Burns & McDonnell

January 29, 2007

Mr. Cris Miller
Senior Environmental Projects Administrator
Basin Electric Power Cooperative
1717 E. Interstate Ave
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Leland Olds Station Unit 1and Unit 2
NDDH Comments December 1, 2006
BART Determination Study

Dear Mr. Miller:

Burns & McDonnell has reviewed the letter issued by the North Dakota Department of Health (NDDH) to Basin Electric Power Cooperative (BEPC) dated December 1, 2006[1]. This letter report addresses the issues raised by the NDDH and refers to the results of additional visibility impairment improvement modeling for Unit 1 (submitted as separate documents under separate cover letters) as requested.

Burns & McDonnell was retained by BEPC to perform the previously issued BART Determination Study[2]. Basin Electric Power Cooperative's (BEPC's) Units 1 and 2 at the Leland Olds Station (LOS) were determined to be BART eligible by the NDDH. The referenced BART analysis was conducted in accordance with the eligibility conclusion made by NDDH and follows the steps outlined in the finalized Regional Haze Regulations [RHR] and Guidelines for Best Available Retrofit Technology (BART) Determinations[3] (July 6, 2005) to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The NDDH protocol[4] (November 2005) provided a state specific modeling protocol for use in the analysis.

Burns & McDonnell responses are in the form of reiterating the NDDH's comments verbatim followed by a brief reply to address the issues raised.

NDDH Comment #1 *The National Park Service has indicated that 98% SO_2 control has been proposed on several other projects such as Thoroughbred, LGE-Trimble and Mustang. Although the Department recognizes that such sources have not been built, and that they will be firing coal not common to our region, we ask that Basin provide comments on this issue.*

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[1] See Reference number 1.
[2] See Reference number 2.
[3] See Reference number 3.
[4] See Reference number 4.

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B&McD Response #1 This issue has been addressed by the EPA in the New Source Performance Standards (NSPS) recently promulgated as final rule amendments to 40 CFR part 60, subparts Da, Db, and Dc emission standards effective February 27, 2006[5].

In establishing the final SO_2 emission standards for EUSGUs, in specific response to the issue of reflecting best demonstrated technology (BDT) for SO_2 removal greater than 98 percent, the "EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended SO_2 standard is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions".[6]

Basin Electric has provided information regarding predicted future coal quality that indicates a higher level and variability of sulfur content that will be required to be controlled. Burns & McDonnell believes that it would not be possible to operate the units at Leland Olds Station continuously under ideal operating conditions such that an average 98% level of SO_2 emissions control could be sustained for every 30-day rolling period. The projects mentioned by the National Park Service have not been constructed and have not demonstrated the ability to achieve and sustain 98% SO_2 emissions control for every 30-day rolling period.

Burns & McDonnell believes that a 30-day rolling average requirement of 98 percent control suggested by the National Park Service as BART for SO_2 removal is inappropriate for the EUSGUs at Leland Olds Station. The referenced BART Determination Study report[7] analysis for Unit 1 and Unit 2 evaluated available technologies and recommended effective levels of SO_2 removal considered suitable for the determination of BART appropriate for this facility given the statutory factors required for the analysis.

NDDH Comment #2 *With respect to the 90% and 95% SO_2 control options, emission rates were provided that are based on coal-to-stack control efficiencies. We believe a wet scrubber is capable of achieving 95% control of the inlet concentration to the scrubber and dry scrubber is capable of achieving 90%. Emission rates that reflect 90% and 95% inlet to outlet control efficiencies should be provided.*

B&McD Response #2 The BART SO_2 emission rates provided in the BART Determination Study report were calculated based upon 100% of the sulfur input in the coal assumed to be converted to SO_2 in the boiler and emitted in the flue gas. The FGD scrubber SO_2 removal efficiencies for Leland Olds Station boilers were assumed to be relative to the inlet mass rate and type of scrubber for the respective boilers: 90% for Unit 1's dry scrubber, and 95% for Unit 2's wet scrubber. Likewise, the recommended 30-day rolling average SO_2 BART emission limits were calculated similarly, with sulfur and heat contents of the lignite coal being changed to be reflective of expected

[5] See Reference number 5.
[6] Ibid Reference 5, pg 9870.
[7] Ibid Reference 2.

