BART Determination
for
Milton R. Young Station Units 1 and 2

I. Source Description

A Owner Unit 1: Minnkota Power Cooperative, Inc.
B. Owner Unit 2: Square Butte Electric Cooperative
C. Operator Units 1 & 2: Minnkota Power Cooperative, Inc.
D. Source Type: Electric Utility Steam Generating Unit
E. BART Eligible Units

1. Unit 1 Boiler
2. Unit 2 Boiler
3. Auxiliary Boiler
4. Unit 1 Fire Pump
5. Unit 2 Fire Pump
6. Emergency Generator
7. Materials Handling Equipment

a. Unit 1 - Crusher House and Conveyer 1C
b. Unit 1 - Coal Silos
c. Unit 2 - Crusher House
d. Unit 2 - Coal Silos
e. Unit 1 - Flyash Silo Vent
f. Unit 1 - Flyash Silo (rotary unloader)
g. Unit 2 - Flyash Silo Vent
h. Unit 2 - Flyash Ash Silo (rotary unloader)
i. Unit 1 - Truck Dump
j. Unit 2 - Truck Dump
k. Water Treatment Plant Lime Storage Silo

D. Unit Description

1. Unit 1:

Generator Nameplate Capacity: 257 MWe
Boiler Rating: 3200 x 10^6 Btu/hr
Startup: 1970
Fuel: North Dakota Lignite Firing Method: Cyclone
Existing Air Pollution Control Equipment: Electrostatic Precipitator

2. Unit 2:

Generator Nameplate Capacity: 477 MWe
Boiler Rating: 6300 x 10^6 Btu/hr
Startup: 1975
Fuel: North Dakota Lignite
Firing Method: Cyclone
Existing Air Pollution Control Equipment: Electrostatic precipitator and wet scrubber

3. Auxiliary Boiler:

Boiler Rating: 78 x 10^6 Btu/hr
Fuel: #1 or #2 fuel oil

4. Unit 1 Fire Pump:
Rating: 237 Bhp

5. Unit 2 Fire Pump:
Rating: 190 Bhp
Fuel: Diesel fuel

6. Emergency Generator:
Rating: 355 Bhp
Fuel: Diesel fuel

7. Materials Handling Equipment:

   a. Unit 1 Crusher House and Conveyer 1C:
   Existing Air Pollution Control Equipment: Rotoclone

   b. Unit 1 Coal Silo:
   Existing Air Pollution Control Equipment: Rotoclone

   c. Unit 2 Crusher House:
   Existing Air Pollution Control Equipment: Rotoclone

   d. Unit 2 Coal Silos:
   Existing Air Pollution Control Equipment: Rotoclone

   e. Unit 1 Flyash Vent:
   Existing Air Pollution Control Equipment: Electrostatic Precipitator

f. Unit 1 Flyash Silo (rotary unloader):
Existing Air Pollution Control Equipment: None - fugitive emissions

g. Unit 2 Flyash Silo Vent:
Existing Air Pollution Control Equipment: Fabric Filter/Electrostatic Precipitator

h. Unit 2 Flyash Silo (rotary unloader)
Existing Air Pollution Control Equipment: None - fugitive emissions

i. Unit 1 Truck Dump:
Existing Air Pollution Control Equipment: None

j. Unit 2 Truck Dump:
Existing Air Pollution Control Equipment: None

k. Unit 2 Lime Storage Silo Vent:
Existing Air Pollution Control Equipment: Bin vent filter

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Unit 1 Boiler	SO_2 (tons)	18,095	23,179	19,958	18,020	21,586	20,148
	SO_2 (lb/10^6 Btu)	1.91	2.00	1.85	1.77	1.87	1.88
	NO_x (tons)	7,584	9,220	8,459	8,325	9,738	8,665
	NO_x (lb/10^6 Btu)	0.80	0.78	0.79	0.82	0.84	0.81
	PM (tons)	213	238	205	330	103	218
	PM (lb/10^6 Btu)	0.023	0.021	0.019	0.032	0.009	0.021
Unit 2 Boiler	SO_2 (tons)	21,078	12,377	8,707	10,064	9,795	12,404
	SO_2 (lb/10^6 Btu)	0.98	0.78	0.49	0.52	0.58	0.67
	NO_x (tons)	17,727	13,287	14,278	14,578	13,655	14,705
	NO_x (lb/10^6 Btu)	0.84	0.83	0.81	0.77	0.81	0.81
	PM (tons)	164	131	385	1885	109	535
	PM (lb/10^6 Btu)	0.008	0.008	0.022	0.097	0.006	0.028

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Auxiliary Boiler	SO_2 (tons) NO_x (tons)	<2 <1	<2 <1	<2 <1	<2 <1	<2 <1	<2 <1
Unit 1 Fire Pump	SO_2 (tons) NO_x (tons)	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1
Unit 2 Fire Pump	SO_2 (tons) NO_x (tons)	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1
Emergency Generator	SO_2 (tons) NO_x (tons)	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1	<1 <1
Unit 1 Crusher House	PM (tons)	0.4	0.4	0.4	0.4	0.4	0.4
Unit 1 Coal Silo	PM (tons)	0.5	0.6	0.5	0.5	0.6	0.4
Unit 2 Crusher House	PM (tons)	0.2	0.1	0.1	0.1	0.1	0.1
Unit 2 Coal Silo	PM (tons)	2.4	2.0	2.4	2.3	2.0	2.2
Unit 2 Flyash Silo Vent	PM (tons)	<1	<1	<1	<1	<1	<1
Unit 1 Truck Dump	PM (tons)	10.0	11.1	10.6	8.9	11.2	10.4
Unit 2 Truck Dump	PM (tons)	20.4	16.7	20.1	19.8	17.1	18.8
Unit 2 Lime Storage Silo Vent	PM (tons)	<1	<1	<1	<1	<1	<1
Unit 1 Flyash Silo Vent	PM (tons)	<1	<1	<1	<1	<1	<1
Lime Storage Silo	PM (tons)	<1	<1	<1	<1	<1	<1

II. Site Characteristics

The M.R. Young Station is located in east central Oliver County near the town of Center, North Dakota. The facility receives its lignite from BNI Coal Ltd.'s Center Mine which is located immediately adjacent to the plant. The original design of Unit 1 only incorporated a multiclone for air pollution control, the electrostatic precipitator was added in the 1970s. Unit 2 was built with an electrostatic precipitator and a wet scrubber. Because of the original design and the close proximity to Nelson Lake, there are some space constraints at the facility. Minnkota has not indicated that the space constraints are insurmountable. Therefore, site constraints are an economic issue when evaluating the various control alternatives.

III. BART Evaluation of Unit 1

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Powerspan ECO®
Fuel Switching
Coal Cleaning

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located near Nelson Lake, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Center Mine was tested. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

A recent decision by the Seventh Circuit Court of Appeals on a BACT for Prairie Generating Company, LLC indicated that fuel switching was not required for mine mouth coal generating facilities. The Department believes the decision would also apply to BART determinations. Therefore, the Department did not consider coal switching.

