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October 4, 2012

Attention: Draft Permit No. 0170004-038-AC

Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management
Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

Via email and hand delivery

RE: Comments regarding Progress Energy Florida, Inc.'s draft air construction permit for the Crystal River Power Plant (Draft Permit No. 0170004-038-AC)

Dear Mr. Koerner:

Thank you for accepting these comments on behalf of the Sierra Club, National Parks Conservation Association, Earthjustice, and their hundreds of members in Florida who will be substantially affected by the draft permit for construction at Progress Energy's existing Crystal River Power Plant which is located in Citrus County at 15760 West Power Line Street in Crystal River, Florida. This permit does not assure compliance with state or federal law, and should not be issued in its current form.

This permit is being issued as part of the Florida Department of Environmental Protection's proposed Florida Regional Haze State Implementation Plan, which is required by the Clean Air Act and by Florida law. The permit is apparently intended to implement a "Best Available Retrofit Technology" (BART) determination for Crystal River's Units 1 and 2. These units are aging, largely uncontrolled coal-fired boilers which emit a variety of haze-causing pollutants including NO_X, a dangerous air pollutant which also contributes to visibility impairment in Florida.[1]

[1] FL DEP, *Regional Haze Plan for Florida Class I Areas*, (Amended September 17, 2012)("Florida Haze Plan") at 131-133. (Sets out the proposed BART determinations implemented by this permit.)

Our analysis indicates that the Crystal River BART determination cannot assure compliance with required reductions in visibility-impairing pollutants. The permit fails to set emissions limits for NO_X which are commensurate with BART if the facility does not retire by December 31, 2020.

This permit, therefore, may not properly issue. "The Department may issue a permit only after it receives reasonable assurance that the installation will not cause pollution in violation of any of the provisions of Chapter 403, F.S., or the rules promulgated thereunder."[2] This permit violates both prongs of this requirement. For the reasons explained in the attached analysis, it does not reasonably assure compliance with the Florida BART rule, 62-296.340, the federal regional haze rule, 40 C.F.R. § 51.308 (which is incorporated by reference into Florida law), or the Clean Air Act, 42 U.S.C. § 7491.

The permit also offers no reasonable assurance that Crystal River will not "cause pollution in violation" of Florida law.[3] Pollution is:

> The presence in the outdoor atmosphere or waters of the state of any substances, contaminants, noise, or manmade or human-induced impairment of air or waters or alteration of the chemical, physical, biological, or radiological integrity of air or water in quantities or at levels which are or may be potentially harmful or injurious to human health or welfare, animal or plant life, or property or which unreasonably interfere with the enjoyment of life or property, including outdoor recreation unless authorized by applicable law.[4]

As our comments below explain, Crystal River's proposed emissions, authorized by this draft permit, will continue to cause or contribute to visibility impairment in the region's Class I areas and across the state due to the presence of NO_X which, again, is a dangerous pollutant that contributes significantly towards smog and acid rain.

The proposed emissions levels do not reflect an adequate NO_X BART determination as they are higher than they should be, and so will allow visibility impairment and high levels of NO_X pollution to persist longer and more severely than a legally-compliant permit would do. The permit therefore harms the health and welfare of the people, plants, and animals of the region, and further unreasonably interferes with the enjoyment of the property affected by Crystal River's emissions.

I. Overview

The draft permit's NO_X BART determinations are legally and technically flawed.

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[2] F.A.C. 62-4.030; *see also* 62-4.070(1) (same); 62-212.300(3)(a)(2) (requiring applicant to demonstrate that they will comply with all relevant law)

[3] *See* F.A.C. 62-4.030

[4] F.S. 403.031(7)

This permit has plainly been proposed as part of the implementation process for Florida's Regional Haze Implementation Plan, and so must be evaluated based upon its compliance with relevant haze rules. With regard to NO_X, Florida DEP proposes two future emissions reduction scenarios to satisfy the Florida Regional Haze Implementation Plan for NO_X BART, from which Progress would have to select one of these options by January 1, 2015.[5] The options are: (1) ending coal combustion operations at Crystal River Units 1 and 2 by December 31, 2020, or (2) installing and operating NO_X control systems including selective catalytic reduction (SCR) systems before January 1, 2018, or within five years of the effective date of EPA's approval of this specific requirement in the Florida Haze Plan, whichever is later. Under this option, Crystal River may emit no more than 0.09 pounds of NO_X per million metric Btu (lb NO_X/MMBtu) on a 30-boiler operating day rolling average basis for Crystal River Units 1 and 2.[6] Florida's Haze Plan currently focuses on BART for Crystal River "under the option to shut down these units," but explains that if Progress "choose[s] not to shutdown," the NO_x limits in "Permit No. 017004-038-AC"—this proposed permit—shall apply.[7] Progress's application likewise explains that this permit is needed to comply with BART requirements.[8]

We focus our discussion on NO_X BART option 2 below. Option 2 is not BART because it does not set emissions levels commensurate with the "*best* available retrofit technology," and so allows impermissibly excessive emissions. The permit may not issue with these options in their current form.

II. NO_X Visibility Impairment in Florida

NO_X is an important contributor to visibility impairment in Florida. Progress Energy Florida's Crystal River Power Plant is a BART-eligible source of NO_X, so must it be properly controlled to ensure protection of wild spaces and public health.

The regional haze program imposes a legal obligation on all states to abate the adverse visibility effects[9] to which its haze causing facilities contribute in order to restore visibility levels to their natural conditions as mandated by the Clean Air Act. Emissions from many states contribute

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[5] FL DEP, Crystal River Power Plant Units 1 and 2 Draft Air Permit (Air Permit No. 0170004-038-AC) at 3.

[6] FL DEP, *Technical Evaluation and Preliminary Determination* (Crystal River Power Plant Units 1 and 2) ("TEPD") at 4.

[7] FL DEP, *Regional Haze Plan for Florida Class I Areas*, (Amended September 17, 2012)("Florida Haze Plan") at 133, 135-36.

[8] Progress Energy, *Crystal River South Power Plant Application for A Minor Source Air Construction Permit for SCR Installation* ("Progress Application") at 1-2 (Sept. 2012).

[9] Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances, color and geologic formation. While some haze causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze forming pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), volatile organic compounds (VOCs), and ammonia (NH_3) contribute directly to haze or form haze after being converted in the atmosphere. These air pollutants contribute to the deterioration of air quality and reduced visibility in our nation's national parks, wilderness areas, and wildlife refuges. Visibility impairment is measured in deciviews, which is understood as the perceptible change in visibility. The higher the deciview value is, the worse the impairment.

significantly to visibility impairment at the region's Class I areas. Florida has three Class I areas within its borders for which visibility is considered to be an important value: Everglades National Park, Chassahowitzka Wilderness Area, and St. Marks National Wildlife Refuge; it also impact Class I areas in nearby states. In order to reach the mandated goal of natural visibility, it is important for Florida to minimize its emissions in accordance with the Regional Haze Rule.

NO_X causes visibility impairment and also harms public health. It is a precursor to ground level ozone, which is associated with respiratory diseases, asthma attacks, and decreased lung function. In addition, NO_X reacts with ammonia, moisture, and other compounds to form particulates that can cause and worsen respiratory diseases, aggravate heart disease, and lead to premature death.[10]

Haze-causing emissions can also harm terrestrial and aquatic plants and animals, soil health, and moving and stationary waterbodies—entire ecosystems—by contributing to acid rain, ozone formation, and nitrogen deposition. Nitrogen deposition, caused by wet and dry deposition of nitrates derived from NO_X emissions, causes well known adverse impacts on ecological systems.[11] Acid rain causes acidification of lakes and streams and can damage certain types of trees and soils. In addition, acid rain accelerates the decay of building materials and paints, including irreplaceable buildings, statues, and sculptures that are part of our nation's cultural heritage.[12] Further, haze-causing pollutants are precursors to ozone. Ground-level ozone formation impacts plants and ecosystems by: "interfering with the ability of sensitive plants to produce and store food, making them more susceptible to certain diseases, insects, other pollutants, competition and harsh weather; damaging the leaves of trees and other plants, negatively impacting the appearance of urban vegetation, as well as vegetation in national parks and recreation areas; and reducing forest growth and crop yields, potentially impacting species diversity in ecosystems."[13]

According to DEP, baseline visibility impacts for Crystal River units 1 and 2 weres 6.43 dv (apparently at the Chassahowitzka Class I area) for 2003 with 29.5% contributed from nitrate and NO_2.[14] Thus, NO_X emissions from these units contribute to nearly one-third of the total visibility impacts resulting from Crystal River's air pollution emissions. Reducing NO_X emission from units 1 and 2 by over 90% will significantly improve air quality and visibility from current conditions.

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[10] EPA, Health – Nitrogen Dioxide, http://www.epa.gov/air/nitrogenoxides/health.html (last visited October 3, 2012).

[11] See, e.g., discussion of impacts on Everglades National Park, available at http://www.nature.nps.gov/air/Permits/aris/ever/?CFID=18408140&CFTOKEN=17241962

[12] Available at http://www.epa.gov/acidrain/effects/index.html

[13] Available at http://www.epa.gov/glo/health.html

[14] Florida Haze Plan at 133. Baseline visibility impacts estimate based on the maximum 8th highest 24-hour average visibility impact contributed by nitrate particles and NO_2. DEP must also consider the visibility impacts of Crystal River's NO_x emissions on other Class I areas which it affects. It does not appear to have done so, but must complete this analysis, if it has not, before finalizing the permit in any form, because the analysis affects the BART determination implemented by this permit.

III. NO_X BART at Crystal River Unit 1 and Unit 2

The proposed draft air permit for Crystal River Units 1 and 2 correctly selects SCR as BART, but fails to set the appropriate control efficiency standards. The proposed 0.09 lb NO_X/MMBtu allowable emission rate is not BART because lower emission rates can be cost-effectively achieved. When this is corrected, an emission limit of no higher than 0.05 lbs NO_X/MMBtu emerges as the appropriate control. We discuss the details associated with this analysis below.

First, prior to any of the steps involved in a BART analysis, we note that Crystal River Units 1 and 2 have improperly been evaluated jointly. These units are similar, but are of different sizes—Unit 1 is equipped with a 499 foot stack and Unit 2 has a 502 foot stack[15]—and have different existing controls installed. We believe a separate analysis would be more appropriate. Likewise, the proposed BART limit is combined across the two units. This obscures the emission reduction from each unit; unit-specific limits are required.

BART is defined as an emission limitation that is:

> . . . based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[16]

The five-step BART process outlined in EPA's BART Guidelines makes clear that BART requires an evaluation of the top level of pollution reduction achievable with each control system evaluated in a BART analysis. EPA's BART Guidelines provide that, if a control system can be operated at a wide range of control efficiencies, "the most stringent emissions control level that the technology is capable of achieving" must be evaluated.[17] The BART Guidelines further require that "[y]ou should consider recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate."[18]

The BART Guidelines also provide:

> In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review, or regarding the prior

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[15] FL DEP, *Technical Evaluation and Preliminary Determination (*Crystal River Power Plant Units 1 and 2) at 3.

[16] 40 C.F.R. §51.301

[17] Section IV.D.3. of the BART Guidelines at 40 C.F.R. Part 51, Appendix Y.

[18] *Id.*

> application of the control alternative. However, you should explain the basis for choosing the alternate level (or range) of control in the BART analysis. Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.[19]

Further, while one can consider varying levels of pollution control in evaluation of a particular control device, one "must consider the most stringent level as one of the control options."[20]

Florida DEP did not follow these guidelines or otherwise meet the intent of the BART requirements because it did not evaluate the most stringent control efficiencies associated with operating SCR. Florida DEP's evaluations assumed, based on no apparent engineering analysis beyond one paragraph of assertions in Progress' permit application,[21] that SCR is capable of achieving an emissions rate of just 0.09 lbs/MMBtu NO_X, rather than a lower emission rate. A level of 0.09 lbs/MMBtu reflects no more than 80-90% reduction from current emissions from these units; SCR is well known to be capable of control efficiency greater than 90% and limits of 0.05 lbs/MMBtu or less on a 30 day rolling average.

During the relevant baseline period from 2000-2004, Crystal River Unit 1 had a maximum 30 day average of 0.43 lbs/MMbtu with an average of 0.38 lbs/MMBtu; Unit 2's maximum was 0.53 lbs/MMBtu and its average was 0.42 lbs/MMBtu during that time.[22] A 90% reduction from the maximum baseline values leads to limits of 0.043 and 0.053 lbs/MMBtu for Units 1 and 2 respectively.

Recent emissions also support a lower limit than 0.09 lbs/MMBtu. From 2008-2011, maximum and average 30 day rolling averages at Unit1 were 0.46 and 0.38 lbs/MMBtu; these values were 0.44 and 0.34 lbs/MMBtu at Unit 2. Ninety percent reductions from the maximum of these recent emissions lead to limits of 0.046 and 0.044 lbs/MMBtu at Units 1 and 2.

Taking a 90% reduction from regulated limits rather than actual emissions likewise yields emission limits lower than 0.09 lbs/MMBtu. During the period 2011-2015, the units 1 and 2 may operate under an approved alternative contemporaneous emission limitation of 0.57 lb NO_X/MMBtu (as part of a company-wide NO_X averaging plan).[23] The permitted NO_X emission factor for Units 1 and 2 is 0.40 lb NO_X/MMBtu in accordance with published values specified in

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[19] Section IV.D. of the BART Guidelines at 40 C.F.R. Part 51, Appendix Y

[20] *Id.*

[21] *See* Progress Application at 2.

[22] Data drawn from EPA's Clean Air Markets Database; these are calculated as calendar-day rolling averages rather than Boiler Operating Day (BOD) rolling averages (as suggested by the BART Guidelines) and therefore are likely biased high.

[23] FL DEP, *Technical Evaluation and Preliminary Determination* (Crystal River Power Plant Units 1 and 2) at 8.

40 C.F.R. § 76.6, "Revised NO_X emission limitations for Group 1, Phase II boilers."[24] Reducing these limits by 90% results in emission limits from 0.04-0.057 lbs/MMBtu.

Conversely, Crystal River's proposed 0.09 lb NO_x MMBtu limit reflects only a 79-83% reduction from the maximum of baseline emissions on a 30 day rolling average. It does not reflect the 90% control efficiency that even Progress acknowledges is possible. On the other hand, our proposed limit of no higher than 0.05 lb NO_X/MMBtu is justified because it is clearly a reflection of an easily achievable 90% reduction from baseline emissions at these units. It is also consistent with EPA's prior BART determinations, as we describe in detail below.

A. Over 90% Reductions and Low Limits are Achievable According to Existing Industry Experience

It is widely recognized today that all major SCR catalyst vendors[25] can easily guarantee at least 90% efficiency for SCRs burning coals with a wide range of properties. Vendor experience lists[26] indicate that SCRs are routinely designed for 90% NO_X control, depending on purchaser specifications.

Reflecting on this experience in 2003, Sargent and Lundy, stated that "[A]ll Sargent & Lundy-designed SCR reactors at coal-fired units, which have been placed into service, have achieved their guaranteed NO_X reduction efficiencies within the specified ammonia slip limits. The minimum design NO_X reduction efficiency was 85% and the maximum reduction efficiency was in excess of 90%... Design of SCR reactors for removal efficiencies greater than 90% at ammonia slip levels less than 2 ppm to 3 ppm has been demonstrated and should be considered as a feasible design criterion."[27]

Cormetech, a SCR catalyst vendor, noted the following in a 2007 paper: "It is common for units to be designed for NO_X removal efficiencies of 90%, and operate at efficiencies that are greater than the design value."[28] Siemens AG, another catalyst supplier notes: "Selective Catalytic Reduction (SCR) is currently the most widely applied state of the art technology for controlling NO_X emissions from coal fired power plants... across Germany, many other parts of Europe, in

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[24] Group I, Phase II NO_X Limits. Online at: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=818b9b5f4cf5d4626ab37358edf347c7&rgn=div8&view=text&node=40:17.0.1.1.5.0.1.7&idno=40

[25] These include Haldor Topsoe (Attached as Exhibit 1), Hitachi (Attached as Exhibit 2), Johnson-Matthey/Argillon (Attached as Exhibit 3), CERAM (Attached as Exhibit 4), etc.

[26] *See, e.g.*, Babcock-Hitachi K.K, NO_X Removal Coal Plant Supply List (Attached as Exhibit 5); Argillon Experience List US Coal Plants (Attached as Exhibit 3); Hitachi, SCR System and NO_X Catalyst Experience, Coal, February 2010 (Attached as Exhibit 2); Haldor Topsoe, References, October 2009 (Attached as Exhibit 1).

[27] Kurtides, T., Lessons Learned From SCR Reactor Retrofit, COAL-GEN, August 6-8, 2003, Sargent and Lundy, available at http://www.adeq.state.ar.us/ftproot/pub/commission/p/Closed%20Permit%20Dockets%202006-2010/08-007-P%20AEP%20Service%20Corp%20&%20Swepco-Hempstead%20Co%20Hunting%20Club/2008-12-03_Ex._7_SCR_Lessons_Learned_from_SCR_Reactor_Retrofit_Coal-G.pdf

[28] Rutherford, S., Coal-Fired SCR Applications in the US – Challenges and Strategies for Successful Operation and Emission Compliance, Cormetech Inc., VGB Workshop "Flue Gas Cleaning 2007," Vienna, Austria, May 22–23, 2007, available at http://www.cormetech.com/brochures/2007_VGB_Conference_Paper.pdf

Japan, as well as in the U.S. This technology has been proven to be reliable over almost two decades of use under the most extreme conditions. SCR can reduce NO_X emissions up to >93% in many cases..."[29]

Continuous emission monitoring data submitted by utilities to U.S. EPA's Clean Air Markets Division (CAMD) and analyzed by others indicate that "90% removal efficiency is currently being achieved by a significant portion of the coal-fired SCR fleet."[30] Over 30 individual units have achieved greater than 90% NO_X reduction[31], with NO_X removal of 90% achieved on 10,000 MW of coal-fired generation in 2004.[32] The McIlvaine Reports, a source of control technology information for BACT determination,[33] reported that three of Haldor Topsoe's SCR installations averaged over 95% NO_X reduction during the 2005 ozone season.[34]

Similarly, EPA analyzed Clean Air Markets NO_X data for twenty-two existing units that are achieving limits below 0.07 lb/MMBtu on a 30-day rolling average. Eight of these units were operating at or above 90% removal efficiency and not one was operating at less than 86%.[35] Moreover, this data was collected from 2003, before the NO_X SIP Call[36] and other regulatory programs for NO_X were in place. Because compliance with the NO_X SIP Call was generally not required until May of 2005, performance has improved since that point.[37] A 2010 reanalysis of Clean Air Markets data by EPA indicates that "many boilers retrofitted with SCR are achieving an emission rate of 0.03-0.06 lb/MMBtu."[38]

SCR system designers have analyzed EPA's Clean Air Market's continuous emission monitoring systems data to determine the NO_X levels that are currently being achieved by over 100 SCR-

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[29] Karina Rigby and others, SCR: The Most Effective Technology for NO_X Reduction in Large Combustion Plants, available at http://legsys.infomil.nl/legsys/noxconf/uk/pdf/combust/rigby.pdf

[30] James E. Staudt and Clayton Erickson. Selective Catalytic Reduction System Performance and Reliability Review, Andover Technology Partners, p. 15, available at http://www.gaepd.org/air/airpermit/downloads/permits/psd/dockets/longleaf/appealdocs/exhibits/excluded/Petitioners/P-006-1.pdf

[31] *Id.*, p. 1.

[32] LG&E Energy, Selective Catalytic Reduction: From Planning to Operation (attached as Exhibit 6); Competitive Power College, December 2005, p. 77 (attached as Exhibit 7).

[33] EPA NSR Workshop Manual, available at http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

[34] McIlvaine, Utility E-Alert #798, November 3, 2006. (Attached as Exhibit 8.)

[35] Srivastava et al., Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, Table 4, available at http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf

[36] Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57356 (Oct 27, 1998).

[37] Manuel J. Oliva and Sikander R. Khan, Performance Analysis of SCR Installations on Coal-Fired Boilers, Pittsburgh Coal Conference, September 2005, p. 3. (Attached as Exhibit 9.)

[38] Letter from Callie A. Videtick, Director Air Program, EPA Region 8, to Paul Tourangeau, Director Colorado Department of Public Health and the Environment, October 26, 2010, Re: Regional Haze State Implementation Plan, p. 3. (Attached as Exhibit 10.)

equipped coal-fired boilers. This analysis identified 25 units that are achieving NO_X emissions less than 0.05 lb/MMBtu on an hourly average basis.[39] Others have reported similar results.[40]

B. Examples of U.S. EPA BART Determinations

This high level of control is reflected elsewhere in the BART program nationally, as well as other regulatory programs.

EPA's final Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and BART Determination for New Mexico, for instance, sets a 0.05 lb/MMBtu NO_x emissions limit for the San Juan Generating Station, a coal-fired power plant not unlike Crystal River.[41] EPA did so on the basis of a careful cost analysis and a detailed evaluation of SCR performance across the country. EPA reported that:

> "retrofit SCR installations are capable of achieving a NO_X limit of 0.05 lbs/MMBtu on a continuous basis. Therefore, we believe the statement that a retrofit SCR would only be capable of achieving 0.07 lb/MMBtu on a continuous basis, is factually incorrect."[42]

EPA reported, for instance that:

> "The Havana Unit 9 data shows that it has operated under 0.05 lbs/MMBtu from mid-2009 to the end of 2010 on a continuous basis. In fact, this unit has operated under 0.035 lbs/MMBtu for much of that time. The Parish Unit 7 data shows that it has operated under 0.05 lbs/MMBtu from mid-2006 to mid-2010 on a continuous basis. In fact, this unit has operated for months at approximately 0.035 lbs/MMBtu, and for approximately 2 years at approximately 0.04 lbs/MMBtu."[43]

Summarizing its review, EPA concluded that "lower NO_x emissions [than even 0.05 lb/MMBtu] are achievable from the existing fleet of SCR-equipped units" and noted that it "may be technically feasible... for some SCR retrofits to reliably meet an NO_x limit of 0.035 lb/MMBtu on a 30 day rolling basis."[44] Although EPA nonetheless conservatively set BART at 0.05

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[39] Clay Erickson, Robert Lisauskas, and Anthony Licata, What New in SCRs, DOE"s Environmental Control Conference, May 16, 2006, p. 28, available at http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Licata.pdf; LG&E Energy, Selective Catalytic Reduction: From Planning to Operation, CompetitivePowerCollege, December 2005, p. 75-77. (Attached as Exhibit 7.)

[40] M.J. Oliva and S.R. Khan, Performance Analysis of SCR Installations on Coal-Fired Boilers, Pittsburgh Coal Conference, September 2005. (Attached as Exhibit 9.)

[41] 76 Fed. Reg. 52,388, 52,403, 52,406 (Aug. 22, 2011).

[42] *Id.* at 52,403 (regarding the BART determination for the San Juan Generating Station and referencing the performance of the nearby Navajo Generating Station), available at http://www.gpo.gov/fdsys/pkg/FR-2011-08-22/html/2011-20682.htm

[43] *Id.* At 52,404.

[44] *Id.*

lb/MMBtu, the fact that SCR technology can achieve emissions rates that are just a third of FL DEP's proposed limit here persuasively shows that a 0.09 lb/MMBtu does not reflect BART.

EPA has repeatedly made clear that an emission rate of no more than 0.05 lb/MMBtu rate is an appropriate starting point for BART analysis. In its Final Haze SIP/FIP determination for Nebraska, for instance, issued just months ago, EPA rejected the state's attempts to avoid that emissions rate as BART. It, again, emphasized that an "SCR is capable of achieving" the more stringent control rate of 0.05 lbs/MMBtu."[45] This was, EPA added, a control "range that many states and EPA have found to be reasonable for NO_X BART controls."[46]

EPA's recent proposed haze FIP/SIP for Arizona likewise rejects state efforts to avoid the 0.05 lb/MMBtu emission rate which SCR is plainly capable of achieving. There, EPA emphasized the same BART requirement we have cited above: the analysis must begin with "the most stringent available control option."[47] In the NO_x context, this most stringent option is SCR (with other relevant upgrades) achieving an emission rate of no more than 0.05 lb/MMBtu—or an even lower rate, as EPA acknowledges has been achieved at some units. EPA therefore proposed to disapprove Arizona's less stringent determinations for 7 different coal units in Arizona, replacing them with a 0.050 lb/MMBtu emission rate keyed to SCR.[48] Such controls should be presumed to be available for Crystal River as well, especially because Progress concedes that a control efficiency as high as 90% is achievable.[49]

The record in this case contains no evidence that the Crystal River units cannot be retrofitted with an SCR designed to achieve 90% NO_X reduction or higher. This would reduce the annual average NO_X emissions from these units to below 0.05 lb/MMBtu on a 30 day rolling basis. Thus, Florida DEP's evaluation is faulty in that it does not examine the most stringent level of control provided by the use of SCR, namely no higher than 0.05 lbs/MMBtu on a 30 day rolling average.

EPA has already approved NO_X requirements as evidence that an allowable emission rate lower than 0.09 lb/MMBtu can be cost-effectively achieved. Florida cannot approve its proposed emission rate on this record consistent with its BART obligations.

IV. Air Pollution from Crystal River

The proposed BART determinations which this draft permit implements appropriately identifies SCR as BART, but fails to set an appropriate emission limit reflecting the control efficiency of which SCR is capable. These inadequate proposed NO_X controls will illegally allow Crystal River to emit excess amounts of air pollution that will continue to impermissibly and

[45] 77 Fed. Reg. 40,150, 40.159 (July 6, 2012).

[46] *Id.* at 40,160.

[47] 77 Fed. Reg. 42,834, 42,861 (July 20, 2012).

[48] *Id.* at 42,866.

[49] Progress Application at 2.

unnecessarily impair Class I air quality. The permit must not be issued without correcting this error.

We expect that DEP will, nonetheless, assert that this permit will not cause "air pollution" as defined under Florida law because the Crystal River facility (including units not controlled by this draft permit) has reduced its NO_X emissions in recent years.[50] This argument is wrong.

First, Florida law requires both that a source will not cause air pollution, defined, in essence, as pollution potentially harmful to public health and welfare,[51] and that a permit assure compliance with all relevant law. [52] To the extent that the draft permit violates BART requirements, it does not assure compliance with relevant law, and may not issue. It also, of course, impairs public health and welfare by foregoing attainable visibility improvements by reducing pollution which is also harmful to humans, wildlife, and plants. These failures are present whether or not Crystal River has reduced its pollution from its previous levels. The issue is not whether Crystal River pollutes somewhat less than it once did. The issue, instead, is whether Crystal River emits as *little* contamination as the law requires.

Further, the pollution reductions on which DEP apparently relies have occurred almost entirely because of control technology upgrades at Crystal River units 4 and 5, which are not controlled by this permit.[53] To the extent that pollution has decreased from units 1 and 2, it appears to have only done so because the units have been used somewhat less in recent years; Florida DEP's charts reflect this declining capacity factor's impact on air emissions.[54] These reductions do not reflect pollution controls, and so may not continue. In any event, neither set of reductions is relevant here. BART is a unit-by-unit analysis, applicable to individual sources. The past performance of units 4 and 5 has nothing to do with the BART determinations here. Nor do the (minimal) reductions in pollution from units 1 and 2 due to their relative disuse. BART looks forward, to the maximum level of emissions control achievable; a plant's past performance is only relevant to the extent that it demonstrates that emissions reductions are possible (as Progress here concedes). At bottom, what matters here is that the law requires units 1 and 2 to reduce their emissions to a level which reflects BART. If they have not done so, they are emitting illegal and excessive air pollution. Because the permit does not reflect BART emission levels, it therefore does not reasonably assure compliance with Florida's pollution prohibition or with relevant federal and state law relating to the haze program.

V. Conclusion

[50] *See* TEPD at 8-10 (providing data to this effect); *see also* FL DEP, Final Determination on Permit 0170004-036-AC at 3-6 (making similar assertions with regard to SO_2 emissions from Crystal River).

[51] F.S. 403.031(7)

[52] F.A.C. 62-4.030; *see also* 62-4.070(1) (same); 62-212.300(3)(a)(2) (requiring applicant to demonstrate that they will comply with all relevant law)

[53] *See* TEPD at Figure 8.

[54] *See id.* at Figure 7.

The Legislature charged DEP to "achieve and maintain such levels of air quality as will protect human health and safety and, to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this state, and facilitate the enjoyment of the natural attractions of this state." F.S. 403.021. It further recognized that industry would have to "install new machinery, equipment, and facilities" in order to comply with this charge, F.S. 403.021(7)(b). The draft permit fails to comply with these mandates: It allows pollution to continue indefinitely and fails to require Crystal River's owners to clean up the plant consistent with the controls provided by best available retrofit technology.

DEP therefore must not finalize this permit in its current form. Its terms clearly do not comply with the BART and are not approvable by EPA. In short, because DEP lacks any reasonable assurance that this permit will assure compliance with pollution control mandates, it must revise or at a minimum not finalize the permit.

We would be happy to discuss this matter further with you and your staff, and look forward to Florida DEP's continued efforts to improve the controls in this permit.

Sincerely,

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Exhibit 1

References

RESEARCH | TECHNOLOGY | CATALYSTS

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Topsøe SCR DeNOx Technology and Catalyst

HALDOR TOPSØE

CATALYSING YOUR BUSINESS

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Coal-fired boilers					
High-dust installations					
Belgium					
Electrabel NV					
• Langerlo Unit 2 (Deutsche Babcock)	250 MW	80%	DNX-558	Catalyst Design of ammonia storage	2000
China					
Guohua					
▪ Taishan Unit 5 (Topsoe/Korea Cottrell)	600 MW	80%	DNX-864	Catalyst System Design Hardware	2006
Fujian Huadian					
▪ Kemen Units 3 &4 (Shanghai Longking)	2 x 600 MW	80%	DNX-864	Catalyst	2008
Fujian Hongshan					
▪ Unit 1 and 2 (Shanghai Longking)	2 x 600 MW	50%	DNX-864	Catalyst	2009
Shanghai Electric Power Co					
▪ Wujing TPP Units 1 and 2	2 x 300 MW	80%	DNX-964	Catalyst	2009
Taiyuan Iron & Steel Company					
▪ Units 1 & 2 (TISCO)	2 x 300 MW	80%	DNX-684	Catalyst System Design Hardware	2008
Yangcheng Int. Power Gen					
▪ Yangcheng Unit 8 (DETE)	600 MW	80%	DNX-464	Catalyst and system Design	2007
YanShan Petrochemical					
▪ Boiler (Envirgy)	312,000 Nm^3/hr	90%	DNX-858	Catalyst	2008
Denmark					
Elkraft, Stigsnæs					
• Demonstration Plant	4 MW	90%	DNX-362	Catalyst	1987-1992
DONG Energy					
▪ Ensted Unit 3 (ABB, Deutsche Babcock,	600 MW	88-93%	DNX-464	Catalyst and system design Hard ware	1996

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Topsøe)				Construction	
DONG Energy ▪ Esbjerg Unit 3 (Fisia Babcock)	400 MW	90%	DNX-674	Catalyst	2004
DONG Energy ▪ Studstrup Unit 3 (B&W Energy)	350 MW	90%	DNX-664	Catalyst	2007
DONG Energy ▪ Avedøre Unit 1 (Haldor Topsøe)	250 MW	80%	DNX-664	Catalyst System Design Hardware Construction	1993
Vattenfall Nordic ▪ Amager Unit 3 (Noell)	250 MW	94%	DNX-564	Catalyst	2000
Vattenfall Nordic ▪ Fyn Unit 7 (Fisia Babcock)	400 MW	90%	DNX-664	Catalyst	2007
Korea					
STX Energy ▪ Banwol Units 1-3 (STX Engine)	3 x 60 MW	76%	DNX-664	Catalyst	2006
Taiwan					
Formosa Plastic Group ▪ LP2 (Envirgy)	80 MW	Spare	DNX-684	Catalyst	2008
USA					
AES ▪ Cayuga Unit 1, NY (Foster Wheeler)	150 MW	90%	DNX-758	Catalyst Design of ammonia injection and flow rectifiers	2001
AEP ▪ Amos Unit 2	800 MW	Spare	DNX-364	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Allegheny Energy					
▪ Harrison Unit 1, WV	650 MW	>90%	DNX-664	Catalyst	2002
▪ Harrison Unit 2, WV	650 MW	>90%	DNX-664	Design of ammonia	2003
▪ Harrison Unit 3, WV	650 MW	>90%	DNX-664	injection and flow	2003
▪ Pleasant Unit 1, WV	650 MW	>90%	DNX-664	rectifiers	2003
▪ Pleasant Unit 2, WV	650 MW	>90%	DNX-664		2003
(Parsons)					
Vectren					
▪ Warrick Unit 4 , IN	300 MW	Spare	DNX-364	Catalyst	2008
City of Lakeland					
▪ McIntosh Unit 3, FL	365 MW	86%	DNX-684	Catalyst	2008
Cogentrix					
▪ Logan, NJ	225 MW	Spare	DNX-884	Catalyst	2006
Constellation Power					
▪ H.A. Wagner Unit 3	350 MW	Spare	DNX-958	Catalyst	2009
Duke/Cinergy					
▪ Belews Creek, Unit 1, NC	1200 MW	Spare	DNX-164	Catalyst	2007
▪ Belews Creek Unit 2, NC	1200 MW	Spare	DNX-164	Catalyst	2005
▪ Cliffside Unit 5, NC	590 MW	Spare	DNX-664	Catalyst	2008
▪ Gibson Unit 1, IN	650 MW	Spare	DNX-164	Catalyst	2007
▪ Gibson Unit 4, IN	650 MW	Spare	DNX-164	Catalyst	2007
▪ Gibson Unit 5, IN	650 MW	Spare	DNX-364	Catalyst	2006
▪ Miami Fort Unit 7, OH	530 MW	Spare	DNX-264	Catalyst	2006
▪ Miami Fort Unit 8, OH	530 MW	Spare	DNX-264	Catalyst	2007
Midwest Generation EME, LLC					
▪ Homer City Unit 1, PA	685 MW	Spare	DNX-764	Catalyst	2005
▪ Homer City Unit 2, PA	685 MW	Spare	DNX-764	Catalyst	2005
▪ Homer City Unit 3, PA	700 MW	Spare	DNX-764	Catalyst	2005
Orion Power Midwest					
▪ Chewick Station	600 MW		DNX-164	Catalyst	2009
Owensboro Municipal					
▪ Elmer Smith Unit 1, KY	150 MW	85 %	DNX-374	Catalyst	2003
(Sargent & Lundy)				Design of ammonia injection and flow rectifiers	

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
SIPCO					
▪ Marion Unit 4, IL (Sargent & Lundy)	195 MW	92%	DNX-584	Catalyst Design of ammonia injection and flow rectifiers	2003
NRG/ Texas Genco					
▪ W.A. Parish Unit 5,TX	690 MW	85%	DNX-484	Catalyst	2003
▪ W.A. Parish Unit 6,TX	690 MW	85%	DNX-484	Design of ammonia	2003
▪ W.A. Parish Unit 7,TX	590 MW	80%	DNX-684	injection and flow	2004
▪ W.A. Parish Unit 8,TX (Sargent & Lundy)	590 MW	85%	DNX-684	rectifiers	2003
Tucson Electric Power					
▪ Springerville Unit 4 (Foster Wheeler)	400 MW	70%	DNX-774	Catalyst	2009
Longview Power					
▪ Maidsville, WV (FWEC)	650 MW	83%	DNX-664	Catalyst	2011
Luminant (TXU Generation Company)					
▪ Sandow Unit 4 (Babcock & Wilcox)	545 MW		DNX-774	Catalyst	2010
XCel Energy					
▪ Comanche Unit 3, CO (Alstom)	750 MW	36%	DNX-864	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Coal-fired boilers Low-dust installations					
Denmark					
DONG Energy					
▪ Skærbæk SNOX demonstration plant	4 MW	>95%	DNX-532	Catalyst System design Hardware Construction	1987-1992
Vattenfall Nordic					
▪ Nordjylland Unit 2 SNOX plant	300 MW	>95%	DNX-632	Catalyst System design Hardware Construction	1991
Vattenfall Nordic					
▪ Amager Unit 1 (Alstom)	150 MW	90%	DNX-949	Catalyst	2009
USA					
Duke Energy, Union, KY					
▪ East Bend Unit 2	650 MW	Spare	DNX-149	Catalyst	2009
Ohio Edison Co.					
▪ SNOX Plant, Niles, OH	35 MW	> 95%	DNX-932	Catalyst	1991
PowerSouth Energy Coop., AL					
▪ Lowman Unit 2	258 MW	90%	DNX-154	Catalyst	2007
▪ Lowman Unit 3 (Black & Veatch)	258 MW	90%	DNX-154	Catalyst	2008
Southern Company Services					
▪ Gaston Unit 5, AL	890 MW	90%	DNX-141	Catalyst Design of ammonia injection and flow rectifiers	2006
WE Energies, WI					
▪ Oak Creek Units 5 & 6	2 x 262 MW	57%	DNX-949	Catalyst	2011
▪ Oak Creek Units 7 & 8	2 x 305 MW	57%	DNX-949	Catalyst	2011

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Bio-fuel- fired boilers High-dust installations					
Denmark					
DONG Energy					
▪ Avedøre Unit 2	400 MW	80%	DNX-564	Catalyst	2001
Sweden					
Vattenfall					
▪ Uppsala Unit 5	120 MW	75%	DNX-857	Catalyst	2005
USA					
Corn Fiber, Ft. Dodge, IA					
▪ Waste Boiler (Peerless)	68,000 Nm^3/hr	82%	DNX-954	Catalyst	2008
Sierra Power, Terra Bella, CA					
▪ Wood fired boiler	7 MW	65%	DNX-955	Catalyst	2008

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Bio-fuel-fired boilers Low-dust installations					
USA					
Corrugated Services, Forney, TX					
▪ Boiler	87,200 Nm^3/hr	75%	DNX-930	Catalyst	2008
SUEZ Energy, Pinetree Power					
▪ Bethlehem, NH	16 MW	46%	DNX-949	Catalyst	2008
▪ West Ossipee, NH	22 MW	46%	DNX-949	Catalyst	2008
Synterprise Global Solutions, TN					
▪ Wood fired boiler	88,700 Nm^3/hr	35%	DNX-931	Catalyst	2008
United Corrstack, Reading PA					
▪ Community Power		81%	DNX-939	Catalyst	2008

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Oil-fired boilers					
Austria					
OMV Refinery					
▪ Schwecat, SNOX plant	830,000 Nm^3/hr	90%	DNX-939	Catalyst	2007
Korea					
KEWESPO					
▪ Ulsan Unit 4	400 MW	52%	DNX-340	Catalyst	2003
▪ Ulsan Unit 5	400 MW	52%	DNX-340	Catalyst	2002
▪ Ulsan Unit 6 (Daewoo)	400 MW	52%	DNX-340	Catalyst	2002
KOWEPO					
▪ PyongTeak Unit 1	350 MW	80%	DNX-659	Catalyst	2007
▪ PyongTaek Unit 2 (Doosan)	350 MW	80%	DNX-659	Catalyst	2006
KOSPO					
▪ NamJeju Unit 3	100 MW	75%	DNX-940	Catalyst	2006
▪ NamJeju Unit 4 (Doosan)	100 MW	75%	DNX-940	Catalyst	2006
New Caledonia					
Goro Nickel					
▪ 3 Units (Inco Australia)	84,000 Nm^3/hr	67%	DNX-959	Catalyst	2008
Sweden					
Shell Refinery, Gothenburg				Catalyst	
▪ Unit 1 (Haldor Topsøe)	60 MW	94%	DNX-950	System design Hardware	1998
Preem Refinery, Gothenburg					
▪ Unit 1 (Alstom)	80,000 Nm^3/hr	90%	DNX-640	Catalyst	2003
Middle East					
Undisclosed client					
▪ Unit 1 & 2 (Babcock Noell)	2 x 150 MW		DNX-949	Catalyst System Design	2008

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Gas-fired boilers					
Qatar					
Shell PEARL, Ras Lafan					
▪ Unit 1 & 2 (Envirgy)	180,000 Nm^3/hr	45%	DNX-630	Catalyst	2008
Russia					
AO Mosenergo, Moscow					
▪ TP 27 Unit 1	120 MW	67%	DNX-962	Catalyst	1996
▪ TP 27 Unit 2 (ZAO Topsøe Yaroslav)	120 MW	67%	DNX-962	System design Hardware Construction	1999
Dzerzhinskaya					
▪ Power Station, Dzerzhinsk (ZAO Topsøe Yaroslav)	120 MW	80%	DNX-652	Catalyst System design Hardware Construction	1999
USA					
AES, CA					
▪ Huntington Beach Units 1 & 2 (AUS)	215 MW	>90%	DNX-930	Catalyst	2001
Celanese, Pasadena, TX	Steam Gen.				
▪ Clear Lake Cogen Units 1-4 (AUS)	4 x 250,000 lbs/hr	>95%	DNX-930	Catalyst	2002
City of Burbank, Burbank, CA					
▪ Olive Units 1 & 2 (AUS)	2 x 50 MW	98%	DNX-930	Catalyst	2003
Dynegy, Chula Vista, CA					
▪ South Bay Unit 4 (URS)	235 MW	>90%	DNX-940	Catalyst	2001
Exelon, Fort Worth, TX					
▪ Handley Units 4 & 5 (AUS)	2 x 470 MW	98%	DNX-930/940	Catalyst	2003
Formosa Plastics, Comfort, TX					
▪ Units 1 & 2	2 x 128,000 Nm^3/hr	90%	DNX-929	Catalyst	2009
Gillette, Boston, MA					
▪ Unit 3 (Peerless)	68,000 Nm^3/hr	85%	DNX-940	Catalyst	2004

