

Comments and Responses to NDDH Regarding U.S. EPA Region 8's July 31, 2008 Comments and Plains Justice July 30, 2008 Comments on NDDH Preliminary NO_x BACT Determination for Milton R. Young Station (MRYS)

September 22, 2008

Burns & McDonnell (B&McD), and their SCR consultant, Tackticks LLC, along with the Energy & Environmental Research Center (EERC) of the University of North Dakota, have reviewed the EPA's comments (U.S. EPA, 2008), those of the Department of Justice's commenter, Hans Hartenstein (Hartenstein, 2008), and Plains Justice (Plains Justice, 2008). These are responses regarding selective catalytic reduction (SCR) technology feasibility and non-SCR concerns pertaining to the NDDH's Preliminary NO_x BACT Determination for Nitrogen Oxides for Milton R. Young Station Units 1 and 2, dated June 2008 (NDDH, 2008). We continue to believe that the administrative record fully supports a finding by the North Dakota Department of Health ("NDDH") that separated over-fire air (SOFA) in conjunction with selective non-catalytic reduction (SNCR) technology is Best Available Control Technology for electric generating units that utilize cyclone burners firing North Dakota lignite. The following sections address specific topics mentioned in the EPA's comments and other issues in greater detail.

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General Regulatory Considerations

In determining BACT, the limits placed on MRYS will be required for the plant's lifetime. In order for the units to run, emission rates will need to be met. Any emissions limit exceedance can result in a violation subject to significant financial penalties, injunctive relief and possible unforeseen equipment changes or plant outages. Many of the boilers referenced in EPA's report are not subject to New Source Review but some other form of regulation such as the NOx State Implementation Plan (SIP) Call program. There is a significant difference in NOx SIP and NSR. The NOx SIP Call is a seasonal (May to October) cap and trade program. Under this program, a utility's NOx emissions are capped to a level below historic emissions. The utility has the option to apply pollution controls and/or buy offsets from other utilities. Under the NOx SIP program, a problem with the pollution control equipment can be overcome by buying allowances while continuing to operate their units. NSR requires the controls be operating continuously and properly during plant operation.

1. EPA is deviating from a case-by-case BACT analysis by casting a wide net over SCR and insisting that it will work on all fuels and boiler types. Based on their comments, and those of DOJ's expert, in essence, "any problem can be overcome, SCR has been used successfully everywhere and no long term problems exist". However, as detailed later, our experts have found many instances where SCR was not used as a reduction strategy, or was unsuccessful.

In Minnkota's case, the combustion process from cyclone boilers and the North Dakota lignite makes application of SCR infeasible. Our specific combustion issue revolves around the size and type of combustion products produced in a cyclone-fired boiler when firing a high-sodium-containing lignite. The cyclone combustion process occurs at higher temperatures and different air distributions than other boiler types. Cyclone firing combustion products are partitioned between the slag that flows out of the bottom of the furnace and the flue gas containing impurities. The flue gas impurities are enriched in alkali (sodium and potassium) species relative to other boiler types. These species are known to blind and poison the SCR catalyst. The impurities of concern are vaporized during the cyclone combustion process to form a gas and upon gas cooling these gas phase impurities will condense to form aerosols or small particles that will deposit on the surface and in the pores of SCR catalysts. Once deposited, these alkali-rich materials will react with other gas phase species and deposited particles causing blinding or can react with active sites in the catalyst causing poisoning. This is well documented by Tackticks (see Appendix A) as well as by the DOJ's expert (Hartenstein). In a TESCR system, the flue gas passes through a precipitator and scrubber prior to reaching the SCR system. Large particles can be removed from the precipitator and scrubber. However, the removal of aerosols and small particulate (less than 2 microns in diameter) is dependent on the aerosol and small particle size and composition. Sodium, potassium and alkali aerosols are not easily removed from the precipitator and scrubber and no vendors will guarantee removal rates. In a TESCR application for a high-sodium lignite fired cyclone, the TESCR catalyst is likely to be exposed to appreciable concentrations of sodium, potassium and alkali concentrations. The second part of this case-by-case BACT evaluates the fuel used. North Dakota lignite is known to have a much higher levels of catalyst poisoning constituents than other lignite types. The lethal combination of the high temperature cyclone firing combustion process and high levels of catalyst poisoning constituents present in the lignite make this specific application technically infeasible.

2. Some catalyst vendors have "guaranteed catalyst operation" for the Minnkota units, according to DOJ's expert. EPA has taken a "guarantee" as a demonstration that the SCR application for North Dakota lignite is commercial. From the discussion above, EPA would lead us to

believe that the high sodium levels and the cyclone combustion processes resulting in an abundance of SCR blinding and poisoning alkali species in the flue gas are inconsequential since a vendor will provide equipment to Minnkota. However, Minnkota has to evaluate a guarantee on the long term viability of meeting an emissions limit, including catalyst maintenance and replacement requirements, and therefore we must question the vendor on numerous issues.

- **Does the vendor look at the long term compliance obligations that Minnkota will be subject to?** The vendor guarantees and contractual language will vary from project to project. For example, a vendor could guarantee a one time performance of their product and meet their obligation. However, the end user is stuck with a product that does not provide long term compliance. Some vendor language may guarantee a product for a longer period but assumes that certain operational conditions are met during that time period. If the operating conditions deviate, the vendor is no longer responsible. It is not unusual for vendors to guarantee performance then have to settle claims or change offer. Yet, Minnkota will still need to meet emission limits for the plant's lifetime.
 - **The only test data (Coyote) for a cyclone boiler burning North Dakota lignite resulted in significant catalyst blinding and plugging in a short time period. How does a vendor resolve this issue?** Burns & McDonnell and EERC contacted Haldor Topsoe (HT) about this issue (B&McD and EERC, 2007). HT participated in the Coyote test that showed catalyst blinding and plugging was so severe that they could not make catalyst reactivity measurements. HT suggested that they would increase the pitch of the catalyst but had no solution for severe blinding and plugging of the catalyst pore structure. HT indicated that there were no catalyst designs available that would alleviate the severe blinding and plugging of the pore structure due to the high levels of sodium-rich aerosols present in flue derived from the cyclone-fired combustion of ND lignite.
3. EPA has claimed the Coyote pilot-scale SCR test to be completely invalid and no conclusions can be made. The Coyote test was developed by a consortium of Cormetech (catalyst vendor), Haldor Topsoe (catalyst vendor), Hitachi (SCR system provider), EPRI (research

agency), US. DOE, Alliant Energy, Otter Tail Power, Ameren, Dynegy, and Lignite Energy Council. This pilot test was intended to evaluate the fouling potential of SCR on lignite coal. DOJ's expert claims the test was fatally flawed, yet the participants in the test included vendors that design and install SCR systems as well as end-user utilities that have applied SCR on their boilers. This team was competent and, like many pilot tests, it is meant as a learning opportunity. Certainly, further testing may change some of the testing parameters, but the intent was to evaluate the system. Minnkota believes this testing was valid for its intended purpose and from this sole test, it was determined that there are significant impediments to using SCR on MRYS. The test results showed catalyst blinding and plugging due to sodium and potassium rich species. Peer reviewed literature written by many authors have verified that sodium and potassium species are fatal to the catalyst life.

Corrections, Clarifications and Omissions of Hartenstein and EPA Comments

The EPA's SCR technology comments (U.S. EPA. 2008) rely heavily on their interpretation of information mostly repeated from earlier comments to Minnkota and opinions expressed by the Department of Justice's (DOJ) commenter (Hartenstein, 2008), Many of these comments need to be clarified for the record.

1. Hartenstein implies that lignite-fired boilers are significantly represented among the 30,000 MW of SCR systems installed in Europe. This is misleading and substantially incorrect. Very few of the many SCRs retrofit in Europe were installed on lignite-fired utility boilers. Tackticks has advised that to the best of their knowledge, they are aware of SCR being originally installed at only two plants, and neither of these plants is operational today.
2. The EPA argues that NDDH's preliminary BACT Determination does not properly compare the emissions from other coal-fired boilers with high fuel sodium content to other boilers that successfully operate SCRs firing Powder River Basin (PRB) coal with high dust SCRs in the United States and are comparable to the Young Station boilers for their flyash alkali contents. The EPA ignored the Department's supporting detailed information by EERC that explains

why SCRs are not able to tolerate the higher levels of alkali species contained in flue gas such as exhausted from the MRYS boilers as compared to the PRB coal fired boilers..

3. In addition, the EPA and Hartenstein did not provide any substantial technical information that demonstrates that effective solutions to prevent or remove pore pluggage and blinding of SCR catalyst from sodium- and potassium-rich species present in the flue gas stream exhausted from a North Dakota lignite-fired cyclone boiler, whether installed in a conventional hot-side or cold-side application downstream of a wet scrubber, have been developed by catalyst vendors.
4. Hartenstein did not demonstrate he had an understanding of Center lignite characteristics and variability issues. Specifically, he did not understand how soluble sodium is used to define the abundance of organically associated sodium in lignite and how sodium will vary because of the abundance of other ash forming components in the coal. The abundance of sodium and other ash forming components vary dramatically and uniquely in North Dakota (Fort Union region) lignite coal and result in operational challenges. Hartenstein does not understand the differences between Fort Union lignite and Texas lignite. He indicates that the installations of SCR on Powder River Basin (PRB) subbituminous coal and testing on Texas lignite indicate feasibility for SCR on ND lignite even though the levels of sodium in typical PRB coal and Texas lignites are very low (0.7 to 1.5% Na₂O) as compared to 4.4 % Na₂O for Center lignite. The amount and form of alkali species in the coal along with combustion processes influence their ability to be enriched in the aerosol and fine particle fraction of the fly ash. The size and composition of the particle along with gas velocity determines their ability to penetrate and deposit on SCR catalyst passages and in pores and cause plugging, blinding, and poisoning.
5. Hartenstein did not address the issue of the partitioning of ash-forming species between the slag and fly ash components in cyclone-fired systems that result in an enrichment of sodium and other flame-volatilized species in the flue gas. These flame-volatilized species will condense homogeneously to produce abundant sodium and potassium-rich aerosols because

of the lower level of entrained solid ash particles in cyclone combustion-derived flue gases relative to pulverized coal combustion derived flue gas.

6. Hartenstein did not address the formation of aerosols and how that can impact SCR performance. The key issue for high sodium Fort Union (North Dakota lignite) coals fired in cyclone-fired boilers is the abundance of alkali-rich aerosols in the flue gas that can penetrate into the pores of SCR catalyst, causing blinding and poisoning. This is an issue for high dust and low dust / tail-end SCR applications. He appears to not be familiar with the diffusion mechanism of transport of aerosols deep into the SCR catalysts that can cause poisoning and plugging. Hartenstein appears to confuse the importance of catalyst pitch relative to pore plugging and blinding. He incorrectly suggests that catalyst pitch will solve the pore plugging and blinding problem. Using wider pitch catalyst does not eliminate the penetration of alkali-rich aerosols deep into SCR catalyst causing pore plugging and blinding problems. The impact of such aerosols that pass through the electrostatic precipitator (ESP) on the performance of low dust SCR applications was not discussed by Hartenstein. This fine ash that escapes from the ESP is finer than the bulk flyash and has a higher catalyst plugging potential due to a higher tendency to agglomerate. In addition, Hartenstein did not consider information provided on Powerspan barrier discharge reactor pilot slipstream testing that showed alkali rich accumulations downstream of the Unit 1 ESP at the MRY station.
7. Hartenstein's knowledge of gas-solid reaction mechanisms to form sulfate and pyrosulfate phase *in situ* in SCR catalysts appears to be very limited and was not adequately addressed.
8. Hartenstein did not discuss the recent literature on catalyst poisoning studies in Europe associated with cofiring high alkali (Na and K) containing biomass. This testing has showed significant poisoning of catalysts due to alkali aerosol penetration into catalysts and the subsequent reaction with catalyst active components causing poisoning.
9. Hartenstein did not offer information that more than 20,000 MW of lignite fired units in Germany were not required to install SCR in order to comply with the national regulation, or that even new lignite-fired units being installed today in Germany are not equipped with SCR

of any type. He did not state that Germany had only one cyclone-fired boiler operating with a LDSCR (Walsum Unit 7), or that the unit burns bituminous coal; nor did he advise that Voitsberg Unit 3, a boiler in Austria firing lignite coal, only ran for a short time with a high-dust SCR and was subsequently shutdown and demolished. He states that TESCR technology was “generally adopted as a universally applicable SCR solution for all types...” but failed to mention that there has never been another TESCR built after Siersdorf, (which was finished in early 1991 and has subsequently been decommissioned), in the United States or Europe. To the best of our knowledge, there is no TESCR anywhere in the world on a lignite-fired utility boiler. He cites “Ceram’s extensive experience with lignite..”, but fails to report that this consists of only one plant with Ceram catalyst having operated for a short period of time on lignite and a few pilot programs, so that it is dubious to say that this vendor has extensive experience on lignite fired boiler SCR plants (see Appendix A). There are numerous other instances of missing or factually incorrect information attributed to Mr. Hartenstein discussed in Appendix A.

10. Again, the EPA fails to recognize conclusively that ash chemical and physical properties of the Texas lignite (Wilcox formation) that TXU proposes to burn at the new Oak Grove powerplant where SCR is being installed (but has not yet begun operation) do not represent what is fired in North Dakota, and therefore technical feasibility and expected performance in a Texas lignite-fired pulverized coal boiler SCR application is not transferable to North Dakota lignite-fired cyclone burner units due to the significant differences in flue gas and ash chemical and physical properties. The composition of the Texas lignite fired at Martin Lake, where SCR mini-SCR pilot testing has been conducted, is typical of the composition of lignite fired at Sandow, with sodium oxide levels in the Texas lignite ash equal to 0.7%. The levels of sodium oxide in Center lignite average 4.4% and can be as high as 13% in as-fired samples. Hartenstein (2008) does not provide information on chemical composition of any fuels that are comparable to high sodium ND lignite where SCR installation have been installed and tested or successfully operated.

11. No examples were provided of on-line cleaning methods nor catalyst that would prove resistant to damage from such methods that would be effective in removing surface blinding and pore plugging deposits such as those seen in the Coyote pilot test catalyst even with the suggested edge erosion prevention measures in place. Hans Hartenstein does not address this issue in his comments. Hartenstein implies in his report (2008), that catalyst that has been poisoned by sodium compounds can be regenerated in-situ, and that this technique is well developed. There is extremely limited experience with in-situ catalyst cleaning on coal-fired units. It has never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst (see Appendix A).

The following discussion will provide information on the following topics relevant to the EPA's comments: an SCR technology review and update; the variability of lignite; results of Coyote pilot testing; soluble sodium; differences in flue gas composition; catalyst poisoning, blinding and plugging; applicability of SCR development for Texas lignite; SCR catalyst erosion and cleaning; pilot testing for SCR catalyst; vendor guarantees for TESCR; temperature variations for HDSCR; Burns & McDonnell's SCR experience; comments by Sargent and Lundy on SCR experience; comments on Hans Hartenstein's qualifications for SCR expert opinions; fuel switching/blending/cleaning; non-SCR controls; and conclusions.

SCR Technology Review and Update

The literature provided by Hartenstein in his expert report (Hartenstein, 2008) did not provide any new information that would indicate the SCR technology is feasible for NO_x reduction at the MRY plant. Much of the information Hartenstein provided was reviewed earlier by the Energy & Environmental Research Center (EERC) and Burns and McDonnell. In addition, the reports provided by Hartenstein were not peer reviewed and were derived primarily from companies who have vested interests in the SCR technology and typically do not discuss problems and challenges. The reports from EPRI provided more useful information on the characteristics of the Texas lignite.

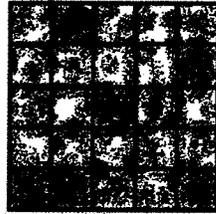
Hartenstein (2008) provided little information indicating that he is familiar with blinding and poisoning processes involving alkali (sodium and potassium). A demonstrated understanding of

the blinding, plugging, and poison due to firing alkali-rich fuels is vital in determining the feasibility of SCR technologies. Much of this background information has been provided in EERC's previous comments (2007 and earlier). In addition, a significant amount of work has recently been conducted in Europe on blinding and poisoning of SCR catalysts associated with firing biomass alone and with coal. Much of the discussions are focused on the impact of alkali-rich aerosols on catalyst deactivation.

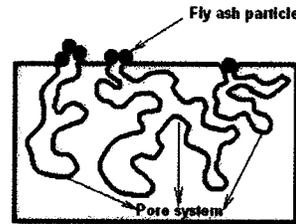
Since Hartenstein does not adequately address key mechanisms of catalyst deactivation and poisons, it is appropriate to provide a summary of the technical information. Guo (2006) who conducted testing of catalyst deactivation studies described the mechanisms of catalyst deactivation as shown in Figure 1. There are four primary types of catalyst deactivation.

- The first is channel plugging and is impacted by so called "popcorn ash" or in many cases typical of ash deposit fragments. Channel plugging is largely driven by the size of the ash materials carried back into the flue gas treatment system and can typically be controlled by the use of large particle ash screens to remove the ash, or by providing larger pitch catalyst.
- The second type is pore plugging by small fly ash particles. Small particles sometimes become lodged in the openings to the catalyst pore system and can cause plugging. These particles are typically not bonded and can be removed by various cleaning technologies.
- The third type is masking of the macrosurface by a dense phase. These phases that form are typically sulfates. The sulfates have formed as a result of in-situ sulfation of deposited alkali and alkaline earth materials.
- The fourth type is poisoning of the active sites in the catalyst. The active sites in SCR catalyst can be poisoned by the diffusion of various types of aerosols. The aerosols will diffuse into the pores and react with the active components of the catalyst.

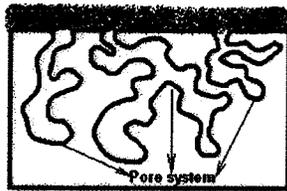
Channel plugging: ash particles plug the monolith channel



Plugging: Microscopic blockage of catalyst pore system by small fly ash particles



Fouling/Masking: Macroscopic blockage of catalyst surface dense second-phase coating



Poisoning: Deactivation of catalyst active sites by chemical attack

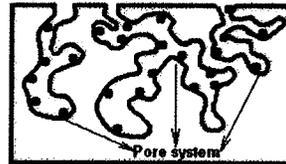


Figure 1. General mechanisms of SCR catalyst deactivation (Guo, 2006).

High sodium lignites are prone to form abundant levels of aerosols when fired in a cyclone burner. Aerosols are formed as a result of the homogenous condensation of flame-volatilized species in combustion systems. During combustion of lignite, sodium, potassium, sulfur, and other components will vaporize and upon gas cooling these components will condense to form aerosols and other particles. As a result of these interactions, the resulting ash composition and mass distribution as a function of size is also shown in Figure 2. Typical ash derived from coal combustion has a bimodal to multimodal size distribution that consists of a submicron and supermicron size fraction as shown in Figure 3. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The intermediate size mode at about 2 micrometers is derived from the more refractory organically associated elements such as calcium and magnesium. The larger particles at approximately 12 to 15 μm are derived from the mineral grains present in the coal. The larger-size particles have been called the residual ash by some investigators (Sarofim and others, 1977) because these ash particles resemble, to a limited degree, the original minerals

in the coal. Sodium and other flame-volatilized components are concentrated in the finer size fractions of ash as shown in Figure 4. This figure illustrates the increase in the sodium content in the finer size fractions of ash as a result of firing high sodium lignite. The sodium content of the 3rd stage (1–3 micrometer size cut) of the sampling train approached 20% Na_2O .