The Department considers the Powerspan ECO® technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the information provided by Minnkota Power Coop. in their Annual Emission Inventory Reports, the Department has calculated the baseline emission rate (2001-2002) at 21,519 tons per year.

Alternative	Control Efficiency (%)	Baseline Emissions (tons/yr)	Emissions*	
			(tons/yr)	(lb/106 Btu)
Wet Scrubber	95	21,519	1,076	0.10
Circulating Dry Scrubber	93	21,519	1,506	0.14
Spray Dryer	90	21,519	2,152	0.20

* Emission rate (lb/10^6 Btu) is an annual average rate. Future coal is expected to have higher sulfur content and a higher emission rate.

The cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Wet Scrubber	20,443	22,584,000	1,105	N/A
Circulating Dry Scrubber	20,013	24,650,000	1,232	N/A
Spray Dryer	19,367	23,676,000	1,222	N/A

* Costs for wet scrubber and spray dryer provided by Minnkota. Circulating Dry Scrubber costs are the Department's estimate based on costs provided by Basin Electric for Leland Olds Unit 2.

Step 4: Evaluate Impacts and Document Results

Minnkota has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of either a wet scrubber or spray dryer.

Step 5: Evaluate Visibility Results

The alternatives are a wet scrubber operating at 95% removal efficiency, a circulating dry scrubber at 93% control and a spray dryer operating at 90% efficiency. Minnkota has proposed to install a wet scrubber operating at 95% removal efficiency. Since this is the most efficient technology, an evaluation of the impact on visibility for each alternative was not necessary. However, Minnkota did evaluate the impact on visibility for the 95% and 90% control options. The results based on the 90th and 98th percentile value are shown in the following tables.

Unit 1
Delta Deciview
90th Percentile
SO_2

Year	Unit	90% Control	95% Control	Difference
2000	TRNP-SU	0.200	0.167	0.033
2001	TRNP-SU	0.302	0.095	0.207
2002	TRNP-SU	0.258	0.247	0.011
Average	TRNP-SU	0.253	0.170	0.084
2000	TRNP-NU	0.157	0.144	0.013
2001	TRNP-NU	0.419	0.117	0.302
2002	TRNP-NU	0.244	0.222	0.022
Average	TRNP-NU	0.273	0.161	0.112
2000	Elkhorn Ranch	0.122	0.109	0.013
2001	Elkhorn Ranch	0.209	0.068	0.141
2002	Elkhorn Ranch	0.155	0.148	0.007
Average	Elkhorn Ranch	0.162	0.108	0.054
2000	Lostwood W.A.	0.277	0.274	0.003
2001	Lostwood W.A.	0.488	0.280	0.208
2002	Lostwood W.A.	0.201	0.189	0.012
Average	Lostwood W.A.	0.322	0.248	0.074
Overall Average		0.253	0.172	0.081

Unit 1 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**90% Control**	**95% Control**	**Difference**
2000	TRNP-SU	0.594	0.583	0.011
2001	TRNP-SU	1.219	0.635	0.584
2002	TRNP-SU	1.768	1.694	0.074
Average	TRNP-SU	1.194	0.971	0.223
2000	TRNP-NU	1.097	0.762	0.335
2001	TRNP-NU	1.833	0.837	0.996
2002	TRNP-NU	1.594	1.522	0.072
Average	TRNP-NU	1.508	1.040	0.468
2000	Elkhorn Ranch	0.528	0.482	0.046
2001	Elkhorn Ranch	1.049	0.525	0.524
2002	Elkhorn Ranch	1.589	1.533	0.056
Average	Elkhorn Ranch	1.055	0.847	0.209
2000	Lostwood W.A.	0.870	0.820	0.050
2001	Lostwood W.A.	2.003	1.194	0.809
2002	Lostwood W.A.	0.899	0.839	0.060
Average	Lostwood W.A.	1.257	0.951	0.306
Overall Average		1.254	0.952	0.301

Step 6: Select BART

The cost effectiveness is reasonable for all technologies evaluated and the incremental cost from one technology to another is not excessive. There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. Minnkota has proposed that BART is a wet scrubber operating at 95% control efficiency. The Department concurs with the use of a wet scrubber achieving a 95% reduction efficiency. Minnkota is a party to a Consent Decree which resolved alleged New Source Review violations at the M.R. Young Station. The Consent Decree states that if Minnkota installs a wet scrubber, they must comply with a 95% reduction requirement with no alternative emission rate ($lb/10^6$ Btu) limit. Therefore, the Department proposes that BART is a reduction efficiency of 95% of the inlet sulfur dioxide concentration to the scrubber on a 30-day rolling average basis (30 d.r.a.).

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator (Upgrade)

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

The baseline emission rate from Unit 1 was calculated by the Department at 268 tons per year based on data for 2002-2003.

Alternative	Control Efficiency	Emissions	
		(tons/yr)	($lb/10^6$ Btu)
Baghouse	99.7+	134	0.013
New ESP	99.7	158	0.015
CoHPAC	99.7	158	0.015
Baseline (Existing ESP)	99.0	268	0.026

Alternative	Emissions* Reduction (tpy)	Annualized** Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baghouse	134	5,284,000	39,433	37,545***
New ESP	90	4,643,000	51,589	N/A
CoHPAC	90	3,632,000	40,355	40,355
Baseline (Existing ESP)	0	1,822,000	---	

* Reductions from the baseline emission rate.
** Costs provided by Minnkota.
*** Incremental cost between baghouse and CoHPAC. New ESP is an inferior option since it costs more than CoHPAC with no additional emissions reductions.

Step 4: Evaluate Impacts and Document the Results

Minnkota has evaluated the energy and non-air quality effects of each option. The Department has determined that the effects will not preclude the selection of any of the options.

Step 5: Evaluate Visibility Impacts

The different alternatives were not modeled because of the high cost effectiveness. However, the maximum 24-hour emission rate during the baseline period was modeled. The results are as follows:

Unit 1 Delta Deciview PM			
Year	Unit	90th Percentile	98th Percentile
2000	TRNP-SU	0.0004	0.0015
2001	TRNP-SU	0.0006	0.0048
2002	TRNP-SU	0.0016	0.0023
Average	TRNP-SU	0.0007	0.0029
2000	TRNP-NU	0.0002	0.0004
2001	TRNP-NU	0.0011	0.0007
2002	TRNP-NU	0.0004	0.0059
Average	TRNP-NU	0.0006	0.0023
2000	TRNP-Elkhorn Ranch	0.0003	0.0010
2001	TRNP-Elkhorn Ranch	0.0002	0.0031
2002	TRNP-Elkhorn Ranch	0.0004	0.0020
Average	TRNP-Elkhorn Ranch	0.0003	0.0020
2000	Lostwood W. A.	0.0018	0.0007
2001	Lostwood W.A.	0.0013	0.0058
2002	Lostwood W. A.	0.0015	0.0007
Average	Lostwood W. A.	0.0015	0.0024
Overall Average		0.0013	0.0024

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the new baghouse. This system has a cost effectiveness of $39,433 per ton of particulate when compared to the current emission control system (ESP operating at 99.0% efficiency). The Department considers this cost to be excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit is equipped with an electrostatic precipitator that is achieving 99.0% Control efficiency. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate emitted was eliminated, the most improvement in visibility at any Class I area would be approximately 0.0015 deciviews based on the 3-year average of the 90th percentile (0.0024 deciviews based on the 98th percentile). The Department considers this amount of improvement to be insignificant. Since none of the control alternatives will eliminate all of the particulate matter emissions, the visibility improvement will be even less.

