United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

N3615 (2350)

November 21, 2011

Carl Daly
Director, Air Program
Environmental Protection Agency
Region 8, Mailcode 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129

EPA Docket ID: EPA-R08-0AR-2010-0406

Dear ~~Mr. Daly:~~ Carl

The National Park Service (NPS) has reviewed the Environmental Protection Agency's (EPA's) proposed "Approval and Promulgation of Air Quality Implementation Plans; North Dakota; Regional Haze State Implementation Plan (SIP); Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze". Our review focused on the determinations for Best Available Retrofit Technology (BART) and for reasonable progress in improving visibility for North Dakota electric generating units (EGUs).

As discussed in detail in the enclosed comments, we agree with EPA's BART determinations for nitrogen oxide emissions from North Dakota's EGUs. For sulfur dioxide emissions from these facilities, we recommend that specific emissions limits be set for the BART determinations. For Particulate Matter with diameter less than 10 micrometers (PM10), we recommend that EPA set lower emission limits that more closely reflect the performance capability of the control technology.

We recommend that Selective Catalytic Reduction technology should be required for the Coyote Generating Station under the reasonable progress provisions because Class I areas in North Dakota are not projected to meet the uniform rate of progress, the total and incremental control costs for Coyote are less than those for the Leland Olds and M.R. Young BART units, and Coyote is closer to the Class I areas than the BART units.

We appreciate the opportunity to work closely with the State of North Dakota and EPA to make progress toward achieving natural visibility conditions at our National Parks and Wilderness Areas. For further information regarding our comments, please contact Don Shepherd of my staff at (303) 969-2075.

Sincerely,

John Bunyak
Chief, Policy, Planning, and Permit Review Branch

Enclosure

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

NPS Comments on Best Available Retrofit Technology (BART)
and Reasonable Progress for Visibility
November 21, 2011

General Comments on BART

We appreciate this opportunity to comment upon the EPA proposal for Best Available Retrofit Technology (BART) for the seven Electric Generating Units (EGUs) in North Dakota that North Dakota Division of Air Quality (NDDAQ) has identified as being subject to BART.[1] According to EPA's Clean Air Markets (CAM) database, in 2010 North Dakota ranked #12 in sulfur dioxide (SO_2) emissions (124,096 tons) and #19 for nitrogen oxides (NO_x) emissions (54,744 tons). Below are the 2010 emissions and rankings of the ND EGUs (out of 3581 EGUs in the CAM database).

SO_2 Emissions and Rankings

FACILITY_NAME	UNIT ID	SO2 MASS (tons)	SO2 MASS Rank	SO2 RATE (lb/mmBtu)	SO2 RATE Rank	HEAT INPUT (mmBtu)	HEAT INPUT Rank
Antelope Valley	B1	8,479	177	0.429	695	39,571,458	125
Antelope Valley	B2	6,413	226	0.405	718	31,668,162	210
Coal Creek	1	9,438	153	0.382	729	49,409,811	54
Coal Creek	2	8,678	168	0.413	711	41,998,558	105
Coyote	B1	13,691	79	0.778	378	35,201,254	172
Leland Olds	1	17,203	45	2.249	90	15,297,310	419
Leland Olds	2	28,776	8	2.139	97	26,903,299	258
Milton R Young	B1	19,287	31	1.858	128	20,765,112	340
Milton R Young	B2	7,776	192	0.540	592	28,813,320	237
R M Heskett	B2	1,871	624	0.846	346	4,424,302	1,410
Stanton	1	2,293	564	0.489	635	9,373,038	811
Stanton	10	156	1,021	0.061	1,073	5,126,027	1,324

[1] In Section 7.3.4, the NDDAQ Plan describes the steps taken that result in excluding the Montana Dakota Utilities R.M. Heskett Unit No. 2 from BART review. After the Heskett Unit No. 2 failed the exclusion modeling analysis under the revised North Dakota protocol, ENSR Corporation developed a third protocol for Heskett Unit No. 2. Our concerns with the work performed by ENSR Corporation center on the use of a 1 kilometer grid (as opposed to the recommended 4 kilometer grid), and that the calculation for maximum impact incorrectly treats Theodore Roosevelt NP as three separate Class I areas. Based on agreed-upon methods and its baseline emissions, we believe that Heskett Unit No. 2 may be subject to BART requirements, and EPA should revisit this issue.

