

## 2008 Power Plant Air Pollutant Control “Mega” Symposium - Table of Contents

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## Session 1: Carbon Management Technologies

### **Global Climate Change: The Electric Utility Challenge**

Paper #: 18

F. Princiotta, *USEPA, Research Triangle Park, NC.*

The control of greenhouse gases presents a monumental challenge. Industrialization and population growth provide strong drivers for accelerating greenhouse gas emissions, especially carbon dioxide. In light of the long lifetime of CO<sub>2</sub>, and the recent 3% CO<sub>2</sub> annual emission growth rate, major reductions of emissions over time will be necessary to stabilize atmospheric concentrations. The presentation quantifies the degree of emission control needed for several CO<sub>2</sub> global concentrations and warming increments. The paper then focuses on electricity production and technologies currently and potentially available to mitigate emissions. Conventional coal boilers with CO<sub>2</sub> capture and sequestration, integrated combined cycle gasification (IGCC) with capture and sequestration, solar, wind and nuclear options are compared. For these key technologies, the paper describes the state of development, current and projected costs, projected technology penetrations, and the projected ability to contribute to quantifiable CO<sub>2</sub> emission reductions in identifiable time frames.

### **Carbon Capture for Pulverized-Coal-Based Power Plants: DOE/NETL's R&D Program**

Paper #: 43

T. Fout, *DOE/NETL, Morgantown, WV*; T. Feeley, H. Pennline, S. Plasynski, *DOE/NETL, Pittsburgh, PA*; A. Jones, *SAIC, Pittsburgh, PA.*

DOE/NETL initiated a Carbon Sequestration R&D Program in 1997 to develop economically viable **options** for reducing carbon dioxide (CO<sub>2</sub>) emissions from coal-based power plants. One of the goals of DOE/NETL's carbon capture R&D effort is to develop **advanced** CO<sub>2</sub> capture technologies for both existing and new pulverized-coal (PC) power plants that can achieve 90% CO<sub>2</sub> capture at less than a 20% increase in the cost of energy services.

DOE/NETL is funding laboratory through pilot-scale development of a number of advanced CO<sub>2</sub> capture technologies for PC-based power plants that offer potentially significant cost and efficiency improvements over state-of-the-art amine-based systems. The current portfolio of post-combustion R&D projects includes ammonia-based scrubbing, advanced membranes, solid sorbents, metal organic frameworks, and ionic liquids. DOE/NETL is also sponsoring research in the area of oxy-combustion and chemical looping. This paper will provide a status update on the results of DOE/NETL's post-combustion and oxy-combustion R&D activities.

## **Fluor's Econamine FG Plus<sup>SM</sup> Technology for CO<sub>2</sub> Capture for Coal-fired Power Plants**

Paper #: 67

S. Reddy, *Fluor Enterprises, Inc, Aliso Viejo, CA*; D. Johnson, *Fluor Enterprises, Inc, Greenville, SC*.

Fluor's Econamine FG Plus<sup>SM</sup> (EFG+) is one of the leading technologies for large scale post-combustion CO<sub>2</sub> capture. This paper describes recent EFG<sup>+</sup> process enhancements including solvent formulation, absorber intercooling, reclaiming, environmental signature betterment and heat integration.

The pre-treatment of fluegas from coal fired power plants is critical for minimizing solvent loss. Strategies for trim removal of SO<sub>x</sub>, NO<sub>x</sub>, dust and other impurities to make the fluegas suitable for amine systems are described.

Available plot space for capture plants is often limited, especially in retrofit situations. Very large diameter absorbers for power plant, furnace and boiler fluegases have been developed to minimize plot space by a reduction in the number parallel of trains. These designs were based on prior knowledge gained in gas processing and refining applications together with the use of computational fluid dynamics.

## **MHI's CO<sub>2</sub> Capture Technology Demonstration Testing from the Flue Gas of a Coal Fired Boiler**

Paper #: 64

S. Holton, *Mitsubishi Heavy Industries America, Inc., Austin, TX*; M. Iijima, S. Iwasaki, *Mitsubishi Heavy Industries, Yokohama, Japan*.

In response to concerns over climate change, and in recognition that fossil fuels such as coal will persist as a dominant part of the energy mix in many countries throughout the world, Mitsubishi Heavy Industries Ltd (MHI) has undertaken extensive research and development of post combustion CO<sub>2</sub> capture technology. This has resulted in the commercial deployment of an increasing number of international CO<sub>2</sub> capture plants, mainly in the fertilizer production industry which utilize natural gas. However, in parallel, MHI has also completed over 4000 hours of demonstration testing (10 metric-ton/day) of CO<sub>2</sub> capture applied to coal fired flue gas streams and has achieved outstanding results. This testing has been critical in furthering our understanding of the impacts of various impurities contained within coal fired flue gas streams and the results have been used to develop specific countermeasures and to optimize performance and design specifications for scale up.