After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Minnkota is under a Consent Decree which limits particulate emissions to 0.030 $lb/10^6$ Btu if they install a wet scrubber or 0.015 $lb/10^6$ if they install a dry scrubber with baghouse. Since Minnkota will install a wet scrubber, the Department proposes that BART is represented by an emission limit of 0.030 $lb/10^6$ Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by a wet scrubber. This technology will achieve a 40-60% reduction as sulfuric acid mist emissions.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

AP-42, Compilation of Air Pollutant Emission Factors[2], suggests the condensible particulate matter emission rate could be as high as 0.02 $lb/10^6$ Btu. This emission rate is less than the current emissions of filterable particulate matter. The emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO)
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced SNCR (HE-SNCR)
Rich Reagent Injection (RRI)
Rotomix® (ROFA + SNCR)
Conventional Gas Reburn (CGR)
CGR + SNCR w/separated overfire air (SOFA)
Coal Reburn
Coal Reburn + SNCR
Fuel Lean Gas Reburn (FLGR™)
FLGR™ + SOFA
Rotating Overfire Air (ROFA)
Separated Overfire Air (SOFA)
Advanced SOFA (ASOFA)
Combustion Improvements (Included with SOFA and ASOFA)
Oxygen Enhanced Combustion (OEC)

Step 2: Eliminate Technically Infeasible Options

Minnkota believes SCR is not technically feasible at the M.R. Young Station. The Department does not consider high dust SCR to be technically feasible at this time. However, the Department believes low dust and tail end and SCR have a good probability of successful application at M.R. Young Station (see discussion in Appendix B.5). Minnkota has determined the following technologies are also technically infeasible:

ECO®
HE-SNCR
RRI
Rotomix® (ASOFA + SNCR evaluated)
CGR + SNCR
Coal Reburn + SNCR
FLGR™ + SNCR
OEC®

The Department agrees with Minnkota's determination regarding technical feasibility, except for LDSCR and TESCR. ROFA, SOFA, and ASOFA are similar and only ASOFA will be evaluated further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Alternative	Control Efficiency* (%)	Emissions (tons/yr)	Emissions ($lb/10^6$ Btu)
SCR w/reheat + ASOFA	90	903	0.085
SNCR + ASOFA	58.1	3,784	0.355
Gas Reburn + ASOFA	56.0	3,974	0.374
Coal Reburn + ASOFA	54.6	4,100	0.385
FLGR + ASOFA	45.9	4,886	0.460
ASOFA	39.5	5,464	0.513
SNCR	37	5,690	0.535
SOFA/ROFA	<28	6,503	0.611
Baseline	0	9,032	0.849

* Control efficiency specified by Minnkota in their analysis except for SCR. The Department believes a reduction effiency of 90% for ASOFA and SCR is more appropriate on a long-term basis.
** Based on the Department's calculation of baseline emissions. The $lb/10^6$ Btu emission rate is an annual average rate.

The estimated costs for the most efficient alternatives are as follows:

Alternative	Emissions Reduction (tpy)	Annualized Cost ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Low Dust SCR + ASOFA	8,129	33,526,000/ 52,193,000	4,124/6,421	9,043/15,523
Tail End SCR + ASOFA*	8,129	39,307,000/ 56,095,000	4,835/6,901	11,050/16,877
SNCR + ASOFA	5,248	7,472,000	1,424	2,966***
Gas Reburn + ASOFA**	5,058	37,334,000	7,381	
Coal Reburn + ASOFA**	4,931	11,388,000	2,309	
FLGR + ASOFA	4,146	16,990,000	4,098	
ASOFA	3,568	2,489,000	698	

* Two different cost estimates are provided for SCR. This represents the range of costs provided by Minnkota for two different catalyst replacement scenarios and two different cost

bases – stand alone SCR systems for each unit and shared facilities.
** Inferior options to SNCR + ASOFA
*** Incremental cost for SNCR + ASOFA versus ASOFA

Minnkota has provided calculations of cost effectiveness and incremental cost effectiveness based on an NO_x removal efficiency of 93.8% and a baseline emission rate that is more reflective of potential emissions (the Department used 90% efficiency and historical data to calculate baseline emission rate). Minnkota used the most optimistic projections of efficiency and baseline emissions to show that LDSCR and TESCR are not cost effective even under those conditions. Minnkota's estimated costs are:

Alternative	Emissions Reduction (tons)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Low Dust SCR + ASOFA	9,348/9,401	33,526,000/ 52,193,000	3,586/5,552	7,575/12,806
Tail End SCR + ASOFA	9,345/9,398	39,307,000/ 56,095,000	4,206/5,969	9,264/13,936
SNCR + ASOFA	4,025	7,472,000	1,265	---
Coal Reburn + ASOFA	4,275	11,388,000	2,037	---
FLGR + ASOFA	4,343	16,990,000	3,635	---
ASOFA	5,260	2,489,000	613	---

*Range of costs using two different catalyst replacement schedules and two different cost bases – stand alone SCR systems and shared facilities between M.R. Young 1 and 2.

SCR technology has never been applied to a boiler that combusts North Dakota lignite. There are many unknowns that will affect the cost of either LDSCR or TESCR at the M.R. Young Station including:

1) The catalyst deactivation rate
2) Catalyst volume required
3) Catalyst surface area required
4) Required reagent injection rate
5) Expected reagent slip
6) Whether formation of ammonium bisulfate and/or ammonium sulfate will be at an acceptable rate
7) An appropriate catalyst maintenance plan

All of these will affect either the initial construction cost and/or annual operation and maintenance costs. The amount of catalyst required will affect the initial capital cost as well as the replacement cost. The life of the catalyst and the amount of reagent required will have a large impact on the annual operating cost. If a wet electrostatic precipitator is required to control ammonium bisulfate/ammonium sulfate emissions, both the initial capital cost and operation and maintenance costs will rise dramatically. Given the many unknowns with North Dakota lignite, estimating the cost of an SCR system is extremely difficult and subject to many different opinions regarding estimating procedures. The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate; however, the BART process cannot mandate that pilot testing be conducted to determine costs. The Department believes the cost estimate without pilot testing, although not ideal, will suffice based on the information that is available at the current time.

Step 4: Evaluate Impacts and Document Results

Minnkota has not identified any environmental impacts or energy impacts that would preclude of the use of any of the previously evaluated emission control alternatives.