NO_x Emissions and Rankings

FACILITY_NAME	UNIT ID	NOX MASS (tons)	NOX MASS Rank	NOX RATE (lb/mmBtu)	NOX RATE Rank	HEAT INPUT (mmBtu)	HEAT INPUT Rank
Antelope Valley	B1	7,521	24	0.375	231	39,571,458	125
Antelope Valley	B2	5,508	47	0.341	326	31,668,162	210
Coal Creek	1	5,199	58	0.211	710	49,409,811	54
Coal Creek	2	3,473	145	0.166	895	41,998,558	105
Coyote	B1	12,323	5	0.702	24	35,201,254	172
Leland Olds	1	2,188	264	0.288	476	15,297,310	419
Leland Olds	2	4,237	96	0.314	389	26,903,299	258
Milton R Young	B1	5,604	45	0.540	57	20,765,112	340
Milton R Young	B2	5,857	40	0.409	170	28,813,320	237
R M Heskett	B2	796	703	0.372	238	4,424,302	1,410
Stanton	1	1,175	495	0.252	586	9,373,038	811
Stanton	10	720	742	0.281	495	5,126,027	1,324

While we are pleased that EPA and NDDAQ are proposing major reductions in the visibility-impairing pollutants, SO_2, and NO_x, under the BART program, we believe that additional NO_X reductions can be achieved under the reasonable progress analysis. Based on our analyses, summarized below, and described in detail in the enclosed documents, we believe that additional NO_x reductions beyond those identified by EPA and NDDAQ are technically feasible and cost-effective. Our comments below address the five-step process described by EPA's BART Guidelines, primarily with respect to those NO_x reductions.

Purpose of the BART Program

The core purpose of the BART program is to improve visibility in our Class I areas. BART is not necessarily the most cost-effective solution. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is essential to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected.

Five-Step BART Process

Step 1: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

All of the SO_2 and NO_x analyses included a reasonable suite of options.

Step 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

We commend EPA for the thoroughness of its effort to evaluate the potential for applying Selective Catalytic Reduction (SCR) to North Dakota lignite-fired boilers.

Step 3: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The ability of SCR to reduce emissions, as assumed by EPA, was consistent with available information (EPA's Clean Air Markets data and vendor guarantees) which show that SCR can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis. We agree that a NO_X limit of 0.07 lb/mmBtu is appropriate (with an adequate "safety-margin") for combustion controls + SCR on a 30-day rolling average.

Step 4: EVALUATE IMPACTS AND DOCUMENT RESULTS

According to EPA's BART Guidelines, "the basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option."

While we recognize that the BART Guidelines must allow flexibility to address differing situations, that flexibility also makes it difficult to compare results. In our analyses (which we describe below), we have attempted to develop an approach that is consistent enough to allow such comparison among the ND EGUs.

In lieu of the vendor data cited above, we believe that EPA's Integrated Planning Model (IPM) can provide a useful tool for estimating certain SCR capital costs based upon analyses of recent utility industry SCR costs. We have developed cost estimates for application of SCR to all of the BART-eligible EGUs based upon use of IPM to estimate Direct Capital Costs (DCC). The IPM "Bare Module Costs" are similar to DCC as defined by the EPA Control Cost Manual (CCM), and are more representative of current costs than the 1998 vintage CCM estimates. We believe that this approach to estimating DCC is consistent with the BART Guidelines in that it uses recent and objective industry data from a referenced (EPA) source.