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Inland Paper and Packaging					
▪ Steam Plant, Ontario, CA	73,400 Nm^3/hr	90%	DNX-930	Catalyst	1995
LADWP, Playa Del Rey, CA					
▪ Scattergood Units 1 & 2 (AUS)	2 x 180 MW	>90%	DNX-930	Catalyst	2001
Lyondell Equistar, Channelview, TX					
▪ Channelview South Units 1-3 (KBR)	3 x 282,000 Nm^3/hr	96%	DNX-931	Catalyst	2004
Merck Rahney, Rahway, NJ	Steam Gen.				
▪ Unit 1 LP	230,000 lbs/hr	>90%	DNX-930	Catalyst	2003
▪ Unit 2 LP	230,000 lbs/hr	>90%	DNX-930	Catalyst	2003
▪ Unit 1 HP (Peerless)	230,000 lbs/hr	>90%	DNX-930	Catalyst	2003
Northrop Grumman, CA					
▪ Steam Boiler	135,500 Nm^3/hr	79%	DNX-939	Catalyst	2009
Pacific Coast Producers, CA					
▪ Unit 1-2	2 x 36,500 Nm^3/hr	93%	DNX-929	Catalyst	2008-09
▪ Unit 3	47,000 Nm^3/hr	93%	DNX-920	Catalyst	2008
Reliant Energy					
▪ Etiwanda Units 3 & 4, CA (AUS)	2 x 330 MW	>90%	DNX-930	Catalyst	2001
Saputo Cheese, Fresno, CA					
▪ Unit 1	32,000 Nm3/hr	83&	DNX-929	Catalyst	2008

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Pet-coke-fired boilers					
Italy					
Enichem					
▪ SNOX Demonstration Plant		95%	DNX-950	Catalyst System design	1991
Agip Petroli					
▪ Gela	300 MW	95%	DNX-950	Catalyst System design	1999

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Stationary diesel engines					
Denmark					
Grindsted El- og Varmeværk					
▪ Tårnvej Unit 1	6.6 MW	83%	DNX-653	Catalyst	1994
▪ Tårnvej Unit 2 (Wärtsila)	6.6 MW	83%	DNX-653	System Design Hardware	1994
▪ Grønningen Unit 1	6.1 MW	30%	DNX-953	Turnkey	2001
Slangerup Kraftvarmeværk		90%			
▪ Unit 1	1.6 MW		DNX-653	Catalyst	1991
Hundested Kraftvarmeværk					
▪ Unit 1	3.5 MW	80%	DNX-653	Catalyst System Design Hardware	1991
Finland					
Waasa Pilot Power Plant					
▪ Unit 1	11.7 MW	92%	DNX-951	Catalyst	1998
▪ Unit 2 (Wärtsilä)	23.3 MW	94%	DNX-951	System Design Hardware	1998
Korea					
Korea Midland					
▪ Jeju Island Unit 2 (Doosan Engine Co.)	40 MW	> 87%	DNX-351	Catalyst System Design Hardware	2008
Korea Midland					
▪ Jeju Island Unit 1 (HSD Engine Co.)	40 MW	> 87%	DNX-351	Catalyst System Design Hardware	2005
Middle East					
Undisclosed Client					
▪ Units 1-4 (Wärtsilä)	4 x 6.5 MW	60%	DNX-951	Catalyst System Design Hardware	1998
Undisclosed Client					
▪ Units 1-2 (Hyundai Heavy Industries)	2 x 9 MW	67%	DNX-951	Catalyst System Design Hardware	2003
Sweden					
Pharmacia AB					
▪ Unit 1	3.8 MW	95%	DNX-650	Catalyst System Design Hardware	1993

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Taiwan					
Taiwan Cement Corp., 20 MW ▪ Units 1-3 (Wärtsilä)	3 x 6.5 MW	84%	DNX-951	Catalyst System Design Hardware	1995
Tung-Chi Paper, Taichung ▪ Unit 1 (Wärtsilä)	6.5 MW	84%	DNX-653	Catalyst System Design Hardware	1995
Chung Hwa Chemical Ind. Work, Taoyuan, 26 MW ▪ Units 1-4 (Wärtsilä)	4 x 6.5 MW	84%	DNX-951	Catalyst System Design Hardware	1996-97
TTET, Taiyuan, 13 MW plant ▪ Units 1-2 (Wärtsilä)	2 x 6.5 MW	84%	DNX-951	Catalyst System Design Hardware	1998
Asia Polymer Corp. Kaohsiung 20 MW plant ▪ Units 1-3 (Wärtsilä)	3 x 6.5 MW	84%	DNX-951	Catalyst System Design Hardware	1998
TYC, 33 MW plant ▪ Units 1-3 (Wärtsilä)	3 x11 MW	84%	DNX-951	Catalyst System Design Hardware	1999
Turkey					
Aksa Enerji, Samsun 126 MW ▪ Units 1-7	7 x 18 MW	87%	DNX-951	Catalyst System Design Hardware	2002
Ankara Enerji, 53 MW plant ▪ Units 1-7	7 x 8 MW	86%	DNX-951	Catalyst System Design Hardware	2002
Cengiz Enerji, Samsun, 126 MW ▪ Units 1-7	7 x 18 MW	87%	DNX-951	Catalyst System Design Hardware	2002

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
United Kingdom					
Citigen Limited, London, 33 MW					
▪ Units 1-2	2 x 16 MW	94%	DNX-653	Catalyst System Design Hardware	1993
USA					
BL England, NJ					
▪ 4 Units (CCA)	4 x 2 MW	75%	DNX-939	Catalyst	2007
Citizen Utilities Co, Kauai, Hawaii					
▪ Unit 5	7.9 MW	60%	DNX-653	Catalyst System Design Hardware	1991
Eastern Concrete, NJ					
▪ Unit 1	0.9 MW			Catalyst	2008
Weldon Quarry, NJ					
▪ Unit 1	0.3 MW			Catalyst	2008
Holmes Tools & Eng., FL					
▪ Units 1-4	4 x 2.5 MW	90%	DNX-329	Catalyst	2009
▪ Units 5-6	2 x 2.2 MW	90%	DNX-949	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Marine diesel engines					
Finland					
Silja Line OY, Helsinki					
▪ M/S Silja Symphony Aux engine	3 MW	95%	DNX-653	Catalyst System Design	1994
▪ M/S Serenade Aux engine	3 MW	95%	DNX-653	Hardware	1994
▪ M/S Festival Main engines 1-4	4 x 6 MW	91%	DNX-953	Catalyst System Design Hardware	2001
(Wärtsila)					
Norway					
Navion ASA, Stavanger				Catalyst	
▪ Main engine	4.3 MW	88%	DNX-953	System Design Hardware	2001
Sweden					
Stena Line AB, Gothenburg					
M/S Stena Jutlandia					
▪ Aux. engines 1-4	4 x 1.8 MW	90%	DNX-951	Catalyst	1996
▪ Main engines 1-4	4 x 6.5 MW	90%	DNX-951	System Design Hardware	1996
USA					
USS-POSCO					
Korean cargo ships, main engine:					
▪ M/V Pacific Success	7.9 MW	92%	DNX-662	Catalyst	1989
▪ M/V Pittsburg	7.9 MW	92%	DNX-662	System Design	1989
▪ M/V Delta Pride	7.9 MW	92%	DNX-662	Hardware	1991
▪ M/V New Horizon	7.9 MW	92%	DNX-662		1992
Seastreak NYC Ferry					
▪ One installation		70%	DNX-640	Catalyst	2005
(CCA)					

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Gas engines					
Denmark					
Gartneriet A. Pedersen, Bellinge				Catalyst	
▪ Unit 1	3.1 MW	90%	DNX-953	System Design	1995
▪ Unit 2	2.7 MW	90%	DNX-953	Hardware	1997
Gartneriet A. Pedersen, Bellinge					
▪ Unit 3 (Catcon)	14,000 Nm^3/hr	97%	DNX-920	Catalyst	2007
Torup Gartneri, Lundby				Catalyst	
▪ Unit 1	2.7 MW	90%	DNX-953	System Design Hardware	1997
Gartneriet Rosborg-Bellinge				Catalyst	
▪ Unit 1	2.8 MW	95%	DNX-951	System Design Hardware	1998
Masnedø Gartnerier, Masnedø					
▪ Units 1-2	2 x 1.6 MW	88%	DNX-953	Turnkey	1998
▪ Units 3-4	2 x 3 MW	90%	DNX-931		1999
Italy					
Fertilvita S.r.L., Corteolona-Pavia Two Units (ECODECCO)	12,000 Nm^3/hr	>90%	DNX-920	Catalyst	2006-7
Spain					
Carboneco Aliaga		90%	DNX-931	Catalyst	2007
▪ Unit 1					
Courant Energies					
▪ Neoelectra, Les, Units 1-5	5 x 3 MW	90%	DNX-631	Catalyst	2002
▪ Neoelectra, El Grado, Units 1-4 (Union Engineering A/S)	4 x 3 MW	90%	DNX-631	System Design Hardware	2002
USA					
Chevron Texaco, San Ramon, CA			DNX-920	Catalyst	2004
▪ Units 1-2 (EnviroKinetics)					
Rentech Midwest East Dubuque, IL			DNX-620	Catalyst	2008

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Wawona Frozen Foods					
▪ Fresno, CA	2.1 MW	90%	DNX-930	Catalyst	2003
▪ Clovis, CA	2.1 MW	90%	DNX-930	Catalyst	2003
(Technip Coflexip)					
Pine Prairie Energy Center					
▪ Easton, LA	4 x 6 MW	90%	DNX-920	Catalyst	2006
▪ Easton, LA	2 x 6 MW	90%	DNX-920	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Gas turbines					
Austria					
EVN AG					
▪ Theiss Unit 2 (Alstom)	995.000 Nm^3/hr	60%	DNX-921	Catalyst	2008
Canada					
IST					
▪ Waterbury Generation	100 MW	90%	DNX-629	Catalyst	2009
Sithe, Brampton, Ontario					
▪ Goreway Units 1-3 (Deltak)	850 MW	86%	DNX-920	Catalyst	2007
Sithe, St. Claire, Ontario					
▪ Greenfield Units 1-3 (Deltak)	800 MW	87%	DNX-920	Catalyst	2007
Chile					
Sociedad Electrica, Santiago					
▪ Nueva Renca	1.8 mill Nm^3/hr	90%	DNX-929	Catalyst	2009
China					
Huadian					
▪ Beijing TPP Units 1 & 2 (CHEC)	250 MW	50%	DNX-920	Catalyst	2007
Denmark					
Frederikshavn Kraftvarmeværk	17 MW	75%	DNX-950	Turnkey	1998
Hirtshals Fjernvarme	9 MW	65%	DNX-930	Turnkey	1998
Ringkøbing Krafvarmeværk (Catcon)	6 MW	62%	DNX-620	Catalyst	2007
Skjern Kraftvarmeværk (Catcon)	6 MW	62%	DNX-620	Catalyst	2007
Vrå Varmeværk					
▪ Vrå Unit 1 (Catcon)	8 MW	73%	DNX-320	Catalyst	2007
France					
Esso Refinery, Fos-sur-Mer					
▪ Unit 1 (Envirgy)	269.000 Nm^3/hr	80%	DNX-920	Catalyst	2008

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Italy					
API Energia, Falconara					
▪ IGCC Plant Unit 1	150 MW	50%	DNX-939	Catalyst	2003
ISAB, Priolo					
▪ IGCC plant, Units 1-2 (Snamprogetti/Foster Wheeler)	2 x 161 MW	80%	DNX-930	Catalyst	1999
Korea					
Sithe Icheon Cogen					
▪ Unit 1	500,000 Nm^3/hr	90%	DNX-959	Catalyst	2009
Mexico					
Sempra LNG					
▪ Energia Costa Azul, Ensenada	5 x 10 MW	90%	DNX-920	Catalyst	2006
Norway					
Statoil, Kaarstoe					
▪ Unit 1 (Envirgy)	2.1 mill Nm^3/hr	90%	DNX-920	Catalyst	2007
Statoil, Mongstad					
▪ Units 1 & 2 (Peerless)	1.2 mill Nm^3/hr	72%	DNX-920	Catalyst	2008
Qatar					
Messiaeed					
▪ Units 1-6 (Peerless)		82%	DNX-920	Catalyst	2008-09
Saudi Arabia					
National Industrialization Co. Saudi Polyolefins Company					
▪ Unit 1	1.4 mill. Nm^3/hr	82%	DNX-930	Catalyst	2004
Switzerland					
Thermatel, Monthey					
▪ Unit 1	400,000 Nm3/hr	56%	DNX-920	Catalyst	2009
Sweden					
Göteborg Energi, Rya CHPP Gothenburg					
▪ Units 1-3 (Envirgy)	250 MW	77%	DNX-920	Catalyst	2006

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Thailand					
PITUT/Thai Shinryo					
▪ Pitut Central Utility, 2 units (Petro Chem)	2 x 150 MW	76%	DNX-920	Catalyst	2008
USA					
AES Red Oak, NJ					
▪ Units 1-3 (Foster Wheeler)	3 x 277 MW	88%	DNX-930	Catalyst	2001
Air Products Chemicals, TX					
▪ Port Arthur II (Deltak)	80 MW		DNX-920	Catalyst	2005
Alliant – Madison Gas & Elec., WI ▪ Units 1-2 (Deltak)	2 x 75 MW	90%	DNX-930	Catalyst	2005
Billerica Energy Center, MA Units 1-4 (Turner Enviro)	4 x 60 MW	90%	DNX-620	Catalyst	2008
B. Braun Medical, Irvine, CA					
▪ Unit 1 + 2	2 x 3 MW	90%	DNX-930	Catalyst	2000/ 2007
Braintree Energy Center					
▪ Thomas A. Watson Units 1 & 2	116 MW	90%	DNX-920	Catalyst	2008
BP/Duke, South Houston Green Power, Texas City, TX					
▪ Units 1-3 (Deltak)	3 x 170 MW	85%	DNX-930	Catalyst	2003
BP/EME Watson Cogeneration					
▪ Unit 1	80 MW	94%	DNX-950	Catalyst	2002
▪ Unit 2	80 MW	94%	DNX-950	Catalyst	2003
▪ Unit 3	80 MW	94%	DNX-950	Catalyst	2004
▪ Unit 4	80 MW	94%	DNX-950	Catalyst	2005
Bryan Texas Utilities, TX					
▪ Dansby Unit 2	393.000 Nm^3/hr	90%	DNX-620	Catalyst	2008
California Dairies, Tipton, CA					
▪ Unit 1 (Deltak)	27 tons steam/hr	90%	DNX-920	Catalyst	2004

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Constellation Energy, UT					
▪ West Valley Units 1-4	4 x 334300 Nm^3/hr	82%	DNX-629	Catalyst	2009
Corona Cogen, Corona, CA					
▪ Unit 1	470.000 Nm^3/hr	93%	DNX-920	Catalyst	2008
DG Power LLC					
▪ Calpeak Border, CA	45 MW	95%	DNX-930	Catalyst	2001
▪ Calpeak El Cajon, CA	45 MW	95%	DNX-930	Catalyst	2001
▪ Calpeak Escondido, CA	45 MW	95%	DNX-930	Catalyst	2001
▪ Calpeak Midway, CA	45 MW	95%	DNX-930	Catalyst	2001
▪ Calpeak Mission, CA	45 MW	95%	DNX-930	Catalyst	2001
▪ Calpeak Panoche, CA	45 MW	95%	DNX-930	Catalyst	2001
▪ Calpeak Vaca Dixon, CA (Peerless)	45 MW	95%	DNX-930	Catalyst	2001
City of Burbank, Burbank, CA					
▪ Lake Unit 1 (Turner Envirologic)	44 MW	92%	DNX-920	Catalyst	2005
City of Glendale, CA					
▪ Unit 8A	24 MW	95%	DNX-930	Catalyst	2000
▪ Unit 8B & 8C (AUS)	47 MW	95%	DNX-930	Catalyst	2000
City of Pasadena, Pasadena, CA					
▪ GT 1 & 2	2 x 44 MW		DNX-630	Catalyst	2005
Conectiv Mid Merit					
▪ Units 1-6, Bethlehem, PA (Hamon Research Cottrell)	6 x 225 MW	80%	DNX-930	Catalyst	2003
▪ Units 1-3, Delta, PA (Vogt)	3 x 225 MW	80%	DNX-920	Catalyst	2009
ConEd, West Springfield, MA					
▪ Units 1-2 (Peerless)	2 x 44 MW	92%	DNX-630	Catalyst	2002
Dartmouth Power, MA					
▪ Unit 1	23 MW	90%	DNX-929	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
DEMEC Power, Smyrna, DE					
▪ Unit 1 (Peerless)	44 MW	82%	DNX-930	Catalyst	2001
Diamond Generation					
▪ Indigo, 3 Units (EnviroKinetics)	3 x 50 MW		DNX-630	Catalyst	2006
Duke Power, Rowan, NC					
▪ Buck & Dan River Units	2 x 1.4 mill Nm^3/hr	83%	DNX-929	Catalyst	2011
EIF, Panoche, CA					
▪ 4 Units	4 x 100 MW			Catalyst	2008
El Paso Merchant Energy Linden, NJ					
▪ Unit 1 (Foster Wheeler)	181 MW	86%	DNX-930	Catalyst	2001
Hawaii Electric Light Company					
▪ 2 Units (KOPEC)	215,000 Nm3/hr	64%	DNX-321	Catalyst	2008
GE Aero Energy, Panoche, CA					
▪ 4 Units	4 x 100 MW	93%	DNX-620	Catalyst	2008
Keyspan, Greenport, NY					
▪ Greenport Unit 1	54 MW		DNX-630	Catalyst	2006
Kleen Energy, Middletown, CT					
▪ Units 1 & 2	164 MW	86%	DNX-929	Catalyst	2010
Mint Farm Energy Center					
▪ Longview, WA	170 MW	90%	DNX-920	Catalyst	2007
Modesto Irrigation District, CA					
▪ McClure Station Units 1 & 2	2 x 80 MW	> 90%	DNX-920	Catalyst	2005
▪ Woodland Station 1 (AUS)	40 MW	95%	DNX-930	Catalyst	2004
Motiva, Port Arthur, TX					
▪ 4 GT's (Vogt)	4 x 31 MW	77%	DNX-920	Catalyst	2008-9

SCR DeNOx technology and catalyst

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Nevada Power Comp., NV ▪ Harry Allen Units 1 &2	2 x 175 MW	85%	DNX-929	Catalyst	2011
NRG, Baytown, TX ▪ Cedar Bayou Unit 4, 2 GT's	2 x 215 MW	80%	DNX-920	Catalyst	2009
NuCoastal Energy, TX ▪ Unit 1 (Vogt)	1.3 mill Nm^3/hr	85%	DNX-920	Catalyst	2008
Pacific Energy, Finley, WA ▪ Benton-PUD Unit 1 (Peerless)	45 MW	90%	DNX-430	Catalyst	2001
PacifiCorp, Mona, UT ▪ Currant Creek	225 MW	89%	DNX-929	Catalyst	2008
PG&E, Avenal, CA ▪ Kettleman Compressor Station - 2 Units	76,100 Nm^3/hr	90%	DNX-929	Catalyst	2009-10
Pfizer Global Mfg., Groton, CT ▪ Unit 1 (Deltak)	123,000 Nm^3/hr	93%	DNX-920	Catalyst	2008
Puget Sound Energy, Fredonia,WA ▪ Patch - Unit 1 & 2 (Peerlees)	2 x 45 MW	95%	DNX-930	Catalyst	2001
PPL University Park, IL ▪ Units 1 &2	425,000 Nm^3/hr	92%	DNX-629	Catalyst	2009
PPL Wallingford, Wallingford, CT ▪ Units 1-5	5 x 45 MW	92%	DNX-620	Catalyst	2006
San Gabriel Cogen., Pomona, CA ▪ San Gabriel Unit 1 (Peerless)	36 MW	85%	DNX-930	Catalyst	2001
Santee Cooper, Iva, SC ▪ Rainey Station Unit 1 A&B	2 x 200 MW		DNX-920	Catalyst	2005

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Sikorsky Aircraft, Startford, CT					
▪ Unit 1	132,700 Nm^3/hr	90%	DNX-929	Catalyst	2009
Starwood Power, Montclair, CA					
▪ 2 Units	2 x 60 MW	93%	DNX-929	Catalyst	2009
Southern Company, Goat Rock, AL					
▪ Franklin Units 1-4	4 x 225 MW	86%	DNX-930	Catalyst	2003
▪ Franklin Units 5-6 (Deltak)	2 x 225 MW	86%	DNX-920	Catalyst	2008
Southern Company Autagaville, AL					
▪ Autagaville Units 1-4 (Deltak)	4 x 225 MW	86%	DNX-930	Catalyst	2003
Southern Company, Orlando, FL					
▪ Orlando Units 1 & 2 (Deltak)	2 x 225 MW	86%	DNX-930	Catalyst	2003
Southern Company, Orlando, FL					
▪ Stanton Unit B (Vogt)		86%	DNX-920	Catalyst	2009
Southern Company, Savannah, GA					
▪ Savannah Units 10A & B	2 x 225 MW	86%	DNX-930	Catalyst	2004
▪ Savannah Units 11A & B (Deltak)	2 x 225 MW	86%	DNX-920	Catalyst	2004
St. Agnes Medical Center, Fresno, CA					
▪ Units 1 & 2 (Wahlco)	2 x 3.5 MW	80%	DNX-330	Catalyst	2002
Starwood Energy, Fresno, CA					
▪ Units 1 & 2 (EnviroKinetics)	2 x 45 MW	80%	DNX-920	Catalyst	2008

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
TransAlta, Centralia, WA ▪ Hanford Expansion Units 1-4 (Peerless)	4 x 64 MW	93%	DNX-630	Catalyst	2001
United Cogen ▪ San Francisco, CA	10 MW	79%	DNX-920	Catalyst Replacement	2007
University of California, San Francisco, CA ▪ Units 1 & 2	2 x 5 MW	90%	DNX-920	Catalyst	2004
University of California, Irvine, CA ▪ Irvine Cogen Unit 1 (Deltak)	10 MW		DNX-930	Catalyst	2005
Village of Freeport, Freeport, NY ▪ Power Plant Unit 2 (Turner Enviro.)	44 MW		DNX-630	Catalyst	2005
Wellhead Energy, Fresno, CA ▪ Fresno Cogen, Unit 1 (EnviroKinetics)	48 MW	95%	DNX-920	Catalyst	2004
VENOCO ▪ Oil Rig (TurnerEnviro.)	3 x 5 MW	90%	DNX-940	Catalyst	2006
Wisconsin Public Service Power, Combined Locks, WI ▪ Appleton Coated Unit 1 (Deltak)	44 MW	88%	DNX-930	Catalyst	2001

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Refineries/petrochemical plants					
Brazil					
Petrobras					
▪ Two SNOX plants	565,000 Nm^3/hr	94%	DNX-939	Catalyst	2010
Qatar					
Shell Oil Pearl					
▪ SMR Line 1	594,000 Nm^3/hr	68%	DNX-930	Catalyst	2008
▪ SMR Line 2	594,000 Nm^3/hr	68%	DNX-930	Catalyst	2008
(KTI)					
South Africa					
Sasol Synfuel Pty. Ltd.					
▪ Secunda, Rectisol Off-gas	183,000 Nm^3/hr	62%	DNX-330	Catalyst	2007
USA					
Air Liquide					
▪ El Segundo, SMR Heater, CA	268,000 Nm^3/hr	90%	DNX-930	Catalyst	2004
▪ Freeport, SMR Heater, TX	72,500 Nm^3/hr	90%	DNX-930	Catalyst	2004
▪ Freeport, Aux Boiler, TX			DNX-920	Catalyst	2006
▪ Bayport Plant, SMR Heater,TX			DNX-930	Catalyst	2006
Air Products					
▪ Baytown, TX, Aux. boiler			DNX-930	Catalyst	2005
▪ Convent-Motiva, CA, SMR			DNX-920	Catalyst	2005
▪ Martinez, CA, SMR heater	340,000 Nm^3/hr	90%	DNX-930	Catalyst	2004
▪ Port Arthur, TX, SMR heater			DNX-930	Catalyst	2005
▪ Wilmington, CA, SMR heater			DNX-930	Catalyst	2005
▪ Baton Rouge, LA, SMR heater	310,000 Nm^3/hr	90%	DNX-929	Catalyst	2009
▪ Pasadena, 2 SMR heaters	2x284,000 Nm^3/hr	91%	DNX-929	Catalyst	2008
BOC BP Refinery, Toledo, OH					
▪ SMR Heaters	140,000 Nm^3/hr	93%	DNX-920	Catalyst	2005
(Rentech)					
BP Carson, CA					
▪ SMR Heater			DNX-930	Catalyst	2004
BP, Whiting, IN					
▪ 5 Boilers	5 x 246,000 Nm^3/hr	95%	DNX-929	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Chevron, El Segundo, CA				Catalyst and	
▪ Reformer Heater	270,000 Nm^3/hr	90%	DNX-930	system design	2000
▪ Vacuum Heater	25,000 Nm^3/hr	90%	DNX-930	Catalyst	2001
▪ Coker/Naptha Heater				Catalyst	2002
▪ Coker	25,000 Nm^3/hr	88%	DNX-930	Catalyst	2007
Chevron Phillips, Cedar Bayou, TX					
▪ BA 101-113 Olefin Furnaces	13 x 68,000 Nm^3/hr	93%	DNX-930	Catalyst	2003-04
Citgo, Lemond, Il					
▪ FCC Unit			DNX-858	Catalyst	2006
ConocoPhillips,					
▪ Bayway, IL, SMR heater	71,000 Nm^3/hr	91%	DNX-930	Catalyst	2005
▪ Rodeo, CA, Platformer Heater	76,000 Nm^3/hr	95%	DNX-630	Catalyst	2002
▪ Rodeo, CA, Prefractionator	22,000 Nm^3/hr	90%	DNX-930	Catalyst	2002
▪ Rodeo, CA, Vacuum Tower	13,000 Nm^3/hr	90%	DNX-930	Catalyst	2003
▪ Rodeo, CA, Reclaim Charge	155,000 Nm^3/hr	95%	DNX-930	Catalyst	2003
▪ Wilmington, CA, Boiler		95%	DNX-920	Catalyst	2008
▪ Sweeny, TX, Crude Heater			DNX-930	Catalyst	2004
ConocoPhillips, Linden, NJ					
▪ Vacuum Furnace	204,000 Nm^3/hr	90%	DNX-939	Catalyst	2010
Dow Chemical, Freeport,TX					
▪ Heater (Peerless)			DNX-930	Catalyst	2002
ExxonMobil, Torrance, CA					
▪ Boiler				Catalyst	2005
▪ Crude Heater	245,000 Nm^3/hr	95%	DNX-940	Catalyst	2003
▪ FCC Preheater	33,000 Nm^3/hr	90%	DNX-950	Catalyst	2004
Flying J					
▪ Big West Boiler, CA	76,000 Nm^3/hr	97%	DNX-920	Catalyst	2006
▪ Big West Crude Heater, CA	55,000 Nm^3/hr	90%	DNX-920	Catalyst	2006
▪ Big West SMR Heater, CA	79,000 Nm^3/hr	90%	DNX-920	Catalyst	2006
▪ Big West Heater, CA (AUS)	29,000 Nm^3/hr	90%	DNX-920	Catalyst	2006
Hovensa, St. Croix, USVI Heater	250,000 Nm^3/hr	61%	DNX-930	Catalyst	2008

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Lurgi NOVA					
▪ SMR Heater	336,000 Nm^3/hr	94%	DNX-920	Catalyst	2010
Marathon Oil					
▪ Garyville, LA, 3 Units					
▪ Robinson, IL, Crude Heater	196,000 Nm^3/hr	95%	DNX-930	Catalyst	2002
▪ St. Paul, MN, SMR Heater	36,000 Nm^3/hr	90%	DNX-930	Catalyst	2003
Motiva, Port Arthur, TX					
▪ 2 x Crude Heater				Catalyst	2008
▪ 2 x Vacuum Heater				Catalyst	2008
Navajo Refining					
▪ Reformer	103,500 Nm^3/hr	90%	DNX-929	Catalyst	2009
Nova Chemicals, Seabrook, TX					
▪ Steam Super Heater (KTI)	44,000 Nm^3/hr	98%	DNX-930	Catalyst	2004
Paramount refining, CA					
▪ Crude Heater (On Quest)	25,100 Nm^3/hr	90%	DNX-939	Catalyst	2007
Praxair					
▪ Geismar, LA, SMR Heater			DNX-930	Catalyst	2003
▪ Ontario, CA, SMR Heater			DNX-920	Catalyst	2006
▪ Port Arthur, TX, SMR Heater			DNX-920	Catalyst	2005
▪ Richmond, CA, 2 Units			DNX-920	Catalyst	2008
▪ Texas City, SMR heater HU-1	306,000 Nm/hr	91%	DNX-920	Catalyst	2004
▪ Texas City, SMR heater HU-2			DNX-920	Catalyst	2005
▪ Texas City, SMR heater HU-3			DNX-920	Catalyst	2005
▪ Whiting, IL, SMR Heater			DNX-920	Catalyst	2005
Praxair, Whiting, IL					
▪ 2 SMR Heaters	275,000 Nm^3/hr	90%	DNX-929	Catalyst	2010
Sabina Petrochemicals, TX					
▪ C4 Olefins Boiler (Peerless)	83,000 Nm^3/hr	80%	DNX-930	Catalyst	2002

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Shell Oil Products, US					
▪ Martinez, CA, Delayed Coker			DNX-949	Catalyst	2006
Shell Oil Products, Deer Park, TX				Catalyst	2004
▪ FCC/CO boiler	385,000 Nm^3/hr	90%	DNX-958	System design	
Shell Oil Comp., Deer Park, TX					
▪ CRU3 heater	272,200 Nm^3/hr	90%	DNX-949	Catalyst	2009
Sinclair Tulsa Refining, OK					
▪ FCC Unit		92%	DNX-958	Catalyst System design	2009
▪ 3 boilers	3 x 95,000 Nm^3/hr	97%	DNX-929	Catalyst	2009
Sterling Chemicals, Texas City, TX					
▪ Styrene Heater (KTI)	143,000 Nm^3/hr	94%	DNX-330	Catalyst	2004
Tosco, Rodeo, CA					
▪ Platformer Heater	71,000 Nm^3/hr	91%	DNX-630	Catalyst	2002
▪ Prefractionator Heater	76,000 Nm^3/hr	95%	DNX-930	Catalyst	2002
▪ Vacuum Tower Heater	22,000 Nm^3/hr	90%	DNX-930	Catalyst	2003
▪ Reclaim Charge Heater (KTI)	13,000 Nm^3/hr	90%	DNX-930	Catalyst	2003
Tosco, Rodeo, CA					
▪ Heater (OnQuest)	55,000 Nm^3/hr	90%	DNX-930	Catalyst	2006
Tesoro Golden Eagle Refinery, Martinez, CA					
▪ Heater F-27	97,000 Nm^3/hr	89%	DNX-930	Catalyst	2002
▪ Heater F-50	138,000 Nm^3/hr	92%	DNX-930	Catalyst	2002
▪ Heater F-51 (Peerless)	108,000 Nm^3/hr	88%	DNX-630	Catalyst	2002
Tesoro Los Angeles refinery, CA					
▪ Wilmington, Heater HTU44	20,000 Nm^3/hr	92%	DNX-940	Catalyst	2002
▪ Wilmington, Heater CRU-2	56,000 Nm^3/hr	92%	DNX-940	Catalyst	2002
▪ Wilmington, Heater CRU-3	40,000 Nm^3/hr	94%	DNX-930	Catalyst	2002

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Valero					
▪ Houston Refinery, 3 boilers	125,000 Nm^3/hr	90%	DNX-920	Catalyst	2005
▪ St. Charles, LA, 2 SMR			DNX-920	Catalyst	2006
▪ Texas City Ref., 3 boilers	118,000 Nm^3/hr	90%	DNX-920	Catalyst	2005
▪ Benicia, CA, 2 FCC	347,200 Nm^3/hr	96%	DNX-164	Catalyst	2009

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Waste incineration					
Belgium					
Bruxelles Energie, Brussels					
▪ Incineration plant - 3 lines (CTU)	3 x 200,000 Nm^3/hr	83%	DNX-930	Catalyst	2006
Czech Republic					
Palivony Kombinat, Vresova				Catalyst	
▪ Off-gas incinerator (SNOX)	54,000 Nm^3/hr	95%	DNX-932	System Design	1993
France					
Siom de la Valee Chevreuse					
▪ Incineration Plant Line 1	90,000 Nm^3/hr	70%	DNX-939	Catalyst	2008
▪ Incineration Plant Line 2 (Area Impianti)	54,000 Nm^3/hr	77%	DNX-930	Catalyst	2007
Vinci Environment					
▪ Incineration Plant - 2 lines (Speic)	2 x 53,000 Nm^3/hr	50% + DeDioxin	DNX-930	Catalyst	2005
Holland					
AVR Afvalverwerking					
▪ Incineration plant	70,000 Nm^3/hr	92%	DNX-929	Catalyst	2009
SITA ReEnergy					
▪ Incineration Plant	67,000 Nm^3/hr	80% + DeDioxin	DNX-949	Catalyst	2007
Ireland					
Eli Lilly, Dunderrow, Kinsale					
▪ Incinerator	10,000 Nm^3/hr	78% + DeDioxin	DNX-930	Catalyst	2006
Italy					
Noy Ambiente, Dalmine					
▪ Incineration Plant	68,000 Nm^3/hr	94%	DNX-930	Catalyst	2007
Provincia Autonoma di Bolzano				Catalyst	
▪ Incineration Plant	117,000 Nm^3/hr	85% + DeDioxin	DNX-930	System Design Hardware	1996

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Middle East					
Undisclosed client					
▪ One unit (KEU)	34,700 Nm3/hr	80%	DNX-920	Catalyst	2005
Romania					
SNP Petrocehm S.A. Arpechim, Petesti					
▪ Gas incineration (Vichem, France)	140,000 Nm^3/hr	99%	DNX-940	Catalyst System Design Hardware	2004
Spain					
Uquifa, Sant Celoni					
▪ Pharmaceutical Plant	9,000 Nm^3/hr	90%	DNX-950	Catalyst System Design Hardware	1998
Thailand					
Ministry of Industrial Works, Bang Poo Industrial Estate					
▪ Waste Incinerator	45 tons/day	90%	DNX-930	Catalyst	2004
USA					
Clean Harbors, Deer Park, TX					
▪ Incinerator Haz. Waste			DNX-930	Catalyst	2004
OxyChem,	4 x				
▪ Deer Park, TX, Incinerator	36,000 Nm^3/hr	DeDioxin	DNX-930	Catalyst	2002
▪ Ingleside, TX, Incinerator			DNX-930	Catalyst	2002
White Mountain Energy, Berlin, NH					
▪ SOG incinerator (Wahlco)	87,000 Nm^3/hr	86%	DNX-958	Catalyst	2004

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Other applications					
Australia					
Australian Gold Reagents Kwinana, Western Australia				Catalyst System Design Hardware	
▪ Sodium Cyanide Production	38,000 Nm^3/hr	> 90%	DNX-930		1998
China					
Baoshan Iron & Steel Co.					
▪ WSA plant (Topsoe)	12,700 Nm^3/hr	91%	DNX-930	Catalyst	2008
Chongqing iron & Steel					
▪ WSA plant	10,000 Nm^3/hr	90%	DNX-939	Catalyst	2009
Handan Iron & Steel					
▪ WSA plant (Topsoe)	10,500 Nm^3/hr	75%	DNX-920	Catalyst	2008
Panzinhua Iron & Steel Co					
▪ WSA plant (Topsoe)	10,000 Nm^3/hr	89%	DNX-939	Catalyst	2010
SGIS Songhan Co. Ldt.					
▪ WSA plant Unit 1	10,000 Nm^3/hr	75%	DNX-920	Catalyst	2009
▪ WSA plant Unit 2 (Topsoe)	10,000 Nm^3/hr	75%	DNX-939	Catalyst	2009
Denmark					
Haldor Topsøe A/S, Frederikssund					
▪ Catalyst Production Plant 1	30,000 Nm^3/hr	90%	DNX-652	Catalyst	1999
▪ Catalyst Production Plant 2	36,000 Nm^3/hr	90%	DNX-930	System Design	1999
▪ Catalyst Production Plant 3	36,000 Nm^3/hr	90%	DNX-930	Hardware	1999
▪ Catalyst Production Plant 4	36,000 Nm^3/hr	90%	DNX-930		1999
France					
ITC SA					
▪ Unit 1	6,700 Nm3/hr	98%	DNX-639	Catalyst	2008
Germany					
Dow Stade					
▪ Chemical Plant (KEU/John Zink)	22,000 Nm^3/hr	95%	DNX-949	Catalyst	2008

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Umicore AG					
▪ Catox plant (KEU)	34,000 Nm^3/hr	94%	DNX-930	Catalyst	1999
Holland					
Nyrstar Budel Zink, Budel					
▪ Sulphuric Acid Plant (Kvaerner Chemetics)	1000 MTPD	95%	DNX-330	Catalyst System Design	1999
India					
Deepak Fertilizers & Petrochemicals Co. Ltd.					
▪ Nitric Acid Plant	45,000 Nm^3/hr	95%	DNX-920	Catalyst System Design	2000
Gujarat Narmeda Valley Fertilizers Co. Ltd.					
▪ WSA Plant	36,000 Nm^3/hr	92%	DNX-939	Catalyst	2009
Sejal Architectural Glass					
▪ Float glass line	74,000 Nm^3/hr	80%	DNX-949	Catalyst	2009
Japan					
Asahi Chemical Industry Co. Ltd., Kawasaki					
▪ Spent Acid Regeneration	50,000 Nm^3/hr	95%	DNX-652	Catalyst System Design Hardware	1993
Hachinohe Smelting					
▪ Zink Smelter	70,000 Nm^3/hr	75%	DNX-329	Catalyst	2009
Korea					
Namhae Chemical Corp., Yochon					
▪ DNT/MNT Production	3,000 Nm^3/hr	99%	DNX-930	Catalyst System Design Hardware	1998
Posco					
▪ Sinter metal plant, 2 units (Korea Cotrell)	1,350,000 Nm^3/hr	82% + DeDioxin	DNX-939	Catalyst	2007
Northern Ireland					
Coca Cola, Lisburn					
▪ Unit 1	12,400 Nm^3/hr	95%	DNX-631	Catalyst	2009

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End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
Romania					
Coca Cola, Ploiesti					
▪ Unit 1	12,400 Nm^3/hr	95%	DNX-631	Catalyst	2009
Russia					
Ministry of Oil refining and Petrochemical Industry, Ishimbay	8,000 Nm^3/hr	70%	DNX-652	Catalyst System Design Hardware	-
Taiwan					
Formosa Plastics Group					
▪ Spent Acid Regeneration	17,000 Nm^3/hr	90%	DNX-630	Catalyst	1995
Saudi Arabia					
Eastern Petrochemical Co. Ltd.					
▪ Units 1 & 2 (KEU/John Zink)	100,000 Nm^3/hr	43% + DeDioxin	DNX-659	Catalyst	2007
Sweden					
Wstinghouse Electric Sweden, Västerås					
▪ Nuclear Fuel Rod Production	7,500 Nm^3/hr	60%	DNX-930	Catalyst System Design Hardware	1997
LKAB, Kiruna					
▪ Sinter Metal Plant, Unit 4 (Alstom)	433,000 Nm^3/hr	90%	DNX-749	Catalyst	2007
Switzerland					
CIMO					
▪ Unit 1 (KEU)	25,500 Nm^3/hr	>95%	DNX-940	Catalyst	2004
UK					
Astra Zeneca, Bristol					
▪ Unit 1	2,900 Nm^3/hr	90%	DNX.950	Catalyst	2001
USA					
Beta Steel Corp., Portage, IN					
▪ Steel Kiln	91,000 Nm^3/hr	95%	DNX-930	Catalyst	2003

SCR DeNOx technology and catalyst

End User (Contractor)	Plant size	DeNOx	Catalyst	Scope of supply	Start-up year
California Steel, Fontana, CA					
▪ Steel Kiln Unit 1		95%	DNX-930	Catalyst	2005
▪ Steel Kiln Unit 2	126,400 Nm^3/hr	95%	DNX-930	Catalyst	2009
Corcoran Tomato Plant, CA					
▪ Two Boilers (AUS)			DNX-920	Catalyst	2008
CSI, CA					
▪ Unit 1 (Peerless)	7,000 Nm^3/hr	88%	DNX-930	Catalyst	2000
DistriGas, Boston, MA	2x				
▪ LNG Plant	65,000 Nm^3/hr	> 90%	DNX-930	Catalyst	2001
GE Quartz, Hebron, OH					
▪ Newark Plant, 10 Units in Glass Plant			DNX-930	Catalyst	2005
Haldor Topsoe Inc., Houston, TX					
▪ Catalyst Production Plant 1	18,000 Nm^3/hr	90%	DNX-652	Catalyst	1994
▪ Catalyst Production Plant 2	6,000 Nm^3/hr	97%	DNX-951	System Design Hardware	2001
Momentive, Hebron, OH					
▪ 10 Units in Quartz Plant			DNX-930	Catalyst	2005
Nucor Steel, Decator, AL					
▪ Steel Kiln	17,000 Nm^3/hr	84%	DNX-320	Catalyst	2007
PPG Industries Inc., PA					
▪ Glass plant	107,000 Nm^3/hr	80%	DNX-359	Catalyst	2009
Rohm & Haas, TX					
▪ Unit 1 (EnviroKinetics)	225,000 Nm^3/hr	95%	DNX-930	Catalyst	2004
Wabash Rental Power					
▪ Mobil Power boiler (Vector Systems)				Catalyst	2008
Y2K Textiles, Fullerton, CA					
▪ Gas fired package boiler	2 x 5,000 Nm^3/hr	>70%	DNX-930	Catalyst	2000

DeNOx 09.07.2009

Exhibit 2

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SCR System and NOx Catalyst Experience

COAL

No.	Customer	Plant	Gas Source	MW or Gas Flow Rate (Nm3/H)	Fuel	DeNOx Eff. (%)	Commercial Operation	Country	System	Notes
1	East Kentucky Power Cooperative	Cooper Unit 2	CB	225 MW	Coal	88	2013	U.S.A.	✓	System provided by Hitachi, CM Catalyst
2	PSEG	Hudson Unit 2	CB	600 MW	Coal	90.9	2011	U.S.A.	✓	System provided by Hitachi
4	Duke Energy	Cliffside Unit 6	CB	2,602,800	Coal	81.3	2011	U.S.A.	✓	System provided by Hitachi, CM Catalyst
19	Minnesota Power	Boswell Unit 3	CB	355MW	PRB	90	2009	U.S.A.	✓	System provided by HPSA
20	Seminole	Seminole Units 1	CB	715 MW	70% Ilinois Coal 30% Pet Coke	90.3	2009	U.S.A.	✓	System provided by HPSA
21	Seminole	Seminole Units 2	CB	715 MW	70% Ilinois Coal 30% Pet Coke	90.3	2009	U.S.A.	✓	System provided by HPSA
22	Wisconsin Energy	Elm Road Unit 2	CB	680	Bit.	80	2009	U.S.A.	✓	System provided by Hitachi
28	MidAmerican Energy	Council Bluffs	CB	750	PRB	66.7	2008	U.S.A.	✓	System provided by Hitachi
30	Wisconsin Energy	Elm Road Unit 1	CB	680	Bit.	80	2008	U.S.A.	✓	System provided by Hitachi

Exhibit 3

Plant/Unit	MW	SCR Type, Catalyst Type	NOx Removal Efficiency
> Gibson 2+3	1,320	high dust, plate	85 %
> Merrimack 1+2	450	high dust, plate	90 %
> Birchwood	250	high dust, plate	54 %
> Gavin 1+2	2,600	high dust, plate	90 %
> Baldwin 2	660	high dust, plate	90 %
> Stanton	450	high dust, plate	90 %
> Brandon Shores	700	low dust after ESP, honeycomb	90 %
Amos 3	1,300	high dust, plate	90 %
Indiantown	300	high dust, plate	60 %
Logan	220	high dust, plate	60 %
Miami Fort 8	520	high dust, plate	85 %
Mountaineer 1	1,300	high dust, plate	90 %
Wagner 3	450	high dust, plate	54 %
Mercer 2	320	high dust, plate	85 %
East Bend 2	650	low dust after ESP, honeycomb	85 %

Exhibit 4

CERAM-Frauenthal Honeycomb Catalyst Experience Summary

CERAM's Frauenthal plant (Porzellanfabrik Frauenthal GmbH) was established in 1921. CERAM-Frauenthal began homogeneous honeycomb catalyst production in 1985 under the Mitsubishi license. Table 1 summarizes CERAM's comprehensive SCR catalyst applications experience. In total, our experience base comprises over 300 applications requiring over 38.000 cubic meters of catalyst. This is nearly equivalent to the catalyst required for 30.000 MW of electric generation. The CERAM production plant is located in Frauental, Austria and was the first Mitsubishi licensee located outside of Japan.