## **Integrated SO<sub>2</sub> Control and CO<sub>2</sub> Capture in a Coal Fired Power Plant**

Paper #: 53

C. Ryan, *Cansolv Technologies Inc, Montreal, QC, Canada*.

Cansolv Technologies is a leading provider of amine based regenerable SO<sub>2</sub> and CO<sub>2</sub> capture technologies and has successfully deployed the CANSOLV® SO<sub>2</sub> Scrubbing

process in several commercial boiler, refinery and tail gas applications. After more than 6000 hours of pilot testing, the CANSOLV® CO<sub>2</sub> Capture process is currently being rolled out in a 50 ton/day demonstration at a major North American coal fired power plant. The plant is scheduled to be commissioned in October of 2008. The CO<sub>2</sub> capture process will be fully heat integrated with the regenerable CANSOLV SO<sub>2</sub> process to achieve best in class energy and cooling water consumption per ton of CO<sub>2</sub> captured. The paper will present the range of piloting results from campaigns in Japan, Canada, Norway and the US and will present the design features of the CANSOLV SO<sub>2</sub>-CO<sub>2</sub> Coal Fired Demonstration Plant.

### **Testing of Ammonia-based CO<sub>2</sub> Capture with Multi-Pollutant Control Technology**

Paper #: 91

C. McLarnon, *Powerspan Corp., Portsmouth, NH*; M. Jones, *FirstEnergy Corp., Akron, OH*.

Powerspan has been developing a CO<sub>2</sub> capture process, called ECO<sub>2</sub><sup>TM</sup>, since 2004 in conjunction with the U.S. DOE National Energy Technology Laboratory (NETL) under a cooperative research and development agreement. In December 2007 Powerspan announced it exclusively licensed a patent for the process from NETL. Powerspan has conducted extensive laboratory testing to establish the effectiveness of the process for CO<sub>2</sub> capture and has initiated a pilot test program with FirstEnergy at the R.E. Burger Plant. A 1-MW pilot demonstration is scheduled to begin in 2008, which will produce 20 tons of sequestration ready CO<sub>2</sub> per day. The pilot will demonstrate CO<sub>2</sub> capture through integration with the ECO multi-pollutant control process. The pilot program will also prepare the technology for a 125-MW commercial scale CCS demonstration project planned with NRG Energy for the WA Parish plant in 2012. The results of laboratory and pilot testing to date will be reviewed.

### **CCS with Alstom's Chilled Ammonia Process at AEP's Mountaineer Plant**

Paper #: 167

D. Muraskin, S. Black, M. Cage, *ALSTOM Power, Inc., Knoxville, TN*; G. Spitznogle, M. Hammond, B. Sherrick, *American Electric Power, Columbus, OH*.

Alstom and American Electric Power are jointly participating in the installation of a carbon dioxide capture Product Validation Facility at AEP's Mountaineer Power Generating Station. The carbon dioxide capture technology to be installed at Mountaineer is Alstom's Chilled Ammonia Process; AEP is working with Battelle to develop the geologic storage system. The Product Validation Facility is approximately 20 MWe in size and involves the treatment of a slipstream of combustion flue gases from a coal-fired boiler. The flue gas slipstream is taken from a location downstream of the Mountaineer's existing wet flue gas desulfurization system. The project is presently in the engineering design phase and involves the capture of carbon dioxide gas, CO<sub>2</sub> compression, and storage in two geologic reservoirs on site. The following paper summarizes Alstom's Chilled Ammonia Process technology and provides the details of the CO<sub>2</sub> Capture Product Validation Facility and Geologic Storage Project scope and objectives.

## **The “Dry Carbonate” Sorbent Technology for CO<sub>2</sub> Removal from Flue Gas of Existing Coal-Fired Power Plants**

Paper #: 113

T. Nelson, D. Green, R. Gupta, *RTI International, Research Triangle Park, NC*; W. Jozewicz, *ARCADIS U.S., Inc., Research Triangle Park, NC*; N. Hutson, *United States Environmental Protection Agency, Research Triangle Park, NC*.

The reversible reaction between sodium carbonate, CO<sub>2</sub> and H<sub>2</sub>O, to form sodium bicarbonate can be used in a thermal-swing process to recover concentrated CO<sub>2</sub> from power plant flue gas. A process based on this reaction has been developed. Field testing of a prototype “Dry Carbonate Process” has been conducted using natural gas-derived and coal-derived flue gases from a combustor. Greater than 90% removal of CO<sub>2</sub> was achieved during testing. The system was exposed to flue gas for over 230 hours and the most promising process conditions were determined from collected data. Pollutants in the flue gas had no effect on sorbent performance. The sorbent showed little physical attrition over hundreds of cycles. An economic evaluation shows the “Dry Carbonate Process” has significant advantages over existing technologies. Modifications to the process have been considered and additional research will be conducted before constructing a pilot-scale unit capable of capturing 1 ton/day CO<sub>2</sub>.

