X	Demonstrated on coal-fired PC units	Included in the evaluation of other staged combustion systems.
BOFA/ROFA plus SNCR	--		X	Demonstrated on coal-fired PC units	Included in the evaluation of other SNCR control systems.
NOxStar™	--		X	Demonstrated on coal-fired PC units.	Not available as BART retrofit technology for AFBC unit.
Exxon Thermal DeNOx™	--	X			Included in the evaluation of other SNCR control systems.
Pahlman Process	--		X	Demonstrated on coal-fired PC units.	Not available as BART retrofit technology for AFBC unit.

Control Technology	Approx. NO_x Controlled NOx Emission Rate (ppmvd @3% O_2)	In Service on Existing AFBC Boilers Yes	No	In Service on Other Combustion Sources?	Technically Feasible for Heskett Unit 2?
Wet NOx Scrubbing	--		X	Demonstrated on industrial boilers.	Not available as BART retrofit technology for AFBC unit.

2.3 Step 3: Evaluate Control Effectiveness of Technically Feasible Technologies

The control effectiveness of each technically feasible retrofit technology was discussed in Step 2. The effectiveness of each retrofit technology identified as being technically feasible and commercially available for NO_x control at Heskett Unit 2 are presented in Table 2-3 in descending order of control efficiency.

Table 2-3
Summary of Technically Feasible
Main Boiler NO_X Control Technologies

Control Technology	NO_x Emissions (lb/mmBtu)	% Reduction from Original Baseline	% Reduction from AFBC Baseline
AFBC + Low Dust SCR	0.08	82%	75%
AFBC + SNCR	0.22	52%	33%
AFBC + Staged Combustion	0.26	44%	20%
AFBC Combustion	0.326	35%	--
Baseline NOx Emission Rate	0.463	--	--

2.4 Step 4: Evaluate Impacts and Document the Results

Step 4 of the BART determination requires an evaluation of the economic, energy, and non-air-quality environmental impacts of each technically feasible retrofit technology. This evaluation should take into consideration the remaining useful life of the unit. Table 2-4 presents the capital costs and annual operating costs associated with building and operating each control system. A summary of the Step 4 economic and environmental impact evaluations is provided in Table 2-5.

Table 2-4
NO_x Emission Control System
Cost Summary

Control Technology	Total Capital Investment ($)	Total Capital Investment ($/kW-net)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
AFBC + Low Dust SCR	$19,544,200	$250	$1,844,800	$2,770,700	$4,615,500
AFBC + SNCR	$3,590,000	$46	$338,900	$921,400	$1,260,300
AFBC + Staged Combustion	$1,313,000	$17	$144,200	$179,800	$324,000
AFBC Combustion	NA	NA	NA	NA	NA

Table 2-5
Summary of BART Impact Evaluations

Control Technology	Emissions (tpy)	Annual Reduction in Emissions		Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)	Environmental Impacts
		From Original Baseline (tpy)	From AFBC Baseline (tpy)			
AFBC + Low Dust SCR	273	1,307	809	$4,615,300	$5,750	Increased CO and VOC emissions associated with re-heating the flue gas. Increased SO_2 to SO_3 oxidation across the SCR, and increased condensible PM emissions including H_2SO_4. Ammonia emissions associated with ammonia slip may be a precursor to the formation of visibility impairing particles such as ammonium sulfate and ammonium nitrate.
AFBC + SNCR	751	829	361	$1,260,300	$3,491	Ammonia emissions associated with ammonia slip may be a precursor to the formation of visibility impairing particles such as ammonium sulfate and ammonium nitrate.
AFBC + Staged Combustion	887	693	225	$324,000	$1,440	Potential changes to flue gas characteristics may impact the unit's ability to capture mercury emissions.
AFBC Combustion	1,112	468	--	NA	NA	Boiler modified to AFBC configuration in 1987.
(Baseline)	1,580	--	--	NA	NA	

BART Economic Evaluation – NOx
Staged Combustion Details

CAPITAL COSTS	Cost [$]		Basis
Direct Capital Costs			
Urea Based SNCR Costs			
Duct work and Dampers	$360,000		
OFA Ports	$150,000		
Forced Draft Fan Modifications	$90,000		
Instruments and Controls	$120,000		
Misc. Other Direct Capital Costs	$75,000		
Total Direct Cost	$795,000		
Indirect Capital Costs			
Engineering	$119,000	15.0%	of TDC. Basis: EPA/452/B-02-001, Section 4.2, and CUECost default values for SNCR. Increased from 10% to 15% to account for retrofit engineering.
Construction and Field Expenses	$80,000	10.0%	of TDC. Basis: EPA/452/B-02-001, Section 4.2, and CUECost default values for SNCR. Increased from 5% to 10% to account for retrofit expenses.
Contractor Fees/Permitting/Modeling	$80,000	10.0%	of TDC. Basis: Typical for pollution control systems.
Start-Up/Testing	$40,000	5.0%	of TDC. Basis: Typical startup costs for OFA systems
Performance Testing	$40,000	5.0%	of TDC. Basis: Typical performance testing cost for OFA systems (approx. 20 days).
Contingencies	$159,000	20.0%	of TDC. Basis: EPA/452/B-02-001, Section 4.2, and CUECost default value of 20% (for SNCR). Consistent with contingency for retrofit project.
Total Indirect Capital Costs	$518,000		
Total Capital Costs			
Total Capital Investment (TCI)	$1,313,000		
Total Capital Investment ($/kW-net)	$17		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1098	15	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	$144,200	7%	pretax marginal rate of return on private investment

OPERATING COSTS			Basis
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Urea Reagent Cost	$0	$ -	NA
Water Cost	$0	$ -	NA
Boiler Efficiency Penalty	$6,800		cost @ $0.80/mmBtu
Auxiliary Power Cost	$28,500	$ 45	Based on auxiliary power requirement of 0.1% (gross) and $45/MWh.
Total Variable O&M Cost	$35,300		
Fixed O&M Costs			
Additional Operators per shift	0.125		Assumed slight increase in operator hours to account for inspections of the OFA control system.
Operating Labor	$52,600		3 shifts/day, 365 days/year @ $46/hour (salary + benefits) which is equal to an annual operator cost of $100,000/year.
Supervisory Labor	$7,900	15.0%	of operating labor. OAQPS Chapter 2, page 2-29.
Maintenance Materials	$19,700	1.5%	EPA/452/B-02-001, and used the Maintenance Default Factor for SNCR (1.5% of Total Capital Investment) Section 4.2.
Maintenance Labor	$11,800	60.0%	of maintenance materials cost (S&L O&M estimate).
Total Fixed O&M Cost	$92,000		
Indirect Operating Cost			
Property Taxes	$13,100	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Insurance	$13,100	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Administration	$26,300	2%	of total capital investment. OAQPS Chapter 2, page 2-32.
Total Indirect Operating Cost	$52,500		
Total Annual Operating Cost	$179,800		
TOTAL ANNUAL COST			
Annualized Capital Cost	$144,200		
Annual Operating Cost	$179,800		
Total Annual Cost	$324,000		

BART Economic Evaluation – NOx
SNCR Details

CAPITAL COSTS	Cost ($)		Basis
Direct Capital Costs			
Urea Based SNCR Costs			Based on U.S.EPA's Cuecost worksheets and equipment cost estimates prepared by S&L for similar projects. Includes the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the SNCR control system, urea handling system, flue gas ductwork, instrumentation and controls.
Urea Storage & Handling	$392,000		
Urea Injection	$771,000		
Controls/Miscellaneous	$309,000		
Air Heater Modifications	$703,000		
Total Direct Cost (TDC)	$2,175,000		
Indirect Capital Costs			
Engineering	$326,000	15.0%	of TDC. Basis: EPA/452/B-02-001, Section 4.2, and CUECost default values. Increased from 10% to 15% to account for retrofit engineering.
Construction and Field Expenses	$218,000	10.0%	of TDC. Basis: EPA/452/B-02-001, Section 4.2, and CUECost default values. Increased from 5% to 10% to account for retrofit expenses.
Contractor Fees/Permitting/Modeling	$218,000	10.0%	of TDC. Basis: Typical for pollution control systems.
Start-Up/Testing	$109,000	5.0%	of TDC. Basis: Typical startup costs for SNCR
Performance Testing	$109,000	5.0%	of TDC. Basis: Typical performance testing cost for SNCR (approx. 20 days).
Contingencies	$435,000	20.0%	of TDC. Basis: EPA/452/B-02-001, Section 4.2, and CUECost default value of 20%. Consistent with contingency for retrofit project.
Total Indirect Capital Costs	$1,415,000		
Total Capital Costs			
Total Capital Investment (TCI)	$3,590,000		
Total Capital Investment ($/kW-net)	$46		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0944	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	$338,900	7%	pretax marginal rate of return on private investment

OPERATING COSTS			Basis
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Urea Consumption (lb/hr)	253		
Urea Reagent Cost	$518,100	$ 550	Based on maximum heat input, NOx removal rate (lb/hr), NH3/N2 molar ratio approximately 2.0 (NSR), and $550/ton for urea solution.
Water Cost	$1,300	$ 1	Based on urea feed rate and $1/1000 gal.
Boiler Efficiency Penalty	$8,200		0.15% boiler efficiency penalty, equivalent fuel cost @ $0.8/mmBtu
Auxiliary Power Cost	$42,700	$ 45	Based on auxiliary power requirement of 0.15% (gross) and $45/MWh
Total Variable O&M Cost	$570,300		
Fixed O&M Costs			
Additional Operators per shift	0.250		Based on S&L O&M estimate for SNCR control system.
Operating Labor	$105,100		3 shifts/day, 365 days/year @ $48/hour (salary + benefits) which is equal to an annual operator cost of $100,000/year.
Supervisory Labor	$15,800	15.0%	of operating labor. OAQPS Chapter 2, page 2-29.
Maintenance Materials	$53,900	1.5%	EPA/452/B-02-001, Maintenance Default Factor for SNCR (1.5% of Total Capital Investment) Section 4.2.
Maintenance Labor	$32,300	60.0%	of maintenance materials cost (S&L O&M estimate).
Total Fixed O&M Cost	$207,100		
Indirect Operating Cost			
Property Taxes	$36,000	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Insurance	$36,000	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Administration	$72,000	2%	of total capital investment. OAQPS Chapter 2, page 2-32.
Total Indirect Operating Cost	$144,000		
Total Annual Operating Cost	$921,400		
TOTAL ANNUAL COST			
Annualized Capital Cost	$338,900		
Annual Operating Cost	$921,400		
Total Annual Cost	$1,260,300		

BART Economic Evaluation - NOx
Low-Dust SCR Details

CAPITAL COSTS	Cost [$]		Basis
Direct Capital Costs			
Reactor Housing and Installation	$4,885,000		Based on U.S.EPA's Cuecost worksheets and equipment cost estimates prepared by S&L for similar projects. Includes the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the low-dust SCR reactor system, ammonia handing system, flue gas ductwork and fans, instruments and controls.
Ammonia Handling and Injection	$1,297,000		
Flue Gas Handling:Ductwork and Fans	$3,877,000		
Air Preheater Modifications	$819,000		
Misc. Other Direct Capital Costs	$500,000		
Equipment Capital Cost Subtotal	$11,378,000		
Instruments & Controls	$228,000		
Taxes	$683,000		
Freight	$569,000		
Total Direct Cost (TDC)	$12,858,000		
Indirect Capital Costs			
Engineering	$1,928,700	15.0%	of TDC. Basis: EPA/452/B-02-001. Section 4.2. and CUECost default values. Increased from 10% to 20% to account for low-dust SCR engineering and retrofit considerations.
Construction and Field Expenses	$642,900	5.0%	of TDC. Basis: EPA/452/B-02-001. Section 4.2. and CUECost default values. Increased from 5% to 10% to account for retrofit expenses
Contractor Fees	$1,285,800	10.0%	of TDC. Basis: Typical for pollution control systems.
Start-Up	$128,600	1.0%	of TDC. Basis: Typical startup costs for SCR
Performance Testing	$128,600	1.0%	of TDC. Basis: Typical performance testing cost for SCR (approx. 20 days).
Contingencies	$2,571,600	20.0%	of TDC. Basis: EPA/452/B-02-001. Section 4.2. and CUECost default value of 20%. Consistent with contingency for retrofit project.
Total Indirect Capital Costs	$6,686,200		
Total Capital Costs			
Total Capital Investment	$19,544,200		
Total Capital Investment ($/kW-net)	$250		
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0944	20	life of equipment (years)
Annualized Capital Costs	$1,844,800	7%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	80		Based on maximum heat input, NOx removal rate (lb/hr), and NH2/N2 ratio of approximately 1.02.
Ammonia Reagent Cost	$126,100	$ 400	Based on ammonia use, capacity factor listed above, and $400/ton reagent cost.
Supplementary Heat (re-heat flue gas)	$955,400	$ 8	Based on heat input to flue gas re-heater and fuel cost of $8/mmBtu for natural gas.
Catalyst Volume (ft3)	3,957	5,800	Based on exhaust gas flow rate, and assuming a space velocity of 5,800 1/hr for a low-dust SCR.
Catalyst Replacement Cost	$247,300	$ 250	Based on catalyst cost of $250/ft3 and catalyst life of 4 years.
Auxiliary Power Cost	$299,400	$ 45	Based on 16" pressure drop across the SCR, 0.065 MWh/inch auxiliary power requirement, and $45/MWh.
Total Variable O&M Cost	$1,632,157		
Fixed O&M Costs			
Additional Operators per shift	0.250		Based on S&L O&M estimate for SCR control system.
Operating Labor	$73,400		3 shifts/day, 365 days/year @ $33.50/hour (salary + benefits) which is equal to an annual operator salary of $70,000/year.
Supervisory Labor	$11,000	15.0%	of operating labor. OAQPS Chapter 2, page 2-29.
Maintenance Materials	$170,700	1.5%	CUECost Maintenance Default Factor for SCR (1.5% of installed cost).
Maintenance Labor	$102,400	60.0%	of maintenance materials cost (S&L O&M estimate).
Total Fixed O&M Cost	$357,500		
Indirect Operating Cost			
Property Taxes	$195,000	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Insurance	$195,000	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Administration	$391,000	2%	of total capital investment. OAQPS Chapter 2, page 2-32.
Total Indirect Operating Cost	$781,000		
Total Annual Operating Cost	$2,770,700		
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,844,800		
Annual Operating Cost	$2,770,700		
Total Annual Cost	$4,615,500		

BART Economic Evaluation – SO_2
Limestone with Dry FGD Control System

CAPITAL COSTS	Cost [$]	Basis
Direct Capital Costs		
Limestone Injection to CFB	$2,800,000	Based on U.S.EPA's Cuecost worksheets and equipment cost estimates prepared by S&L for similar projects. Includes the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation, for the SDA reaction towers, recycle pumps, induced draft fans, lime receiving, lime handling, and solids handling systems
Reagent Feed System	$5,986,000	
SO2 Removal System	$1,725,000	
Spray Dryers	$7,738,000	
Flue Gas Handling System	$2,155,000	
ID Fans	$827,000	
Waste / Byproduct Handling System	$1,664,000	
Support Equipment	$2,248,000	
Chimney Modifications	$3,994,000	
Fabric Filter Baghouse	$4,948,600	Included 1/2 the total capital cost for the fabric filter because the dry FGD control system must be followed by particulate control, and it is not physically possible to locate the dry FGD control system between the boiler and the existing ESP
Total Purchased Equipment Cost (PEC)	$34,085,600	
Indirect Capital Costs		
Engineering	$3,409,000	10.0% of PEC. Source: OAQPS Manual Chapter 5, Table 1.3, page 1-27.
Construction and Field Expenses	$3,409,000	10.0% of PEC. Source: OAQPS Manual Chapter 5, Table 1.3, page 1-27.
Contractor Fees	$3,409,000	10.0% of PEC. Source: OAQPS Manual Chapter 5, Table 1.3, page 1-27.
Start-Up	$341,000	1.0% of PEC. Source: OAQPS Manual Chapter 5, Table 1.3, page 1-27.
Performance Tests	$341,000	1.0% of PEC. Source: OAQPS Manual Chapter 5, Table 1.3, page 1-27.
Contingencies	$1,023,000	3.0% of PEC. Source: OAQPS Manual Chapter 5, Table 1.3, page 1-27.
Total Indirect Capital Costs (IC)	$11,932,000	
Total Capital Costs		
Total Capital Investment	$46,017,600	
Total Capital Investment ($/kW -net)	$588	
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.0944	20 years.
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	$4,344,000	7% pretax marginal rate of return on private investment. Interest rate used in OAQPS Manual (Chapter 2 page 2-15).