higher short-term future variability in the sulfur concentration and lower fuel heat content[8]. The analysis did not assume any reduction of lignite sulfur input assumed due to fuel processing or boiler firing, and this is consistent with normally accepted practice for estimating emissions at the inlet of an SO_2 control device. This also agrees with the EPA's recommended method for calculating Potential To Emit emission rates as defined in the NSR Manual[9]. Burns & McDonnell believes that the appropriate method to calculate outlet emissions for the BART Determination Study analysis of the Leland Olds Station units is to assume that 100% of the calculated sulfur predicted to be contained in the future coal feed to the boiler is converted to sulfur oxides. The presumed level of SO_2 control was applied across the FGD scrubber to the inlet mass emissions, and subsequently resulted in the amount of SO_2 mass emissions released to the atmosphere that was included in the referenced study report.

NDDH Comment #3 *For Unit 1, basic separated overfire air (SOFA) with selective non-catalytic reduction (SNCR) was evaluated for costs. However, no modeling was conducted to show the effects on visibility for this alternative. The Department believes that close examination of all factors associated with this alternative will be necessary before such an alternative can be eliminated. As we have indicated in the past, BART selection is made using the top-down approach considering all the statutory factors including visibility improvement. Although the presumptive level factor will be weighed in our BART determination, we also believe it is necessary to conduct a complete evaluation of more efficient technologies that may be cost-effective. Therefore, the Department requests that modeling be conducted for the basic SOFA plus SNCR alternative and the results submitted for review. In addition, the remaining factors (i.e., energy impacts, non-air quality environmental impacts, etc.) should be addressed.*

B&McD Response #3 There is published and regulatory agency-provided information associated with the RHR that conflicts with the premise that all technically feasible control alternatives that are cost-effective and have minimal energy and non-air environmental impacts must be evaluated for visibility impairment impact as part of a BART Determination process. The BART Stakeholder Meeting with the NDDH on July 27, 2005 included an NDDH verbal response to the question (paraphrased) "If a source agrees to presumptive limits even though they are at a facility that is less than 750 MW, would a BART Determination be required along with Air Quality Modeling? The NDDH verbal response referenced the RHR BART Guideline (presumably pg 68 of the final July 6, 2005 FR version of the RHR) which, when paraphrased, essentially states that if a source applies the most stringent applicable technology, then it is not required to perform the Air Quality modeling. Also, the NDDH is believed to have asked EPA Region 8 this (or a similar) question and their quick answer was basically that if a utility accepted presumptive BART not only would they not perform the AQ modeling they would not have to perform a BART determination for that unit for that pollutant.

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[8] Ibid Reference 2, pages 158 and 233 for Unit 1; pages 188 and 236 for Unit 2.
[9] See Reference number 6, Article II.B.6, page A.19.

In the EPA's corrected RHR Comment Response Document, the EPA provided a response to a commenter (0215) that said "if an EGU is achieving the default/presumption for NOx, it should not be required to do a BART determination for that pollutant" [10]. The EPA's response in this same document was "We agree that a streamlined BART process is warranted for such sources"[11].

Because the EPA established the presumptive BART NO_X emission limits based on combustion controls for boilers other than cyclone-fired ones, post-combustion controls for sources without existing post-combustion controls, including selective non-catalytic reduction (SNCR) technology "are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis"[12].

LOS Unit 1's highest 24-month rolling average NO_X emission rate during the years 2000-2004 was 0.285 lb/mmBtu. This was slightly below the presumptive BART level of 0.29 lb/mmBtu for a lignite-fired dry-bottom pulverized coal boiler greater than 200 MW located at a power plant with a generating capacity of more than 750 MW. The BART Determination Study report recommended a 30-day rolling average BART NO_X emission rate for LOS Unit 1 of 0.29 lb/mmBtu[13]. The RHR leaves it up to the individual states to determine whether to apply the EPA's presumptive BART NO_X emission rate limits for units greater than 200 MW operating at power plants with a total generating capacity of less than 750 MW.