IPM also estimates "Engineering and construction management costs," which are similar to the "Indirect Installation Costs" included in the CCM estimate of Total Capital Investment (TCI). However, IPM includes "Owners Costs" and Allowance for Funds Utilized During Construction (AFUDC), which are not typically allowed by the CCM method. To address this last issue with IPM, we have applied the CCM method to estimate the TCI based upon the IPM estimate of DCC. In every case we have evaluated using the CCM method, the TCI is 141% of the DCC. (All of the CCM estimates for Indirect Installation Costs are based upon percentages of the DCC. This approach is not unique to the CCM, as we have observed that most such cost analyses provided by industry consultants are based upon ratios applied to certain fundamental estimates.) Once IPM produces an estimate of DCC, it is multiplied by 141% to estimate the TCI. The result is a slightly lower estimate of TCI that IPM produces, because the IPM Owners Costs and AFUDC are not included in the CCM 141% factor.

We believe that the Operation and Maintenance (O&M) cost estimates produced by the CCM method are more "transparent" and more flexible than those produced by IPM. For example, IPM assumes use of urea as the SCR reagent, but we have found that anhydrous ammonia is usually the most cost-effective option, and we have used that assumption in our CCM-based estimates for O&M costs.

In general, the CCM approach can more-accurately describe a specific situation. For example, in addressing the cost of reheating the scrubber effluent to accommodate tail-end SCR, it was a simple and transparent matter to add that cost to the CCM estimates for Direct Annual Costs (DAC). We estimated the additional reheat cost as a proportion of the cost estimated for Leland Olds Unit #2 by Dr. Fox, EPA's consultant.

Finally, because IPM does not include Indirect Annual Costs (IAC) or adjustments for inflation, we used the CCM method for estimating IAC and used the Chemical Engineering Plant Cost Index (CEPCI) to adjust all costs to 2010$.

We have included Excel-based workbooks which describe the characteristics of each EGU and its 2000 – 2010 emissions, based upon CAM data. Because the Regional Haze program is behind schedule, in many cases a given EGU has proceeded to install combustion control equipment and thus already reduced NO_x emissions. While we commend any reduction in emissions, the effect is to complicate the BART analysis. In these situations, the question becomes, "What are the base case NO_x emissions against which we are now evaluating control strategies, and how do we allocate costs between recent and future control strategies?" We recommend that EPA consider both the incremental costs and benefits of adding more controls (e.g., SCR), as well as the total costs and benefits of the BART control strategy (e.g., combustion controls + SCR). Where an EGU has already acted to reduce emissions, we split the CAM data to show emissions before and after those controls.

Our "IPM Capital Costs" and "Given/Assume" tabs work together to show the data we used and its sources. In the absence of a showing of some unusually-difficult retrofit situation, we assumed a retrofit factor = 1 for each EGU. Cost for catalyst and reagent were assumed to be consistent among the ND EGUs and were taken from industry data.[2] On the Given/Assume tab, we chose to partially override the CCM estimate of TCI by instead using the IPM estimate for DCC as the basis for the CCM estimate of TCI. We estimated the additional reheat cost as a proportion of the cost estimated for Leland Olds Unit #2 by Dr. Fox.

The Boiler Calcs, SCR Reactor, and Reagent tabs provide information on gas flow rate, catalyst volume and reagent use that is used later to estimate related operating costs. The DCC tab shows the CCM estimate. The highlighted cells on "ICC & TCI" tab show the DCC as estimated by IPM, and the resulting TCI = 141% of DCC. The "IPM O&M" tab

[2] CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSIONS CONTROL TECHNOLOGIES Prepared by J. Edward Cichanowicz Prepared for Utility Air Regulatory Group January 2010

shows the IPM estimates (not used by our method) for O&M costs. Annual Direct, Indirect, and Total costs calculated per the CCM method (and were used by our method) are shown on the "Ann Tab," which also includes the corresponding IPM estimates for comparison. The results of these analyses were then compiled into a "Summary" tab for each EGU workbook.