OPERATING COSTS			Basis
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Lime Reagent Cost	$60,100	$ 75	Based on maximum heat input, SO2 removal rate (lb/hr), 1.05 stoichiometry, 90% CaO, and reactant cost of $75/ton for lime.
Water Cost	$28,500	$ 1	Based on 0.75 gpm/MW-gross, $1/1000 gal
FGD Waste Disposal Cost	$48,900	$ 5	Based on maximum heat input, SO2 removal rate (lb/hr), and $5/ton on-site disposal cost. Disposal cost includes lime by-products, and limestone injection by-products, but does not include fly ash.
Auxiliary Power Cost	$313,300	$ 45	Based on auxiliary power requirement of 1.10% (net) and $45/MW.
Total Variable O&M Costs	$450,800		
Fixed O&M Costs			
Additional Operators per shift	0.75		Based on S&L O&M estimate for dry FGD.
Operating Labor	$220,100		3 shifts/day, 365 days/year @ $33.50/hour (salary + benefits) which is equal to an annual operator salary of $70,000/year.
Supervisor Labor	$33,000	15.0%	of operating labor. OAQPS Chapter 2, page 2-29.
Maintenance Materials	$1,704,300	5.0%	CUECost Maintenance Default Factor for lime spray dryer.
Maintenance Labor	$1,022,600	60.0%	of maintenance materials cost (S&L O&M estimate).
Total Fixed O&M Cost	$2,980,000		
Indirect Operating Cost			
Property Taxes	$460,000	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Insurance	$460,000	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Administration	$920,000	2%	of total capital investment. OAQPS Chapter 2, page 2-32.
Total Indirect Operating Cost	$1,840,000		
Total Annual Operating Cost	$5,270,800		
TOTAL ANNUAL COST			
Annualized Capital Cost	$4,344,000		
Annual Operating Cost	$5,270,800		
Total Annual Cost	$9,614,800		

BART Economic Evaluation – SO_2
Wet FGD Details

CAPITAL COSTS	Cost [$]		Basis
Total Purchased Equipment Cost (PEC)	$65,913,363		Total capital cost estimates were based on USEPA's CueCost Worksheet, and compared to equipment cost estimates prepared by S&L for similarly sized projects. Direct capital costs include the cost of major components, ancillary equipment, duct work, foundations, and mechanical erection for the FGD absorber towers, recycle pumps, induced draft fans, limestone receiving, limestone handling, thickeners and sludge handling systems.
General Facilities	$6,591,336		
Engineering Fees	$6,591,336		
Contingency	$13,182,673		
Total Plant Cost	$92,278,708		
Total Plant Cost (TPC) w/ Prime Contractor's Markup	$95,047,069		
Total Cash Expended (TCE)	$92,305,585		
Allow. for Funds During Constr. (AFDC)	$10,120,914		
Total Plant Investment (TPI)	$102,426,499		
Preproduction Costs	$3,747,145		
Inventory Capital	$330,918		
Total Capital Requirement (TCR)	$106,505,000		
Total Capital Investment ($/kW - net)	$207		
Capital Recovery Factor = $i(1+i)^n/(1+i)^n - 1$	0.0806	30	years.
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	$8,582,900	7%	pretax marginal rate of return on private investment. Interest rate used in OAQPS Manual (Chapter 2 page 2-15).
OPERATING COSTS			**Basis**
Operating & Maintenance Costs (based on 90% capacity factor)			
Variable O&M Costs			
Limestone Reagent Cost	$620,100	$ 30	Based on maximum heat input, SO2 removal rate (lb/hr), 1.05 stoichiometry, 90% CaCO3, 90% capacity factor, and $30/ton for limestone.
Water Cost	$270,200		Based on 1.0 gpm/MW-gross, 90% capacity factor, and $1/1000 gal
FGD Waste Disposal Cost	$344,000	$ 10	Based on maximum heat input, SO2 removal rate (lb/hr), 90% capacity factor, forced oxidation 90% dry, and $10/ton on-site disposal cost. Disposal cost only includes additional WFGD by-products and does not include fly ash or CFB limestone by-products.
Auxiliary Power Cost	$3,377,400	$ 30	Based on auxiliary power requirement of 2.5% (net), 90% capacity factor, and $30/MW.
Total Variable O&M Costs	$4,611,700		
Fixed O&M Costs			
Additional Operators per shift	3.0		Based on S&L O&M estimate for wet FGD.
Operating Labor	$880,400		3 shifts/day, 365 days/year @ $33.50/hour (salary + benefits) which is equal to an annual operator salary of $70,000/year.
Supervisor Labor	$132,100	15.0%	of operating labor. OAQPS Chapter 2, page 2-29.
Maintenance Materials	$3,295,700	5.0%	CUECost Maintenance Default Factor for limestone scrubber with forced oxidation
Maintenance Labor	$1,977,400	60.0%	of maintenance materials cost (S&L O&M estimate).
Total Fixed O&M Cost	$6,285,600		
Indirect Operating Cost			
Property Taxes	$659,100	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Insurance	$659,100	1%	of total capital investment. OAQPS Chapter 2, page 2-32.
Administration	$1,318,300	2%	of total capital investment. OAQPS Chapter 2, page 2-32.
Total Indirect Operating Cost	$2,636,500		
Total Annual Operating Cost	$13,533,800		
TOTAL ANNUAL COST			
Annualized Capital Cost	$8,582,900		
Annual Operating Cost	$13,533,800		
Total Annual Cost	$22,116,700		

North Dakota
Department of Health
CUECOST Model Spreadsheets
(Verification Only)

APC Technology Choices						
Description	**Units**	**Input 1**	**Input 2**	**Input 3**	**Input 4**	**Input 5**
FGD Process	Integer	1	2	0	0	0
(1 = LSFO, 2 = LSD)						
Particulate Control	Integer	2	1	0	0	0
(1 = Fabric Filter, 2 = ESP)						
NOx Control	Integer	1	2	0	0	0
(1 = SCR, 2 = SNCR, 3 = LNBs, 4 = NGR)						

INPUTS						
Description	**Units**	**Input 1**	**Input 2**	**Input 3**	**Input 4**	**Input 5**
General Plant Technical Inputs						
Location - State	Abbrev.	ND	ND	0	0	0
MW Equivalent of Flue Gas to Control System	MW	78	78	0	0	0
Net Plant Heat Rate	Btu/kWhr	10,500	10,500	0	0	0
Plant Capacity Factor	%	90%	90%	0%	0%	0%
Total Air Downstream of Economizer	%	120%	120%	0%	0%	0%
Air Heater Leakage	%	12%	12%	0%	0%	0%
Air Heater Outlet Gas Temperature	°F	300	300	0	0	0
Inlet Air Temperature	°F	80	80	0	0	0
Ambient Absolute Pressure	In. of Hg	29.4	29.4	0	0	0
Pressure After Air Heater	In. of H2O	-12	-12	0	0	0
Moisture in Air	lb/lb dry air	0.013	0.013	0	0	0
Ash Split:						
Fly Ash	%	80%	80%	0%	0%	0%
Bottom Ash	%	20%	20%	0%	0%	0%
Seismic Zone	Integer	1	1	0	0	0
Retrofit Factor	Integer	1.3	1.3	0	0	0
(1.0 = new, 1.3 = medium, 1.6 = difficult)						
Select Coal	Integer	7	7	0	0	0
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	0	0	0
Economic Inputs						
Cost Basis -Year Dollars	Year	1998	1998	0	0	0
Sevice Life (levelization period)	Years	30	30	0	0	0
Inflation Rate	%	3%	3%	0%	0%	0%
After Tax Discount Rate (current $'s)	%	9%	9%	0%	0%	0%
AFDC Rate (current $'s)	%	11%	11%	0%	0%	0%
First-year Carrying Charge (current $'s)	%	22%	22%	0%	0%	0%
Levelized Carrying Charge (current $'s)	%	17%	17%	0%	0%	0%
First-year Carrying Charge (constant $'s)	%	16%	16%	0%	0%	0%
Levelized Carrying Charge (constant $'s)	%	12%	12%	0%	0%	0%
Sales Tax	%	6%	6%	0%	0%	0%
Escalation Rates:						
Consumables (O&M)	%	3%	3%	0%	0%	0%
Capital Costs:						
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	0	0	0
If "Yes" input cost basis CE Plant Index.	Integer	388	388	0	0	0
If "No" input escalation rate.	%	3%	3%	0%	0%	0%
Construction Labor Rate	$/hr	$35	$35	$0	$0	$0
Prime Contractor's Markup	%	3%	3%	0%	0%	0%
Operating Labor Rate	$/hr	$30	$30	$0	$0	$0
Power Cost	Mills/kWh	25	25	0	0	0
Steam Cost	$/1000 lbs	3.5	3.5	0	0	0
Limestone Forced Oxidation (LSFO) Inputs						
SO2 Removal Required	%	95%	95%	0%	0%	0%
L/G Ratio	gal / 1000 acf	125	125	0	0	0
Design Scrubber with Dibasic Acid Addition?	Integer	2	1	0	0	0
(1 = yes, 2 = no)						

Adiabatic Saturation Temperature	°F	127	127	0	0	0
Reagent Feed Ratio	Factor	1.05	1.05	0	0	0
(Mole CaCO3 / Mole SO2 removed)						
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	0%	0%	0%
Stacking, Landfill, Wallboard	Integer	1	1	0	0	0
(1 = stacking, 2 = lanfill, 3 = wallboard)						
Number of Absorbers	Integer	1	1	0	0	0
(Max. Capacity = 700 MW per absorber)						
Absorber Material	Integer	1	1	0	0	0
(1 = alloy, 2 = RLCS)						
Absorber Pressure Drop	in. H2O	6	6	0	0	0
Reheat Required ?	Integer	1	1	0	0	0
(1 = yes, 2 = no)						
Amount of Reheat	°F	25	25	0	0	0
Reagent Bulk Storage	Days	60	60	0	0	0
Reagent Cost (delivered)	$/ton	$15	$15	$0	$0	$0
Landfill Disposal Cost	$/ton	$30	$30	$0	$0	$0
Stacking Disposal Cost	$/ton	$6	$6	$0	$0	$0
Credit for Gypsum Byproduct	$/ton	$2	$2	$0	$0	$0
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	0%	0%	0%
SO2 Removal	%	5%	5%	0%	0%	0%
Flue Gas Handling	%	5%	5%	0%	0%	0%
Waste / Byproduct	%	5%	5%	0%	0%	0%
Support Equipment	%	5%	5%	0%	0%	0%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	0%	0%	0%
SO2 Removal	%	20%	20%	0%	0%	0%
Flue Gas Handling	%	20%	20%	0%	0%	0%
Waste / Byproduct	%	20%	20%	0%	0%	0%
Support Equipment	%	20%	20%	0%	0%	0%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	0%	0%	0%
SO2 Removal	%	10%	10%	0%	0%	0%
Flue Gas Handling	%	10%	10%	0%	0%	0%
Waste / Byproduct	%	10%	10%	0%	0%	0%
Support Equipment	%	10%	10%	0%	0%	0%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	0%	0%	0%
SO2 Removal	%	10%	10%	0%	0%	0%
Flue Gas Handling	%	10%	10%	0%	0%	0%
Waste / Byproduct	%	10%	10%	0%	0%	0%
Support Equipment	%	10%	10%	0%	0%	0%
Lime Spray Dryer (LSD) Inputs						
SO2 Removal Required	%	90%	90%	0%	0%	0%
Adiabatic Saturation Temperature	°F	127	127	0	0	0
Flue Gas Approach to Saturation	°F	20	20	0	0	0
Spray Dryer Outlet Temperature	°F	147	147	0	0	0
Reagent Feed Ratio	Factor	1.02	1.02	0.00	0.00	0.00
(Mole CaO / Mole Inlet SO2)						
Recycle Rate	Factor	8.25	8.25	0	0	0
(lb recycle / lb lime feed)						
Recycle Slurry Solids Concentration	Wt. %	35%	35%	0%	0%	0%
Number of Absorbers	Integer	2	2	0	0	0
(Max. Capacity = 300 MW per spray dryer)						
Absorber Material	Integer	1	1	0	0	0
(1 = alloy, 2 = RLCS)						
Spray Dryer Pressure Drop	in. H2O	5	5	0	0	0
Reagent Bulk Storage	Days	60	60	0	0	0
Reagent Cost (delivered)	$/ton	$65	$65	$0	$0	$0
Dry Waste Disposal Cost	$/ton	$30	$30	$0	$0	$0
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	0%	0%	0%
SO2 Removal	%	5%	5%	0%	0%	0%
Flue Gas Handling	%	5%	5%	0%	0%	0%
Waste / Byproduct	%	5%	5%	0%	0%	0%
Support Equipment	%	5%	5%	0%	0%	0%
Contingency by Area (% of Installed Cost)						