## **Results from Lab and Field Testing of Novel CO<sub>2</sub> Sorbents for Existing Coal-Fired Power Plants**

Paper #: 173

H. Krutka, S. Sjostrom, J. Bustard, *ADA-ES, Inc., Littleton, CO*.

Technologies for carbon capture from existing coal-fired utilities are rapidly being developed. Solid sorbents have many potential benefits compared to other technologies for CO<sub>2</sub> capture, such as ease of handling, greater capacity, reduced energy for regeneration, etc. ADA-ES has completed lab-scale testing (simulated and actual flue gas) of solid sorbents designed to capture CO<sub>2</sub>. The traits tested included the CO<sub>2</sub> capacity, regeneration potential, reactivity to other flue gas constituents, and energy necessary for regeneration. CO<sub>2</sub> capacities ranged from <1 wt% to >6 wt%. Most sorbents regenerated completely and were suited for multiple-cycle use. This paper will compare the sorption/regeneration characteristics for several different sorbents and discuss the potential of the technology.

## **Catalytic CO<sub>2</sub> Recycle (CCR) Technology**

Paper #: 8

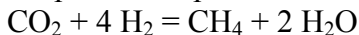
J. Ralston, E. Fareid, *Recycle CO<sub>2</sub> (RCO<sub>2</sub>) Inc., Kingport, TN*.

A process has been developed and patented in Norway for the removal of CO<sub>2</sub>. The CO<sub>2</sub> is catalytically converted to two useful products, methane and water. The methane generated can be used to generate electricity. This is an energy efficient process to remove CO<sub>2</sub>. No isolation or compression of the CO<sub>2</sub> is required.

The main catalytic reaction is between CO<sub>2</sub> and H<sub>2</sub> and produces methane and water.

This reaction can be expressed as follows:

temperature + pressure



Carbon dioxide hydrogen catalyst methane water

This paper will describe the reactor design, the parameters that control the reaction, flow diagram, material and energy balances, estimated costs, and an update of pilot plant evaluations in France and USA. The paper will also explore the financial benefits obtained from the use of the methane produced to generate electricity.

### **Oxyfuel Combustion Retrofits for Existing Power Stations**

Paper #: 130

K. Tigges, F. Klauke, C. Bergins, *Hitachi Power Europe GmbH, Duisburg, Germany*; S. Wu, O. Walchuk, A. Kukoski, *Hitachi Power Systems America, Ltd, Basking Ridge, NJ*.

Oxyfuel combustion is one of the promising technologies to enable CCS for new and existing coal-fired power plants. For retrofit applications, oxyfuel is an attractive option because it does not have major impact on the boiler-turbine steam cycle.

This paper presents case studies for retrofitting oxyfuel combustion technology in large state-of-the-art power plants that are originally commissioned and operated in air-fired mode. The overall process design for the modified power plant is outlined; necessary modifications of relevant components are explained.

It is shown that future CO<sub>2</sub> emission regulations can be met by retrofitting oxyfuel technology. The retrofit measures ensure that the power stations still can run under both air-fired and oxyfuel-fired conditions if required by regulation / market conditions. This provides additional operational and commercial benefits for the operator of the plant and reduces the technical risk of implementing new components and processes not yet proven in the power sector.

## **Session 2: Mercury: Overview and FGD-based Controls**

### **DOE/NETL's Mercury Control Technology R&D Program - Taking Technology from Concept to Commercial Reality**

Paper #: 42

T. Feeley, L. Brickett, *DOE/NETL, Pittsburgh, PA*; B. O'Palko, *DOE/NETL, Morgantown, WV*; A. Jones, *SAIC, Pittsburgh, PA*.

DOE/NETL has worked with industry, research organizations, and academia to develop advanced mercury control technology for coal-based power systems. Over the past seven years, this research has focused on the full-scale and slip-stream field testing of activated carbon injection (ACI) and flue gas desulfurization enhancements at nearly 50 U.S. coal-fired power plants. The goal of the field testing was to demonstrate high levels (50-90%) of mercury capture over an extended period of operation, while also reducing the cost of mercury removal. The field testing program has successfully met this goal. Due in large

part to this success, coal-fired power plant operators have begun to install mercury control technology in response to CAMR and state regulations. As of October 2007, orders have been placed for over 36 gigawatts of ACI. This paper will provide an update on DOE/NETL's mercury control technology R&D program, including an assessment of the cost of capture.