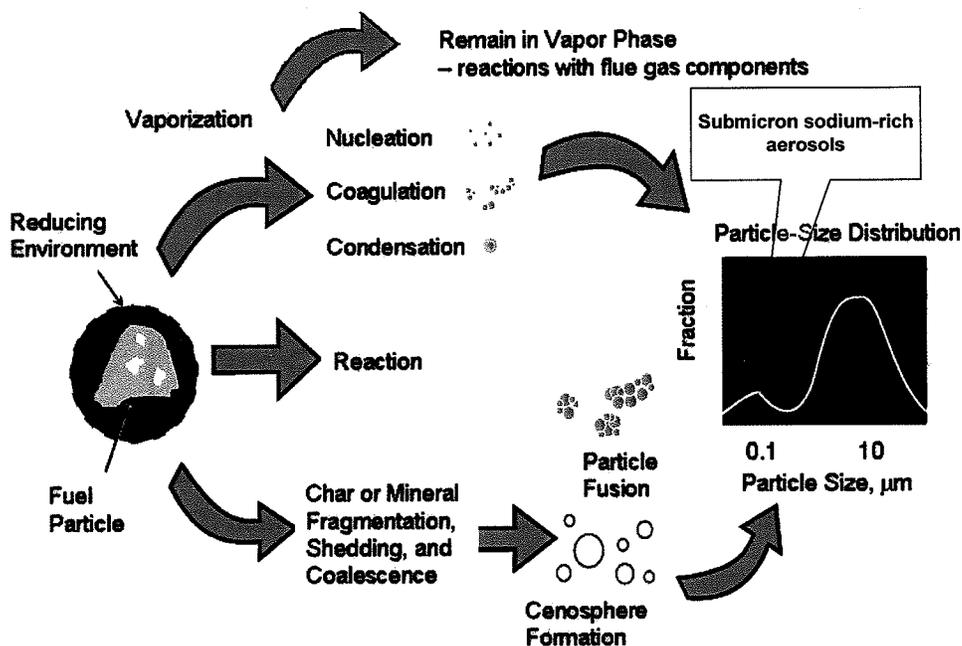


Figure 2. Transformation of inorganic components present in coal during combustion.

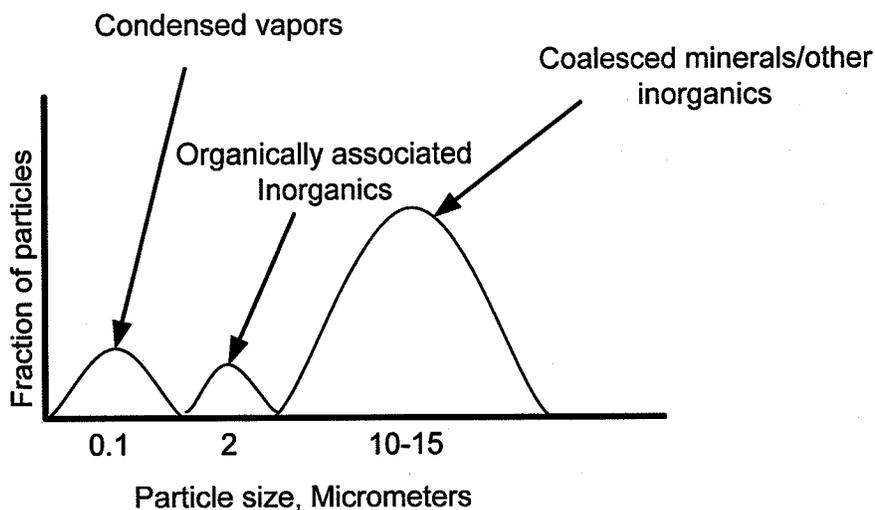


Figure 3. Final size distribution of ash particles produced upon combustion of lignitic coals (Benson and Laumb, 2007).

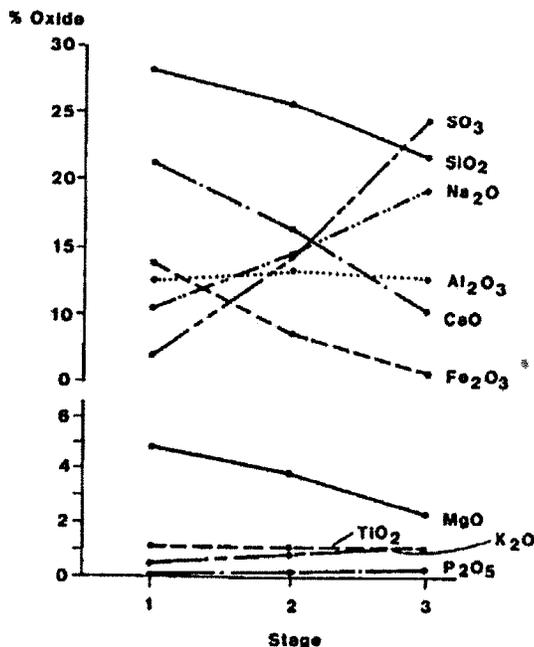


Figure 4. Composition distribution of ash particles during combustion of North Dakota Lignite (Benson and others, 1983).

The transport of intermediate ash species (i.e., inorganic vapors, liquids, and solids) is a function of the state and size of the ash species and system conditions such as gas flow patterns, gas velocity, and temperature. Several processes are involved in the transport of ash particles. These processes have been described by Raask (1985) and Rosner (1986). The primary transport mechanisms are illustrated in Figure 5. For larger particles inertial impaction and eddy impaction in turbulent regions are the dominant mechanisms. The aerosols (small particles $<1 \mu\text{m}$) and vapor-phase species are transported by the vapor phase and small particle diffusion. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, and inertial impaction.

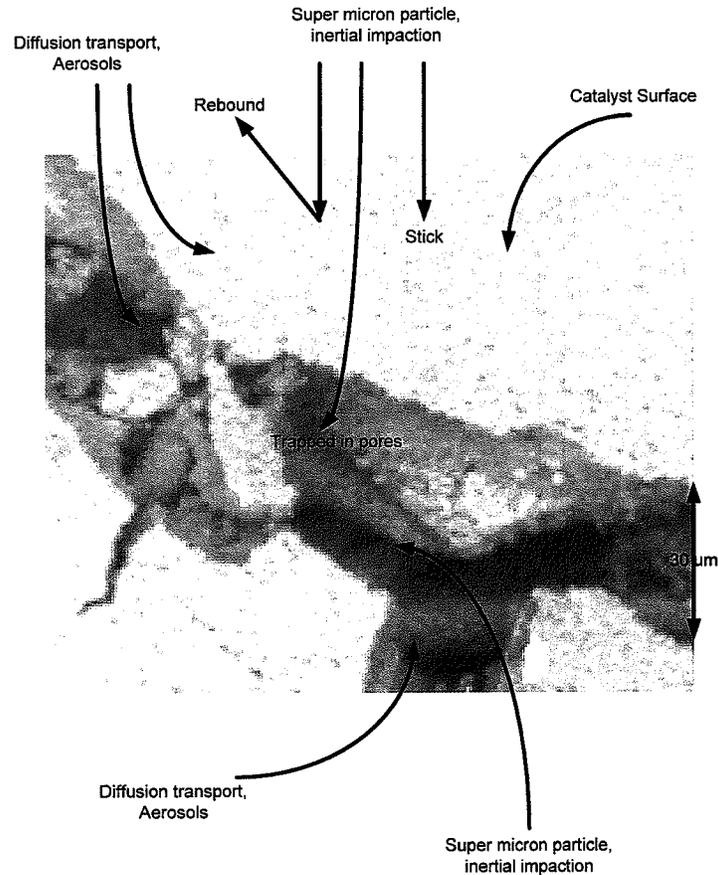
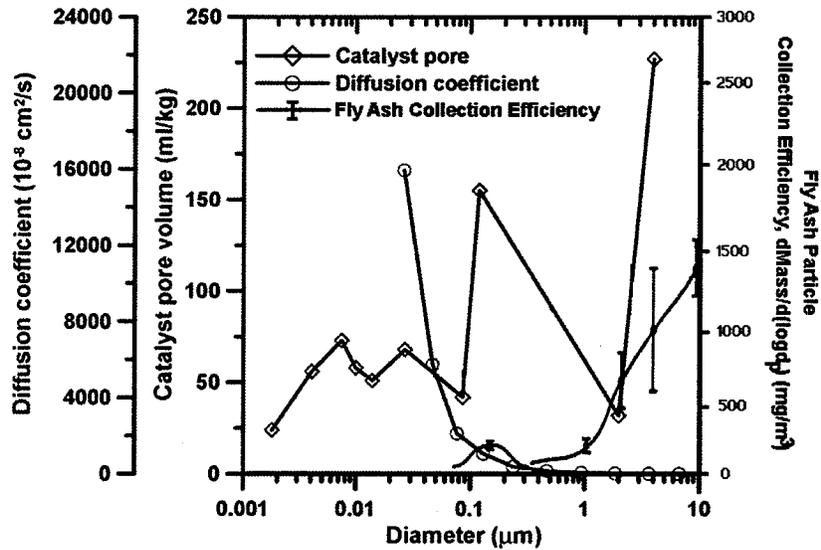
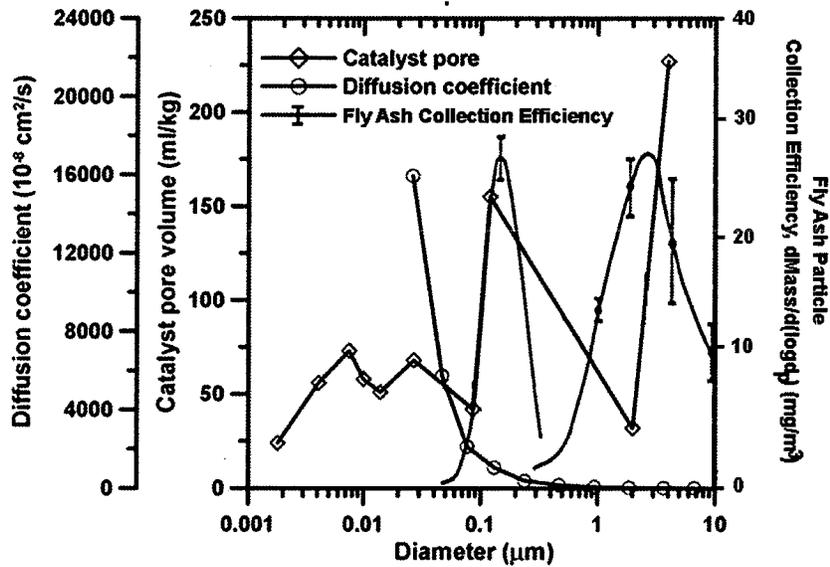


Figure 5. Scanning electron microscope secondary electron image of SCR surface structure before exposure to flue gases.

Recent work conducted by Zheng and others (2008) in a paper entitled “Deactivation of V_2O_5 - WO_3 - TiO_2 SCR catalyst at biomass fired power plant entitled “Elucidation of mechanisms by lab- and pilot-scale experiments” described the diffusion of aerosols and their ability to cause catalyst poisoning. Figure 6 shows a plot of the aerosol concentration as a function of size, catalyst pore size, and the diffusion coefficient with size. These result show that diffusion of the submicron aerosol is highly likely since potential for diffusion increases with the smaller size fraction of particles and that the mechanism will be active for particulate from upstream and downstream of the particulate control device such as an ESP. These efforts followed earlier studies where Zheng and others (2005) biomass-derived alkali rich aerosols caused a drop in NO_x reduction activity by 52% after about 1140 hours of operation.



a. Comparison to ESP inlet size distribution of fly ash.



b. Comparison to ESP outlet size distribution of fly ash

Figure 6. Comparison of the size distribution of the aerosol produced during combustion with the diffusion coefficient and catalyst pore size (Modified after Zheng and others (2008) with data from Linak and Wendt (1994)).

The association of alkali and alkaline earth elements in Center lignite is similar to the associations found in biomass. In both Center lignite and biomass materials the alkali and alkaline earth elements are largely organically associated. An analysis of a wood residue biomass material that is similar to lignite is shown in Table 1. The total alkali (Na₂O+K₂O)

calculated on a lb/mmBTU basis for the wood residue is 0.10. The total alkali for the average Center lignite was determined to be 0.84 lb/mmBTU. Compositions of various biomass types were compiled by Miles and others (1995) and they found the total alkali ranged from 0.06 to 1.15 lb/mmBTU. The overall chemical compositions for the biomass are listed in Tables 2 through 5 along with the water soluble alkali. Miles and others (1995) conducted chemical fractionation, a procedure that determines the abundance of alkali and other elements that is soluble (associated as soluble species and with the fuel organic fraction), on the biomass and found that the alkali were mainly organically associated.

Because of the organic association alkali species vaporize upon combustion and condense to form aerosols upon gas cooling. This vaporization of alkali during biomass combustion resulting in the formation of aerosols has been investigated by numerous researchers. One of the most recent paper is by Hindiyarti and others (2008).

Table 1. Example of a wood residue biomass composition.

Wood Residue Biomass	
Proximate Analysis, as received, wt%	
Moisture	7.30
Volatile Matter	76.82
Fixed Carbon	15.25
Ash	0.6
Ultimate Analysis, as received, wt%	
Hydrogen	6.1
Carbon	46.85
Nitrogen	0.1
Sulfur	0.1
Oxygen	46.05
Ash	0.63
Heating Value, Btu/lb	8274
Ash Composition, wt% equivalent oxide	
SiO ₂	27.7
Al ₂ O ₃	11.0
Fe ₂ O ₃	10.0
TiO ₂	0.5
P ₂ O ₅	1.4
CaO	28.4
MgO	5.9
Na ₂ O	4.9
K ₂ O	7.6
SO ₃	2.5
Lb alkali (Na ₂ O+K ₂ O)/mBtu	0.10

Table 2. Wood Fuel Blends: Alkali Deposit Investigation Samples (Miles and others 1995).

Fuel Type	Fuel Blend CFB-1		Fuel Blend FBC-1		Fuel Blend Grate-1		Fuel Blend CFB-3		Fuel Blend CFB-2		Fuel Blend Grate-1	
	Urban wood - Ag	Dry	Urban wood - Ag	Dry	Urban wood	Dry	Wood-Pil	Dry	Wood-Almond	Dry	Wood-20% Straw	Dry
Proximate Analysis												
Fixed Carbon	12.36	19.79	13.02	16.93	12.69	15.23	11.55	18.10	12.32	15.94	15.45	16.67
Volatile Matter	47.40	75.89	62.02	80.57	66.02	79.23	48.95	76.77	59.77	77.28	68.65	75.14
Ash	2.70	4.32	1.93	2.50	4.62	5.54	3.27	5.13	5.25	6.78	7.59	8.19
Moisture	37.54	--	23.03	--	16.67	--	36.23	--	22.66	--	7.31	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis												
Carbon	32.13	51.44	38.24	49.69	40.64	48.77	31.00	48.62	36.7	47.45	44.01	47.48
Hydrogen	3.54	5.67	4.51	5.87	4.8	5.76	3.68	5.78	4.28	5.53	5.38	5.81
Oxygen	23.81	38.13	32.01	41.57	32.99	39.59	25.36	39.76	30.6	39.57	35.28	38.05
Nitrogen	0.26	0.41	0.25	0.33	0.22	0.27	0.42	0.65	0.45	0.59	0.32	0.35
Sulfur	0.02	0.03	0.03	0.04	0.06	0.07	0.04	0.06	0.06	0.08	0.11	0.12
Ash	2.7	4.32	1.93	2.5	4.62	5.54	3.27	5.13	5.25	6.78	7.59	8.19
Moisture	37.54	--	23.03	--	16.67	--	36.23	--	22.66	--	7.31	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	5,506	8,815	6,449	8,379	6,967	8,361	5,388	8,450	5,281	6,828	7,492	8,083
Chlorine %	<0.01	0.01	0.04	0.05	0.05	0.06	0.02	0.03	0.02	0.03	0.12	0.13
Water Soluble Alkalis %												
Na ₂ O	0.008	0.013	0.034	0.044								
K ₂ O	0.097	0.155	0.132	0.172								
CaO		0.226										
Elemental Composition												
SiO ₂		39.96		28.81		55.12		52.55		45.60		55.50
Al ₂ O ₃		12.03		8.47		12.49		13.15		10.75		9.37
TiO ₂		0.87		0.83		0.72		0.43		0.54		0.50
Fe ₂ O ₃		7.43		3.28		4.51		8.18		4.06		4.77
CaO		19.23		27.99		13.53		10.06		18.96		11.04
MgO		4.30		4.49		2.93		3.27		4.22		2.55
Na ₂ O		1.53		3.18		3.19		5.90		3.08		2.98
K ₂ O		5.36		8.86		4.78		5.04		6.26		6.40
SO ₃		1.74		2.00		1.92		2.10		2.06		1.80
P ₂ O ₅		1.50		2.57		0.88		1.90		1.47		1.04
CO ₂		6.05		6.07		-0.07		-2.58		3.00		4.05
Undetermined				3.45		100.07		100.00		100.00		100.00
TOTAL		100.00		100.00		100.00		100.00		100.00		100.00
Alkali_Lb/MMBtu		0.34		0.36		0.53		0.66		0.93		0.95

Table 3. Wood Fuel Blends: Various (Miles and others 1995).

Fuel Type	Wood Red Oak Sawdust		Wood Fir Mill Waste		Wood Furniture Waste		Wood Hybrid Poplar		Wood Alder/Fir Sawdust		Wood Poplar-Coarse		Wood Forest Residuals		Wood Christmas Trees	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Proximate Analysis																
Fixed Carbon	11.92	13.47	6.47	17.48	11.77	13.39	11.63	12.49	9.14	19.31	11.44	12.26	6.96	13.62	12.93	20.80
Volatile Matter	76.35	86.22	30.38	82.11	72.98	83.00	78.97	84.81	36.27	76.56	80.33	86.14	42.10	82.41	46.02	73.99
Ash	0.28	0.31	0.15	0.41	3.18	3.61	2.51	2.70	1.96	4.13	1.49	1.60	2.03	3.97	3.24	5.21
Moisture	11.45	--	63.00	--	12.07	--	6.89	--	52.63	--	6.74	--	48.91	--	37.81	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis																
Carbon	44.24	49.96	18.95	51.23	43.85	49.87	46.72	50.18	24.17	51.02	47.39	50.82	25.7	50.31	32.09	51.59
Hydrogen	5.24	5.92	2.21	5.98	5.2	5.91	5.64	6.06	2.75	5.8	5.49	5.89	2.35	4.59	3.47	5.58
Oxygen	38.76	43.77	15.66	42.29	35.42	40.29	37.66	40.44	18.25	38.54	38.32	41.08	20.42	39.99	22.82	36.70
Nitrogen	0.03	0.03	0.02	0.06	0.25	0.29	0.56	0.6	0.22	0.46	0.55	0.59	0.53	1.03	0.32	0.52
Sulfur	<0.01	0.01	0.01	0.03	0.03	0.03	0.02	0.02	0.02	0.05	0.02	0.02	0.06	0.11	0.25	0.40
Ash	0.28	0.31	0.15	0.41	3.18	3.61	2.51	2.7	1.96	4.13	1.49	1.6	2.03	3.97	3.24	5.21
Moisture	11.45	--	63.00	--	12.07	--	6.89	--	52.63	--	6.74	--	48.91	--	37.81	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb																
HHV, Btu/lb	7.415	8.374	3.248	8.779	7.613	8.658	7.615	8.178	4.150	8.760	7.590	8.139	4.429	8.670	5.603	9.009
Chlorine %																
Chlorine %	<0.01	<0.01	0.07	0.19	<0.01	<0.01	0.01	0.01	<0.01	0.02	0.04	0.04	0.02	0.04		
Water Soluble Alkalis %																
Na ₂ O	<0.001	0.001	0.051	0.139					0.004	0.009						
K ₂ O	0.069	0.078	0.019	0.051					0.086	0.181						
CaO	0.017															
Elemental Composition																
SiO ₂	20.97	15.17		15.17		57.62		5.90		33.36		0.88		17.78		38.89
Al ₂ O ₃	2.99	3.96		3.96		12.23		0.84		11.54		0.31		3.55		14.74
TiO ₂	0.27	0.27		0.27		0.50		0.30		0.92		0.16		0.50		0.36
Fe ₂ O ₃	2.94	6.58		6.58		5.63		1.40		7.62		0.57		1.58		9.30
CaO	10.90	11.90		11.90		13.89		49.92		24.90		44.40		45.46		9.50
MgO	4.15	4.59		4.59		3.28		18.40		3.81		4.32		7.48		2.52
Na ₂ O	1.40	23.50		23.50		2.36		0.13		1.71		0.23		2.13		0.53
K ₂ O	22.40	7.00		7.00		3.77		9.64		5.75		20.08		8.52		7.86
SO ₃	2.69	2.93		2.93		1.00		2.04		0.78		3.95		2.78		11.36
PO ₅	1.33	2.87		2.87		0.50		1.34		1.90		0.15		7.44		2.40
CO ₂ /other	14.30	18.92		18.92		-0.78		8.18		1.85		19.52		2.78		2.54
Undetermined	15.66	2.31		2.31		100.00		1.91		3.86		5.43		2.78		100.00
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Alkali, Lb/MMBtu	0.09	0.14		0.14		0.26		0.32		0.35		0.40		0.49		0.49

Table 4. Urban Waste Fuels and Residues (Miles and others 1995).