Reagent Feed	%	20%	20%	0%	0%	0%
SO2 Removal	%	20%	20%	0%	0%	0%
Flue Gas Handling	%	20%	20%	0%	0%	0%
Waste / Byproduct	%	20%	20%	0%	0%	0%
Support Equipment	%	20%	20%	0%	0%	0%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	0%	0%	0%
SO2 Removal	%	10%	10%	0%	0%	0%
Flue Gas Handling	%	10%	10%	0%	0%	0%
Waste / Byproduct	%	10%	10%	0%	0%	0%
Support Equipment	%	10%	10%	0%	0%	0%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	0%	0%	0%
SO2 Removal	%	10%	10%	0%	0%	0%
Flue Gas Handling	%	10%	10%	0%	0%	0%
Waste / Byproduct	%	10%	10%	0%	0%	0%
Support Equipment	%	10%	10%	0%	0%	0%
Particulate Control Inputs						
Outlet Particulate Emission Limit	lbs/MMBtu	0.015	0.015	0	0	0
Fabric Filter:						
Pressure Drop	in. H2O	6	6	0	0	0
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	0	0	0
Gas-to-Cloth Ratio	ACFM/ft^2	3.5	3.5	0	0	0
Bag Material (RGFF fiberglass only)	Integer	2	2	0	0	0
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)						
Bag Diameter	inches	6	6	0	0	0
Bag Length	feet	20	20	0	0	0
Bag Reach		3	3	0	0	0
Compartments out of Service	%	10%	10%	0%	0%	0%
Bag Life	Years	5	5	0	0	0
Maintenance (% of installed cost)	%	5%	5%	0%	0%	0%
Contingency (% of installed cost)	%	20%	20%	0%	0%	0%
General Facilities (% of installed cost)	%	10%	10%	0%	0%	0%
Engineering Fees (% of installed cost)	%	10%	10%	0%	0%	0%
ESP:						
Strength of the electric field in the ESP = E	kV/cm	10.0	10.0	0.0	0.0	0.0
Plate Spacing	in.	12	12	0	0	0
Plate Height	ft.	36	36	0	0	0
Pressure Drop	in. H2O	3	3	0	0	0
Maintenance (% of installed cost)	%	5%	5%	0%	0%	0%
Contingency (% of installed cost)	%	20%	20%	0%	0%	0%
General Facilities (% of installed cost)	%	10%	10%	0%	0%	0%
Engineering Fees (% of installed cost)	%	10%	10%	0%	0%	0%
NOx Control Inputs						
Selective Catalytic Reduction (SCR) Inputs						
NH3/NOX Stoichiometric Ratio	NH3/NOX	0.9	0.9	0	0	0
NOX Reduction Efficiency	Fraction	0.80	0.80	0.00	0.00	0.00
Inlet NOx	lbs/MMBtu	0.36	0.36	0	0	0
Space Velocity (Calculated if zero)	1/hr	0	0	0	0	0
Overall Catalyst Life	years	3	3	0	0	0
Ammonia Cost	$/ton	205.66	205.66	0	0	0
Catalyst Cost	$/ft3	356.34	356.34	0	0	0
Solid Waste Disposal Cost	$/ton	11.48	11.48	0	0	0
Maintenance (% of installed cost)	%	1.5%	1.5%	0.0%	0.0%	0.0%
Contingency (% of installed cost)	%	20%	20%	0%	0%	0%
General Facilities (% of installed cost)	%	5%	5%	0%	0%	0%
Engineering Fees (% of installed cost)	%	10%	10%	0%	0%	0%
Number of Reactors	integer	2	2	0	0	0
Number of Air Preheaters	integer	1	1	0	0	0
Selective NonCatalytic Reduction (SNCR) Inputs						
Reagent	1:Urea 2:Ammonia	1	1	0	0	0
Number of Injector Levels	integer	3	3	0	0	0

Number of Injectors	integer	18	18	0	0	0
Number of Lance Levels	integer	0	0	0	0	0
Number of Lances	integer	0	0	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	0	0	0
NOX Reduction Efficiency	Fraction	0.40	0.40	0.00	0.00	0.00
Inlet NOx	lbs/MMBtu	0.36	0.36	0	0	0
NH3/NOX Stoichiometric Ratio	NH3/NOX	1.2	1.2	0	0	0
Urea/NOX Stoichiometric Ratio	Urea/NOX	1.2	1.2	0	0	0
Urea Cost	$/ton	225	224.95	0	0	0
Ammonia Cost	$/ton	205.66	205.66	0	0	0
Water Cost	$/1,000 gal	0.407	0.407	0	0	0
Maintenance (% of installed cost)	%	1.5%	1.5%	0.0%	0.0%	0.0%
Contingency (% of installed cost)	%	20%	20%	0%	0%	0%
General Facilities (% of installed cost)	%	5%	5%	0%	0%	0%
Engineering Fees (% of installed cost)	%	10%	10%	0%	0%	0%
Low NOX Burner Technology Inputs						
NOX Reduction Efficiency	fraction	0.35	0.35	0.35	0.35	0.35
Boiler Type	T:T-fired, W:Wall	T	T	T	T	T
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%	1.2%	1.2%
Natural Gas Reburning Inputs						
NOX Reduction Efficiency	fraction	0.61	0.61	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	2.31	2.31	2.31	2.31	2.31
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

SUMMARY OF COSTS						
Description	**Units**	**Input 1**	**Input 2**	**Input 3**	**Input 4**	**Input 5**
APC Technologies						
NOx Control		SCR	SNCR	NGR	NGR	NGR
Particulate Control		ESP	PJFF	PJFF	PJFF	PJFF
SO2 Control		LSFO	LSD	LSD	LSD	LSD
NOx Control Costs →		SCR	SNCR	NGR	NGR	NGR
Total Capital Requirement (TCR)	$	$10,027,752	$1,553,228	#N/A	#N/A	#N/A
	$/kW	$128.6	$19.9	#N/A	#N/A	#N/A
First Year Costs						
Fixed O&M	$	$174,883	$87,020	#N/A	#N/A	#N/A
	$/kW-Yr	2.24	1.12	#N/A	#N/A	#N/A
	Mills/kWH	0.28	0.14	#N/A	#N/A	#N/A
	$/ton NOx removed	$152	$151	#N/A	#N/A	#N/A
Variable O&M	$	$617,062	$209,602	$0	$0	$0
	$/kW-Yr	7.91	2.69	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	1.00	0.34	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton NOx removed	$537	$365	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$	$2,236,189	$346,370	#N/A	#N/A	#N/A
	$/kW-Yr	28.67	4.44	#N/A	#N/A	#N/A
	Mills/kWH	3.64	0.56	#N/A	#N/A	#N/A
	$/ton NOx removed	$1,945	$603	#N/A	#N/A	#N/A
TOTAL	$	$3,028,133	$642,992	#N/A	#N/A	#N/A
	$/kW-Yr	38.82	8.24	#N/A	#N/A	#N/A
	Mills/kWH	4.92	1.05	#N/A	#N/A	#N/A
	$/ton NOx removed	$2,634	$1,118	#N/A	#N/A	#N/A
Levelized Current Dollars						
Fixed O&M	$/kW-Yr	3.05	1.52	#N/A	#N/A	#N/A
	Mills/kWH	0.39	0.19	#N/A	#N/A	#N/A
	$/ton NOx removed	$207	$206	#N/A	#N/A	#N/A
Variable O&M	$/kW-Yr	10.77	3.66	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	1.37	0.46	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton NOx removed	$730	$496	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$/kW-Yr	21.73	3.37	#N/A	#N/A	#N/A
	Mills/kWH	2.76	0.43	#N/A	#N/A	#N/A
	$/ton NOx removed	$1,474	$457	#N/A	#N/A	#N/A
TOTAL	$/kW-Yr	35.54	8.54	#N/A	#N/A	#N/A
	Mills/kWH	4.51	1.08	#N/A	#N/A	#N/A
	$/ton NOx removed	$2,411	$1,159	#N/A	#N/A	#N/A
Levelized Constant Dollars						
Fixed O&M	$/kW-Yr	2.24	1.12	#N/A	#N/A	#N/A
	Mills/kWH	0.28	0.14	#N/A	#N/A	#N/A
	$/ton NOx removed	$152	$151	#N/A	#N/A	#N/A
Variable O&M	$/kW-Yr	7.91	2.69	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	1.00	0.34	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton NOx removed	$537	$365	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$/kW-Yr	15.04	2.33	#N/A	#N/A	#N/A
	Mills/kWH	2.71	0.42	#N/A	#N/A	#N/A
	$/ton NOx removed	$1,449	$449	#N/A	#N/A	#N/A
TOTAL	$/kW-Yr	25.19	6.13	#N/A	#N/A	#N/A
	Mills/kWH	4.00	0.90	#N/A	#N/A	#N/A
	$/ton NOx removed	$2,138	$965	#N/A	#N/A	#N/A
Particulate Control Costs →		ESP	PJFF	PJFF	PJFF	PJFF
Total Capital Requirement (TCR)	$	$8,962,187	$9,875,231	#DIV/0!	#DIV/0!	#DIV/0!
	$/kW	$115	$127	#DIV/0!	#DIV/0!	#DIV/0!
First Year Costs						
Fixed O&M	$	$316,128	$348,334	#DIV/0!	#DIV/0!	#DIV/0!
	$/kW-Yr	4.05	4.47	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	0.51	0.57	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$15.0	$3.8	#DIV/0!	#DIV/0!	#DIV/0!
Variable O&M	$	$46,923	$233,002	#DIV/0!	#DIV/0!	#DIV/0!
	$/kW-Yr	0.60	2.99	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	0.08	0.38	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$2.2	$2.5	#DIV/0!	#DIV/0!	#DIV/0!

Fixed Charges	$	$1,998,568	$2,202,176	#DIV/0!	#DIV/0!	#DIV/0!
	$/kW-Yr	25.62	28.23	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	3.25	3.58	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$95.0	$23.8	#DIV/0!	#DIV/0!	#DIV/0!
TOTAL	$	$2,361,619	$2,783,512	#DIV/0!	#DIV/0!	#DIV/0!
	$/kW-Yr	30.28	35.69	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	3.84	4.53	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$112.2	$30.1	#DIV/0!	#DIV/0!	#DIV/0!
Levelized Current Dollars						
Fixed O&M	$/kW-Yr	5.52	6.08	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	0.70	0.77	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$20.4	$5.1	#DIV/0!	#DIV/0!	#DIV/0!
Variable O&M	$/kW-Yr	0.82	4.07	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	0.10	0.52	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$3.0	$3.4	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$/kW-Yr	19.42	21.40	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	2.46	2.71	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$72.0	$18.1	#DIV/0!	#DIV/0!	#DIV/0!
TOTAL	$/kW-Yr	25.75	31.54	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	3.27	4.00	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$95.4	$26.6	#DIV/0!	#DIV/0!	#DIV/0!
Levelized Constant Dollars						
Fixed O&M	$/kW-Yr	4.05	4.47	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	0.51	0.57	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$15.0	$3.8	#DIV/0!	#DIV/0!	#DIV/0!
Variable O&M	$/kW-Yr	0.60	2.99	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	0.08	0.38	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$2.2	$2.5	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$/kW-Yr	13.44	14.81	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	2.42	2.67	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$70.8	$17.8	#DIV/0!	#DIV/0!	#DIV/0!
TOTAL	$/kW-Yr	18.10	22.27	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	3.01	3.61	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton PM removed	$88.0	$24.0	#DIV/0!	#DIV/0!	#DIV/0!
SO2 Control Costs →		LSFO	LSD	LSD	LSD	LSD
Total Capital Requirement (TCR)	$	$48,800,638	$37,564,351	#N/A	#N/A	#N/A
	$/kW	$626	$482	#N/A	#N/A	#N/A
First Year Costs						
Fixed O&M	$	$2,691,290	$2,092,480	#NUM!	#NUM!	#NUM!
	$/kW-Yr	34.50	26.83	#NUM!	#NUM!	#NUM!
	Mills/kWH	4.38	3.40	#NUM!	#NUM!	#NUM!
	$/ton SO2 removed	$350.4	$287.6	#NUM!	#NUM!	#NUM!
Variable O&M	$	$903,322	$1,828,714	#DIV/0!	#DIV/0!	#DIV/0!
	$/kW-Yr	11.58	23.45	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	1.47	2.97	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton SO2 removed	$117.6	$251.3	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$	$10,882,542	$8,376,850	#N/A	#N/A	#N/A
	$/kW-Yr	139.52	107.40	#N/A	#N/A	#N/A
	Mills/kWH	17.70	13.62	#N/A	#N/A	#N/A
	$/ton SO2 removed	$1,416.9	$1,151.3	#N/A	#N/A	#N/A
TOTAL	$	$14,477,154	$12,298,045	#NUM!	#NUM!	#NUM!
	$/kW-Yr	185.60	157.67	#NUM!	#NUM!	#NUM!
	Mills/kWH	23.54	20.00	#NUM!	#NUM!	#NUM!
	$/ton SO2 removed	$1,885	$1,690	#N/A	#N/A	#N/A
Levelized Current Dollars						
Fixed O&M	$/kW-Yr	46.95	36.51	#NUM!	#NUM!	#NUM!
	Mills/kWH	5.96	4.63	#NUM!	#NUM!	#NUM!
	$/ton SO2 removed	$476.8	$391.3	#NUM!	#NUM!	#NUM!
Variable O&M	$/kW-Yr	15.76	31.90	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	2.00	4.05	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton SO2 removed	$160.1	$342.0	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$/kW-Yr	105.73	81.39	#N/A	#N/A	#N/A
	Mills/kWH	13.41	10.32	#N/A	#N/A	#N/A
	$/ton SO2 removed	$1,073.8	$872.5	#N/A	#N/A	#N/A
TOTAL	$/kW-Yr	168.45	149.80	#NUM!	#NUM!	#NUM!
	Mills/kWH	21.37	19.00	#NUM!	#NUM!	#NUM!
	$/ton SO2 removed	$1,710.7	$1,605.9	#NUM!	#NUM!	#NUM!
Levelized Constant Dollars						
Fixed O&M	$/kW-Yr	34.50	26.83	#NUM!	#NUM!	#NUM!

	Mills/kWH	4.38	3.40	#NUM!	#NUM!	#NUM!
	$/ton SO2 removed	$350.4	$287.6	#NUM!	#NUM!	#NUM!
Variable O&M	$/kW-Yr	11.58	23.45	#DIV/0!	#DIV/0!	#DIV/0!
	Mills/kWH	1.47	2.97	#DIV/0!	#DIV/0!	#DIV/0!
	$/ton SO2 removed	$117.6	$251.3	#DIV/0!	#DIV/0!	#DIV/0!
Fixed Charges	$/kW-Yr	73.20	56.35	#N/A	#N/A	#N/A
	Mills/kWH	13.19	10.15	#N/A	#N/A	#N/A
	$/ton SO2 removed	$1,055.9	$858.0	#N/A	#N/A	#N/A
TOTAL	$/kW-Yr	119.29	106.62	#NUM!	#NUM!	#NUM!
	Mills/kWH	19.03	16.53	#NUM!	#NUM!	#NUM!
	$/ton SO2 removed	$1,524.0	$1,396.9	#NUM!	#NUM!	#NUM!

Appendix A.2.4
Permit to Construct

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

FILE

July 22, 2010

Ms. Abbie Krebsbach
Environmental Manager
Montana Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

Re: Heskett Station Unit 2 Limestone Injection Project

Dear Ms. Krebsbach:

Enclosed is a Permit to Construct which establishes sulfur dioxide emission limits for the R.M. Heskett Station Unit 2. A public comment period was held regarding the Permit to Construct and other elements of the North Dakota Regional Haze State Implementation Plan Supplement No. 1 from June 10 through July 11, 2010. The only significant change to the draft Permit to Construct was a revision of the language in the first sentence under Section II, Permit Conditions. This sentence was revised to indicate that the limits are only effective if, and when, EPA approves those limits as part of the North Dakota Regional Haze SIP.

Please advise the Department within 15 days after completing the project to allow for an inspection by the Department. Compliance with the emission limits in the Permit to Construct must be achieved as expeditiously as possible but not later than five years after the Environmental Protection Agency's approval of those limits as part of the North Dakota Regional Haze SIP.

In addition, within 12 months after commencing operation of the new and/or modified equipment, a permit revision application for the project for a significant modification to the Title V Permit to Operate must be submitted to the Department.

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

Sincerely,

Terry O'Clair

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

TLO/TB:saj
Enc:
xc: Gail Fallon, EPA Region 8
Custer District Health Unit, Mandan, ND

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

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33-15, Chapter 33-15-14 and Chapter 33-15-25), the North Dakota Department of Health hereby grants a Permit to Construct for the following source:

I. **General Information**:

A. **Permit to Construct Number**: PTC10028

B. **Source**:

1. **Name**: R.M. Heskett Station Unit 2

2. **Location**: Mandan, North Dakota, Morton County

3. **Source Type**: Fossil-fuel fired steam electric unit with a nominal generating capacity of 916.5 million British thermal units per hour (10^6 Btu/hr).