### **Near and Long Term Options for Controlling Mercury Emissions from Power Plants**

Paper #: 25

R. Chang, *EPRI, Palo Alto, CA.*

The Electric Power Research Institute (EPRI) and individual electric power generating companies have worked closely with the U.S. Department of Energy (DOE), pollution control suppliers, and engineering consulting firms to develop and evaluate mercury controls for coal-fired power plants. As a result of these efforts, mercury controls for a number of coals and basic unit configurations are nearing commercial readiness. At the same time, novel mercury control approaches are also being proposed. Much data from testing at many power plant sites, encompassing a variety of configurations, operating conditions, and coal type have been gathered in the past ten years by EPRI and others. This paper will summarize field data obtained to date from various test sites documenting mercury control technologies and their effectiveness, trends, issues that need to be addressed, implications on current cost for mercury control, and newer technologies that are under development.

### **SCR/Wet-FGD Mercury Co-Benefits Improvement - 5 MW Demonstration Test**

Paper #: 7

S. Honjo, B. Welliver, T. Shinoda, *Mitsubishi Heavy Industries America, Inc., Austin, TX*; Y. Nakayama, *Mitsubishi Heavy Industries, Ltd., Yokohama, Japan*; S. Okino, *Mitsubishi Heavy Industries, Ltd., Hiroshima, Japan*; N. Irvin, M. Berry, *Southern Company Generation, Birmingham, AL*; T. Hastings, *Cormetech, Inc., Durham, NC.*

Mercury removal by SCR oxidation and FGD capture, including re-emissions control, is demonstrated at 5 MW scale at Southern Company's Mercury Research Center. The objective is to demonstrate MHI's patented mercury removal process and "Hybrid" system. The technology consists of a combination of SCR and FGD process control to improve mercury removal co-benefits. HCl injection is provided upstream of SCR catalyst used for NO<sub>x</sub> control to increase oxidation of elemental mercury (Hg<sup>0</sup>). MHI's downstream wet FGD technology, known as a Double-Contact-Flow-Scrubber (DCFS), removes oxidized mercury (Hg<sup>2+</sup>). Re-emission of mercury from the DCFS is minimized by control of the absorbent oxidation-reduction-potential (ORP) by adjusting the amount of oxidation air supplied to the DCFS. Results from the operation of 5 MW scale SCR and mobile 2 MW scale DCFS are reported. The demonstration test results confirm that the "Hybrid" system can control Hg emissions to below 1ug/m<sup>3</sup>N(total) or greater than 90% removal.

## **Pilot Scale Studies of Mercury Oxidation by SCR Catalyst**

Paper #: 41

C. Dene, A. Jimenez, *Electric Power Research Institute, Palo Alto, CA*; A. Freeman Sibley, *Southern Company Generation, Birmingham, AL*; W. Hinton, *W. S. Hinton & Associates, Gulf Breeze, FL*.

Under EPA's Clean Air Mercury Rule, utilities look to find ways to reduce mercury emissions. SCR catalysts are known to oxidize mercury, making capture easier. However, the mercury oxidation across catalysts is not well understood with respect to many operational parameters. Southern Company and Gulf Power, in conjunction with EPRI are conducting test programs at the Mercury Research Center. A parallel effort at the Alabama Power Company Gorgas Plant is evaluating impact of catalyst regeneration on mercury oxidation.

The MRC program will investigate the mercury oxidation behavior of SCR catalysts for various operating conditions. Utilizing a very low chlorine coal, parameters such as flow, temperature, and chlorine level were varied to measure the mercury speciation and capture response. The Regenerated catalyst program is investigating the difference in mercury oxidation between aged, regenerated and new catalyst. Results from the first catalysts tested in each program will be discussed.

## **Pilot Scale Study of Mercury Removal in CT-121 Wet FGD Process**

Paper #: 46

S. Kido, D. Takeda, A. Kumagai, *Chiyoda Corporation, Yokohama, Japan*; P. Mehta, M. Amick, *Black & Veatch Corporation, Overland Park, KS*; J. Irvin, C. Tyree, *Southern Company, Birmingham, AL*.

Wet scrubbers offer co-benefit mercury (Hg) control. Efficient Hg removal, like SO<sub>2</sub> removal, requires absorption of gas phase species. Absorption requires water solubility. Mercury emitted from coal combustion is mostly (90+%) elemental mercury (Hg<sup>0</sup>). Elemental Hg is insoluble. Consequently, wet scrubbers ostensibly have little co-benefit when Hg<sup>0</sup> is the dominant species. Even if Hg<sup>2+</sup> is captured, it may be reduced and re-emitted. Here we evaluate Hg removal and re-emission using a pilot-scale FGD process. A 3 MW equivalent CT-121 FGD process was installed at Gulf Power's Mercury Research Center (MRC). The FGD process was located downstream of a selective catalytic reduction (SCR) catalyst and electrostatic precipitator (ESP). Mercury oxidation was achieved via SCR oxidation and bromine addition to coal. Efficient Hg oxidation upstream led to satisfactory mercury capture in CT-121 scrubber.