CERAM's first coal-fired installation (high dust) began commercial operation in 1986 at the Mellach Station located in Austria. As of 2005, two of the **original** catalyst layers were in operation at the Mellach Station after more than 100,000 operating hours (nearly 19 years). This is an excellent example of the quality and durability of our catalysts.

CERAM's experience spans nearly all possible SCR configurations (high dust, low dust, and tail-end) and for nearly every conceivable fuel type. Our catalyst has been used on applications with sulfur contents as high as 5% with vanadium contents as high as 400 ppm and ash contents as high as 30%. Additionally, our catalyst has been installed in SCR systems operating as low as 300 F and as high as 1100 F (without tempering). Our catalyst is used in SCR systems treating flue gas from the following fuels and source types.

- Bituminous and subbituminous coals
- Distillate and residual fuel oils
- Orimulsion
- Natural gas
- Synthetic gas
- Wood and peat
- Municipal and residual derived fuel waste
- Industrial, hospital, and hazardous waste incinerators
- Chemical weapons

- Ethylene crackers, HNO_3, and FCC units
- Blast furnace and coke oven gas
- Steel production and pickling
- Glass production plants

As a result of our extensive experience base CERAM-Frauenthal has significantly improved our catalyst product from the original Mitsubishi license basis. Unlike other licensor/licensee arrangements, our applications experience and product innovations do not migrate to other Mitsubishi licensees. They are CERAM's sole property.

CERAM
CATALYSTS • HONEYCOMBS

Reference List as of August 2006

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
1.	**FHKW Mellach**	SGP	STEWEAG	AUT	Bituminous coal, High dust	287 m³	1986
2.	**BHKW Donaustadt Block 2**	SGP	Wiener Stadtwerke	AUT	Oil / Gas	80 m³	1987
3.	**Wedel I/II**	Steinmüller	HEW	DEU	Coal, High dust	370 m³	1987
4.	**München Süd**	Steinmüller	Stadtwerke München	DEU	Natural gas	88 m³	1988
5.	**Altbach**	Steinmüller	EnBW	DEU	Coal / Oil	132 m³	1987 / 88
6.	**BHKW Donaustadt Block 1**	SGP	Wiener Stadtwerke	AUT	Oil / Gas	80 m³	1988
7.	**GuD Leopoldau**	SGP	Wiener Stadtwerke	AUT	Natural gas	114 m³	1988
8.	**FHKW Mellach 4. Lage**	SGP	STEWEAG	AUT	Bituminous coal, High dust	94 m³	1988
9.	**Charlottenburg**	Steinmüller	BEW	DEU	Tail end	198 m³	1989
10.	**Karlsruhe**	DBA	EnBW	DEU	Coal, Tail end	60 m³	1988
11.	**Niederrad**	DBA		DEU	Natural gas	26 m³	1988
12.	**Bexbach**	EVT	SaarEnergie	DEU	Coal, High dust	858 m³	1988
13.	**Herne 1, 2, 3**	KWH	STEAG	DEU	Coal, Tail end	501 m³	1989
14.	**Voerde West I/II**	KWH	STEAG	DEU	Coal, Tail end	535 m³	1989
15.	**Lünen 11**	KWH	STEAG	DEU	Coal, Tail end	243 m³	1989
16.	**Lünen 10**	KWH	STEAG	DEU	Coal, Tail end	94 m³	1989
17.	**MVA Spittelau**	SGP	Heizbetriebe Wien	AUT	Municipal waste, Tail end	39 m³	1989

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
18.	Weiher 3	Steinmüller	SaarEnergie	DEU	Coal, High dust	617 m³	1990
19.	BHKW Voitsberg 3	SGP	Österr. Draukraftwerke	AUT	Brown coal, High dust	405 m³	1990
20.	Ceilcote	SGP	MGC Plasma AG	CHE	Hazardous waste	2 m³	1990
21.	MVA Heidelberg	SGP	UNI-Bauamt Heidelberg	DEU	Hospital waste, Low temp.	3 m³	1990
22.	STEAG Repl., 1 layer	STEAG	STEAG	DEU	Coal, Tail End	46 m³	1991
23.	KW Simmering Block 3	SGP	Wiener Stadtwerke	AUT	Heavy oil, High dust	208 m³	1992
24.	Tiefstack	Steinmüller		DEU	Coal	212 m³	1992
25.	MVA Rotterdam	SGP	AVR	NLD	Municipal waste, Low temp.	321 m³	1993 / 95
26.	MVA Spittelau Dioxin	SGP	Heizbetriebe Wien	AUT	Municipal waste, Tail end	22 m³	1991
27.	Bexbach	Saarbergwerke AG		DEU	Coal, High dust	286 m³	1992
28.	FHKW Linz Mitte	SGP	ESG Linz	AUT	Heavy oil, High dust	85 m³	1992
29.	VISBY	SGP	Vattenfall	SWE	Oil / Diesel engine	60 m³	1992
30.	Knoll	SGP		CHE	Waste, High dust	2 m³	1992
31.	BHKW Voitsberg 3	SGP	Österr. Draukraftwerke	AUT	Brown coal, High dust, Additional delivery	60 m³	1992
32.	MVA Flötzersteig	AEE	Heizbetriebe Wien	AUT	Municipal waste, Tail end	52 m³	1992
33.	GuD KW Linz Süd	AEE	ESG Linz	AUT	Natural gas	42 m³	1993
34.	MVA Burgkirchen	SHL	ZAS	DEU	Waste, Tail end	24 m³	1993

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
35.	Fiume Santo	IDRECO	ENEL	ITA	Coal / Oil	602 m³	1994 / 96
36.	RDK7	BASF	EnBW	DEU	Coal, High dust	182 m³	1993
37.	München Nord	BASF	Stadtwerke München	DEU	Waste, Tail end	49 m³	1993
38.	VA-Stahl 85 MW Block 6	AEE	VÖEST Alpine Stahl	AUT	Blast furnance-, Coking plant- and Natural gas	41 m³	1994
39.	FCC Scanraff	AEE	Skandinaviska Raffinaderi	SWE	FCC	31 m³	1994
40.	BHKW Salzburg Nord	AEE	Salzburger Stadtwerke	AUT	Heavy oil, High dust	15 m³	1994
41.	Bayer Dormagen	BASF	Lentjes	DEU	Hazardous waste, Tail end	32 m³	1994
42.	MVA Schwandorf	BASF	Lentjes	DEU	Municipal waste	130 m³	1994
43.	Philips Glasfabrik	BASF	ABB	DEU	Glass trough	13 m³	1994
44.	Karlshamn	BASF	ABB	SWE	Oil, High dust	122 m³	1994
45.	Nijmegen	BASF	KRC	NLD	Municipal waste, Tail end	35 m³	1994
46.	Bremen Block 5	BASF	Stadtwerke Bremen	DEU	Coal, High dust	46 m³	1994
47.	Mannheim	BASF	GKW Mannheim	DEU	Coal, High dust	168 m³	1994
48.	Lünen 11	BASF	STEAG	DEU	Coal, Tail end	80 m³	1994
49.	Akzo	BASF	Uhde	NLD	HNO_3	4 m³	1994
50.	Ibbenbüren	BASF	Preussag / RWE	DEU	Coal, Tail end	143 m³	1994
51.	Schott Mainz, Wanne 7	BASF	Glaswerke Schott / KRC	DEU	Glass trough	10 m³	1994

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Reference List as of August 2006

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
52.	FCC Shell Hamburg	BASF	Shell / Hugo Petersen	DEU	FCC	15 m³	1994
53.	MVA Mannheim K1-3	BASF	EVT	DEU	Municipal waste, Tail end	86 m³	1994
54.	MVA Essen Karnap	BASF	EVT	DEU	Municipal waste, Tail end	140 m³	1994
55.	ZVSMM Schwabach	BASF	Lurgi	DEU	Chemical waste	9 m³	1994
56.	Kiruna	BASF		SWE	Peat, Wood	13 m³	1994
57.	RSMV Ciba Geigy	BASF	Ciba Geigy	CHE	Hazardous waste	12 m³	1995
58.	SW Bremen Block 6	BASF	Stadtwerke Bremen	DEU	Coal	124 m³	1995
59.	BASF Residue Incin. N800	BASF	BASF	DEU	Hazardous waste, Low dust	233 m³	1995
60.	MVA Wels	AEE	WAV	AUT	Municipal waste, Tail end	20 m³	1995
61.	GuD VA-Stahl Block 01	AEE	VÖEST Alpine Stahl	AUT	Blast furnance-, Coking plant- and Natural gas	21 m³	1995
62.	KVA Thurgau	AEE	Verband KVA Thurgau	CHE	Municipal and industrial waste, Tail end	33 m³	1996
63.	MVA Bielefeld	BASF		DEU	Municipal waste	204 m³	1996
64.	MVA Leudelingen	BASF		LUX	Municipal waste, Tail end	16 m³	1995
65.	MHKW Darmstadt	BASF		DEU	Municipal waste	100 m³	1995
66.	Wuppertal	BASF		DEU	Municipal waste, Low temp.	154 m³	1995
67.	Bayer Bürrig	BASF	Bayer	DEU	Chemical waste	43 m³	1995
68.	Bayer Uerdingen	BASF	Bayer	DEU	Chemical waste	12 m³	1995

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
69.	**SYSAV**	BASF	Sysav	SWE	Municipal waste	11 m³	1995
70.	**ROW Wesseling**	BASF	ROW	DEU	Waste	24 m³	1995
71.	**Tiefstack**	BASF		DEU	Coal	86 m³	1995
72.	**Schwarzheide**	BASF	Integral	DEU	Hazardous waste, Tail end	29 m³	1995
73.	**MVA Iserlohn**	BASF		DEU	Municipal waste	87 m³	1995
74.	**FHKW Mellach**	AEE	STEWEAG	AUT	Bituminous coal, High dust, Additional delivery	95 m³	1995
75.	**SMVA Lonza**	AEE	Lonza AG	CHE	Residue, Tail end	25 m³	1995
76.	**St. Gilla**	ENEL	ENEL	ITA	Heavy oil, In Duct	13 m³	1995
77.	**EBS DG5**	Integral	Entsorgungsbetriebe Simmering	AUT	Diesel	3 m³	1995
78.	**RDK7**	BASF	EnBW	DEU	Coal, Additional delivery	182 m³	1995
79.	**Montalto di Castro**	Termokimik	ENEL	ITA	Oil	1100 m³	1995,96,97
80.	**CZ Süd**	BASF	BASF	DEU	Residue, Tail end	3 m³	1996
81.	**Höchst**	BASF	Hoechst AG	DEU	Hazardous waste	21 m³	1996
82.	**Karlshamn 2**	BASF		SWE	Oil, High dust	122 m³	1996
83.	**KVA St. Gallen**	BASF	AEE	CHE	Municipal waste, Tail end	11 m³	1996
84.	**MHKW Ludwigshafen**	BASF		DEU	Municipal waste	78 m³	1996
85.	**MVA Flingern**	BASF		DEU	Municipal waste, Tail end	106 m³	1996

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
86.	Euroglas	BASF		FRA	Glass trough	19 m³	1996
87.	MHKW Bamberg	BASF		DEU	Municipal waste	21 m³	1996
88.	HKW München Nord	BASF		DEU	Municipal waste	63 m³	1996
89.	MKW Weissenhorn	BASF		DEU	Municipal waste	41 m³	1996
90.	KW Werndorf II	Integral	STEWEAG	AUT	Heavy oil, Natural gas	59 m³	1996
91.	MVA Zavin	AEE		NLD	Hospital waste, Low temp.	7 m³	1996
92.	Lukens Steel	Seiler		USA	Steel pickling	4 m³	1996
93.	Colombes	Integral		FRA	Waste, Tail end	20 m³	1996
94.	Chemie Linz	Integral	DSM - Fine Chemicals	AUT	Chemical residue	2 m³	1996
95.	SMVA Munster	AEE	Wehreswissensch. Institut	DEU	chem. weapon, cumbustion, Tail end	4 m³	1997
96.	CIBA Geigy	Smogless		ITA	Waste	6 m³	1997
97.	MVA Mannheim IV	BASF		DEU	Municipal waste, Tail end	46 m³	1997
98.	MVA Zagreb	Hafner		HRV	Waste	4 m³	1997
99.	KW Simmering 1/2	Integral	Wienstrom	AUT	Natural gas	67 m³	1997
100.	Schott Mainz	BASF	Glaswerke Schott	DEU	Glass trough	10 m³	1997
101.	SW Bremen KW Hafen 5	BASF	Stadtwerke Bremen	DEU	Coal, Additional delivery	59 m³	1997
102.	SW Bremen KW Hafen 6	BASF	Stadtwerke Bremen	DEU	Coal, Additional delivery	125 m³	1997

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
103.	Torrevaldaliga	Termokimik	ENEL	ITA	Oil	900 m³	1997 / 98
104.	SW Bremen HKW Hastedt	BASF	Stadtwerke Bremen	DEU	Coal, Additional delivery	47 m³	1997
105.	SW Bremen KW Hafen 6	BASF	Stadtwerke Bremen	DEU	Coal, Additional delivery	60 m³	1997
106.	BHKW	Jenbacher	Jenbacher	AUT		1 m³	1997
107.	GMVA Niederrhein	BASF		DEU	Municipal waste	58 m³	1997
108.	Eisenwerke Kaiserslautern	BASF		DEU		5 m³	1997
109.	Lonza	BASF	Lonza AG	CHE	Residue	2 m³	1997
110.	Weatherly	BASF	Farmland Industries	USA	HNO_3	10 m³	1997
111.	FCC Shell Hamburg	BASF	Shell	DEU	FCC	15 m³	1997
112.	RMVA Köln	BASF		DEU	Municipal waste	115 m³	1997
113.	FCC Shell Rotterdam	AEE	Raffinerie Shell-Rotterdam	NLD	FCC	39 m³	1997
114.	ROW - Werk Wesseling, Unit 19	BASF	Rheinische Olefinwerke	DEU	Ethylencracker	16 m³	1997
115.	Steuler	BASF		DEU		12 m³	1997
116.	MVA Lenzing	Integral		AUT	Waste, Tail end	29 m³	1997
117.	BASF N806	BASF	BASF	DEU	Hazardous waste, Low dust	24 m³	1997
118.	Vado Ligure	Termokimik	ENEL	ITA	Coal, High dust	560 m³	1997 / 98
119.	Schott Glaswerke, Wanne 7	BASF	Glaswerke Schott	DEU	Glass trough, Additional delivery	10 m³	1998

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Reference List as of August 2006

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
120.	**ROW Wesseling**	BASF	ROW	DEU	Chemcial waste	26 m³	1998
121.	**MVA Constanti**	BASF	AE-Energietechnik	ESP	Hazardous waste, Low dust	29 m³	1998
122.	**MVA Wuppertal**	Integral		DEU	Municipal waste, Low temp., Additional delivery	51 m³	1998
123.	**SW Bremen**	BASF	Stadtwerke Bremen	DEU	Coal	37 m³	1998
124.	**KVA Basel**	BASF		CHE	Municipal waste, Low dust	58 m³	1998
125.	**GKM Mannheim Block 7**	BASF	GKW Mannheim	DEU	Coal, Additional delivery	168 m³	1998
126.	**GT Geismar**	BASF		USA	Natural gas, Low temp.	81 m³	1998
127.	**MVA Würzburg**	BASF		DEU	Municipal waste, High dust	16 m³	1998
128.	**GKM Mannheim Block 8**	BASF	GKW Mannheim	DEU	Coal, Additional delivery	195 m³	1998
129.	**ND Salpetersäureanlage**	BASF	BASF	DEU	HNO_3, Low temperature	44 m³	1998
130.	**MVA Buchs**	BASF	AE	CHE	Municipal waste, Tail end	54 m³	1998
131.	**Weatherly 2**	BASF	Farmland Industries	USA	HNO_3	10 m³	1999
132.	**SMVA Ostrava**	AE-Energietechnik		CZE	Hazardous waste, Tail end	9 m³	1999
133.	**BASF N806**	BASF	BASF	DEU	Hazardous waste, Low dust	8 m³	1999
134.	**MVA Niederurnen**	BASF		CHE	Municipal waste	57 m³	1999
135.	**Mariehamn**	BASF	Aura Marine	FIN		9 m³	1999
136.	**Eisenwerke Kaiserslautern**	BASF		DEU		12 m³	1999

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
137.	Thermoselect Karlsruhe	BASF	Steuler	DEU	Waste	9 m³	1999
138.	San Filippo del Mela 5/6	ENEL	ENEL	ITA	Orimulsion	167 m³	1999
139.	Sulcis 3	ENEL	ENEL	ITA	Coal / Oil, Tail end	127 m³	1999
140.	SW Bremen HKW Hastedt	BASF	Stadtwerke Bremen	DEU	Coal, High dust, Additional delivery	48 m³	1999
141.	TRV-Wesseling	BASF		DEU	Industrial- and hazardous waste	13 m³	1999
142.	GT Falconara	ABB Sadelmi SpA	API Refinery	ITA	Syn. gas, destilled fuel	49 m³	1999
143.	La Spezia	ENEL	ENEL	ITA	Coal, High dust	525 m³	2000
144.	KW Simmering 1/2	Integral	Wienstrom	AUT	Natural gas	21 m³	2000
145.	Homer City Unit 1, 2, 3	BASF	ABB	USA	Coal, High dust	1913 m³	2000
146.	Salzburg Mitte	Integral	Stadtwerke Salzburg	AUT	Oil, High dust	10 m³	2000
147.	Dalmine	Integral		ITA	Waste, Tail end	13 m³	2000
148.	Rhodia	BASF	Rhodia	DEU	Hazardous/Liquide waste	14 m³	2000
149.	Smurfit Newsprint, Pomona	WAHLCO	Energy Products of Idaho	USA	Natural gas	26 m³	2000
150.	Hot Strip Mill Oven 22	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	37 m³	2000
151.	DEA Hamburg	BASF	DEA	DEU	Oil	20 m³	2000
152.	Genf Linie 5, 6, 3	BASF	SIG / AE-Energietechnik	CHE	Municipal waste, Low dust	139 m³	2000/01
153.	St. Agnes Medical Center	WAHLCO		USA	Natural gas, Oil	7 m³	2000/01

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
154.	BASF N810	BASF	BASF	DEU	Hazardous waste, Low dust, Additional delivery	29 m³	2001
155.	ROW-Wesseling TRV	BASF	ROW	DEU	Industrial- and hazardous waste, Additional delivery	13 m³	2001
156.	BASF FINA Steam Cracker	BASF	Deltak	USA	Gas turbine	7 m³	2001
157.	Elenac - Werk Wesseling Unit 20-24	BASF	Elenac GmbH	DEU	Ethylencracker, Tail end	51 m³	2001
158.	Elenac - Werk Wesseling	BASF	Elenac GmbH	DEU	Ethylencracker, Tail end, Additional delivery	8 m³	2001
159.	KW Bexbach	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	6 m³	2001
160.	KW Weiher 3	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	369 m³	2001
161.	MVA Fribourg	BASF		CHE	Waste, Tail end	33 m³	2001
162.	Creteil	BASF	ELEX	FRA	Municipal waste, Tail end	48 m³	2001
163.	HIMTEC	BASF		ITA	Municipal waste, Tail end	5 m³	2001
164.	GuD Donaustadt Block 3	Integral	Wienstrom	AUT	Combined Cycle, Natural gas	74 m³	2001
165.	VA-Stahl Block 3	Integral	VA-Stahl	AUT	Blast furnance-, Coking plant- and Natural gas	11 m³	2001
166.	GT West Phoenix Unit 3	HRC	Pinnacle West Energy Corp. / Vogt NEM	USA	Natural gas	54 m³	2001
167.	CO-Catalyst Rotterdam	AE-Energietechnik	AVR	NLD	Municipal waste, Tail end, CO Oxidation	6 m³	2001
168.	RDK 7	BASF	EnBW	DEU	Coal, High dust, Additional delivery	198 m³	2001
169.	Deparia	Deparia Engineering S.r.l.		ITA	Low Sulfur Oil, Diesel engine	7 m³	2001
170.	MVA Bamberg	BASF		DEU	Municipal waste, Tail end	7 m³	2001

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171.	Vado Ligure	ENEL	Tirreno Power	ITA	Coal, High dust, Additional delivery	87 m³	2001
172.	Kirikkale	BASF	Steuler	TUR	Heavy oil, Diesel engine	83 m³	2001
173.	Refinery Texas City	BASF	BP Amoco Oil Company / KBR	USA	Refinery	29 m³	2001
174.	Goat Rock 1A&1B	HRC	Georgia Power / Vogt NEM	USA	Natural gas, Combined cycle	91 m³	2001
175.	Wansley 6A & 6B	HRC	Georgia Power / Vogt NEM	USA	Natural gas, Combined cycle	91 m³	2001
176.	Wansley 7A & 7B	HRC	Georgia Power / Vogt NEM	USA	Natural gas, Combined cycle	91 m³	2001
177.	MVA Zavin	BASF	Steuler	NLD	Hospital waste, Low temperature, Additional delivery	3 m³	2001
178.	Thermoselect Karlsruhe	BASF	EnBW	DEU	Waste	7 m³	2001
179.	Stuart Unit 1, 2, 3, 4	Black & Veatch	Dayton Power & Light	USA	Coal, High dust	2792 m³	2001/2/3
180.	Coffeen Unit 2	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High dust	711 m³	2002
181.	Killen	Black & Veatch	Dayton Power & Light	USA	Coal, Low dust	326 m³	2002
182.	KW Hamborn	BASF	Alstom Power	DEU	Blast furnance-, Coking plant- and Natural gas	69 m³	2002
183.	Michigan City Unit 12	Black & Veatch	NIPSCO	USA	Coal, High dust	583 m³	2002
184.	GT Zeeland	HRC	EPI / Vogt NEM	USA	Natural gas, Combined cycle	80 m³	2002
185.	GT Perryville	HRC	EPI / Vogt NEM	USA	Natural gas, Combined cycle	69 m³	2002
186.	GuD Salzburg Mitte	Integral	Stadtwerke Salzburg	AUT	Natural gas, Combined cycle	26 m³	2002
187.	KW Weiher 3	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	369 m³	2002

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188.	**MVA Würzburg**	BASF	BBP Environment	DEU	Municipal waste, High dust	34 m³	2002
189.	**TRV Wesseling**	BASF		DEU	Industrial- and hazardous waste, Additional delivery	13 m³	2002
190.	**Hot Strip Mill Oven 21**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	37 m³	2002
191.	**Halmstads Renhallnings AB**	BASF	BBP Environment	SWE	Municipal waste, Tail end	19 m³	2002
192.	**Kauai Island**	HRC	Kauai Power / IST	USA	Natural gas, Combined cycle	25 m³	2002
193.	**PSEG Tracy**	HRC	GWF Energy	USA	Natural gas, Simple cycle, High temp.	44 m³	2002
194.	**Batman Diesel Power Plant**	HRC	Fernas / Pasiner	TUR	Heavy oil, Diesel engine	69 m³	2002
195.	**Bayer Antwerpen**	BASF	Bayer AG	BEL	Industrial waste, Tail end	13 m³	2002
196.	**KVA Turgi**	BASF	GV Region Baden-Brugg	CHE	Municipal waste, Tail end	11 m³	2002
197.	**HKW 1 Kraftwerk Altbach**	BASF	Neckarwerke	DEU	Coal, High dust, Additional delivery	132 m³	2002
198.	**FCC Shell Hamburg**	BASF	Shell & DEA Oil	DEU	FCC, Additional delivery	15 m³	2002
199.	**FCC Shell Rotterdam**	BASF	Shell & DEA Oil	NLD	FCC, Additional delivery	20 m³	2002
200.	**Homer City**	BASF	Midwest Generation / ALSTOM POWER	USA	Coal, High dust, Additional delivery	196 m³	2002
201.	**Vado Ligure**	Interpower	Interpower	ITA	Coal, High dust, Additional delivery	88 m³	2002
202.	**Hot Strip Mill Oven 22**	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp., Additional del.	39 m³	2002
203.	**GMVA Oberhausen**	BASF		DEU	Municipal waste, Tail end	19 m³	2002
204.	**MVA Malmö**	BASF	LAB	SWE	Municipal waste, Tail end	30 m³	2002

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205.	KVA Thurgau	BASF	CTU	CHE	Municipal waste, Tail end, Additional delivery	8 m³	2002
206.	VA-Stahl Block 3	Integral	VA-Stahl	AUT	Blast furnance-, Coking plant- & Natural gas, Additional del.	7 m³	2002
207.	Nijmegen	BASF		NLD	Municipal waste, Tail end, Additional delivery	6 m³	2002
208.	RWE Solar	BASF	RWE	DEU	Pickling bath from solar cell production, NH3-Oxidation	1 m³	2002
209.	BASF FINA Steam Cracker	BASF	KTI	USA	Gas turbine	14 m³	2002
210.	Genf Linie 5	BASF	CTU	CHE	Municipal waste, Low dust, Additional delivery	55 m³	2002
211.	Basell MG4	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker, Low temp.	33 m³	2002
212.	Shell Godorf	AE	Shell & DEA Oil	DEU	Refinery, Residue oil boiler	71 m³	2002/3
213.	Dallman Station Unit 31, 32, 33	Black & Veatch	City of Springfield	USA	Bituminous Coal, High dust	498 m³	2002/3
214.	Korsika Unit 1	BASF	EdF / Steuler	FRA	Diesel engine, Heavy/low sulphur oil	12 m³	2003
215.	Baytown Olefins Plant	BASF	Exxon Mobil Chemical Co. / KTI	USA	Gas turbine	25 m³	2003
216.	GT East River Unit 1 + 2	HRC	Vogt NEM	USA	Natural gas, Combined cycle	131 m³	2003
217.	Coffeen Unit 1	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High dust	438 m³	2003
218.	Culley Unit 3	Black & Veatch	Sigeco	USA	Coal, High dust	304 m³	2003
219.	Schahfer Unit 14	Black & Veatch	NIPSCO	USA	Coal, High dust	583 m³	2003
220.	Ravenswood	HRC	Keyspan/Kawasaki	USA	Natural gas, Combined cycle	88 m³	2003
221.	Edwards Station Unit 3	LLNA	AES/Cilco	USA	Coal, High dust	434 m³	2003

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222.	T.A. Lauta	AE	STEAG	DEU	Municipal waste, Tail end, Low temp.	47 m³	2003
223.	Bailly 8	Black & Veatch	NIPSCO	USA	Coal, High dust	531 m³	2003
224.	Duck Creek Unit 1	LLNA	AES / Cilco	USA	Coal, High dust	555 m³	2003
225.	Cheswick Station # 1	Babcock & Wilcox	Orion Power Midwest	USA	Coal, High dust	861 m³	2003
226.	Collombey	HRC Italy	Tamoil	CHE	FCC	37 m³	2003
227.	NAS-CAPL	Andritz AG		USA	Steel pickling	2 m³	2003
228.	RSMVA Basel	BASF	Valorec Services AG	CHE	Residue, Additional delivery	12 m³	2003
229.	EBS WSO 4	Integral	Fernwärme Wien	AUT	Sludge, Municipal waste	22 m³	2003
230.	Schweizerhalle	BASF	Valorec Services AG	CHE	Residue	13 m³	2003
231.	Nimes	Integral		FRA	Waste, Tail end	9 m³	2003
232.	Le Havre	Integral		FRA	Waste, Tail end	13 m³	2003
233.	TRV Niklasdorf	AEE		AUT	Waste, Tail end	12 m³	2003
234.	Coffeen Unit 1	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High dust, Additional delivery	219 m³	2003
235.	Texas City	HRC	Praxair / SFPC (Selas Linde)	USA	Hydrogen reformer	16 m³	2003
236.	Port Arthur	HRC	Praxair / SFPC (Selas Linde)	USA	Hydrogen reformer	16 m³	2003
237.	Nijmegen Line 2	BASF		NLD	Municipal waste, Tail end, Additional delivery	11 m³	2003
238.	Reggio Emilia	HRC Italia	Protecma	ITA	Natural gas, Gasturbine	16 m³	2003

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239.	MVA Constanti	BASF		ESP	Hazardous waste, Low dust, Additional delivery	10 m³	2003
240.	Baytown Olefins Plant - 3rd layer	BASF	Exxon Mobil Chemical Co. / KTI	USA	Gasturbine, Additional delivery	12 m³	2003
241.	Schott Mainz, Wanne 5	BASF	Glaswerke Schott	DEU	Glass trough, Additional delivery	10 m³	2003
242.	BASF Freeport	BASF	BASF	USA	Syngas Hydro	15 m³	2003
243.	KVA St. Gallen	BASF		CHE	Municipal waste, Tail end, Additional delivery	9 m³	2003
244.	HKW Wedel I	BASF	HEW	DEU	Coal, High dust, Additional delivery	59 m³	2003
245.	FUSINA	ENEL	ENEL	ITA	Coal, High dust	104 m³	2003
246.	Hot Strip Mill - Oven 23	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m³	2003
247.	TBA Arnoldstein	AEE	KRV	AUT	Municipal waste, Tail end, Low temp.	14 m³	2003
248.	FCC 22696 & 22697	BASF	Chinese Petroleum Corp.	TWN	FCC	27 m³	2003
249.	1/2003	BASF	Eisenwerke Kaiserslautern	DEU	Glass trough, Additional delivery	5 m³	2003
250.	2/2003	BASF	Eisenwerke Kaiserslautern	DEU	Glass trough, Additional delivery	19 m³	2003
251.	Vado Ligure	Mosca Servizi Amb.	Interpower	ITA	Coal, High dust, Additional delivery	11 m³	2003
252.	GuD Salzburg Mitte	Integral	Stadtwerke Salzburg	AUT	Comb. Cycle, Natural gas, Add. del., NOx + CO-removal	11 m³	2003
253.	Borlänge	BASF	ELEX	SWE	Steel band annealing plant	5 m³	2003
254.	FCC Scanraff	AEE	Skandinaviska Raffinaderi	SWE	FCC, Additional delivery	10 m³	2003
255.	VA-Stahl Block 05	AEE	VA-Stahl	AUT	Blast furnance-, Coking plant- & Natural gas	20 m³	2003

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256.	*DOMO Caproleuna*	BASF		DEU	Residue, Tail end	3 m³	2003
257.	Höchst	BASF	Höchst	DEU	Hazardous waste, Additional delivery	11 m³	2003
258.	Baytown Olefins Plant, GT 2 & 3	BASF	Exxon Mobil Chemical Co. / KTI	USA	Gasturbine	74 m³	2003
259.	Hot Strip Mill - Oven 24	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m³	2003
260.	TRV Wesseling	BASF		DEU	Industrial- and hazardous waste, Additional delivery	13 m³	2004
261.	HKW Wedel I, 2nd layer	BASF	HEW	DEU	Coal, High dust, Additional delivery	60 m³	2004
262.	Brindisi Nord Unit 3 & 4	Termokimik	Edipower	ITA	Coal, High dust	660 m³	2004
263.	Warrick Unit 4	Black & Veatch	Sigeco	USA	Coal, High dust	354 m³	2004
264.	Brown Unit 1, 2	Black & Veatch	Sigeco	USA	Coal, High dust	708 m³	2004
265.	Colleferro Unit 1 & 2	Mosca Servizi Amb.	Termokimik	ITA	Municipal waste, Tail end	36 m³	2004
266.	Tracy	GWF Energy	GWF Energy	USA	Nat. gas, GT Simple cycle, High temp., Additional del.	44 m³	2004
267.	KW Bexbach	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	286 m³	2004
268.	Voerde Block A	BASF	STEAG	DEU	Coal, High dust, Additional delivery	350 m³	2004
269.	Canal Station Unit 1	MIRANT	Mirant	USA	Oil, Raw gas, Additional delivery	308 m³	2004
270.	Cuneo	BASF	Glaverbel Italy S.r.l. / Lurgi Bischoff GmbH	ITA	Glass trough	14 m³	2004
271.	Scholven E	BASF	E.ON	DEU	Coal, High dust, Additional delivery	193 m³	2004
272.	Homer City Unit 3	Midwest Generation	Midwest Generation / ALSTOM POWER	USA	Coal, High dust, Additional delivery	246 m³	2004

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273.	**Samcheonpo TPP # 3 & 4**	Halla	KOSEP	KOR	Coal, High dust	904 m³	2004
274.	**Vado Ligure**	Mosca Servizi Amb.	Interpower	ITA	Coal, High dust, Additional delivery	22 m³	2004
275.	**Scholven B**	BASF	E.ON	DEU	Coal, High dust, Additional delivery	193 m³	2004
276.	**Voerde Block B**	BASF	STEAG	DEU	Coal, High dust, Additional delivery	350 m³	2004
277.	**FCC Shell Hamburg**	BASF	Shell Deutschland Oil GmbH	DEU	FCC, Additional delivery	15 m³	2004
278.	**Genf Linie 6**	BASF	SIG / CTU	CHE	Municipal waste, Low dust, Additional delivery	72 m³	2004
279.	**Basell MG4 - Ofen 31 & 32**	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker, Low temp., Additional delivery	66 m³	2004
280.	**Basell - Ofen 20-24**	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker, Additional delivery	15 m³	2004
281.	**ICDI Charleroi**	HRC		BEL	Municipal waste, Low dust	7 m³	2004
282.	**KVA Basel**	BASF		CHE	Municipal waste, Low dust	29 m³	2004
283.	**FCC Shell Rotterdam**	BASF	Shell Nederland Raffinaderij B.V.	NLD	FCC, Additional delivery	20 m³	2004
284.	**Brown Unit 1**	Black & Veatch	Sigeco	USA	Coal, High dust, Additional delivery	152 m³	2005
285.	**Warrick Unit 4**	Black & Veatch	Sigeco	USA	Coal, High dust, Additional delivery	177 m³	2005
286.	**WAV II Wels**	LAB GmbH	Energie AG Oberösterreich	AUT	Municipal waste, Tail end	41 m³	2005
287.	**VA-Stahl Block 04**	AEE	VA-Stahl	AUT	Blast furnance-, Coking plant- and Natural gas	20 m³	2005
288.	**Sammel SCR Simmering**	Envirgy	Fernwärme Wien	AUT	Sludge, Hazardous Waste, Tail end, Low temp.	125 m³	2005
289.	**Stuart Unit 4**	Dayton Power & Light	Dayton Power & Light	USA	Coal, High dust, Additional delivery	473 m³	2005

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290.	**Ostrava**	SPOVO	SPOVO	CZE	Hazardous waste, Tail end, Low temp. Additional delivery	3 m³	2005
291.	**Scholven C**	BASF	E.ON	DEU	Coal, High dust, Additional delivery	193 m³	2005
292.	**Saint Ouen Unit 1-3**	BASF	LAB / SYCTOM	FRA	Municipal waste, Tail end	219 m³	2005
293.	**Fort Dodge**	BASF	Farmland Industries	USA	Nitric Acid Plant, Additional delviery	10 m³	2005
294.	**Brest**	Mosca Servizi Amb.	Termokimik	FRA	Municipal waste, Tail end	14 m³	2005
295.	**Edwards Station Unit 3**	Ameren Energy	Ameren Energy	USA	Coal, High dust, Additional delivery	203 m³	2005
296.	**Coffeen Unit 1**	Ameren Energy	Ameren Energy	USA	Coal, High dust, Additional delivery	219 m³	2005
297.	**NAS-SCR**	Andritz AG		USA	Steel pickling	5 m³	2005
298.	**SKS-HAPL**	Andritz AG		CHN	Steel pickling	5 m³	2005
299.	**Scholven D**	BASF	E.ON	DEU	Coal, High dust, Additional delivery	193 m³	2005
300.	**Techwin**	BASF		KOR	Plywood plant, Tail end	7 m³	2005
301.	**MSWI Bordeaux**	BASF	ASTRIA / HRC	FRA	Municipal waste, Tail end	85 m³	2005
302.	**CVDU Nice**	BASF	LAB	FRA	Municipal waste, Tail end	157 m³	2005
303.	**Korsika Unit 1**	BASF	EdF / Steuler	FRA	Diesel engine, Heavy/low sulphur oil, Additional del.	9 m³	2005
304.	**MVA Malmö**	BASF	LAB	SWE	Municipal waste, Tail end, Additional delivery	22 m³	2005
305.	**Grenelle**	HRC	CPCU	FRA	Heavy oil, High dust	35 m³	2005
306.	**Tirmadrid**	Integral		ESP	Municipal waste, Tail end, Low temp.	133 m³	2005

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307.	Rennes	BASF	Von Roll	FRA	Municipal waste, Tail end	23 m³	2005
308.	Nantes	BASF	Von Roll	FRA	Municipal waste, Tail end	34 m³	2005
309.	Coueron / Nantes	BASF	LAB	FRA	Municipal waste, Tail end	12 m³	2005
310.	Recycling Komb. Rotterdam	BASF		NLD	Residue, Tail end	13 m³	2005
311.	FHKW Mellach, Repl. 4th layer	VERBUND	VERBUND	AUT	Coal, High dust, Additional delivery	94 m³	2005
312.	Vado Ligure	Mosca Servizi Amb.	Tirreno Power	ITA	Coal, High dust, Additional delivery	87 m³	2005
313.	Basell Ofen 19	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker, Additional delivery	7 m³	2005
314.	Basell - Ofen 20-24	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker, Additional delivery	22 m³	2005
315.	Gas engines	BASF	Steuler	FRA	Gas engines, High temp.	4 m³	2005
316.	BASF Incineration plant	BASF	BASF	DEU	Residue, Raw gas, NOx- + CO-removal	5 m³	2005
317.	Chaumont	HRC	SHMVD Chaumont	FRA	Municipal waste, Tail end	13 m³	2005
318.	Yiehpyr	Seiler	Yieh United Steel	TWN	Steel pickling	1 m³	2005
319.	Victoria Nitric Acid Plant	BASF	Invista	USA	Nitric Acid Plant	4 m³	2005
320.	ZPSS-PYR	Andritz AG	Zhangjiagang Pohang Stainless Steel Co., Ltd.	CHN	Steel pickling	4 m³	2005
321.	JIN-CAPL	Andritz AG	Jindal Stainless Steel Ltd.	IND	Steel pickling	2 m³	2005
322.	LIANCAPL	Andritz AG	Lianzhong Stainless Steel Co., Ltd.	CHN	Steel pickling	2 m³	2005
323.	Boussois	BASF	Glaverbel Italy S.r.l. / Lurgi Bischoff GmbH	FRA	Glass trough	13 m³	2005