Thus, due to the EPA's comment response coupled with direct feedback from NDDH regarding the specific relevant issue, there was reason to believe that if BEPC accepted the presumptive BART NO_X emission limit of 0.29 lb/mmBtu for a lignite-fired dry bottom pulverized coal boiler greater than 200 MW located at a power plant with a generating capacity of more than 750 MW for Unit 1, that a BART analysis and visibility modeling of all feasible NO_X reduction technologies including post-combustion alternatives would not be required for LOS Unit 1. Basin's BART Determination Study report analysis for Unit 1 did, however, include the technical feasibility analysis of appropriate, available NO_X reduction technologies, along with visibility modeling and impairment improvement evaluation for a single combustion control-based alternative with the next lowest emission rate (basic SOFA).

As shown in Table 2.4-14 of Basin's BART Determination Study report[14] analysis for Unit 1, the incremental visibility impairment reduction of SOFA vs. presumptive NO_X emissions based on future PTE heat input conditions was typically less than 0.01 at three TRNP Class 1 areas, and was below 0.02 at Lostwood NWR. The corrected incremental control cost increases significantly from basic SOFA to the SNCR with basic SOFA alternative ($4,060/ton) vs $208/ton for basic SOFA versus presumptive NO_X emissions for the future PTE pre-control case. The expected incremental

[10] See Reference 7, page 238.
[11] Ibid Reference 7, page 238.
[12] Ibid Reference 3, page 39134.
[13] Ibid Reference 2, page ES-4 and page 241.
[14] Ibid Reference 2, page 88.

visibility impairment reduction of SNCR with SOFA vs. basic SOFA was found to be of a similar very small magnitude (maximum 0.021 dV) because the NO_X emission rate change of 0.062 lb/mmBtu (0.230-0.168 lb/mmBtu) between these alternatives was comparable to the NO_X emission rate change of 0.060 lb/mmBtu (0.290-0.230 lb/mmBtu) from presumptive NO_X to basic SOFA.

While the RHR BART Guidelines[15] do not use the words "top-down", it is left up to the states to establish the appropriate approach for the BART analysis and determination. The referenced BART Determination Study report[16] analysis for Unit 1 evaluated available technologies and recommended effective levels of NO_X emissions considered suitable for the determination of BART appropriate for this facility given the statutory factors required for the analysis.

In a spirit of cooperation, the visibility improvement modeling and analysis of the impacts, including the other statutory factors required for a BART determination for the SNCR with basic SOFA alternative applied to LOS Unit 1's pre-control NO_X emissions are being provided to the NDDH as a separate document[17].

NDDH Comment #4 *We would like a better explanation of how the estimated emissions for the various alternatives for NO_X control were estimated. The discussion should include emissions achieved at other facilities based on these alternatives and how those numbers compare to proposed emission rates for Leland Olds Station.*

B&McD Response #4 The referenced BART Determination Study report[18] provided numerous references on pages 127-131 and an extensive list summarizing recent NO_X reduction projects in the United States in Appendix A3. Although there is a significant amount of experience with certain commonly applied techniques and technologies for NO_X control on coal-fired boilers, such as low-NO_X burners (LNBs) and separated overfire air, there is a noticeable lack of such experience on wall-fired pulverized coal and cyclone boilers designed and built for firing North Dakota lignite.

For LOS Unit 1, the long-term average pre-control NO_X levels with original burners but without close-coupled overfire air (CCOFA, prior to 1995) were estimated to be much higher than 0.29 lb/mmBtu. The EPA's Technical Support Document for BART NO_X Limits[19] published with the RHR Guidelines established a Pre-Control rate of 0.74 lb/mmBtu and an Effective Control Case 1a NO_X Emission Rate of 0.23 lb/mmBtu for LOS Unit 1. This would be a pre-to-post control reduction of approximately 69 percent, which is higher than the example low-NOx burner retrofits summarized in Appendix A3 (pages A3-13 though A3-15) of the referenced BART Determination Study report. The EPA's Case 1a assumed installation of current NO_X combustion

[15] Ibid Reference 3.
[16] Ibid Reference 2.
[17] See Impacts Analysis of Basic SOFA with SNCR Alternative for Leland Olds Unit 1, 1/29/2007.
[18] Ibid Reference 2.
[19] See Reference 8, Excel Spreadsheet page 270.

controls (LNBs and SOFA) for units with no prior controls, or which have controls installed before 1997. This is the situation applicable to Leland Olds Station Unit 1.