### **Full-scale Demonstration of Oxidation Catalyst for Enhanced Mercury Control by Wet FGD**

Paper #: 97

G. Blythe, *URS Corporation, Austin, TX*; B. Freeman, *EPRI, Palo Alto, CA*; C. Miller, *US DOE-NETL, Pittsburgh, PA*; J. Madrid, *LCRA, Austin, TX*.

The paper will present results from a 200-MW demonstration of a low-temperature mercury oxidation catalyst at LCRA's Fayette Power Plant. The demonstration is co-sponsored by DOE, EPRI, LCRA, TVA, Great River Energy, Southern Company, SRP, Ontario Power, Westar, Johnson Matthey and URS. The catalyst is installed upstream of one of two operating wet FGD modules on Unit 3, which is rated at 460-MW. The catalyst oxidizes flue gas elemental mercury to promote mercury removal in the wet FGD. Construction to support catalyst installation will be completed in January 2008, and installation is expected in early March, with startup immediately thereafter. Results will be presented from four months of catalyst operation, and will include mercury oxidation across the catalyst as a function of time, mercury removal across the full-scale wet FGD by mercury species, and flue gas pressure drop across the catalyst. Process economics will also be discussed.

### **Evaluation of the Impact of Chlorine on Mercury Oxidation in a Pilot-Scale Coal Combustor-The Effect of Coal Blending**

Paper #: 83

S. Serre, C. Lee, *US EPA, Research Triangle Park, NC*; T. Hastings, *Cormetech, Inc., Durham, NC*; P. Chu, *EPRI, Palo Alto, CA*.

Tests were conducted on a 4 MM BTU/hr pilot scale combustor equipped with an SCR reactor to investigate the effect of blending PRB coal with an eastern bituminous coal on the speciation of Hg across an SCR catalyst. Tests were conducted in which 100% bituminous coal to 100% sub-bituminous PRB were fired to examine the effect on mercury oxidation. Several blends were run with bituminous coal comprising the minority fraction. It was determined that a higher percentage of the total Hg was present as oxidized Hg as the chlorine in the coal increased. The other hydrogen halides such as HBr and HF do not appear to be in appreciable concentrations to have an impact on oxidation. A blend that contained at least 35% bituminous coal was necessary to obtain an oxidized Hg concentration of 60% with 100% bituminous coal producing just under 90%.

### **Field Study of Mercury Partitioning in Wet FGD Byproducts**

Paper #: 151

M. Richardson, G. Blythe, *URS Corporation, Austin, TX*; R. Rhudy, *EPRI, Palo Alto, CA*.

This EPRI project, which began in 2004, is determining mechanisms that control mercury partitioning between solid byproducts and liquor in wet FGD systems. This partitioning may impact the extent of mercury re-emissions from wet FGD systems, and hence net mercury capture, and mercury concentrations in gypsum used for wallboard as well as in FGD wastewater. The project approach has been to collect data from a range of wet FGD

systems to attempt to elucidate mechanisms. Data have also been collected on the partitioning of arsenic and selenium. These data are being correlated to determine what factors appear to control partitioning of these metals. Extensive data collection and sample analysis efforts have been completed, and efforts are currently underway to analyze and report this information. By the time of the symposium, an interim report will have been prepared and key findings will be available for presentation.

### **Session 3: NO<sub>x</sub>: Combined Controls**

#### **Combustion Optimization Utilizing Computational Fluid Dynamic Modeling**

Paper #: 76

B. King, *Burns & McDonnell, Kansas City, MO*; M. Welch, *Otter Tail Power Company, Fergus Falls, MN*.

This paper reports on the NO<sub>x</sub> Reduction Project performed at the 77 MW front fired Unit 3 Hoot Lake Power Plant in Fergus Falls Minnesota. Otter Tail Power Company initiated a NO<sub>x</sub> Reduction Project that included new replacement burners and the development of an overfire air system.

- Phase I - extensive computational fluid modeling to determine the optimal overfire air design.
- Phase II - Procurement
- Phase III - Installation
- Phase IV - Combustion Tuning effort to optimize the system

The discussion will focus on how tuning was complemented through observations that correlated to multiple CFD model runs. CO pockets were created and eliminated by manipulating OFA port adjustments as simulated in CFD models.