Fuel Type	Wood Demolition		Wood Land Clearing		Wood Yard Waste		Waste Paper Mixed Waste Paper		Refuse Derived Fuel Tacoma		Currency Shredded	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Proximate Analysis												
Fixed Carbon	11.21	12.32	7.04	13.87	8.41	13.59	6.76	7.42	0.45	0.47	11.13	11.67
Volatile Matter	67.84	74.56	35.38	69.63	40.90	66.04	76.87	84.25	70.29	73.40	79.02	82.86
Ash	11.94	13.12	8.39	16.50	12.62	20.37	7.60	8.33	25.02	26.13	5.21	5.47
Moisture	9.01	--	49.19	--	38.07	--	8.75	--	4.24	--	4.64	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis												
Carbon	42.13	46.3	21.5	42.32	25.72	41.54	43.79	47.99	38.02	39.70	40.90	42.89
Hydrogen	4.9	5.39	2.55	5.02	2.97	4.79	6.05	6.63	5.53	5.78	5.69	5.97
Oxygen	31.39	34.5	18.17	35.77	19.94	32.21	33.61	36.84	26.09	27.24	41.61	43.62
Nitrogen	0.52	0.57	0.17	0.33	0.53	0.85	0.13	0.14	0.77	0.80	1.67	1.75
Sulfur	0.11	0.12	0.03	0.06	0.15	0.24	0.07	0.07	0.33	0.35	0.28	0.30
Ash	11.94	13.12	8.39	16.5	12.62	20.37	7.6	8.33	25.02	26.13	5.21	5.47
Moisture	9.01	--	49.19	--	38.07	--	8.75	--	4.24	--	4.64	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	7,203	7,916	3,764	7,408	4,341	7,009	8,152	8,934	6,396	6,679	7,480	7,967
Chlorine %	0.05	0.05	0.01	0.02	0.19	0.3						
Water Soluble Alkalies %												
Na ₂ O			0.008	0.015							0.214	0.224
K ₂ O			0.095	0.187							0.123	0.129
CaO												
Elemental Composition												
SiO ₂		45.91		65.77		59.65		28.10			33.81	2.99
Al ₂ O ₃		15.55		14.84		3.06		52.56			12.71	11.92
TiO ₂		2.09		0.55		0.32		4.29			1.66	24.30
Fe ₂ O ₃		12.02		5.27		1.97		0.81			5.47	19.55
CaO		13.51		5.78		23.75		7.49			23.44	12.38
MgO		2.55		1.81		2.15		2.36			5.64	1.38
Na ₂ O		1.13		2.70		1.00		0.53			1.19	3.58
K ₂ O		2.14		2.19		2.96		0.16			0.20	1.94
SO ₃		2.45		0.36		2.44		1.70			2.63	9.30
P ₂ O ₅		0.94		0.66		1.97		0.20			0.67	0.78
CO ₂ /other		1.71		-0.38		0.73		1.80			12.58	10.61
Undetermined												
TOTAL		100.00		100.00		100.00		100.00			100.00	100.00
Alkali, Lb/MMBtu		0.54		1.09		1.15		0.06			0.54	0.38

Table 5. Wood Fuel: Energy Crops (Miles and others 1995).

Fuel Type	Willow SV1.3Yr		Willow SV1.1Yr		Willow SP3.1Yr		Willow SH3.1Yr		Willow SA22.1Yr		Willow SA22.3Yr		Willow SA22.Top		Willow SA22-Batt	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry						
Proximate Analysis																
Fixed Carbon	12.40	13.82	12.09	13.99	14.22	15.75	14.09	16.14	14.75	16.67	14.47	16.07	16.70	17.99	13.18	14.81
Volatile Matter	76.52	85.23	73.38	84.91	74.99	83.05	71.74	82.16	72.43	81.83	74.01	82.22	73.92	79.67	74.82	84.13
Ash	0.85	0.95	0.95	1.10	1.08	1.20	1.49	1.70	1.33	1.50	1.54	1.71	2.17	2.34	0.94	1.06
Moisture	10.23	--	13.58	--	9.71	--	12.68	--	11.49	--	9.98	--	7.21	--	11.06	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Ultimate Analysis																
Carbon	44.07	49.09	41.43	47.94	45.41	50.29	42.65	48.85	44.03	49.75	44.92	49.9	45.86	48.42	43.53	48.95
Hydrogen	5.29	5.89	5.05	5.84	5.43	6.01	5.27	6.04	5.31	6.00	5.31	5.9	5.47	5.89	5.38	6.05
Oxygen	39.21	43.69	38.39	44.43	37.85	41.93	37.24	42.64	37.18	42.01	37.63	41.81	38.28	41.27	38.73	43.54
Nitrogen	0.32	0.35	0.55	0.63	0.45	0.5	0.62	0.71	0.58	0.65	0.55	0.61	0.89	0.96	0.32	0.36
Sulfur	0.03	0.03	0.05	0.06	0.07	0.07	0.05	0.06	0.08	0.09	0.07	0.07	0.12	0.12	0.04	0.04
Ash	0.85	0.95	0.95	1.1	1.08	1.2	1.49	1.70	1.33	1.50	1.54	1.71	2.17	2.34	0.94	1.06
Moisture	10.23	--	13.58	--	9.71	--	12.68	--	11.49	--	9.98	--	7.21	--	11.06	--
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV, Btu/lb	7,478	8,330	7,194	8,325	7,848	8,691	7,373	8,443	7,485	8,457	7,583	8,424	7,896	8,510	7,405	8,326
Chlorine %	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01	<0.01	0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.01
Water Soluble Alkalis %																
Na ₂ O	0.021	0.023	0.010	0.012	0.022	0.024	0.011	0.013	0.004	0.004	0.007	0.007	0.066	0.071	0.010	0.011
K ₂ O	0.113	0.126	0.147	0.012	0.245	0.271	0.243	0.278	0.270	0.305	0.242	0.268	0.466	0.503	0.145	0.163
CaO																
Elemental Composition																
SiO ₂		8.08		16.76		2.83		1.11		1.89		2.95		2.05		1.82
Al ₂ O ₃		1.39		3.01		0.12		0.09		0.16		1.41		1.97		1.48
TiO ₂		0.06		0.07		0.06		0.00		0.04		0.05		0.03		0.05
Fe ₂ O ₃		0.84		0.85		0.42		0.21		0.30		0.73		0.35		0.49
CaO		45.62		34.83		36.51		40.48		32.00		41.20		34.18		44.68
MgO		1.16		2.46		1.54		3.04		7.67		2.47		2.98		2.16
Na ₂ O		2.47		3.05		1.97		0.77		0.65		0.94		2.67		0.86
K ₂ O		13.20		12.20		19.9		13.90		22.10		15.00		18.4		15.30
SO ₃		1.15		1.70		1.94		1.70		3.09		1.83		2.92		2.33
P ₂ O ₅		10.04		10.36		12.9		8.16		11.68		7.40		7.1		7.18
CO ₂ /other		13.67		17.58		19.85		27.10		17.65		18.24		22.64		18.34
Undetermined		2.32		-2.87		1.96		3.44		2.77		8.38		4.71		5.31
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Alkali, Lb/MMBtu		0.18		0.20		0.30		0.30		0.40		0.32		0.58		0.21

Hartenstein (2008) indicated that “sodium is not a poison at SCR operating temperatures.” This statement is inconsistent with Hartenstein’s past claims, where he makes the following statement (Hartenstein and Licata, 1996) “...elements such as sodium and potassium, are known to cause permanent irreversible deactivation of SCR catalysts.” There is literature information indicating that sodium is a poison at SCR operating temperatures. The poisoning mechanisms of alkali and alkaline earth oxides on vanadia catalysts were investigated by Chen and others (1990). Their work found that the deactivation is directly related to the basicity of the poisons. The ranking of the strengths of the poisons are listed as follows: $\text{Cs}_2\text{O} > \text{Rb}_2\text{O} > \text{K}_2\text{O} > \text{PbO} > \text{Na}_2\text{O} > \text{LiO} > \text{CaO} > \text{P}_2\text{O}_5$. Figure 7 shows the activities of the catalyst with various elements added. The testing was conducted at 300°C. In addition, Guo (2006) conducted a study on the intrinsic SCR activity for NO with NH_3 reaction and found that the additions of K, Na, and Ca greatly decrease the NO reduction activity of 1% $\text{V}_2\text{O}_5 - 9\% \text{WO}_3/\text{TiO}_2$ as illustrated in Figure 8.

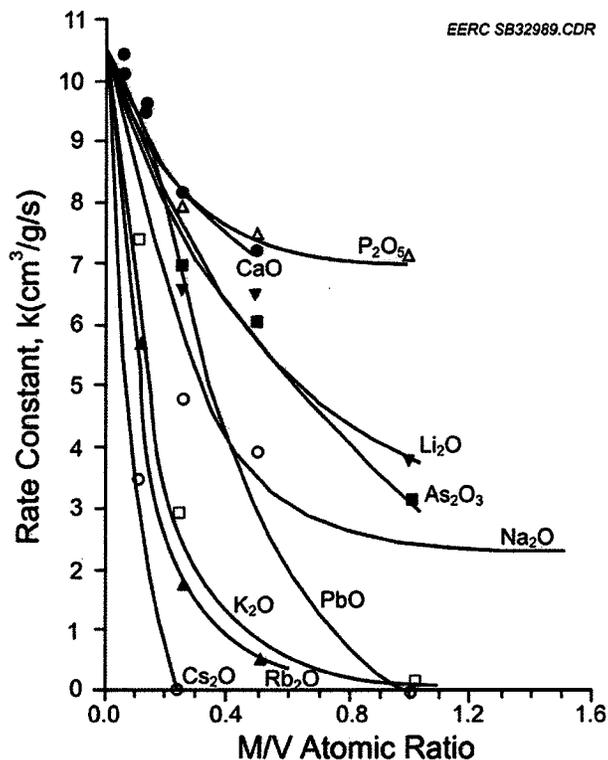


Figure 7. Rate constants for a $\text{V}_2\text{O}_5/\text{TiO}_2$ combined with different amount of oxide poisons (Chen and others, 1990).

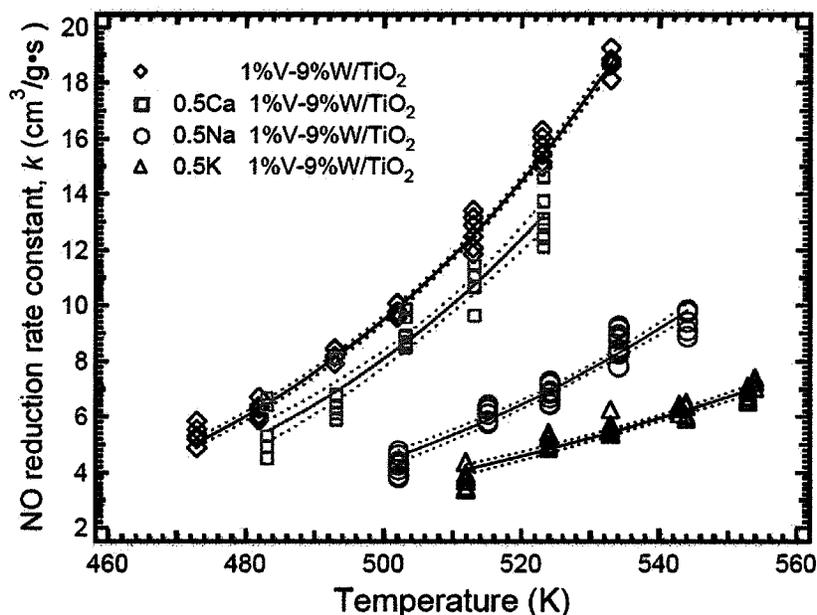


Figure 8. Impact of NO_x reduction rate constant as a result of poisoning by sodium, potassium, and calcium (Guo, 2006).

The mechanisms of catalyst deactivation due to alkali components are currently being investigated in depth. Several studies are being conducted in Europe because of poisoning of catalysts due to biomass firing and co-firing. The diffusion of alkali (Na and K) vapor has been ruled out as was correctly stated by Hartenstein (2008) because it will be in the condensed form at SCR temperatures. However, the presence of alkali aerosols does contribute to the deactivation of catalysts (Zheng and others 2008, Zheng and others 2005). The rates of deactivation in full-scale and laboratory studies were about 1% per day. They indicated that the in-situ formation of liquid potassium-vanadium-pyrosulfates could be one of the possible mechanisms. However, testing showed that the deactivation reactions also take place in the absence of SO₂ due to aerosol penetration into the catalyst.

The exact form of the alkali aerosol (hydroxide, sulfate, or other) that contributes to poisoning is not known. Zheng and others (2008) indicate the possible mechanism of deactivation occurs by the diffusion of aerosol particles rich in alkali into the catalyst pores followed by reaction with the V-OH groups producing -V-O-K (Na). These observations are consistent with the work conducted by Kling and others (2007) who investigated deactivation of SCR catalysts in three

biomass and peat fired 100 MW-scale combustion systems. They found that the increased levels of sodium and potassium accumulated in the SCR catalyst was derived from the ultra fine particles (aerosols). These accumulations of aerosols resulted in decreased the NO_x reduction catalytic activity as shown in Figure 9.

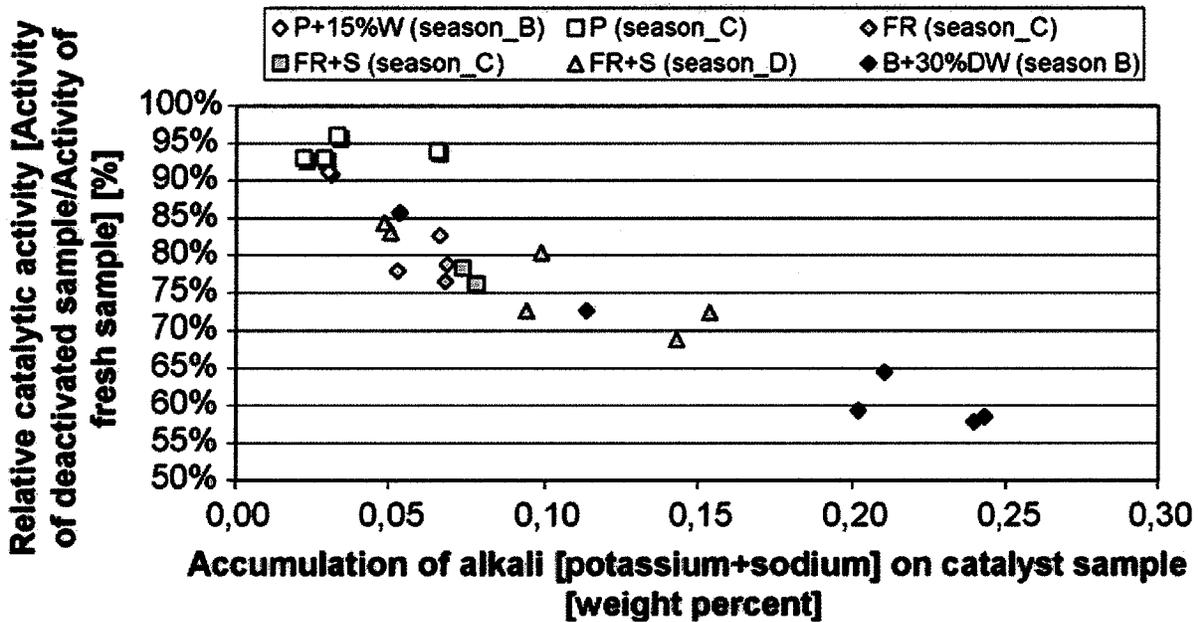


Figure 9. Reduction in catalytic activity as a function of accumulation of alkali in the catalyst (Kling and others (2007)).

Recent testing conducted by Strege and others (2008) at a stoker-fired utility boiler firing a blend of biomass and Powder River Basin coal (PRB) found that the catalyst deactivation rate was about 18% per 1000 hours. The components responsible for the deactivation were sodium, potassium, and calcium sulfate-based materials. Alkali components (sodium and potassium) were found deep inside the catalyst.

Broske (2003) in an EPRI report indicated that for analysis of spent catalysts from medium sulfur bituminous (Appalachian) coal found that the concentration of sodium and potassium species accumulated to over 100 times the levels found in new catalysts. The levels reached in the catalyst were between 4000 and 6000 ppm. This is for an Appalachian coal that typically has

low levels of sodium in the ash. In this particular catalyst, arsenic was found to be the primary contributor to poisoning but the alkali (sodium and potassium) also contributed.

The impact of aerosols on the performance of low dust SCR applications was not discussed by Hartenstein (2008). The impacts have been identified by Copolo and others (2003). They indicated in their paper that “The ash however, that escapes from the precipitators is finer than the ash in general Although less likely to cause erosion, it does have a higher plugging potential as finer ash has been found to have a higher tendency to agglomerate.” In addition, Hartenstein (2008) did not consider information provided on ash accumulations downstream of the ESP at the MRY station. Testing of Powerspan’s barrier discharge reactor (Tolbert and Benson, 2008) was conducted to determine the potential application of the Powerspan technology for new power generation firing high sodium ND lignite. The barrier discharge reactor is placed downstream of particulate control systems to enable the oxidation of NO to NO_x species that will allow for capture in an ammonia-based scrubbing system. A slipstream barrier discharge reactor system was designed by Powerspan and the EERC and installed downstream of the ESP on Unit 1 at the MRY Station. The gas temperature was approximately 300°F.

The primary concern regarding the success of the Powerspan technology was that sodium-rich aerosols exiting the ESP would accumulate on the quartz rod resulting in decreased performance of the barrier discharge reactor. At two week intervals during the testing campaign, the reactor was inspected and rods were removed for analysis. The ash accumulation resulted in decreased nitrogen oxide (NO) oxidation due to accumulations of alkali and alkaline earth sulfate rich ash layer on the rods. An example of the ash accumulation on the rod after exposure to flue gases downstream of the ESP is illustrated in Figure 10. The exposed quartz rods were mounted in epoxy resin and cross-sectioned for scanning electron microscopy and x-ray microanalysis. The image in Figure 10 shows a highly bonded ash coating on the surface of the quartz rod. The red line represents the line analyzed across deposit and the quartz rod. The length of the line is 22µm. The abundance elements were determined along the red line shown in Figure 10. The levels of sodium and potassium in the bonded ash layer were greater than 10 percent.

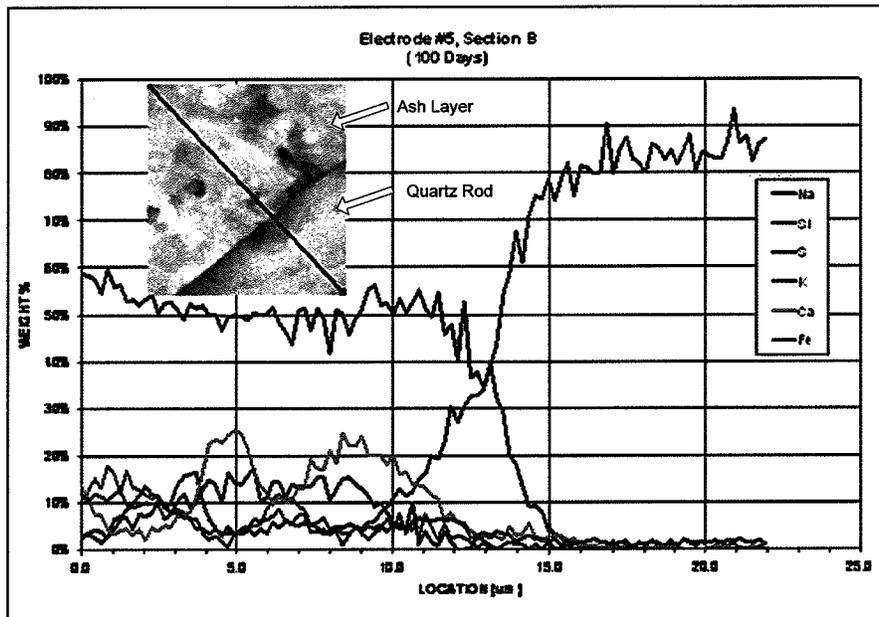


Figure 10. SEM image of quartz rod exposed to flue gas downstream of the ESP at MRY Unit 1 with element composition line scan across the deposit and quartz rod (Tolbert and Benson, 2008).