Considering the information included above and in other available technical literature, the referenced BART Determination Study report established 0.23 lb/mmBtu as the estimated post-control 24-month rolling average NO_X emission rate for LOS Unit 1 when retrofitted with SOFA in combination with low-NOx burners. This was a 20.7% reduction from the presumptive BART NO_X rate of 0.290 lb/mmBtu[20]. The referenced BEPC LOS BART study's Unit 1 visibility improvement modeling and impact analysis also assumed a 20.7% reduction from the average NO_X rate of 760.4 lbs/hr (presumptive BART) to 603.1 lbs/hr for the highest 24-hour (daily) post-control condition with low-NOx burners and SOFA[21]. SNCR with basic SOFA assumed an additional 26.8 percent reduction beyond the 0.23 lb/mmBtu basic SOFA control level, estimated to be 0.168 lb/mmBtu or 42 percent below the presumptive BART baseline of 0.29 lb/mmBtu[22]. This estimated additional reduction percentage for SNCR performance applied to LOS Unit 1 is similar to the levels achieved by other wall-fired boilers retrofitted with this technology as summarized in Appendix A3 (pages A3-21 though A3-26) of the referenced BART Determination Study report. It is also 77.3% lower than the EPA's Pre-Control NO_X emission rate of 0.74 lb/mmBtu.

For LOS Unit 2, the long-term average pre-control NO_X levels with previous firing practices was estimated to be much higher than the pre-control future PTE baseline of 0.67 lb/mmBtu established in the referenced BART Determination Study report[23]. The EPA's Technical Support Document for BART NO_X Limits[24] published with the RHR Guidelines established a Pre-Control rate of 1.03 lb/mmBtu and an Effective Control Case 1a NO_X Emission Rate of 0.52 lb/mmBtu for LOS Unit 2. This would be a pre-to-post control reduction of approximately 50 percent, which is similar or higher than some of the cyclone SOFA retrofits with modest amounts of substoichiometric combustion summarized in Appendix A3 (pages A3-1 though A3-2) of the referenced BART Determination Study report. The EPA's Case 1a assumed installation of current NO_X combustion controls for units with no prior controls, or which have controls installed before 1997. The current combustion control technology analyzed by the EPA for cyclone units is coal reburning[25]. This is the situation applicable to Leland Olds Station Unit 2.

Considering the information included above and in other available technical literature, the referenced BART Determination Study report established 0.48 lb/mmBtu as the estimated post-control 24-month rolling average NO_X emission rate for LOS Unit 2 with the advanced form of SOFA, which was a 28% reduction from the pre-control

[20] Ibid Reference 2, Table 2.3-2 on page 58.
[21] Ibid Reference 2, Table 1.4-1 on page 19, and pages 85-95.
[22] Ibid Reference 2, Table 2.3-2 on page 58.
[23] Ibid Reference 2, Table 2.3-4 on page 61.
[24] Ibid Reference 8, Excel Spreadsheet page 270.
[25] Ibid Reference 3, page 39134, footnote 63.

future PTE baseline rate of 0.67 lb/mmBtu[26]. The referenced BART study's LOS Unit 2 visibility improvement modeling and impact analysis also assumed a 0.48 lb/mmBtu NO_X emission rate with the advanced form of SOFA, which represents a reduction of nearly 38 percent from the average NO_X rate of 3,959 lbs/hr for the highest 24-hour (daily) post-control condition without ASOFA[27]. The referenced BART study also assumed an additional 36.7 percent reduction beyond the 0.48 ASOFA control level for the 24-month rolling average NO_X emission rate of LOS Unit 2's SNCR with ASOFA alternative, estimated to be 0.304 lb/mmBtu or 54.5 percent below the future PTE pre-control baseline of 0.67 lb/mmBtu[28].

The expected post-control SNCR NO_X emission rate depends on the NO_X inlet concentration, type of reagent (aqueous urea), the amount of time that the flue gas is within the optimum temperature window for the SNCR process, and the amount of ammonia slip that is considered acceptable. Generally, the higher the NO_X inlet concentration and/or allowable ammonia slip in the boiler outlet flue gas, the higher the NOx reduction percentage that can be achieved. This estimated additional reduction performance for SNCR applied to LOS Unit 2 is similar to or better than the percentage reductions achieved by other cyclone-fired boilers retrofitted with this technology as summarized in Appendix A3 (pages A3-7 though A3-9) of the referenced BART Determination Study report. The amount of ammonia slip emitted was not always disclosed in the technical literature or vendor experience summaries for SNCR projects, and this has a significant influence on the resulting NO_X reduction expected.

