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:

May 14, 2010

N3615 (2350)

Terry L. O'Clair, P.E., Director
Division of Air Quality
North Dakota Department of Health
Environmental Health Section
918 E. Divide Ave., 2nd Floor
Bismarck, North Dakota 58501-1947

Dear ~~Mr. O'Clair~~ Terry:

As requested in your March 8, 2010, letter, the National Park Service (NPS) is submitting the enclosed comments regarding the proposed Reasonable Progress determinations for the R. M. Heskett Unit #2 near Mandan, North Dakota. R. M. Heskett is located within 300 km of two Class I areas, Lostwood National Wildlife Refuge administered by the U.S. Fish & Wildlife Service, and Theodore Roosevelt National Park administered by the NPS. Our technical comments are enclosed and raise concerns about the estimates of control effectiveness, costs, and visibility improvements.

We look forward to working with the North Dakota Department of Health and with EPA as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd of my staff (don_shepherd@nps.gov, 303-969-2075) if you have any questions or comments.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch

Enclosure

cc:
Callie Videtich
Air Technical Assistance Unit (8P-AR)
U.S. EPA Region V-III
999 18th St., Suite 300
Denver, Colorado 80202-2466

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

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

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

Reasonable Progress Control Technology Analysis

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

Sulfur Dioxide

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

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

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

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

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

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

Step 4: Evaluate Impacts and Document Results

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

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

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

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

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

Nitrogen Oxides

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

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

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

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

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

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

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

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

Time Necessary for Compliance

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

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

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

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

Results, Conclusions & Recommendations

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

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