The bulk composition of ash scraped from selected quartz rods was determined by x-ray fluorescence (XRF). The rods sampled were from three electrodes that were exposed to flue gas downstream of the ESP for 20, 48, and 107 days. The bulk composition summarized in Table 6 shows significant levels of sodium, calcium, and potassium along with sulfur.

Table 6. Bulk composition of ash removed from electrode samples obtained from rod removed at 20, 48, and 107 days.

Oxides (wt.%)	(a)	(b)	(c)	Elemental (wt.%)	(d)	(e)
SiO ₂	10.3	10.8	22.0	Si	9.6	15.8
Al ₂ O ₃	4.1	4.3	8.8	Al	4.4	7.2
Fe ₂ O ₃	4.3	4.5	9.2	Fe	6.0	9.8
TiO ₂	0.2	0.2	0.4	Ti	0.2	0.4
P ₂ O ₅	0.1	0.1	0.2	P	0.1	0.2
CaO	10.5	11.0	22.5	Ca	15.1	24.7
MgO	2.1	2.2	4.4	Mg	2.5	4.1
Na ₂ O	11.7	12.3	25.1	Na	17.4	28.5
K ₂ O	3.4	3.6	7.3	K	5.7	9.3
SO ₃	48.5	51.0	----	S	39.0	----
Total	95.0					
(a) Oxide concentrations (wt.%) on an ash basis. (b) Oxide concentrations normalized to a closure of 100%. (c) Oxide concentrations renormalized to a SO ₃ -free basis. (d) Elemental concentrations (wt.%) on an ash basis. (e) Elemental concentrations renormalized to a S-free basis.						
Comments: BaO = 0.87% Unknowns = 3.54% SrO = 0.34%						

In the 1999 technical paper, Mr. Hartenstein (1999) and his co-authors reported SCR catalyst deactivation due to sodium at the RWE Staudinger plant in Germany. Specifically, it is reported on page 5 of the referenced paper that "...the fly ash from the German coal formed highly adhesive deposits, while the portion of South African coal contributed to the formation of a liquefied fly ash. The reason for this was determined by a chemical analysis of the fly ash. It can be seen that the content of the alkali sulfate, which adheres to the surface of the fly ash particles, favors the tendency to agglomerate. A phase analysis of the deposits revealed crystalline sodium aluminum sulfate and potassium aluminum sulfate (NaAl(SO₄)₂;KAl(SO₄)₂)."

This information supports the Department's opinion related to the formation of sodium-related deposits on the SCR catalyst that accelerate the deactivation of the catalysts. This information conflicts with Mr. Hartenstein's statement, on page A-28 of his expert report, that the "...the intrusion of liquid pyrosulfates is no major concern with respect to a severe, rapid catalyst deactivation."

Variability of Lignite

North Dakota lignite or lignite from the Fort Union Region of North America has very unique properties. The Fort Union lignite coals are unique because of the extraordinarily high levels of alkali and alkaline earth elements that are associated with the organic or combustible fraction of the coal. The constituents that are organically associated are considered ion exchangeable or soluble sodium. The association of the sodium in Fort Union lignites is similar to the association of sodium and potassium found in biomass. In addition, the coal contains mineral grains consisting of mixed clays, quartz, and sulfides that vary significantly in abundance. The form of the element influences their form in the flue gas. For example, organically associated sodium will vaporize during combustion and form an aerosol upon gas cooling, while mineral associated sodium (sodium in a clay) is less likely to vaporize and will be retained with the clay-derived particle. The sodium associated with the aerosol is much more reactive than sodium associated with a melted clay-derived particle.

The organically-associated elements are prone to vaporize during combustion. These organically associated elements will condense homogeneously to form submicron sized aerosols or ultrafine particles. In addition, the organically associated elements will react with aluminosilicates producing low-viscosity (low melting point silicate-based liquids) phases and with sulfur-producing sulfates and pyrosulfate. These elements contribute to the formation of deposits on ceramic/refractory surfaces, cyclones, heat-transfer surfaces, SCR catalysts, and gas filters. Formation of these deposits will lead to operability problems, with the potential to shut down the system. Lignite composition is highly variable and, therefore, will contribute to a range of challenges. As a result of these challenges and efforts to identify problematic species, a significant database of selected North Dakota lignites, specifically Center lignite, has been developed to provide the basis for understanding the behavior of lignite and to project potential challenges. The variability of the Center mine lignite characteristics are summarized in Table 7.

Table 7. Center lignite composition (moisture, ash, sulfur, and heating value expressed on an as-received basis; and ash composition expressed as weight percent equivalent oxide of the ash produced at 750 °C).

	Moisture,%	Ash, %	Sulfur%	Btu/lb	Al ₂ O ₃	BaO	CaO	Fe ₂ O ₃	MgO	P ₂ O ₅	K ₂ O	SiO ₂	Na ₂ O	SO ₃
Average	37.13	9.64	0.98	6578	11.68	0.52	13.15	8.90	3.99	0.12	1.33	36.04	4.40	18.39
Max	39.37	25.46*	2.55	7101	15.62	1.22	23.96	24.72	7.09	1.00	2.30	55.98	13.03	34.50
Min	33.56	4.97	0.47	5852	6.31	0.20	6.80	5.38	2.30	0.01	0.16	12.30	0.55	8.12
90th Perc.	38.10	12.51	1.29	6820	14.23	0.84	19.92	12.20	5.68	0.41	1.92	45.98	8.71	26.25
10th Perc.	35.95	7.06	0.72	6359	9.58	0.37	9.73	7.08	3.00	0.04	0.61	22.70	1.99	14.35
45th Perc.	37.17	9.33	0.90	6552	11.62	0.47	12.15	8.34	3.81	0.09	1.36	36.99	4.09	17.30
55th Perc.	37.37	9.75	0.94	6592	11.97	0.50	12.74	8.68	3.97	0.10	1.44	38.36	4.61	18.02

* High value may be an analysis or reporting error. Sample could not be reanalyzed to verify.

Hartenstein (2008) indicated that “I am not aware of a single case where high variability of heat and ash contents of the coals and/or of the constituents that make up the ash preclude the principles of the SCR technology from being technically feasible and applicable.” Hartenstein did not indicate how he would identify a design coal for the catalyst design for high dust SCR based on the lignite characteristic. In addition, Hartenstein incorrectly assumes that over the range of fuel properties the performance of the particulate control systems will not be impacted, thus avoiding impact on a low-dust or tail-end SCR. In cases where there is high sodium and low ash contents, the abundance of aerosol particles increases dramatically. These particles can make their way through particulate control devices and can impact the performance of low dust and tail-end SCR as discussed previously.

Hartenstein (2008) does not provide information on chemical composition of the fuels that are comparable to high sodium lignite where SCR installation have been installed and tested or successfully operated. The composition of the Texas lignite fired at Martin Lake is typical of the composition of lignite fired at Sandow and is shown in Table 8. The sodium oxide levels in the Texas lignite ash is 0.7%. The levels of sodium oxide in Center lignite average 4.4% and can be as high as 13% in as-fired samples.

It is surprising that Hartenstein did not discuss his experience with German Ruhr Brown coal as described in a paper by Hartenstein and others (1999) where they found that “... the pressure drop across the catalyst layers rapidly increased....” when they fired German Ruhr coal alone. The problem was associated with the highly “adhesive” fly ash bonded with an alkali sulfate phase. They were unable to fire 100% lignite and had to rely on blending with a South African coal to reduce the problem. He also stated that “We have also learned that we had to analyze not only for sodium (Na) and potassium (K) content of the coal but also we need to know if the Na and K compounds are water-soluble. In a water soluble form, these alkaline metals are highly mobile and will migrate throughout the catalyst material reducing active sites.”

Table 8. Average Texas Lignite Coal and Ash Composition (Ulvog and Wiemuth, 2003)

Proximate Analysis			Ash Analysis			Trace Constituents		
Moisture	% As Received	34.6	PO ₅	%	0.2	Sb	mg/Kg	<0.5
Ash	% As Received	11.5	SiO ₂	%	44.6	As	mg/Kg	<.05
Volatiles	% As Received	26.4	Fe ₂ O ₃	%	8.5	B	mg/Kg	155.6
Fixed Carbon	% As Received	27.5	Al ₂ O ₃	%	15.8	Cd	mg/Kg	<.05
Sulfur	% As Received	1.1	TiO ₂	%	1.0	Cr	mg/Kg	11.2
BTU/Lb	% As Received	6928	Mn ₂ O ₃	%	0.1	Cu	mg/Kg	15.3
			CaO	%	10.0	Pb	mg/Kg	<0.5
			MgO	%	2.5	Mn	mg/Kg	82.4
			K ₂ O	%	0.9	Hg	mg/Kg	0.0
			Na ₂ O	%	0.7	Mo	mg/Kg	0.8
			SO ₃	%	12.8	Se	mg/Kg	1.8
			SrO	%	0.1	Zn	mg/Kg	13.4
			BaO	%	0.6			
			Undetermined	%	2.2			

Results of the Coyote Pilot Testing

Hartenstein stated “The HDSCR Coyote pilot testing was ill-designed and fundamentally flawed.” Hartenstein based this statement on his flawed interpretation of the Coyote testing. Hartenstein (2008) incorrectly interpreted the testing at Coyote Station as follows: “Admittedly, the Coyote Pilot Testing results seem to indicate worse pluggage than the Baldwin Pilot Testing results. However, it must be noted that the same pilot test reactor and the same catalyst, which had been already used (and plugged) at Baldwin was subsequently used at Coyote. The well known fact that catalyst that had been plugged and only mechanically cleaned is more likely to quickly plug again than new, unused catalyst was simply ignored.”

Hartenstein (2008) described the reactor as being “ill-designed.” The reactor system initial design was based on a design provided by Cormetech. The final design was reviewed and approved by the project team that included Cormetech, Haldor Topsoe, Hitachi, EPRI, US. DOE, Alliant Energy, Otter Tail Power, Ameren, Dynegy, and Lignite Energy Council. In

addition, the selection of catalyst for the testing at Coyote was based on the recommendations of Haldor Topsoe. The testing protocols including the soot blowing media and frequency as well as all operating conditions were reviewed and approved by the aforementioned project team.

The following describes how the testing was conducted and is clearly described in Benson and others (2005).

1. The same reactor system used at Baldwin station was moved to the Coyote Station and installed.
2. The system was completely cleaned prior to operations at the Coyote Station.
3. Fresh catalyst was installed in reactor prior to testing at the Coyote Station.
4. At approximately two month intervals, the reactor was inspected and sections of the catalyst were removed for analysis, and fresh catalyst replaced the catalyst section that was removed.
5. The catalyst sections were analyzed for pore plugging and Haldor Topsoe was going to conduct activity measurements.
6. Haldor Topsoe indicated that the catalyst was too plugged to measure reactivity.

The slipstream reactors worked well at the Baldwin Station (cyclone PRB fired) and Columbia (pulverized coal tangential PRB fired) with minor to moderate fouling. The same reactor used at Baldwin was used at the Coyote Station. The pitch of the catalyst used at Coyote Station was 6mm as recommended by Hansen at Haldor Topsoe. A comparison of the first 500 hours with both systems using fresh catalysts is shown in Figures 11 and 12 for Baldwin and Coyote Station, respectively.

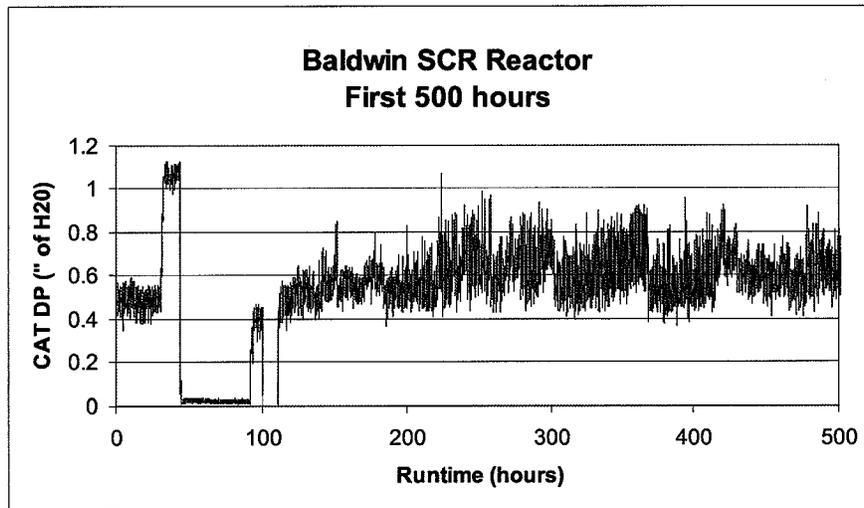


Figure 11. Pressure drop across SCR reactor during first 500 hours of testing at Baldwin

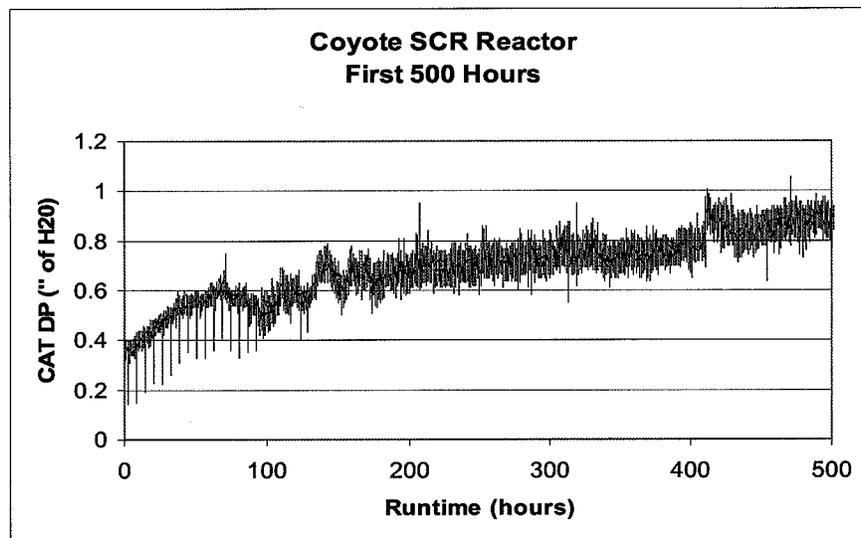


Figure 12. Pressure drop across SCR reactor during first 500 hours of testing at Coyote

Initially, at Baldwin there were some problems with start up and operation of the reactor because of plant outages. The pressure drop at the end of 500 hours averaged about 0.6 inches of water. The pressure drop for Coyote Station is shown in Figure 12, and at the end of 500 hours the pressure drop averaged about 0.85 inches of water. The plugging and blinding of the catalyst was severe.

Soluble Sodium

Soluble sodium is used to describe the form of sodium in the coal as well as forms of sodium in ash. The soluble form of sodium in coal is used to describe the abundance of sodium associated with the water soluble and organic fraction of the coal. During combustion the soluble sodium (organically associated) in the coal is much more likely to vaporize than an insoluble form. This is especially true for a cyclone-fired boiler. Upon gas cooling the alkali vapors will condense to form aerosols or sometimes called ultrafine particles. These ultrafine particles can diffuse into the pores of the catalyst and react with V-OH groups forming V-O-K(Na) rendering the site inactive (Zheng and others 2008). Hartenstein's following interpretation is inconsistent with the work by Zheng and others (2008) which is co-authored by one of the lead scientists from Haldor Topsoe.

”Unfortunately, the Department fails to realize what was pointed out by one of the most experienced catalyst suppliers, namely that “sodium is not a poison to catalyst at SCR operating temperatures.” Thus, the elaborate comparison of emission factors of sodium, potassium, calcium, and magnesium emission factors with the fly ash may have some academic value but is effectively meaningless for the correct prediction of catalyst deactivation, since particle bound sodium, potassium, calcium and magnesium in the fly ash are not mobile and therefore are not catalyst poisons.”

The abundance of alkali aerosols in the flue gas as depicted by emission factor will have an impact on the rate of catalyst deactivation by the formation of aerosols that directly poison sites or produce pyrosulfates. The impact of the abundance of alkali (sodium and potassium) is clearly illustrated by the recent work conducted by (Kling and others (2007)).

The formation of pyrosulfates as described earlier (EERC and Burns and McDonnell) is consistent with recent investigations of alkali poisoning of catalyst (Zheng and others 2008, Zheng and others 2005). They indicated that the in situ formation of liquid potassium-vanadium-pyrosulfates could be one of the possible mechanisms. Hartenstein (2008) states “Alternatively, these pyrosulfate compounds would have to be present in a liquid so that their dissociated ions (i.e. Na⁺, K⁺) would be mobile in order to enter the catalyst pores and react with the catalyst's

active sites.” He does not consider their in-situ formation as a result of the reaction of accumulated Na or K-rich aerosols with SO₃ and vanadium in the pores of the catalyst. Vanadium and iron compounds are known to catalyze the formation of pyrosulfates. Hartenstein (2008) also incorrectly states the range of melting points of the pyrosulfate phases (650 to 750°F). The melting points of selected pyrosulfates are listed in Table 9 and have a range of (535 to 1281°F).

Table 9. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
K ₃ Fe(SO ₄) ₃	618	1144
K ₃ Al(SO ₄) ₃	654	1209
KFe(SO ₄) ₂	694	1281
Na ₃ Fe(SO ₄) ₃	624	1155
Na ₃ Al(SO ₄) ₃	646	1195
NaFe(SO ₄) ₂	690	1274
Na ₂ S ₂ O ₇	401	754
K ₂ S ₂ O ₇	300	572
(K _{1.5} Na _{0.5})S ₂ O ₇	279	535

Differences in Flue Gas Composition

The flue gas derived from the cyclone combustion of high sodium lignite contains an abundance of alkali-rich aerosols. This is well known and has been published by Benson and others (1983) as well as other investigators. The abundance of alkali rich aerosols is similar to that found in biomass combustion systems. Recently, work conducted by Zheng and other (2008) point out the importance of the aerosol particles and catalyst poisoning.

Hartenstein again makes the incorrect claim that “sodium is not a catalyst poison at SCR operating temperature” and dismisses the uniqueness of the flue gas derived from high sodium lignites. However, he provides no example of a coal fired in a boiler that produces a flue gas that is characteristic of flue gases produced from North Dakota lignite where SCR has been installed and successfully operated.

Catalyst Poisoning, Blinding and Plugging

The pores of the catalyst exposed to the alkali-rich flue gas derived from the cyclone-fired combustion of ND lignite at the Coyote pilot test were plugged. Penetration into the pores was extensive. Sulfation of the alkali components resulted in filling and plugging of the pores of the catalyst. Cyclone firing increases the abundance of alkali and other flame-volatilized species in the flue gas stream. The more refractory components end up in the slag. The alkali-rich flue gas stream is deficient in larger entrained ash particles derived from quartz and clay mineral in the flue gas stream. Upon gas cooling the alkali components will largely condense homogeneously to form alkali-rich aerosols because of the low abundance of larger ash particles for heterogeneous condensation. This results in a flue gas with higher alkali aerosol content than produced by pulverized coal fired systems.

The aerosols diffuse into the catalyst pores and are subsequently sulfated or interact with catalyst active sites resulting in plugging/blinding and deactivation, respectively. There does not appear to be a catalyst material that has shown significantly improvement over the past catalyst relative to the performance in high sodium containing system. The specific question was asked to Flemming Hansen of Haldor Topsoe (Hansen, 2007) as to whether improvements have been made in catalysts over the ones tested at Coyote Station that warrant further testing. He indicated that no formulation or design changes have been made to improve their performance in high sodium containing flue gases.

Applicability of SCR Development for Texas Lignite

EPA provided several comments regarding future application of high-dust SCR at TXU's Oak Grove facility as an example that it should not be eliminated as technically infeasible (at MRYS) on the basis of catalyst plugging and deactivation. The EPA mentioned catalyst vendors' beliefs, and an opinion by Electric Power Research Institute (EPRI) issued on September 7, 2006 and determinations by the Texas Commission on Environmental Quality. The EPA also states that "while the properties of North Dakota and Texas lignite might not be the same..." that the "same

basic principle applies that the accelerated catalyst replacement requirements are a matter of economics and not technical feasibility” (U.S. EPA, 2008, Enclosure 2).

As responses to previous EPA opinions on this subject have been presented elsewhere (Minnkota, 2007A, 2007B, 2007C, 2008), the EPA fails to recognize conclusively that ash chemical and physical properties of Texas lignite (Wilcox formation) that TXU proposes to burn at the new Oak Grove powerplant do not represent what is fired in North Dakota, and its technical feasibility and expected performance in an SCR application is not transferable to North Dakota lignite-fired cyclone burner units due to the significant differences in flue gas and ash chemical and physical properties.