Step 5: VISIBILITY IMPROVEMENT DETERMINATION
We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused" by the BART source. It follows that, if emission from the BART source are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for. We are pleased that EPA agrees with us on this issue. In its January 23, 2009, letter to Nebraska, EPA states,

> Even when used only as a supplement to $/ton, a $/dv analysis is likely to be meaningless if the analysis does not take into account the visibility impacts at multiple Class I areas or ignores the total improvement (i.e., the frequency, magnitude, and duration of the modeled changes in visibility).

The BART Guidelines attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. Finally, we note that EPA summed visibility impacts across multiple Class I areas in the analyses it published in Federal Register notices for its actions regarding the San Juan Generating Station (SJGS), the Four Corners Power Plant (FCPP), and the Navajo Generating Station (NGS). EPA also sums visibility impacts in its "better-than-BART" demonstrations.

We share EPA's concern that NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. For three EGUs, NDDAQ used incorrect techniques to assess (and underestimate) visibility improvements.[3] In many cases, instead

---

[3] MEMORANDUM From: Gail Tonnesen, Regional Modeler To: North Dakota Regional Haze FileDate: September 1, 2011 Re: Modeling Single Source Visibility Impacts
Issue: What is the appropriate choice of background visibility conditions to be used in evaluating single source visibility impacts?

of evaluating a candidate BART strategy by determining the visibility improvement that would result from that particular strategy versus a "standard" baseline (e.g., the proposed SO_2 control options), the only analyses of visibility improvements were of the incremental differences between competing BART options. Finally, despite our several attempts to advise NDDAQ that Theodore Roosevelt NP is a single Class I area, the NDDAQ modeling analyses treated Theodore Roosevelt NP as three separate Class I areas, which could reduce the likelihood that a source would trigger BART review. EPA could have addressed these modeling issues by conducting its own modeling analyses, as EPA did regarding the SJGS, the FCPP, and NGS.

BART DETERMINATIONS

BART is not necessarily the most cost-effective option. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. As with Best Available Control Technology analyses, one can look to actions by other entities to inform the decision-making process. For example, Oregon established a cost/ton threshold of $7,300 based upon the premise that improving visibility in multiple Class I areas warrants a higher cost/ton than where only one Class I area is affected. In its BART proposal for San Juan Generating Station, New Mexico used a range from $5,946/ton to $7,398/ton. Colorado used $5,000/ton (but considered higher costs when multiple Class I areas are impacted), New York used $5,500/ton, and Wisconsin used $7,000 - $10,000/ton as its BART threshold. EPA has proposed SCR at FCPP at $2,500 - $3,200/ton, and at SJGS at $1,600 - $1,900/ton.

Summary: The primary issue in dispute in the North Dakota Department of Health (NDDH) *[continued from previous page]* BART modeling is the choice of background visibility conditions to be used when evaluating single source impacts on visibility impairment in BART determinations. EPA rulemaking, guidance, and policy memos clearly and consistently state that natural background visibility levels must be used to evaluate visibility impacts of individual sources. The NDDH argues that EPA allows for discretion in the approach used to perform visibility modeling and proposes an alternate approach using current emissions and existing background visibility conditions to evaluate the impact of single sources on visibility impairment. EPA does allow limited discretion; for example, the states may use natural background conditions based on either annual average natural visibility or the average of the 20% best natural visibility days. However, NDDH's proposed approach is far outside the bounds of the allowable discretion. In fact, in its final rulemaking on BART modeling, EPA specifically considered and rejected approaches similar to that adopted by NDDH.