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324.	**Tallink III**	BASF	H&H Umwelttechnik GmbH	Baltic Sea	Marine Diesel	21 m³	2005
325.	**TIS-SCR**	Andritz AG	Shanxi Taigang Stainless Steel Co. Ltd.	CHN	Steel pickling	2 m³	2005
326.	**GKK Kiel**	BASF	E.ON	DEU	Coal, High dust	185 m³	2005
327.	**Constanti**	BASF		ESP	Residue, Low dust, Additional delivery	20 m³	2005
328.	**KCM Krupp**	MF Technik		DEU	Steel pickling, Additional delivery	1 m³	2005
329.	**Kimhae**	BASF	SPECO	KOR	Municipal waste, Tail end, Additional delivery	5 m³	2005
330.	**Basell Ofen 34**	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker	33 m³	2005
331.	**Scholven C**	BASF	E.ON	DEU	Coal, High dust, Additional delivery	193 m³	2005
332.	**Basell Ofen 36**	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker	6 m³	2005
333.	**BASF CZ Süd**	BASF	BASF	DEU	Residue, Tail end, Additional delivery	3 m³	2005
334.	**NINGPYR**	Andritz AG	Baosteel Group	CHN	Steel pickling, Additional delivery	3 m³	2005
335.	**JIS-CAPL**	Andritz AG	Jiuquan Iron & Steel Co., Ltd.	CHN	Steel pickling	1 m³	2005
336.	**JIS-DRAP**	Andritz AG	Jiuquan Iron & Steel Co., Ltd.	CHN	Steel pickling	1 m³	2005
337.	**Steuler 80736**	BASF	Steuler	DEU	Waste, Tail end	6 m³	2005
338.	**La Spezia 3&4**	ENEL Produzione	ENEL	ITA	Coal, High dust, Additional delivery	179 m³	2005
339.	**Korsika Unit 4**	BASF	EdF / Steuler	FRA	Diesel engine, Heavy/Low sulphur oil	17 m³	2005
340.	**Baopyr**	Andritz AG		CHN	Steel pickling, Additional delivery	7 m³	2005

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341.	**Duck Creek**	Ameren Energy	Ameren Energy	USA	Coal, High dust, Additional delivery	203 m³	2005
342.	**Dah Chung**	BASF		TWN	Chemical residue	8 m³	2005
343.	**Steuler 70/271**	BASF	Steuler	DEU	Diesel-/Gas engines	30 m³	2005
344.	**Sangju**	BASF	David Chemical	KOR	Waste, Tail end, Additional delivery	3 m³	2005
345.	**Pos Pyr 2**	Seshin	POSCO	KOR	Steel pickling, Additional delivery	4 m³	2005
346.	**Yonghung Unit 4**	HHI	KOSEP	KOR	Coal, High dust	369 m³	2005
347.	**Roche DeNOx-Anlage A-7001**	Roche Austria GmbH	DSM Chemie Linz	AUT	Process gas, Additional delivery	2 m³	2005
348.	**HKW Heilbronn, Block 7**	BASF	EnBW	DEU	Coal, High dust	141 m³	2005
349.	**KW Münster, K25**	BASF	EnBW	DEU	Coal, High dust	38 m³	2005
350.	**Albemarle Reaktor RE 2001-CO**	BASF	Albemarle Catalysts Company B.V.	NLD	Chemical plant, NH_3-removal	1 m³	2005
351.	**Albemarle Reaktor RE 2001-NOx**	BASF	Albemarle Catalysts Company B.V.	NLD	Chemical plant	3 m³	2005
352.	**WAL-SCR**	Andritz AG	Walsin Lihwa Corp.	TWN	Steel pickling	5 m³	2006
353.	**HDO Incineration Freeport**	BASF	BASF	USA	Residue	36 m³	2006
354.	**Fusina 1&2**	Termoklmik	Enelpower SpA	ITA	Coal, High dust	320 m³	2006
355.	**Korsika Unit 6-7**	BASF	EdF / Steuler	FRA	Diesel engine, Heavy/Low sulphur oil	34 m³	2006
356.	**Columbus**	Andritz AG	Columbus Ltd.	ZAF	Steel pickling, Additional delivery	3 m³	2006
357.	**Biomasse KW Simmering**	Envirgy	Wienstrom GmbH	AUT	Fresh wood, High dust	17 m³	2006

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358.	A.B. Brown Unit 2	VECTREN	VECTREN	USA	Coal, High dust, Additional delivery	152 m³	2006
359.	Genf Linie 5	BASF	SIG	CHE	Municipal waste, Low dust, Additional delivery	72 m³	2006
360.	Steuler 86848	BASF	Steuler	DEU	Diesel engines	20 m³	2006
361.	Vado Ligure	Mosca Servizi Amb.	Tirreno Power	ITA	Coal, High dust, Additional delivery	174 m³	2006
362.	Basell - MG4 Ofen 034	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker, Low temp., Additional delivery	33 m³	2006
363.	Basell - Ofen 17 & 18	BASF	Basell Polyolefine GmbH	DEU	Ethylencracker Additional delivery	8 m³	2006
364.	MSW Ludres	Hamon	Nancy Energie	FRA	Waste, Tail end, Low temperature	40 m³	2006
365.	CENON	Hamon	UIOM de Cenon	FRA	Municipal waste, Tail end	20 m³	2006
366.	Rhodia	BASF	Rhodia	DEU	Hazardous/Liquide waste, Additional delivery	14 m³	2006
367.	Glaswanne QUINN	BASF	QUINN GLASS Ltd.	GBR	Glass trough	19 m³	2006
368.	SH1-HAPL	Andritz AG		CHN	Steel pickling	3 m³	2006
369.	JIN-AP1,2	Andritz AG	Jindal Stainless Steel Ltd.	IND	Steel pickling	4 m³	2006
370.	TISCAPL2	Andritz AG	Tisco Taigang Stainless Steel	CHN	Steel pickling	3 m³	2006
371.	SUWON	KET Co.	Suwon District Heating Corp.	KOR	Oil, High dust	18 m³	2006
372.	YOSU	BASF	Lucky Lotus Corp.	KOR	Chemical residue Additional delivery	24 m³	2006
373.	Columbus	Andritz AG	Columbus Ltd.	ZAF	Steel pickling, Additional delivery	3 m³	2006
374.	Hot Strip Mill - Oven 23	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	12 m³	2006

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Reference List as of August 2006

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
375.	Kimhae	BASF	SPECO	KOR	Municipal waste, Tail end, Additional delivery	5 m³	2006
376.	JIN-AP3	Andritz AG	Jindal Stainless Steel Ltd.	IND	Steel pickling	5 m³	2006
377.	BASF F-407	BASF	BASF	DEU	Chemical residue, Low temperature	4 m³	2006
378.	Korsika Unit 2-3	BASF	EdF / Steuler	FRA	Diesel engine, Heavy/low sulphur oil	34 m³	2006
379.	NANYA	BASF	Lucky Lotus Corp.	TWN	Industrial waste Additional delivery	2 m³	2006
380.	Wushashan Unit 4	Tsinghua Tongfang Ltd.	Datang International Co.	CHN	Coal, High dust	308 m³	2006
381.	Voerde Block B	BASF	STEAG	DEU	Coal, High dust, Additional delivery	350 m³	2006
382.	Ferrara	Alstom	Hera	ITA	Municipal waste, Tail end, Low temp.	54 m³	2006
383.	YUS-CAPL	Andritz AG	Yieh United Steel	TWN	Steel pickling	2 m³	2006
384.	KL3 Brand	Andritz AG	Krupp Thyssen	DEU	Steel pickling	5 m³	2006
385.	Rulen Unit 3, 4, 5	Termokimik	Electrabel / Tractebel	BEL	Coal, High dust	642 m³	2006/07/08
386.	Michigan City Unit 12	NIPSCO	NIPSCO	USA	Coal, High dust, Additional delivery	278 m³	2007
387.	MVA Pfaffenau	Integral	WKU / Envirgy	AUT	Municipal waste, Tail end, Low temp.	68 m³	2007
388.	Dunkerque	BASF	Dunkerque Grand Littoral / Von Roll	FRA	Municipal waste, Tail end	9 m³	2007
389.	Issy-les-Moulineaux	BASF	SYCTOM / Von Roll	FRA	Municipal waste, Tail end, Low temp.	163 m³	2007
390.	Thomas Hill Unit 3	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High dust	802 m³	2007
391.	Korsika Unit 5	BASF	EdF / Steuler	FRA	Diesel engine, Heavy/low sulphur oil	17 m³	2007

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Reference List as of August 2006

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
392.	Forli	Alstom	Hera	ITA	Municipal waste, Tail end, Low temp.	44 m³	2007
393.	Bailly Unit 7	NIPSCO	NIPSCO	USA	Coal, High dust	304 m³	2008
394.	Thomas Hill Unit 1-2	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High dust	656 m³	2008
	TOTAL AMOUNT					**44,503 m³**	

Exhibit 5

KWH - Hitachi

Howard Franklin

NOx REMOVAL COAL PLANT SUPPLY LIST

Bold = Over 2-1/2% S in Fuel for > 10,000 hours

Last Up Date: Oct. 23, 2002

No.	PLANT	GAS SOURCE	GAS FLOW RATE (Nm3/H)	FUEL	DeNOx EFF. (%)	COMMERCIAL OPERATION	COUNTRY
1	**B&W/AES/SOMERSET (KINTIGH)**	**CB**	**675 Mw**	**COAL**	**90**	**2000**	**USA**
2	B&W/FIRST ENERGY/MANSFIELD UNIT 1	CB	856 MW	COAL	90	2003	USA
3	B&W/FIRST ENERGY/MANSFIELD UNIT 2	CB	856 MW	COAL	90	2003	USA
4	B&W/FIRST ENERGY/MANSFIELD UNIT 3	CB	856 MW	COAL	90	2003	USA
5	B&W/FIRST ENERGY/SAMMIS UNIT 6	CB	625 MW	COAL	90	2005	USA
6	B&W/FIRST ENERGY/SAMMIS UNIT 7	CB	629 MW	COAL	90	2005	USA
7	B&W/FIRST ENERGY/EASTLAKE UNIT 5	CB	627 MW	COAL	90	2006	USA
8	B&W/FIRST ENERGY/SAMMIS UNIT 5	CB	315 MW	COAL	90	2003	USA
9	B&W/FIRST ENERGY/ASHTABULA UNIT 5	CB	267 MW	COAL	90	2003	USA
10	B&W/FIRST ENERGY/BAY SHORE UNIT 4	CB	235 MW	COAL	90	2003	USA
11	BBP/LG&E TRIMBLE STATION	CB	525 MW	PET COKE/COAL	90	2002	USA
12	BBP/LG&E MILL CREEK STATON, UNIT 3	CB	480 MW	PET COKE/COAL	90	2003	USA
13	BBP/LG&E MILL CREEK STATION, UNIT 4	CB	480 MW	PET COKE/COAL	90	2003	USA
14	BBP/WKE WILSON STATION	CB	450 MW	PET COKE/COAL	90	2003	USA
15	BBP/WKE GREEN, UNITS 1 & 2	CB	242 MW EACH	PET COKE/COAL	90	2005	USA
16	BBP/KU GHENT STATON, UNIT 1	CB	500 MW	COAL	90	2004	USA
17	BBP/KU GHENT STATON, UNIT 3	CB	500 MW	COAL	90	2003	USA
18	BBP/KU GHENT STATON, UNIT 4	CB	500 MW	COAL	90	2003	USA
19	BBP/KU BROWN STATON, UNIT 1	CB	440 MW	COAL	90	2003	USA
20	FW/USGEN/INDIANTOWN 1st EXTENSION	CB	370 MW	COAL	—	1999	USA

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21	FW/USGEN/INDIANTOWN 2nd EXTENSION	CB	370 MW	COAL	—	2002	USA
22	FW/USGEN/LOGAN 1st EXTENSION	CB	230 MW	COAL	—	2001	USA
23	FW/USGEN/LOGAN+B8 2nd EXTENSION	CB	230 MW	COAL	—	2004	USA
24	FW/USGEN/CARNEYS POINT #2 1st EXTENSION	CB	245 MW	COAL	—	2000	USA
25	FW/USGEN/CARNEYS POINT #1 2nd EXTENSION	CB	245 MW	COAL	—	2001	USA
26	FW/USGEN/CARNEYS POINT #2 2nd EXTENSION	CB	245 MW	COAL	—	2002	USA
27	FW/CP&L ROXBORO 4	CB	700 MW	Coal	79	2001	USA
28	B&W/KCP&L/HAWTHORN #5	CB	500MW	PRB/COAL	55.6	2001	USA
29	B&W/RELIANT-KEYSTONE, UNITS 1 & 2	CB	900 MWe EACH	COAL	90	2003	USA
30	B&W-C/ONTARIO POWER GEN NANTICOKE, UNIT	CB	508 MWe EACH	PRB/COAL	84	2003/2004	CANADA
31	B&W-C/ONTARIO POWER GEN LAMBTON, UNITS	CB	510 MWe EACH	COAL/PET COKE	82.2	2002/2003	CANADA
32	HOKKAIDO	CB	280,000	COAL	80	1980	JAPAN
33	E.P.D.C	CB	399,500	COAL	80	1981	JAPAN
34	E.P.D.C	CB	2,320,000	COAL	80	1983	JAPAN
35	TOHOKU	CB	599,000	COAL	60	1983	JAPAN
36	TOHOKU	CB	599,000	COAL	60	1983	JAPAN
37	CHUGOKU	CB	450,000	COAL	80	1984	JAPAN
38	CHUGOKU	CB	540,000	COAL	80	1984	JAPAN
39	TOYAMA JOINT	CB	629,000	COAL	53	1984	JAPAN
40	TOYAMA JOINT	CB	629,000	COAL	53	1984	JAPAN
41	E.P.D.C.	FBC	188,700	COAL	60	1987	JAPAN
42	E.P.D.C.	CB	3,100,000	COAL	80	1990	JAPAN
43	CHUBU	CB	(700MW)	COAL	80	1992	JAPAN
44	SOMA JOINT	CB	(1000MW)	COAL	80	1994	JAPAN
45	E.P.D.C.	PFBC	(70MW)	COAL	76	1994	JAPAN

46	OKINAWA	CB	(156MW)	COAL	52	1995	JAPAN
47	HOKURIKU	CB	(500MW)	COAL	65	1995	JAPAN
48	E.P.D.C.	CB	(1000MW)	COAL	72	1997	JAPAN
49	TOHOKU	CB	(1000MW)	COAL	74	1998	JAPAN
50	CHUGOKU	PFBC	(250MW)	COAL	85	1999	JAPAN
51	SHIKOKU	CB	(700MW)	COAL	80	2000	JAPAN
52	E.P.D.C.	CB	(1050MW)	COAL	80	2000	JAPAN
53	TOKYO	CB	(1000MW)	COAL	85	2003	JAPAN
54	TAICHUNG 5	CB	550MW	COAL	50	1996	TAIWAN
55	TAICHUNG 6	CB	550MW	COAL	50	1996	TAIWAN
56	TAICHUNG 7	CB	550MW	COAL	50	1997	TAIWAN
57	TAICHUNG 8	CB	550MW	COAL	50	1997	TAIWAN
58	FP1-#1	CB	600MW	COAL	73	1998	TAIWAN
59	FP1-#2	CB	600MW	COAL	73	1999	TAIWAN
60	FP1-#3	CB	600MW	COAL	73	1999	TAIWAN
61	UP1-#A	CB	600MW	COAL	73	2000	TAIWAN
62	UP1-#B	CB	600MW	COAL	73	2000	TAIWAN
63	MP1-#1	IB	314,000	COAL/OIL	80	1998	TAIWAN
64	MP1-#2	IB	314,000	COAL/OIL	80	1998	TAIWAN
65	MP1-#3	IB	314,000	COAL/OIL	80	1999	TAIWAN
66	MP1-#4	IB	314,000	COAL/OIL	80	1999	TAIWAN
67	MP1-#5	IB	314,000	COAL/OIL	80	1999	TAIWAN
68	FHI 500t/h BOILER	IB	457,300	COAL/OIL	80	1998	TAIWAN
69	FHI 500t/h BOILER	IB	457,300	COAL/OIL	80	1999	TAIWAN
70	FP1-#4	CB	600MW	COAL	73	(2000)	TAIWAN

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71	FP1-#5	CB	600MW	COAL	73	(2001)	TAIWAN
72	FHI 500t/h BOILER	IB	457,300	COAL	80	(2000)	TAIWAN
73	FCFC/FHI 520t/h BOILER	IB	450,600	COAL	80	(2000)	TAIWAN
74	HOPING-#1	CB	660MW	COAL	83	(2001)	TAIWAN
75	HOPING-#2	CB	660MW	COAL	83	(2002)	TAIWAN
76	CP-1, #1	CB	600MW	COAL	40	(2000)	CHINA
77	CP-1, #2	CB	600MW	COAL	40	(2000)	CHINA
78	CP-1, #3	CB	600MW	COAL	40	(2000)	CHINA
79	CP-1, #4	CB	600MW	COAL	40	(2001)	CHINA
80	CP-1, #5	CB	600MW	COAL	40	(2001)	CHINA
81	CP-1, #6	CB	600MW	COAL	40	(2001)	CHINA
82	TAICHUNG 1	CB	550MW	COAL	80	(2000)	TAIWAN
83	TAICHUNG 2	CB	550MW	COAL	80	(2000)	TAIWAN
84	TAICHUNG 3	CB	550MW	COAL	80	(2001)	TAIWAN
85	TAICHUNG 4	CB	550MW	COAL	80	(2001)	TAIWAN
86	TAICHUNG 5 Extension	CB	550MW	COAL	80	(2001)	TAIWAN
87	TAICHUNG 6 Extension	CB	550MW	COAL	80	(2000)	TAIWAN
88	TAICHUNG 7 Extension	CB	550MW	COAL	80	(2000)	TAIWAN
89	TAICHUNG 8 Extension	CB	550MW	COAL	80	(2000)	TAIWAN
90	TAICHUNG 9	CB	550MW	COAL	83	(2003)	TAIWAN
91	TAICHUNG 10	CB	550MW	COAL	83	(2004)	TAIWAN
92	SK-4	CB	(500t/h)	COAL	80	(2001)	TAIWAN
93	FCFC 500t/h BOILER(LT-2)	CB	512,800	COAL	81	(2001)	TAIWAN
94	350t/h BOILER(G-8)	CB	358,400	COAL	80	(2001)	TAIWAN
95	DUERNROHR 1	CB	1,235,000	COAL	80	1986	AUSTRIA

96	DUERNROHR 2	CB	1,138,000	COAL	80	1986	AUSTRIA
97	KNEPPER C	CB	260,000	COAL	90	1986	FRG
98	LEININGERWERK 5	CB	1,400,000	COAL	70	1988	FRG
99	SCHWANDORF C	CB	464,000	COAL	80	1988	FRG
100	SCHWANDORF D	CB	1,393,000	COAL	80	1988	FRG
101	MEHRUM 3	CB	2,240,000	COAL	75	1988	FRG
102	WALSUM 7	CB	547,000	COAL	90	1988	FRG
103	WEST 2	CB	287,500	COAL	80	1989	FRG
104	WEST 3	CB	287,500	COAL	80	1989	FRG
105	SCHWANDORF B	CB	464,400	COAL	80	1989	FRG
106	HEYDEN 4	CB	2,470,000	COAL	75	1989	FRG
107	KNEPPER C (EXT)	CB	510,000	COAL	90	1988	FRG
108	VELTHEIM 1	CB	301,000	COAL	82	1989	FRG
109	VASTERAS 1	CB	190,000	COAL	84	1990	SWEDEN
110	VASTERAS 2	CB	190,000	COAL	84	1991	SWEDEN
111	MERI PORI	CB	1,558,000	COAL	50	1993	FINLAND
112	VASTERAS 4	CB	555,000	COAL	86	1992	SWEDEN
113	CONFIDENTIAL	FBC	255,000	COAL	33	1992	SWEDEN
114	VASTERAS 3	CB	350,000	COAL	80	1993	SWEDEN
115	CONFIDENTIAL	FBC	255,000	COAL	33	1993	SWEDEN
116	BRINDISI SUD 1	CB	(660MW)	COAL	80	1996	ITALY
117	BRINDISI SUD 2	CB	(660MW)	COAL	80	1996	ITALY
118	BRINDISI SUD 3	CB	(660MW)	COAL	80	1997	ITALY
119	BRINDISI SUD 4	CB	(660MW)	COAL	80	1997	ITALY
120	**KAWASAKI**	**IB**	**95,000**	**PET COKE**	**46**	**1986**	**JAPAN**

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121	HYOGO	IB	155,000	COAL	60	1986	JAPAN
122	CHIBA	FBC	62,500	COAL	66	1987	JAPAN
123	**FUTATSUKA**	**IB**	**91,200**	**PET COKE**	**70**	**1988**	**JAPAN**
124	HIROHATA 6	CB	413,000	COAL	80	1996	JAPAN
125	**KAWASAKI 3**	**CB**	**283,000**	**PET COKE**	**97**	**1996**	**JAPAN**
126	**KAWASAKI 4**	**CB**	**283,000**	**PET COKE**	**97**	**1997**	**JAPAN**
127	**MIZUSHIMA 7**	**CB**	**283,000**	**PET COKE**	**67**	**1998**	**JAPAN**
128	HIROHATA 7	CB	413,000	COAL	80	1999	JAPAN
129	YAHATA	CB	413,000	COAL	80	1999	JAPAN

Exhibit 6

Selective Catalytic Reduction System Performance and Reliability Review

By
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Presented at Power-Gen International, December 2-4, 2008, Orlando

ABSTRACT

Using the 2005, 2006 and 2007 U.S. Environmental Protection Agency's Electronic Data Reporting (EDR) site (www.epa.gov/airmarkets/emissions/raw/index.html) database of utility stack emissions, a review of installed SCR system NO_x removal performance and reliability has been undertaken. The NO_x emissions for all plants have been determined based upon hourly emissions and gross heat input to determine the plants overall NO_x removal efficiency and average outlet NO_x for the particular Ozone season. The data analysis was performed for all operating hours, including low load and startup conditions. Analysis of the data showed that removal efficiencies of 90% and greater were obtained and that overall Ozone season average NOx emissions rates of less than 0.05 lb/MMBtu were consistently achievable by SCR systems. The analysis also examined the effects of annual versus seasonal control, as this may become more important in the future. Last, the ability of plants to improve their operation over periods of time is also assessed.

This review is an update of a review first presented at the 2006 Mega Symposium that only examined through 2005.[1] An additional two years of data will provide important insight to the ability of facilities to improve operation over time. The review concludes that low NOx emissions rates can be achieved with very low hourly standard deviations. Further the data suggests that not all units with low emissions rate can obtain low standard deviations. The reason for this are investigated as related to boiler and SCR characteristics and system operation.

BACKGROUND

US SCR installations are unique from those of other countries in that the removal efficiencies of the systems are generally higher than in Europe or Japan. US installations also have been installed with full SCR bypass system allowing for the isolation of the system during non-Ozone season operation. These differences are largely due to the US regulatory system of trading NO_x emissions that makes it economically preferable to achieve higher removal efficiencies and operate only during the Ozone season. Unit emission rate caps as practiced in Europe, on the other hand, do not create the same incentive for higher NO_x removal efficiencies.

This is an update of previous work that examined the performance of 120 SCRs on coal-fired utility boilers using 2005 and earlier data. [1] This earlier work concluded that:

- Ninety percent (90%) removal efficiency was being achieved by a significant portion of the coal-fired SCR fleet. And, performance measured in terms of NOx removal efficiency appears to be improving for the majority of units.
- High levels of variability were demonstrated for units equipped with only combustion controls and for units equipped with SCR controls, although the highest variability was for units equipped with SCR. However, some of the units with SCR achieved high NOx reduction (over 90%) with low variability.
- The units with the highest absolute variability in NOx emissions rate were not the units with the lowest outlet NOx emissions rate. In fact, the data showed some units with very low outlet NOx emissions rate (below 0.05 lb/MMBtu) and very low variability. This showed that low emissions rates can be achieved with high reliability.
- A significant amount of variability, although not *all*, was associated with changes in load. So, some significant amount of variability in outlet NOx was associated with operating practices.
- Bituminous units with SCR were achieving similar NOx emissions as PRB units with SCR, although the PRB units have a lower combustion NOx level, This, along with the low variability of PRB emissions, suggested that lower NOx emission rates (higher NOx removal rates) are possible from PRB units.
- Catalyst type did not appear to have a significant impact on reduction or variability.
- The choice of anhydrous ammonia or urea as the ammonia source did not appear to impact reduction rate or variability. There was limited data on aqueous ammonia.
- There appeared to be a learning curve that benefits both NOx removal and variability in controlled NOx emission rates. This learning resulted in significant improvements in NOx removal performance across the fleet of SCRs. Reductions in variability appeared to be occurring as well.
- Annually controlled units that showed low variability, appeared to do so year round. Variability was usually higher in the ozone season, possibly due to higher NOx removal rates.

This effort has the benefit of two more years of operation of coal-fired SCRs, and can examine trends in data that may provide insights to SCR operation. Furthermore, additional units are operating on an annual basis, which will give insight to possible future annual operation.

CURRENT EFFORT

In this effort we have evaluated the population of coal SCRs and examined performance and reliability using EPA reported emissions data. Performance is measured on the basis of outlet NO_x emissions and NO_x reduction. NO_x reduction for seasonally controlled units was evaluated by comparing ozone season emissions to first quarter emissions for that calendar year.

Reliability is more difficult to measure. In our previous effort, we developed measures intended to provide indications of reliability to maintain an emission rate. To this end, reliability was analyzed using two measures:

Equation 1. Coefficient of Variation (CV) of the hourly outlet NO_x during the ozone season, where

$$CV\% = (\text{standard deviation of hourly } NO_x \text{ rate})*100/(\text{average hourly } NO_x \text{ rate})$$

The coefficient of variation is a dimensionless number that allows comparison of the variation of data that have significantly different mean values. If CV is greater than 100%, that means that the standard deviation of the values exceed the average, in such a case the NO_x emissions rates would be greater than the average.

Equation 2. Load Effect (for lack of a better term), Load Effect (LE) was calculated, where

$$LE\% = (((\text{average of hourly NOx rate over ozone season})/(\text{overall ozone season NOx rate}))*100) - 100$$

LE is another dimensionless parameter that indicates how much higher (or lower) the average of hourly NO_x emission rates is compared to the overall rate for the period. Because the reported hourly NO_x rate for any hour is treated equally when taking the average of these values, regardless of the heat input during the particular hour, the average of the hourly NO_x emission rates will normally differ somewhat from the overall NO_x emission rate for the entire season. Therefore, LE is an indication of how the average hourly NO_x rate differs from the overall NO_x emission rate for the period as a result of changes in NO_x emission when unit load changes. If the average of hourly NO_x emission rates over the period exactly equals the overall NO_x, then load changes do not have an effect on NO_x emissions rates and LE will equal zero. For an SCR, LE can be an important indicator. Because ammonia to an SCR may be secured at part load or during shutdown, the NO_x emission rate during those periods will increase and LE will be a positive number. On the other hand, if NO_x at part load is lower than at high load, then LE will be negative. LE gives us a way to measure how important this effect was when analyzing the data for the period in question. As will be shown, some units will show high variability in terms of CV. LE provides a way to determine to what extent the variability is associated with changes in load. In calculating both CV and LE, NO_x rate is measured in lb/MMBtu.

Unfortunately, CV and LE do not fully capture reliability. High variability by either measure can result from normal operating practices, as a result of equipment choices the owner made that limit the load-following ability of the equipment, from other operating choices not associated with varying load, or from equipment problems that impact performance. So, theses measurement provide some insight, but not a complete picture of system reliability.

ANALYSIS DATA SET

In this current work, we looked at the following emissions data sets:

1. 2005, 2006 and 2007 hourly ozone season and first quarter emissions data for units equipped with SCR and operating during the ozone season. After filtering for units with missing data to determine variability, this group was reduced to 125 units.

2. 2005, 2006 and 2007 year round emissions data on 25 annually controlled units equipped with SCR.
3. 2002 thru 2007 hourly Ozone season and first quarter 2002 thru 2005 emissions data for three selected units equipped with SCR on similar size units and known SCR designs.

For each of the data sets, the average of the hourly Ozone season NO_x emission rates were calculated, as was the standard deviation. These are used in calculating CV and LE as described earlier.

Comparison of 2005 through 2007

Recalling from Erickson and Staudt [i], NOx reduction overall improved during the period from 2004 to 2005 for most SCRs monitored in that study. We perform here a similar evaluation for the period from 2004 to 2005. Figure 1 shows the trends for 2005 to 2007 for NOx reduction versus the percent of units that provided that NOx reduction or less. In general, NOx reduction was still generally good, with 50% of the units evaluated achieving 85% or higher NOx reduction in all years and at least 20% of the units at or above 90% removal. However there was a trend toward slightly lower fleet-wide levels of NOx removal. Except for some units achieving over 95% in 2007, the curves are very similar above 90% removal for each year. On the other hand, below 90% removal there tends to be a slightly smaller percentage of units achieving any given emissions capture rate in 2007 than in the previous years. Figure 2 shows that the baselines for the most part did not change a substantially over the period. Figure 3 is a plot of controlled emissions during the ozone period versus percent of units, and it shows that for the units controlled to very low levels, there was very little change over the period in the controlled level of emissions. However, over the 2005 to 2007 period, the emissions for the units controlled to higher levels generally went up. The reason for this is unknown. But, clearly, the units controlled to low levels, in the range of 0.05 lb/MMBtu for the most part continued to control to low levels.

Figures 4, 5, and 6 each show several things for each unit and each year with the units sorted from lowest overall ozone season rate to the highest overall ozone season rate:

1. The average NOx emission achieved over the ozone season for all 125 units evaluated in this study (plotted in a blue line and designated "oz_noxem") determined by the total mass emissions and the total heat input.
2. The average of the hourly averages of the NOx emission rates (plotted on the red line and designated "Average Hourly Oz", which is generally close to the overall ozone season rate; but, often deviates from it significantly.
3. A range shown that indicates plus or minus the standard deviation in hourly averages from the average of the hourly averages. This is an indication of CV. Of course, negative NOx emissions do not occur. So, this is only an indicator of the standard deviation.

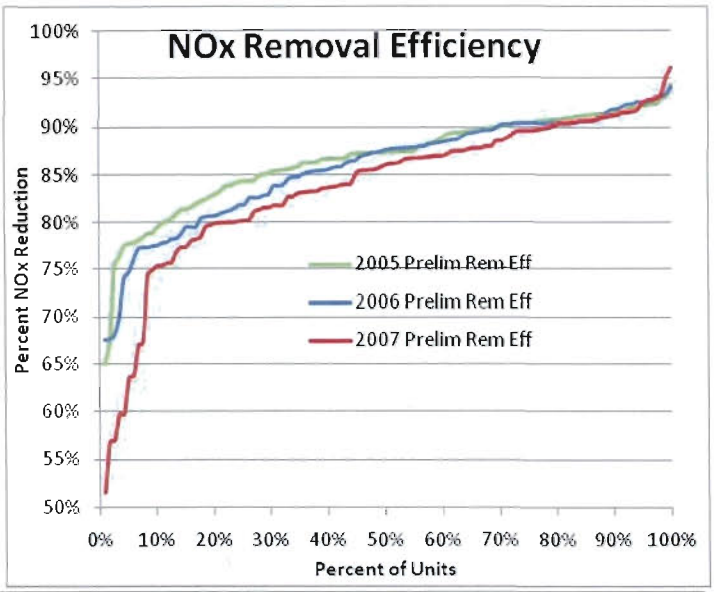


Figure 1. NOx Removal Efficiency versus percent of units at or below that removal efficiency

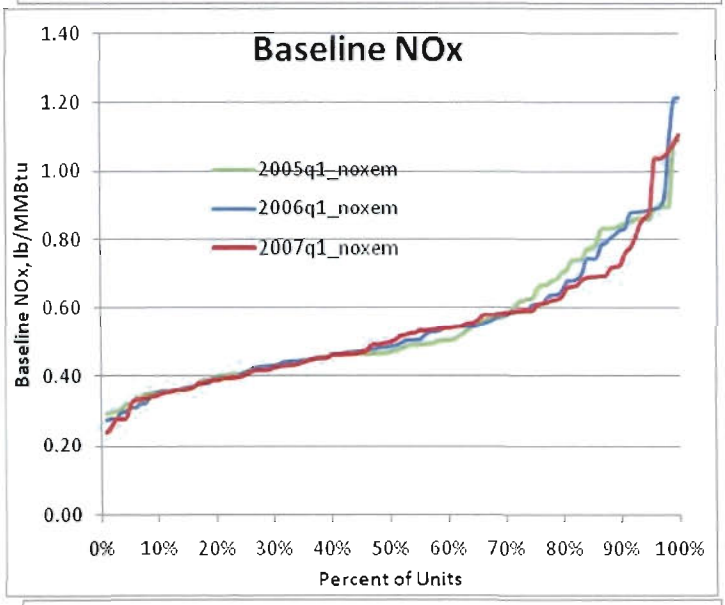


Figure 2. Baseline NOx versus percent of units at or below that baseline NOx level

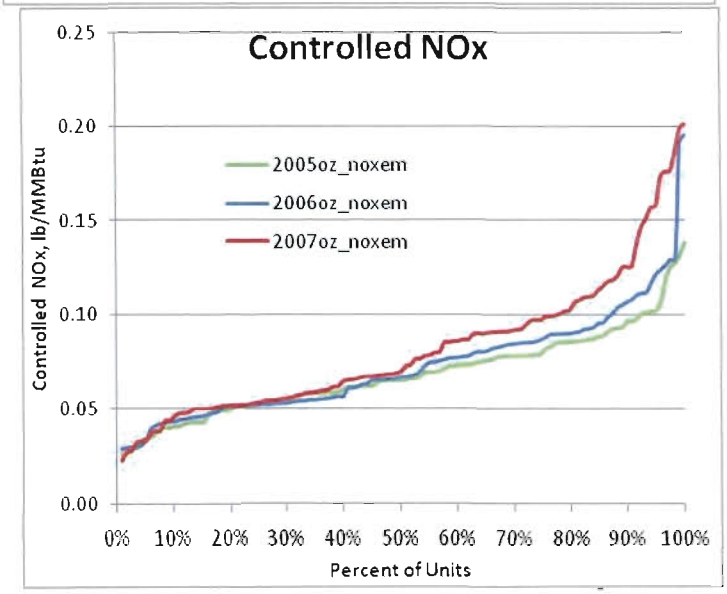


Figure 3. Controlled NOx versus percent of units at or below that controlled NOx level

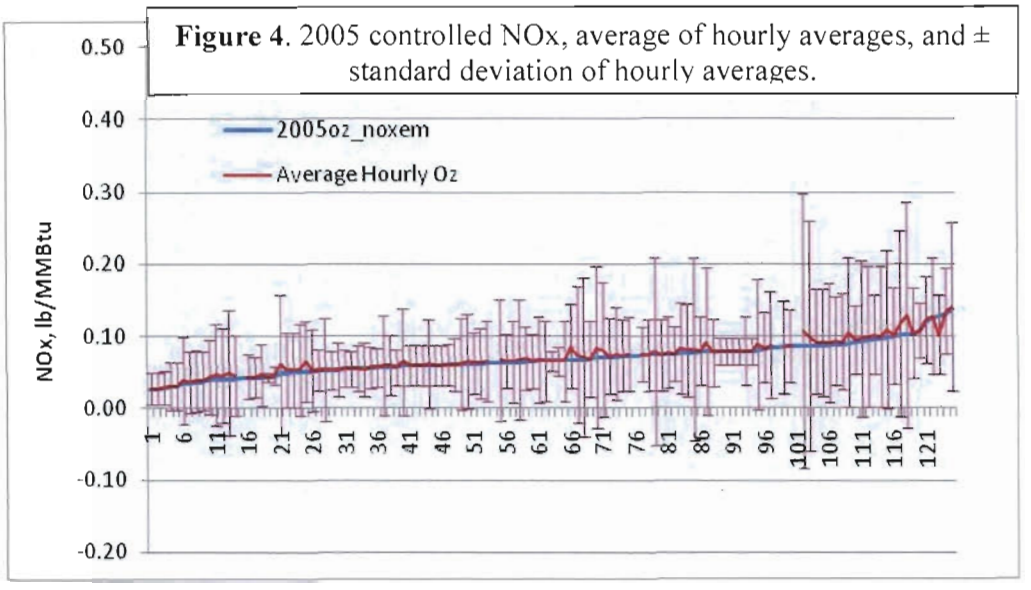


Figure 4. 2005 controlled NOx, average of hourly averages, and ± standard deviation of hourly averages.

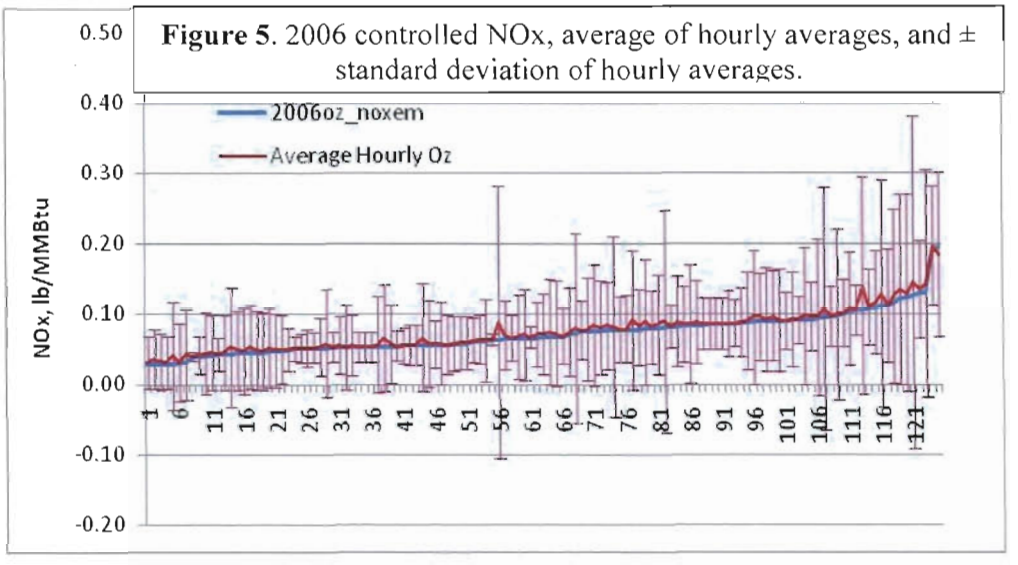


Figure 5. 2006 controlled NOx, average of hourly averages, and ± standard deviation of hourly averages.

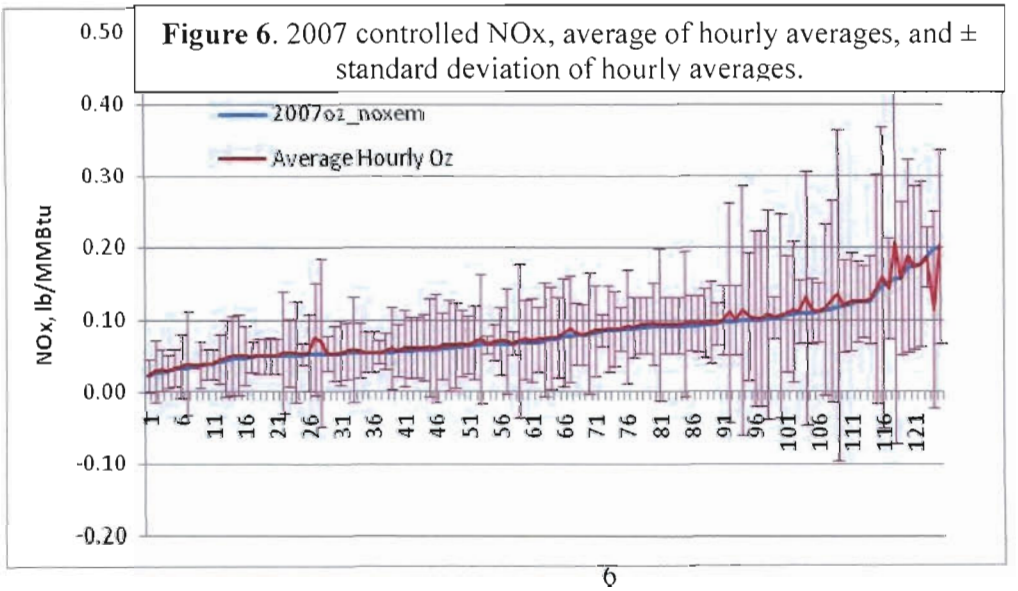


Figure 6. 2007 controlled NOx, average of hourly averages, and ± standard deviation of hourly averages.