C. **Owner/Operator**:

1. **Name**: Montana-Dakota Utilities Co.

2. **Address**: 400 N Fourth Street
Bismarck, ND 58501-4092

II. **Permit Conditions**:

This Permit to Construct establishes sulfur dioxide emission limits for R.M. Heskett Station Unit 2 if, and when, EPA approves those limits as part of the North Dakota Regional Haze SIP. While this Permit to Construct authorizes the construction and initial operation of new or modified air pollution control equipment and process changes to reduce sulfur dioxide emissions, the permittee may be required to apply for a Prevention of Significant Deterioration (PSD) permit to authorize any significant net emissions increase of particulate matter, PM_{10} and/or $PM_{2.5}$, that will result from the installation of the new or modified pollution control equipment and the process changes.

If new emission units are created, a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct, any required PSD permit and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Health and to the conditions specified below:

A. **Special Conditions**:

1. **Emission Limits**: The term "12-month rolling average," as used in this permit, shall be determined by calculating an arithmetic average of all operating hourly rates for the current month and the previous 11 months. A new 12-month rolling average shall be calculated by the 30th day following the end of each month. Each 12-month rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit. The 12-month rolling average emission rate is calculated from average monthly values as follows:

- If demonstrating compliance with the limit in Condition II.A.1.a(1), calculate the SO_2 removal efficiency for the month as determined by the outlet SO_2 emissions measured by the continuous emissions monitoring system (CEMS) and compare to the average sulfur input to the boiler. The average monthly sulfur input to the boiler shall be based on the amount of fuel combusted in the boiler and the average of the coal sulfur concentration samples measured during the month.

- If demonstrating compliance with the limit in Condition II.A.1.a(2), provide the outlet SO_2 emissions as measured and calculated by the CEMS.

a. The permittee shall not discharge or cause the discharge of sulfur dioxide (SO_2) into the atmosphere from Unit 2 in excess of either:

(1) 30.0% of the SO_2 equivalent reaching the inlet of the boiler (70.0% reduction) on a 12-month rolling average basis, or as an alternative;

(2) 0.60 pounds per million British thermal units (lb/10^6 Btu) on a 12-month rolling average basis.

b. The permittee shall conduct an optimization study to establish the highest sustained sulfur (SO_2) removal efficiency achievable by adding limestone to the bed material, taking into account any technical, operational, and reliability considerations, other pollutant emissions and environmental impacts, and cost effectiveness.

(1) Within 180 days of initial start-up of the limestone injection system, the permittee shall submit a protocol that describes the parameters to be monitored/measured during the study and provide a schedule for completion of the study and report.

(2) Upon Department approval of the test protocol and schedule, the optimization study shall be completed and a report submitted to the Department within the schedule approved in the study protocol.

(3) If the study results indicates that sulfur (SO_2) removal beyond the limits in Condition II.A.1.a(1) and II.A.1.a(2) is achievable, after taking into account technical feasibility, operational and reliability consideration, other pollutant emissions and environmental impacts, and cost effectiveness, the permittee shall apply for a Permit to Construct to make the new SO_2 limit federally enforceable. The permittee shall begin complying with the new limit as outlined in the new, or amended, Permit to Construct.

c. The SO_2 emission limits apply at all times including startup, shutdown, emergency and malfunction.

2. **Compliance Date**: Compliance with the emission limits and other requirements of this permit is required as expeditiously as practicable but in no event later than five years after the U.S. Environmental Protection Agency (EPA) approves this permit as part of the Regional Haze SIP. For purposes of establishing the first month of the 12-month rolling average limits in Condition II.A.1., the permittee shall begin monitoring for compliance within five years of EPA approval of the SIP, as described above, or within six months after initial startup of the limestone injection system, whichever is earlier.

3. **Continuous Emission Monitoring System (CEMS)**: The emissions from Unit 2 (main stack) shall be measured by continuous emission monitors (CEM) for SO_2, CO_2, and flow. The monitoring requirements under Condition II.A.4 shall be the compliance determination method for SO_2.

4. **Monitoring Requirements and Conditions**:

a. Requirements:

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Table 1
Monitoring Requirements by Pollutant/Parameter

Pollutant/Parameter	**Monitoring Requirement (Method)**	**Condition Number**
SO_2 (inlet)	Coal Sampling Data	4.b.(6)
SO_2 (outlet)	CEMS	4.b.(1), 4.b.(2), 4.b.(3), 4.b.(4) & 4.b.(6)
CO_2	CEMS	4.b.(1), 4.b.(2), & 4.b.(3) & 4.b.(4)
Flow	Flow Monitor	4.b.(1), 4.b.(2), & 4.b.(3) & 4.b.(4)

b. Emission Monitoring Conditions:

(1) The monitoring shall be in accordance with the following applicable requirements of Chapter 33-15-06 of the North Dakota Air Pollution

Control Rules and the Acid Rain Program. Emissions are calculated using 40 CFR Part 75.

(a) Section 33-15-06-04 of the North Dakota Air Pollution Control Rules, Monitoring Requirements.

(b) 40 CFR 72 and 40 CFR 75.

(2) The Department may require additional performance audits of the CEMS.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate limit. Timely repair of the emission monitoring system must be made.

(4) The permittee shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended procedures, or a site-specific QA/QC Plan required by 40 CFR 75. The permittee shall have the QA/QC Plan available on-site and provide the Department with a copy when requested.

(5) Within 180 days of initial startup of the equipment required to meet the SO_2 limits, conduct an emissions test to measure particulate emissions, using EPA Test Method 5, 5B or Method 17 in 40 CFR Part 60, Appendix A. Other test methods may be used provided they are approved, in advance, by the Department.

(6) The requirements in 40 CFR 60, Appendix A, Method 19, Section 12.5.3 shall be used to determine overall reduction of SO_2 emissions based on outlet CEMS data and inlet coal sample analysis. Section 12.5.3.2 shall be used to calculate the inlet SO_2 rate. In place of the ASTM D 2234 requirements of 12.5.2.1 of Method 19, coal sample collection will be conducted at least daily when the boiler is in operation to generate the average monthly inlet SO_2 emission rate. Coal sample analysis shall occur at least weekly whenever samples are collected during that week. Daily samples within a calendar week may be combined to form a composite sample that is analyzed for the required parameters.

For purposes of determining compliance with the SO_2 percent reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where: The Inlet SO_2 Rate is in units of $lb/10^6$ Btu or lb/hr and the Outlet SO_2 Rate is in the same units as the Inlet SO_2 Rate.

5. **Recordkeeping Requirements**:

a. The permittee shall maintain compliance monitoring records for Unit 2 as outlined in Table 2 - Monitoring Records, that includes the following information:

(1) A copy of the sample analysis report(s), including the date that the sample analysis was performed; the company, entity, or person that performed the analysis; and the testing techniques or methods used.

(2) The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

(3) A copy of all field data sheets from the emissions testing.

(4) A record shall be kept of all major maintenance activities conducted on the emission units or air pollution control equipment.

(5) Records shall be kept as to the type of fuel usage.

Table 2
Monitoring Records

Pollutant/Parameter	**Compliance Monitoring Record**
SO_2 outlet (lb/10^6 Btu & lb/hr)	CEMS Data
SO_2 inlet (lb/10^6 Btu)	Coal Sampling Data
CO_2	CEMS Data
Flow	Flow Monitor Data

b. In addition to requirements outlined in Condition II.5.a., recordkeeping for Unit 2 shall be in accordance with the following applicable requirements of Chapter 33-15-06, Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program:

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75 as incorporated by NDAC 33-15-21-08.1 and 09.

c. The permittee shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. Reporting shall be in accordance with the following applicable requirements of Chapter 33-15-06 and Chapter 33-15-14 of the North Dakota Air Pollution Control Rules and the Acid Rain Program:

(1) Section 33-15-06-05 of the North Dakota Air Pollution Control Rules, Reporting and Recordkeeping Requirements.

(2) 40 CFR 72 and 40 CFR 75 as incorporated by NDAC 33-15-21-08.1 and 09.

(3) NDAC 33-15-14-06.5.

b. Quarterly excess emissions reports for Unit 2 shall be submitted no later than the 30th day following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limits for Unit 2 as outlined in Condition II.A.1.a(1) or (2). Excess emissions shall be reported for the following:

Parameter	Reporting Period
SO_2 % reduction	(Monthly and 12-month rolling average)
or	
SO_2 lb/10^6 Btu at outlet	(Monthly and 12-month rolling average)

c. The permittee shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

d. The permittee shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

e. For emission units where the method of compliance monitoring is demonstrated by either an EPA Test Method or portable analyzer, the test report shall be submitted to the Department within 60 days after completion of the test.

f. The permittee shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each calendar year. Insignificant units/activities listed in this permit do not need to be included in the annual emission inventory report.

g. The permittee shall notify the Department within 15 days of the actual startup date of the equipment required to meet the SO_2 permit limit.

B. **General Conditions**:

1. This permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. The permittee shall comply with all State and Federal environmental laws and rules. In addition, the permittee shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by the permittee to prevent and/or minimize fugitive emissions during the construction period.

4. The permittee shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate Unit 2 and all other emission units including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date: 7/22/10

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

Appendix F.1
Public Participation Record

Notice of Intent
to Amend the
State Implementation Plan
for Air Pollution Control
Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared a supplement to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The supplement addresses requirements for the R.M. Heskett Station Unit 2. The requirements will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The supplement includes a Permit to Construct for R.M. Heskett Station Unit 2 which establishes sulfur dioxide emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from June 11, 2010 through July 11, 2010. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on July 16, 2010 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through July 26, 1020.

The National Park Service, Federal Land Manager for TRNP, has provided comments on the proposed supplement. The comments and the Department's response to those comments may be accessed at the website listed above or by contacting the Department.

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

Dated this 26th day of May 2010

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

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 Dept – Notice of Intent Air Pollution; 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 ND

County of BURLEIGH

Subscribed and sworn to before me this 25th day of JUNE, 2010.

Linda J Judd

LINDA J. JUDD
Notary Public
State of North Dakota
My Commission Expires July 9, 2014

5/29, 6/5 & 12 - 605407

Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared a supplement to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The supplement addresses requirements for the R.M. Heskett Station Unit 2. The requirements will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The supplement includes a Permit to Construct for R.M. Heskett Station Unit 2 which establishes sulfur dioxide emission limits which are intended to improve visibility impairment in TRNP and LWA.

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

Dated this 26th day of May 2010.

Terry L. O'Clair, P.E.
Director, Division of Air Quality
6/5 - 605496

STATE OF NORTH DAKOTA
IN DISTRICT COURT
COUNTY OF BURLEIGH
SOUTH CENTRAL JUDICIAL DISTRICT

Chevy Chase Bank, FSB,
Plaintiff,
vs.
Joie Pfaff; and any person in possession,
Defendants.

Civil No. 10-C-1028

SUMMONS

THE STATE OF NORTH DAKOTA TO THE ABOVE NAMED DEFENDANTS:

You are hereby summoned to appear and defend against the Complaint in this action, which has been filed with the Clerk of Court and is herewith served upon you, by serving upon the undersigned a copy of an answer or other proper response within twenty (20) days after the service of this Summons upon you, exclusive of the day of service. If you fail to do so, judgment by default will be taken against you for the relief demanded in the Complaint. The original Complaint is filed with the Clerk of the District Court in the County in which this action is commenced.

This action relates to the foreclosure of a mortgage upon the following described real property in the County of Burleigh, State of

By: /s/Sandra K. Kuntz
Sandra K. Kuntz, Attorney #05186

THIS IS AN ATTEMPT TO COLLECT THE REFERENCED DEBT AND ANY INFORMATION OBTAINED WILL BE USED FOR THAT PURPOSE. THIS COMMUNICATION IS FROM A DEBT COLLECTOR.

5/22, 29 & 6/5 - 605454

STATE OF NORTH DAKOTA
IN DISTRICT COURT
COUNTY OF BURLEIGH SOUTHWEST JUDICIAL DISTRICT

Billi Jo M. Jackson,
Plaintiff,
vs.
Morris E. Jackson,
Defendant.

Civil No. ________

SUMMONS

THE STATE OF NORTH DAKOTA TO THE ABOVE-NAMED DEFENDANT:

YOU ARE HEREBY SUMMONED and required to appear and defend against the Complaint in the action, which is herewith served upon you, or will be filed with the Clerk of this Court, by serving upon the undersigned an answer or other proper response within twenty (20) days after the service of this Summons upon you, exclusive of the day of service. If you fail to do so, judgment by default will be taken against you for the relief demanded in the Complaint.

NOTICE OF RESTRAINING PROVISIONS

Under Rule 8.4 of the North Dakota Rules of Court, upon service of this Summons, you, and the plaintiff, are bound by the following restraints:

(1) Neither spouse may dispose of, sell, encumber, or otherwise dissipate any of the parties' assets, except:
(A) For necessities of life or for the necessary generation of income or preservation of assets; or
(B) For retaining counsel to carry on or to contest the proceeding.

If a spouse disposes of, sells, encumbers, or otherwise dissipates assets during the interim period, that spouse shall provide to the other spouse an accounting within thirty (30) days.

(2) Neither spouse may harass the other spouse.
(3) All currently available insurance coverage must be maintained and continued without change in coverage or beneficiary designation.

If either spouse violates any of these provisions, that spouse may be in contempt of court.

Dated this 17th day of February, 2010.

/s/Theresa L. Cole
Theresa L. Cole
American Legal Services, P.C.
521 East Main Avenue, Suite 400
Bismarck, ND 58501
(701) 258-1074
Fax (701) 530-1943
ND Bar #05385
Attorney for Plaintiff
6/5, 12 & 19 - 605516

North Dakota, will sell the property described in the Judgment to the highest bidder for cash at public auction at the front door of the Courthouse in the City of Bismarck in the County of Burleigh and State of North Dakota, on June 30, 2010, at the hour of 10:00 A.M. (CT), to satisfy the amount due, with interest thereon, and the costs and expenses of such sale, or so much thereof as the proceeds of such sale will satisfy. The property to be sold is situated in the County of Burleigh and State of North Dakota, and described as follows:

The North 23 Feet of Lot 19, All of Lot 20 and the South 10 Feet of Lot 21, Block 38, Fisher Addition to the City of Bismarck for Street, Highway and Utility Purposes by Instrument Recorded in Book 319, Page 480 aka 1207 N. 14th St. Bismarck, ND 58501.

IN TESTIMONY WHEREOF, I have hereunto set my hand and seal this 13th day of May, 2010.

/s/Pat D. Heinert
Pat D. Heinert
Sheriff of Burleigh County, North Dakota
By: /s/Dan Wentz
Deputy

STATE OF NORTH DAKOTA)
) ss.
County of Burleigh)

On this 13th day of May, 2010, before me, a Notary Public in and for said County and State, personally appeared Dan Wentz, known to me to be the person who is described in, and whose name is subscribed to this instrument.