While NDDH used the required approach - comparison to natural visibility – for determining which BART-eligible sources were subject to BART, and used the same approach for analyzing projected visibility improvement for potential BART controls in almost all cases, NDDH adopted a different approach for analyzing NOx BART controls for three electric generating units: Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2. When NDDH modeled visibility improvements associated with the possible use of SCR as NOx BART for these three units, NDDH evaluated the contribution of each of these sources using degraded background including all sources of emissions in the modeling inventory. Thus, for these three units, NDDH grossly underestimated the projected visibility benefit of the SCR option compared to natural background visibility conditions. NDDH also used degraded background visibility conditions to evaluate potential controls at individual electric generating units under the reasonable progress requirements of EPA's regional haze rule. It is my opinion that this modeling approach was flawed for the same reasons.

From a visibility impairment standpoint, it appears to be more beneficial to reduce NO_x than to reduce SO_2 in ND's cool climate. However, by placing more emphasis upon cost-per-ton ($/ton) of pollutants removed than on visibility improvement, the advantages of reducing NO_x versus SO_2 are overlooked if both are measured with the same $/ton yardstick. For this reason, we recommend that the primary emphasis should be placed upon the cost – per – deciview ($/dv) of improvement.[4] EPA has stated in its Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) "in assessing additional emissions reduction strategies for source categories or individual, large scale sources, simple cost effectiveness based on a dollar-per-ton calculation may not be as meaningful as a dollar per deciview calculation." The same logic applies to BART. Nevertheless, because both NDDAQ and EPA have based their BART determinations on cost – per – ton of pollutant removed, we shall show that the EPA BART proposals are internally consistent and reasonable.

Nitrogen Oxide Controls

It is very important to compare the incremental costs of adding SCR to similar incremental costs, just as it is important to compare total costs at one EGU to total costs at another. To facilitate such comparisons, we have compiled all of the "Summary" tables produced by our Excel workbooks into one "Comparison Tables" file. The final "Summary" tab of our Comparison Tables file includes all of the most-relevant data to provide estimates of the costs and benefits[5] of combustion controls alone, the incremental cost of adding SCR (Incremental Cost Comparison Table), and the total cost of the combination (Total Cost Comparison Table). (These two tables differ only in the parameters that are highlighted.) In the absence of reliable results for the visibility improvements that would result from combustion controls and SCR, we calculated a new parameter which is the product of cost/ton and distance to the nearest Class I area. (This is simply a variation on the approach used by NDDAQ to rank sources by emissions (Q) divided by distance (d) which EPA accepted for determining which sources to evaluate under the Reasonable Progress requirements, as discussed later.) As with cost/ton, the smaller this cost-distance/ton parameter, the more cost-effective the control strategy is judged to be, because, for a given cost/ton, reductions at the nearer EGU should have a greater visibility benefit at the Class I area. As can be seen from our Comparison Tables, of the BART EGUs, the three EGUs (LOS#2, and MRYS #1&#2) for which EPA has proposed controls also have the lowest total costs/ton ($1800 - $2200/ton), the lowest incremental costs/ton for adding SCR ($2400 - $2600/ton), and the lowest cost-distance/ton for both total and incremental costs. It can also be seen that the costs for adding SCR to the next-most-cost-effective candidate EGUs are substantially higher.

---

[4] Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview to improve visibility may appear extraordinarily expensive. However, our (ongoing) analyses of BART proposals from around the US lead us to the conclusion that a cost per dv of $14 – $20 million represents a reasonable average cost-effectiveness for improving visibility at the most-impacted Class I area.

[5] Due to the issues cited by EPA and NPS regarding the modeling analyses of the visibility improvements, we were unable to confidently quantify this benefit.

While we would have preferred that EPA had used a higher cost threshold in determining for which EGUs SCR was cost-effective, we recognize that EPA has reasonably determined that SCR is BART for LOS#2, and MRYS #1&#2. Furthermore, as we noted above, our analysis of CAM data leads us to agree with EPA's proposed 0.07 lb/mmBtu 30-day rolling average limits for these EGUs. We also concur with the BART NO_x limits proposed for the remaining BART EGUs.