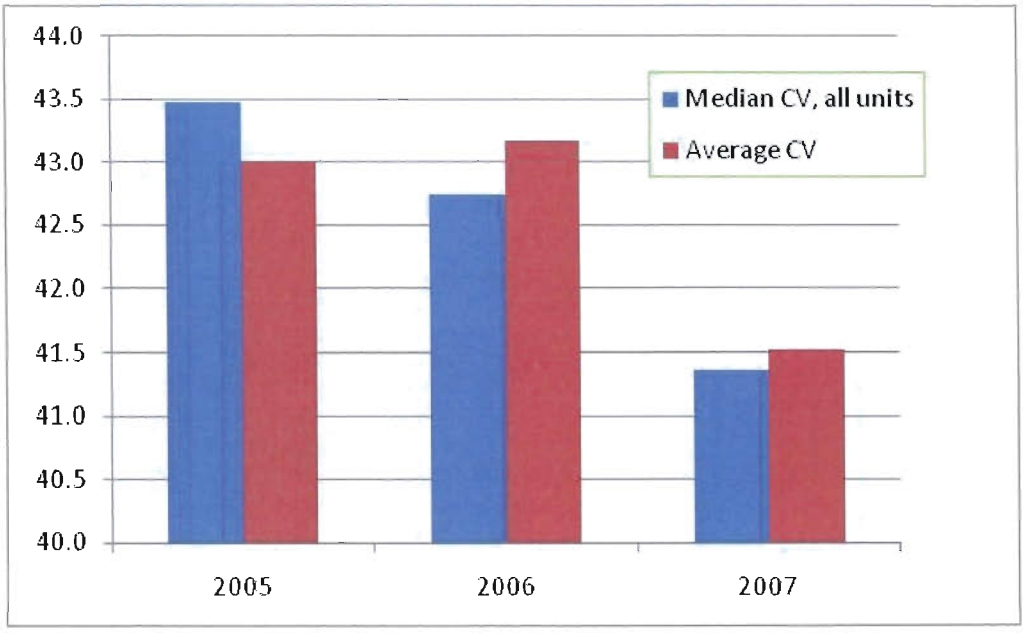
What can be observed from Figures 4-6 are that:

- There was significant variation in the hourly NOx emission rate across the full range of controlled NOx emission levels.
- In some cases the average of the hourly NOx emission rates deviated significantly from the overall ozone season emission rate.
- In most cases where there was a significant difference between the average of the hourly rates and the overall ozone season rate, the average of the hourly rates exceeded the overall ozone season rate. This indicates that for these units the emissions rate at part load is typically higher than at full load. This might be a result of securing SCR operation at part load due to a lack of temperature control.
- In most cases where there was a significant difference between the average of the hourly rates and the overall ozone season rate, there was also a greater standard deviation in the hourly NOx emission rates.
- The variation in hourly emission rates for units controlled to low levels in 2007 seemed to be significantly lower than in prior years.

With regard to this final point, as shown in Figure 7, both the median and average CV dropped significantly over the period from 2005 to 2007, confirming what is visually observed in Figures 4-6 that variation in hourly emissions has dropped overall for the population of boilers. Essentially, controllability, as measured by CV, appeared to improve over the period.

It was also found, when sorting the 125 units for lowest emissions over the ozone period, that of the 25 units with the lowest emissions in 2005, 20 of them were in the lowest 25 in 2006 and 16 of the original 25 were in the lowest 25 in 2007. Low emitting units tend to stay low emitting units.

Figure 7. Median and Average CV for 125 Units



Relationship between CV and LE Over the Period

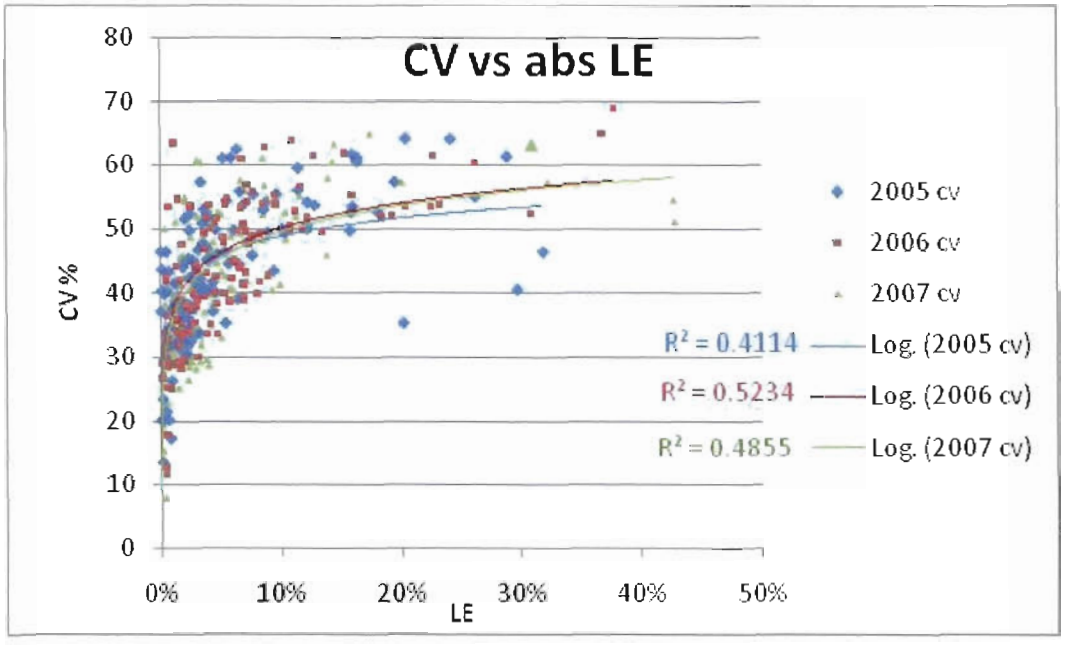
In previous work Erickson and Staudt found a relationship between CV and the absolute value of LE.[i] This relationship showed that CV, or variability in hourly emission rates had a relationship between LE, or the difference between the overall seasonal rate and the average of the hourly rates. As shown in Figure 8, this trend has generally continued. The trend can be characterized as follows:

- When LE is high, CV is always high
- If LE is low, there is no trend in CV – it may be low or high
- When CV is low, LE is always low

The conclusion that can be drawn from this is the following:

In order to have a low CV (variability in hourly NOx emissions), it is *necessary* to have an SCR control system that can control to a prescribed emissions level over a wide load range (which will result in a low LE). However, while this is a necessary condition for a low CV, it is not alone a sufficient condition to result in a low CV. As a result, even if one has an SCR control system that is capable of controlling to an emission rate over a wide load range, other factors can potentially result in having large variation in hourly emissions rates. These other factors would have to be unrelated to load, or they would likely show up as an increase in LE.

Figure 8. CV versus absolute value of LE for 2005 through 2007



Annually controlled versus seasonal units

Of the 125 units in this data set, at least 25 were operated annually by 2007. In years 2005 and 2006, at least 13 of those 25 were operated on an annual basis, with most of the remainder starting annual controls in 2007 as a result of state requirements that took effect in 2007. Because annual operation is of concern in the future for a greater number of facilities, we examined how the performance of these units compared to those of the remainder of the population of SCRs.

As shown in Figure 9, the average ozone season NOx emissions are somewhat higher for the annually controlled units than for the rest of the population. Generally, emissions over the ozone season increased, but slightly less so for the annual units. Keep in mind that 2007 represents the average for 25 units rather than 13 for the preceding years. As shown in Figure 10, the CV of the annually controlled units was generally above the CV of the population in general.

It should also be born in mind that, due to the much smaller population size for the annual units shown in Figures 9 and 10, the standard deviation in ozone season NOx emissions or CV for the small population of annually controlled units is relatively high, making the difference with the rest of the population well below one standard deviation in all cases. As a result, the differences with the rest of the population are statistically of little significance.

Figure 9. Average Ozone Season NOx Emissions (lb/MMBtu) for All Units and for Annually Controlled Units with error bars showing plus and minus one standard deviation

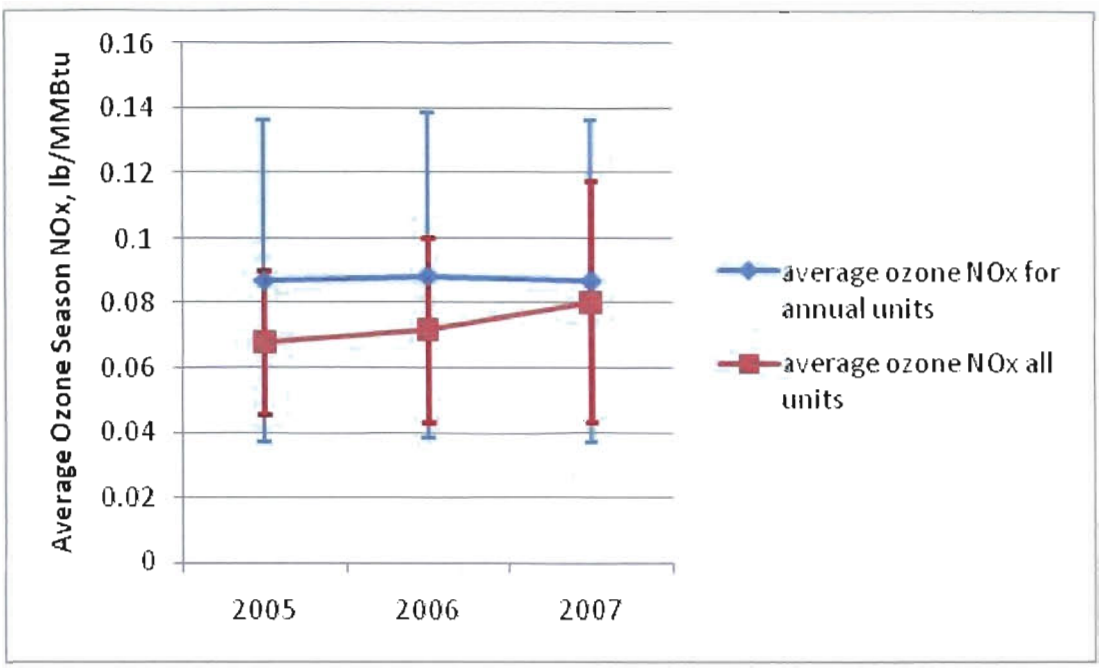
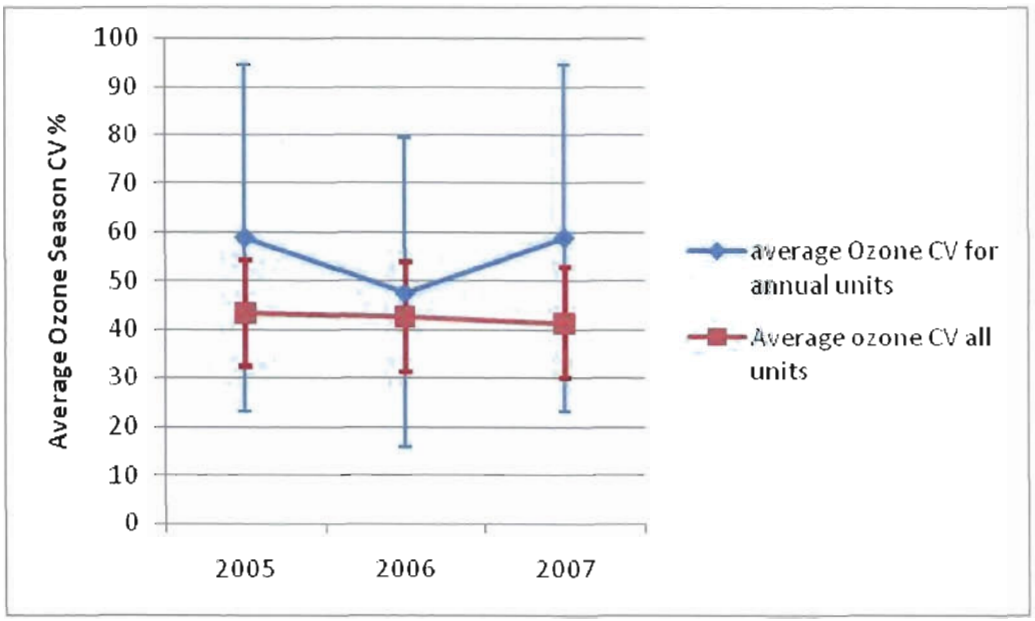


Figure 10. Average Ozone Season CV for All Units and for Annually Controlled Units with error bars showing plus and minus one standard deviation



Analysis of Year Round SCR System Operation

Figure 11 shows the 2007 annual emissions rates and ozone season emission rates for 25 year round operating SCR systems. As shown, for these systems there was fairly good consistency between the emission rates for the two periods. Figure 12 shows the standard deviation in hourly emission rates for these units in 2007 for both annual and ozone season. As shown, the standard deviation in hourly emission rates for both annual and ozone season remain fairly consistent for these units, suggesting little difference in controllability. As expected from Figure 12, the CVs of the hourly emission rates, shown in Figure 13, are also fairly consistent between ozone season and annual emission rates. This confirms that while controllability may differ from plant to plant, for any plant we should expect controllability to be the same between ozone season and annual control.

SCRs 1 through 6 represent early US SCR retrofit plants, plants 7 through 9 are units with the SCR designed as original equipment and the remaining units are units originally designed for Ozone operation that now operate year round. Units 14-25 only came into annual service in 2007. The graph shows considerable variation between plants regardless of above category. As a result, there must be factors that are unit specific, whether operational or design, that attribute to the differences in the units.

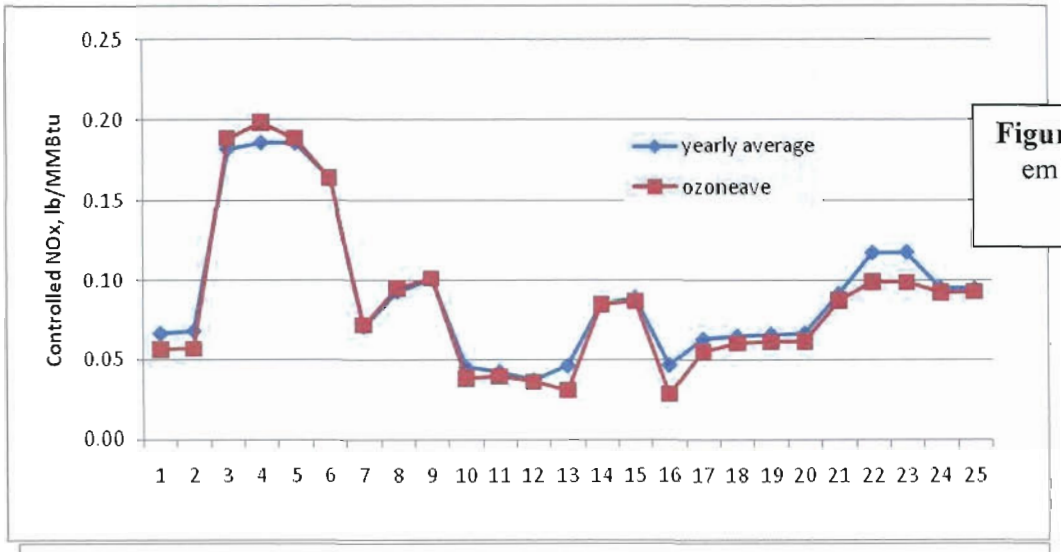


Figure 11. 2007 Controlled NOx emission rate for 25 annually controlled plants

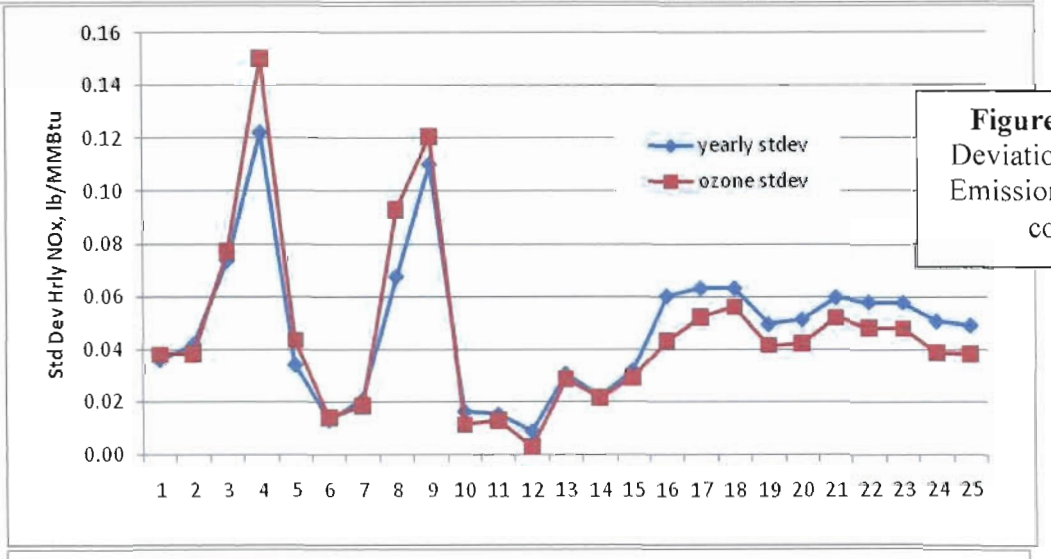


Figure 12. 2007 Standard Deviation in Controlled NOx Emission rate for 25 annually controlled plants

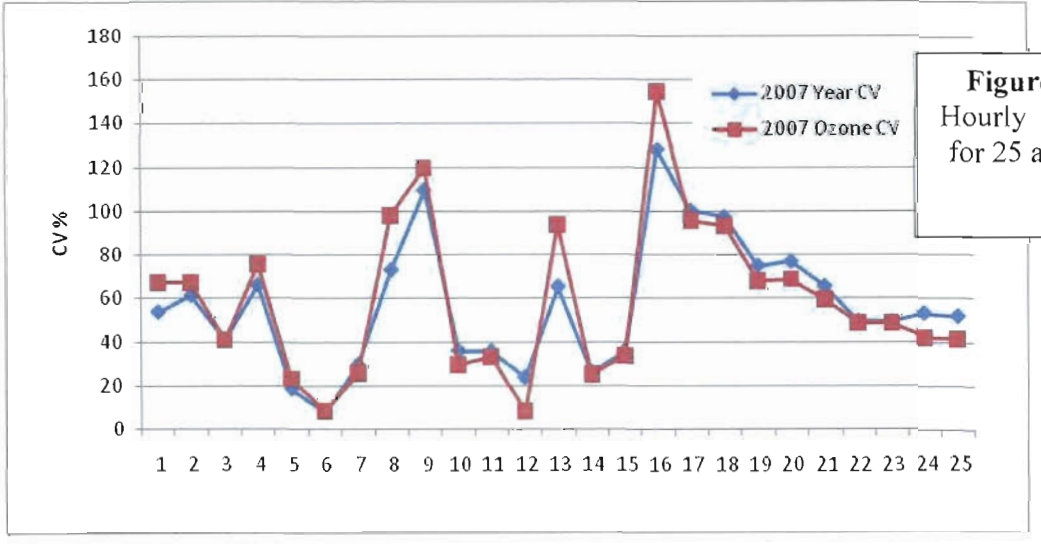


Figure 13. 2007 CV in Hourly NOx Emission rate for 25 annually controlled plants

Figure 14 shows CV of annual hourly NOx emissions for the 25 units for years 2005, 2006 and 2007. As shown, CV by and large remains in the same range for each unit, suggesting that CV is characteristic of the unit's design or operation.

Figure 14. 2007 CV in Hourly NOx Emission rate for 25 annually controlled plants

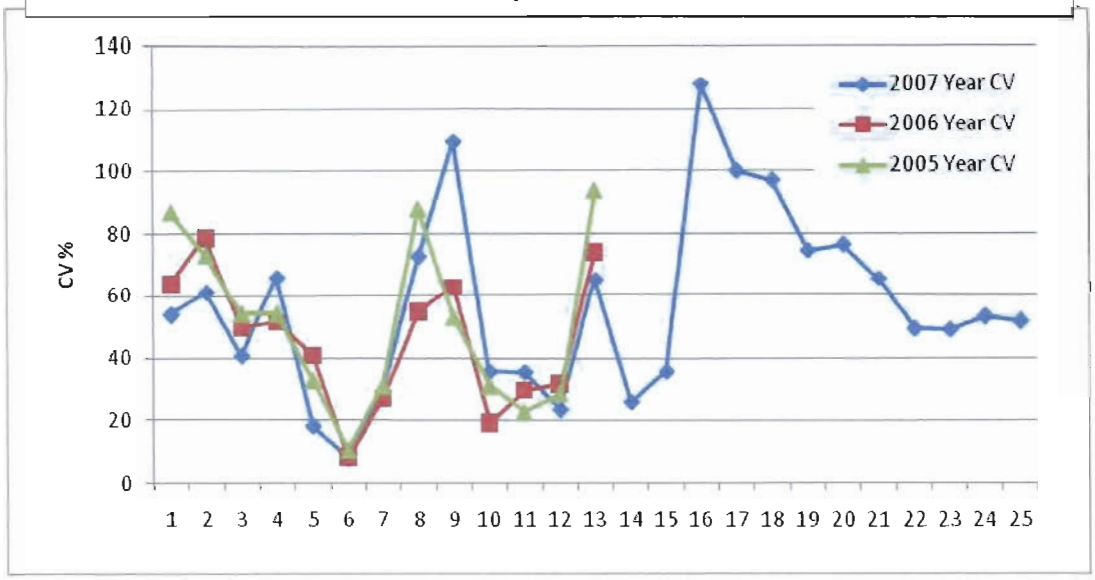
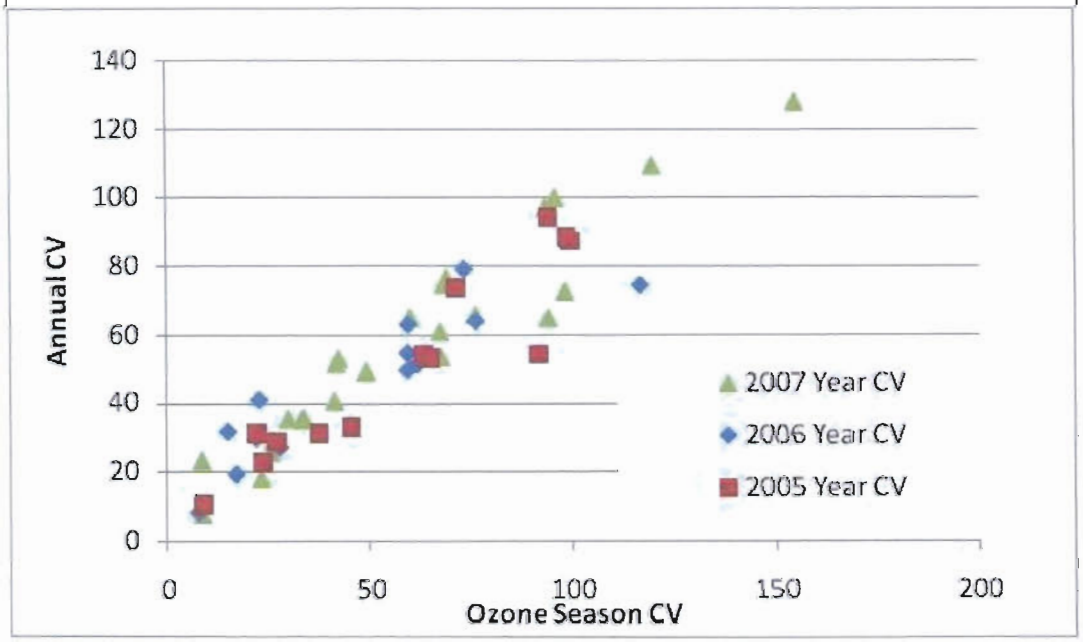


Figure 15 shows annual CV plotted against ozone season CV for each year for each unit. As shown, there is a strong correlation between them. For the most part, CV over the Ozone Season is about the same or slightly higher than CV over the year for these annually-controlled units.

Figure 15. 2007 CV in Hourly NOx Emission rate for 25 annually controlled plants



Analysis of Operational Improvement and Stability Over Time

Figures 16, 17 and 18 show average NO_x, CV of hourly NOx and LE, respectively, for three plants versus years of operation. All three plants fire bituminous coal and are greater than 600 MW in size. Plant one was the first SCR plant for the utility and has no SCR inlet temperature controls. Plants 2 and 3 are owned by the same utility, are the same size, and are not the first SCR systems for utility and employ steam side SCR inlet temperature control. Plant 1 uses anhydrous ammonia while plants 2 and 3 uses urea based ammonia.

Figure 16 shows steady reduction in controlled emission for Plant 3, while Plants 1 and 2 have less consistent emissions performance. Figure 17 shows plant 3 with the lowest CV (and lowest controlled NOx) over most of the period. However, CV of Plant 3 increases in the last two years, approaching that of Plant 2. This illustrates variability of both controlled NOx and CV and LE over time and between plants of similar design. It also shows, in the case of Plant 3, a steady decrease in controlled NOx and CV for the first few years; but, in years 5 and 6 continued reduction in controlled NOx with an increase in CV and absolute value of LE. As a result, it is clear that performance can change over time, and CV will increase if LE increases.

Because Plant 1 does not have temperature control, it would seem reasonable to expect LE for Plant 1 to be the highest. But, that is not the case. Figure 18 shows that a plant without temperature controls (Plant 1) can have similar load effect (LE) as a plant with temperature controls (Plant 2). As a result, operational characteristics of the plant clearly have an impact on these performance metrics.

Figure 19 shows CV plotted against LE and is consistent with what is indicated in Figure 8, that a low CV does not occur without a low LE.

The conclusions related to CV and LE as a function of years of operation are based on six years of data and have not included a detailed investigation of each plant to determine the underlying reasons for the differences. This analysis does indicate that plant operation, even with similar plant and owners, has an effect on the SCR system performance.

Figure 16. Controlled NOx versus year of operation

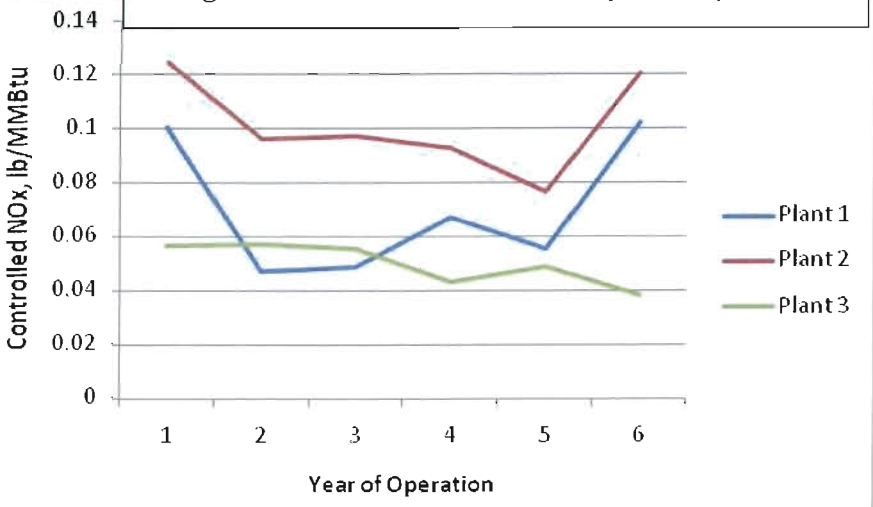


Figure 17 CV versus year of operation

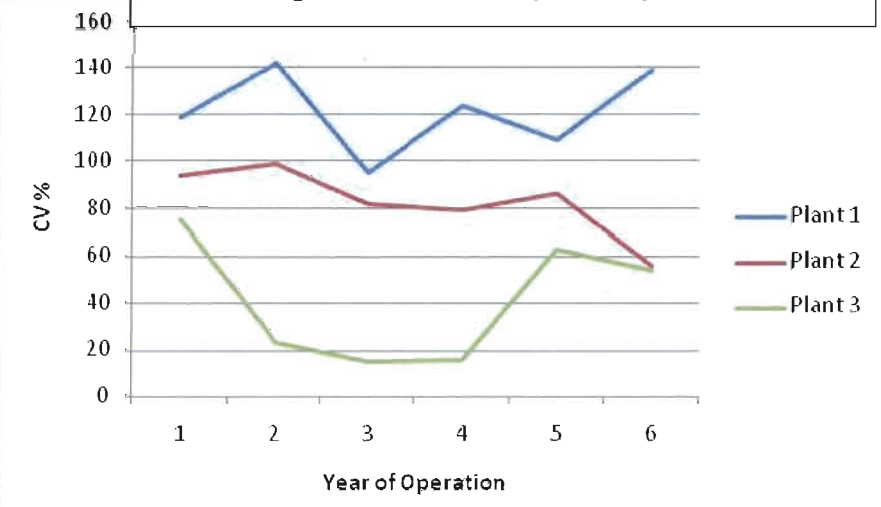


Figure 18. LE versus year of operation

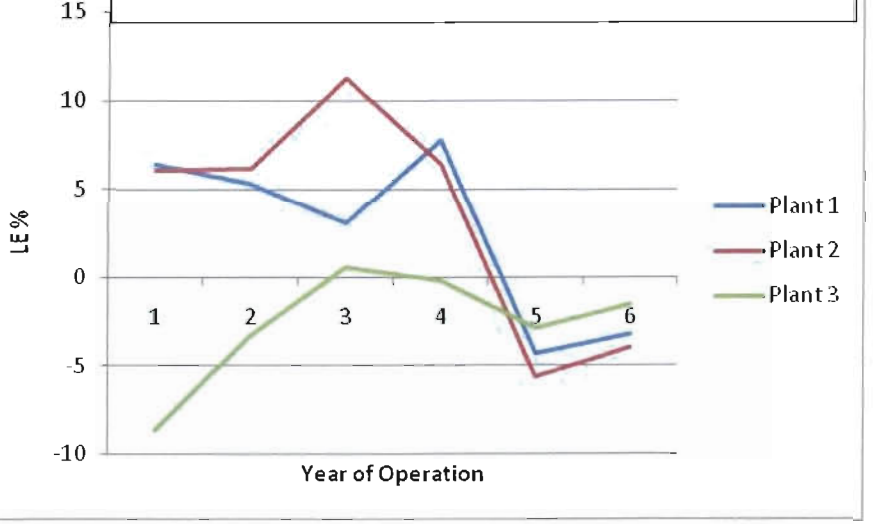
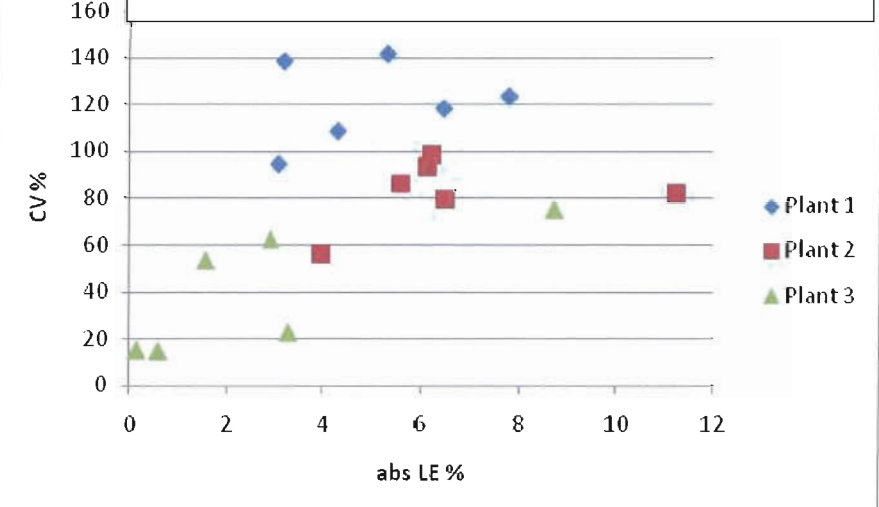


Figure 19. CV versus absolute value of LE



CONCLUSIONS

In this work we examined the performance and reliability of SCRs on US coal-fired utility boilers during the period from 2005 to 2007. Performance was measured in terms of NOx removal and in terms of outlet NOx levels. Reliability is more difficult to measure. However, we used measures of variability of outlet NOx as an indicator of the SCR's reliability in providing NOx control. One of the two measures of variability was used to determine the significance of load in the variability of outlet NOx level. We have reached the following conclusions from this work.

- Ninety percent (90%) removal efficiency continues to be achieved by a significant portion of the coal-fired SCR fleet.
- Performance in terms of NOx removal efficiency, and in terms of outlet emissions rates have remained consistent for the best controlled units. However, for the less well controlled units, performance has fallen off somewhat. The reason for this is unknown.
- Variability in outlet emissions rate has been reduced over the period, indicating a trend toward improving controllability.
- Over the period there was a consistent relationship between Load Effect (LE) and variability (CV). This relationship suggests that having an SCR that can maintain a constant NOx emissions rate over the full load range is a necessary, but not a sufficient, condition for having low variability in emissions rate. Units with low CV consistently had low LE. But, units with low LE did not necessarily have low CV.
- Analysis of annually controlled versus seasonally controlled units over three ozone seasons showed a slight advantage for seasonally controlled units; but, this difference was shown to likely be statistically insignificant.
- Analysis of units with known design characteristics over a period of several years shows significant differences in performance from year to year and between units that are not explained by design characteristics. As a result, operational differences likely have a significant impact on the observed performance.
- Analysis also showed that units can improve operation over time, in terms of both outlet emissions and variability. However, variability, measured by CV will increase if LE increases, even as controlled NOx is reduced.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the contribution of Jeff Bernard and Henry Stelmach for downloading data and the significant data manipulation required to allow this analysis.

REFERENCES

[i] Erickson, C., Staudt, J., "Selective Catalytic Reduction System Performance and Reliability Review", The 2006 Power Plant Air Pollution Control "MEGA" Symposium, Paper # 121, August 28-31, 2006, Baltimore, MD

Exhibit 7

One Source...Many Solutions...One Purpose

Competitive Power College

PowerGen 2005

Selective Catalytic Reduction: From Planning to Operation

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Customers first. Energy that lasts.

One Source...Many Solutions...One Purpose

Presented By

Scott Straight. Director of Project Engineering – LG&E Energy

Joe Strickland. Senior Project Engineer – LG&E Energy

Joseph Langone. Vice President of Business Development. Babcock Power

Michael Kelly. Program Director – Babcock Power

Clayton Erickson. Director of Process Engineering – Babcock Power

Michael Jasinski. Process Engineer – Babcock Power

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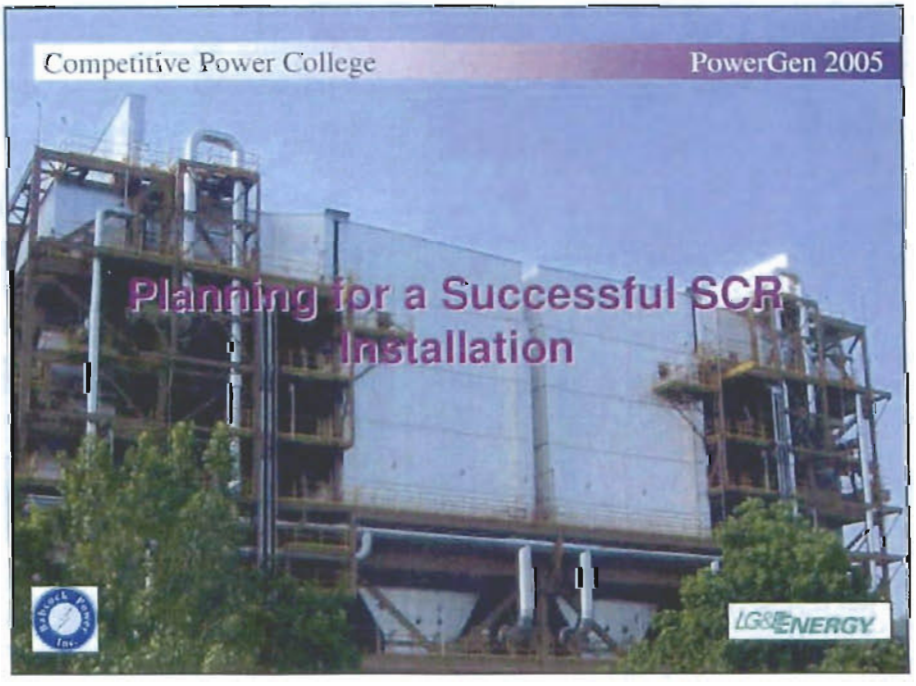
Agenda

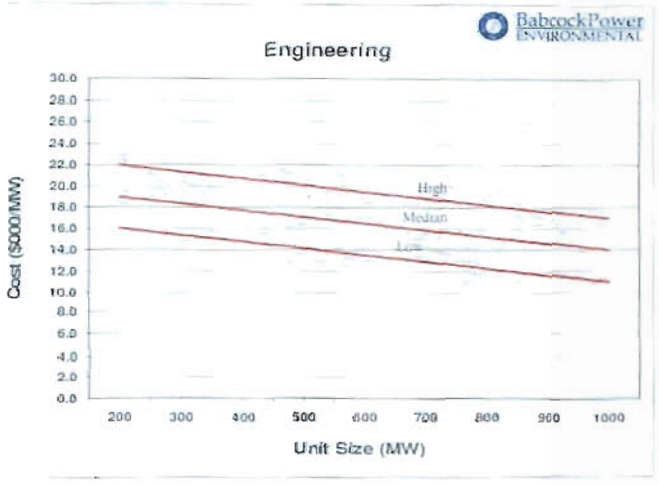
- Planning
- Capital Cost Estimating
- Design
- Construction, Commissioning, and Testing
- Operation
- Maintenance



SCR Construction Sequence Model (Movie)

SCR Capital Cost Estimating Categories

1. Engineering
2. Piling & Foundations
3. Structural Steel
4. SCR Reactor, Ductwork & Expansion Joints
5. Isolation/Control Dampers
6. Catalyst
7. Catalyst Cleaning Systems
8. Ammonia Storage and Feed Systems
9. Dilution/Seal Air Systems
10. Electrical/Instrumentation & Controls



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Piling & Foundation Systems

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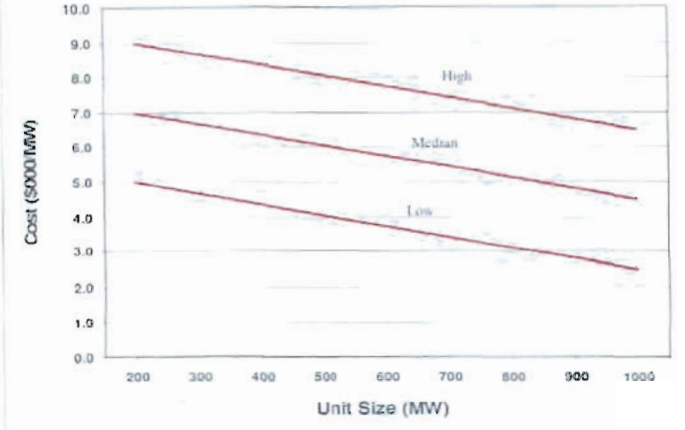

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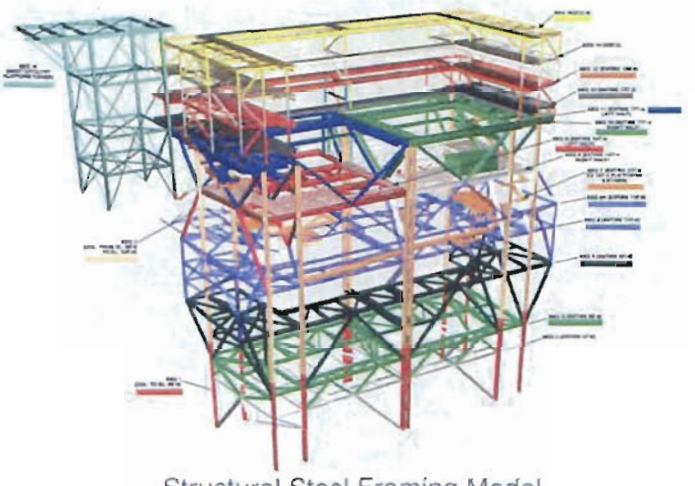

Structural Steel Framing Model

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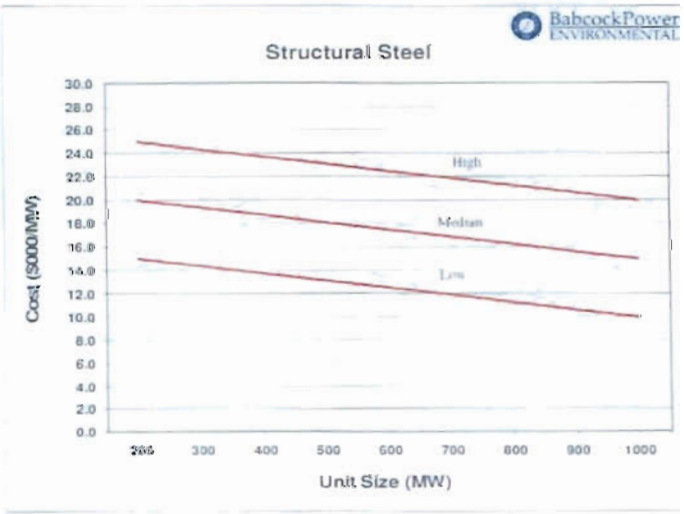
Structural Steel Systems



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SCR Reactor and Ductwork Systems




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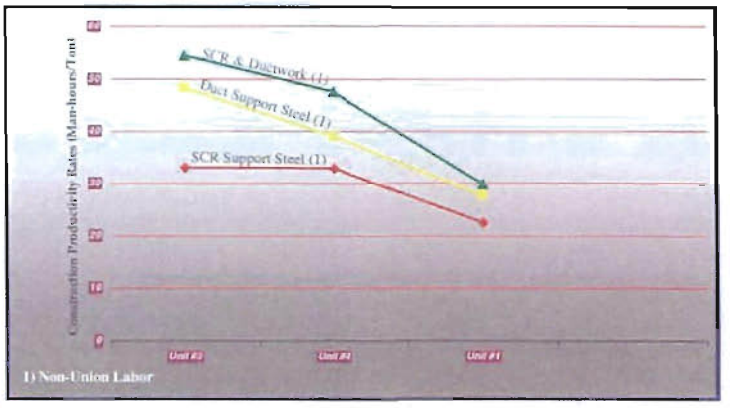
Construction Productivity Rates
Case Study Analysis