Step 5: Evaluate Visibility Impacts

The Department has conducted modeling to determine the improvement in visibility for SCR + ASOFA versus SNCR + ASOFA. The results, based on the BART modeling guidelines, are as follows:

Unit 1 Delta Deciview 90th Percentile				
Year	**Unit**	**SCR + ASOFA**	**SNCR + ASOFA**	**Difference**
2000	TRNP-SU	0.032	0.094	0.062
2001	TRNP-SU	0.023	0.060	0.037
2002	TRNP-SU	0.044	0.118	0.074
Average	TRNP-SU	0.033	0.091	0.058
2000	TRNP-NU	0.025	0.068	0.043
2001	TRNP-NU	0.034	0.079	0.045
2002	TRNP-NU	0.046	0.131	0.085
Average	TRNP-NU	0.035	0.093	0.058
2000	Elkhorn Ranch	0.021	0.059	0.038
2001	Elkhorn Ranch	0.018	0.041	0.023
2002	Elkhorn Ranch	0.026	0.071	0.045
Average	Elkhorn Ranch	0.022	0.057	0.035
2000	Lostwood W.A.	0.045	0.139	0.094
2001	Lostwood W.A.	0.047	0.141	0.094
2002	Lostwood W.A.	0.037	0.102	0.065
Average	Lostwood W.A.	0.043	0.127	0.084
Overall Average		0.033	0.092	0.059

Unit 1 Delta Deciview 98th Percentile				
Year	**Unit**	**SCR + ASOFA**	**SNCR + ASOFA**	**Difference**
2000	TRNP-SU	0.098	0.265	0.167
2001	TRNP-SU	0.116	0.344	0.228
2002	TRNP-SU	0.294	0.847	0.553
Average	TRNP-SU	0.169	0.485	0.316
2000	TRNP-NU	0.118	0.342	0.224
2001	TRNP-NU	0.134	0.385	0.251
2002	TRNP-NU	0.263	0.734	0.471
Average	TRNP-NU	0.172	0.487	0.315
2000	Elkhorn Ranch	0.082	0.246	0.164
2001	Elkhorn Ranch	0.101	0.304	0.203
2002	Elkhorn Ranch	0.288	0.790	0.502
Average	Elkhorn Ranch	0.157	0.447	0.290
2000	Lostwood W.A.	0.134	0.421	0.287
2001	Lostwood W.A.	0.175	0.517	0.342
2002	Lostwood W.A.	0.148	0.435	0.287
Average	Lostwood W.A.	0.152	0.458	0.305
Overall Average		0.163	0.469	0.307

Step 6: Select BART

The cost effectiveness and incremental cost of LDSCR and TESCR is considered excessive or unreasonable. The visibility modeling results indicated only a 0.059 deciview (90^{th} percentile) average improvement for SCR + ASOFA versus SNCR + ASOFA (0.307 deciviews based on 98^{th} percentile). Because modeling based on the BART Guidelines (40 CFR 51, Appendix Y) overpredicts the visibility improvement in North Dakota (see Section 7.4.2), the Department conducted a modeling analysis to determine the amount of improvement when all sources are considered (cumulative analysis). The visibility will only improve 0.01 deciviews on average for the 20% worst days when SCR + ASOFA is compared to SNCR + ASOFA. The Department considers 0.01 deciviews improvement to be negligible.

The Department also considered the cost effectiveness and incremental costs of LDSCR and TESCR calculated by Minnkota. Both of these cost metrics are considered excessive over the entire range. The Department conducted dispersion modeling to determine the visibility improvement if SCR did achieve 93.8% reduction efficiency. The results indicate only a 0.011 deciview improvement in visibility on average for the 20% worst days when SCR + ASOFA is compared to SNCR + ASOFA. The amount of improvement is still negligible. Given the excessive cost and negligible visibility improvement, SCR + ASOFA is not considered BART for Unit 1.

Minnkota has proposed SNCR + ASOFA as BART. SNCR + ASOFA will achieve an emission rate of 0.355 $lb/10^6$ Btu on an annual average basis. The Department has determined that BART, during normal operations, is a limit of 0.36 $lb/10^6$ Btu on a 30-day rolling average basis.

Minnkota has requested a different limit during startup of the boiler. Minnkota's justification for the startup units is found in Section 3.5.2 of their BART analysis. Minnkota is under a Consent Decree which requires a BACT determination for nitrogen oxides. The Consent Decree (Paragraph 66) requires Minnkota to address specific limits during unit startups. Therefore, the proposed BACT and BART limit (which are identical) do not account for startups of the units. If it did, the proposed limit would be substantially higher. In order to harmonize the BACT limits with the BART limits, the Department is proposing separate BART emissions limits for NO_x during startup of Units 1 and 2.

The EPA Air Pollution Control Cost Manual[3] states "The NO_x reduction reaction occurs within a specific temperature range where adequate heat is available to drive the reaction. At lower temperatures the reaction kinetics are slow and ammonia passes through the boiler (ammonia slip). At higher temperatures the reagent oxidizes and additional NO_x is generated. The temperature window is dependent on the reagent utilized. Figure 1.3 shows the NO_x reduction efficiency for urea and ammonia SNCR at various boiler temperatures. For ammonia, the optimum temperature is from 870°C to 1100°C (1600°F to 2000°F)."