#### **NO<sub>x</sub> Reduction on Coal-Fired Units Utilizing Burner Fuel/Air Ratio Control**

Paper #: 99

D. Earley, *Combustion Technologies Corporation, Apex, NC*; B. Kirkenir, *Progress Energy, Raleigh, NC*.

Progress Energy has incorporated on-line combustion optimization/tuning to achieve desired NO<sub>x</sub> levels at their Lee and Sutton Stations. These optimization projects utilized individual burner airflow measurement and continuous burner coal flow measurement to adjust air to fuel ratios. For these projects, the DCS was also modified to allow control of mass flow of air to each overfire air port as well as air to fuel ratio control of each burner. This was accomplished by utilizing the burner secondary air disks to control burner air and by controlling the coal to the burners.

While the objectives of the projects were NO<sub>x</sub> reduction, other desired benefits included decreased opacity, decreased LOI, efficiency improvement and minimized boiler fouling. The NO<sub>x</sub> reduction desired through the combustion changes was 15-20%. The paper will also discuss the other improvements to the unit that were achieved by using the new air and fuel flow controls.

## **Field Operation of a Low NO<sub>x</sub> Burner That Attains Up To 5:1 Turndown**

Paper #: 142

J. Vatsky, J. Shan, T. Larson, *Siemens Environmental Systems & Services, Pluckemin, NJ*; P. O'Kane, *Tarong Energy Operations, Nanango QLD, Australia*; W. Dongping, *Ligang Power Station, Jiangsu Ligang Electric Power Company, Ligang town Jiangyin Jiangsu, China*.

Siemens' Opti-Flow™ low NO<sub>x</sub> burner has matured to yield lower NO<sub>x</sub>, greater simplicity of design and the ability to fire a wide range of pulverized fuels. Some boilers equipped with the Opti-Flow design have converted from 100% bituminous coal to 100% PRB or high ratio PRB/bituminous mixes with no change to the burner components. The excellent flame stability not only allows firing of low volatile coals, but also to operate at high turn-down ratios without utilizing auxiliary fuels for flame stabilization. The primary advantage of this capability is to eliminate the need to remove mills from service when reducing load on cycling units. Two units, a 350MW front fired unit and 350MW opposed-fired unit, have demonstrated the ability to operate at 25% and 20% of full load without the need for auxiliary fuel. This paper describes the designs that enable these results and the specific field experiences.

### **Session 4: Mercury: Sorbents**

#### **Commercial Operating Experience on an Activated Carbon Injection System**

Paper #: 170

J. Mooney, J. Jaeckels, *Alliant Energy, Madison, WI*; T. Starns, *ADA-ES, Inc., Littleton, CO*.

One of the first commercial installations of an ACI system will begin operations at the Alliant Edgewater plant in the first quarter of 2008. Edgewater is a 335-MW plant that fires Powder River Basin (PRB) coal and is configured with a cold-side ESP for particulate control.

The ACI system at Edgewater is configured to inject both upstream and downstream of the air preheater (APH). The initial testing to be conducted will evaluate various levels of mercury control versus PAC injection. Several different AC types will be evaluated, including brominated PAC and concrete-friendly PAC. Other sorbent enhancement tests are also being discussed. The testing will include an analysis of the balance-of-plant impacts on particulate matter emissions and opacity, APH impacts, preliminary operational and economic assessments, and effects of PAC injection on fly ash utilization. The presentation will cover all operational or environmental impacts discovered during commercial operation.

## **Mercury Control at New Generation Western PC Plants**

Paper #: 169

S. Finley, *Colorado Energy Management, LLC, Denver, CO*; J. Amrhein, T. Campbell, S. Sjostrom, *ADA-ES, Inc., Littleton, CO*; A. O'Palko, *U.S. Department of Energy/NETL, Denver, CO*.

A mercury control demonstration has been underway at Rocky Mountain Power's Hardin Station since 2006 through funding from DOE NETL, ADA-ES, and other industry partners.

Hardin fires Powder River Basin (PRB) coal and is configured with selective catalytic reduction (SCR) for NO<sub>x</sub> control, a spray dryer (SDA) for SO<sub>2</sub> control, and a pulse-jet fabric filter (FF) for particulate control. Hardin was chosen as a host site because this configuration is representative of many of the new and proposed power plants that will burn PRB coal.

As of February 2008, the long-term demonstration has gone on for several months and has shown that 90% mercury removal can be maintained at carbon loadings between 1.5 and 2.0 lb/MMacf. This paper will summarize results to date and include the effectiveness of sorbents for mercury control and balance-of-plant impacts. A preliminary economic analysis will also be included.