1) Non-Union Labor

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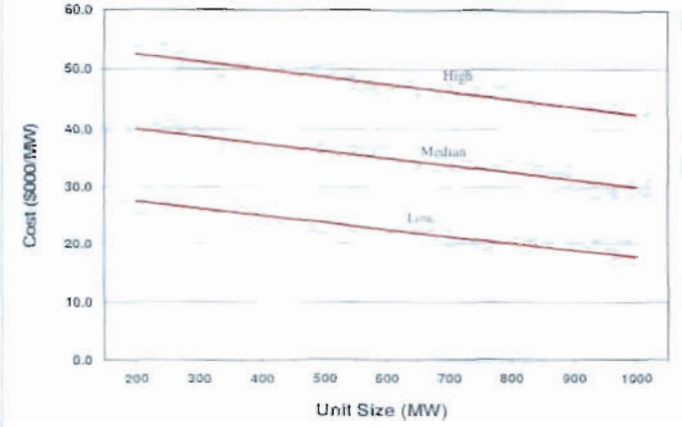
SCR Reactor, Ductwork & Expansion Joints



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Isolation/Control Damper Systems

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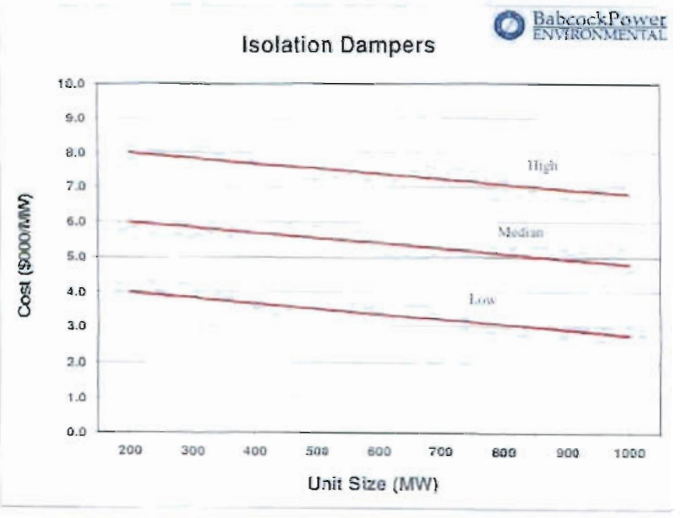

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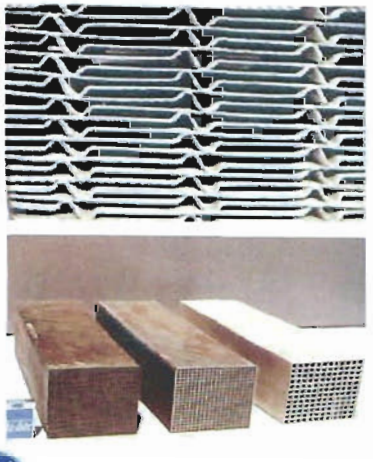
Catalyst Systems



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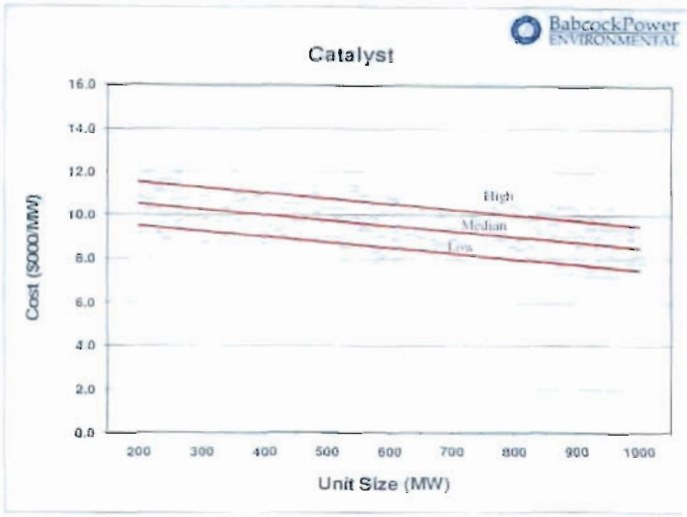

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Catalyst Cleaning Systems

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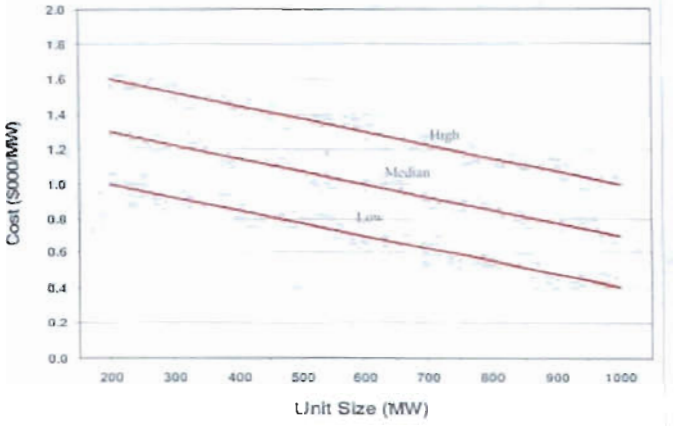
Catalyst Cleaning Systems



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Ammonia Systems

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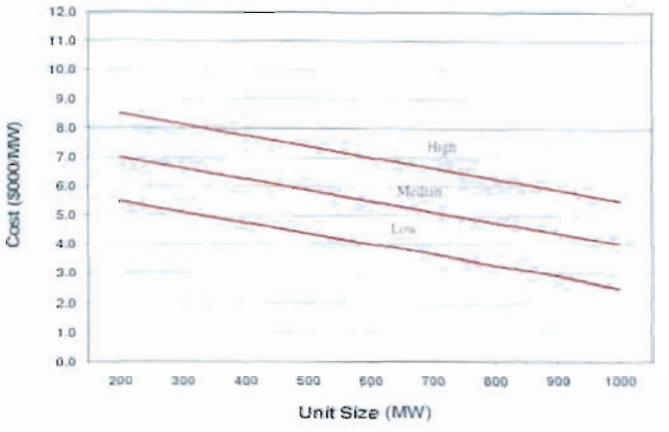
Ammonia Storage & Injection Systems



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Dilution/Seal Air Systems

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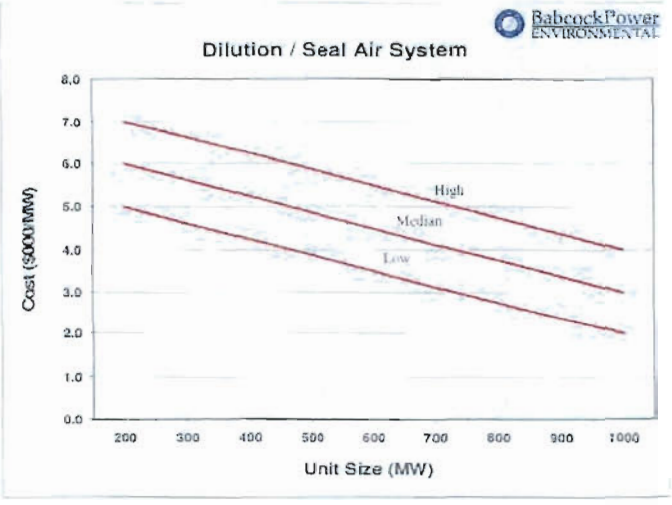
Competitive Power College PowerGen 2005



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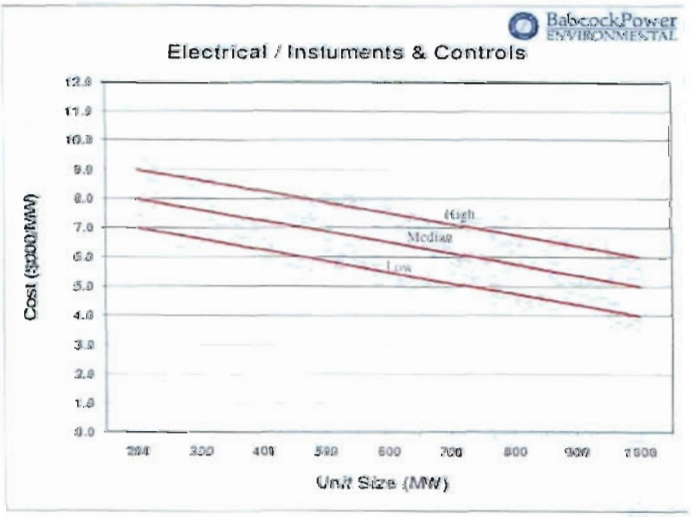
Competitive Power College PowerGen 2005



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Total SCR System
(Average Unit Cost)

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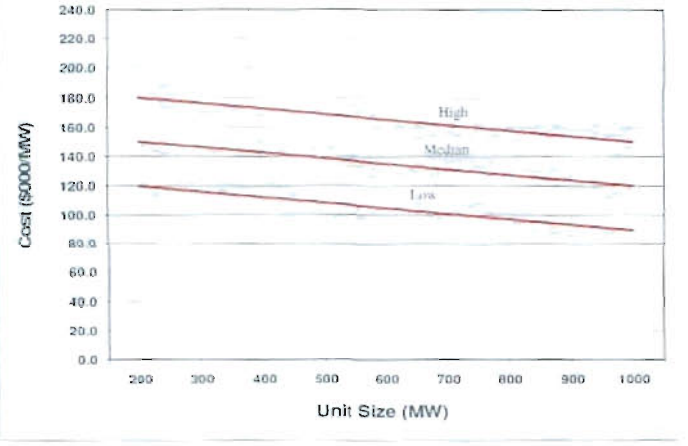

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Potential Additional Capital
Cost Modifications

1. ABS Air Heater Baskets and Cleaning Systems
2. Economizer Bypass System
3. Boiler Surface Modifications
4. Ash Collection System Modifications
5. Retrofit/New ID Fans & Drives
6. Balance of Plant Modifications

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Exhibit 8

UTILITY E-ALERT

#798 – November 3, 2006

Table of Contents

- **300 MW FGD at Datang Huxian No 1 Begins Operation**
- **300 MW FGD at Zhuzhou 4 in Operation**
- **2 x 300 MW FGD at Huadian Neijiang in Operation**
- **2 x 200 MW FGD at Huadian Huangjiaozhaung Begins Operation**
- **2 x 100 MW FGD at Huadian Yibin in Operation**
- **700 MW FGD at Zhuhai No. 1 Begins Operation**
- **SCR Construction Finished at 600 MW Ninghai No. 5**
- **ESP-FF Retrofit on a CFB Boiler**
- **New Units Begin Operation**

GAS/OIL – U.S.

- ***Sargent & Lundy is Design Engineer for Xcel Riverside Repower***

GAS/OIL – WORLD

- ***E.ON to Build 1,200 MW Combined Cycle Power Plant at Grain***

ETHANOL/GASIFICATION

- ***Indiana Gasification to Build $1.5 Billion Plant***
- ***Gasification/CO_2 Removal Demonstration Project in Queensland, Australia***
- ***Natural Gas or Coal for Ethanol Plants***

NUCLEAR

- ***Toshiba Completes Acquisition of Westinghouse Electric***
- ***Atmostryexport to Build 2 x 1,000 MW Nuclear Power Plant in Bulgaria***

RENEWABLES

- ***Vestas to Supply Wind Turbines for Chinese Wind Power Companies***
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HOT TOPICS

- ***Haldor Topsoe Catalyst Efficiency Revisted***
- ***$PM_{2.5}$ Hot Topic Hour Reveals that Firm Guarantees are being made based on Questionable Monitoring Methods***
- ***Hot Topic Discussion of Spray Dryer vs. CFB FGD November 9***

SCHEDULE FOR FUTURE HOT TOPIC HOURS

ACCESSING ALL THE PROJECTS AND INFORMATION ONLINE

COAL – U.S.

Monticello Draft Permit Hearing November 27

TXU Generation Co.'s proposal for expansion (800 MW) at its coal-fired Monticello power plant has received a draft permit from the **Texas Commission on Environmental Quality** (TCEQ). Public comments are being accepted by TCEQ on the air quality permit through November 16. The **State Office of Administrative Hearings** will conduct a public hearing on November 27 in Mount Pleasant.

Shaw Stone & Webster to Provide Construction Labor Services for Gorgas FGD

Shaw Stone & Webster will provide construction labor services to install FGD equipment on three units at **Southern Company** Gorgas. Shaw will also perform boiler maintenance services to support the associated outages.

Duke Expects Higher Costs for New Coal-fired Units at Cliffside

Duke Energy anticipates the cost to add two 800 MW coal units at Cliffside to exceed the $2 billion previously estimated. The first unit is scheduled to commence operations in 2011. The estimated degree of cost increases was sufficient enough such that Duke decided to file the increases with the **North Carolina Utilities Commission** on a confidential basis. The cost increases are based on bids that represent about 20 percent of the construction costs.

Arguments Presented to Supreme Court in Duke NSR Case

Environmental groups and the Bush administration defended a Clinton-era clean air program Wednesday in the Supreme Court, arguing that a power company must install pollution controls on its aging coal-fired plants. A lawyer representing **Duke Energy Corp**. said government regulators suddenly switched their interpretation of 26-year-old federal rules and sued the company six years ago. Lawyers for the environmental groups and the government said Duke and other utilities long ago understood federal requirements and chose not to comply with them. The outcome of the case, Environmental Defense vs. Duke Energy Corp., could affect power plants in 10 states where utility companies are challenging federal requirements under the New Source Review program. At issue is whether the **4th U.S. Circuit Court of Appeals** had the authority to handle the case when it ruled in favor of Duke. Also in dispute is whether emissions should be calculated hourly, as Duke wants, or annually, as the environmental groups and **EPA** say.

Hearings Held on Permit for Sunflower Electric's Proposed 2,100 MW Power Plant

Charles Benjamin, an attorney for the **Sierra Club**'s Kansas chapter, said **Sunflower Electric Power Corp**. is likely to overcome misgivings about potential environmental problems for its proposed 2,100 MW Holcomb/Sand Sage power project because the utility is promoting its plan as economic development. The new plants would be built near Sunflower's existing 350 MW station south of Holcomb, Kansas. The **Kansas Department of Health and Environment** (KDHE) has drafted a proposed permit for the project. The agency had a hearing Thursday in Topeka, attended by about 100 people. KDHE had a hearing Tuesday in Garden City and plans to have a third one November 16 in Lawrence. It will take written testimony until November 30 and expects to decide whether to issue the permit by January.

Fuel Tech Awarded NOxOUT Orders Totaling $4.0 Million

Fuel Tech, Inc. has three orders for air pollution control projects totaling $4.0 million. Placed by a Southeastern utility alliance partner, the orders largely represent the installation phase of four NOxOUT® SNCR projects on coal-fired boilers at three separate plant locations.

FreightCar America Receives Big Order for Coal Railcars for the New TXU Plants

FreightCar America, Inc. has entered into an agreement with **TXU Generation Development Company LLC** to be TXU's exclusive supplier of up to 7,650 aluminum AutoFlood III™ coal-carrying railcars to be delivered in the second half of 2008 through 2009. TXU's actual requirements may change at TXU's discretion, depending chiefly on the timely permitting of its new generating units in the Electricity Reliability Council of Texas power grid. TXU is expanding its power generation capacity by adding production units at its Monticello, Martin Lake, Big Brown, Tradinghouse, Lake Creek, Valley, and Morgan Creek sites in Texas.

PPL Reports FGD Construction on Budget

As previously announced, **PPL** has begun construction of $1.5 billion in pollution-control equipment at coal-fired power plants in Pennsylvania, including sulfur dioxide scrubbers at both units of its Montour power plant and at all three units of its Brunner Island power plant. The scrubbers for both Montour units and Unit 3 at Brunner Island are expected to be in service during 2008, and the scrubber for Units 1 and 2 at Brunner Island is expected to be in service during 2009. Scrubber construction continues to proceed on budget and on schedule.

DPL Reports Capital Expenditures in 2006 Relating to FGD Construction

DPL reports capital expenditures of $283.9 million for the first nine months of 2006 and $138.2 million for the first nine months of 2005. Total capital additions are expected to

approximate $365 million in 2006 primarily related to DPL's FGD construction program at JM Stuart and Killen.

COAL – WORLD

Duchting FGD Pump Orders

Duchting Pumpen is supplying pumps for the following FGD projects.

Order Date	Project	Country
7/2006	Jiangyin Ligang	China
5/2006	Baishan	China
3/2006	Datang Panshan	China
4/2005	Ruien	Belgium
1/2005	Emile Huchet and Gardanne	France

BHEL Proposing IGCC Projects for India

Bharat Heavy Electricals Ltd. (BHEL) has proposed a 400 MW IGCC power plant. BHEL has also proposed to set up a 125 MW IGCC demonstration project in association with the public sector **National Thermal Power Corporation Ltd**. (NTPC). The 125 MW project, estimated to cost Rs900 crore, would be set up near NTPC's Auraiya gas-fired power plant in Uttar Pradesh, India. BHEL would commission the project while NTPC would own and operate it. "We have submitted a feasibility report and are awaiting approvals for the 125 MW IGCC project. Simultaneously, we are also preparing a blueprint for a 400 MW IGCC plant that would be run on a commercial basis," BHEL chairman and managing director A.K. Puri said.

AES TO Build Coal-fired Power Plant in Chhattisgarh

The India government on Thursday approved $370 million in foreign direct investment in a coal-fired power project in the state of Chhattisgarh to be funneled through a local unit of U.S.-based **AES Corp**.

Morocco Plans $1.5 Billion 1,320 MW Coal-fired Power Station

Morocco's **National Electricity Office** (ONE) is launching a pre-qualification tender for a $1.5 billion coal-fired power station as part of a drive to expand electricity production. The coal-fired station would consist of two units of 660 MW each, located in the Cap Rhir area, about 40 km north of the Atlantic resort of Agadir. A presentation meeting on the project is scheduled for November 24 in Casablanca and the deadline for bids is December 20, 2006, ONE said.

B&W Canada/Air Liquide to Develop "Oxyfuel" Technology for SaskPower 300 MW Clean Coal Power Plant

SaskPower has selected the key technology to be used in the removal of carbon dioxide emissions from a proposed $1.5-billion 300 MW clean-coal power project. SaskPower, **Babcock & Wilcox Canada** and **Air Liquide** agreed to jointly develop "oxyfuel" technology. The oxyfuel process removes nitrogen from the combustion air. The gases leaving the boiler are then easier to purify, compress and liquefy for use in enhanced oil recovery (EOR) projects or underground storage. The technology could allow SaskPower to sequester 90 percent of the plant's CO_2—8,000 tonnes a day. If approved, the proposed 300 MW clean-coal power plant could be in service by 2011. SaskPower expects to make the decision on whether to proceed with the clean-coal power plant by mid-2007, following completion of the research on oxyfuel and other pre-commitment feasibility work.

PLN/AES Plan 1,200 MW Coal-fired Power Plant in South Sumatra

PT Perusahaan Listrik Negara (PLN) signed a preliminary deal with **AES Corp.**, Japanese trading firm **Sojitz** and local firm **PT Triaryani** to build a 1,200 MW coal-fired power plant. The cost of the project, to be located in South Sumatra in the west of the Indonesia archipelago, is estimated at about $1.5 billion.

Cormetech to Supply Catalyst for Pego 1 and 2

Cormetech has been awarded a contract by **Alstom Power Sweden AB** to supply SCR for the Tejo Energia Pego Power Plant. Alstom Power Sweden AB will be providing the DeNOx system for the 628 MW power plant which will utilize Cormetech's new 6.9 mm pitch, 22-cell high performance SCR catalyst. The SCR installation was driven by the EU's Large Combustion Plant Directive (LCPD). The Alstom contract will mark the fourteenth European installation for Cormetech.

CHINA

Renewable Energy

105 MW Jiangsu Rudong Wind Farm in Operation

The Jiangsu Rudong wind farm has recently begun operations with about 70 wind units of 1.5 MW. The total designed power for this farm is 600 MW, and construction has been scheduled in three phases. **GE Energy Co.** won the contract for 100 units of 1.5 MW in the phase II construction, and all these units were installed in Shenyang in Liaoning province. It has been estimated that about 1,500 MW of wind power will be in operation in Jiangsu by 2010; this will be about 20 percent of the wind power in China at that time.

300 MW Wind Farm Project at Tulufan Approved

Guodian Energy Co. has an agreement with the government of Tulufan City for a 300 MW wind farm project. The investment is 2.4 Billion RMB. Construction is divided into

six phases. Besides the Tulufan wind farm, there are eight large wind regions in Xinjiang province with the potential available wind power estimated at 80,000 MW.

Six Large Wind Farms will be Constructed in Fujian Province

Six wind farms named Zhangzhou Liu'ao, Dongshan Aojiao, Hui'an Congwu, Changle Jiangtian, Zahngpu Gulei and Zhao'an Meiling will be constructed in the next four years in Fujian province. The overall power of these new units is over 600 MW, and the total investment is more than 10 billion RMB. At present, four provinces including Fujian, Guangdong, Inner Mongolia and Xinjiang, are considered the renewable energy demonstration regions, and the **World Bank** will provide loans to these projects.

Nuclear

6,000 MW Nuclear Power Plants Planned at Rushan and Yueyang (China)

A 6,000 MW nuclear power plant will be constructed at Yueyang in Hunan province. The construction is divided into three phases with a total investment of 60 billion RMB. The Chinese **State Department** has definite plans to install some nuclear power plants in the inland provinces.

China will build a 6 x 1,000 MW nuclear power plant on its northeast coast in Shandong province. The facility will be built in Rushan before 2015, the government's *Xinhua News Agency* said, by **China Nuclear Engineering and Construction Corp.**, which will own 51 percent of it, along with three other companies.

Coal

300 MW FGD at Datang Huxian No 1 Begins Operation

A 300 MW FGD system for Unit 1 at **Datang** Huxian Second Power plant was put into operation on October 30, 2006. The FGD contract was awarded to **Shandong Sanrong Environmental Engineering Protection Co.** in July 2005. The FGD system employs wet limestone/gypsum technology, and the tested removal efficiency of SO_2 is over 95 percent.

300 MW FGD at Zhuzhou 4 in Operation

Datang Zhuzhou Power plant began operation of a 310 MW FGD system for Unit 4 on October 29, 2006. The FGD contract was awarded to **Shanghai Longking Environmental Protection Co.** in October of 2005. The FGD system is wet limestone/gypsum technology, which is licensed by Germany **LLB Co.** The SO_2 removal efficiency was measured to be over 98 percent. The suppliers of the main components of the FGD system are as follows: Slurry pumps--**Jiangsu Feixiang Pump Manufacture Co.**, Screw Air compressors--**Shanghai Fushi Industry Co.**, Wet limestone ball milling-

-**Jinan Heavy Industry Co.**, Adjustable blower--**Shanghai Blower Plant Co.**

2 x 300 MW FGD at Huadian Neijiang in Operation

After a year of construction, **Huadian** Neijiang Power plant began operation of the FGD system for the two 300 MW units on October 31, 2006. The systems are wet limestone/gypsum FGD technology, and SO_2 removal efficiency is over 95 percent.

2 x 200 MW FGD at Huadian Huangjiaozhaung Begins Operation

On October 30, 2006, **Huadian** Huangjiaozhaung (Sichuan province) power plant began operation of the FGD system for two 200 MW units. The system employs wet limestone/gypsum FGD technology, and the SO_2 removal efficiency is over 95 percent.

2 x 100 MW FGD at Huadian Yibin in Operation

Huadian Yibin (Hubei province) power plant began operation of FGD systems for two 100 MW units on October 29, 2006. The systems employ wet limestone/gypsum FGD technology, and the designed removal efficiency of SO_2 is 90 percent. **China Power Investment Yuanda Environmental Protection Co.** was the contractor for the construction.

700 MW FGD at Zhuhai No. 1 Begins Operation

A 700 MW FGD system at Zhuhai (Guangdong province) power plant No. 1 began operation on October 25, 2006. Another 700 MW FGD system is still under construction. The designed SO_2 removal efficiency is over 95 percent.

SCR Construction Finished at 600 MW Ninghai No. 5

The installation of a 600 MW SCR system at Guohua Ninghai (Zhejiang province) power plant No. 5 was just completed. The SCR technology is licensed by **BHK Co**. This is the first deNO_x project in Zhejiang province.

ESP-FF Retrofit on a CFB Boiler

The particulate collector for a 480t/h CFB boiler at Huadian Wuda power plant was changed from the original ESP to the combination of ESP-FF. The dust collection efficiency increases from 99.5 to 99.99 percent. An ESP-FF (electrostatic precipitator-fabric filter) combination is regarded as a promising approach to meet stricter environmental regulations in China.

New Units Begin Operation

A 350 MW unit (No. 3) at **Huadian** Tengzhou Xinyuan cogeneration plant was put into operation on October 28, 2006. Another unit (No. 4, 350 MW) is under construction.

A 300 MW unit (No. 1) at **Baotou Power Co**. was put into operation on October 27, 2006. Another one (No. 2, 300 MW) is under construction.

A 125 MW unit (No. 1) at **Huadian** Changji cogeneration plant was put into operation on October 26, 2006.

Huaneng Yangxun power plant began to operate Unit 5 (600 MW) on October 23, 2006. Unit 6 (600 MW) is still under construction. Units 1-4 are each 300 MW.

GAS/OIL – U.S.

Sargent & Lundy is Design Engineer for Xcel Riverside Repower

Xcel Energy Services has selected **Sargent & Lundy LLC** to perform the detailed design engineering for the Riverside Repowering Project. The project will replace the existing coal-fired units 7 and 8 with a natural gas combined-cycle unit. The final 2 x 2 x 1 configuration will increase the total generating capacity of the plant by approximately 80 MW, generating 480 MW upon completion.

GAS/OIL – WORLD

E.ON to Build 1,200 MW Combined Cycle Power Plant at Grain

E.ON UK has received approval from the **UK Department of Trade and Industry** to build a 1,200 MW combined-cycle gas turbine power plant at the site of its existing Grain oil-fired station in Kent, UK. The construction on the £350 million gas-fired station could start as early as next year, with electricity generation expected in 2009.

ETHANOL/GASIFICATION

Indiana Gasification to Build $1.5 Billion Plant

Governor Mitch Daniels of Indiana announced there are plans to build a $1.5 billion coal gasification plant that would be the first in the country to make pipeline quality natural gas from eastern coal. Several sites are being considered, and the governor said all of them are in the southwestern corner of the state. The plant is scheduled to be online in 2011.

The project is being developed by **Indiana Gasification, LLC**, and will include a methanation process to produce pipeline quality substitute natural as (SNG). It would produce 40 billion cubic feet of pipeline quality SNG annually, which is enough to supply 15 to 20 percent of Indiana's residential and commercial gas demand.

According to the letter of intent for 30-year supply contracts signed by the utilities last week, about two-thirds of the SNG produced by the new plant would be purchased by

Indiana's three largest gas utilities, **Vectren Corporation**, **NIPSCO** (Northern Indiana Public Service Company), and **Citizens Gas** to help meet residential and commercial gas demand. NIPSCO would purchase the remainder of the gas to fuel electric generation for its service territory to meet seasonal demands. The plant will use **GE Energy**'s gasification technology.

Gasification/CO_2 Removal Demonstration Project in Queensland, Australia

Queensland's (Australia) clean coal technology is being developed in three parts in central Queensland, the first being a gasification plant at Stanwell near Rockhampton, which will strip up to 80 percent of the CO_2 produced in current coal-production methods from the gas used to fire a power station. The second part involves transporting the expunged CO_2 in a pipe to the northern Denison Trough near Emerald, and the third involves burying it in an old natural gas field, reports *The Australian*. Professor Greenfield, senior deputy vice-chancellor at the **University of Queensland**, said the cost of producing power using clean coal technology was 30-50 percent higher than conventional methods. "There is no way it could be introduced in a competitive electricity market of the sort we have now, but the price signals will provide an incentive to move in this direction," he said. The project is being coordinated through Stanwell, a power generator fully owned by the Queensland Government, although personnel from **Shell** are also working on the project.

Natural Gas or Coal for Ethanol Plants

Des Moines' logjam over a new ethanol plant comes as the industry continues a trend toward making the fuel by burning coal, reports the *Des Moines Register*. Two companies are vying to build an ethanol plant in southeast Des Moines. One, **Lincolnway Energy** of Nevada, IA, would burn coal, as it does in its Story County plant. The other, **Vision Fuels** of Urbandale, would burn natural gas, a less-polluting but more costly fuel used by most Iowa ethanol facilities. Only a few of Iowa's 26 ethanol plants burn coal, according to the **Iowa Department of Natural Resources**. However, one firm eyeing the Des Moines project and others in Iowa is looking to save money by burning coal.

NUCLEAR

Toshiba Completes Acquisition of Westinghouse Electric

Toshiba has completed the purchase of **Westinghouse Electric Co.**, acquiring a 77 percent stake in the U.S. producer of nuclear power plant equipment for $4.16 billion. The **Shaw Group Inc**. bought a 20 percent stake for $1.08 billion and **Ishikawajima-Harima Heavy Industries Co.** purchased a three percent stake for $162 million. The Westinghouse deal means Toshiba will gain a 28 percent share of the global market, according to the company.

Atmostryexport to Build 2 x 1,000 MW Nuclear Power Plant in Bulgaria

Bulgaria has selected the Russian firm **Atmostryexport** to build a multi-billion dollar nuclear power plant at Belene on the Danube. The two 1,000 MW light-water reactors would join existing installations of the same capacity at Kosloduy. The Kosloduy plant is preparing to shut down two Soviet-era 440 MW nuclear reactors before Bulgaria joins the European Union on January 1, 2007.

RENEWABLES

Vestas to Supply Wind Turbines for Chinese Wind Power Companies

Vestas has orders for 50 units of the V80-2.0 MW wind turbine and 53 units of the V52-850 kW wind turbine for two wind power projects in China. The orders have been placed by **Longyuan Pingtan Wind Power Co., Ltd.** and **Huaneng Shantou Wind Power Co. Ltd**. respectively. Delivery of the turbines will start in Q4 2006 and commissioning of the wind power plants is planned to take place during 2007. The projects are located on the Islands Pingtan and Nanao, located in the southeastern province of Fujian.

Xcel Looks to Hydroelectric and Wind Power

In an application to the **Minnesota Public Utilities Commission**, **Xcel** proposes a combined hydroelectric/wind-power package starting in 2015 to fill a projected baseload shortfall of 375 MW. Xcel would buy 375 MW of power from **Manitoba Hydro** beginning in 2015 and buy or generate 380 MW of wind power by 2015.

Indiana Michigan Power Discussing Wind Farms

Indiana Michigan Power (I&M) has invited 250 residents of Jay, Randolph and Wayne counties to meetings next week to discuss the possibility of developing a wind farm. The electric utility is seeking people willing to lease their land to I&M for the installation of two or three 200-foot meteorological towers to collect wind data. If the data show that a wind farm is feasible, either I&M or a developer would plan to lease land for the installation of wind turbines. "A typical 100 MW wind farm would cover an area up to 12 square miles," Mike Brian, I&M spokesman, said. "It would be spread out over a wide area." While more than 10,000 MW of wind energy capacity have been installed in the United States, Indiana currently has none, though **Orion Energy** is placing up to 135 wind turbines capable of producing 200 MW of electricity in Benton County.

GE Turbines for Su Jia He Kou Hydroelectric Plant in China

GE Energy technology has been selected for a new 300 MW hydropower plant to be located on the Bing Lang Jiang River in Baoshan City, Yunnan Province, China. The Su Jia He Kou hydropower plant will feature three high-head, vertical Francis hydro turbine-generators, each with a maximum 105 MW output. Owner of the new power plant is **Yunnan Baoshan Bing Lang Jiang Hydro Power Development Co. Ltd**. The first unit is expected to enter commercial operation by June of 2009.

HOT TOPICS

Haldor Topsoe Catalyst Efficiency Revisted

During our SCR Hot Topic Hour (October 12) we reviewed the performance of the **Haldor Topsoe** catalyst. Nate White has supplied this additional information:

Haldor Topsoe provides a composite/hybrid (corrugated) SCR catalyst with a Tri-modal pore distribution that increases both catalyst activity and poison resistance. Topsoe has supplied catalyst to twelve coal-fired boilers burning high sulfur, high arsenic coals without limestone addition, one exceeding 28,000 hours of service with only two layers of catalyst. Haldor Topsoe reported they have provided catalyst for several installations that consistently run at less than 0.03 lb/MMBtu NO_x for both bituminous and sub-bituminous coals. Topsoe has over 100,000 hours of operating experience on PRB coal. In fact, three Topsoe supplied SCRs achieved the highest NO_x efficiency for all U.S. coal-fired high dust SCRs, averaging over 95 percent NO_x reduction over the 2005 Ozone season. The Tri-modal pore distribution is also advantageous in reducing SO_2-oxidation. Topsoe has two installations with three catalyst layers that have operated over 100,000 hours with an overall SCR SO_2-oxidation of less than 0.1 percent. They now report they have supplied additional catalyst layers to eight U.S. boilers without adding any measurable increase in SO_2 oxidation, several designed for less than 0.05 percent SO_2 oxidation per layer.

$PM_{2.5}$ Hot Topic Hour Reveals that Firm Guarantees are being made based on Questionable Monitoring Methods

http://www.mcilvainecompany.com/utility/subscriber/Hot_Topic_Hour_Recordings.htm

This link is for registered subscribers and is free of charge. Even though your company may be a subscriber but you are not a registered additional user, you can still access this recording at $95 for a period of six months. But the cost of becoming an additional user is not much more, so this would be a better option. In any case the link for those interested in individual tape access is
http://www.mcilvainecompany.com/FGDnetoppbroch/hottopichourrecordings.htm

This was a very valuable session because we had insights from the individual at EPA most responsible for the specific development of $PM_{2.5}$ monitors, the executive director of the association of companies which has to make guarantees based on the reliability of these instruments, utilities who were knowledgeable enough to spot some of the potential weaknesses in the designs, consultants who are focused on the $PM_{2.5}$ issues, and suppliers of continuous emissions monitors whose results must be correlated with the stack methods.

The undeniable conclusion from this two hour session is that there is a major problem with the time table. Firm guarantees are being made without a reliable method of proving those guarantees. There are many millions of dollars in guarantee risks and hundreds of

millions of dollars in risks involving permission to operate contingent on meeting specific limits as low as 0.018 lbs/MMBtu of particulate 2.5 microns and smaller including condensibles.

Method 202 is the method which will be used to validate the guarantees, but EPA is working on an improved method which will eliminate some of the artifacts. It also has a new conditional method using dilution sampling which appears promising, but this new method is not advanced to the point of replacing Method 202.

Here are some highlights from the presentations:

More than 40 people including utilities, government, A/Es, and suppliers participated in a two- hour discussion of the perplexing problem of measuring and controlling fine particulate. The discussion started with a brief tour of the Particulate Decision tree. An extensive analysis in the Decision Tree shows that discrete fine particle emissions from U.S. power plants could be as low as 100,000 tons per year or as high as one million tons per year. When you add in the condensibles you add another 200,000 to 500,000 tons/yr.

There were six semi-formal presentations and two inputs from expert panelists. The semi-formal presentations can be viewed without the audio directly in the Decision Tree through the links provided below. The full recording with all the presentations both video and audio is available through the Utility Environmental Tracking System,

http://www.mcilvainecompany.com/utility/subscriber/Hot_Topic_Hour_Recordings.htm

or the Power Plant Air Quality Decisions.

http://www.mcilvainecompany.com/ppks/subscriber/Hot_Topic_Hour_Recordings.htm

Ron Myers, EPA

Start ▶ More Particulate Removal Necessary? ▶ Regulations ▶ U.S. ▶ National ▶ PM2.5

Ron provided the very latest data on performance of the dilution sampling system which has been designated as conditional test method CTM 039. This system has been tested on seven sources including utility coal-fired boilers, oil-fired boilers and cement plants. Data correlates well with an improved Method 202 but not will the original method which is referenced in the permits. The designated method has a bias which converts some of the SO_2 and considers it additional particulate.

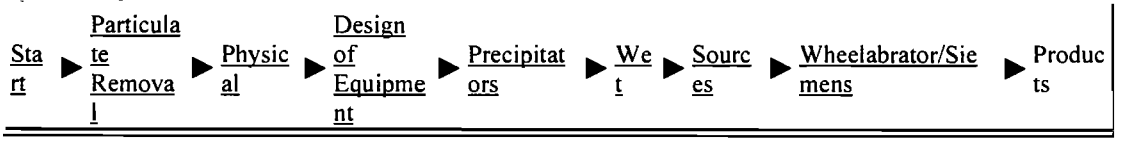
Dave Foerter, ICAC

Start ▶ More Particulate Removal Necessary? ▶ Regulations ▶ U.S. ▶ National ▶ PM2.5

Dave reviewed the history of ambient air particulate legislation and pointed out that this year the 24-hour standard has been reduced from 65 ug/m^3 to 15 ug/m^3. He also

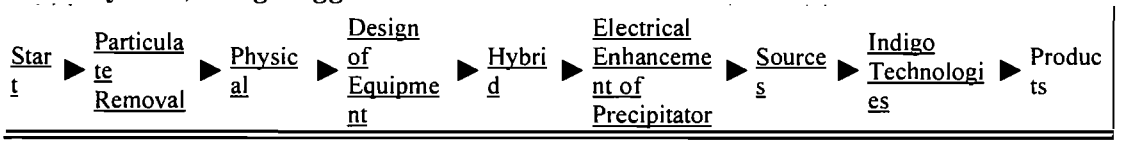
emphasized that the air pollution control companies are being required to make $PM_{2.5}$ guarantees and are in a difficult situation. Since Method 202 results in reporting erroneously high particulate weights and since it is the designated method, it is a big problem for the suppliers.

Buzz Reynolds, Siemens-Wheelabrator



This potentially interesting presentation was postponed due to some access problem. Due to the security software at some of the big companies it takes a special effort to use Webex.

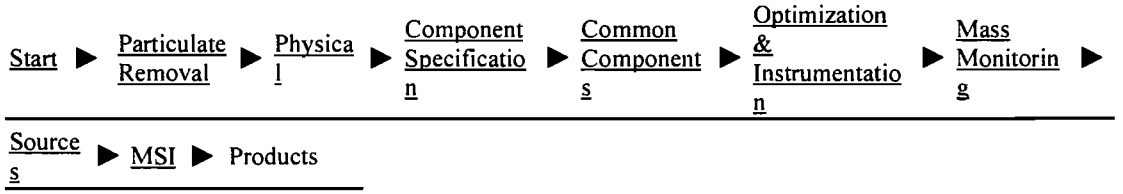
Bob Crynack, Indigo Agglomerator



Bob presented data to show that the Indigo Agglomerator is effective on fine particles. In a subsequent discussion, the question was raised as to the effectiveness on nanoparticles. One hypothesis is that particles less than 100 nanometers will act more like a gas and pass through a fabric filter, but if these particles are charged they may be captured in the fabric filter.

> *Editor note: See discussion of nanoparticles below. But is it possible that precipitators do better on nanoparticles than fabric filters? The problem is that we cannot even count the number of nanoparticles, so proving this hypothesis is not going to be easy.*

Craig Clapsaddle, MSI



Craig provided details on the ability of the BetaGuard particulate mass monitor to accurately measure mass emissions following a wet FGD system. Many States are incorporating mass monitoring requirements downstream of wet FGD in their permits for new plants. Craig pointed out that in some cases there is as much as a 90 percent reduction in discrete fine particulate in the scrubber. Several utilities that were having problems with meeting opacity limits after the precipitator were able to demonstrate compliance by installing the BetaGuard and proving the further reductions in the FGD.

Editor note: Since discrete particulate is a surrogate for heavy metals and there is likely to be significant reduction in the wet scrubber if it follows an old precipitator, this wet stack measurement is particularly valuable.

Otakar Jonas, Jonas Inc.

Tests were run at a DuPont incinerator some years ago and showed the inaccuracies of some of the CEMS in continuously monitoring mass. The acoustic emission monitor has some advantages.

Panelists

John McKenna of ETS was one of the panelists. He pointed out that $PM_{2.5}$ is defined as all particles of this diameter or smaller. So, he asks, what about nanoparticles? John operates a fabric verification program for EPA. When challenging today's fabrics with 100 nanometer particles, there is little difference between fabrics.

But if John were to use a particle counter rather than a weight measurement, he would be able to discern performance differences. As Bob Crynack pointed out in his presentation, there are many thousands of particles less than 0.1 micron in each cubic centimeter of flue gas. So measurement with a condensation nuclei particle counter could show differences of thousands or hundreds of thousands of particles in each cubic foot of flue gas passed through one fabric as compared to another.

Bill Ellison was a panelist and addressed the questions posed at the beginning of the session as follows:

Responding to several of McIlvaine's nine recently posted sub-topic areas:

(1) What percentage of $PM_{2.5}$ is condensables? A major proportion, especially in high-sulfur service. H_2SO_4 is the "tail" wagging the "dog" in the current era of low $PM_{2.5}$ emission limits out of "sync" with sulfur emission limits.

(2) Should there be a separate SO_3 measurement? No. That portion of the H_2SO_4 that would be expected to condense in the real-life flue gas treatment train prior to stack exit should (via the sample/test train) be summed-in with the $PM_{2.5}$ solids catch. Accordingly, the "back end" of the sample train should be operated at the same temperature as that at the stack-inlet, i.e.:

   (a) A nominal 300°F for an unscrubbed unit (or, logically, there is no back end catch available to be caught).