The EPA also fails to recognize and acknowledge that significant pilot testing has been conducted at several power plants in Texas that fire lignite supplied from various locations in Texas, and that there are no cyclone-fired boilers in Texas. The EPA has gone down the same path that tried to compare German SCR applications which lack significant cyclone boiler experience and is not currently required for lignite-fired boilers to be appropriate and comparable to North Dakota lignite-fired cyclone burner units. These are misleading statements and contrary to the presentation of the body of information submitted in support of the NDDH’s preliminary BACT determination for MRYS.

SCR Catalyst Erosion and Cleaning

Various means of resolving catalyst erosion have been previously discussed in earlier comments and responses (Minnkota, 2007A and 2007B). While hardened leading catalyst surfaces may be resistant to erosion from entrained flyash, the more important issues to consider are effectiveness and damage from on-line catalyst cleaning methods. Hans Hartenstein (2008) does not address this issue in his comments.

Effective on-line cleaning of catalyst deposits seen in the Coyote pilot testing, especially with the micropores plugged with sodium-sulfur compounds, does not appear to be achievable.

No examples of on-line cleaning methods nor catalyst that would prove resistant to damage from such methods that would be effective in removing surface blinding and pore plugging deposits such as those seen in the Coyote pilot test catalyst even with the suggested edge erosion prevention measures in place have been identified. It is difficult to compare current experience with lower fouling coals with a hypothetical installation on a cyclone boiler firing North Dakota lignite, without having pilot or full-scale testing experience on the subject fuel to expected surface blinding and pore plugging deposits and cleaning operation conditions.

Hartenstein implies, on page A-36 of his report, that catalyst that has been poisoned by sodium compounds can be regenerated in-situ, and that this technique is well developed. ENBW in Germany developed this technique, but it has never had a commercial success. Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. It also has never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst (see Appendix A).

Pilot Testing for SCR Catalyst

In many cases where SCR technology has been applied to fossil fuel-fired boilers located throughout the world burning a variety of coals and solid petroleum byproducts, extensive pilot testing programs have been performed prior to the implementation on full-scale utility boilers: Germany in the 1980's, the United States in the 1980's for low sulfur and high coals, and in Texas since year 2000 on Texas lignite. The application of SCR technology to coal-fired boiler in Germany has been almost exclusively on non-lignite fired units. Both in Germany and in the United States, it has been demonstrated that it is very difficult to solely rely on SCR catalyst suppliers' experience with similar coals and pulverized coal-fired boilers when developing SCR system designs and understanding process issues that are important to the successful deployment, operation, and maintenance of such emissions reduction technology in strict compliance with regulatory and subsequent permit requirements.

Many pilot test programs have been conducted to implement SCR technology when new and unknown process issues have been raised. There have been multiple pilot tests and research and development programs involving application of SCR technology to fossil fuel-fired utility boilers

in Germany. Several are described in Appendix A by Burns & McDonnell's SCR technology consultant assisting in these responses, who participated in them.

These described pilot SCR test programs include a high dust SCR on a wet bottom boiler before the first high dust SCRs were built in Germany, and a TESCO application. The first tests determined that the catalyst deactivated rapidly, which contradicted what the catalyst suppliers believed, which was that such testing was unnecessary. The HDSCR pilot test revealed the fact that arsenic was unknown as a strong catalyst poison. Most of the German utilities decided not to retrofit wet bottom boilers that had fly ash recirculation with a HDSCR so that arsenic poisoning could be avoided (see Appendix A).

Utilities built tail-end SCRs in Germany that included a wet scrubber ahead of the reactor to avoid the arsenic poisoning problems with the catalyst. Again, pilot testing led to the discovery of a new catalyst poison (SiF_4) which caused the first catalyst layer to lose more than 50 % activity in less than 2,000 hours. This demonstrates that SCR catalysts can be severely deactivated even when boilers burn coals with a SCR configuration that were not expected to cause such problems (see Appendix A).

A recent pilot SCR test program in the Southeast United States involving eastern bituminous coal, Venezuelan coal and pet coke at a utility boiler was performed to account for the influences of the fuel on the NO_x activity and SO_2 oxidation rates of the catalyst. With limited worldwide experience on such a range of fuels, the Utility decided to conduct an extensive pilot program to assess impacts on the catalyst (see Appendix A). Following completion of the pilot testing, the catalyst vendors found it necessary to significantly modify and/or completely withdraw the guarantees they had offered prior to the testing.

Mr. Hartenstein and his co-authors support pilot programs for those SCR applications in which new and uncertain process considerations are encountered. In the referenced technical paper (Hartenstein, 1999), Mr. Hartenstein states: *"In principle, the reduction of NO_x emissions with SCR catalysts is a mature technology, which was developed many years ago. Nevertheless, experience has shown that in many applications, special features were required that necessitate*

further optimization of the DeNOx system. In particular, standard solutions were often not possible or optimal when retrofitting existing power plants.”

In the case of Milton R Young, the uncertainty associated with the high sodium concentration and the presence of sodium aerosols in the flue gas raise serious concerns pertaining to catalyst performance. The potential application of any SCR technology at Milton R. Young suggested by the EPA and Mr. Hartenstein is not standard, and is very unique, due to the special considerations pertaining to the lignite, boiler operating temperatures, flue gas reheating, among others. Pilot testing is certainly warranted before any claims that this technology is feasible at M.R. Yong Station can be confirmed. The pilot testing must utilize new concepts and designs that alleviate the problems associated with alkali aerosols. These new concepts and designs do not appear to be currently available from the vendors.

We disagree with catalyst vendors and Mr. Hartenstein that pilot testing is not required for HDSCR, LDSCR, or TESCR prior to application to the boilers at MRYS. They have not cited any substantiated data that show successful SCR experience from coal-fired boilers with similar boiler- and fuel-specific conditions as present on North Dakota lignite-fired cyclone boilers that make this technology infeasible at Young station. The lack of evidence shown to prove that such factors have been solved such that any form of SCR technology would not require extensive pilot testing and design development for these applications is significant and important in supporting the NDDH's arguments against adopting SCR technology as BACT for MRYS boilers.

As we have stated previously, the application of emission reduction technology that requires such extensive pilot testing and design development should not be considered as available and technically feasible for the purposes of a BACT determination (U.S. EPA, 1990).

Vendor Guarantees for TESCR

Burns & McDonnell's consultant (Tackticks LLC) has significant experience in dealing with SCR system suppliers and catalyst vendors involving their initial willingness to offer guarantees and what they will actually agree to sign in the form of a contract. Mr. Hartenstein (2008)

frequently states that various catalyst and SCR system vendors would be willing to offer performance guarantees for the Milton R. Young Station TESCO.

Examples of cases where SCR vendors have initially said they would guarantee performance without hesitation then subsequently changed their offer or settled a claim by the utility for failure to meet guarantees are described in Appendix A.

It is typical for vendors to do this in the absence of a detailed technical specification and contract with commercial conditions and liquidated damages. Actual performance guarantees that the SCR vendor intends to agree with for the purpose of entering a binding contract will only be offered once all technical issues and challenges have been identified and addressed in the system specification. The vendors will not present performance guarantees for negotiation without having assessed their risk mitigation strategy. As the cost of potentially having to provide one or several levels of replacement catalyst in order to make it through the guarantee and warranty periods is significantly less than 10 percent of the total installed cost for a typical coal-fired SCR project, and the total liquidated damages should such replacement be required prematurely are only a fraction of the utility's potential actual and consequential damages, the supplier's financial exposure is decidedly much less than the buyer's (utility) should such failure to meet guarantees and warranties occur.

Temperature Variations for HDSCR

Hans Hartenstein's comments agree with the NDDH's position that such large boiler flue gas exit temperature variations, as shown in Minnkota's April 2007 response letter (Minnkota, 2007B), would not be tolerable for a high dust SCR at MRYS. Mr. Hartenstein (2008) went further to state this would not be tolerable for any HDSCR installed after any type of firing system burning any type of fuel. The ability to successfully control SCR reactor inlet temperatures in a high-dust SCR application at MRYS without impairing lignite pre-drying has not been confirmed.

The EPA's, Plains Justice's, and Hans Hartenstein's comments (2008) all assume that the SCR catalyst system suppliers (boiler original equipment manufacturers) will solve the stated

temperature problems. None of the catalyst vendors queried offered to guarantee their catalyst's performance with the current situation of too low and excessively high operating temperatures on these boilers under various operating conditions. The SCR system suppliers queried did not offer any examples of successful application of proven solutions to the conditions existing at MRYS (B&McD and EERC, 2008). It is speculative and would be inappropriate to assume these challenges have been or will be solved or to expect meaningful responses from vendors knowing the nature of the conditions involved have not been resolved.

Mr. Hartenstein states, on page A-9 of the referenced opinion report (2008), that no flue gas reheating is typically required for HDSCR (and LDSCR). This is incorrect. The majority of coal-fired boilers with HDSCR technology cannot maintain minimum operating temperature over the entire load range, therefore reheating with economizer bypass, split economizer or supplementary heat input from duct burners is necessary (see Appendix A). Because of the unique arrangement of economizers in the flue gas ductwork from Minnkota's boilers, and lack of a natural gas pipeline serving the plant, this has already been dismissed in previous responses to the EPA's comments (Minnkota, 2007A, 2007B, 2007C, 2008).

Burns & McDonnell's SCR Experience

The NDDH's Preliminary NOx BACT Determination included a statement attesting to the "extensive experience with the design and operation of SCR systems" of Burns & McDonnell, which was refuted by the DOJ's commenter (Hartenstein 2008). A brief summary of Burns & McDonnell's size, years in business as an engineering firm and both general and specific areas of experience and technical expertise, particularly in regards to utility powerplant boiler NOx emissions control was presented to the NDDH and EPA in May, 2007 (B&McD and EERC, 2007).

The issue of experience with SCR systems in this response is a question of relevance. It will be helpful to first discuss what typical phases a project may go through from start to completion.

These are:

- Preliminary study and investigation
- Conceptual Design

- Detailed design
- Procurement
- Fabrication and delivery
- Construction
- Commissioning
- Startup and tuning

Project execution involves all phases listed above and, depending on the project and the contracting strategy; the architectural and engineering (A&E) firm's role may involve all of the above or selected portions of the listed phases while remaining portions are delegated to other entities such as technology suppliers, system vendors, or the owner.

Is Burns & McDonnell's SCR Experience even a relevant factor at this stage of the project? Burns & McDonnell's role in this project has been to perform the BACT analysis, not to design two SCR systems for Units 1 and 2 at Milton R. Young Station. Our experience on performing BACT for utility powerplant units located in the United States is relevant and extensive. Some engineering firms only work on the environmental permitting and study aspects of pollution control and emissions reduction projects while others focus more on the implementation and construction. Burns & McDonnell has successfully worked in both areas and continues to provide these services to our clients. Mr. Hartenstein seems confused as to the role of an engineering firm and from that lack of understanding has made some irrelevant commentary.

What constitutes "SCR Experience"?

Relevant experience in various aspects of a project and specifically a retrofit air pollution control project has to be considered. Burns & McDonnell's role in an air pollution control retrofit project does not typically include the "process design" portion but there are many aspects of retrofit projects that are not specific to just an SCR retrofit project. For example, our structural engineers that are experienced at ductwork arrangement, detailed design of hot flue gas ducts, foundation design, structural steel design, consideration for wind, snow, seismic as well as component thermal expansion and movements all contribute to the project. None of those aspects are specific to SCR process design but all are relevant for SCR system design and Burns

& McDonnell has successfully provided these engineering and design efforts on many projects including SCR retrofit projects.

The specific issue discussed in the EPA's comment document on NDDH's Preliminary BACT Determination (NDDH, 2008) is in regard to SCR process design and catalyst design. In this type of retrofit emissions control project, Burns & McDonnell's role is to serve the Owner's needs and gather the data, resources, and expertise needed to execute the project. Burns & McDonnell would develop and specify the operating conditions, fuel, and flue gas parameters and values that form a basis of design which the catalyst supplier relies on, along with their expertise and proprietary knowledge of their products, to offer a proposed catalyst type, pitch and volume required to meet certain performance guarantees and warranty requirements. The catalyst supplier is in the best position to determine how they propose to meet the specified performance responsibility, understand how that offer fits their business' commercial/financial impact, and whether this may impair or enhance the long term supply of their product.

It is within Burns & McDonnell's ability to assess the relevance of the various catalyst suppliers' offers, their experience, and their level of understanding of the site, the project, the fuel and other system concerns in order to advise the owner as to which vendors are deemed qualified for bidding and executing the pertinent portions of an SCR retrofit project. Many utility owners are not comfortable with performing such technology and vendor assessments alone, nor do they maintain the in-house resources that have expertise to do such tasks to a level that significantly reduces their risk of selecting a vendor to provide a product that ultimately does not meet their requirements nor satisfy their expectations.

As has been pointed out in NDDH's Preliminary BACT Determination (NDDH, 2008) and other supporting documents (Minnkota, 2007A, 2007B, 2007C, 2008; B&McD and EERC, 2007 and 2008; Appendix A), significant concerns exist about the unique characteristics of the fuel burned, type of firing, and flue gas and ash constituents and their influence on the viability of SCR application on these units. We recognize this site-specific situation falls outside the current knowledge and experience base of the potential catalyst suppliers. Additionally, some of the significant concerns on this project have nothing to do with what the catalyst supplier can

address, such as the boiler exit temperature. This concern and ways to address it are rightly placed in the boiler design firm's realm of expertise. Burns & McDonnell's role in this phase of the project is to gather, manage, and assess the technical information and advise the owner based on what these entities claim and what has been done elsewhere as well as to investigate publicly-available technical data that is relevant.

Burns & McDonnell's SCR Experience can be categorized in four distinct areas:

- Preliminary studies
- Conceptual designs and cost estimates
- Engineering management of project implementation
- Detailed design engineering duties

Each of these roles serves an important function during the overall project timeline. We can elaborate and provide more details on each category of specific experience on various projects. This is considered business proprietary information and will only be made available if needed. We do not feel this project-specific information is relevant to the current issue raised by the Hartenstein (2008), and have not included these details at this time but can if required. A summary of the roles and experience is provided below as we feel it will suffice to demonstrate our capability and viability for the role we have served thus far on this effort.

- Preliminary studies

Burns & McDonnell has performed studies for utility clients for many years. The level of detail in what is deemed a preliminary study can be described as typically evaluating various alternatives. In a pollution control retrofit study, various compliance scenarios are evaluated in a screening analysis where technologies are reviewed with regard to several criteria: whether or not the technology is commercially available or under development, the level of experience of the technology, what suppliers are qualified, an evaluation of regulatory impact, very rough screening level cost estimates of the project, discussion of contracting alternatives, and schedule. In some cases when there is uncertainty or a range of alternatives and compliance scenarios, where more than one pollutant is involved, and more than one unit, possible variable levels of control for each pollutant, a matrix of alternatives and

potential outcomes is developed to help narrow the focus of the overall strategy. Burns & McDonnell has performed many studies as described that have involved a wide range of complexity. This experience includes studies for utility clients with multiple unit sites and multiple sites covering SO₂, NO_x, Hg, and particulate emissions along with some current work that includes CO₂ control as potential regulatory impacts are being assessed. Other studies have been specific single unit evaluations of SCR application only that were done to provide the owner a relative cost and impact on the utility operation. In summary, Burns & McDonnell has performed numerous studies of these types over the past thirty plus years, of which SCR technology retrofit was included in nearly every one of them over the past five years.

- Conceptual designs and cost estimates

Typically after the screening level or preliminary study has been performed, many owners need a more definitive and site specific evaluation of the retrofit project for their unit at the site. Burns & McDonnell has performed these evaluations for SCR retrofits; particulate control retrofits including new pulse jet or reverse air fabric filters; electrostatic precipitator projects including rebuilds, upgrades, conversion to fabric filter, and hot side to cold side conversions; and various SO₂ control alternatives including wet flue gas desulfurization (FGD) or semi-dry FGD, including spray dryer scrubbers, and circulating fluidized bed (CFB) dry scrubbers. FGD technology studies have included processes based on various reagents such as wet lime, wet limestone, ammonia, lime spray drying, and a few of the more developmental proprietary processes that are fairly new to the market. Also, we have performed evaluations of upgrades to existing particulate and SO₂ removal systems where upgrade and refurbishment is being evaluated along with new equipment system retrofits to look for the best solution comparing capital cost, arrangement, operating costs, outage requirements, and construction constraints. The level of detail required or desired by an Owner on this type of project can vary. Some of these projects can extend over 12 months in duration and can involve 20-30% of the design effort being complete whereas others are less detailed and can involve 4-8 months of engineering and evaluation.

The main point here is that Burns & McDonnell's experience and expertise is relevant to our role in providing BACT Analysis study reports, additional information and responses as inputs to the NDDH's BACT Determination process. It includes retrofit and new utility and industrial powerplant air pollution control projects involving SCRs and other technologies, and involves individuals who apply process design and operating knowledge, whether they exist within Burns & McDonnell or are available through technology suppliers or consultants, to the specific conditions involved. To suggest that A/E firms provide no value to clients for these projects (Hartenstein, 2008) is personal opinion not based on an informed understanding of project roles and responsibilities nor utility owner perspectives.

Comments by Sargent and Lundy on SCR Experience

On page A-31 of Mr. Hartenstein's report, Hartenstein calls into question the SCR experience of Sargent and Lundy (S&L). The following response to Mr. Hartenstein's comments has been prepared by Mr. William Depriest of S&L (Depriest, 2008):

"S&L's involvement in the U.S. Power Industry's SCR program in the late 1990's and 2000's as presented to the NDDH in May 2007 represents NO_x reduction activities associated with the NO_x SIP CALL and various projects related to NO_x non-attainment areas in the U.S. These NO_x reduction programs represent the vast majority of SCR work in the U.S. during that time frame but it does not include any new unit work or any gas fired combined cycle work which we would classify in a different category of experience. Specifically, we were involved in 53 of 113 units in-service or near to in-service at the time of May 2007 to the best of our knowledge. Again, it is important to note that these NO_x programs represent by-far the vast majority of SCRs in progress in the U.S. at that time and that S&L was clearly a leader in this area.

In regard to Mr. Hartenstein's claims to S&L's role on these projects, I have the following comments:

- S&L provided all of the process design on the vast majority of our SCR projects. In some cases (6) we "teamed" with another entity with SCR expertise and shared in the process design role.
- S&L specified the process design criteria for the catalyst on all of our projects short of the actual formulation chemistry which is typically proprietary to the catalyst supplier.
- S&L has never made claims to either an S&L guarantee position regarding catalyst performance or direct operating experience with SCR systems.”

Comments on Hans Hartenstein’s Qualifications for Expert SCR Opinions

Enclosure 1 of the EPA’s referenced letter (EPA, 2008) included descriptions of relevant work experience, and the resume Mr. Hans-Ulrich Hartenstein in Appendix D. Mr. Hartenstein also made numerous statements in his comments regarding the NDDH’s Preliminary NO_x BACT Determination attesting to his considerable technical knowledge and personal experience with the design and operation of SCR systems (Hartenstein, 2008).

According to Burns & McDonnell’s consultant assisting in these responses to Mr. Hartenstein’s and the EPA’s comments on SCRs, Hartenstein’s claimed personal experience and technical expertise on the design of German SCRs, especially of the tail-end variety, is not what it appears to be (see Appendix A). It is difficult to determine the true extent of Mr. Hartenstein’s SCR technical experience, but his qualifications state that his direct involvement with SCR technology on coal-fired boilers has largely occurred since 1999 in the United States, not in Germany during the majority of the mentioned SCR retrofits. Mr. Hartenstein’s involvement with SCR technology seems to be mostly business development related.

As Mr. Hartenstein states himself on page A-6 of the referenced opinion report (2008), he was not involved in SCR retrofits for utility boilers until 1993. Experience claimed with waste-to-energy LDSCR systems, which are completely different and not comparable to LDSCR systems

on fossil fuel fired boilers, does not transfer effectively to the North Dakota lignite cyclone-fired units in question.