## **Evaluation of Long-Term Balance-of-Plant Effects Resulting from Activated Carbon Injection for Mercury Control at SaskPower's Poplar River Power Station**

Paper #: 89

J. Pavlish, J. Thompson, L. Hamre, *University of North Dakota, Grand Forks, ND*; D. Smith, *SaskPower, Regina, SK, Canada*; L. Brickett, *U.S. Department of Energy, Pittsburgh, PA*; J. Burgess, *Lignite Energy Council, Bismarck, ND*.

A 6-year consortium-led effort focused on the development, testing, and evaluation of various sorbents for mercury control at lignite-fired power plants. Those efforts led to a full-scale project at SaskPower's Poplar River Station, evaluating potential balance-of-plant (BOP) effects associated with long-term use of activated carbon injection (ACI) for mercury control. Various short-term tests (~1 month) have been conducted throughout North America. This project involves long-term (~1 year) testing of ACI. The project, which is still under way, will provide initial data on the effects that long-term ACI has on plant equipment and operations, the reliability and problems associated with operation of a commercial AC system, preliminary economics, and the sustainability of ACI for mercury control. Also, baseline, parametric, and initial long-term data will be presented, as well as a discussion of the BOP issues seen to date and protocols necessary to successfully implement ACI at a full-scale facility.

## **Evaluation of Novel Mercury Sorbents and Balance-of-Plant Impacts at Stanton Units 1 and 10**

Paper #: 154

G. Archer, S. Smokey, *Great River Energy, Elk River, MN*; K. Dombrowski, J. Padilla, C.

Richardson, *URS Corporation, Austin, TX*; R. Chang, *EPRI, Palo Alto, CA*; K. Fisher, *Apogee Scientific, Englewood, CA*; L. Brickett, *DOE-NETL, Morgantown, WV*.

This paper reports the mercury removal results from full-scale sorbent injection tests performed at Great River Energy's Stanton Station Units 1 (ESP) and 10 (spray dryer-fabric filter, SD-FF), which both fire PRB coal. Unit 10 tests focused on evaluating the impact of SD-FF operation (temperature, SD slurry feed rate) on brominated carbon mercury removal effectiveness. Unit 1 tests evaluated mercury removal effectiveness of novel sorbents from three vendors (Calgon, BASF, and Praxair). The Calgon sorbent is an activated carbon that may be more ash compatible. BASF is a mineral based non-carbon, while Praxair is a carbon produced by a novel oxygen process. A sixty day continuous brominated carbon (Norit Darco LH) injection test was then conducted across the Unit 1 ESP to assess any balance of plant impacts (including ash use, and ESP operation and particulate emissions) of sorbent injection.

### **Mercury Reductions in a Bituminous Coal-fired Unit During Sorbent Selection Testing**

Paper #: 180

J. Russell, E. ten Siethoff, *MPR Associates, Inc., Alexandria, VA*; A. Shawl, C. Ash, *RC Cape May Holdings, LLC, Beesley's Point, NJ*.

In December 2007, B. L. England Generating Station Unit 2 tested the performance of three mercury sorbents with a medium sulfur Eastern bituminous coal. The purpose of the testing was to demonstrate which of these competitively bid sorbents would control mercury emissions to comply with the New Jersey mercury control requirements and to characterize the operating costs for achieving that level of control. This paper discusses the mercury control achieved by each of the sorbents, observed impacts on equipment operation, and the relative contribution of the various mercury capture mechanisms (i.e., WFGD, fly ash native removal, and mercury sorbent injection) to the mercury control achieved. Observations concerning mercury flue gas sampling and analysis using sorbent traps (Appendix K) at the ESP inlet and in a wet stack are also discussed.

### **ALSTOM's Mer-Cure™ Technology for Mercury Control in Coal-fired Boilers - A Summary of DOE/NETL-sponsored Programs**

Paper #: 184

S. Kang, C. Edberg, R. Schrecengost, E. Rebula, *ALSTOM Power Inc., Windsor, CT*; P. Noceti, *DOE/NETL, Pittsburgh, PA*.

Over the last years, ALSTOM Power Inc. has successfully completed several DOE/NETL-sponsored field test programs designed to demonstrate Mer-Cure™ technology for mercury control. Mer-Cure™ is a cost-effective solution allowing maximum utilization of carbon-based mercury sorbents. This is achieved by injecting sorbents such as proprietary Mer-Clean™ into the flue gas environment where oxidation and adsorption of gaseous mercury is maximized. Test results show that greater than 90% reduction in baseline stack mercury emissions can be achieved at a sorbent injection rate lower than that of other sorbent-based technologies.

In this paper, the performance of Mer-Cure™ technology from various test campaigns is reviewed in detail from various aspects including mercury control efficiency, balance-of-plant impacts as well as overall plant economics. The demonstration sites include:

- PacifiCorp's Dave Johnston Unit 3;
- Basin Electric's Leland Olds Unit 1;
- Reliant Energy's Portland Unit 1; and
- Lower Colorado River Authority's Fayette Unit 3.