/s/Norma J. Braddock
Notary Public
Burleigh County, North Dakota
My Commission expires: 2/20/13 (Seal)

MACKOFF KELLOGG LAW FIRM
P.O. Box 1097
Dickinson, ND 58602-1097
Attorneys for Plaintiff
(Published: 06/05; 06/12; 6/19/10)
6/5, 12 & 19 - 605478

INVITATION FOR CONSTRUCTION BIDS
THREE AFFILIATED TRIBES
Owner
C/O FBRW
308 4 Bears Complex
New Town, ND 58763
Address

The Three Affiliated Tribes will receive separate sealed bids for the construction of **Four Bears WTP Expansion Phase 2b & Mandaree WTP Expansion Phase 2b Contract 2010-3** at 4 Bears Casino Meeting Rooms, New Town, ND 58763, until **1:30** P.M., Local Time on the **29th** day of **June, 2010**, where and at which time they will be publicly opened and read aloud.

The Work under Contract 2010-3 includes the installation and associated piping of Owner furnished pre-treatment equipment, Owner furnished MF/UF membrane equipment, chemical feed equipment, high service pumps, heating and ventilation, electrical, modifications to existing lagoons, and additional miscellaneous items at Four Bears WTP (Bid Schedule 1) and the installation and associated piping, Owner furnished pre-treatment equipment, Owner furnished MF/UF membrane equipment, chemical feed equipment, heating and ventilation, electrical, and additional miscellaneous items at Mandaree WTP (Bid Schedule 2). Bid Schedule 3 is for combined Bid Schedules 1 and 2 with Bid Adjustment deduct for contract award of both schedules to a single Bidder. The Four Bears and Mandaree projects are located in McKenzie County of North Dakota.

Each BID must be accompanied by a separate envelope containing a copy of a current and valid **North Dakota Contractor's License** (must have been issued at least 10 calendar days before the date of Bid opening.) and a **BIDDER's Bond** equal to five percent of the full amount of the BID, executed by the BIDDER as Principal and by

6/5 Bismarck

NDNA NORTH DAKOTA NEWSPAPER ASSOCIATION

North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185

INVOICE

Order **27875-10061NA0** Invoice # **131966**

June 25, 2010

Advertiser: **Administrative Serv: Accounting**

P.O.#:

Attn: TOM BACHMAN
ND HEALTH DEPARTMENT
600 E BOULEVARD AVE.
DEPT. 301
BISMARCK, ND 58505-0200
Voice: 701.328.5188 Fax: 701.328.5200

Amount Due **$257.61**

Amount Paid

Please detach and return this portion with your payment

Administrative Serv: Accounting Invoice # 27875-10061NA0-131966

Ad Size	Rate Type	Rate	Total	Discount	(%)	Caption	Page	Run Date
Bismarck Tribune (Bismarck ND)								
60.00	SPR2	0.72	43.20	0.00		Notice of Intent Air P		06/05/10
Dickinson Press (Dickinson ND)								
63.00	SPR2	0.63	39.69	0.00		Notice of Intent Air P		06/06/10
Fargo, The Forum (Fargo ND)								
63.00	SPR2	0.69	43.47	0.00		Notice of Intent Air P		06/07/10
Grand Forks Herald (Grand Forks ND)								
63.00	SPR2	0.71	44.73	0.00		Notice of Intent Air P		06/05/10
Minot Daily News (Minot ND)								
87.00	SPR2	0.49	42.63	0.00		Notice of Intent Air P		06/06/10
Williston Herald (Williston ND)								
57.00	SPR2	0.77	43.89	0.00		Notice of Intent Air P		06/06/10

Gross Advertising	257.61	Total Misc	0.00	Amount Paid	0.00
Agency Discount		Tax	0.00	Adjustments	0.00
Other Discount	0.00	Total Billed	257.61	Payment Date	
Service Charge	0.00	Unbilled	0.00	Balance Due	257.61

Your payment is due upon receipt. Thank you in advance for your prompt payment!

OK for Payment
D1250
6/29/10
Terry O'Clair

ND DEPT OF HEALTH
RECEIVED
JUN 28 2010
ACCOUNTING
TIME______

Response
to
Public Comments

<u>Commenter: Dakota Resource Council and National Parks Conservation Association (hereafter referred to as DRC)</u>

<u>Comment 1</u>: DRC questions whether Heskett Unit 2 was properly evaluated under Reasonable Progress instead of under BART.

<u>Response</u>: The Department determined that Heskett Unit 2 was not subject to BART based on refined modeling submitted by MDU on June 9, 2006. This modeling showed that the impact of emissions from Heskett Unit 2 was less than 0.5 deciviews (98^{th} percentile) at the three units of Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The Department, in a letter dated May 8, 2007, agreed that Heskett Unit 2 was not subject to BART. EPA and the FLMs questioned the modeling protocol that was used. A new protocol based on EPA and FLM criteria, which the Department does not necessarily agree with, was developed. MDU submitted modeling based on the EPA and FLM protocol which showed the maximum impact of emissions from Heskett Unit 2 was even less than the previous modeling at 0.28 deciviews (98^{th} percentile). Both EPA and the FLMs have reviewed the 2009 modeling and did not object to the determination that Heskett Unit 2 was not subject to BART.

<u>Comment 2</u>: DRC claims that the modeling that shows Heskett Unit 2 was not subject to BART was not subject to public review.

<u>Response</u>: Both the 2006 and 2009 modeling analyses were posted on the Department's website for review during the public comment period for the Regional Haze SIP (December 2009 - January 2010). The Department made its decision that Heskett Unit 2 was not subject to BART based on the 2006 modeling. The Department agreed to review that decision if the 2009 results showed Heskett Unit 2 was subject to BART. The Department found no reason to revise its May 8, 2007 decision that Heskett Unit 2 was not subject to BART. Both the 2006 and 2009

modeling analysis were included in the final Regional Haze SIP submitted to EPA in March 2010.

The commenter indicates the impact to TRNP is 0.3 deciviews with the cumulative effects of 0.5 deciviews including LWA. These results are from the 2009 modeling analysis. Apparently, the commenter has reviewed the 2009 analysis and extracted data from it.

<u>Comment 3</u>: DRC claims MDU's own modeling results shows Heskett Unit 2 to be subject-to-BART when cumulative impacts to multiple class I areas are "appropriately" considered.

<u>Response</u>: DRC's position that a cumulative assessment of the impacts on multiple Class I areas is required to determine BART applicability is inconsistent with 40 CFR 51, Appendix Y – Guidelines for BART Determinations under Regional Haze. Section III.3 of 40 CFR 51, Appendix Y, under Option 1, states "You can use dispersion modeling to determine that an individual source cannot reasonably be anticipated to cause or contribute to visibility impairment in **<u>a</u>** [emphasis added] Class I area and thus is not subject to BART." There is no discussion regarding adding results for multiple Class I area. The modeling protocol the Department developed for determining whether sources are subject to BART (see Appendix A.1 of SIP) does not require a cumulative assessment of impacts on multiple Class I areas. The determination of whether a source is subject to BART is based on the maximum impact (98^{th} percentile) at any single Class I area. The Department's modeling protocol is consistent with 40 CFR 51, Appendix Y.

<u>Comment 4</u>: The DRC provided several general concerns, with no supporting data for those concerns, regarding the Reasonable Progress Assessment.

4a. DRC states that overestimated costs tend to reduce the apparent cost effectiveness of viable control technologies like Selective Non-Catalytic Reduction (SNCR).

<u>Response</u>: The Department compared the cost of SNCR estimated by MDU to cost estimates for SNCR at four other small (< 200 MWe) facilities. The results show that the MDU cost estimate

(annualized cost) was near the average with two estimates being higher. It appears MDU's estimate is reasonable compared to similar size facilities.

4b. DRC has concerns that comparing costs and cost effectiveness primarily or solely based on North Dakota facilities may be flawed.

Response: The Department did not rely solely on cost estimates from other North Dakota facilities. MDU's cost estimate for SNCR was compared to two facilities in Minnesota, one in Montana and one in North Dakota. MDU's cost estimates for the wet scrubber and spray dryer/baghouse were compared against results from EPA's CUECOST model. This model is used all over the U.S. The cost of low dust SCR was compared to results generated for the PGE Boardman Plant in Oregon (this was a compilation of results by ERG, Inc. from all over the nation) and cost estimates from two North Dakota facilities. MDU's estimate fell within the midrange of ERG's estimated range for high dust SCR at the PGE Boardman plant. Low dust SCR is expected to cost more than high dust SCR because of the flue gas reheat costs. This makes MDU's estimate even more conservative. The Department believes MDU's estimates are within the ± 30% range required for BART control estimates even though this source is not subject to BART.

4c. DRC has concerns about not using the 98th percentile visibility results for determining reasonable progress.

Response: As pointed out in the Response to Comments to EPA's comments on the FLM Consultation version of this supplement, the Regional Haze rule and EPA guidance does not require use of the 98th percentile results. In 40 CFR 51.308(d) it states "The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 states "most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment," Least impaired days means the average visibility impairment (measured in deceiviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

The Department is not aware of any EPA guidance that indicates the 98th percentile visibility results should be used. To the contrary, in EPA's document "Additional Regional Haze Questions" August 3, 2006, this issue is addressed. In the response to Question 1 under the Reasonable Progress section EPA states "Unlike the technical demonstration for CAIR or BART, the reasonable progress demonstration involves a test of a strategy. The strategy includes a suite of controls that has been identified through the identification of pollutants and source categories of pollutants for visibility impairment – **the application of four statutory factors and how much progress is made with a potential strategy with respect to the glide path. Modeling occurs with a strategy and is not a source-specific demonstration like the BART assessment." [Emphasis added]**

In response to Question 2, it is stated "Reasonable progress is not required to be demonstrated based on a source-by-source basis. It is demonstrated based on a control strategy developed from a suite of controls that has been **assessed with the four statutory factors and the uniform rate of progress**." [Emphasis added]

It is clear to the Department that a BART type assessment (i.e. 98th percentile) is not required. In fact, an assessment of individual sources is not required. The Response to both Question 1 and 2 indicates any modeling should be assessed against the uniform rate of progress (glidepath). In Section 2.2 of "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program", the uniform rate of progress, or glidepath, is determined for the average of the 20% worst days or 20% best days.

The Department has provided both the individual modeling results for sources and the cumulative modeling results for a control strategy for the group of sources that remained after the initial evaluation process was completed (see Section 9.1.5 of the RH SIP). We interpret the EPA guidance on Reasonable Progress to indicate that results for individual sources are not required. Therefore, any results presented would not have to include the 98th percentile values and should be compared to the average of the 20% worst days.

4d. DRC has a concern with a 12-month rolling average instead of a 30-day rolling average and indicates the limit should be written as a numeric limit and a percent reduction.

Response: Heskett Unit 2 is subject to review under the Reasonable Progress requirements of the Regional Haze rule, not the BART requirements. The Department has found that it is not reasonable to require any reductions of SO_2 or NO_x emissions from Unit 2. The reductions at Heskett Unit 2 are somewhat voluntary. Therefore, the Department believes that MDU should be afforded some flexibility in achieving the SO_2 reductions. A twelve month rolling average and allowing MDU to meet either a lb/10^6 Btu limit or a percent reduction requirement allows this flexibility while still achieving the reduction of 553 tons per year of SO_2. The Department's modeling shows the proposed reduction in emissions will have virtually no effect on visibility in the Class I areas. Therefore, the averaging period of the emission limit will not affect visibility impacts. The Department has included adequate monitoring, recordkeeping and reporting in Conditions II.A.3-6 of the Permit to Construct. The commenter provided no specifics to dispute this finding.

Comment 5: DRC states that they attach and incorporate by reference the comments submitted on January 8, 2010 for the Regional Haze SIP.

Response: The Department incorporates by reference its response to the January 8, 2010 DRC comments (see Appendix F.8 – Environmental Groups of the North Dakota State Implementation Plan for Regional Haze; Adopted February 24, 2010).

Commenter: Montana Dakota Utilities (MDU)

Comment 1: MDU has concerns that the requirement for a PSD Permit to Construct for changes associated with the SO_2 removal project could delay the installation of the sulfur dioxide removal project. MDU requested that language be included in the supplement for the SO_2 removal project which would allow the compliance date to be changed based on when the PSD Permit to Construct is issued.

Response: The compliance date in the proposed Permit to Construct for the SO_2 removal project states "as expeditiously as possible" but in no event later than five years after the U.S. EPA approval of the permit as part of Regional Haze SIP. The Department interprets the language "expeditiously as possible" of this condition, to allow consideration of the timing of other permits. Therefore, MDU will have up to five years to obtain any other required permits. The supplement will be revised to indicate that the issuance of a PSD permit for the removal project will affect the compliance date for the project.

DAKOTA RESOURCE COUNCIL
P. O. Box 1095, Dickinson ND 58602-1095
(701) 483-2851; www.drcinfo.com

July 11, 2010

Terry O'Clair, Director
Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

RE: Comments on the May 2010 Supplement No. 1 to the North Dakota State Implementation Plan for Regional Haze

Dear Mr. O'Clair:

On behalf of the Dakota Resource Council and the National Parks Conservation Association, we respectfully submit the following comments on the May 2010 Supplement No. 1 to the North Dakota State Implementation Plan (SIP) for Regional Haze (the Supplement), which addresses the Montana Dakota Utilities' (MDU) Heskett Unit 2 (Heskett) under the Reasonable Progress section of the Regional Haze Rule. We additionally attach and incorporate by reference the comments our organizations submitted on the State's Regional Haze Rule.[1]

We submit these comments on behalf of our more than 320,000 members and out of concern for the millions of people who visit America's national parks and public lands each year. North Dakota's recently submitted Regional Haze SIP identified Class I areas affected by emissions from North Dakota facilities, including Heskett. Impacted lands include Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area in North Dakota, as well as public lands in South Dakota, Montana, Minnesota, and Michigan.

We question whether Heskett is properly evaluated under the Reasonable Progress, rather than the Best Available Retrofit Technology (BART), portion of the SIP. Additionally, we echo the concerns raised by the Department of the Interior (DOI) and the Environmental Protection Agency (EPA), which were largely unaddressed by the North Dakota Department of Health (NDDH).

[1] Comments of National Parks Conservation Association et. al. on North Dakota's Regional Haze State Implementation Plan, January 8, 2010.

Review of Heskett under the Reasonable Progress requirements is questionable for two reasons. First, the public has not had opportunity to review the modeling, submitted to NDDH by MDU in December 2009. As described by EPA in its January 8, 2010 comments on the Regional Haze SIP,

> "...this updated modeling was completed after the start of the current public comment period on the Regional Haze SIP...NDDH will need to revise the SIP to include the updated modeling and your related conclusions. The revision will need to follow North Dakota's public participation process for SIP revisions." (p. 3)

However, the modeling this purports to establish Heskett as not subject-to-BART has not, to our knowledge, been subject to public review. Its conclusions are instead here presented as fact.

Second, MDU's own modeling shows Heskett to be subject-to-BART when cumulative impacts to multiple Class I areas are appropriately considered. The impact to Theodore Roosevelt National Park (TRNP) is 0.3 deciviews, with cumulative effects of 0.5 deciviews including Lostwoods National Wildlife Refuge. Based on this cumulative impact, we believe that Heskett is more appropriately evaluated as subject-to-BART.

In general, we concur with the comments submitted by DOI and EPA, and find NDDH's response to these comments inadequate and unpersuasive. In particular we have continued concerns about:

- Overestimated costs, which tend to reduce the apparent cost effectiveness of viable control technologies like Selective Non-Catalytic Reduction (SNCR).
- Comparing costs and cost effectiveness primarily or solely with other North Dakota facilities, which may be similarly flawed, rather than a broader pool. When compared to determinations around the country, most if not all of the options available are cost effective on a $/ton basis.
- The dismissal of 98^{th} percentile day results (and direct EPA comments on this matter) in examining visibility benefits, as required in a BART analysis. This tends to minimize the visibility benefits of emissions reductions.
- The lack of stringency in the limit established, with regard to the numeric limit, averaging time, and other parameters. There is no reason to establish a less stringent 12-month rolling average rather than a 30-day rolling average. Although the optimization described in the permit may result in a lower limit, this process is not subject to review by anyone other than NDDH. The permit limit should require compliance with both a percent emission reduction <u>and</u> a numeric limit, not a choice of one or the other.