Fuel Switching

While clean fuels may be considered to meet BACT requirements, clean fuels may only be considered when the permit applicant proposes to meet BACT using clean fuels. See Pub. Law No. 101-549, § 403(d), 104 Stat. at 2631 (1990) (U.S. Senate Report of the Committee on Environment and Public Works to Accompany S. 1630 (Dec. 20, 1989) discussing the addition of “clean fuels” to the definition of BACT in the 1990 Clean Air Act Amendments).

Fuel switching/blending/cleaning was mentioned in the EPA’s comments (EPA, 2008, Enclosure 2) but only fuel cleaning was questioned as a potential technique that was not fully considered in the NDDH’s analysis. Fuel cleaning has typically been practiced where removal of sulfur, typically as inorganic pyrite form (FeS), is performed by simple density separation methods (“air jigging” in a classifier separate from or within coal pulverizers which reject the heavier pieces). This reduces the amount of sulfur introduced into the furnace and potentially emitted to the downstream gas cleaning equipment.

In Minnkota’s NO_x BACT determination case, fuel cleaning would presumably not be attempting to remove nitrogen from the fuel, for reduction of the formation into NO_x, as this would be impractical from a solid fuel. Nitrogen oxides are also created from nitrogen in the combustion air being exposed to high temperatures in the cyclone burners. So the issue of fuel cleaning is really one of trying to remove elements in the lignite besides nitrogen, for the purpose of mitigating other problems associated with those specific elements. Thus, it appears that the EPA and Plains Justice are raising this issue in trying to use fuel cleaning as an “enabling technique” so that SCR technology could be deployed without resolving the problems associated those problem elements.

Ash is included in the Center lignite supplied from the adjacent mine. Some ash comes from the mineral layers that are above and below the lignite seams as a result of the practical inability to completely separate the lignite from the burden material during mining. The remainder and majority of ash in the lignite is bound within the coal particles. Reducing the amount of bound

ash in the lignite prior to introduction to the boiler would not be practical with known methods of fuel cleaning.

In cyclone boilers, ash is not normally problematic if it melts within the cyclone burner barrel and drains out to become bottom ash. In the case of North Dakota lignite-fired cyclone boilers, there is a high amount of ash that is not captured and drained from the cyclones and lower furnace as bottom ash. Thus, a higher than typical 70:30 bottom ash: flyash ratio for cyclone boilers occurs at MRYS, closer to a 50:50 split. This means that a significant amount of ash is released from the burners as flyash, where these particulates escape and become entrained in the flue gases rising up through the furnace.

As previously discussed in earlier responses, it is sodium and potassium-related elements that would cause SCR catalyst deactivation. These troublesome elements are mostly in forms where they are organically-bound within the coal particles, so simple “air jigging” classification methods are believed to be ineffective.

The arguments for coal cleaning also do not cite specific examples where minerals such as sodium and potassium have been removed economically and would not require pilot testing in order to demonstrate that the technology is developed sufficiently to be successful for this application

Non-SCR NO_x Controls

Plains Justice implies that because various non-SCR NO_x reduction technologies have been demonstrated or pilot-tested on any utility boiler, the control technology would be technically feasible at MRYS. This ignores the differences in specific conditions at the MRYS boilers compared with where the technology has been demonstrated that are pertinent to whether the technology is appropriate and could be successful at MRYS.

Successful implementation of NO_x controls is highly dependent on the specific configuration and process conditions that lend themselves to be compatible within the limits of constructability, survivability, and effectiveness. Just because a control technology is

“technically feasible” based on Plains Justice’s interpretation of the NSR Manual (U.S. EPA, 1990) does not mean it will work effectively at MRYS to reduce NO_x emissions. Many comments by Plains Justice give the impression that they did not review Minnkota’s BACT Analysis study reports (B&McD, 2006), or understand the technical reasons why such non-SCR NO_x control technologies were not evaluated for MRYS.

An example of this is Plains Justice’s suggestion that injection of a fluxing agent to increase melting of solid combustion products will reduce catalyst poisoning due to a reduced amount of flyash. Superficially, this sounds plausible, but where fluxing agents have been added to coal for reduction of impact on SCR catalyst, it is due to the practice of flyash reinjection or firing of bituminous coal with low calcium-to-arsenic ratio. For the cyclone boilers firing North Dakota lignite, the fuel and its response to melting is more complex than other coals where the use of fluxing agents has been demonstrated as described. These cyclone boilers are designed specifically to melt the fuel ash in the cyclone burners as part of the combustion process. Flyash reinjection is not practiced, and arsenic is not significant in North Dakota lignite-fired cyclone boilers; however, sodium is a known catalyst poison and is present in abundance in ND lignite.

The problem with Plains Justice’s argument is that the use of the fluxing agent mentioned would not prevent melting of sodium compounds which creates a fine fume that does not get captured in the molten slag. Sodium, in fact, is preferentially released from the slag that forms in the cyclone burners and lower furnace and is then exhausted where it is available to react with sulfur and calcium to foul and deactivate SCR catalysts. This is the main source of sodium that ends up in the boiler’s exhausted flue gas instead of remaining in the slag. This has been explained in numerous ways by EERC in previous responses to EPA comments (Minnkota, 2007A, 2007B, 2007C, 2008; B&McD and EERC, 2007 and 2008).

Most of the “commercially available solutions” to facilitate the use of SCR that Plains Justice lists involve coal cleaning and drying or beneficiation. MRYS already has cyclone lignite drying systems, which are required for preparing the fuel for proper combustion in the cyclone burners. The arguments for coal cleaning also do not cite specific examples where minerals such as sodium and potassium have been removed economically and would not require pilot testing in

order to demonstrate that the technology is developed sufficiently to be successful for this application.

Minnkota's BACT Analysis reports and previous responses to EPA comments (Minnkota, 2007A, 2007B, 2007C, 2008; B&McD, 2006; B&McD and EERC, 2007 and 2008) have explained that other non-SCR technologies, such as various forms of enhanced selective non-catalytic reduction (SNCR) with natural gas or coal reburn, low NO_x burners, and flue gas recirculation are not appropriate for the operating conditions experienced inside the boilers at MRYS. Plains Justice appears to ignore the arguments previously presented regarding the expected limitations of effective NO_x reduction at MRYS with modest cyclone air-staged combustion compared with lower NO_x emissions demonstrated at Ameren's Sioux plant with deeply staged cyclones using lower furnace urea reagent injection. Oxygen-enhanced combustion, NO_x adsorption from flue gases using activated coke, and various chemical treatment processes have not been demonstrated on cyclone boilers or lignite fuels, and thus would require extensive pilot or full-scale testing in order to assess their potential performance and economics. The interpretation of the NSR Manual (U.S. EPA, 1990) noting that requiring extensive pilot or full-scale demonstration of the technology is outside the BACT process beyond step 2 has already been presented in previous responses (Arfmann and others, 2007).

Conclusions

In the end, EPA's objections to NDDH's Preliminary BACT Determination may be reduced to disputing NDDH's characterization of the gas stream characteristics and the impacts of those characteristics on boiler and emissions control operations. EPA and Hartenstein suggest that these impacts can be resolved by the use of TESCR, and that TESCR technology will work at MRYS (2008). We believe their arguments are flawed because they fail to recognize the significance of these facts:

- There is no prior experience with full-scale SCR on any unit firing North Dakota lignite.
- Results from the only known example of simulating SCR catalyst exposure to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler showed severe catalyst blinding and plugging due to sodium and potassium rich species

(Benson, 2005). Coyote pilot-scale SCR test was intended to evaluate the fouling potential of SCR on lignite coal results. The Coyote test was developed by a consortium of three catalyst vendors, EPRI, U.S. DOE, and other participants that design and install SCR systems as well as end-user utilities that have applied SCR on their boilers. This team was competent and Minnkota believes this testing was valid for its intended purpose. From this sole test, it was determined that there are significant impediments to using SCR on MRYS. Peer-reviewed literature written by many authors has verified that sodium and potassium species are fatal to the catalyst life.

- European SCR experience at lignite-fired utility boilers has been very limited. One HDSCR installation was at Voitsberg Unit 3 (Austria) and there were HDSCRs on three units at the Bayernwerk Schwandorf plant in Germany. These units were not cyclone-fired, the fuel burned was much lower in sodium than North Dakota lignite, and the units are no longer in operation (see Appendix A).
- There have never been, to the best of our knowledge, any tail-end SCRs applied to coal-fired utility boilers burning lignite, whether in Europe or North America (see Appendix A).
- There have not been, to the best of our knowledge, any TESCRS installed on any coal-fired utility boiler anywhere in the world since 1991, when the TESCR on the Siersdorf power station in Germany was placed into service. Siersdorf did not burn lignite, did not have a Wet FGD system, and has since been decommissioned (see Appendix A). This 17-year span since the last TESCR installation on a coal-fired utility boiler belies EPA's contention that TESCR has been universally applied and represents BACT for NOx control on a North Dakota lignite-fired cyclone boiler.
- Contrary to statements made by Mr. Hartenstein (2008), there are no currently active or planned TESCR installations in the U.S. on coal-fired utility boilers. PSEG Mercer Station does not have TESCR configuration (it is LDSCR), and the SCR systems at South Oak Creek Station for WE Energies will also be LDSCR, not TESCR as stated by Hartenstein. The change in SCR type at South Oak Creek was made due to the technical incompatibility of full scrubbing Wet FGD and the type of gas-to-gas heat exchanger

(GGH) required for TESCO. Neither of these plants burn (or will burn) high-sodium lignite (see Appendix A).

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APPENDIX A

**Tackticks, LLC Report
“Comments to Enclosure 1 Hans Hartenstein’ Expert Opinion Report”**

Tackticks, LLC General Company Information

Resume for Volker Rummenhohl

Resume for Robert E. Johnson

Tackticks LLC SCR Consulting and Process Engineering Reference List, June 2007

Minnkota
Milton R. Young Station
NO_x BACT

Comments to Enclosure 1 Hans Hartenstein's Expert Opinion
Report

Prepared for
Burns & McDonnell Engineers

by:

Tackticks, LLC
Volker Rummenhohl, Principal Author
Robert Johnson
September, 2008



Introduction

Mr. Volker Rummenhohl, Tackticks, LLC, has prepared the following comments to Mr. Hans Hartenstein's Expert Opinion Report pertaining to the "Feasibility of SCR Technology for NOx Control Technology for the Milton R. Young Station, Center, North Dakota (July 2008)."

The following comments address five general topics rather than a point by point rebuttal of Mr. Hartenstein's statements. These five general topics are: Mr. Hartenstein's qualifications, information not reported by Mr. Hartenstein, incorrect information presented by Mr. Hartenstein, vendor guarantees and catalyst poisons / pilot tests.

In general, Mr. Hartenstein mainly reports the opinion of third parties and not his own. In some cases where his own opinion is offered, significant materially-related information is either missing or the information he presents is incorrect. For instance, he mistakenly refers to the SCR systems at PSEG Mercer Station as tail end systems. Mr. Hartenstein does not have hands on experience with the design, commissioning, operation or maintenance of tail end SCR systems (TESCR) for coal fired boilers. He also does not have experience with design or commissioning of Low Dust SCR systems (LDSCR) for coal fired boilers.

In his report, Mr. Hartenstein focuses entirely on the catalyst and ignores problems that have occurred with the subsystems of a SCR plant.

Qualifications

As Mr. Hartenstein states himself on page A-6 of the referenced opinion report, he was not involved with SCR retrofits for utility boilers until 1993. His direct involvement with SCR technology on coal-fired boilers has largely occurred since 1999 in the United States, not in Germany during the majority of the mentioned SCR retrofits. Mr. Hartenstein's involvement with SCR technology seems to be mostly business development related. Experience claimed with waste-to-energy LDSCR systems, which are completely different and not comparable to SCR systems on fossil fuel fired boilers, does not transfer effectively to the units in question. The size is much smaller and this allows the use of different pre heat equipment. All waste-to-energy plants in Europe have either activated carbon injection or fixed bed activated carbon plants. Those take out all poisons such as all acidic components, arsenic etc. from the flue gas.

The dead line for the retrofit of SCR systems for fossil fired units was January 1, 1990 in Germany. All but one TESCR system was built and commissioned by that date. The last TESCR system was installed in 1991 at the 170 MW Siersdorf power station, firing bituminous coal, equipped with a dry circulating fluidized bed scrubber and electrostatic precipitator with natural gas-fired duct burners ahead of the TESCR reactor. Mr. Hartenstein was not involved with that project. The author was responsible for process

design and commissioning for the Siersdorf power station's SCR system constructor. This power station has since been decommissioned and dismantled.

Missing information

On page A-11, Mr. Hartenstein references the high dust SCR system (HDSCR) that was installed in 1990 at the Voitsberg Power Station in Austria. This paragraph concludes with the implication that lignite-fired boilers are among the 30,000 MW of SCR systems installed in Europe. However, Mr. Hartenstein does not offer the information that more than 20,000 MW of lignite fired units in Germany were not required to install SCR in order to comply with the national regulation. These units were exempted from the regulation despite the fact that they would not achieve the required emission limit of 200 mg/Nm³. It should be noted that high dust SCR systems were installed and operated at the lignite-fired Bayernwerk Schwandorf plant in Germany. The units fired a Czech lignite and were decommissioned in the late 1990s. Voitsberg Unit 3 and the units at the Bayernwerk Schwandorf plant in Germany, which were not cyclone-fired, have been the only SCRs ever to operate on European lignite, and the fuel they burned was much lower in sodium than contained in North Dakota lignite. To the best of my knowledge, there have been no TESCRs built nor are any currently operating anywhere in the world on lignite-fired utility boilers.

Mr. Hartenstein also did not state in his report that Germany had only one cyclone-fired (slag tap) unit with a SCR system. This unit is Walsum 7, the NO_x emissions control system is a LDSCR, and the unit does not burn lignite.

Mr. Hartenstein also did not explain that the Voitsberg lignite-fired dry-bottom pulverized coal unit operated only for a very short period of time with high dust SCR, before the boiler was taken out of business and decommissioned. The power station does not exist any longer.

Mr. Hartenstein also fails to explain that on utility boilers you cannot send saturated gas from the scrubber to the gas-gas heat exchange (GGH) for the TESCR. The gypsum in the flue gas will deposit on the SCR GGH surface and lead to a fast pressure drop increase. It is extremely difficult or impossible to clean this during an outage. The FGD GGHs are frequently washed with liquid water during operation, which keeps them clean.

Mr. Hartenstein, on page A-10 of his report, displays a diagram purporting to be the configuration of a TESCR downstream of a wet FGD system. What he fails to explain is that there is no TESCR on any utility boiler anywhere in the world that uses this configuration successfully downstream of a wet FGD. For the reasons noted above, the GGH of the TESCR cannot accept the flue gas immediately from the FGD without reheat. This diagram offered by Mr. Hartenstein represents an infeasible configuration.

Mr. Hartenstein reports on page A-50 regarding the "We Energies South Otter (*sic*) Creek Generating Station" and implies that this SCR project proves the viability of TESCR. He fails to explain that for this project, which is located at the South Oak Creek plant,

Alstom and Howden, which are the main GGH suppliers for the SCR market, both required that the flue gas be free of moisture droplets and preheated to allow the use of TESCO. Otherwise they would not offer performance guarantees. This particular project has now changed the SCR system to a LDSCR due, in part, to issues related to the GGH.

In the German TESCO installations, a rotary GGH could be used because the required FGD removal efficiency was about 80% , and the flue gas leaving the FGD could be reheated with bypass or by other means prior to entering the GGH for the TESCO. This is confirmed by the data shown in the boiler process flow diagram from an operating utility boiler plant shown by Mr. Hartenstein on page A-49 of his report. It is clearly seen that the flue gas temperature entering the GGH for the TESCO is 87 °C, or more than 30 degrees C above the saturated flue gas temperature at the FGD absorber outlet (typically 55 °C). Obviously, although not shown on his diagram, the flue gas at this plant has been reheated prior to the inlet to the TESCO GGH. The FGD systems in Germany typically use an “FGD GGH” to accomplish this reheat. However, leakage across the FGD GGH makes a rotary GGH infeasible for TESCO systems following high SO₂ removal efficiency FGD systems, as required in the U.S.

Mr. Hartenstein references several times the “ill-designed” pilot test plant that was conducted at the Coyote Station. However, he does not offer a single reason why the pilot plant was “ill-designed”.

Incorrect Information

Mr. Hartenstein states, on page A-9, that no flue gas re-heating is typically required for HDSCR and LDSCR. This is incorrect. The majority of the units cannot maintain minimum operating temperature over the entire load range, therefore reheating with economizer bypass, split economizer or duct burners is necessary. Vectren installed duct burners on four units.

Denmark and the Netherlands did not have SCR by the end of the 80s, as stated by Mr. Hartenstein on page A-11.

While rotary, tubular and plate type heat exchangers have been used for re-heating flue gas, as noted by Mr. Hartenstein on page A-12, not a single coal fired unit with a LDSCR or TESCO system has a heat exchanger other than rotary. As discussed above, this poses a problem with fouling and leakage when located directly downstream of a wet scrubber without reheat.

Mr. Hartenstein states on page A-12 for turbine limited units: “In this case, the heat rate penalty of the unit may be eliminated completely”. This is complete nonsense. There will still be a penalty since more heat input is necessary for the same electrical output.

Mr. Hartenstein states on page A-13 that it can reasonably be assumed that the retrofit cost today would be the same as stated in an EPRI report from 1989. The cost for rotary heat exchangers for LDSCR and TESCO are much higher today.

Further, Mr. Hartenstein states on the same page that TESCR technology was “generally adopted as a universally applicable SCR solution for all types...” There has never been another TESCR built after Siersdorf, which was finished in early 1991, in the US or Europe.

The following is an excerpt from page A-19 of Mr. Hartenstein’s report concerning minimum operating temperature:

“As a matter of fact, the only thing that dictates the minimum SCR operating temperature are the residual SO₂ and SO₃ concentrations in the flue gas, which determine the ABS reaction equilibrium and thus the probability for ABS deposition on the catalyst and in the gas/gas heat exchanger. This, however, is not an irreversible catalyst poisoning issue but rather a reversible fouling problem not related to the SCR catalyst per se but simply to the reaction chemistry between H₂O, SO₃ and NH₃ in the flue gas at various temperatures.”

It is factually incorrect that the temperature depends only on the SO₂ and SO₃ concentration of the flue gas. It is independent of the SO₂ concentration. Minimum operating temperature depends primarily on the SO₃, ammonia and moisture concentrations in the flue gas. Catalyst fouling is only reversible if no calcium has reacted with the ammonium bisulfate. Once that has happened it becomes irreversible.

On page A-19, Mr. Hartenstein states:

“The reaction equilibrium between ammonium sulfate ((NH₄)₂SO₄) and ammonium hydrogen sulfate (NH₄HSO₄), which is often incorrectly referred to as ammonium bisulfate or ABS, in the flue gas. Both ammonium sulfate and ammonium hydrogen sulfate are products of the inevitable reaction of gaseous sulfur trioxide (SO₃) and ammonia (NH₃) contained in the flue gas upstream of the SCR catalyst.”

Ammonium hydrogen sulfate is a different name for ammonium bisulfate.

Mr. Hartenstein discusses, on page A-22, “Ceram’s extensive experience with lignite..” With only one plant with CERAM catalyst having operated for a short period of time on lignite and a few pilot programs, it is impossible to say that CERAM has extensive experience on lignite fired plants.

Mr. Hartenstein devotes an entire section to soluble sodium (Section 6.3, page A-27). He notes in the second paragraph a statement from one of the catalyst suppliers that sodium is not a catalyst poison at SCR operating temperatures.

Yet, on page 5 of the technical paper, “Utility Experience with SCR in Germany,” presented at the Sixteenth Annual International Pittsburgh Coal Conference in October, 1999, Mr. Hartenstein and his co-authors reported SCR catalyst deactivation due to

sodium at the RWE Staudinger plant in Germany. Specifically, it is reported on page 5 that "...the fly ash from the German coal formed highly adhesive deposits, while the portion of South African coal contributed to the formation of a liquefied fly ash.

The reason for this was determined by a chemical analysis of the fly ash. It can be seen that the content of the alkali sulfate, which adheres to the surface of the fly ash particles, favors the tendency to agglomerate. A phase analysis of the deposits revealed crystalline sodium aluminum sulfate and potassium aluminum sulfate ($\text{NaAl}(\text{SO}_4)_2$; $\text{KAl}(\text{SO}_4)_2$).