Sulfur Dioxide Controls

For several units, NDDAQ proposed alternative SO_2 limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. By definition, BART represents the highest degree of control that meets the five-step test. Where EPA has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met. Similarly, where EPA has determined that a percent reduction limit is reasonable, it should require that that limit be met.[6] If both limits are determined to be reasonable, then both should be required, not either/or as proposed by EPA.

Particulate Matter with Diameter less than 10 micrometers (PM_{10}) Controls

We also have some general comments that apply to all of the PM_{10} analyses. We believe that the BART analyses are deficient because they do not propose limits that realistically reflect the capabilities of the existing ESPs, as well as the proposed new baghouses, to control filterable PM. Instead, the limits on filterable PM_{10} proposed by EPA are two – to – three times the emission rates measured by stack testing and cited by NDDAQ. It appears that EPA is not following its own guidance to consider more stringent emission rates in setting permit limits:

> "If you find that a BART source has controls already in place which are the most stringent controls available (note that this means all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long as these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section."

We recommend that EPA establish permit limits that reflect the capabilities of the BART technology to control filterable PM. While we understand that a certain "safety margin" must be allowed, we believe that the BART limits should be set to encourage continued good operation and maintenance of the pollution control equipment.

Primary Conclusions & Recommendations

Our analyses lead us to the following preliminary conclusions and recommendations (as discussed in detail in the following documents):

---

[6] There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr as proposed by Wyoming, for example), the actual amount of SO_2 emitted is unlimited.

- The modeling issues raised by EPA should be addressed as part of NDDAQ's 2013 "mid-course correction." More emphasis should be placed upon the cumulative visibility benefits that could be derived from the BART program.
- We support EPA's NO_x BART determinations and agree that BART is a 30-day rolling average limit of 0.07 lb/mmBtu for LOS#2, and MRYS #1&#2.
- For SO_2, where EPA has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met. Similarly, where EPA has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then both should be required, not either/or as proposed by EPA.
- EPA should establish permit limits that reflect the capabilities of the BART technology to control filterable PM.

REASONABLE PROGRESS GOALS

Based on Q/d and some source process information, NDDAQ narrowed the focus of any additional control measures under the reasonable progress measures to the Basin Electric Antelope Valley Station (AVS) facility, the Otter Tail Power Coyote Station, the Dakota Gasification Great Plains Synfuels Plant, and the Hess Corporation Tioga Gas Plant. As shown in the table below, the two power generation facilities, Coyote and AVS, have emissions and Q/d impacts that are similar to, if not greater than, BART sources that will be required to add controls. To put these Q/d values into perspective, we have included similar calculations for all ND EGUs based upon 2010 emissions in EPA's CAM database:

FACILITY NAME	UNIT ID	SO_2 MASS	NOx MASS	SO2+NOx	Distance (km)	Q/d
Antelope Valley	B1	8,479	7,521	16,000	107	149.5
Antelope Valley	B2	6,413	5,508	11,921	107	111.4
Coal Creek	1	9,438	5,199	14,637	159	92.1
Coal Creek	2	8,678	3,473	12,151	159	76.4
Coyote	B1	13,691	12,323	26,014	112	232.3
Leland Olds	1	17,203	2,188	19,391	145	133.7
Leland Olds	2	28,776	4,237	33,013	145	227.7
Milton R Young	B1	19,287	5,604	24,891	160	155.6
Milton R Young	B2	7,813	6,001	13,814	160	86.3
R M Heskett	B2	1,871	796	2,667	185	14.4
Stanton	1	2,293	1,175	3,468	148	23.4
Stanton	10	156	720	876	148	5.9

According to NDDAQ:

The available control options were evaluated by WRAP's contractor EC/R Incorporated. The report on this evaluation is found in Appendix I.1. The cost for the wet scrubber at the Coyote Station was adjusted to represent the gross capacity of the facility (450 MWe vs 427 MWe) which is larger than EC/R evaluated. Also, the removal efficiency for a new wet scrubber was adjusted from 90% to 95%. The costs associated with the various control technologies are shown in Table 9.8.