We ask that the analysis of the Heskett facility be considered in the context of the far-reaching impacts of the facility's emissions on air quality, visibility, public lands and public health. The Heskett facility is likely more appropriately considered under the BART rubric rather than Reasonable Progress. This analysis, like many in the Regional Haze Plan, seems to have overinflated costs, underestimated benefits, and a severely limited the pool of comparison for what is deemed "cost effective," thereby making reasonable technologies appear less so. There is no reason for NDDH to allow the Heskett facility to reduce its emissions a minimal amount when better, cost effective options exist.

Thank you for the opportunity to comment on the Reasonable Progress analysis of the Heskett facility.

Sincerely,

Mark Trechock, Staff Director
Dakota Resource Council
P.O. Box 1095
Dickinson, ND 58602-1095
701-483-2851

Stephanie Kodish
National Parks Conservation Association
706 Walnut Street, Suite 200
Knoxville, TN 37902
865-329-2424

CC: U.S. EPA Region 8
NPS, Air Resources Division

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
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(701) 222-7900

July 9, 2010

Mr. Terry O'Clair
Director
Division of Air Quality – 2nd Floor
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: Comments on the North Dakota Department of Health May 2010 Supplement No. 1 to the State Implementation Plan for Reducing Regional Haze

Terry
Dear Mr. O'Clair:

Montana Dakota Utilities Co. (Montana-Dakota) is submitting this letter to provide comment on Supplement No. 1 to the North Dakota State Implementation for Regional Haze (RH SIP Supplement) dated May 2010. Montana-Dakota generates, transmits and distributes electricity and distributes natural gas in North Dakota, South Dakota, Montana and Wyoming. The company owns and operates electric steam generating facilities which are subject to extensive regulation under the Federal Clean Air Act. The following comments pertain to R.M. Heskett Station Unit 2 (Heskett Unit 2) in the RH SIP Supplement.

The RH SIP Supplement incorporates a permit to construct (PTC) specific to Heskett Unit 2. Section II of the PTC acknowledges that certain physical changes that will be necessary to meet the sulfur dioxide conditions in this PTC may require a separate permit:

> *"While this Permit to Construct authorizes the construction and initial operation of new or modified air pollution control equipment and process changes to reduce sulfur dioxide emissions, the permittee may be required to apply for a Prevention of Significant Deterioration (PSD) permit to authorize any significant net emissions increase of particulate matter, PM10 and/or PM2.5 that will result from the installation of the new or modified pollution control equipment and process changes.*

This condition is unique to Heskett Unit 2 as compared to the other PTCs that will be issued to North Dakota power plants subject to BART and Reasonable Progress Goals; therefore, it is important to address possible timing concerns that arise from a situation where permitting delays to authorize a project could prevent meeting the compliance date specified in PTC condition II.A.2. Specifically, if a PSD permit is required in order to meet the conditions in the PTC, then the time necessary to complete PSD review can take several months and could potentially jeopardize the timing of project completion.

The purpose of this comment letter is to request that the RH SIP acknowledge the inherent risk in issuing a PTC for an emissions reduction when the PTC itself does not authorize changes to the facility that are necessary to meet the emissions reduction. We request that the following language be inserted on page 5 of the RH SIP Supplement at the end of the section titled "Time Necessary for Compliance" as evidence of this acknowledgement:

> *"The Department recognizes that limestone injection in the Unit 2 AFBC may potentially cause an increase in other pollutants for which a separate permit to construct, including a PSD permit, may be necessitated. If a related permit to construct is required, then that permitting schedule may impact the timing of the contemplated SO_2 emissions reductions permit attached to this supplement. The Department recognizes that the SO_2 reduction permit may need to be modified to address the schedule for processing any related permit action."*

Thank you for the opportunity to provide comments on the proposed RH SIP Supplement. Please contact me at (701) 222-7844 if you would like to discuss this further.

Sincerely,

Abbie Krebsbach
Environmental Manager

cc: Andrea Stomberg, Vice President Electric Supply
Alan Welte, Generation Manager
Tony Stroh, R.M. Heskett Station Manager

Appendix J.1.5
National Park Service
Consultation Comments on Supplement No. 1
And
Department's Response

NPS Preliminary Comments on Reasonable Progress Requirements for Montana Dakota Utilities (MDU) R.M. Heskett Station Unit #2
May 14, 2010

Montana Dakota Utilities (MDU) operates the R. M. Heskett Station Unit #2 near Mandan, North Dakota, about 160 km east of Theodore Roosevelt National Park (NP), a Class I area administered by the National Park Service. Heskett #2 includes an atmospheric bubbling fluidized bed boiler fired with lignite from an adjacent mine and is rated at 78 MW output. Current emission control equipment consists of an electrostatic precipitator.

Out of 3,558 Electric Generating Units (EGUs) in EPA's Clean Air Markets (CAM) database in 2008, Heskett #2 ranked #713 for SO_2 at 2,403 tons and #988 for NO_x at 432 tons. According to modeling results provided by MDU, emissions from Heskett #2 cause 0.3 dv of impairment in visibility at Theodore Roosevelt NP and 0.5 dv cumulatively when Lostwood National Wildlife Refuge is included. Consistent with EPA guidance, the North Dakota Department of Health (NDDH) has selected 0.5 dv at each Class I area individually as its significance level for triggering review under the Best Available Retrofit Technology (BART) program. Therefore, NDDH has determined that Heskett #2 is not subject to BART. However, NDDH did review Heskett #2 with respect to reasonable progress control requirements.

Reasonable Progress Control Technology Analysis

While the "standard" five-step BART analysis is not specified for analyses under the Reasonable Progress program, it provides a useful approach that is consistent and comparable to actual BART analyses.

Sulfur Dioxide

Step 1: Identify All Available Technologies
We agree that NDDH has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDH's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
We disagree with NDDH's estimates of 94% control effectiveness of limestone injection and a spray-dryer with a baghouse to achieve 0.09 lb/mmBtu. For example, NDDH has issued two permits for fluidized bed boilers burning ND lignite in the past decade. According to EPA's RACT/BACT/LAER Clearinghouse (RBLC), NDDH issued a permit on 9/14/07 to Great River Energy for the 112 MW Spiritwood Station. That permit limited SO_2 emissions to 0.06 lb/mmBtu saying "SULFUR DIOXIDE CONTROL SYSTEM (LIMESTONE INJECTION AND SPRAY DRYER) WILL ACHIEVE 98.7% REMOVAL OF POTENTIAL EMISSIONS BASED ON THE WORST CASE 30 DAY

LIGNITE. THE REMOVAL RATE WILL BE 98.8% BASED ON THE WORST CASE 24 HOUR LIGNITE."

The RBLC also contains an entry for a permit issued by NDDH on 6/03/05 to MDU for the 220 MW Gascoyne Generating Station which states, "THE [98.9%] EFFICIENCY IS THE OVERALL REMOVAL EFFICIENCY OF POTENTIAL SO2 EMISSIONS (COAL-TO-STACK) USING BOTH LIMESTONE INJECTION AND A SPRAY DRYER. IT IS BASED ON BURNING LIGNITE THAT CONTAINS 1.0 % SULFUR (AS-RECEIVED) AND THE 30 DAY ROLLING AVERAGE EMISSION RATE OF 0.038 LB/MMBTU."

NDDH has presented no justification for the much lower 94% efficiency it used in its analysis.

We also disagree with NDDH's assumption that limestone injection into the fluidized bed can achieve only 60% control and reduce SO_2 no lower than 0.364 lb/mmBtu. It is generally accepted that a limestone fluidized bed boiler can inherently remove 90% of the uncontrolled SO_2.[1] Applying that 90% reduction to the 2.15 lb/mmBtu average uncontrolled emission rate provided by MDU yields a 0.215 lb/mmBtu emission rate from the boiler.

Step 4: Evaluate Impacts and Document Results

Despite repeated advice from EPA against using the CUECost model instead of the OAQPS Control Cost Manual (Cost Manual), MDU and NDDH have used the CUECost model to estimate the costs of the wet scrubber and spray-dryer options. We believe this has resulted in an overestimation of costs. For example, MDU has estimated the Total Capital Investment (TCI) for a spray-dryer at $37,564,351 or $482/kW. By comparison, the Colorado Department of Public Health and Environment has determined that BART for the 85 MW Martin Drake Unit #6 is a spray dryer with a TCI of $447/kW.

It is impossible from the data provided to evaluate MDU's estimates for operating costs. We request that MDU and/or NDDH provide an evaluation of operating costs in a manner that is transparent and similar to that presented in the Cost Manual. For example, in the evaluation of the spray-dryer option, we request estimates of use rates for solvent and reagent, waste generation rate, and the cost of electricity associated with the scrubber. NDDH and MDU have improperly increased the operation and maintenance costs by 36%--this is not supported and not allowed by the Cost Manual.

NDDH should support and explain its $9,815,000 estimate for the Total Annual Cost for the spray-dryer/baghouse combination.

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[1] For example, NDDH estimated that limestone injection would achieve 88% SO_2 control in its May 2007 analysis of Westmoreland Power's Gascoyne 500 MW circulating fluidized bed boiler.

Step 5: Evaluate Visibility Results
It is impossible from the data provided to evaluate MDU's estimates of the visibility improvements resulting from the control options evaluated. As noted by EPA in its May 12, 2010, letter, "...visibility improvements are likely underestimated by your hybrid modeling system..." NDDH should at least use the method described in the 12/09 BART modeling report.

<u>Nitrogen Oxides</u>

Step 1: Identify All Available Technologies
We agree that NDDH has chosen a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options
We agree with NDDH's selection of technically feasible options.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology
NDDH has assumed that SNCR can reduce NO_x emissions by 33%.[2] We believe that MDU's assumption of 40% NO_x reduction is more appropriate.

Step 4: Evaluate Impacts and Document Results
We believe that NDDH has overestimated the capital cost of SNCR by comparing the $52/kW cost at Heskett to an average[3] of costs from other BART analyses conducted by sources trying to avoid addition of SNCR. According to the Institute of Clean Air Companies,[4] "Typical SNCR capital costs (including installation) for utility applications are $5-15/kW, vendor scope, which corresponds to a maximum of $20/kW if balance-of-plant capital requirements are included."

It is impossible from the data provided to evaluate MDU's estimates for SNCR operating costs. We request that MDU and/or NDDH provide an evaluation of operating costs in a manner that is transparent and similar to that presented in the Cost Manual.

We note that, while NDDH presented much lower Total Annual Costs based upon applying the Cost Manual approach, it provided neither its Cost Manual-based analysis nor a reason for rejecting the Cost Manual result in favor of the MDU cost which was more than two times higher.

Step 5: Evaluate Visibility Results
It is impossible from the data provided to evaluate MDU's estimates of the visibility improvements resulting from the control options evaluated. As noted by EPA in its May 12, 2010, letter, "...visibility improvements are likely underestimated by your hybrid modeling system..." NDDH should at least use the method described in the 12/09 BART modeling report.

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[2] NDDH estimated that SNCR would achieve 40% NO_X control in its May 2007 analysis of Westmoreland Power's Gascoyne 500 MW circulating fluidized bed boiler.
[3] which should not have included Heskett
[4] May 2000 White Paper on "Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions"

Time Necessary for Compliance
"The Department [NDDH] believes up to 6.5 years would be necessary for some control options (i.e., scrubbers and selective catalytic reduction)." We believe that such controls could be added much more expeditiously. For example, Minnesota Power has advised the MN Public Utilities commission of the following schedule for installation of a spray-dryer, carbon injection, SCR and a baghouse at its 330 MW Boswell Unit #3.

Minnesota Power's Boswell 3 Environmental Improvement Plan
submitted
October 27, 2006
to the
Minnesota Public Utilities Commission
Docket No. E015/M-06-1501

Pursuant to Minn. Stat. §§ 216B.6851, subd. 5, 216B.1692, the following table presents the planned schedule for implementation activities:

Activity	Timeline
Phase 1 - Conceptual Engineering	
Target Procurement Activities - Environmental Equipment	Apr 2006 - Oct 2006
Target Procurement Activities - Turbine/Generator	Oct 2006 - May 2007
Phase 2 - Final Design & Procurement	
Fabricate/Deliver - SCR (incl. major steel and truss work)	Jun 2007 - May 2008
Fabricate/Deliver - Fabric Filter	Apr 2008 - May 2008
Fabricate/Deliver - FGD System	Dec 2007 - Jun 2008
Fabricate/Deliver - Turbine/Generator	Jun 2007 - Dec 2008
Phase 3 - Construction	
Site Preparation	Apr 2007 - Jun 2007
Construction - SCR	Jun 2007 - Jun 2009
Construction - Fabric Filter	Jun 2007 - May 2009
Construction - FGD	Jun 2007 - Jun 2009
Construction - Chimney/Monitoring Equipment	Apr 2009 - Jun 2009
Construction - Turbine/Generator	Jan 2009 - Nov 2009
Phase 4- Start-Up	
Checkout & Commission for Tuning	Dec 2008 - Jun 2009
Final Plant Start-Up and Tuning	Apr 2009 -Sep 2009

Results, Conclusions & Recommendations

- MDU is proposing to voluntarily replace the sand in the fluidized bed with limestone to improve SO_2 capture to 0.60 lb/mmBtu. We believe that this approach is capable of much lower (e.g., 0.20 lb/mmBtu) SO_2 emissions.

- NDDH has improperly relied upon the CUECost model to estimate costs instead of the OAQPS Control Cost Manual approach recommended by EPA.
- NDDH should show the parameters used to estimate operating costs so that these critical evaluations are transparent and can be evaluated by outside parties.
- NDDH has overestimated the costs of the spray-dryer/baghouse option, and underestimated its benefits.
- NDDH should base its estimates of SNCR Total Capital Investment costs upon industry data for actual installations instead of inflated cost estimates provided by MDU and other sources seeking to avoid additional controls.
- NDDH presented much lower Total Annual Costs based upon an application of the Cost Manual approach and should provide that analysis as well as a reason for rejecting the Cost Manual result in favor of the MDU cost which was more than two times higher.
- NDDH is proposing no additional NO_x reductions. We believe that a proper analysis that reflects the higher control efficiency and lower costs of SNCR may result in significantly better cost-effectiveness, and lead to a different conclusion.
- NDDH should at least use the method described in the 12/09 BART modeling report.