This information would tend to support the Department's opinion related to the formation of sodium-related deposits on the SCR catalyst and accelerate the deactivation of the catalysts. This information would also tend to conflict with Mr. Hartenstein's statement, on page A-28 of his expert report, that the "...the intrusion of liquid pyrosulfates is no major concern with respect to a severe, rapid catalyst deactivation."

Mr. Hartenstein states on page A-29:

"...of less than seventy two (72) hours, SCR reactors are typically "buttoned up hot," which means the SCR reactor is isolated from the flue gas path during shut down by means of putting it in a bypass mode while the SCR is still at its design operating temperature. The cooling rate of such a "buttoned up hot" SCR reactor is known to be extremely slow. Unless forced cooled with ambient air no "buttoned up hot" SCR reactor loses more than approximately 50-100 degrees and therefore gets nowhere near the sulfuric acid or even the moisture condensation temperature in a seventy two (72) hour period."

This is a statement, which is incorrect and must be based on the lack of practical experience. I have been involved in several measurements of cool down rates for SCR units. The rate differs in a range between five and ten degree Fahrenheit per hour depending on the quality of the dampers and the insulation, the unit size, catalyst volume installed and the ambient conditions. It must also be considered that the boiler is operated at low loads before during the shut down phase. This means the starting temperature is already very low. Almost all units are below the acid dew point after 72 hours and most of them at the water dew point.

Mr. Hartenstein takes exception to the Department's statement on page A-29, as excerpted below:

"The Department concludes that "the flue gas generated at M.R. Young Station is different from the flue at any plant where SCR technology has been applied." The absoluteness of this statement, which is not even limited to power plans, is quite amazing as it indubitably implies that the Department has complete detailed knowledge not only of the flue gas composition of every other power plant in the world equipped with an SCR system but also of every other plant in the world where the SCR technology is applied. Even though theoretically possible, the lack of any data from all these other plants

strongly suggests that this may be highly questionable and largely overreaching. As a matter of fact, I am sure that I could easily present to the Department several plants where the SCR technology has been applied successfully that the Department doesn't even know that these plants existed."

The statement of the Department can be easily supported since there is not a single SCR system in operation on a lignite fired boiler in the United States, nor in Europe, at this time.

The statements on pages A-31 and A-32 that Burns & McDonnell never has given a guarantee and never provided process design are incorrect.

On page A-32, Mr. Hartenstein states:

"As a matter of fact, all catalyst related performance guarantees (NOx removal efficiency or activity, SO₂/SO₃ conversion rate, catalyst life or deactivation rate, etc.) are never provided by anyone other than the catalyst manufacturers. Even the SCR equipment suppliers only pass through the catalyst performance guarantees obtained from the catalyst manufacturers to the end customer. And at least two (2) of these catalyst manufacturers, namely Haldor Topsoe and CERAM were clearly willing to provide industry standard type performance guarantees for their catalyst."

This statement can only be explained by a lack of involvement in the design of SCR plants. Catalyst performance guarantees are not always a pass through from the system supplier. Depending on the contract, there are a lot of other issues that are not done by the catalyst supplier. Distributions, pop-corn ash screens, control system, and analyzer system all impact the performance of the SCR catalyst but may not be guaranteed by the catalyst supplier. These are typically warranted by the system supplier.

On page A-39, Mr. Hartenstein states:

"Yet, the most successful SCR retrofits in the U.S. were done as turn-key installations without the use of an A/E."

There are certainly many examples of successful SCR projects which were executed on different contractual conditions.

Mr. Hartenstein states on page A-50 that the SCR systems at PSE&G Mercer Generating Station are TESCR. This is incorrect. Both SCR systems at this plant are LDSCR with flue gas re-heating. Mr. Hartenstein also states that the SCR systems at WE Energy South Oak Creek Station will be TESCR. This is also incorrect. South Oak Creek started out as TESCR, but technical difficulties have forced the change to a LDSCR.

Vendor Guarantees

Mr. Hartenstein frequently states that various catalyst and SCR system vendors would be willing to offer performance guarantees for the Milton R. Young Station SCR. It is typical for vendors to do this in the absence of a detailed specification and contract with commercial conditions and liquidated damages. Performance guarantees will only be offered once all technical issues and challenges have been identified and addressed in the system specification. The vendors will not present performance guarantees for negotiation without having assessed their risk mitigation strategy.

A recent example of this occurred on the retrofit of SCR systems on two units in Florida. Three catalyst vendors provided totally different sets of preliminary guarantees at the beginning of the project. All three suppliers changed their guarantees after a 2,000 hour pilot test significantly identified the effects of various fuels on the expected performance of the catalyst.

Another example occurred several years ago on three SCR units in Pennsylvania. Two catalyst suppliers (Haldor Topsoe and CERAM) provided guarantees based on their experience with similar coals, but were very surprised about the rapid deactivation of the catalyst. These companies are those most cited in Mr. Hartenstein's paper. The money the utility received in a settlement with the turn key supplier was a very small fraction of the long term operating costs absorbed by the Utility to maintain SCR system operation.

Catalyst Poisons and Pilot Projects

In many cases where SCR technology has been applied to fossil fuel-fired boilers located throughout the world burning a variety of coals and solid petroleum byproducts, extensive pilot testing programs have been performed prior to implementation on full-scale power plants: Germany in the 1980's, United States in 1980's, and in Texas since year 2002.

There are two pilot tests and one R&D program in which the author was involved with in Germany. The results of these programs emphasize the importance of understanding design and process issues for certain applications. These also demonstrated that it is very difficult to solely rely on experience with similar coals and boilers.

The first was a pilot program for a high dust SCR on a wet bottom boiler at the Franken power station in Germany. This was before the first HDSCRs were built in Germany. All catalyst suppliers said that it would be unnecessary to conduct a test program, since these companies had sufficient experience basis from the units in Japan. It turned out that the catalyst deactivated rapidly. Some catalyst types lost almost all of their activity in just 200 hours. At this time, arsenic was not known to be an issue for the catalyst because it had not been observed in the Japanese SCR systems. The pilot test revealed the fact that arsenic is a heavy catalyst poison. Most of the utilities decided not to retrofit wet bottom boilers that had fly ash recirculation with a HDSCR so that arsenic poisoning could be avoided.

The second pilot program was in the Reuter power station in Berlin. The author was involved in a pilot plant that included a wet scrubber and a TESCO. The result was that it is impossible to have saturated flue gas going to the GGH of the TESCO without drying and pre heating it. The gypsum in the flue gas plugged the TESCO GGH with no means to clean it. The temperatures are too high to clean it with liquid water as it is frequently done on the FGD GGHs.

Utilities built TESCOs in Germany to avoid the arsenic problems. Everybody thought that an indefinite catalyst lifetime could be expected. It was even more surprising to see that the first layer on which activity was measured lost more than 50 % activity in less than 2,000 hours. Again, a new catalyst poison was detected. It was SiF_4 , a gaseous component which forms on the plates of the FGD rotary heat exchanger in a reaction of SiO_2 , H_2SO_4 and HF. It was an R&D project of several million dollars to detect the poison, the formation mechanism and the solution. Lime was injected upstream of the FGD, which bound the sulfuric acid on the GGH plates. The capital cost of the lime system is certainly not included in the EPRI cost reports referenced by Mr. Hartenstein.

See:

German Experience Sheds Light on SCR O&M Issues, September 1992 issue of Power magazine, Coauthor. (attached).

The author also participated in a more recent pilot test program for a Southeast U.S. Utility. At this particular plant, a proposed SCR system had to be designed for three very different fuels: Eastern bituminous, Venezuelan coal and pet coke. Due to very stringent permit conditions related to NO_x , NH_3 and SO_3 emissions, the SCR system and catalyst had to account for the influences of the fuel on the NO_x activity and SO_2 oxidation rates of the catalyst. With limited worldwide experience on such a range of fuels, the Utility decided to conduct an extensive pilot program to assess impacts on the catalyst. All three suppliers changed their guarantees after a 2,000 hour pilot test identified significant effects of the various fuels on the expected performance of the catalyst. This SCR is not yet operational.

The EPA also fails to recognize and acknowledge that significant pilot testing has been conducted at two power plants in Texas that fire lignite supplied from various locations in Texas, and that there are no cyclone-fired boilers in Texas. The EPA has gone down the same path that tried to compare German SCR applications, which lack significant cyclone boiler experience and is not currently required for lignite-fired boilers, to be appropriate and comparable to North Dakota lignite-fired cyclone burner units. These are misleading statements and contrary to the presentation of the body of information submitted in support of the NDDH's preliminary BACT determination for MRYS.

These examples emphasize the importance of understanding the intricate process design issues that will influence SCR performance. The industry has benefitted from the many

pilot test programs that have been conducted to implement SCR technology when new and unknown process issues have been raised. In the case of Milton R Young, the uncertainty associated with the high sodium concentration and the presence of sodium aerosols in the flue gas raise questions pertaining to catalyst performance. Pilot testing is certainly warranted.

Mr. Hartenstein and his co-authors support pilot programs for those SCR applications in which new and uncertain process considerations are encountered. On page 2 of the technical paper, "Utility Experience with SCR in Germany," presented at the Sixteenth Annual International Pittsburgh Coal Conference in October, 1999, Mr. Hartenstein states: *"In principle, the reduction of NOx emissions with SCR catalysts is a mature technology, which was developed many years ago. Nevertheless, experience has shown that in many applications, special features were required that necessitate further optimization of the DeNOx system. In particular, standard solutions were often not possible or optimal when retrofitting existing power plants."*

Mr. Hartenstein implies, on page A-36 of his report, that catalyst that has been poisoned by sodium compounds can be regenerated in-situ, and that this technique is well developed. Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. ENBW in Germany developed this technique, but it has never had a commercial success. It also has never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst.

The possible application of any SCR technology at Milton R. Young is not standard, due to the special considerations pertaining to the lignite, boiler operating temperatures, flue gas reheating, among others.

C: HN, VAN, WHP, REJ, PLC, FES
LIB.

Experience sheds light on SCR O&M issues

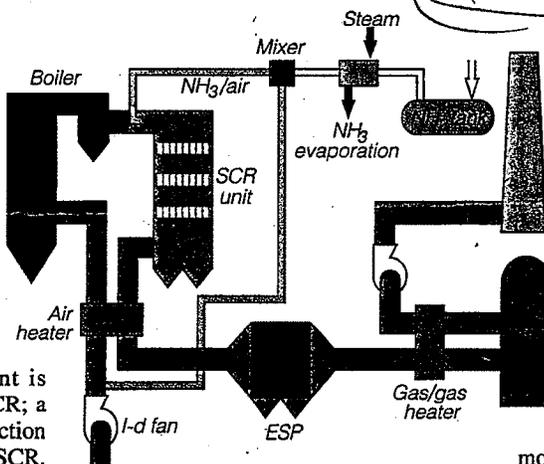
German application of selective catalytic reduction (SCR) for controlling NO_x from coal-fired boilers is extensive. But while design of SCR units is well-known, operating and maintenance experience highlights critical issues that may not be understood by US power producers

By Volker Rummenhohl and Helmut Weiler, Steag AG, and William Ellison, Ellison Consultants

Whether prompted by federal, state, or local regulations, it seems clear that new coal-fired powerplants built in the US will require high-efficiency NO_x control. SCR is perhaps the most widely applied technique worldwide for this purpose (POWER special reports, "Controlling NO_x emissions," September 1988; "Clean Air Act Amendments: The Engineering Response," June 1991). One non-utility generating (NUG) plant is being built in New Jersey with an SCR; a utility coal-fired boiler under construction in Florida provides space for a future SCR.

In Germany, SCR has been widely applied to coal-fired boilers. Thus, it is important to transfer the operation and maintenance (O&M) experience from Germany to future US installations.

Steag AG has extensive experience with SCR (table) in a wide array of configurations, including boilers fired by ballast coal



1. High-dust systems are located between the economizer and the air heater

with sulfur content similar to US bituminous coals.

Background

In the early 1980s, the NO_x emissions

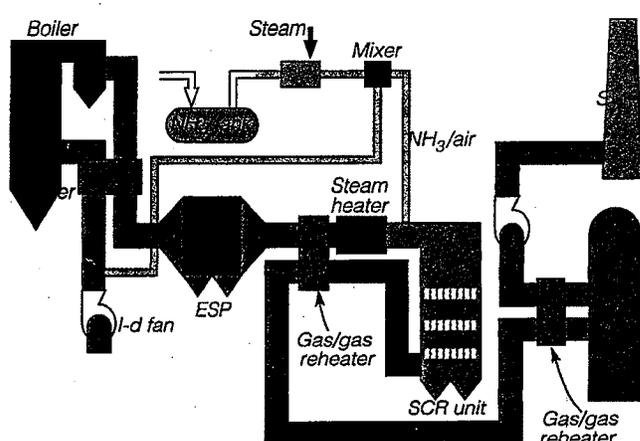
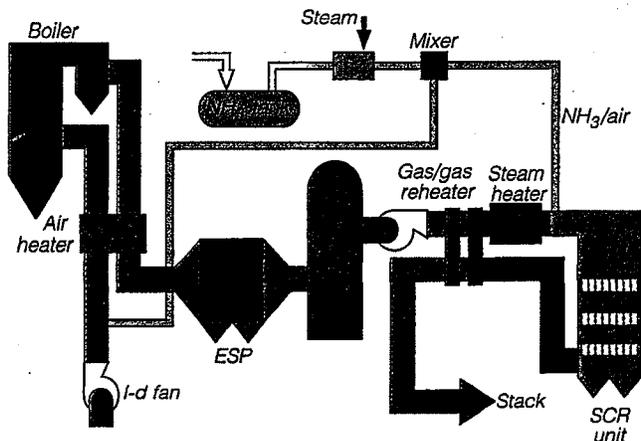
limit for large coal-fired boilers was reduced to around 100 ppm. To prepare to meet the new stringent standard, Steag AG began pilot-testing SCR in the mid-1980s. Catalysts for SCR had been pioneered commercially in Japan. However, the characteristics of German powerplants were significantly different, including:

- German plants burn a wide variety of low-rank domestic coals with a high content of inerts and impurities; Japanese power stations typically burn high-quality imported coals.

- Slagging-type boilers are common in Germany, but not in Japan.

- At least 90% NO_x removal was the objective for many German plants while Japan utilities had to accomplish 80%.

All conventional pulverized-coal-fired (p-c) units in Steag's system are equipped with so-called "high-dust" SCR configurations (Fig 1), referring to placement of the SCR reactor ahead of the air heater.



For all but one slag-tap unit, the SCR unit is located in a tail-end arrangement (Fig 2), or after the flue-gas desulfurization (FGD) system. In this case, a gas-to-gas flue-gas reheater and a steam-fed heater are located between the FGD and SCR units. The steam-fed heater is used to regulate the temperature of the flue gas entering the SCR unit. This also helps optimize the reduction of NO_x emissions during startup.

Unit 7 at the Walsum station, a slag-tap unit, includes the SCR reactor after the electrostatic precipitator (ESP) but ahead of the FGD system. This is referred to as the "low-dust" configuration (Fig 3).

High-dust units

Two units, Walsum-9 and Herne-4, burn high-ash, medium-to-high-sulfur coal and exhibit high flyash concentrations entering the SCR unit. Plate-type catalysts have proved superior to honeycomb-shaped modules in resisting abrasion and fouling.

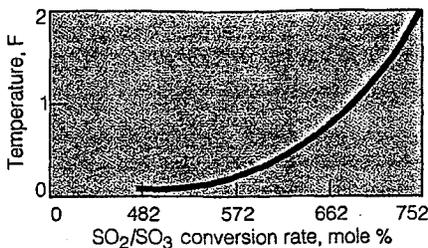
Loss of catalyst activity over time has been considerably less than originally expected for high-dust SCR units. One key factor is the fine lime content of the coal. Here's why: Catalysts also oxidize SO₂ to SO₃. Lime content of the coal neutralizes the sulfuric acid that results from this conversion. If the neutralizing capacity of the coal is not high enough, it is increased by adding limestone or other alkaline compounds to the coal or flue gas.

The first catalyst charge at Walsum-9 had to be upgraded after 27,000 hours of service. Around 25% of the original catalyst capacity had to be added at this point because ammonia slip—that amount that escapes unreacted—caused a disagreeable odor threshold in the flyash and rendered it useless for sale to the construction industry. The original design value of 5 ppm for ammonia slip was too high in Germany.

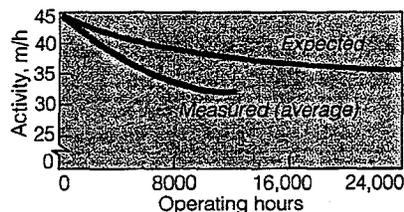
It takes very little ammonia to make ash unsalable. The odor threshold is reached when ammonia content reaches 80 mg/kg of ash—equivalent to 3 ppm, measured at the air-heater inlet, when firing ballast coal or 1.5 ppm when firing high-quality, low-ash coal.

The conversion of SO₂ to SO₃ in SCR systems requires special attention. High SO₃ levels result in corrosion of air heaters, ESPs, and FGD systems as well as the potential for the release of acid aerosols from the stack. Note that wet FGD systems designed for SO₂ removal typically cannot control sulfuric acid aerosol emissions.

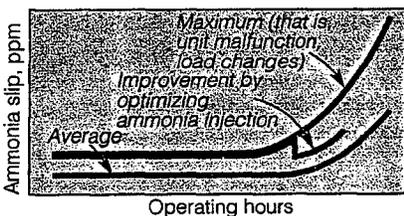
Before SCR retrofit, the German p-c-fired boilers typically operated with flue-gas tempera-



4. Conversion of SO₂ to SO₃ is highly dependent on temperature



5. Catalyst activity was found to degrade because of poisoning by SiF₄. Lime hydrate injection mitigates the degradation



6. Ammonia slip rises as catalyst ages; optimizing ammonia feed helps stem the increase

tures at full load ranging between 700 and 715F at the economizer outlet. However, the conversion of SO₂ to SO₃ is temperature dependent (Fig 4). Thus, sootblowing schedules were modified to keep the boilers cleaner and lower flue-gas temperatures to between 660 and 690F. This action reduced SO₃ concentrations at the air-heater inlet from 80 to 40 mg/m³. This is equivalent to from 22 to 11 ppm. Overall, however, Steag's experience is that high-

dust SCR has in some units limited the boiler's operating range.

Tail-end systems

Experience with the tail-end arrangement was expected to be much better in terms of chemical and physical service life. After all, the flue gas here is low in sulfur compounds and flyash, and materials that can poison the catalyst—arsenic and other heavy metals—are removed by the FGD system upstream. Unfortunately, after only a few thousand operating hours, an extremely high fall off in catalyst activity was observed, particularly on the first layers of honeycomb modules (Fig 5).

The decline in catalyst effectiveness is attributed to the formation of a coating of silicon compounds on catalyst surfaces, generally caused by the presence of silicon fluoride (SiF₄). Sulfuric acid, which condenses onto the FGD flue-gas reheater plates, traps SiF₄ and HF. These compounds combine and later split at the clean gas side into highly corrosive hydrogen fluoride and SiF₄.

Solution to the problem proved to be the injection of lime hydrate downstream of the ESP. This compound reacts with acid gases to form calcium sulfate, calcium fluoride, and other calcium halide compounds. These solids are removed either in the FGD unit or by sootblowing after they deposit on plates in the flue-gas reheater.

Tail-end systems entail high operating expense because of the intermediate steam heating required and the added pressure drop, increasing fan power requirements. On the plus side, they do not limit boiler operation because SCR inlet temperature can be regulated by the steam heater, independent of the boiler.

Monitoring crucial

Regardless of arrangement, monitoring SCR effectiveness must go beyond catalyst activity measurements. At Steag's plants, measurements are taken from sampling systems installed between catalyst layers in

addition to recommended measurements taken immediately after the SCR unit. NO_x and NH₃ measurements are taken to detect catalyst degradation early.