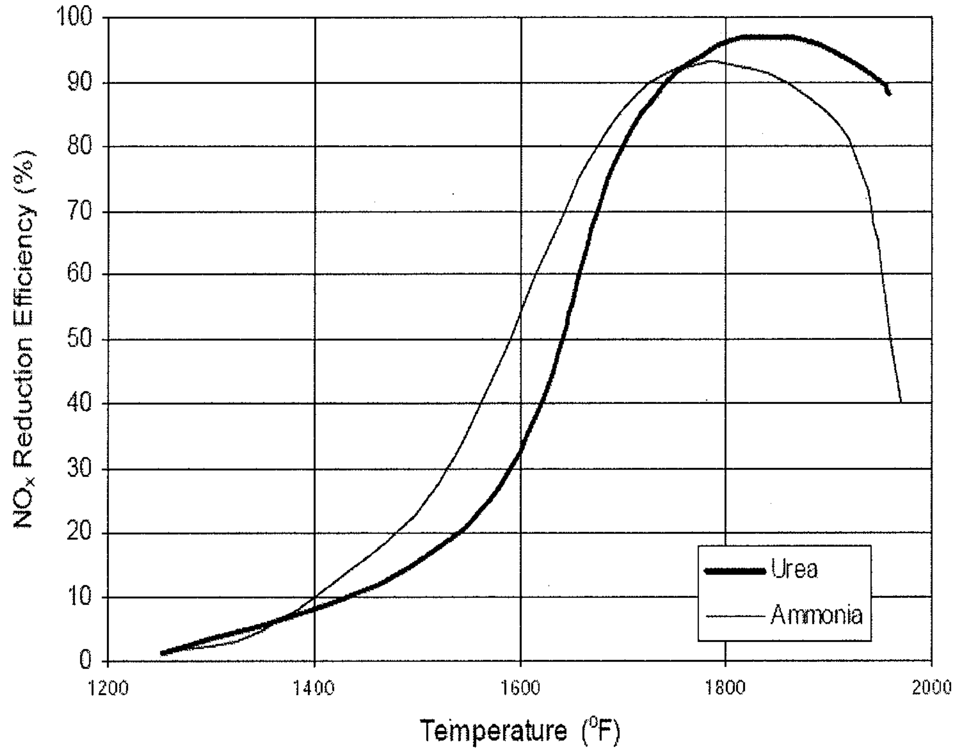

Figure 1.3: Effect of Temperature on NO_x Reduction

" Flue gas temperature within the boiler depends on the boiler design and operating conditions. These are generally set to meet steam generation requirements and are not always ideal for the SNCR process. Flue gas temperatures in the upper furnace through the convective pass may vary by ±150°C (300°F) from one boiler to the next [1]. In addition, fluctuations in the boiler load profile affect the temperature within the boiler. At lower load profiles, the temperature within the boiler is lower. Variations in the flue gas temperature make the design and operation of an SNCR system more difficult."

It is clear to the Department that startup of the boiler will affect the SNCR system and perhaps the overfire system also (see p. 3-42 to p. 3-42 of Minnkota's BART analysis). Minnkota has stated that startup has lasted up to 61 hours (2.54 days) for Unit 1. Including 2.54 days of noncompliance within a 30-day rolling average emission rate calculation will make compliance extremely difficult. In recent PSD application reviews for power plants, the Department has found sufficient cause to provide alternative limits under BACT for periods of startup and shutdown. The State of Montana in the permit for the Highwood Generating Station, EPA Region 9 in the permit for the Desert Rock Energy Center and the State of Nebraska in the Ag Soy Processing plant permit also included alternative limits for NO_x during startup and shutdown.

Minnkota has recommended in the October 2006 BACT submittal an emission limit of 0.98 lb/10^6 Btu (24-hr rolling average) for periods of startup. This value is based on historical data for startups from 2001 - 2005. Based on a rated heat input of 3200 x 10^6 Btu/hr, this equates to 3136 lb/hr. The rated heat input will generally not be achieved during a startup and a lower emission limit for startup is warranted. Minnkota has proposed a reduced startup limit of 2070.2 lb/hr on a 24-hour rolling average basis (see November 11, 2007 submittal). The Department proposes that NO_x emissions be limited to 2070.2 lb/hr on a 24-hour rolling average basis during startup. The normal BART limit of 0.36 lb/10^6 Btu will apply during all other periods including malfunctions.

IV. BART Evaluation of Unit II

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

New Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Flash Dryer Absorber
Powerspan ECO®

Fuel Switching
Coal Cleaning
Upgrade Existing Scrubber

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located near Nelson lake, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Although Evergreen Energy indicates the technology has been tested on lignite, there is no indication that lignite from the Freedom Mine was tested. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

The Department considers the Powerspan ECO® technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency (%)	Baseline Emissions (tons/yr)**	Emissions	
			(tons/yr)	(lb/10^6 Btu)*
New Wet Scrubber	95	18,090	1,964	0.11
Upgrade Existing Scrubber	95	18,090	1,964	0.11
Circulating Dry Scrubber	93	18,090	2,749	0.16
Upgrade Existing	90	18,090	3,928	0.23

Alternative	Control Efficiency (%)	Baseline Emissions (tons/yr)**	Emissions	
			(tons/yr)	(lb/10^6 Btu)*
Scrubber				
Spray Dryer	90	18,090	3.928	0.23
Flash Dryer Absorber	90	18,090	3,928	0.23

* Annual average emission rate.
** Based on an annual average sulfur content of 0.93% and 2000-2001 operating data.

Unit 2 is equipped with a lime/flyash scrubber that achieved an average SO_2 reduction efficiency (inlet to outlet) of approximately 65% for the period 2000-2004. It is obvious that upgrading the existing scrubber to either 90% or 95% control efficiency will be the most cost effective alternative.

Alternative	Emissions Reduction (tpy)	Annualized Cost ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Upgrade existing scrubber to 95%	16,126	8,414,000	522	550
Upgrade existing scrubber to 90%	14,162	7,333,000	518	N/A

Step 4: Evaluate Impacts and Document Results

Minnkota has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the available options.

Step 5: Evaluate Visibility Results

The two primary alternatives are upgrading the existing scrubber to achieve a reduction efficiency of 90% or 95%. The effects on visibility shown below are based on Minnkota's estimate of SO_2 reductions.

Unit 2 Delta Deciview 90th Percentile SO_2				
Year	**Unit**	**95% Reduction**	**90% Reduction**	**Difference**
2000	TRNP-SU	0.317	0.340	0.023
2001	TRNP-SU	0.154	0.332	0.178
2002	TRNP-SU	0.442	0.497	0.055
Average	TRNP-SU	0.304	0.390	0.085
2000	TRNP-NU	0.241	0.257	0.016
2001	TRNP-NU	0.214	0.442	0.228
2002	TRNP-NU	0.359	0.419	0.051
Average	TRNP-NU	0.271	0.370	0.098
2000	Elkhorn Ranch	0.175	0.201	0.026
2001	Elkhorn Ranch	0.119	0.215	0.096
2002	Elkhorn Ranch	0.219	0.259	0.040
Average	Elkhorn Ranch	0.171	0.225	0.054
2000	Lostwood W.A.	0.421	0.494	0.073
2001	Lostwood W.A.	0.450	0.580	0130
2002	Lostwood W.A.	0.344	0.405	0.061
Average	Lostwood W.A.	0.405	0.493	0.081
Overall Average				0.081

Unit 2 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**95% Reduction**	**90% Reduction**	**Difference**
2000	TRNP-SU	1.096	1.159	0.063
2001	TRNP-SU	1.095	1.476	0.381
2002	TRNP-SU	2.876	3.080	0.204
Average	TRNP-SU	1.689	1.905	0.216
2000	TRNP-NU	1.199	1.332	0.133
2001	TRNP-NU	1.314	1.793	0.479
2002	TRNP-NU	2.464	2.666	0.202
Average	TRNP-NU	1.659	1.930	0.271
2000	Elkhorn Ranch	0.827	1.068	0.241
2001	Elkhorn Ranch	0.863	1.310	0.447
2002	Elkhorn Ranch	2.601	2.789	0.188
Average	Elkhorn Ranch	1.430	1.722	0.292
2000	Lostwood W.A.	1.311	1.443	0.132
2001	Lostwood W.A.	1.654	2.042	0.388
2002	Lostwood W.A.	1.343	1.486	0.143
Average	Lostwood W.A.	1.436	1.657	0.221
Overall Average				0.250

Step 6: Select BART

The Consent Decree that covers M.R. Young Station Unit 2 only requires 90% reduction of SO_2 emissions by the scrubber. Minnkota has proposed that BART is represented by improvements to the existing scrubber such that a 90% reduction efficiency will be achieved on a 30-day rolling average basis. Minnkota states that the costs associated with each alternative (90% or 95% reduction) are reasonable based on other regulatory analysis. The Department believes the costs are quite low and very reasonable. Minnkota has not identified any energy or non-air quality impacts that would preclude either alternative. Minnkota's choice of 90% reduction as BART is based on the visibility modeling results. The difference, according to Minnkota's results, indicate an average visibility impact reduction of only 0.082 deciviews based on the 90th percentile value (0.250 dv based on 98th percentile). However, the difference in visibility impact between the two alternatives will be as much as 0.228 deciviews based on the 90th percentile (0.479 deciviews based on 98th percentile) for year 2001 in TRNP-NU. Although the average visibility improvement is small, this factor must be considered with the other four factors.