Response to
National Park Service
Comments
May 14, 2010

Sulfur Dioxide:

1. The NPS does not agree with 94% reduction of SO_2 from limestone injection and a spray dryer.

Response
Heskett Unit 2 is an atmospheric bubbling fluidized bed boiler, not a circulating fluidized bed boiler like the Gascoyne 175 and Gascoyne 500 plants. In addition, this unit was not originally designed as a bubbling fluidized bed combustor. It was converted from a spreader stoker design to a bubbling bed combustor in 1986. Thus, this unit may not be able to achieve 90% reduction by limestone injection that was proposed for the Gascoyne plants. North Dakota has one other bubbling bed combustor operating at Red Trail Energy, LLC. This boiler has not been able to achieve 90% SO_2 reduction with limestone injection. This boiler has both limestone injection and sodium bicarbonate injection into the flue gas (estimated at 70-90% efficiency). The two systems at this bubbling fluidized bed combustor have achieved a maximum combined SO_2 removal efficiency of 92.1%. In the BACT review for Red Trail Energy, it was estimated that limestone injection and a spray dryer would reduce SO_2 emissions by 93% at this bubbling fluidized bed combustor. This is primarily due to a lower removal efficiency for limestone injection. The amount of SO_2 removal by limestone injection plus a spray dryer at Heskett Unit 2 is not known at this time due to its retrofit status. However, the Department believes 94% is reasonable based on the uncertainties (retrofit) and the experience with Red Trail's bubbling fluidized bed combustor. The evaluated emission rate of 0.055 lb/10^6 Btu is very similar to the Gascoyne 500 value of 0.06 lb/10^6 Btu for a spray dryer plus limestone injection.

Regarding limestone injection, the additional 60% SO_2 reduction by limestone injected into the combustor equates to 82% overall reduction within the combustor. Based on our experience with Red Trail and the fact that Heskett Unit 2 was not originally designed as a bubbling fluidized bed unit, we believe 82% is reasonable.

2. NDDH has used the CUE Cost Model to generate costs for wet scrubber and spray dryer instead on the Control Cost Manual.

Response
The commenter is incorrect in this statement. The costs that were used in this evaluation for a spray and wet scrubber were provided by MDU. The NDDH only used the CUE Cost model to verify MDU's cost estimates. MDU provided a site specific cost estimate for the wet scrubber and spray dryer using the Control Cost Manual procedures. Additional information has been provided to show the specifics of each cost estimate.

The NPS points out that the Colorado Department of Public Health estimated the cost of a spray dryer at Martin Drake Unit #6 at $447/kw compared to $482/kw at Heskett Unit 2. This is a 7.8% difference in the cost of the spray dryer. Site specific factors can easily account for this amount of difference. In addition, the estimate for controls for Reasonable Progress, as well as BART, only have to have a $\pm$30% accuracy. The estimate provided by MDU is well within this range when compared to the estimate for Martin Drake Unit #6.

3. The NDDH should support and explain its $9,815,000 estimate for the Total Annual Cost for the spray dryer/baghouse combination.

   Response
   The cost for the spray dryer/baghouse was provided by MDU and adjusted to 2009 dollars. MDU Used the Control Cost Manual procedures for estimating the cost. Details of the analysis have been included in the supplement.

4. As noted by EPA in its May 12, 2010, letter "...visibility improvements are likely underestimated by your hybrid modeling system; NDDH should use the modeling method described in the 12/09 BART Modeling report."

   Response
   States in the west are relying on WRAP's modeling to establish Regional Haze visibility improvement progress much like we suspect EPA will for their own purposes in preparing the Montana Regional Haze SIP. As shown in Table 8.11 of our Regional Haze SIP, the Department's hybrid modeling approach predicts significantly greater improvement in visibility for the BART controls compared to WRAP's modeling. This was expected, given the more realistic treatment of point source plumes by Calpuff compared to WRAP's grid modeling. Therefore, it appears inconsistent for EPA, or the NPS, to argue that the Department's hybrid modeling system is underestimating visibility improvement, while accepting WRAP's modeling of visibility improvement for other states. The Department has included in Section 8.6 of our Regional Haze SIP submittal a Performance Evaluation of the hybrid modeling system. The results show very good agreement between modeled concentrations and observed concentrations at the 98th percentile, 90th percentile, average of the 20% worst days and annual average.

   The comment also suggests that the modeling results should include the 98th percentile results. We believe including the 98th percentile results is contrary to rule and EPA guidance on this issue. In 40 CFR 51.308(d) it states "The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 states "most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment." Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

The Department is not aware of any EPA guidance that indicates the 98th percentile visibility results should be used. To the contrary, in EPA's document "Additional Regional Haze Questions" August 3, 2006, this issue is addressed. In the response to Question 1 under the Reasonable Progress section it states "Unlike the technical demonstration for CAIR or BART, the reasonable progress demonstration involves a test of a strategy. The strategy includes a suite of controls that has been identified through the identification of pollutants and source categories of pollutants for visibility impairment – the possible controls for these pollutants (and their precursors) and source categories – **the application of four statutory factors and how much progress is made with a potential strategy with respect to the glide path. Modeling occurs with a strategy and is not a source-specific demonstration like the BART assessment.** [emphasis added]

The response to Question 2 in the "Additional Regional haze Questions" document, it is stated "Reasonable progress is not required to be demonstrated on a source-by-source basis. It is demonstrated based on a control strategy developed from a suite of controls that has been **assessed with the four statutory factors and the uniform rate of progress**. [emphasis added]

It is clear to the Department that a BART type assessment (i.e. 98th percentile) is not required. In fact, an assessment of individual sources is not required. The Response to both Question 1 and 2 indicates any modeling should be assessed against the uniform rate of progress (glidepath). Section 2.2 of "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program", the uniform rate of progress, or glidepath, is determined for the average of the 20% worst days and 20% best days.

The Department has provided both the individual modeling results for sources and the cumulative modeling results for a control strategy for the group of sources that were left after the initial evaluation process was completed (see Section 9.5.1 of the RH SIP). We interpret the EPA guidance on Reasonable Progress to indicate that results for individual sources are not required. Therefore, any results presented would not have to include the 98th percentile values and should be compared to the average of the 20% worst days.

Nitrogen Oxides

1. We believe that NDDH has overestimated the capital cost of SNCR.

Response

The cost for SNCR that was used in the analysis was provided by MDU (adjusted to 2009 dollars). The Department verified the cost by comparing MDU's estimate to other similar sized facilities. MDU's estimate was near the middle of the range of costs evaluated. MDU's estimate is a site specific estimate for a combustion unit that was retrofitted to be a fluidized bubbling bed combustor. The details of the estimate have been included in the supplement. The NDDH believes the estimate is within the ±30% accuracy required for this analysis and more accurate since it is site specific.

The annual operating cost was $1,041,000 per year (2009 dollars) or $13.36/kw. This is nearly identical to the SNCR annual operating cost at M.R. Young Station Unit 1 of $13.44/kw (2006 dollars) and $14.06/kw (2006 dollars) at Stanton Unit 1. The operators of M.R. Young Station have not tried to avoid putting on SNCR. In fact, it may be just the opposite. The Stanton Unit 1 estimate was made using EPA's Control Cost Manual. The NDDH believes the MDU estimate is within the $\pm$30% accuracy required for this analysis.

2. Visibility modeling should use the method described in the 12/09 BART modeling report.

Response
See response to Comment 4 under the sulfur dioxide section.

Time Necessary for Compliance

The NPS believes controls can be added more expeditiously.

Response
The Department provided a time necessary for installing the top control technologies that were considered cost effective. The amount of time will be affected by an available work force and scheduled outages. Several sources have begun working on BART controls early because of concerns about product and work force availability. We believe the amount of time is reasonable for a source subject to the Reasonable Progress requirements.

Results, Conclusions and Recommendations

1. The voluntary control of limestone injection can achieve a lower SO_2 emission rate than 0.60 lb/10^6 Btu.

Response
The NDDH has determined that no additional controls are required under the Reasonable Progress portion of the Regional Haze rules. The addition of limestone is somewhat voluntary by MDU. The 0.60 lb/10^6 Btu emission rate is the rate that MDU is comfortable that the particulate matter emission limits can be met using an electrostatic precipitator. An optimization study will be conducted to determine if a greater sulfur dioxide removal efficiency can be achieved. If it can, the proposed permit requires the lower emission rate (greater removal efficiency).

2. NDDH should not rely on the CUE Cost model.

Response
See response to Comments 2 and 3 in sulfur dioxide section and Comment 1 of the nitrogen oxides section.

3. NDDH should show the parameters used to estimate costs.

Response
The beginning of the supplement discusses the source characteristics, capacity, baseline emission rates, estimated control efficiencies, etc. The inlet sulfur content is shown in the excerpts from MDU's draft BART analysis. All the information needed to estimate the operating cost, and the capital cost, is available.

4. NDDH has overestimated the cost of spray dryer/baghouse option.

Response
See response to Comments 1 and 2 in the sulfur dioxide section.

5. NDDH should base its estimates on SNCR Total Capital Investment Costs on industry data instead of inflated estimates by sources seeking to avoid controls.

Response
The Department has made a comparison of MDU's estimated capital and annualized costs to other estimates in BART analyses. This comparison showed very good agreement with the average of all units. The annualized cost agrees very well with estimates for the M.R. Young Station and Leland Olds Station on a dollar-per-kilowatt basis. The NPS has been using the out-of-date EPA Control Cost Manual to estimate costs. The NDDH believes the site specific estimate for Heskett Unit 2 is reasonable based on the estimates provided for other facilities.

6. NDDH should provide reasons for rejecting the Cost Control Manual results in favor of the MDU results.

Response
See response to Comment 6 of this section and page 3 of the Supplementary Cost Information.

7. NPS believes a proper NO_x cost analysis will lead to a different conclusion about costs.

Response
The NDDH believes the site-specific cost estimate provided MDU is sufficiently accurate for the Reasonable Progress analysis (see Response to Comment 1, Nitrogen Oxides section and Comments 2, 5 and 6 of this section). The amount of visibility improvement in the most impaired days for the application of SNCR will be less than 0.009 deciviews (estimated at 0.001 deciviews). This amount of visibility improvement is negligible. As stated in EPA's Guidance for Settling Reasonable Progress Goals under the Regional Haze Program (June 1, 2007), the NDDH has the right to include other relevant factors in its decision on reasonable progress. The cost of SNCR on a dollar-per-ton and dollar-per-deciview basis is excessive. The negligible amount of visibility improvement and the cost clearly indicates SNCR is not reasonable.

8. NDDH should use the BART modeling methodology.

Response

See response to Comment 4 in the Sulfur Dioxide section.

Appendix J.3.3
U.S. Environmental Protection Agency
Comments on Supplement No. 1
And
Department's Response

ENCLOSURE 1

EPA Region 8 Preliminary Comments on March 8, 2010 Draft Regional Haze SIP Supplement Number 1 (FLM Consultation Version)

General Comment

- As noted in our January 8, 2010 comment letter for Antelope Valley Station and Coyote Station, based on your analysis, there appear to be available controls for Heskett Station Unit 2 under Reasonable Progress that carry similar costs to those found reasonable under BART. Given that the potential visibility improvements are likely underestimated by your hybrid modeling system, the analysis does not support your conclusions that it is not reasonable to impose these controls at this time. For further guidance, please refer to the Regional Haze Rule (64 FR 35732, July 1, 1999).

Detailed Comments

SIP Text:

1. Reasonable Progress Goals – Required Controls for Point Sources and Table 9.9, Visibility Improvement and Cost Effectiveness:
   North Dakota Department of Health (NDDH) has chosen to heavily rely on visibility improvement to reject Reasonable Progress controls for Heskett Station Unit 2 and other facilities on a unit-by-unit basis. However, visibility improvement is not one of the four Reasonable Progress statutory factors (cost of compliance, time necessary for compliance, energy/non-air quality environmental impacts of compliance, and remaining useful life of any potentially affected sources). While we think the State has the flexibility to consider visibility improvement for individual unit controls in its decision-making, we have concerns with the State's methodology.

   When considering visibility improvement associated with controls at individual units, we consider it important to include the 98th percentile day results in addition to the 20% worst days' results. Looking only at the 20% worst days dilutes the beneficial impacts of individual unit controls. We recognize that part of the focus in setting the reasonable progress goals vis-a-vis the uniform rate of progress is on the 20% worst days, but the uniform rate of progress and the reasonable progress goals represent cumulative impacts and reductions across a range of sources and source categories. In that context, a cumulative regional scale deciview improvement value may have a different meaning because it is compared to a value needed to reach the uniform rate of progress. For example, while a deciview improvement of 0.1 deciview might not seem significant in an absolute sense, it may be significant if total deciview improvement needed to reach the uniform rate of progress is 1 or 2 deciviews. For evaluating individual unit visibility impacts, the BART approach represents the more reasonable model because it is specifically geared to consideration of unit-by-unit impacts. In our view, since the 98th percentile day results are used in determining BART, they should also be used in determining Reasonable Progress controls for individual units. Also, a relatively low visibility benefit for controlling an individual unit should not be a major factor when selecting Reasonable Progress measures; given the ultimate purpose of the Regional Haze program, cumulative effects across sources need to be considered. Heskett Station and other power plants are some of the larger emitters in the State and controls are available at reasonable cost effectiveness levels.

2. Table 9.8, Control Options Cost:
   Table 9.8 requires some clarification. The statement in the middle of the table with an asterisk is unclear and could perhaps be deleted. Regarding footnote b, as the State used the Montana-Dakota Utilities Company (MDU) estimate, the references to Leland Olds and M.R. Young should be removed to eliminate confusion. NDDH references information related to the PGE Boardman plant. EPA Region 10 has not determined that these analyses are reasonable. Furthermore, in general we do not recommend relying on the CUECost model. This was the model that MDU primarily used to estimate the costs that you refer to in your analyses. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual where possible (70 FR 39166, July 6, 2005).

3. Section 10.6.1.3, R.M. Heskett Station Unit 2:
   It appears that MDU and NDDH believe at least this minimal level of control is reasonable now. As such, it should be included as a required Reasonable Progress control in the SIP. NDDH notes that MDU has committed to increase SO_2 removal efficiency to a minimum of 70% in this planning period. We note that in a June 9, 2006 letter from MDU to Terry O'Clair, MDU commits to "control SO_2 emissions by installing and operating the necessary equipment to use limestone as the bed material in the boiler." Is this still the intended technical approach for limestone injection? We suggest language be included in the SIP text to clarify the intended technical approach for limestone injection. In addition, the proposed 0.60 lb/MMBtu emission limit is problematic; as discussed in comment 5 below, a more stringent limit is appropriate and reflects optimal use of the control technology.

<u>NDDH Proposed Permit to Construct – Heskett Station:</u>

4. Based on your discussions with MDU, it appears that this level of minimal control is considered reasonable at this time. Therefore, even if you disagree with our other comments regarding Reasonable Progress, at least this level of SO_2 control should be included in the SIP as a required Reasonable Progress control measure. As such, the permit should more closely mirror the BART permit format, including the appropriate 30-day rolling average emission limit and compliance determination, monitoring, recordkeeping, and reporting requirements.

5. Based on our review of the control efficiency and emission rate specified in the proposed permit, the emission limit should calculate out to 0.38 lb/MMBtu, not 0.60 lb/MMBtu. The permit control efficiency of 70% removal is on a basis of SO_2 equivalent to the boiler inlet, while the 60% control efficiency that appears in Supplement No. 1 is on the basis of

uncontrolled SO_2 in the exhaust stream. Considering that your analysis and cost estimates are based on the latter, the permit limits should be revised to be consistent with the findings in the analysis.