(b) The flue gas wet bulb temperature, e.g. 122°F for bituminous coal-firing, for wet scrubbed units.

(c) The above temperature for wet scrubbers plus the unit's actual amount of temperature approach to wet bulb for dry or semi-dry scrubbers (an appreciable "back end" catch for spray dryers but not for CFB scrubbers.)

Editor's comments: Bill is recommending an approach which measures the real time particulate. But the SO_3 will convert to H_2SO_4 within a short distance from the stack. (The difference is that all the SO_3 is converted prior to the stack exit when wet scrubbers are used. However, some of the SO_3 is captured.) Therefore EPA is considering this primary particulate as part of PM 2.5. By contrast SO_2 forms compounds much farther from the stack and is therefore considered a source of secondary particulate. Bill's approach will make the dry scrubber people happy. But the wet scrubber people will justifiably point out that within a short distance from the stack the H_2SO_4 will be less rather than more. Therefore why discourage more SO_3 removal?

(3) If I already have a precipitator, how much further reduction will I achieve when I install my wet FGD? None. Absent a wet ESP mist eliminator and its mitigating effect, $PM_{2.5}$ will increase due to each of:

(a) $H_2SO_4(\ell)$ formation in the wet scrubber, (i.e. that portion of raw-gas $SO_3/H_2SO_4(v)$ not removed in the scrubber, e.g. 50%).

(b) The solids component, suspended and dissolved, of the scrubber carryover, less that amount of particulate solids removed (inefficiently) in the wet scrubber, the latter being minimal in the case of an existing upstream precipitator of modern sizing with high solid particulate removal efficiency.

Editor note. However, many of the installations involve new FGD on plants with old precipitators. In general the scrubber can bring emissions down to 0.05 lbs/MMBtu. So if the inlet is 0.15 lbs/MMBtu then the scrubber can achieve a 66% reduction. But if the precipitator outlet emission is only 0.02 lbs/MMBtu the scrubber will not likely have any additional reduction. There is one exception. When there is a precipitator excursion, the scrubber particulate capture will be significant.

Hot Topic Discussion of Spray Dryer vs. CFB FGD November 9

Join us at 9:00 a.m., November 9th for the Hot Topic Hour discussion of dry FGD. This 90 minute web/audio discussion will address all the important selection factors including:

When is dry FGD a better choice than wet?
How do spray dryer, CFB, and CDS systems compare in efficiency and reliability?
Can spray dryer systems achieve more than 90 percent efficiency with high acid dewpoints?
How do dual fluid nozzles and rotary atomizers compare in performance?
How much downtime is required for rotary atomizers?
Will there be lime available in the quantity needed and at an affordable price?
How do you dispose of the flyash gypsum mix?
What removal efficiency will you achieve on SO_3?
Can ACI be co-injected for mercury removal?
What bag and media selections are best for this application?

For more information on this and other hot topic hours discussions click on

http://www.mcilvainecompany.com/FGDnetoppbroch/Default1.htm

SCHEDULE FOR FUTURE HOT TOPIC HOURS

November 16	**Mercury CEMS: Commercial availability**
November 27	***Power-Gen – all day decision making session in Orlando***
December 7	**Air Pollution Investment Opportunities**
December 11-13	***DOE Mercury, Pittsburgh - available for discussions***
January 11	**Corrosion materials options**
January 18	**Comparison of limestone wet scrubber designs**
January 21-24	***EUEC Tucson - available for discussions***
February 1	**Chinese FGD/SCR program and impact on the world**
February 15	**Mercury control cost and performance**
February 22	**SO_3 issues and answers**

ACCESSING ALL THE PROJECTS AND INFORMATION ONLINE

This Utility E-Alert is part of the **Utility Upgrade Environmental Tracking System.** The system allows you to instantly retrieve project details, profiles of each coal-fired plant worldwide, the right contacts at the OEM and A/E firms and summaries of all the scheduled FGD and SCR projects.

You need a user name and password to access this system. If you have forgotten these or are not sure whether you are eligible, email editor@mcilvainecompany.com.

Exhibit 9

[To Index]

PERFORMANCE ANALYSIS OF SCR INSTALLATIONS ON COAL-FIRED BOILERS

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ABSTRACT

The United States Environmental Protection Agency collects hourly emissions data from utilities and industrial sources subject to the NO_X Budget Trading Program. Currently, over 2,600 NO_X emission sources located across the U.S. are subject to the reporting requirements of this program. Coal-fired boilers represent a significant portion of these sources, with a large number being equipped with a variety of NO_X controls, including the selective catalytic reduction (SCR) technology. The NO_X controls operate under varying operating conditions, which are affected by the type of boiler and fuel characteristics applicable to each installation. This paper presents an analysis of the performance of SCR systems installed on these coal-fired boilers. The NO_X emission data analyzed include boiler operation, both with and without the SCR systems.

The paper examines the effects of types of coals burned in different installations on the SCR system performance. In addition, the SCR system performance levels have been compared with the performance levels for other types of NO_X controls.

INTRODUCTION

Sources subject to the NO_X Budget Trading Program (NBP) are required to submit hourly NO_X emissions data to EPA. The NBP is a multi-state cap and trade program applicable to large stationary sources during the ozone season, which lasts from May 1 through September 30 of each year. Sources are provided allowances and at the end of the ozone season, each source must hold sufficient allowances to cover all NO_X emissions the source emits during the ozone season. To monitor emissions, sources use continuous emission monitoring systems (CEMS) or other approved monitoring methods under EPA's 40 CFR part 75 monitoring requirements.[1]

The 2004 ozone season represented the first trading period for the NBP. Prior to 2004, only eight northeastern states and the District of Columbia, members of the Ozone Transport Commission (OTC), traded NO_X emission allowances during the ozone season. In 2004, an additional 11 states implemented the ozone season control requirements, beginning on May 31, 2004. Future ozone season trading for all sources under the NBP will occur during the entire ozone season of May 1 though September 30.

The NBP allows sources the flexibility of compliance by either reducing ozone season emissions or by purchasing available allowances. If a source's emissions are less than the allowances it holds, the source can trade the unused allowances to another source or bank the allowances for use in a future ozone season.[2] However, because the available allowances are part of a "capped" pool for the entire program, the cost of purchasing additional allowances to cover excessive emissions may be high. Sources choosing to reduce ozone season NO_X emissions may do so by changing unit operation, unit combustion modification, or by the use of add-on control devices. This paper will examine the performance of these sources, especially the coal-fired units that have installed SCR and other control devices to reduce their ozone season NO_X emissions.

NO_X REGULATIONS, A HISTORICAL PERSPECTIVE

The Acid Rain Program established under Title IV of the 1990 Clean Air Act Amendments (CAAA) provided incentives for rapid development and deployment of modern NO_X control technologies to combustion sources in the US. This program called for major NO_X reductions from coal-fired electric utility units in two phases. Initially, these requirements applied to the Group 1 boilers, which were of wall- and tangential-fired types. The first phase covered 239 units and became effective in 1996. The total number of Group 1 units affected by the second phase grew to 881 and this phase became effective in 2000. In general, the NO_X control technologies used to meet the program requirements included combustion optimization and combustion controls.

The combustion optimization consisted of techniques that modified the existing combustion process to create conditions conducive to lowering NO_X emissions, such as low excess air, burners out of service, and improved boiler controls and instrumentation. The combustion controls consisted of low- NO_X burner (LNB) and overfire air (OFA) technologies that replaced the existing combustion process. LNB basically controls the

mixing of air and fuel to create low- NO_X conditions, such as reduced oxygen availability in the initial combustion zone or less-intense flame. The OFA system creates a fuel-rich primary combustion zone and a fuel-lean, lower temperature secondary combustion zone where a portion of the boiler combustion air is injected through ports located above the uppermost burners.

In 1996, the part of the CAAA covering Group 2 boilers was established. Similar to Group 1 boilers for the second phase, it also became effective in 2000 and affected a total number of 165 units. Group 2 boilers included the types that were not part of the Group 1 boilers, such as cell-burner, cyclone, wet-bottom, and vertically-fired boiler types. The technologies used to comply with this regulation included mostly combustion controls (LNB and OFA). However, a few boilers were also retrofitted with post-combustion control technologies, including selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes.

In the SNCR process, a reagent, urea or ammonia, is injected into the flue gas stream inside the boiler to reduce NO_X to nitrogen and water. The gas temperature at the injection point must be in an appropriate range for this reaction to take place. The SCR process also uses ammonia to reduce NO_X to nitrogen vapor and water. However, ammonia is injected upstream of a catalyst contained in a reactor, which is located downstream of the boiler. The catalyst allows for a more efficient reaction between ammonia and NO_X at lower temperatures than the SNCR process.

The 1990 CAAA also established the OTC NO_X Reduction Program to mitigate interstate transport of pollution in the Northeast. In 1994, eleven states and the District of Columbia signed a Memorandum of Understanding committing to the reduction of NO_X emissions throughout the region. From 1999 to 2002, most of the OTC states achieved deep NO_X reductions through an ozone season cap and trade program. The NO_X control technologies used for these reductions mostly included combustion controls and SCR.

The Environmental Protection Agency (EPA) proposed the NO_X SIP call rule in 1997 and finalized it in 1998. This rule required 22 states and the District of Columbia to amend their state implementation plans (SIPs) and limit NO_X emissions, beginning in 2003. The EPA set an ozone season NO_X budget for each affected state, essentially placing a cap on emissions from May 1 to September 30 in the particular state. As a result of litigation activities, compliance for some states on this rule was delayed to 2004. The SCR technology was used for NO_x control by a large number of affected sources in all states to comply with the requirements of this rule.

In 2003, the EPA proposed the Clean Air Interstate Rule (CAIR), which imposed limits on emissions of pollutants contributing to the increase of fine particulate in the atmosphere. These pollutants included both NO_X and SO2, which are precursors of fine particulate. The rule was finalized in 2005, with the first phase for NO_X starting in 2009 and the second phase in 2015. Based on EPA's projections, requirements for this rule will mostly be met by the use of the SCR technology in the affected sources.

The results presented in this paper cover the sources that were affected by the OTC and NO_X SIP call initiatives. These results are based on the information submitted by these sources as part of the NBP requirements to EPA.[3] Table 1 summarizes the NO_X control technologies that were retrofitted to these sources for compliance purposes. Many of the control technologies are used in tandem with another control device (e.g., LNB along with SCR) and were added later by the source as it became affected by new requirements. Retrofits or updated equipment are usually indicated (e.g., LNB with close-coupled OFA) as a single device with the older device listed as retired. All of the equipment listed in Table 1 represents controls or modifications installed prior to the 2004 ozone season.

Table 1 also lists the 2004 NOx mass emissions for various sources, for both the ozone- and non-ozone seasons. As indicated in Table 1, the vast majority of NO_X emissions were from the Electric Utility sector, especially the coal fired units. The Electric Utility sector as well as the Small Power Producer sector had the largest drop in NO_X emissions between the ozone and non-ozone seasons. The difference between the ozone and non-ozone season NO_X emissions for the remaining sectors varied. These sectors are comprised of units generally used for industrial processes and small power generation.

The Electric Utility sector comprises the highest number of emissions controls, which is weighted heavily to LNB technologies or a combination of LNB technologies and catalytic reduction add-on controls (SCR and SNCR). The largest number of SCR installations is in the Electric Utility Sector (112 SCRs installed prior to the 2004 ozone season). The use of LNB technologies is the most prevalent in the remaining sectors and besides the application of SCR on turbines, few add-on controls were added to meet compliance requirements for these sectors.

Table 1 provides data by source category and primary fuel type. The primary fuels are not necessarily the only fuels used by these sources. Many combustion turbines, for example, are designed as dual-fired units, capable of burning either natural gas or distillate fuel oil. Therefore, a control may be added to a source designed to be used only when the primary fuel is being combusted (i.e. DLNB for a dual-fired turbine effective only when natural gas is combusted).

The category of industrial boilers and process heaters consists of all industrial units including those used in iron and steel production, pulp and paper mills and petroleum refineries. Industrial turbines are segregated into a separate category. It should be noted that industrial turbines had very little operating hours in 2004, specifically while burning oil, and did not operate at all during the 2004 non-ozone season.

In some cases the NO_X emissions provided in Table 1 are lower in the non-ozone season than in the ozone season. The reason for this seemingly counterintuitive data is that these units operated more hours during the ozone season than in the non-ozone season. For example, coal-fired industrial boilers and process heaters had a 41 percent reduction in heat input in the non-ozone season from the ozone season. The lower heat input during the non-ozone season is the reason behind all the lower NO_X emissions data in the non-ozone season provided in Table 1.

Table 1. Control Technologies Breakdown

Source Category	Units (Note 1)	Primary Fuel Type	NO_X Controls Installed Prior to 2004 Ozone Season (Note 2)	2004 Ozone Season NO_X Emissions (tons)	2004 non-Ozone Season NO_X Emissions (tons)
Cement Kilns	2	Coal	Other	3,397	4,773
Cogeneration Units	75	Coal	LNB, SNCR, OFA, Other	11,109	7,264
	9 (2)	Oil	LNB, H2O, Other	105	444
	144 (127)	Gas	LNB, DLNB, SCR, SNCR, STM, H2O, Other	5,017	3,698
Electric Utility and Small Power Producer Units	663	Coal	LNB, LNBO, LNC1, LNC2, LNC3, LNCB, SCR, SNCR, OFA, CM, H2O, Other	506,602	1,305,167
	462 (313)	Oil	LNB, DLNB, LNBO, LNC1, SCR, SNCR, OFA, CM, STM, H2O, Other	23,970	36,530
	922 (867)	Gas	LNB, DLNB, LNBO, LNC1, LNC2, DLNB, SCR, SNCR, OFA, CM, H2O, STM, Other	8,859	7,142
Industrial Boilers and Process Heaters	114	Coal	LNB, LNBO, LNC1, LNCB, SCR, SNCR, OFA, CM, STM, Other	26,804	21,136
	11	Oil	LNB, LNCB	651	347
	154 (10)	Gas	LNB, DLNB, LNBO, SCR, OFA, CM, STM, Other	5,839	6,020
Industrial Turbines	2	Oil	H2O	< 1	0
	7	Gas	DLNB, SCR, H2O	65	80

Notes:

1. The numbers in parenthesis represents number of turbines, except in the Industrial Turbine category, which is made up exclusively of turbines.

2. LNB – Low NO_X Burner
   OFA – Overfire Air
   LNBO – LNB with OFA
   LNC1 – LNB with close-coupled OFA (Tangentially Fired Boilers only)
   LNC2 – LNB with separated OFA (Tangentially Fired Boilers only)
   LNC3 – LNB with close-coupled and separated OFA (Tangentially Fired Boilers only)
   LNCB – LNB for Cell Burners
   DLNB – Dry LNB (Turbines only)
   H2O – Water Injection (Turbines and Cyclone Boilers only)
   STM – Steam Injection (Turbines only)
   SCR – Selective Catalytic Reduction
   SNCR – Selective non-Catalytic Reduction
   CM – Combustion Modification / Fuel Reburning
   Other – Other Combustion Modification or Optimization System
   N/R – No Control Device Reported

It should be noted that all emissions data used in this analysis have been collected and quality-assured by the Clean Air Markets Division of the EPA. The data represent hourly air emissions data from sources subject to reporting requirements of 40 CFR Part 75. NBP sources reported quality-assured emissions data for more than 99 percent of their operating hours in 2004.

OVERALL OZONE SEASON PERFORMANCE

As shown in Table 1, 2004 NO_X emissions were significantly lower during the ozone season than the non-ozone season. Specifically, there was a 57 percent reduction in total NO_X emissions from the non-ozone season to the ozone season. For all units in Table 1 there was only a 20 percent drop in heat input between the non-ozone season and the ozone season. The difference between the drop in emissions and heat input indicates that the reduction in the ozone season NO_X emissions was not solely because of the reduced unit operation. In fact, this difference reflects the NOx reduction effectiveness of the add-on controls installed on some of the units that may not have been operated during the non-ozone season.

To further examine the effect of add-on controls, especially those commencing operation during 2004, an analysis of the reported 2003 and 2004 ozone-season NOx mass emissions was conducted. Table 2 provides a summary of the total NBP NO_X emissions during these two seasons.

Table 2. Change in Heat Input and NO_X Emissions

	2003 Ozone Season	2004 Ozone Season
Total NO_X Emissions (tons)	812×10^3	581×10^3
Total Heat Input (mmBtu/hr)	5.6×10^9	5.7×10^9

As indicated in Table 2, the 2004 NO_X mass emissions are approximately 28 percent lower than the 2003 emissions. This reduction in emissions occurred despite the fact that more sources reported NO_X mass emissions during the ozone season in 2004 than in 2003. The heat input for these units increased by approximately 2 percent. This very slight increase suggests that no dramatic change in overall types of fuel burned between both ozone seasons occurred. Although a specific operating parameter trend shift is difficult to summarize, clearly an increase in heat input for the same group of units should produce larger values of NO_X emissions during the 2004 ozone season, which was not the case. A more detailed analysis of the unit hourly data may provide valuable insight as to specific operating parameter changes, such as changes in types of fuels burned, however it would not account for such a large drop in emissions. Therefore, the reduction in emissions could only be due to a change in unit operation (i.e., change in

fuel, reduction in operating hours, etc.), or an increase in NO_X emission controls, such as combustion modifications or add-on control devices.

A summary of the units which have added NO_X controls is provided in Table 3. As before, only units that reported emissions data for both the 2003 and 2004 ozone seasons were evaluated for changes in control data. These changes reflect the number of controls installed prior to the beginning of each ozone season, May 1, 2003 and May 31, 2004, respectively.

Table 3. Change in NO_X emission controls

	Installed prior to 2003 Ozone Season	Installed prior to 2004 Ozone Season	Difference 2003 to 2004
SCR add-on control	278	331	53
SNCR add-on control	46	57	11
"other" controls or combustion modifications	1,519	1,553	34
Units with "other" controls or combustion modifications without add-on controls	1,235	1,171	- 64

The number of SCR and SNCR add-on control devices indicates the number of units which have installed the controls prior to each ozone season. The "other" controls or combustion modifications number indicates the total number of devices for all units, including multiple controls per unit (e.g., LNB and OFA). The last row in Table 3 indicates the total number of units which have some type of control or combustion modification, excluding units that have SCR or SNCR.

As indicated in Table 3, the number of units retrofitted with all types of NO_X controls increased between the 2003 and 2004 ozone seasons. The majority of this increase was in the application of SCR and SNCR controls; the number of units retrofitted with these two technologies increased by 18 and 23 percent, respectively. Most of the "other" controls or combustion modifications were installed as an original part of the unit or as a retrofit prior to the 2003 ozone season, thus explaining the small difference between the 2004 and 2003 ozone seasons. The reason for a decrease in the number of units with only the "other" controls or combustion modifications is due to the fact that the majority of all new SCR and SNCR installations occurred on units that were already equipped with some type of NO_X emissions controls. The installation of SCR and SNCR controls to units with already existing controls suggests that these new installations were a result of the NO_X emission compliance requirements imposed by recent regulations, such as the OTC and NO_X SIP call.

The largest increase in the application of controls involved SCR, with 53 new SCR installations added during the period between the 2003 to the 2004 ozone seasons. Although SNCR installations increased by a slightly higher percentage, the number of units is small in comparison to those that installed SCR. In addition, 48 of the 53 SCRs added between the 2003 and 2004 ozone seasons were installed on the Electric Utility coal-fired units (5 additional SCRs were installed on Electric Utility gas-fired combined cycle units). Therefore, the lower NO_X emissions previously indicated are due mainly to an increased effort in NO_X emission reduction measures, and specifically because of the installation of SCR add-on control devices to the larger coal-fired units.

This same difference in installed controls applies directly to any emissions comparison between the 2004 ozone and non-ozone seasons. Any controls installed prior to the 2003 ozone season would have been installed prior to January 1, 2004, the beginning of the 2004 non-ozone season. However, any add-on control devices such as SCR and SNCR may not have been operated during the 2004 non-ozone season, even if they had been installed prior to January 1, 2004.

COAL-FIRED BOILER EMISSIONS ANALYSIS

To evaluate the impact of increased application of add-on control devices to coal-fired boilers, an analysis of the reported NO_X emission rates (lb/mmBtu) for all coal-fired NBP units was conducted. One factor considered in this analysis was the shorter reporting period of May 31 through September 30, 2004, for units not previously subject to OTC requirements. Therefore, all NO_X emission and heat input data was compared for consistent periods (May 1 to September 30) for the 2003 and 2004 ozone seasons. The NO_X rate emissions data was adjusted to take into account that some units were subject to the shorter effective 2004 ozone season where the controls would be operated.

The analysis for coal-fired boilers was performed for each coal-fired boiler type. A breakdown of the different coal-fired boiler types along with the type of controls associated with each is provided in Table 4. The analysis was limited to all NBP coal-fired units that reported emissions data for both the 2003 and 2004 ozone seasons.

As indicated previously for all units, the addition of SCRs and SNCRs represents the largest changes in NO_X reduction for the coal-fired units. Specifically, SCR installations increased by 75 percent, SNCR installations increased by 29 percent, and "other" controls or modifications increased by 3 percent. Most of the units which added an SCR or SNCR already had some type of control or combustion modification to reduce NO_X emissions and are further reducing NO_X emissions via the installation of the add-on control device.

Dry bottom wall-fired and tangentially-fired boilers, which represent the largest group of coal-fired boilers (69 percent), had a significant increase in both SCR and SNCR installations. However, a clear trend toward SCR installation is indicated by the large number (48) of units that installed SCR as an add-on control device. To evaluate the effect that the added controls have had on the coal-fired units, a breakdown of their

respective NO_X emissions is provided in Table 5 for the 2003 and 2004 ozone and non-ozone seasons. As a point of reference, NO_X emissions for 2000 were 1,074,488 tons during the ozone season and 1,530,759 tons during the non-ozone season.

Table 4. Breakdown of Coal Boiler Types

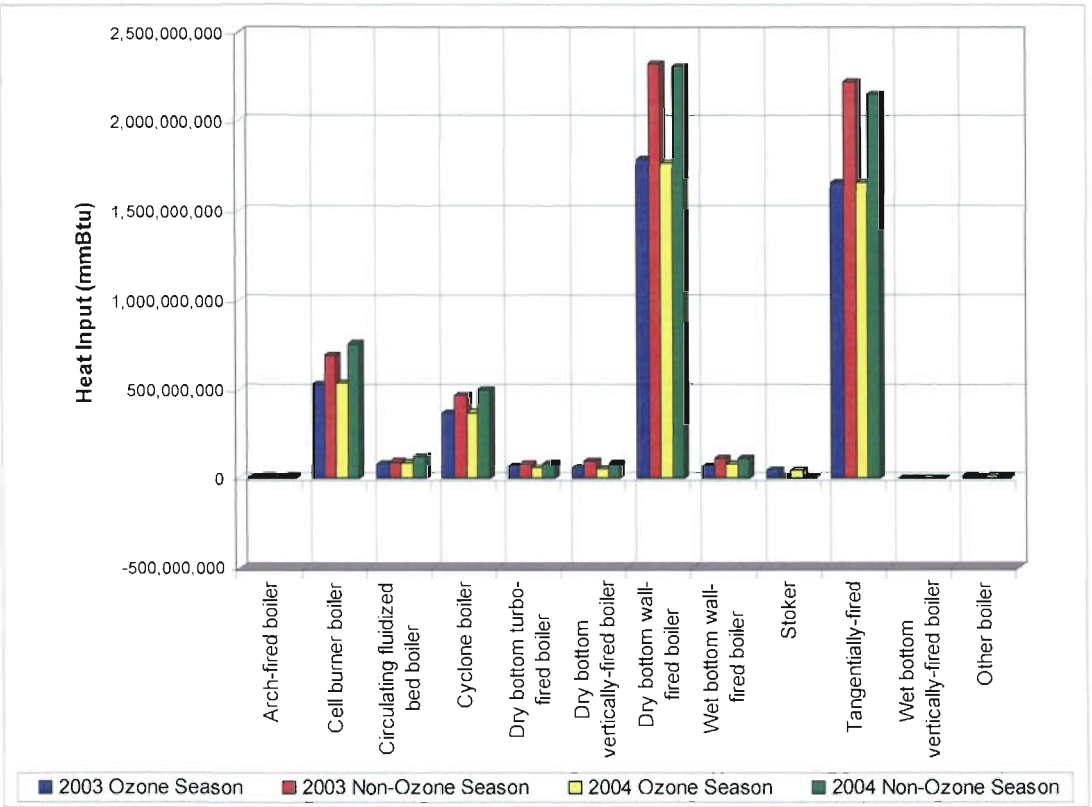
Boiler Type	Units	SCRs prior to 2003 Ozone Season	SCRs prior to 2004 Ozone Season	SNCRs prior to 2003 Ozone Season	SNCRs prior to 2004 Ozone Season	"Other" controls or modifications prior to 2003 Ozone Season	"Other" controls or modifications prior to 2004 Ozone Season
Arch-fired	9						
Cell burner	29	7	16	1	1	25	28
Circulating fluidized bed	41			10	12	15	15
Cyclone	48	14	18	2	2	36	38
Dry bottom turbo-fired	8	0	1			6	6
Dry bottom vertically-fired	21			3	3	15	15
Dry bottom wall-fired	282	26	39	7	10	217	221
Stoker	59			2	2	43	43
Tangentially-fired	265	14	28	11	17	181	184
Wet bottom vertically-fired	2						
Wet bottom wall-fired	20	3	10	2	2	15	15
"other"	12					4	6
Total	**796**	**64**	**112**	**38**	**49**	**557**	**571**

Table 5. NO_X Emissions from Coal-Fired Boilers

Boiler Type	2003 Ozone Season NO_X Emissions (tons)	2003 non-Ozone Season NO_X Emissions (tons)	2004 Ozone Season NO_X Emissions (tons)	2004 non-Ozone Season NO_X Emissions (tons)
Arch-fired	1,428	3,376	1,942	2,680
Cell burner	108,947	206,381	55,184	208,830
Circulating fluidized bed	6,694	7,338	6,640	11,024
Cyclone	68,936	173,482	44,598	182,187
Dry bottom turbo-fired	14,139	18,706	9,696	18,442
Dry bottom vertically-fired	17,102	28,617	8,959	21,667
Dry bottom wall-fired	292,521	509,415	212,248	472,030
Stoker	10,172	1,763	8,315	1,772
Tangentially-fired	225,857	394,028	184,377	365,909
Wet bottom vertically-fired	67	0	56	0
Wet bottom wall-fired	16,090	44,913	9,493	45,406
"other"	3,702	1,855	3,008	3,119
Total	**765,654**	**1,389,874**	**544,516**	**1,333,065**

There is a clear reduction in NO_X emissions between the 2003 and 2004 ozone seasons which seems specifically due to the added installations of NO_X control devices (both add-on and "other" controls and modifications). However, changes in emissions between the non-ozone seasons may be in part due to operational changes to the boilers. Figure 1 provides a look at the 2003 and 2004 heat input values for each coal-fired boiler type.

Figure 1. Heat Input Comparison for Coal-Fired Boilers



NO_X emissions between the 2003 and 2004 ozone seasons were reduced by a total of 29 percent. The largest reductions in ozone season emissions came from the cell burner and dry bottom vertical-fired boilers, with a reduction of approximately 49 percent for each boiler category. However, the largest drop in overall emissions, a total of over 80,000 tons, came from the largest group of units (dry bottom wall-fired boilers). Emissions for the wet bottom vertically-fired boilers (2 units) were low due to infrequent use and these in fact did not operate at all during both the 2003 and 2004 non-ozone seasons. Emissions between the 2004 non-ozone and ozone seasons were reduced approximately by 59 percent. Wet bottom wall-fired, cyclone and cell burner boilers had reductions of greater than 70 percent (79 percent for wet bottom wall-fired boilers) between the non-

ozone and ozone seasons. Although the dry bottom wall-fired boilers had reductions of only 55 percent, they reduced NO_X emissions by almost 260,000 tons. Only the stoker and wet bottom vertically-fired boilers had emissions increase from the non-ozone season to the ozone season by approximately 6,600 tons.

The overall heat input for all coal-fired boilers remained relatively constant between the ozone seasons (approximately 4.7×10^9 mmBtu). Similarly, the overall heat input for these boilers between the non-ozone seasons also remained constant (approximately 6.1×10^9 mmBtu). Changes in heat input between the 2003 and 2004 ozone seasons and non-ozone seasons were less than 1 percent. The relatively steady heat input suggests that the changes in the NO_X mass emissions are due to the frequency of operation of NO_X emission controls, both in the ozone and non-ozone seasons. However, because "other" controls and modifications are generally an integral part of the boiler, any changes are due to the add-on control devices. That is to say, any decrease in NO_X emissions during the ozone season and subsequent increases in NO_X emissions during the non-ozone season are due to the operation of the add-on control devices. Heat input reductions between the 2004 non-ozone and ozone seasons were 24 percent, with reductions up to 39 percent for the dry bottom vertically-fired boilers. These reductions in heat input are much lower than the NO_X emission reductions of 59 percent overall and up to 79 percent. The stoker and wet bottom vertically-fired boilers had heat input reductions between the two seasons, which account for the corresponding drop in NO_X emissions.

As shown in Table 6, except for the 21 boilers listed as "Arch-fired" and "Other," the various boiler types achieved emission rate reductions of at least 15 percent between the 2004 ozone and non-ozone seasons. The highest reductions were achieved by smaller groups of boilers (i.e. wet bottom wall-fired, cyclone and cell burner boilers); however, significant reductions were achieved by the largest group of boilers (dry bottom wall-fired and tangentially -fired), with at least a 37 percent reduction in NO_X rate between

Table 6. Comparison of Coal-Fired Unit NO_X Emission Rates

Boiler Type	2004 Ozone Season NO_X Rate	2004 Non-Ozone Season NO_X Rate	Percent Difference
Arch-fired boiler	0.410	0.412	1%
Cell burner boiler	0.174	0.551	69%
Circulating fluidized bed boiler	0.133	0.174	24%
Cyclone boiler	0.211	0.726	71%
Dry bottom turbo-fired boiler	0.280	0.420	33%
Dry bottom vertically-fired boiler	0.319	0.492	35%
Dry bottom wall-fired boiler	0.219	0.409	46%
Stoker	0.329	0.388	15%
Tangentially-fired	0.213	0.340	37%
Wet bottom vertically-fired boiler	0.393	0.000	N/A
Wet bottom wall-fired boiler	0.163	0.782	79%
Other boiler	0.375	0.352	-7%

Notes: N/A – Not Applicable

the ozone and non-ozone seasons. The wet bottom vertically-fired boilers reported zero NO_X rate data for the 2004 non-ozone season, as these units did not operate. Only one boiler category (Other) had an increase in NO_X rate from the ozone season to the non-ozone season; these 12 units (mainly industrial boilers) with few controls did not operate many hours in 2004.

CONTROL EFFECTIVENESS OF COAL-FIRED BOILERS

The type of coal burned by a boiler can play a significant role in the overall effectiveness of control technologies applied for NO_X reduction. The sources reporting to the NBP did not include information on specific types of coals burned in their facilities. The information used in this analysis on the types of coals for various sources was obtained from data reported by the Department of Energy.[4] Based on this information, most of the coal-fired units in the NBP burned either bituminous or sub-bituminous coal. Specifically, units burning bituminous coal accounted for the majority of all NO_X emissions during both the 2004 ozone and non-ozone seasons. Dry bottom wall-fired and tangentially-fired boilers accounted for the largest portion of these emissions. Except for a few categories of boilers, NO_X emissions were dramatically lower during the ozone season than in the non-ozone season, as would be expected.

To better examine the effect of coal type on the effectiveness of various NO_X control technologies, a comparison of NO_X rates for different combinations of boiler and coal types was performed. Table 7 lists information on the NO_X rates for facilities utilizing add-on controls, while Table 8 provides the same information for facilities utilizing combustion modifications or "other" controls. Since some of the technologies have not been applied to certain boiler and coal combinations, these are not included in the data presented in Tables 7 and 8. For example, no data was available for coal-fired boilers burning sub-bituminous coal that had SNCR controls.

Table 7. NO_X Rate Comparison of Coal-Fired units with Add-on Controls

Boiler Type	Number of Units	Unit Capacity Range (MW)	2004 Ozone Season NO_X Rate (lb/mmBtu)	2004 Non-Ozone Season NO_X Rate (lb/mmBtu)	Control Efficiency (%)
Coal-fired Boilers with SCR Bituminous Coal	93	90 to 1,300	0.09	0.51	82%
Coal-fired Boilers with SCR Sub-Bituminous Coal	19	330 to 825	0.11	0.56	80%
Coal-fired Boilers with SNCR Bituminous Coal	29	50 to 199	0.28	0.37	25%
Coal-fired Boilers with SNCR Bituminous Coal	8	200 to 700	0.25	0.41	38%

Table 7 lists NO_X emission rates (lb/mmBtu) for both the 2004 ozone and non-ozone seasons. These rates are based on NO_X measurements taken at each unit stack. The NBP sources do not report uncontrolled NO_X emissions or the emissions at the inlet of the control devices, such as SCR. Therefore, it is not possible to provide direct estimates of the effectiveness of controls. However, as shown in Table 7, the NO_X emission rates reported for the ozone season are well below the levels reported for the non-ozone season. The only possible explanation for this difference is that the SCR and SNCR controls installed on these units were, in general, not operated during the non-ozone season. Therefore, the difference between the reported NO_X rates for the ozone and non-ozone season to a large extent reflects the effectiveness of these controls when they were in operation during the ozone season. The NO_X reduction efficiency comparisons presented in this paper are based on this difference between the NO_X rates for the ozone and non-ozone seasons.

As indicated in Table 7, units with SCR controls achieved the highest NO_X reduction efficiencies. The average efficiency achieved by the boilers firing bituminous coals is approximately the same as that for the units firing sub-bituminous coals (82 vs. 80 percent). Therefore, these data show that SCR effectiveness was not influenced by the types of coal being fired in the NBP boiler installations.

Units with SNCR controls achieved a more modest emission reduction than those with SCR, with the average NO_X reduction effectiveness reported at 32 percent. An analysis was conducted to examine the SNCR effectiveness between small and large size units. The average NO_X reduction efficiency for SNCR systems installed on units smaller than 200 MW was 25 percent and that for units 200 MW and larger was 38 percent. This is in contrast to the common belief that SNCR is not effective on large size units.

It should be noted that there were not many large units included in the above SNCR comparison (a total of 8 units), compared to a relatively greater number of smaller units (total 29). However, this comparison at least shows that SNCR can be as effective on larger size units as on small units.

In Table 8, the ozone and non-ozone season NO_X rate information has been provided separately for different types of boilers. It should be noted that, for most of these boiler categories, the control devices are typically "fixed" and cannot be turned on or off, as is possible with the add-on controls (SCR and SNCR). In some cases, such as for cyclone-fired boilers, water injection has been used, which is the one technology identified that can be turned off during the non-ozone season. Some sources have not identified the type of technology or technique used for NO_X reduction (these sources identify the type of control used as "other"). It is expected that these sources are using techniques such as low-nitrogen fuels or combustion optimization for NO_X control purposes. In this case, it would be possible for a source to switch to a higher-nitrogen fuel, during the times when certain NO_x control goals do not have to be met. Also, sources using combustion

controls would have the option to reduce amounts of OFA, in the absence of an incentive to maximize NO_x control.

A comparison of the NO_X emission rates listed in Table 8 for the ozone and non-ozone seasons provides for interesting observations. NO_x emission data are available for several types of boilers firing both bituminous and sub-bituminous coals. These data show that the type of coal does not affect performance of controls used on the cell-burner and cyclone boilers, as the effectiveness of these controls is fairly comparable with the two coal types. However, this effectiveness is substantially better for the dry-bottom wall-fired and tangentially-fired boilers firing sub-bituminous coals, as compared to the same boilers firing bituminous coals. The controls used in these boilers have generally included combustion controls, consisting of LNB and/or OFA. The cyclone boilers have also used water injection, in some cases.

Table 8. NO_X Rate Comparison of Coal-Fired units with Combustion Modifications or "Other" Controls

Boiler Type	2004 Ozone Season NO_X Rate (lb/mmBtu)	2004 Non-Ozone Season NO_X Rate (lb/mmBtu)	Control Efficiency (%)
Cell burner (Bituminous)	0.31	0.45	32%
Cell burner (Sub-Bituminous)	0.35	0.50	30%
Circulating fluidized bed (bituminous)	0.12	0.08	-53%
Cyclone (Bituminous)	0.42	0.71	41%
Cyclone (Sub-Bituminous)	0.39	0.61	36%
Dry bottom turbo-fired (Bituminous)	0.33	0.43	24%
Dry bottom vertically-fired (Bituminous)	0.33	0.48	32%
Dry bottom wall-fired (Bituminous)	0.32	0.44	28%
Dry bottom wall-fired (Sub-Bituminous)	0.20	0.22	10%
Other (Bituminous)	0.30	0.33	11%
Stoker (Bituminous)	0.30	0.53	44%
Tangentially-fired (Bituminous)	0.28	0.33	15%
Tangentially-fired (Sub-Bituminous)	0.15	0.15	3%

The coal characteristics may not have a substantial effect on the performance of controls installed on cell-burner and cyclone boilers, due to the specific combustion designs used

in these boilers. One common aspect of these designs is the high temperature in the combustion zones of these boilers, which affects and promotes high NO_x generation rates.

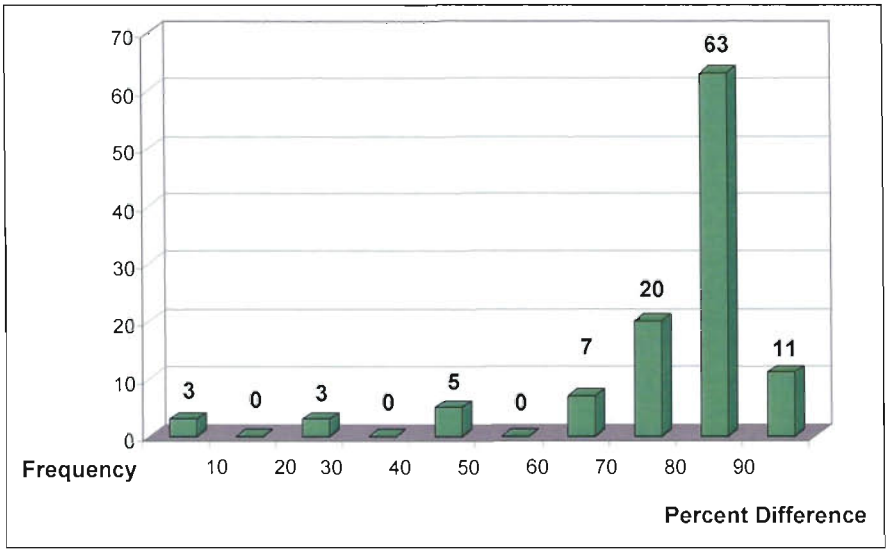
The effect of coal characteristics on the performance of combustion controls for certain types of boilers is a well-established fact, which is also being reflected in the Table 8 NO_X data for the wall- and tangentially-fired boilers.[5] Certain of these characteristics, such as high-volatile and low-nitrogen contents, of sub-bituminous coals provide for higher NO_X reduction efficiencies of combustion controls applied to these boilers.

For certain boiler categories in Table 8, the NO_X rate for the non-ozone season is higher than that for the ozone season. It is possible that some of these sources did not have an incentive to operate the controls at their maximum capabilities, because of the absence of any specific NO_X limit requirements during the non-ozone season. As discussed previously, it would be possible for these sources to turn off water injection systems (for cyclone boilers), use higher-nitrogen fuels, or reduce overfire air injection rates. However, some of the seasonal NO_X rate differences may have been caused by the normal variations in plant operations and characteristics of fuels fired by these sources.

SCR PERFORMANCE ANALYSIS

Further analysis of the SCR performance on coal-fired boilers was performed by examining data for individual coal-fired units equipped with SCRs. Specifically, the percent differences in NO_X rates were compared between the 2004 ozone and non-ozone seasons for all coal-fired units with SCRs. This analysis was conducted for the 112 coal-fired units that were retrofitted with SCR prior to 2004. Figure 2 provides a distribution of the percent change in NO_X rates between the 2004 ozone and non-ozone seasons.

Figure 2. Distribution of SCR Effectiveness Levels

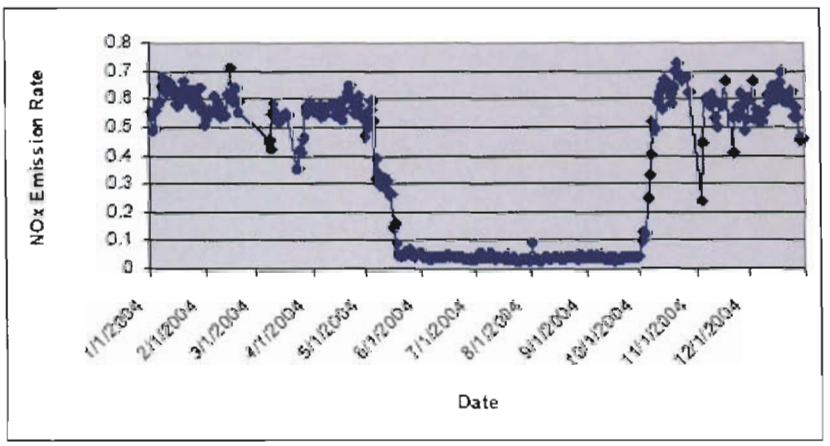


These percent changes in NO_X rates reflect the effectiveness of the SCR installations, plotted on the horizontal axis of the graph in Figure 2. Each bar in this graph represents a range of effectiveness or NO_X reduction efficiencies for the SCR installations (e.g., the second bar from the right shows units with effectiveness ranging from 80 to 90 percent). The vertical axis plots the number of installations for each range of effectiveness.