The reasonable progress goals in 40 CFR 51.308(d)(1) requires improvement in the most impaired days. The most impaired days are defined in 40 CFR 51.301 as the average visibility impairment for the twenty percent days with the highest amount of visibility impairment. Therefore, modeling addressed the 20% worst days for both TRNP and LWA Class I areas. The results for each candidate source were compared with the results using the unmodified future emissions inventory (Table 8.11) to determine the additional visibility improvement due to the tested control technology.

EPA has stated in their Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) "in assessing additional emissions reduction strategies for source categories or individual, large scale sources, simple cost effectiveness based on a dollar-per-ton calculation may not be as meaningful as a dollar per deciview calculation." It has been determined that requiring additional controls, beyond BART, on existing point sources will not substantially improve visibility in the Class I Federal Areas. The maximum combined improvement based on the Department's cumulative modeling for the average of the 20% worst days is 0.11 deciviews at LWA and 0.03 deciviews at TRNP for the most efficient control options for each source that is cost effective. This amounts to a 0.17% improvement at TRNP over the baseline condition for the most impaired days and 0.56% improvement at LWA. Other less efficient control technology options would provide substantially less visibility improvement in the Class I areas. The total capital cost to achieve this improvement is approximately 243 million dollars with an annualized cost of approximately 68 million dollars. Based on the data in Tables 9.8 and 9.9, the cost effectiveness is over 618 million dollars per deciview of improvement at LWA and 2.3 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 these non-BART sources during this planning period.** (emphasis added)

According to EPA:
In addition to evaluating the four statutory factors, North Dakota also considered the visibility impacts associated with the control options for each RP source. However, **in modeling visibility impacts, North Dakota used a hybrid cumulative modeling approach that is inappropriate for determining the visibility impact for individual sources.** As with the modeling North Dakota conducted for its NOx BART analysis for MRYS Units 1 and 2 and LOS Unit 2, the approach fails to compare single-source impacts to natural background. While there is no requirement that States, when performing RP analyses, follow the modeling procedures set out in the BART guidelines, or that they consider visibility impacts at all, we find that **North Dakota's visibility modeling significantly understates the visibility improvement that would be realized for the control options under consideration. Accordingly, we are disregarding the modeling analysis that North Dakota has used to support its RP determinations for individual sources.** (emphasis added)

NPS: It is clear from the statement by NDDAQ that the basis for its decision that no additional controls were appropriate was its determination that the resulting cost/deciview would be excessive. It is equally clear that EPA has recognized that the methods used by NDDAQ to reach that conclusion are invalid. For example, NDDAQ refers to the evaluations performed by EC/R as the basis for its cost estimates, and EC/R estimated the cost of SCR at Coyote at $1541 - $3082/ton, which includes costs found by EPA to be acceptable. However, in its Table 9.8, NDDAQ has escalated that cost to $4337 - $6232/ton, noting that it has derived those estimates from the BART cost estimate for LOS#2 and MRYS, which, as EPA has stated repeatedly, are overestimated. EPA has also stated that NDDAQ's method for estimating visibility improvement is invalid. Therefore, both the costs and the visibility improvement values used by NDDAQ to arrive at the cost/deciview values on which it based its RP determinations are invalid.