The Alliant Edgewater Unit 4 and AmerenUE Sioux Unit 1 cyclone SOFA retrofits were operated with substantially more substoichiometric combustion conditions (below 0.90) than expected to be sustainable at LOS for Unit 2. Therefore, those NO_X reduction projects summarized in the referenced BART Determination Study report have reported greater percentage NO_X emission rate reductions resulting from deeply-staged cyclones and SOFA than are anticipated for LOS Unit 2 for operation with modestly-staged cyclones and ASOFA. As described in the referenced BART study, there is significant concern about the ability to control and sustain adequate ash slag fluidity, coverage, and tapping during deeply-staged cyclone operation for LOS Unit 2 when firing lignite coal. This means that the subsequent estimates for NO_X emission rates when ASOFA is considered alone and when combined with other technically-feasible technologies at LOS for Unit 2 will not reach the low levels of NO_X emission rates that were demonstrated on subbituminous coals at these other cyclone-fired boilers[29].

NDDH Comment #5 *We ask that you address the use of combustion optimization systems (COS) for the reduction of NO_X emissions from both units.*

[26] Ibid Reference 2, Table 2.3-4 on page 61.
[27] Ibid Reference 2, Table 1.4-1 on page 19, and pages 116-126.
[28] Ibid Reference 2, Table 2.3-4 on page 61.
[29] Ibid Reference 2, Appendix A3, pages A1, and A3-7 through A3-9.

B&McD Response #5 When establishing presumptive NO_X emission limits for BART-eligible coal-fired units, the RHR Guidelines did not include combustion optimization systems as "types of current combustion [NO_X] control technology options assumed include low NO_X burners, over-fire air, and coal reburning"[30]. All boilers that fire fuel to generate steam include some form of combustion control, primarily to safeguard personnel and equipment from inappropriate operation that could result in explosions. "Combustion optimization systems (COS) refers to the active control of combustion. These active combustion control measures seek to find an optimum combustion efficiency and to control combustion (and hence emissions) at that efficiency. Another approach uses a neural network computer software program to find the optimum control point. Still another approach is to use software to optimize inputs for the defined output"[31].

COS have been developed over the past ten years to manipulate boiler fuel/air combustion hardware adjustments to reduce NO_X and minimize CO emissions, increase boiler thermal efficiency, decrease flyash combustibles loss (also called LOI or loss-on-ignition), and decrease flue gas temperature variations within the furnace. There are two major aspects to COS:

- the control system with its software and hardware controllers; and
- the field devices, which include actuators and sensors.

COS can be operated on a stand-alone basis or combined with other optimization systems for furnace sootblowers, boiler steam cycle efficiency and capacity, and post-combustion NO_X reduction and reagent injection control.

A reference technical paper summarizing combustion controls for the western region of the United States stated that the number of neural networks installed at any of the 110 coal-fired EGUs in the WRAP paper was "unknown but significant". It also stated that "at least 35 installations of GNOCIS have been identified, and Pegasus [NeuSIGHT, by NeuCo, Inc.] has many more, however, the total number of installations of neural networks with enhanced monitoring could not be identified. However, enhanced monitoring has been in use for a number of years and it is expected that many units do utilize some form of it to optimize performance"[32]. It should be noted that neural networks were listed as an addition to low NO_X burners, close-coupled and separated overfire air combustion controls for state-of-the-art NO_X reduction techniques, but not for cyclone-firing.

One COS vendor offers technology "to integrate existing controls, control systems, sensors and computer hardware with advanced optimization techniques in a proprietary software environment to reduce emissions, increase efficiency, and increase availability. [This technology] literally learns on-line the interrelationships between important process control settings and real-time performance, constantly searching for overall performance improvements and make adjustments automatically and in real-

[30] Ibid Reference 3, page 39134.
[31] See Reference 9, page 16.
[32] See Reference 10, Table 3 on page 3-7, and page 3-11.

time"[33]. One of the COA projects mentioned in the referenced technical literature is a 2003-2007 U.S. DOE Clean Coal Power Initiative (CCPI) project at Dynegy Midwest Generation's Baldwin Energy Complex[34]. The initial potential benefits expected from the implementation of this demonstration project identified "NO_X emissions reductions of 5%"[35].