Note that both the absolute value of ammonia slip and range of ammonia slip within which the plant can be operated with NO_x compliance rise as the catalyst ages. Constant improvement of ammonia feed regulation has assisted in reducing ammonia slip (Fig 6). ■

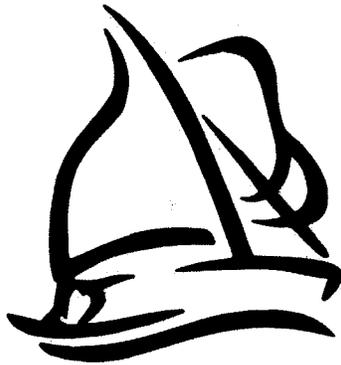
Overview of Steag powerplants using SCR

(May 1992 survey)

Station	Output MW	Furnace type	NO _x in mg/Nm ³	Config	SCR type	SCR start date	Operating hours
Bergkamen	747	Dry ash	800	HD ¹	HnyComb ²	11/89	20,400
Voerde-A	710	Dry ash	950	HD	HnyComb	11/89	15,500
Voerde-B	710	Dry ash	950	HD	HnyComb	10/89	16,500
Herne-1, -2	150 ⁵	Slag tap	1200	TE ³	HnyComb	10/89	16,500
Herne-3	300	Slag tap	1500	TE	HnyComb	10/89	18,200
Herne-4	500	Dry ash	400	HD	Plate	12/89	17,000
Luenen-10	150	Slag tap	1200	TE	HnyComb	11/89	16,000
Luenen-11	350	Slag tap	1400	TE	HnyComb	11/89	18,440
Walsum-9	410	Dry ash	650	HD	Plate	10/88	26,000
Walsum-7	150	Slag tap	1200	LD ⁴	Plate	10/88	17,000
West-1	350	Slag tap	1400	TE	HnyComb	11/89	17,800
West-2	350	Slag tap	1400	TE	HnyComb	11/89	17,500

¹High dust (SCR reactor ahead of air heater) ²Honeycomb ³Tail end (SCR reactor after FGD system) ⁴Low dust (SCR reactor after particulate collector but ahead of FGD system) ⁵Each unit

check Siemens List



Tackticks, LLC

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Tackticks, LLC

1.1 General Company Description

Tackticks, LLC has a broad range of engineering experience with SCR systems and related power plant operations. Tackticks, LLC was formed in 2001 by Volker Rummenhohl after working within the SCR industry for almost twenty years, first in Europe then in the US. Tackticks has been involved with SCR's using gas, coal, oil and all types of waste fuel used in boilers, simple cycle and combined cycle systems and incinerators.

The company's primary focus is optimizing process design, catalyst selection and performance of SCR systems on coal-fired boilers. The company's clients are Electric Utilities, Independent Power Producers, Architect & Engineers, OEM's and component suppliers. Tackticks has also been involved in the design of SCR systems, start ups, ammonia injection grid tuning, performance testing, trouble shooting and O & M support.

Tackticks, LLC has special experience with the design, operation and maintenance support of operating units with generation exceeding 15,000 MW. The company's services are targeted to minimize the operating costs of the SCR system, to diagnose operating problems, to enhance overall performance and to assist Clients in managing the most comprehensive catalyst strategies.

The involvement in the SCR strategy contracts enables Tackticks, LLC to be at the front of technology advancement and development.

Tackticks, LLC also currently owns seventy five percent of the flow modeling company FlowTack, LLC. FlowTack, LLC performs CFD and physical flow models for all kind of technologies. Among those technologies is of course also the SCR technology. FlowTack also designs ammonia injection grids for SCR systems.

General Description of Services

The following is a general description of Tackticks' services:

Process Design

Tackticks can assist Clients define the appropriate SCR design parameters. Historical boiler operating data will be reviewed and assessed to determine unit process data at full, mid and low loads. Tackticks can assist Clients in selecting SCR catalyst performance requirements so that the Client's NOx emission control strategy is effectively met with minimum negative impact due to ammonia slip and SO2 oxidation.

Tackticks will help define process distribution requirements so that long term performance and operational demands are met.

SCR Arrangement

Tackticks can assist Clients in determining preliminary SCR arrangements and reviewing initial design criteria. With the use of Computational Fluid Dynamics modeling, Tackticks can recommend optimal arrangements of duct configuration and flow correction devices in order to maintain appropriate flue gas velocities, velocity distribution, fly ash distribution and ammonia to NOx distribution within the SCR system.

Specification Review & Preparation

Tackticks can assist Clients by reviewing turnkey specifications with special attention paid to, but not limited to, design data, guarantees, process design, equipment, catalyst design, potential impacts on boiler and unit operation.

Tackticks can also prepare technical specifications for Clients. Our company focus is generally applied to catalyst selection, ammonia injection grid design, flow modeling and flow correction requirements, reagent system requirements and performance guarantees.

Proposal Evaluation

Tackticks has also evaluated proposals for Clients. The company's assistance in this area can range from a complete technical assessment of a proposed design and its compliance with the specification to an analysis of a specific technical issue. Tackticks will assist in the development of evaluation criteria, preparation of questions to the suppliers, and recommendation of the most qualified supplier.

SCR Troubleshooting and Optimization

Tackticks can assist Operators in solving current operational issues and suggesting improvements to the SCR system in order to enhance overall performance. Services include systems audits, ammonia injection grid tuning, catalyst testing and system inspections.

Requirements for Annual SCR Operation

Tackticks can review SCR operational procedures to ensure appropriateness for annual operation. This includes all operating sub-systems of the SCR system. Tackticks can evaluate seasonal catalyst performance and update for year-round operation. Catalyst management plans can be updated accordingly to coincide with unit outage schedules.

Volker Rummenhohl
247 Booth Meadow Lane
Durham, NC 27713-5810

Work Experience:

FlowTack, LLC

Manager

January 2004 – Present

Mr. Rummenhohl manages FlowTack, LLC a flow model and computational fluid dynamics company.

Tackticks, LLC

President

February 2001 - Present

Mr. Rummenhohl is currently the president of Tackticks, LLC, a consulting firm located in Durham, North Carolina. Tackticks provides process consulting for air quality control systems and specializes in SCR systems. Consulting work includes review of arrangement drawings, writing and reviewing air quality specifications, general process consulting, training, and support during project startup. Mr. Rummenhohl continues to consult with Black & Veatch on the evaluation and design of SCR projects.

STEAG AG

Manager, North America

September 1993 – February 2001

Mr. Rummenhohl was the Manager of STEAG AG's liaison office in Durham, North Carolina. His responsibilities include marketing and implementing the company's experience and expertise in designing, engineering, startup, commissioning, and performance testing of Selective Catalytic Reduction (SCR) systems in North America. During his time in this position, Mr. Rummenhohl has consulted for a number of U.S. utilities, architectural and engineering firms, and manufacturers, conducted seminars, and presented oral and written testimony for regulatory agencies. He was located in the United States to consult with Black & Veatch on the evaluation and design of domestic SCR projects.

STEAG AG

Division Manager, Environmental Engineering Group

January 1990 - August 1993

Duties included the maintenance and continued improvement / optimization of SCR systems for over 5,300 MW of coal fueled electric and cogeneration capacity owned and operated by STEAG. These systems have now been in operation for in excess of 600,000 cumulative hours. Additionally, Mr. Rummenhohl was responsible for the design and engineering of SCR plants. This includes the three SCR plants for the residual oil fired power station Leuna.

Lentjes AG
Project Engineer and Manager
1983 – 1990

Lentjes AG is one of Germany's largest designers, engineers, and constructors of SCR systems. In the position of project engineer and manager, Mr. Rummenhohl was involved in the design, engineering, procurement, construction, and commissioning of over \$600 million of SCR systems throughout Germany. Responsibilities included supervision of the startup and commissioning of SCR retrofit systems for 2,200 MW.

University of Dortmund
1981 - 1983

Mr. Rummenhohl is a 1981 graduate engineer with an advanced degree in chemical engineering ("Diplom Ingenieur," comparable to a U.S. Master of Science degree) from the University of Dortmund. After graduation, Mr. Rummenhohl taught as an Assistant Professor for a period of two years at the University.

U.S. Technical Papers

Pre Heater Pluggage Issues, presented at the 2006 NO_x Round Table, Charlotte, NC, January, 2006, Author.

Start-Up and Shutdown of SCR Systems Impact on the Lifetime of the Systems, presented at the 24th Annual Electric Utility Chemistry Workshop at the University of Illinois, May 11-13, 2004, Author.

Effective Catalyst and SCR System Management, presented at the 24th Annual Electric Utility Chemistry Workshop at the University of Illinois, May 11-13, 2004, Coauthor.

SCR Experience on High Sulfur Fuel, presented at the 2003 NO_x Round Table, Birmingham, AL January 28-30, 2003, Author.

Design & Initial Start Up Results from the New Madrid SCR Retrofit Project, presented at the ICAC Forum 2000, Washington, DC March 20-24, 2000, Coauthor.

Economic Alternatives for Effective NO_x Emissions Reduction, presented at the DOE SCR and SNCR NO_x Emission Controls Conference, Pittsburgh, Pennsylvania, May 15-16, 1997, Coauthor.

Helping the Utility Compete and Comply: Lessons Learned Lead to Informed Decision-making for NO_x Emissions Reductions, presented at the PowerGen Americas Conference Anaheim, California, December 5-7, 1995, Coauthor.

Effects on Catalytic Activity and SO₂/SO₃ Conversion of DeNO_x Catalytic Converters Downstream of Oil-Fired Power Plants: Causes and Remedial Measures, presented at EPRI/EPA 1993 Joint Symposium on Stationary NO_x Control, Miami, Florida, May 24-27, 1993, Coauthor.

SNCR, SCR and Hybrid Systems Capabilities, Limitations, and Cost, presented at EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, May 16-19, 1995, Coauthor.

The Impact of SCR and SNCR Systems on Plant Equipment and Operations, presented at the ICAC NO_x Emissions Control Conference, Arlington, Virginia, November 2, 1994, Coauthor.

Relating the German DeNO_x Experience to U.S. Power Plants: Lessons Learned from More Than 30,000 MW of DeNO_x Retrofits, presented at the ASME Joint International Power Generation Conference, Phoenix, Arizona, October 3, 1994
Coauthor.

The Effects of Various Parameters on SCR System Cost, presented at the PowerGen Americas '93 Conference, Dallas, Texas, November 17, 1993, Coauthor.

Alternative NO_x Emission Reduction System Comparison, presented at the 1993 USDOE Coal-Fired Power Plant Upgrade Conference, Warsaw, Poland, June 17, 1993, Coauthor.

German Experience Sheds Light on SCR O&M Issues, September 1992 issue of Power magazine, Coauthor.

ROBERT E. JOHNSON

PROFESSIONAL EXPERIENCE

Mar 2007 – Present Tackticks, LLC – Durham, NC

Air Pollution Control Consultant – Specific focus on Selective Catalytic Reduction (SCR) technology and applications. Principal responsibilities include SCR process design analysis and recommendations, Flow Modeling Analysis, SCR performance evaluation, ammonia injection grid design and tuning, SCR system inspections.

2003 – Feb 2007 Burns & McDonnell Engineers – Kansas City, MO

SCR Program Manager – Responsible for promoting BMcD's SCR-related activities within the Power Industry. Provided technical consultation on in-house projects to Clients and Project Teams as well as assisting Clients with operating performance evaluations.

Major Accomplishments

- Member of the Team that secured a major SCR design engineering project from a major Midwestern Cooperative.
- Lead technical advisor for ten (10) SCR projects.

**1996 – 2003 C & I Ceramics USA – Alpharetta, GA
(formerly Siemens Power Generation)**

Vice-President, Sales – Responsible for Sales of Siemens' SCR Catalysts to the Power Industry

Major Accomplishments

- Negotiated systemwide agreements with three U.S. Utilities for the supply of SCR catalyst for SIP-related compliance projects.
- Successfully negotiated contracts with other Utilities for similar projects.
- Total Sales in excess of \$300 million.

1989 – 1996 Wahco Environmental Systems – Leawood, Kansas

Vice President of New Technologies – Responsible for the commercialization and market development of Wahco's NOx emission control technology. Coordinated technology assessment and research activities.

Major Accomplishments

- Sold Wahco's first commercial Staged NOx Reduction System on a gas-fired boiler.
- Negotiated partnerships with key participants in demonstration programs for Staged NOx Reduction System. Instrumental in selecting customers for demonstration sites; successfully negotiated first demonstration on a coal-fired boiler.

- Negotiated first commercial flue gas conditioning installations on a coal-fired cogeneration plant, a hot-side electrostatic precipitator, and the industry's first baghouse application.

1983 – 1989

Belco Technologies Corporation – Parsippany, New Jersey

Regional Manager – Directed air pollution control equipment sales for special projects involving new accounts and existing customers with emphasis on flue gas conditioning and microprocessor based control systems.

Major Accomplishments

- Sold Company's first flue gas conditioning system, first precipitator rebuild on a cement kiln, and first new precipitator installation on a cement kiln.
- Sold \$2 million of equipment upgrades, control systems and parts.

1983

Israel Electric Company – Independent Consultant

1977 – 1982

Apollo Technologies, Inc. – Regional Manager, Technical Services

EDUCATION

Bachelor of Science, Fairleigh Dickinson University, 1976
Bachelor of Arts, University of Notre Dame, 1975

Technical Papers & Presentations

"Selective Catalytic Reduction Performance Project at Public Service Electric and Gas Company's Mercer Generating Station Unit No. 2;" Wallace, Gibbons et al., presented at EPRI/EPA 1995 Joint Symposium on Stationary Combustion NOx Control, May 16-19, 1995, Kansas City Missouri

"Selective Catalytic Reduction: Successful Commercial Performance on Two U.S. Coal-Fired Boilers;" Wagner, Bullock et al; presented at EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, The Mega Symposium, August 25-29, 1997, Washington, D.C.

"SCR For a 460 MW Coal Fueled Unit: Stanton Unit 2 Design, Startup, and Operation;" Cochran, Scarlett et al; presented at EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, The Mega Symposium, August 25-29, 1997, Washington, D.C.

"Current Practices for Monitoring Ammonia Slip from SCR Processes;" Sigling, Johnson; presented at FETC 1998 Conference on SCR and SNCR for NOx Control, May, 1998, Pittsburgh, Pennsylvania

"Powder River Basin (PRB) Coal and High Arsenic Concentrations: Catalyst Specific Issues and Operating Experience;" Rigby, Hums et al.; presented at EPRI Workshop on Selective Catalytic Reduction, April 18-21, 2000, Memphis, Tennessee

"SCR Catalyst Design Issues and Operating Experience: Coals with High Arsenic Concentrations and Coals from the Powder River Basin;" Rigby, Sigling, et al; presented at The International Joint Power Generation Conference, July 23-28, 2000, Miami Beach, Florida

"U.S. Utility Coal-Fired Selective Catalytic Reduction Applications: SCR Catalyst-Specific Issues and Operating Experience;" Sigling, Johnson; presented at EPRI 2001 Workshop on Selective Catalytic Reduction, November 13-15, 2001, Baltimore, Maryland

"U.S. Utility Coal-Fired SCR Applications: SCR Catalyst-Specific Issues and Operating Experiences;" Sigling, Johnson; presented at ICAC Forum 2002, February, 2002, Houston, Texas

"SCR Catalyst Performance: New Information for U.S. Operators;" Sigling, Johnson; presented at EPRI 2002 Workshop on Selective Catalytic Reduction; October 16, 2002, Atlanta, Georgia

"Peak SCR Performance Requires Consolidated Program Management;" presented at Electric Power 2004, April 1, 2004, Baltimore, Maryland

"SCR Update for Simple Cycle Gas Turbine Applications;" presented at Power Gen International 2004, December, 2004, Orlando, Florida

"Selective Catalytic Reduction System Design Considerations;" presented at Power Gen International 2004, December, 2004, Orlando, Florida

"Selective Catalytic Reduction System Design Considerations;" presented at the 110th Plant Design and Operating Committee, January, 2005, Fort Worth, Texas

"SCR Program Management;" presented at the 110th Plant Design and Operating Committee, January, 2005, Fort Worth, Texas

"How Can You Maximize Results from Your SCR Catalyst Replacement?" presented at Burns & McDonnell 2006 Coal Symposium, April, 2006, Kansas City, Missouri

"SCR Program Management: A Powerful Program to Enhance Plant Operations;" presented at the 57th Annual Generation Conference, Association of Rural Electric Generating Cooperatives, June, 2006, Cincinnati, Ohio

"Thomas Hill Unit 3 SCR Retrofit Design Approach Avoids Increases in Draft Loss;" presented at Coal Gen 2006, August, 2006, Cincinnati, Ohio

"SCR Technology for Coal Fired Boilers: Design Considerations for Proper Performance;" presented at Power Gen Asia, September, 2006, Hong Kong

"Environmental Controls Retrofit Project at AECI Thomas Hill Energy Center;" presented at EPRI 2006 Workshop on SCR, November, 2006, Dearborn, Michigan

"Thomas Hill Unit 3 SCR Retrofit Design Approach Avoids Increases in Draft Loss;" presented at Power Gen International 2006, November, 2006, Orlando, Florida

Tackticks LLC SCR Consulting and Process Engineering Reference List

June, 2007

Plant	Size MW	Fuel	Utility/IPP	Time Service Provided	Remarks
New Madrid 1	600	PRB Coal	AECI	2001	High Dust
Stuart 1-4	4*600	Bit. Coal	Dayton Power & Light	2001 -	High Dust
Killen 2	600	Bit. Coal	Dayton Power & Light	2001 -	Low Dust/ Hot ESP
Cully 3	265	Bit. Coal	VECTREN	2001 - 2003	High Dust
Warrick 4	325	Bit. Coal	VECTREN	2001 -	High Dust
Brown 1	265	Bit. Coal	VECTREN	2002 -	High Dust
Brown 2	265	Bit. Coal	VECTREN	2001 -	High Dust
Desert Basin (Trouble Shooting)	180	Gas	Reliant Energy	2001	HRSG
Michigan City 12	540	PRB/Bit. Blend	NIPSCO	2001 - 2003	High Dust
Shafer 14	540	Bit. Coal	NIPSCO	2001 -	High Dust
Bailly 8	420	High Sulfur Coal	NIPSCO	2002 -	High Dust
Dallman 31 & 32	2 * 85	High Sulfur Coal	CWLP Springfield	2001 - 2003	High Dust
Dallman 33	150	High Sulfur Coal	CWLP Springfield	2001 - 2003	High Dust
Lambton 3 & 4	2 * 500	High Sulfur Coal	Ontario Power Generation	2001 - 2003	High Dust
Nanitoke 7 & 8	2 * 500	PRB/ Bit. Blend	Ontario Power Generation	2001 -	High Dust
E.D. Edwards 3	365	Bit. Coal	Ameren	Current	High Dust
Duck Creek	440	Bit. Coal	Ameren	Current	High Dust
Mercer 1 & 2	2 * 325	Bit. Coal	PSE&G	2002 -	Low Dust/ Cold ESP
Powerton (project delayed)	2 * 700	Bit. Coal	MidWest Gen	2001 - 2002	Low Dust/ Cold ESP
Homer City 1 & 2 (upgrades)	2 * 600	Bit. Coal	MidWest Gen	2002-2005	High Dust
Brandon Shores 1 & 2 (upgrades)	2 * 650	Bit. Coal	Constellation Energy	2002	Low Dust/ Hot ESP
Canal 1 & 2 (upgrades)	2 * 600	Oil	MIRANT	2001 -	High Dust

Plant	Size MW	Fuel	Utility/IPP	Time Service Provided	Remarks
Lovett 3,4,5	435	Bit. Coal	MIRANT	2002 -	High Dust
Harding Street	470	Bit. Coal	AES	2003-2004	High Dust
Weston	600	Bit. Coal	Wisconsin Public Service Corp.	2004 -	High Dust
Prairie State	2*750	High Sulfur Coal	Peabody Energy	2004 -	High Dust
Thoroughbred	2*750	High Sulfur Coal	Peabody Energy	2004 -	High Dust
Homer City 3 (upgrades)	650	Bit. Coal	MidWest Gen	2002-2005	High Dust
Thomas Hill 1,2,3	1135	PRB	AECI	2005-2010	High Dust
Elmer Smith PS Unit 1 (Trouble Shooting)	150	Bit. Coal	OMU	2005	High Dust
St. Johns River Power Plant	2* 660	Petcoke, Bit. Coal	SJRPP	2005-2009	High Dust
Northport Unit 3	150	Oil	Key Spann Energy	2005-	High Dust
La Cygne Unit 1	800	PRB	Kansas Power & Light	2005	High Dust
Sibley Unit 3	420	PRB	Aquila	Current	High Dust
Southwest Unit 1	194	PRB	City Utilities Springfield MO	Current	High Dust
Oak Creek Units 5 - 8	1,200	PRB	WE Energy	Current	Tail End
Trimble County Unit 2	900	Bit. Coal	LGE Energy	Current	High Dust
Southern Company (Various Plants)		PRB, Bit. Coal	Southern Company	Current	High Dust
Total	> 28,300 MW				