According to the Clean Air Markets Division database, the highest uncontrolled emission rate (exhaust) at Heskett Station Unit 2 in the past ten years was 0.95 lb/MMBtu. At 60% control this equates to a 0.38 lb/MMBtu limit. In comparison, we find the 0.60 lb/MMBtu specified in the proposed permit represents an excessive margin of compliance, at only about 37% control. We would expect that the proposed permit specify an initial limit in the vicinity of 0.38 lb/MMBtu. If NDDH has reason to believe a lower limit might not be achievable, the permit could include a provision to adjust the limit upward, pending review of stack test results. In order to adjust the permit limit later, a SIP revision would be required. An optimization study that is not defined in the permit and is subject only to NDDH approval (not EPA approval) does not ensure, in terms of federal enforceability, that the source will ultimately be subject to an emission limit in lb/MMBtu that corresponds to at least 60% control. If NDDH wants to require an optimization study to determine if controls can do better than 0.38 lb/MMBtu and 60% control, we would have no issue with that.

NORTH DAKOTA
DEPARTMENT *of* HEALTH

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May 27, 2010

Ms. Callie Videtich
Director, Air Program
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Comments on RH SIP
Supplement No. 1

Dear Ms. Videtich:

This letter is in response to comments that your staff provided on the Department's Supplement No. 1 to the North Dakota State Implementation Plan for Regional Haze. With respect to the comments, our responses are as follows:

General Comment

As noted in our January 8, 2010 comment letter for Antelope Valley Station and Coyote Station, based on your analysis, there appear to be available controls for Heskett Station Unit 2 under Reasonable Progress that carry similar costs to those found reasonable under BART. Given that the potential visibility improvements are likely underestimated by your hybrid modeling system, the analysis does not support your conclusions that it is not reasonable to impose these controls at this time. For further guidance, please refer to the Regional Haze Rule (64 FR 35732, July 1, 1999).

Response:

The only controls at Heskett Station Unit 2 that have costs on a dollar-per-ton basis that are similar to required BART controls are limestone injection for sulfur dioxide control and staged combustion for nitrogen oxides controls. Limestone injection has a cost of more than $116.7 million per deciview and staged combustion has a cost greater than $40.7 million per deciview. These costs are considered excessive. EPA Guidance (Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program; June 1, 2007) states "therefore, in assessing additional emissions reduction strategies for source categories or individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation". Clearly, cost on a dollar-per-deciview basis is one of the four statutory factors that must be evaluated. We have evaluated all four statutory factors.

The EPA Guidelines, Section 5.0, states "However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant." Since the purpose of the Regional Haze rules is to improve visibility in the Federal Class I areas, the Department has determined that actual visibility improvement by a reduction strategy for a source category, or source, is a relevant factor. The maximum improvement for the most impaired days is 0.009 deciviews when sulfur dioxide emissions from Heskett Station Unit 2 are reduced by 95% and nitrogen oxides by 40%. Any control alternative that reduces emissions by a smaller amount would have even less impact on visibility impairment. The 0.009 deciview improvement represents 0.05% improvement at Theodore Roosevelt National Park and Lostwood Wilderness Area. This amount of visibility improvement is negligible and does not warrant additional controls.

The comment also states "Given that the potential visibility improvements are likely underestimated by your hybrid modeling system, the analysis does not support your conclusions that it is not reasonable to impose these controls at this time." States in the west are relying on WRAP's modeling to establish Regional Haze visibility improvement progress much like we suspect EPA will for their own purposes in preparing the Montana Regional Haze SIP. As shown in Table 8.11 of our Regional Haze SIP, the Department's hybrid modeling approach predicts significantly greater improvement in visibility for the BART controls compared to WRAP's modeling. This was expected, given the more realistic treatment of point source plumes by Calpuff compared to WRAP's grid modeling. Therefore, it appears inconsistent for EPA to argue that the Department's hybrid modeling system is underestimating visibility improvement, while accepting WRAP's modeling of visibility improvement for other states.

The Department has included in Section 8.6 of our Regional Haze SIP submittal a Performance Evaluation of the hybrid modeling system. The results show very good agreement between modeled concentrations and observed concentrations for the 98th percentile, 90th percentile, average of the 20% worst days and the annual average. EPA has provided no basis for your statement that our hybrid modeling system is likely underestimating the amount of visibility improvement!

Based on the excessive cost and virtually no visibility improvement from additional air pollution controls, we have determined that no additional controls are reasonable at this time.

<u>SIP Test</u>

1. *Reasonable Progress Goals – Required Controls for Point Source and Table 9.9, Visibility Improvement and Cost Effectiveness:*

   North Dakota Department of Health (NDDH) has chosen to heavily rely on visibility improvement to reject Reasonable Progress controls for Heskett Station Unit 2 and other facilities on a unit-by-unit basis. However, visibility improvement is not one of the four Reasonable Progress statutory factors (cost of compliance, time necessary for compliance, *energy/non-air quality environmental impacts of compliance, and remaining useful life of any potentially affected sources). While we think the State has the flexibility to consider visibility improvement for individual unit controls in its decision-making, we have concerns with the State's methodology.*

When considering visibility improvement associated with controls at individual units, we consider it important to include the 98th percentile day results in addition to the 20% worst days' results. Looking only at the 20% worst days dilutes the beneficial impacts of individual unit controls. We recognize that part of the focus in setting the reasonable progress goals vis-à-vis the uniform rate of progress is on the 20% worst days, but the uniform rate of progress and the reasonable progress goals represent cumulative impacts and reductions across a range of sources and source categories. In that context, a cumulative regional scale deciview improvement value may have a different meaning because it is compared to a value needed to reach the uniform rate of progress. For example, while a deciview improvement of 0.1 deciview might not seem significant in an absolute sense, it may be significant if total deciview improvement needed to reach the uniform rate of progress is 1 or 2 deciviews. For evaluating individual unit visibility impacts, the BART approach represents the more reasonable model because it is specifically geared to consideration of unit-by-unit impacts. In our view, since the 98th percentile day results are used in determining BART, they should also be used in determining Reasonable Progress controls for individual units. Also, a relatively low visibility benefit for controlling an individual unit should not be a major factor when selecting Reasonable Progress measures; given the ultimate purpose of the Regional Haze program, cumulative effects across sources need to be considered. Heskett Station and other power plants are some of the larger emitters in the State and controls are available at reasonable cost effectiveness levels.

Response:

As stated in the response to the General Comment, the Department evaluated the cost on a dollar-per-ton and dollar-per-deciview basis (statutory factor). The Department also used its allowed discretion in evaluating the amount of actual visibility improvement (deciviews). After having considered all four statutory factors, and other relevant factors as allowed by EPA guidance, the Department has concluded that no additional controls are warranted. This decision was not based solely on the amount of visibility improvement as you have suggested.

The comment also suggests that the modeling results should include the 98th percentile results. We believe including the 98th percentile results is contrary to rule and EPA guidance on this issue. In 40 CFR 51.308(d) it states "The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 states "most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment." Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

The Department is not aware of any EPA guidance that indicates the 98th percentile visibility results should be used. To the contrary, in EPA's document "Additional Regional Haze Questions" August 3, 2006, this issue is addressed. In the response to Question 1 under the Reasonable Progress section it states "Unlike the technical demonstration for CAIR or BART, the reasonable progress demonstration involves a test of a strategy. The strategy includes a suite of controls that has been identified through the identification of pollutants and source categories of pollutants for visibility impairment – the possible controls for these pollutants (and their precursors) and source categories – **the application of four statutory factors and how much progress is made with a potential strategy with respect to the glide path. Modeling occurs with a strategy and is not a source-specific demonstration like the BART assessment. [Emphasis added]**

In response to Question 2, it is stated "Reasonable progress is not required to be demonstrated based on a source-by-source basis. It is demonstrated based on a control strategy developed from a suite of controls that has been **assessed with the four statutory factors and the uniform rate of progress**. [Emphasis added]

It is clear to the Department that a BART type assessment (i.e 98th percentile) is not required. In fact, an assessment of individual sources is not required. The Response to both Question 1 and 2 indicates any modeling should be assessed against the uniform rate of progress (glidepath). In Section 2.2 of "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program", the uniform rate of progress, or glidepath, is determined for the average of the 20% worst days or 20% best days.

The Department has provided both the individual modeling results for sources and the cumulative modeling results for a control strategy for the group of sources that were left after the initial evaluation process was completed (see Section 9.5.1 of the RH SIP). We interpret the EPA guidance on Reasonable Progress to indicate that results for individual sources is not required. Therefore, any results presented would not have to include the 98th percentile values and should be compared to the average of the 20% worst days.

With regard to cost, you claim that some of the controls are available at a reasonable cost. However, EPA has provided no guidance on cost effectiveness on either a dollar-per-ton, or more importantly, a dollar-per-deciview basis. As you have pointed out, other relevant factors may be considered in our decision regarding controls for Reasonable Progress. We believe the lack of visibility improvement by the addition of controls is extremely relevant.

2. *Table 9.8, Control Options Cost:*

Table 9.8 requires some clarification. The statement in the middle of the table with an asterisk is unclear and could perhaps be deleted. Regarding footnote b, as the State used the Montana-Dakota Utilities Company (MDU) estimate, the references to Leland Olds and M.R. Young should be removed to eliminate confusion. NDDH references information related to the PGE Boardman plant. EPA Region 10 has not determined that these analyses are reasonable. Furthermore, in general we do not recommend relying on the CUE Cost model.

This was the model that MDU primarily used to estimate the costs that you refer to in your analyses. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual where possible (70 FR 39166, July 6, 2005).

Response:

The statement in the middle of the table and footnote b will be removed.

Regarding the CUE Cost Model, the Department only used it to determine the cost of controls for Heskett Unit 2 for the purpose of checking MDU's estimate. Based on our testing of the CUE Cost Model for SNCR versus the Control Cost Manual, it appears they provide similar results. All costs were provided by MDU or extrapolated from other BART analyses. MDU used the Control Cost Manual Procedures to develop their cost estimate. Additional information has been included which provides the details of MDU's cost estimates.

The Department has also reviewed the estimated cost of the baghouse and compared it to the cost at Stanton Unit 1 and the Gascoyne 175 plant. The annualized cost for Stanton Unit 1 was $25.92/kw (2007 dollars) and $15.34/kw (2004 dollars) at Gascoyne 175. The annualized cost at Heskett Unit 2 is $16.66/kw (2009 dollars). Both the Stanton Unit 1 and Gascoyne 175 estimates were prepared using the procedures of the Control Cost Manual. We believe the estimate is accurate. The CUE Cost Model is easier to use and is provided by EPA. It appears to provide reliable results.

3. *Section 10.6.1.3, R.M. Heskett Station Unit 2:*

   It appears that MDU and NDDH believe at least this minimal level of control is reasonable now. As such, it should be included as a required Reasonable Progress control in the SIP. NDDH notes that MDU has committed to increase SO_2 removal efficiency to a minimum of 70% in this planning period. We note that in June 9, 2006 letter from MDU to Terry O'Clair, MDU commits to "control SO_2 emissions by installing and operating the necessary equipment to use limestone as the bed material in the boiler." Is this still the intended technical approach for limestone injection? We suggest language be included in the SIP text to clarify the intended technical approach for limestone injection. In addition, the proposed 0.60 lb/MMBtu emission limit is problematic; as discussed in comment 5 below, a more stringent limit is appropriate and reflects optimal use of the control technology.

Response:

The Department has determined that additional controls at Heskett Unit 2 are not reasonable at this time. The SO_2 reductions that will be achieved are an agreement between the Department and MDU and are not required by the Regional Haze rules.

The technical approach is still to use limestone in the bed of Heskett Unit 2 to achieve reductions from their current sulfur dioxide emission rate. Section 10.6.1.3 already indicates that limestone will be injected into the boilers. Whether the limestone will replace all of the bed material is unknown at this time. We believe Section 10.6.1.4 covers this issue.

NDDH Proposed Permit to Construct – Heskett Station

4. *Based on your discussions with MDU, it appears that this level of minimal control is considered reasonable at this time. Therefore, even if you disagree with our other comments regarding Reasonable Progress, at least the level of SO_2 control should be included in the SIP as required Reasonable Progress control measure. As such, the permit should more closely mirror the BART permit format, including the appropriate 30-day rolling average emission limit and compliance determination, monitoring, recordkeeping, and reporting requirements.*

Response:

Since we have determined that no additional controls are required under Reasonable Progress, we believe it is inappropriate to include the reductions that will be achieved at Heskett Station Unit 2 under that portion of the SIP. We have included the reductions in 10.6.1, Emission Reductions Due to Ongoing Air Pollution Control Programs. Because of our findings on the Reasonable Progress analyses and the somewhat voluntary nature of the reductions, we believe the discussion of the Heskett Unit 2 reductions is more appropriately included in this section. For the same reasons, we believe the Permit to Construct should afford MDU some flexibility in meeting the emission limits.

5. *Based on our review of the control efficiency and emission rate specified in the proposed permit, the emission limit should calculate out to 0.38 lb/MMBtu, not 0.60 lb/MMBtu. The permit control efficiency of 70% removal is on a basis of SO_2 equivalent to the boiler inlet, while the 60% control efficiency that appears in Supplement No. 1 is on the basis of uncontrolled SO_2 in the exhaust stream. Considering that your analysis and cost estimates are based on the latter, the permit limits should be revised to be consistent with the findings in the analysis.*

   According to the Clean Air Markets Division database, the highest uncontrolled emission rate (exhaust) at Heskett Station Unit 2 in the past ten years was 0.95 lb/MMBtu. AT 60% control this equates to a 0.38lb/MMBtu limit. In comparison, we find the 0.50 lb/MMBtu specified in the proposed permit represents an excessive margin of compliance, at only about 37% control. We would expect that the proposed permit specify an initial limit in the vicinity of 0.38 lb/MMBtu. If NDDH has reason to believe a lower limit might not be achievable, the permit could include a provision to adjust the limit upward, pending review of stack test results. In order to adjust the permit limit later, a SIP revision would be required. An optimization study that is not defined in the permit and is subject only to NDDH approval (not EPA approval) does not ensure, in terms of federal enforceability, that the source will ultimately be subject to an emission *limit in lb/MMBtu that corresponds to at least 60% control. If NDDH wants to require an optimization study to determine if controls can do better than 0.38 lb/MMBtu and 60% control, we would have no issue with that.*

Response:

The 70% reduction of potential SO_2 emissions is the rate that MDU believes can be achieved while still maintaining compliance with their particulate matter emission limit. Since Heskett Unit 2 is equipped with an electrostatic precipitator, not a baghouse, the Department believes an increase in particulate matter emissions is a concern. This is one of the reasons for the optimization study. In addition, the amount of SO_2 reduction from limestone injection at a retrofitted bubbling fluidized bed combustor is unknown. Our experience with Red Trail Energy's bubbling fluidized bed combustor indicates that the 80-90% removal rate at circulating fluidized bed combustion units may not be achievable at some bubbling fluidized bed units.

The Reasonable Progress analysis indicates a 60% reduction from the current actual emissions. This equates to an 82% reduction of the potential-to-emit. The agreement (included in the Permit to Construct) only requires an overall removal efficiency of 70% from the potential-to-emit. The agreement with MDU will reduce current emissions by about 34% (see Section 10.6.1.3). Using a baseline of 0.91 lb/10^6 Btu, this equates to 0.60 lb/10^6 Btu. Based on an annual average sulfur content of 0.71% and a heat content of 7100 Btu/lb, the potential-to-emit is 2.0 lb/10^6 Btu. Thirty percent of the sulfur reaching the inlet of the boiler (70% reduction of the inlet sulfur content) equates to 0.60 lb/10^6 Btu.

The Department cannot guarantee that emissions will be any lower than 0.60 lb/10^6 Btu after the optimization study is completed. If a lower rate can be achieved, the Permit to Construct requires the lower rate.

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:csc
xc: Abby Krebsbach, MDU