According to data presented in a early 2006 technical journal, the average NO_X concentration at the inlets to the Baldwin Unit 1 cyclone boilers' SCR reactors can be reduced by approximately 7.7% from non-optimized baseline[36]. Total Project Funding is budgeted at $19 million, and this does not "entail the addition of process equipment" to the host facility[37]. It should be mentioned that a significant amount of field instrumentation and distributed control systems and local area networks already installed at Baldwin Station were likely the main reasons why this latter statement was made. Unfortunately, it is not possible to determine the actual installed cost of the NO_X emission reduction portion of this project that would normally be attributable to the scope of the neural network COS, and how this might relate to the cost of a commercially-available, dedicated COS for each cyclone or tangentially-fired boiler at Baldwin.

Another technical paper from April 2005 describes some improvements made to the neural control software model initially used for controlling NO_X by controlling cyclone combustion air/fuel stoichiometry at Baldwin Station. It is unclear that the claimed NO_X reductions achieved fairly early in the demonstration project (15-20%) were sustainable or that they represent only those gains strictly due to the COS. There were aspects of the COS methods that were incomplete or had detrimental effects to other operations that led to further changes in the tuning of the optimizer[38].

Several referenced technical papers have been written summarizing another COS called Generic NO_X Control Intelligence System (GNOCIS), applied at Southern Company's Georgia Power - Plant Hammond Unit 4. "GNOCIS is a software package designed to improve utility boiler efficiency and reduce NO_X emissions through careful control of operating parameters. GNOCIS can operate on units that burn gas, oil, or coal and is available for all combustion firing geometries". Also, "GNOCIS uses a neural network to model the combustion characteristics of a boiler. In one of the more common forms, a neural network (computer code that models a system's responses) consists of three layers: an input layer, a hidden layer, and an output layer. The input layer receives signals from monitored variables and transmits them to the hidden layer, which contains interconnected neurons for pattern recognition. After processing, signals are sent to the output layer, which outputs recommend settings for the control variables. Thus, a neural network is, in effect, a sophisticated curve-fitting tool. Neural networks

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[33] See Reference 11.
[34] See Reference 12.
[35] See Reference 12 Fact Sheet and Reference 13 background sheet.
[36] See Reference 14, Figure 3, page 3.
[37] Ibid Reference 12, page 2 and page 1.
[38] See Reference 15.

can recognize patterns in input data, but before the network can associate a particular pattern with a corresponding plant state, it must be "trained". The training phase can be time consuming and usually involves feeding historical data to the program. However, once a network has been trained, it can respond very rapidly to new inputs. An advantage of a neural network is that, if any inputs are faulty, prediction capability degrades only gradually compared to most other modeling techniques. In order for GNOCIS to function effectively, a properly designed and installed control system is essential"[39].

The vast majority of these COS are believed to have been applied to pulverized coal-fired boilers with low-NO_X burners and SOFA[40]. The reference technical literature stated that testing with the GNOCIS program set to control boiler operations, full-load NO_X emissions were reduced from between 14 percent and 10 percent over baseline, depending on the mode that the COS was operating in. The COS mode for minimizing NO_X emissions at full load produced the 14% reduction, maximizing efficiency operating mode showed a 12% decrease, while the minimize flyash LOI mode resulted in the 10% drop over full-load baseline emissions[41].

In regards to the cost of this COS, "If a distributed control system (DCS) is present, installing GNOCIS on the boiler is relatively inexpensive and can significantly improve plant operations".[42] Also, "Estimates by the participant for costs that could be used for planning a retrofit a 500-MWe power plant similar to Hammond Unit 4 are: GNOCIS $0.25 million ($0.50/kW). These estimates are based upon actual Hammond Unit 4 costs, as well as cost data available from EPRI and other sources. Of course, site-specific factors, such as boiler size, age, design, furnace configuration, windbox design, and condition, plant layout, etc., can significantly affect these estimates. Insufficient data are available to allow estimation of installing full unit optimization hardware and software"[43].