The cost of upgrading the existing wet scrubber to achieve 95% control is very reasonable. There are no unacceptable energy and non-air quality environmental impacts, the remaining useful life is greater than 20 years, and there is a small degree of visibility improvement. The Department proposes that BART is represented by improvements to the existing wet scrubber which will achieve approximately 95% reduction in SO_2 emissions. BART is 95% reduction efficiency from the inlet of the scrubber to the outlet of the scrubber.

Data on future coal sulfur content was submitted by Minnkota in an April 18, 2007 response to comments (Table C.11). The core sample data indicates a maximum sulfur content of 5.6%, an average sulfur content of 0.93% and a standard deviation of 0.53%. Based on an average sulfur content of 0.93%, the uncontrolled emission rate would be approximately 2.26 lb/10^6 Btu. However, the unit will have to comply with the BART emission limit at all times on a 30-day rolling average basis. Adding one standard deviation to the average sulfur content yields a design sulfur content of 1.46% or an uncontrolled emission rate of 3.48 lb/10^6 Btu.

A scrubber operating at 95% removal efficiency will achieve an annual average emission rate of 0.11 lb/10^6 Btu based on average coal or 0.17 lb/10^6 Btu based on a design sulfur content of 1.46%. This is equivalent to approximately 0.15 lb/10^6 Btu to 0.23 lb/10^6 Btu on a 30-day rolling average basis. The existing scrubber is a mid 1970s design and maintaining 95% reduction continuously will be more difficult than with new designs that are 30 years more advanced. Because of the age of the scrubber and some uncertainty in the future coal sulfur content, the Department has determined that an alternative limit be incorporated into the BART limit. Minnkota has agreed to limit SO_2 emissions to no more than 0.15 lb/10^6 Btu. The Department has determined that BART is 95% reduction or 0.15 lb/10^6 Btu on a 30-day rolling average basis. This is the same as the presumptive BART level listed in 40 CFR 51, Appendix Y even though the unit is not subject to the presumptive level (i.e., plant is less than 750 MWe and existing SO_2 controls achieve greater than 50% efficiency). However, the Consent Decree requires a minimum of 90% reduction. This requirement will also be incorporated into the BART limit.

B. Filterable Particulate Matter (PM/PM_{10})

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency (%)	Emissions*	
		(tons/yr)	(lb/10^6 Btu)
Baghouse	99.7+	248	0.013
New ESP	99.7	286	0.015
CoHPAC	99.7	286	0.015
Baseline (Existing ESP)	≈99.0	1,135	0.060

* Based on the Department's estimate of baseline emissions.

Alternative	Emissions* Reduction (tpy)	Annualized** Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baghouse	887	8,249,000	9,300	67,553***
New ESP	849	7,520,000	8,857	---
CoHPAC	849	5,682,000	6,693	9,472
Baseline (Existing ESP)	0	2,973,000	-	-

* Reductions from baseline emission rate.
** Costs provided by Minnkota.
*** Baghouse compared to CoHPAC.

Step 4: Evaluate Impacts and Document Results

Minnkota has evaluated the energy and non-air quality environmental impacts associated with each alternative and determined that these impacts would not prelude the selection of any of the alternatives as BART. The Department agrees with this determination.

Step 5: Evaluate Visibility Results

The different alternatives were not modeled because of the high cost effectiveness. However, the maximum 24-hour average emission rate from the baseline period was modeled. The results are as follows:

Unit 2 Delta Deciview PM			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.0054	0.0151
2001	TRNP-SU	0.0037	0.0068
2002	TRNP-SU	0.0100	0.0090
Average	TRNP-SU	0.0064	0.0103
2000	TRNP-NU	0.0034	0.0024
2001	TRNP-NU	0.0042	0.0093
2002	TRNP-NU	0.0073	0.0106
Average	TRNP-NU	0.0050	0.0074
2000	Elkhorn Ranch	0.0013	0.0046
2001	Elkhorn Ranch	0.0006	0.0054
2002	Elkhorn Ranch	0.0005	0.0082
Average	Elkhorn Ranch	0.0008	0.0061
2000	Lostwood W.A.	0.0009	0.0032
2001	Lostwood W.A.	0.0040	0.0165
2002	Lostwood W.A.	0.0009	0.0123
Average	Lostwood W.A.	0.0019	0.0107
Overall Average		0.0035	0.0086

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate matter emissions is CoHPAC, which has a cost effectiveness of $6,693 per ton. The Department considers this cost to be excessive. There are no energy or non-air quality impacts that would preclude the selection of any of the feasible control options.

The unit is equipped with an electrostatic precipitator that is achieving at least 99.0% control efficiency. The baseline emission rate is 0.06 lb/10^6 Btu; however, the average emission rate for this unit for 2000-2004 was 0.028 lb/10^6 Btu. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate matter emitted was eliminated, the most improvement in visibility at any Class I area would be 0.0064 deciviews based on the 90^{th} percentile (0.0103 deciviews based on 98^{th} percentile). The Department considers this amount of improvement to be negligible. Since none of the control alternatives will eliminate all of the particulate matter emissions, the visibility improvement will even be less.

Minnkota is currently under a Consent Decree (CD) which limits particulate emissions to 0.030 lb/10^6 Btu. After considering all of the factors, the Department proposes that BART for filterable particulate matter is no additional controls. Since the CD requires a lower limit, the Department proposes that BART is represented by an emission limit of 0.030 lb/10^6 Btu (average of three test runs).

C. Condensible Particulate Matter (PM_{10})

See the discussion for Unit 1 in Section III.C. Any additional control technology for controlling condensible particulate matter will result in less than a 0.0064 deciview (90^{th} percentile) improvement at any Class I area. The Department considers the use of a wet scrubber and good combustion practices to represent BART for condensible particulate matter from Unit 2. The BART limit for sulfur dioxide (95% reduction) and good combustion practices will act as a surrogate for condensible particulate matter.

D. Nitrogen Oxides

Introduction – See discussion in Appendix B.5 and Section III.D. The rationale will apply to Unit 2 that applies to Unit 1.