As indicated in Figure 2, the majority of units (94 units or 84 percent) achieved a minimum NO_X emission effectiveness of 70 percent. More then half of these units achieved significant NO_X emission reductions of 80 to 90 percent. Eleven units achieved an effectiveness of greater than 90 percent. The median percent reduction for these units was 83 percent.

Although not every unit may have limited their SCR operation to the ozone season, it is clear that the majority of units did operate their SCR systems only during this season and correspondingly achieved significant NO_X emission rate reductions. A typical pattern of an SCR operation solely during the ozone season is provided in Figure 3. The pattern is typical of actual data recorded from coal-fired units equipped with this technology. In this particular case, the unit is a bituminous coal-fired dry bottom, wall-fired boiler, equipped with both LNB and SCR. The unit achieved a NO_X reduction of greater than 90 percent between the non-ozone and ozone seasons. Not all units are likely to achieve such high efficiencies with SCR, due to design limitations or financial considerations that are a strong part of the cap and trade system under which these units operate. However, the ability to operate the SCR at these high efficiency levels is demonstrated by the data presented in Figure 3.

Figure 3. Ozone Season NO_X Emission Rate Reduction Using an SCR



It should also be noted that some SCR installations remained in operation during the entire 2004 period. The operation of SCR during the non-ozone season was most likely necessary for these installations to meet NO_X emission limits required by their air permits. As an example, Figure 4 shows NO_X emission data for a unit with a year-round

SCR operation. Since this unit was included in the overall analysis, it explains the reason for the very low performance of some of the installations reflected in Figure 2. However, this may not be the only reason for this low performance. It is highly unlikely that any SCR system was designed for some of the relatively low efficiencies (e.g., <50 percent) reflected in Figure 2. However, since the sources had the option to buy NO_X allowances from others or use allowances available from other units within their control, some of the SCRs may not have been fully utilized for economic reasons. Operational problems can also be another potential reason for certain installations.

Another measure of the SCR effectiveness is the controlled NO_X emission rate (lb/mmBtu) achieved at the outlet of an SCR system. Table 9 provides data on controlled NO_X emission rates for all units included in this analysis. The majority (approximately 90 percent) of units achieved NO_X emission rates of at least 0.15 lb/mmBtu. The median NO_X rate for all 112 units was 0.08 lb/mmBtu. A significant number of installations (20) achieved rates of at least 0.06 lb/mmBtu or lower.

Figure 4. Full Year NO_X Emission Rate Reduction Using an SCR

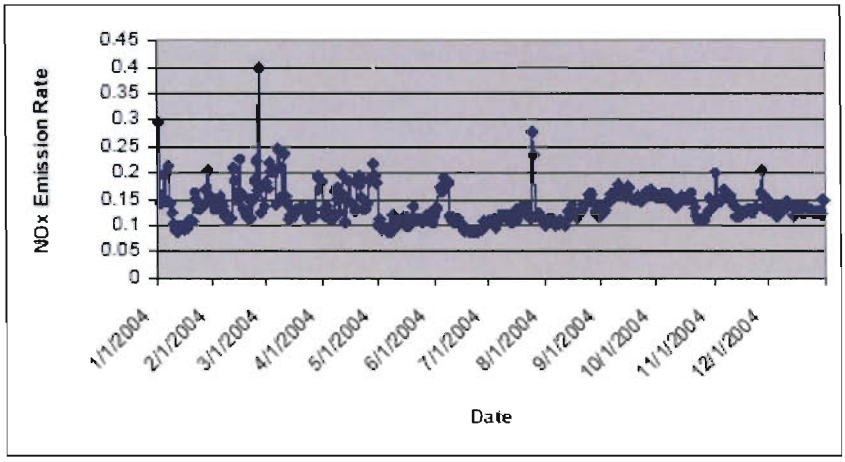


Table 9. NO_X Emission Rate Reductions of Coal-Fired Units with SCR

Category	Number of Units	Percent of Total Units
Total Units	112	
Units with NO_X Rate <= 0.05	11	10%
Units with NO_X Rate <= 0.06	20	18%
Units with NO_X Rate <= 0.07	35	31%
Units with NO_X Rate <= 0.10	71	63%
Units with NO_X Rate <= 0.12	84	75%
Units with NO_X Rate <= 0.15	100	89%

CONCLUSIONS

This paper presents the results of an analysis of the hourly emissions data submitted by sources subject to the NO_X Budget Program being managed by EPA. The main objective of this analysis was to establish the NO_X control effectiveness of various technologies used by these sources. The following key observations resulted from the analysis:

- Coal-fired boilers accounted for the majority of NO_X emissions and also achieved the largest NO_X emission reductions during the 2004 ozone season.

- A relatively large number of add-on controls (53 SCRs and 11 SNCRs) were retrofitted to various sources, between the 2003 and 2004 ozone seasons. The majority of the new SCRs were added to Electric Utility coal-fired boilers.

- The total number of SCR installations on coal-fired boilers during the 2004 ozone season was 112, which represented an electric generating capacity of approximately 55,000 MW.

- The coal-fired boilers reporting into the program mainly fired bituminous and sub-bituminous coals. The SCR effectiveness was not affected by the type of coal burned, as the SCR performance was approximately the same for installations firing these two types of coals.

- The majority of SCR installations achieved an effectiveness ranging from 80 to 90 percent, with several units achieving effectiveness greater than 90 percent. A controlled NO_X rate of 0.06 lb/mmBtu or lower was achieved by 20 units. It is to be noted that the average SCR effectiveness will be influenced by several factors, including the SCR design efficiency, the uncontrolled NO_X level of each source at the SCR inlet, the required controlled NO_X level at the stack for each source, and the level of SCR operation selected by each source, which may be affected by economic considerations associated with the cap and trade program under which these SCR installations operate. With these considerations and the fact that a significant number of SCR installations achieved close to or better than 90 percent effectiveness, it can be concluded that the SCR technology is capable of achieving at least 90 percent effectiveness.

- SNCR effectiveness for coal-fired boilers was about 32 percent, with larger units of greater than 200 MW capacity achieving better NO_X reductions.

- Most sources equipped with add-on controls utilized them only during the ozone-season, as these controls were not in operation during the non-ozone season

- The performance of combustion controls was significantly better for the wall- and tangentially-fired boilers firing sub-bituminous coals, compared to the performance with bituminous coals. However, the coal type did not have an impact on the control effectiveness for the cell-burner and cyclone boilers.

DISCLAIMER

The views and opinions expressed here are those of the author(s) alone and do not necessarily represent the policies of the U.S. Environmental Protection Agency.

REFERENCES

1. Code of Federal Regulations, 40CFR75, Continuous Emission Monitoring, July 1, 2002
2. Office of Air and Radiation, Clean Air Market Programs, EPA-430-R-04-010, NO_X Budget Trading Program: 2003 Progress and Compliance Report.
3. EPA website, Clean Air Market Programs, http://www.epa.gov/airmarkets
4. EIA Form 767 data for 2003, http://www.eia.doe.gov/cneaf/electricity/page/eia767hist.html
5. S. Khan, et. Al., "Updating Performance and Cost of NOx Control Technologies in the Integrated Planning Model," Mega Symposium, August 31- September 3, 2004 Washington, DC

Exhibit 10

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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OCT 26 2010

Ref: 8P-AR

Paul Tourangeau, Director
Air Pollution Control State
Colorado Department of Public Health and the Environment
4300 Cherry Creek Dr. S.
Denver, CO 80246-1530

RE: Regional Haze State Implementation Plan

Dear Mr. Tourangeau:

EPA has completed its review of the Regional Haze State Implementation Plan (RH SIP) documents that will be considered by the Air Quality Control Commission (AQCC) on November 18th. Specifically, we are commenting on the Best Available Retrofit Technology (BART) sources not covered under House Bill 10-1365. Our comments are provided in the enclosure to this letter. We will be providing comments on changes to Regulation Number 3 – Stationary Source Permitting and Air Pollution Emission Notice Requirements in our comments on the documents that will be considered by the AQCC on December 16th.

We want to emphasize that we will only come to a final conclusion on the adequacy of Colorado's BART determinations when we act on Colorado's RH SIP through public comment and rulemaking. We want to acknowledge the State's tremendous efforts in revising its RH SIP! We have appreciated working with you and your staff during the development of the plan. If you have any questions, please contact Laurel Dygowski of my staff at (303) 312-6144.

Sincerely,

Callie A. Videtich, Director
Air Program

Enclosure

ENCLOSURE

Modeling

1. EPA has reviewed the State's BART modeling protocol, dated April 12, 2006, as well the supplemental protocol dated April 15, 2010. We find that the methods and procedures established by the Division for modeling BART sources are consistent with *Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule* (the BART guideline). We also find that they are consistent with EPA's *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts.* Therefore, we consider the modeling results used to assess visibility improvement to be acceptable for the purposes of selecting BART.

2. Colorado selected Pre-control emission rates intended to reflect peak 24-hour average emission rates that may occur in the future under the source's current permit. The State used several methods to determine pre-control emission rates including use of 3 to 5 years of historical emissions rates or allowable short term permitted emission limits. EPA considers these to be reasonable methods for establishing baseline conditions in modeling the visibility benefits of potential control technologies.

3. EPA also reviewed the ammonia background concentration Colorado selected for use in the Calpuff visibility modeling. For sources located in northeast Colorado (e.g., Pawnee) and along the South Platte River, a domain-wide ammonia background value of 44 ppb is used, while a 1.0 ppb value is used in Northwest Colorado. Intermediate ammonia background values were used to model sources along the Front Range. EPA thinks that these values are reasonable for evaluating BART control strategies given the limited amount ammonia background monitoring data that is available.

Significant Comments

General

4. The State needs to include in the technical support document (TSD) the supporting information for the BART analyses and determinations. This includes, but is not limited to, the BART submittals from the sources, any other supporting materials submitted by the sources, modeling information, and cost information prepared by the State.

5. The State has provided a summary five factor analysis in Chapter 6 of the RH SIP and complete five factor analyses in Appendix C of the Technical Support Document (TSD). Since the majority of technical information is contained in the TSD five factor analyses, most of our comments pertain to these documents.

We do want to point out that any changes that are made to the five factor analyses need to be reflected in Section 6 of the SIP when appropriate.

6. The non-air quality impacts in the SIP and five factor analysis for each control measure are inconsistent. The State needs to provide consistent language on the non-air quality impacts in the SIP and five factor analysis. The State also needs to make sure that it does not include air quality impacts in this discussion or impacts that should be considered as part of costs or other factors in the BART determination. Also, the discussion on non-air quality impacts from wet scrubbing needs to include a quantitative analysis on the water usage of wet scrubbing versus dry scrubbing.

7. Aspects of the State's criteria for selecting NOx controls are very concerning. First, the criteria discriminate against SCR as a potential control option vis-a-vis SNCR and SCR and SNCR vis-a-vis other NOx control options. Under the criteria, if the cost of SCR is under $5,000/ton and the modeled visibility benefit is 0.20 delta-deciview or greater but less than 0.50 delta-deciview, SCR would be rejected automatically. But SNCR would be considered acceptable with those same $/ton and delta-deciview values. We find no rational basis for this distinction. And, we can think of no rational basis for establishing benchmarks for post-combustion controls but not for any other types of NOx controls. Second, the criteria appear to preclude a reasonable weighing of the five factors where the delta deciview benefit is well over 0.50 but the cost is higher than $5,000/ton. Craig is an example of this scenario – in the current projections.[1]

8. The cost effectiveness for SNCR and SCR for sources is well in excess of that found in several references for these control technologies. Further information on cost effectiveness is provided in the source specific comments.

9. The Division uses an emission rate of 0.07 lb/MMBtu in its analysis of the SCR control option for several sources. However, many EGUs that have installed SCR retrofits have demonstrated performance levels below 0.07 lb/MMBtu. A CAMD database search reveals that many boilers retrofitted with SCR are achieving an emission rate of 0.03 – 0.06 lb/MMBtu. Accordingly, the State needs to use an emission rate in the analyses that takes into consideration that which is currently being demonstrated at similar facilities.

10. The visibility results section in each analysis only addresses visibility improvements at the most impacted Class I area. Since visibility improvements are also likely at other nearby Class I Areas, the State needs to provide visibility modeling information for other Class I areas. This information will help inform the selection of BART.

[1] As we explain in our specific comments on Craig, the costs for SCR at Craig need to be recalculated and should be substantially lower.

11. We agree that modeling NOx and SO2 controls together, as the State has done in the "combo" scenario, will give a more realistic estimate of the expected visibility improvement. For example, the State's analysis shows that substantial visibility improvements are expected when combining controls at Craig. When SCR is combined with a SO2 emission limit of 0.10 lb/MMBtu (30 day rolling limit), the number of days with impacts above 0.5 dv at Mt. Zirkel is reduced from 207 to 57 days (for the three years of modeled meteorology). In addition, the 98th percentile impact is reduced from 3.73 to 1.17 dv. This level of visibility improvement should be a very compelling factor in selecting BART controls, but the State has only considered the improvement from individual control options. The State needs to consider the benefits of combining controls when selecting BART.

Cemex

SIP Language

12. The dryer limit for SO2 of 36.7 tpy is roughly 40 times the baseline emissions (0.89 tpy) used in the analysis. The State needs to establish an emission limit for the dryer that is closer to the actual emissions.

13. Page 52 - The State has not provided any costs for dry sorbent injection (DSI). Costs for this control option needs to be provided as part of the five factor analysis.

Cemex Five Factor Analysis

14. Page 2 - Please identify whether an alkali bypass is utilized by the Lyons kiln as it relates to control options considered for NOx.

15. Page 15 - Step 1: Identify All Available Technologies. The combination of LNB and SNCR also needs to be evaluated. The combination of LNB and SNCR would reduce NOx emissions from the Lyons kiln between 60% and 85%.

16. As established by EPA in considering the Best Demonstrated Technology for the Portland Cement Kiln NSPS, SCR is an available control option for cement kilns. It has also been recognized as available technology for cement kilns in EPA's *Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns* (November 2007), as well as the *Assessment of NOx Emissions Reduction Strategies for Cement Kilns - Ellis County* prepared by ERG for the Texas Commission on Environmental Quality (July 2006), as well as control technology reviews by the Florida Department of Environmental Protection. As such, the State has incorrectly determined that SCR is technically infeasible for cement kilns on the basis that is not commercially available. It would be more accurate for the State to determine that SCR is not

technically infeasible on the grounds that it is not applicable at the Lyons facility due to the unique design of the kiln. The State has provided adequate information in the analysis to allow the reader to conclude that the site specific application of SCR at the Lyons facility is not feasible.

17. Page 23 - In this section, the discussion notes that EPA's 2007 Alternative Control Techniques (ACT) Document Update primarily addresses the newer PH/PC style kilns. It also implies that SNCR applied to newer preheater/precalciner (PH/PC) kilns would achieve higher control efficiency than when applied to the older, modified long kiln design at the Lyons facility. Based on this assumption, the State has evaluated SNCR at a control efficiency of 45% on a 30-day rolling average. However, as documented in EPA's ACT document, the control efficiency of SNCR is highly dependent on, and increases sharply with, the inlet NOx concentration (see Section 8.4.3 of ACT document). Given that the uncontrolled emissions for the Lyons kiln (7.39 lbs/ton of clinker per 2002 APEN) are much higher than that for a PH/PC kiln (nominally 4.2 lbs/ton of clinker), a much higher control efficiency would be expected at the Lyons kiln. The stated emission limit of 255.3 lbs/hour (approximately equal to 4.06 lb/ton of clinker) underestimates the level of performance that can be achieved with SNCR alone and certainly underestimates the level of performance that could be achieved with LNB in combination with SNCR. Evidence shows that the Lyons kiln is able to obtain an emission rate of 3.0 lbs/ton clinker or lower with the combination of LNB and SNCR. In addition, the monitoring, recordkeeping, and reporting requirements for the Lyons kiln needs to include ammonia injection rate and ammonia slip as parameters.

18. Page 24-25 – SNCR combined with LNBs is a technically feasible option. The State has not provided an analysis for this option, citing the fact that Cemex did not submit information on this. The basis for doing a five factor analysis does not rely on whether a source submitted information. The State needs to provide an analysis for SNCR combined with LNBs.

19. Page 27 – The information provided on the RACT/BACT/LAER data and following discussion on page 28 belongs in the control effectiveness discussion, not in the discussion on selection of BART control. In addition, the BACT limits in the table have been incorrectly compared to the BART limit determined for the Lyons kiln. The BACT limit of 8.0 lbs/ton of clinker referenced for the Continental Cement kiln in Missouri is above even the baseline uncontrolled rate for Lyons of 7.39 lbs/ton of clinker and is therefore clearly not comparable. The BACT limit of 4.0 lbs/ton of clinker for the LaFarge kiln in Iowa is for a kiln that utilizes only good combustion practices, and not SNCR. For more comparable BACT limits established for kilns operating SNCR, see Appendix A of the ACT document. For the combination of SNCR and LNB (and typically staged combustion), Appendix A of the ACT

document gives BACT limits ranging from 1.95 to 2.85 lb/ton of clinker (over 30-day or annual averaging periods).

CENC

SIP Language

20. Page 57 – The State indicates that it has eliminated SCR because of excessive costs. The consideration of SCR also needs to include the visibility improvements.

21. Page 59 - The baseline (2006-2008) annual average emission rates (lb/hr) for the CENC BART sources has been incorrectly calculated, resulting in artificially high BART emission limits. The State used the maximum rated heat input capacity for the boilers, giving baseline annual average emission rates for boilers 4 and 5 of 179 lb/hr and 224 lb/hr, respectively. By contrast, the CAMD database shows that actual annual average emission rates for boilers 4 and 5 were 142 lb/hr and 163 lb/hr, respectively. Using the corrected baseline gives 12-month rolling average emission limits for boilers 4 and 5 of 92 lb/hr and 80 lb/hr, respectively. Similarly, it gives 30-day rolling average emission limits for boilers 4 and 5 of 106 lb/hr and 91 lb/hr, respectively. The State needs to revise the emission limits accordingly.

CENC Five Factor Analysis

22. Page 4, Table 4 - The emission factors have been computed using a conversion factor of 26 to convert from a lb/ton basis to a lb/MMBtu basis. This conversion factor is applicable to bituminous coals having a nominal heating value of 13,000 Btu/lb. Yet Table 4 shows heating values (2006-2008 average) that are lower than this value. The emission factors need to be corrected to reflect the actual heating values during the baseline period. Correcting the emission factors in this way may change the percent emission reductions presented in Table 1 for some pollutants where AP-42 was used to establish uncontrolled emissions.

23. Page 8 –The document states: "*Using alternative approaches to operations management, CENC proposes a new, enforceable permit limit to reduce peak lb/hr SO_2 emissions. CENC can employ a variety of options to reduce emissions: dispatch natural gas-fired capacity, reduce total system load, and/or reduce coal firing rate to maintain a new peak SO_2 limits. Since these two boilers already have CEMs and stack flow monitors installed, the CEMs could be used to demonstrate continuous compliance. CENC proposes reducing peak levels with limits at 280 lb/hr for Boiler 4 and 500 lb/hour for Boiler 5 on a 24-hour average basis. This option is technically feasible for Boilers 4 and 5.*" The five factor analysis goes on to indicate that CENC has proposed a limit of 280 lb/hour on Boiler 4 and 500 lb/hour on Boiler 5, yet the State's BART determination is the current Title V limit of 1.2lb/MMBtu on both units. The language above indicates that

CENC proposed a lower limit. The State needs to clarify whether CENC proposed to take a lower limit and why the State did not determine it was BART. Even if the State concludes that no new SO2 controls are reasonable for BART, an analysis needs to be provided to determine whether more stringent emissions limits should be imposed as BART based on actual emissions from the units. In addition, the emission limit needs to be based on a 30-day rolling average (see 70 FR 39172).

24. Page 15 – The State indicates that in the operating permit, the boilers are required to meet a PM limit of 0.1 lb/MMBtu but then goes on to state that the existing regulatory requirements of 0.07 lb/MMBtu represent BART. The State needs to clarify what the limits for PM are and the limit established needs to be based on current actual emissions, which appear to be lower than 0.07 lb/MMBtu.

25. Page 20 - The cost effectiveness for SNCR is well in excess of that provided by various cost references for SNCR. In particular, the costs given for Units 4 and 5 of about $2,900 and $3,350 per ton, respectively, are roughly double the range given in the 2000 NESCAUM study of $1,300 to $1,800 per ton (though the latter are in year 1999 dollars). The NESCAUM costs are specific to industrial boilers that would be in same size range as the CENC boilers and subject to many of the same retrofit difficulties. Therefore these factors are already inherent in the NESCAUM cost estimates. The costs for SNCR are higher than expected and need to be re-evaluated. Adjusting costs to current year dollars would not change this conclusion.

26. Page 20 - The cost effectiveness for SCR is well in excess of that provided by various cost references for SCR. In particular, the costs given for Units 4 and 5 of about $8,150 and $11,764 per ton, respectively, are several times the cost given in the NESCAUM study of $2,000 per ton (though the latter are in year 1999 dollars). The NESCAUM costs are specific to industrial boilers that would be in same size range as the CENC boilers and subject to many of the same retrofit difficulties. Therefore these factors are already inherent in the NESCAUM cost estimates. The costs for SCR are higher than expected and need to be re-evaluated. Adjusting costs to current year dollars would not change this conclusion.

Comanche

SIP Language

27. Page 60 – The text reflects PSCo's assertion that a third scrubber module on Comanche 1 and 2 is not feasible. The State needs to indicate that it has reviewed the ductwork and layout of the plant and either agrees or disagrees with PSCo's assertion. The TSD needs to provide details supporting the State's

conclusions – e.g., available space, site plan, space needed for an additional module.

28. Page 61 – The State can not eliminate SCR from consideration based on costs alone. The consideration of BART for SCR also needs to include the visibility improvement associated with it.

Comanche Five Factor Analysis

29. Page 3 - The emission factors have been computed using a conversion factor of 26 to convert from a lb/ton basis to a lb/MMBtu basis. This conversion factor is applicable to bituminous coals having a nominal heating value of 13,000 Btu/lb. Given that the coals used at Comanche are of the sub-bituminous type (with the exception of their treatment for NOx), it is more appropriate to use a conversion factor of 20 that reflects coals with a nominal heating value of 10,000 Btu/lb. An even more appropriate approach would be to use the representative heating value of 8,550 Btu/lb from the mines supplying the units as given in Table 3, or use recent APEN data. Correcting the emission factors in this way may change the percent emission reductions presented in Table 1 for some pollutants where AP-42 was used to establish uncontrolled emissions.

30. Page 5 – The State needs to evaluate other potential upgrades including improved operations and maintenance, use of more reagent, and keeping more spare parts on hand.

31. Page 9 – The State has titled this section "Additional equipment and maintenance" but the section actually evaluates emissions limit tightening. There is no analysis provided that looks at additional equipment and maintenance. The State needs to evaluate improved operations and maintenance as a possible upgrade. If the State concludes through this analysis that upgrades are not BART, the State needs to evaluate emission tightening based on current performance separately.

32. Page 12 - The Comanche BART units have achieved an average emission rate in the first six months of 2010 of around 0.06 lb/MMBtu. And on a 30-day calendar basis, the units achieved better than 0.08 lb/MMBtu, with exception of one month at Unit 2. Therefore, based on the demonstrated performance at the Comanche BART units, as well as that for similar units burning sub-bituminous coal, the units should be able to meet an emission limit of 0.10 lb/MMBtu or lower on a 30-day rolling average. Since lowering the emission limit is a zero cost option, the State needs to make this BART for these units.

33. Page 17 - The annualized costs used in the analysis are based on capital costs of $80,154,000 (or $247/kW) and $83,122,000 (or $248/kW) for Units 1 and 2, respectively (both in 2009$). By contrast, a recent survey conducted by the EUCG of SCR retrofits to EGUs in the 300-600 MW range revealed an average

installed cost of $124.28/kW and a maximum installed cost of $192.13/kW (both in 2004 dollars) (See http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/). Similarly, the DOE EIA reports SCR capital costs of $131/kW (2008 dollars) for EGUs of 500 MW in size (See http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf). The CUECost model was used to provide capital, operating, and maintenance costs for NOx control options. Cost estimates should be based on the *OAQPS Control Cost Manual*, where possible (see 70 FR 39166). Section 4 of the Control Cost Manual provides capital and annual costing procedures and data for combustion and post-combustion NOx controls. Therefore, since it is possible to use the Control Cost Manual, the State should use it for calculating costs for NOx controls. The BART Guidelines do allow for using other sources of cost information, but the information must be reasonable and valid. While we recognize that capital costs are highly dependent on site-specific factors. the CUECost model yields high capital costs for the Comanche facility. In addition, the analysis does not identify any site-specific factors that would result in capital costs that are at the high end of what has been observed in the industry. Using the Control Cost Manual to estimate capital costs for the Comanche BART units yields a cost of approximately $120/kW, obviously much lower than the CUECost result. Accordingly, the capital costs used in the analysis are higher than expected and need to be revised by the State.

34. The State needs to evaluate emissions tightening based on current operations. Reviewing NOx performance for the units from June 2009 to June 2010 on a 30 day calendar basis, leads to a conclusion that more reasonable limits for Units 1 and 2 would be 0.15 lb/MMBtu and 0.18 lb/MMBtu, respectively.

Craig SIP Language

35. In both the SIP language and the five factor analysis, the State needs to add "Existing Process with Optimized Limits" as a technically feasible control option and evaluate it through the five factors. The State needs to evaluate this separate of any upgrades and evaluate the emission limit the source could achieve based on current emissions and operations.

36. Pages 64 and 65 – The State can not eliminate SCR from consideration based on costs alone. The consideration of BART for SCR also needs to include the visibility improvement associated with it. Also, as stated below in our comments, the costs for SCR for Craig do not seem to have been calculated correctly. Even if $6200 and $6400 per ton were valid cost numbers for SCR, the State needs to consider the large deciview improvements (about 1 deciview per unit) associated with SCR in its determination of BART for Craig.

efficiency would be expected on a long-term basis than what was shown through actual testing.

17. Page 24 – The State should remove the statement "Thus if EPA desires higher control efficiency, the penalty is more visibility impairment downwind of the source." The State is making the argument that higher control efficiencies could result in more nitrogen deposition and possible visibility impairment at Rocky Mountain National Park. The State should simply provide their analysis without referring to what EPA may desire.

18. Page 24 – Table 10 – The column titled "Annual Controlled NOx Emissions" should be titled "Annual NOx Emissions".

19. Page 25 – The discussion pertaining to SNCR control efficiency seems to be repetitive of the discussion on page 23. Also, since it pertains to control efficiency, it should be in that section of the analysis.

20. Page 25 – Since the State has not provided information on SNCR in combination with LNBs, the State can not demonstrate that it has selected the most stringent level of control.

21. Page 27 - The selection of BART should state whether the emission limits are reflective of an alkali bypass system. If an alkali bypass system is utilized, the selection of BART should state what percentage of the kiln exhaust is permitted to flow through the bypass system in a 30-day period.

CENC SIP Language

22. Page 56 - The State should include in the SIP the assumed control efficiency for each control measure evaluated.

23. Page 56 – The State should provide a description of what SO2 emissions management is and why it would only achieve a 1 ton reduction.

24. Page 56 - The State indicates that the BART determination for SO2 is no controls with SO2 emission rates of 1.2 lb/MMBtu at both boilers. We assume this is the current limit for the source but the State should provide this information in the SIP.

25. Page 58 – The State indicates that NOx BART for Boiler 4 consists of the current regulatory requirements of low NOx burners with over-fire air but then goes on to say that the current regulatory requirements for Boiler 4 are amended to clarify that the current regulatory NOx BART control for Boiler 4 is actually low NOx burners with separated overfire air as specified in CENC's original BART application. This section is unclear. The State should specify what

regulatory requirements it is referring to and make it clear that the BART determination is LNB with SOFA.

CENC Five Factor Analysis

26. Page 8 - BACT determinations are only relevant when compared to like control technologies. Accordingly, we suggest revising any discussion of BACT determinations to address emission limits only for DSI on industrial boilers (if available).

27. Page 8, Table 5 - The "SO2 approximate emissions reductions (%)" should be given relative to a fully uncontrolled emission rate. Since both units are currently fully uncontrolled, the 2000-2005 or 2006-2008 baseline can be used. Percent reductions relative to the potential to emit (PTE) derived from permit limits are not relevant in making BART determinations.

Comanche SIP Language

28. Page 59 – Last line, the document states, "The supplier offers no upgrade in atomizer design to improve SO2 removal at Hayden." The text should say "Comanche."

29. Page 60 –The document states: *"No additional equipment or maintenance could achieve a lower limit."* The State should provide additional explanation for this statement.

30. Page 60 – The SIP indicates that a lower emission limit was not considered in part because a lower emission limit of 0.08 lbs/MMBtu would not provide a discernible visibility improvement. The five factor analysis does not indicate that this was a factor in determining the emission limit but that the determination relied on PSCos assessment that a lower limit was not achievable. The SIP and five factor analysis need to be consistent. In addition, given that a lower limit appears to be a zero cost option, it is hard to understand how lower limit is not reasonable

31. Page 60 - The State should indicate that since it determined Comanche has the most stringent PM stringent level of control, a five factor analysis is not required per the BART Guidelines.

Comanche Five Factor Analysis

32. Page 1 - The source classification code (SCC) for the Comanche BART units is listed as 1-01-002-02. As given in AP-42, the correct SCC for Unit 1, a dry bottom, tangentially fired boiler firing sub-bituminous coal is 1-01-002-26. The correct SCC for Unit 2, a dry bottom, wall fired boiler firing sub-

bituminous coal is 1-01-002-22. This may affect the selection of emission factors used in the remainder of the analysis.

33. Page 5-6 – There are numerous typographical errors in Section A, including repetition of data and a reference to Hayden instead of Comanche.

34. Page 6 - The percent emission reductions presented for Comanche Units 1 and 2 in this section are 76% and 82% respectively. However, these values have been calculated by comparing the 2009 annual emissions to the 2005-2007 annual average emissions. As the emission limit of 0.12 lb/MMBtu was not applicable until July 1, 2009, the full benefit of the LSD installations is not reflected until after that date. For example, in the first six months of 2010, CAMD data indicates that Unit 1 achieved an emission rate of 0.06 lb/MMBtu, giving a control efficiency of 88.2% over the 2005-2007 baseline. Similarly, Unit 2 also achieved an emission rate of 0.063 lb/MMBtu, giving a control efficiency of 87.9%. This is not surprising since most recent LSD applications have demonstrated control efficiencies of around 90%. The State should compute control efficiencies relative to the actual emission rates that were observed after the emission limit became applicable on July 1, 2009.

35. Page 11, Tables 6 and 7 – The text on the bottom of Page 10 indicates that the combo modeling assumed an SO2 emission rate for the Comanche BART units of 0.12 lbs/MMBtu. However, the tables show 0.07 lbs/MMBtu. Please correct this inconsistency.

36. Page 12 - This section states that *"Table 1, estimated control efficiencies for the baghouse are over 95% for PM and over 85% for PM10."* However, Table 1 actually shows control efficiencies over 99.5% for PM and over 98.4% for PM10. Moreover, the control efficiencies stated in the text are not indicative of the level of control routinely achieved with fabric filter baghouses. Please revise the text to reflect the level of emission reductions expected for this BART selection.

37. Page 12, Table 8 - The table shows control efficiencies based on permit emission limits not actual emissions from stack test results. In addition, the permitted emission limits are at least a magnitude higher than what the baghouses are achieving in practice. As a result, the percent reductions shown are far below what is routinely demonstrated by fabric filter baghouses. Thus, the percent emission reductions in the table should be based on the stack test results.

Craig SIP Language

38. Page 64 – For the PM BART determination, the State should indicate how they determined that the current emission limits represent the most stringent level of control, i.e. review of recent BACT determinations. The State should also

indicate that since it determined it is the most stringent level of control, a five factor analysis is not required per the BART Guidelines. The same language should be added to the TSD five factor analysis.

39. Page 64 – The SIP states that SNCR and SCR were found to be technically feasible for NOx. The five factor analysis indicates that in addition to SNCR and SCR, LNB/ULNB and a neural network system are technically feasible. All control scenarios found to be technically feasible should be stated in the SIP.

Craig Five Factor Analysis

40. Page 1 - The SCC for the Craig BART units is listed as 1-01-002-02. As given in AP-42, the correct SCC for a pulverized coal, dry bottom, wall fired boiler firing sub-bituminous coal is 1-01-002-22. This may affect the selection of emission factors used in the remainder of the analysis.

41. Page 1 – The State says that the units at Craig were approved for Early Election for NOx. It would be helpful if the State provided an explanation of what this is.

42. Page 1, Table 1 - The percent emission SO2 reductions provided for Units 1 and 2 of 77.6% and 79.5%, respectively, underestimate reductions given that the wet scrubbers achieved an extremely high level of performance of around 0.05 lb/MMBtu between 2006 to 2008 (as given in Table 2). It appears that the percent emissions reductions for SO_2 have been estimated relative to CAMD emissions data for the "pre-control" period 2000-2001. However, since (less efficient) wet limestone scrubbers were in operation in 2000-2001, the emission reductions do not represent the true level of control relative to an uncontrolled baseline. When compared to the uncontrolled emissions (derived from AP-42), the emission reduction achieved by the scrubbers on Units 1 and 2 is approximately 93.8%. In fact, Units 1 and 2 are currently required by the RAVI Long-Term Strategy, as approved in the SIP in 2001, to achieve at least a 90% reduction of SO_2 (on a 90 boiler operating day average). As we have commented before, control efficiencies should be provided relative to an uncontrolled baseline so that they may be compared to established performance levels for the control option under consideration. We do recognize that the BART determination is made relative to emission reductions in an established baseline period. Therefore, we recommend providing the control efficiency relative to the uncontrolled emissions both for any controls installed during the baseline period and any additional control options under consideration.

43. Page 4 – The State should list "emissions tightening with current operations" as a technically feasible option and evaluate this option through the five factor analysis.

44. Page 7 - Control efficiencies should be provided relative to an uncontrolled baseline so that they may be compared to established performance levels for the control option under consideration. We do recognize that the BART determination is made relative to emission reductions in an established baseline period. Therefore, we recommend providing the control efficiency relative to the uncontrolled emissions both for any controls installed during the baseline period and any additional control options under consideration.

45. Page 9, Table 9 - The control efficiency for PM10 should be revised to reflect correction of the uncontrolled emission factor as described above for SO2 emissions.

46. Page 9 - This section states that the units are exceeding a control efficiency of 95%. However, fabric filter baghouses are capable of achieving much higher control efficiencies of at least 99%. Moreover, the control efficiencies stated in the text are not indicative of the level of control routinely achieved with fabric filter baghouses. Please revise the text to reflect the level of emission reductions expected for this BART selection.

47. Page 13 - The NOx percent reduction rates identified in the AWMA study the State references in its analysis are based on an assumed inlet concentration of 0.5 lb/MMBtu (as achieved by combustion controls) and not actual inlet data. By contrast, the inlet concentration at the Craig Units 1 and 2 would be 0.278 and 0.271 lb/MMBtu, repectively. Therefore, it is appropriate to use the emission rates from the AWMA study, but not the reduction efficiency when establishing the expected performance for post combustion NOx controls.

48. Page 16, Table 13 - There is a discrepancy between the State estimated control efficiency reported in the table (83.2%) and that shown in Table 10 (74.0%).

Hayden SIP Language

49. Page 66 – The State provides a discussion of possible scrubber upgrades. In the discussion of additional equipment and maintenance the State says that "This emission limit is 0.13 lbs/MMBtu." There is no explanation provided for why this is the emission limit evaluated for this type of upgrade and the State should provide that information in the SIP.

50. Page 67 – It would be helpful if the State provided an explanation in the SIP as to how the control efficiencies for semi-dry FGD upgrade and an additional scrubber vessel were determined for each unit. From the cost tables, it appears that the FGD upgrade would obtain less benefit at Unit 2 than at Unit 1 but the additional scrubber module would obtain more benefit at Unit 2 than Unit 1.

51. Page 67 – The third table on the page is confusing. First, the State should explain what the daily maximums represent. In addition, the table lists "Semi-

Dry FGD (LSD)" twice but there is no explanation at to what this control is or how the associated control efficiencies were calculated.

52. Page 68 - The State should indicate that since it determined Hayden has the most stringent PM level of control, a five factor analysis is not required per the BART Guidelines.

53. Page 69 – We suggest removing the language that pertains to the costs and visibility benefits for SCR falling within the guidance criteria and replacing it with language to the effect that costs are reasonable given the significant visibility benefits, thus the State has determined SCR is BART.

Hayden Five Factor Analysis

54. Page 1 - The SCC for the Hayden BART units is listed as 1-01-002-02. We suggest that the appropriate SCC for the boiler type and coal type should be listed. As both bituminous and sub-bituminous coals were fired during the baseline period, list the SCC for the coal predominately used.

55. Page 1,Table 1 - The last sentence should read "All equipment commenced operation."

56. Page 3 - Please provide the percent of Colowyo and Twentymile coal fired during the 2006-2008 baseline period.

57. Page 4 – In addition to possible scrubber upgrades that the State has evaluated, SO2 emission limit tightening based on current operations should be evaluated in the five factor analysis separately from the upgrades.

58. Page 7 - Control efficiencies should be provided relative to an uncontrolled baseline so that they may be compared to established performance levels for the control option under consideration. We do recognize that the BART determination is made relative to emission reductions in an established baseline period. Therefore, we recommend providing the control efficiency relative to the uncontrolled emissions both for any controls installed during the baseline period and any additional control options under consideration.

59. Page 11, Table 12 - Table 12 does not show the cost effectiveness ($/dv) for the additional scrubber module control option. Please include this metric for this control option. Also, please also include the cost effectiveness ($/dv) for the combo control option.

60. Page 9 - This section states that the units are exceeding a control efficiency of 95%. However, fabric filter baghouses are typically capable of achieving much higher control efficiencies of at least 99%. Moreover, the control efficiencies stated in the text are not indicative of the level of control routinely achieved

with fabric filter baghouses. Please revise the text to reflect the level of emission reductions expected for this BART selection.

61. Page 15 - Control efficiencies should be provided relative to an uncontrolled baseline so that they may be compared to established performance levels for the control option under consideration. We do recognize that the BART determination is made relative to emission reductions in an established baseline period. Therefore, we recommend providing the control efficiency relative to the uncontrolled emissions both for any controls installed during the baseline period and any additional control options under consideration.

62. Page 21, Table 20 - Table 20 does not show the cost effectiveness ($/dv) for the additional scrubber module control option. Please include this metric for this control option.

Martin Drake SIP Language

63. Page 71 - The State should provide the visibility improvement for Unit 5 associated with dry FGD at 76% and 90% control. The State has determined that this control is technically feasible for Unit 5 and costs have been provided but not the expected visibility improvement.

64. Page 72 – The State should explain why it determined that 0.13 lbs/MMBtu is BART when the cost and visibility tables show that 0.12 lbs/MMBtu was evaluated.

65. Page 72 – The State should include language in the particulate matter section that indicates that since the units currently have the most stringent control options in place, no five factor analysis is needed per the BART Guidelines.

66. Page 72 – It would be helpful for the State to include the emission rate evaluated for each NOx control in the "NOx Control Comparison" tables.

67. Page 74 – The State should explain why the proposed NOx limits for all three units are higher than the emission rates that were used to calculate cost effectiveness and visibility improvement.

Martin Drake Five Factor Analysis

68. Page 3 - Please provide the percent of various coals fired during the 2006-2008 averaging period used to establish coal specifications in Table 4

69. Page 3, Section III – The State indicates that the initial BART submittal from Martin Drake indicated that burning sub-bituminous coal would have little effect on NOx emissions. The State should indicate whether it would have an

effect on SO2 emissions as well. The section goes on to say that this effect is boiler specific. The State should clarify what this statement means.

70. Page 9 – The analysis provides a discussion on the additional energy costs associated with LSD and DSI. This discussion belongs in the energy and non-air quality impacts section.

71. Page 12, Tables 10-12 - The annualized costs are based on a 5.5% cost of recovery factor, while the State has used 7% at other facilities. Please explain why a CRF of 5.5% has been used for CSU Drake.

72. Page 14 –The document states: *"The State finds the negative environmental impacts of a traditional wet FGD control system as well as the potential space limitations at the Drake plant far outweigh minimal incremental SO2 emission reduction benefits (tons of SO2 reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when compared to LSD or the pilot NeuStream-S FGD scrubber when applied to the small boilers at the Drake Plant (Unit 5 - 51 MW, Unit 6 - 85 MW, Unit 7 - 142 MW)."* The State has not provided the incremental visibility improvement of wet FGD compared to LSD or the pilot Neustream and this language should be removed. Also, it is not appropriate to say that the potential space limitations outweigh the potential visibility benefits; available space is not one of the five factors. The State could simply provide that the non-air quality environmental impacts outweigh the visibility benefits from this technology and that the State therefore has eliminated it as BART.

73. Page 22 – The State lists LNB + OFA in Table 17 as being partially installed. It is not clear what this means and the State should provide further explanation as Table 1 only indicates that the source has installed LNBs.

74. Page 25 – The cost effectiveness for OFA for Unit 5 is not correct. The table in the SIP shows the correct number of $683.