Due to the time span from the actual installation of the digital control system in June 1994 followed by GNOCIS testing starting in February 1996, until the date of the reference technical report (March 2004) and then to the present (January 2007), the expected cost of installing this COS at Hammond Unit 4 is difficult to estimate in today's dollars from a review of the available technical literature.
There have been few published technical papers or articles in utility trade journals/magazines that document COS applied to cyclone-fired boilers. One 2002 technical reference provided an implementation cost range between $30 and $60/kW, claiming fuel and operating flexibility for low NO_X emission rates from tangentially-fired, wall-fired, and cyclone-fired boilers[44]. The exact details of such modifications have not been published, although the general scope of this referenced firm's COS

[39] See Reference 16, pages 17 and 18.
[40] Ibid Reference 10, pages 3-11 and 3-12.
[41] Ibid Reference 16, page 8.
[42] Ibid Reference 16, page 9.
[43] Ibid Reference 16, pages 43 and 44.
[44] See Reference 17, page 4.

involved changes that went well beyond what is typically included for these kinds of retrofit projects in terms of field instrumentation and controls hardware. Unfortunately, it is not possible to determine the actual installed cost of the portion and the amount of NO_X emission reductions for these projects that would normally be attributable to the scope of traditional COS "neural network" retrofit projects.

Basin has already implemented improvements to the Leland Olds Station Unit 2 boiler distributed controls system in spring 2006, and plans on installing similar DCS control upgrades on Unit 1 in fall 2007. It is difficult to estimate the amount of potential NO_X emission reductions and costs of adding available commercial COS to either LOS unit due to the site-specific nature of such installations. The need to identify the levels of field instrumentation and control devices for integration with the COS and the fact that the alternatives recommended as BART for NO_X control have not been installed would require further detailed investigation. The opportunity to make significant additional NO_X emission reductions strictly from adopting and adapting neural networks to the LOS boilers is uncertain but is believed to be limited due to the improvements already planned and/or incorporated by the installation of the DCS upgrades and other operational procedures in effect.

An electronic copy of this document has been sent to you via email. The referenced "Impacts Analysis of Basic SOFA with SNCR Alternative for Leland Olds Unit 1, 1/29/2007" has been sent to you via email with a separate cover letter.

As always, please contact Bob Blakley at (816) 822-3842 rblakley@burnsmcd.com, or Carl Weilert at (816) 822-3103 or cweilert@burnsmcd.com if questions arise.

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References:

1- NDDH Environmental Health Section letter by Terry L. O'Clair, P.E. to Cris Miller, Basin Electric Power Cooperative, Re: BART Determination Study, dated December 1, 2006.
2- "BART DETERMINATION STUDY for Leland Olds Station Unit 1 and 2 Basin Electric Cooperative" Final Draft, August 2006.
3 - Federal Register /Vol. 70, No. 128/ Wednesday, July 6, 2005 / Rules and Regulations, Part III Environmental Protection Agency 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule.
4 - "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final)", November, 2005, North Dakota Department of Health (NDDH), Division of Air Quality.
5 - Federal Register /Vol. 71, No. 38/ Monday, February 27, 2006 / Rules and Regulations, Part II Environmental Protection Agency 40 CFR Part 60, Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule.
6 - EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").
7 – EPA docket Regional Haze Regulations; Revisions to Provision Governing Alternative to Source-Specific Best Available Retrofit Technology (Bart) Determinations, "Comment Response Document – correction", OAR-2002-0076-0508, dated June 16, 2005.
8 – Technical Support Document Methodology For Developing BART NOx Presumptive Limits, Environmental Protection Agency, Clean Air Markets Division, June 15, 2005, OAR-2002-0076-0445, with Attachments, including Excel Spreadsheet OAR-2002-0076-0446 (1199 pages).
9 – EPA Technical Bulletin – Nitrogen Oxides (NOx), How and Why They Are Controlled, Clean Air Technology Center, Office of Air Quality Planning and Standards (OAQPS), EPA 456/F-99-006R, November 1999.
10 – "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region, Draft Report", prepared for the Western Regional Air Partnership by Eastern Research Group, Inc., ERG Contract Number 30204-101, dated April 26, 2005, available at:
http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf
11 – "Integrated Optimization Of Combustion And Post-Combustion Systems For Coal-Fired Boilers", by Dr. Daniel Kohn and Rob James, NeuCo, Inc., and Dr. Soung S. Kim, U.S. Department of Energy. Available at
http://www.netl.doe.gov/publications/proceedings/03/scr-sncr/Final_Kohn.pdf
12 – "Demonstration of Integrated Optimization Software at the Baldwin Energy Complex", 2003 CCPI Program project brief available at
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