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced -SNCR with or without Advanced Separated Overfire Air (ASOFA)
Rich Reagent Injection (RRI) + SNCR + ASOFA

Rotomix® (ROFA + SNCR)
Conventional Gas Reburn plus SNCR (CGB + SNCR)
Coal Reburn
Coal Reburn + SNCR
Fuel Lean Gas Reburn (FLGR™)
FLGR™ + SOFA
SOFA or Advanced SOFA (ASOFA)
Rotating Overfire Air (ROFA)
Combustion Improvements (Included with ASOFA)
Oxygen Enhanced Combustion (OEC)

Step 2: Eliminate Technically Infeasible Options

Minnkota considers SCR to be technically infeasible at the M.R. Young Station. The Department does not consider high SCR to be technically feasible at this time. However, LDSCR and TESCR are considered technically feasible (see discussion in Appendix B.5 and III.D. of this analysis). Minnkota has determined the following technologies are also technically infeasible:

LDSCR
TESCR
ECO®
HE-SNCR
RRI
Rotomix® (ASOFA + SNCR evaluated)
CGR + SNCR
Coal Reburn + SNCR
FLGR™ + SNCR
OEC®

The Department agrees with Minnkota's determination regarding technical feasibility except for LDSCR and TESCR. ROFA, SOFA, and ASOFA are similar and only ASOFA will be evaluated further.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the historic baseline emissions, the expected emissions are as follows:

Alternative	**Control Efficiency * (%)**	**Emissions** (tons/yr)	**Emissions** ($lb/10^6$ Btu)
SCR w/reheat + ASOFA	90	1,551	0.079
SNCR + ASOFA	58.0	6,513	0.330
Gas Reburn +	55.4	6,916	0.350

Alternative	Control Efficiency * (%)	Emissions** (tons/yr)	(lb/10^6 Btu)
ASOFA			
Coal Reburn + ASOFA	54.2	7,102	0.360
FLGR + ASOFA	45.0	8,529	0.432
ASOFA	37.7	9,661	0.489
Baseline	---	15,507	---

*Control efficiency specified by Minnkota in their analysis except for SCR.
**Based on the Department's estimate of baseline emissions. The lb/10^6 Btu emission rate is an annual average rate.

The estimated costs for the most efficient alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Low Dust SCR + ASOFA	13,956	57,351,000/ 89,072,000	4,109/ 6,382	9,260/ 15,652
Tail End SCR + ASOFA*	13,956	66,506,000/ 98,818,000	4,765/7,081	11,105/17,616
SNCR + ASOFA	8,994	11,405,000	1,268	N/A
Gas Reburn + ASOFA**	8,591	63,883,000	7,436	N/A
Coal Reburn + ASOFA**	8,405	19,475,000	2,317	N/A
FLGR + ASOFA	6,978	29,313,000	4,201	N/A
ASOFA	5,846	4,376,000	749	

* Two different estimates of cost are provided for SCR. These represent the range of costs provided by Minnkota based on two catalyst replacement scenarios and two cost bases – stand along SCR systems or shared facilities.
** Inferior options to SNCR + ASOFA

Minnkota has calculated the cost effectiveness and incremental cost effectiveness based on 93.8% removal efficiency and a baseline emission rate that is more reflective of potential emissions instead on historical emissions. This represents the costs under the most optimistic conditions. The Minnkota calculations are:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Low Dust SCR + ASOFA	14,862/14,980	57,351,000/ 89,072,000	3,859/5,946	8,331/13,812
Tail End SCR + ASOFA	14,857/14,980	66,506,000/ 98,818,000	4,477/6,597	10,007/15,550
SNCR + ASOFA	9,372	11,618,000	1,240	2,263
ASOFA	6,172	4,376,000	709	---

** Range of costs using two different catalyst replacement schedules and two different cost bases – standalone SCR systems and shared facilities between Unit 1 and 2.

Step 4: Evaluate Impacts and Document Results

Minnkota has not identified any environmental or energy impact that would preclude of the use of any of the previously evaluated emission control alternatives.

Step 5: Evaluate Visibility Impacts

The following tables show the visibility improvement of SCR + ASFOA versus SNCR + ASOFA.

Unit 2 Delta Deciview 90th Percentile NO_x				
Year	**Unit**	**SCR + ASOFA**	**ASOFA+SNCR**	**Difference**
2000	TRNP-SU	0.057	0.127	0.070
2001	TRNP-SU	0.047	0.066	0.019
2002	TRNP-SU	0.087	0.186	0.099
Average	TRNP-SU	0.064	0.126	0.063
2000	TRNP-NU	0.049	0.090	0.041
2001	TRNP-SU	0.061	0.098	0.037
2002	TRNP-SU	0.088	0.158	0.070
Average	TRNP-SU	0.066	0.115	0.049
2000	Elkhorn Ranch	0.040	0.069	0.029
2001	Elkhorn Ranch	0.030	0.056	0.026
2002	Elkhorn Ranch	0.049	0.096	0.047
Average	Elkhorn Ranch	0.040	0.074	0.034
2000	Lostwood W.A.	0.092	0.190	0.098
2001	Lostwood W.A.	0.087	0.193	0.096
2002	Lostwood W.A.	0.066	0.134	0.068
Average	Lostwood W.A.	0.082	0.169	0.087
Overall Average		0.063	0.121	0.058

Unit 2 Delta Deciview 98th Percentile NO_x				
Year	**Unit**	**SCR + ASOFA**	**ASOFA+SNCR**	**Difference**
2000	TRNP-SU	0.214	0.464	0.250
2001	TRNP-SU	0.225	0.498	0.273
2002	TRNP-SU	0.558	1.124	0.566
Average	TRNP-SU	0.332	0.695	0.363
2000	TRNP-NU	0.200	0.455	0.255
2001	TRNP-NU	0.259	0.556	0.297
2002	TRNP-NU	0.466	1.088	0.622
Average	TRNP-NU	0.308	0.700	0.391
2000	Elkhorn Ranch	0.163	0.425	0.262
2001	Elkhorn Ranch	0.197	0.429	0.232
2002	Elkhorn Ranch	0.432	1.025	0.593
Average	Elkhorn Ranch	0.264	0.626	0.362
2000	Lostwood W.A.	0.230	0.524	0.294
2001	Lostwood W.A.	0.336	0.636	0.320
2002	Lostwood W.A.	0.295	0.566	0.271
Average	Lostwood W.A.	0.287	0.582	0.295
Overall Average		0.298	0.651	0.353

Because the BART modeling guidance (40 CFR 61, Appendix Y) uses single source modeling, the modeling overpredicts the amount of improvement for North Dakota (see Section 7.4.2 of SIP). The Department has conducted modeling with all sources included in the inventory. The results of this modeling indicates that visibility at TRNP will only improve 0.02 deciviews on average for the 20% worst days when SCR + ASOFA is utilized versus SNCR + ASOFA. At LWA, the visibility will only improve 0.01 deciviews.