Under these circumstances, NDDAQ has not met its responsibility to conduct a valid Reasonable Progress analysis, and EPA must therefore assume that responsibility. Nevertheless, EPA is improperly proposing to defer to the NDDAQ determinations, with the Coyote power plant a prime example:

> EPA is proposing to approve the State's conclusion that no additional SO_2 control is warranted for this planning period. The cost effectiveness value for a new wet scrubber is $2,593 per ton. While this is within the range of cost effectiveness values that North Dakota, other states, and we have considered reasonable in the BART context, it is not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context. We emphasize that Coyote currently employs a spray dryer to control SO2 emissions at a control efficiency of approximately 66%. The existence of these controls has also influenced our decision. EPA does not agree with the State's conclusion that no additional NOx controls are reasonable for this planning period. In particular, the cost effectiveness value for ASOFA is $246 per ton. This value is very reasonable and far less than many of the cost effectiveness values the State found reasonable in making its BART determinations. Given the predicted NOx reduction of approximately 5,223 tons per year, and the fact that North Dakota's reasonable progress goals will not meet the uniform rate of progress, we find that it was unreasonable for the State to reject this highly inexpensive control for reasonable progress. However, as noted above, the State reached an agreement whereby the owner/operator of Coyote Station will meet a NOx emission limit of 0.50 lb/MMBtu by July 1, 2018. It is anticipated the source will meet this limit by installing OFA. North Dakota has made this limit enforceable through a permit to construct that it submitted as part of SIP Amendment No. 1. While we disagree with the State's reasoning regarding reasonable progress, we find the proposed limit to be reasonable to meet reasonable

EPA's is obligated to base its decisions upon an objective and rational analysis, and it cannot simply opine that the NDDAQ analysis is seriously flawed and then propose to approve it. Such an approach is inconsistent the Reasonable Progress provisions of the Regional Haze Rule.

We evaluated the costs associated with adding SCR to both AVS and Coyote using the same methods that we used for the BART EGUs, and our results were included in our Comparison Tables file. While the total, incremental, and distance-factored costs/ton of adding SCR at AVS are substantially higher than those costs for LOS#2, and MRYS #1&#2, addition of SCR to the Coyote Station would be more cost-effective than at any other ND EGU, including LOS#2, and MRYS #1&#2.

Reasonable Progress Analysis for Otter Tail Power Company Coyote Station

Otter Tail Power Company (Otter Tail) operates the Coyote Station near Beulah, in Mercer County, North Dakota. The single unit is a cyclone boiler fired with lignite that began operation in 1981 and is rated at 450 MW output. Current emission control equipment consists of a Lime Spray Dryer (SO_2) and Fabric Filter (PM). Of 3581 EGUs in the CAM database in 2010, Coyote ranked #79 for SO_2 at 13,691 tons and #5 for NO_x at 12,323 tons. The Coyote Station is also the second-closest (after AVS) to Theodore Roosevelt NP, and, as a result of its high emissions and proximity, Coyote has the highest Q/d of any ND source.

Considering the magnitude of Coyote's emissions and its proximity to Theodore Roosevelt NP, we are concerned that no analysis was performed of upgrading the Lime Spray Dryer (as at AVS) and that the analysis of adding SCR was cursory, at best. While we commend NDDAQ for reducing allowable NO_x emissions to 0.50 lb/mmBtu, Coyote would still have the highest "controlled" emission limit of any ND EGU. And, had Coyote emitted at an annual rate of 0.50 lb/mmBtu in 2010, it would still have ranked as the #13 largest NO_x emitter of any EGU in the CAM database. All of these factors lead us to believe that additional evaluation of reducing Coyote's NO_x emissions is necessary.

We applied the same cost-estimation methods to Coyote as we used for the other ND EGUs and our detailed analysis is included in this submission. Our results are also summarized in our Comparison Tables file and show that the total ($1600/ton), incremental ($2300/ton), and distance-factored costs/ton of adding SCR at Coyote are substantially lower than those costs for LOS#2, and MRYS #1&#2 (and all other ND EGUs). EPA must be consistent in its approach, and, barring some factor unknown to us—Coyote is similar to LOS#2, and MRYS #1&#2 in boiler type, fuel, and size—EPA must conclude that Reasonable Progress is the same 30-day rolling average limit of 0.07 lb/mmBtu at Coyote.