Step 6: Select BART

The cost effectiveness of SCR (LDSCR and TESCR) + ASOFA is considered excessive over the entire range of costs. The Department considers the incremental cost over the entire range of costs to be excessive for SCR + ASOFA when compared to SNCR + ASOFA. The BART type modeling predicts an average improvement of 0.058 deciviews based on the 90th percentile (0.353 deciviews based on the 98th percentile); but overpredicts the amount of improvement (see Section 7.4.2 of SIP). The Department's cumulative modeling predicts a 0.02 deciview improvement at TRNP and 0.01 deciview improvement at LWA for the most impaired days when compared to SNCR + ASOFA. There are no environmental or energy impacts that would preclude the selection of any of the control alternatives as BART and the unit is expected to have greater than a 20 year remaining life.

The Department has also considered the cost effectiveness and incremental costs provided by Minnkota. The costs calculated by Minnkota are also considered excessive. The Department also conducted modeling to determine the amount of visibility improvement if SCR did achieve 93.8% NO_x removal. The results indicated a 0.021 deciview improvement for SCR + ASOFA versus SNCR + ASOFA at TRNP and a 0.011 deciview improvement of LWA during the most impaired days.

Because of the excessive cost effectiveness and incremental cost and negligible visibility improvement, SCR + ASOFA is eliminated as a BART alternative. The Department has determined that BART is represented by SNCR + ASOFA. This technology will achieve an annual average emission rate of 0.33 lb/10^6 Btu. Based on a 30-day rolling average basis, an emission rate of 0.35 lb/10^6 Btu is achievable and is proposed as BART for normal operating conditions.

Minnkota has requested an alternative BART limit during startup. Minnkota's justification is found in Section 3.5.2 of their BART analysis. The Department believes an alternative limit is justified (see discussion in Section III.D. Step 6). Therefore, the Department proposes a limit of 3,995.6 lb/hr on a 24-hour rolling average basis during startup.

V. BART Evaluation for Auxiliary Boiler

The auxiliary boiler is a #1 or #2 fuel-oil fired boiler with a nominal rating of 78 x 10^6 Btu/hr. The auxiliary boiler is normally only used when both units at the M.R. Young Station are down. During cold weather, the auxiliary boiler may be used if one unit is off line. During the baseline period (2000-2004), the auxiliary boiler was operated approximately 100 hours per year. Based on the estimated 100 hours per year of operation, the annual emissions from the unit were:

NO_x	0.56 tons
SO_2	1.2 tons
PM	0.06 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls. The current permit limits the fuel used in the boiler to #1 or #2 fuel oil. BART is the use of #1 or #2 fuel oil.

VI. BART Evaluation for Emergency Fire Pump and Diesel Generator

The fire pumps and emergency generator are powered by diesel engines and are used for emergency purposes only. Most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the fire pumps operated approximately 1.2 hours per year and the emergency generator operated approximately 30 hours per year.

Based on this utilization the estimated annual emissions are as follows:

Pollutant	Unit 1 Fire Pump (tons/yr)	Unit 2 Fire Pump (tons/yr)	Emergency Generator (tons/yr)
NO_x	0.04	0.03	0.17
SO_2	0.003	0.002	0.01
PM	0.003	0.002	0.01

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at the M.R. Young Station that emit to the atmosphere are as follows:

EUI	Description	Existing Control Equipment	Baseline Emissions (tons/yr)
M1	Unit 1 crusher house and conveyor 1C	Rotoclone	0.4
M2	Unit 1 Coal Silos	Rotoclone	0.5
M3	Unit 2 Crusher House	Rotoclone	0.1
M4	Unit 2 Coal Silos	Rotoclone	2.2
M5	Unit 1 Flyash Silo	ESP	<1
M6	Unit 2 Flyash Silo	ESP	<1
M7	Unit 2 Lime Storage Silo	Bin Vent Filter	<1
M8	Unit 1 Truck Dump	None	10.4
M9	Unit 2 Truck Dump	None	18.8
M12	Lime Storage Silo	Baghouse	<1

Based on the small quantity emissions from the sources, it is apparent that no additional control equipment will be cost effective and will have very little impact on visibility in the Class I areas. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limits for the units are BART.

VIII. Summary

Source Unit	Proposed* BART Limit/Work Practice				Emissions Reduction** (tons/yr)		
	PM	SO_2	NO_x	Units	PM	SO_2	NO_x
Unit 1 Boiler	0.030	95% reduction	0.36	lb/10^6 Btu	0	19,140	4,808
Unit 2 Boiler	0.030	0.15 and 90% reduction or 95% reduction	0.35	lb/10^6 Btu	0	9,665	8,313
Auxiliary Boiler	Use #2 Fuel Oil			N/A	0	0	0
Fire Pumps and Diesel Generator	Use low sulfur diesel fuel			N/A	0	0	0
M1	---	---	---	lb/hr	0	---	---
M2	---	---	---	lb/hr	0	---	---
M3	---	---	---	lb/hr	0	---	---
M4	---	---	---	lb/hr	0	---	---
M5	---	---	---	lb/hr	0	---	---
M6	---	---	---	lb/hr	0	---	---
M7	---	---	---	lb/hr	0	---	---
M8	---	---	---	lb/hr	0	---	---
M9	---C	---	---	lb/hr	0	---	---
Total						28,805	13,121

* Emission limits for PM are a 3-hour average. The limits for SO_2 and NO_x are on a 30-day rolling average basis.

** Reductions from 2000-2004 average emission rate.

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using continuous emission monitors which are installed and maintained as required by 40 CFR 75.

Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring.

2. For purposes of determining compliance with the SO_2 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:

Inlet SO_2 Rate is in units of lb/10^6 Btu.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. If Minnkota chooses to comply with the 95% reduction requirement at Unit 2, Minnkota may average the % reduction from Unit 1 and Unit 2 provided:

   A) The average reduction is at least 95% as determined in accordance with the following formula:

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER = Allowable Emission Rate (% reduction)
ER_1 = Actual Emission Rate (% reduction) of Unit 1 based on lb/10^6 Btu
ER_2 = Actual Emissions Rate (% reduction) of Unit 2 based on lb/10^6 Btu
HI_1 = Actual Heat Input (MMBtu) of Unit 1
HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes: ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average is determined for the 30 successive boiler operating days (must be on a % reduction basis).

   B) The reduction by Unit 1 is at least 95%, and

   C) The reduction by Unit 2 is at least 90%.

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

References

1. K-Fuels® website, 2007. www.evgenergy.com

2. EPA, 1995. Compilation of Air Pollutant Emission Factors Volume 1: Stationary Point and Area Sources. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

3. EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02/B-02-001, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

4. Minnkota Power Cooperative, Inc., 2006. BART Determination Study for Milton R. Young Unit 1 and 2; Minnkota Power Cooperative; October 2006.

5. Minnkota Power Cooperative, Inc., 2007. BART Determination Study for Milton R. Young Station Units 1 and 2; Minnkota Power Cooperative, Inc.; August 2007.

6. Minnkota Power Cooperative, Inc., 2009. NO_x Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1; Minnkota Power Cooperative, Inc.; November 2009.

7. Minnkota Power Cooperative, Inc., 2009. NO_x Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 2; Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative; November 2009.