### **Session 5: NOx: SCR**

#### **Design, Installation and Startup Experience on a High Removal Efficiency SCR System**

Paper #: 108

C. Erickson, *Babcock Power Inc, Worcester, MA*; S. Dean, B. Rogan, *Mirant, Upper Marlboro, MD*.

The retrofit of SCR systems to Mirant's Unit 1 & 2 at the Morgantown station required several innovation designs and construction methods to meet the demanding project requirements. The design needed to address SCR operation down to 35% boiler load, several options to meet this were reviewed. The chosen design was an economizer gas bypass in gas temperature zone greater than 1000F due to the boiler arrangement of the units. The requirements for NOx removal were 92.5% on both units with 2 ppm ammonia slip and low SO<sub>2</sub> to SO<sub>3</sub> conversion. This high removal was considered with the design of mixing systems that included a complete LPA screen installation. This paper will discuss the steps taken in design and construction to ensure that the SCR technology applied at Morgantown was successful, this discuss will include a review of operational data from the Summer 2007 commissioning of the first unit.

#### **St Johns River Power Park 2 x 670 MW SCR Designed to Ensure Fuel Flexibility**

Paper #: 96

G. Smith, *St Johns River Power Park, Jacksonville, FL*; D. Fischer, *Black & Veatch Corporation, Overland Park, KS*; N. Roshia, J. Cochran, *CERAM Environmental, Inc., Overland Park, KS*; R. Branning, *Tackticks, LLC, Jacksonville, FL*; K. Robinson, *Black & Veatch Corporation, Raleigh, NC*; V. Rummenhohl, *Tackticks, LLC, Durham, NC*.

The St Johns River Power Park is installing SCR systems on two pulverized coal units cofiring high arsenic and silica coals with up to 30% petcoke (high vanadium and sulfur). This fuel combination created significant challenges for maintaining low SO<sub>2</sub>/SO<sub>3</sub> conversion rate while accommodating high catalyst deactivation and high erosion potential.

During project design development, attention was paid to the effect of various fuel characteristics on process configuration, catalyst design, and equipment life. Additional consideration was given to operations and fuel management strategies to minimize fuel

impacts on SCR operation. This paper discusses the design challenges faced and special features incorporated to maintain fuel flexibility and plant availability, including catalyst procurement, reactor/ductwork design, and other system features. Additionally, results are presented regarding testing various catalyst types after exposure to flue gas from cofiring 30% petcoke and 70% coal for up to 6,000 hours and from the SCR system performance test.

### **LPA Screen Installation at DTE**

Paper #: 38

B. Jamar, *Evonik Energy Services (formerly Steag LLC), Kings Mountain, NC*; J. Brown, *Detroit Edison, Monroe, MI*.

Evonik's large particle ash (LPA) screen design was selected for retrofitting Detroit Edison's 800 MW Monroe Power Plant, Unit 4. Design for this installation provided an opportunity to utilize our comprehensive flow modeling tools matched with engineering one of the most detailed installations to date.

Challenges included modeling and analyzing the optimal locations for the screens using flow software and physical parameters; designing a unique screen assembly for the economizer bypass maximizing open flow area in a minimal space; screen design at the economizer outlet taking into account existing interferences, pressure drop and erosion guarantees, as well as design and installation of electric rapping systems integrated to DCS.

Evonik first developed their patented LPA screen design in 1996. This screen design reliably and continuously prevents the intrusion of LPA into the SCR reactor by effectively removing the particles from the flue gas stream without plugging or eroding the screens.

### **Determining SCR Reactor Potential *In Situ***

Paper #: 17

R. Smith, L. Muzio, *FERCo, Laguna Hills, CA*; A. Sibley, K. Harrison, *Southern Company Services, Birmingham, AL*.

The U.S. utility industry has installed over 100 GW of coal based SCR systems. In these systems, Catalyst Activity will gradually decrease, requiring the addition and/or replacement of catalyst material.

Traditionally, Catalyst Activity is monitored by physically removing catalyst samples from the reactor along with laboratory testing. This was easily accomplished while operating SCR systems on a five-month ozone season basis. However, with shift to year-round operation the opportunity to obtain samples is reduced. Hence, there is a need for new tools to aid making informed catalyst management decisions.

The current paper presents the results of a three-ozone-season demonstration of a new system to measure catalyst activity and reactor potential *in situ*. The *in situ* measurement

technique is similar to the traditional laboratory measurement but occurs within the SCR reactor, while the reactor is operating. The results of this demonstration are in reasonable agreement with laboratory tests of activity.

### **In Situ NO<sub>x</sub> Measurements to Assess SCR Efficiency**

Paper #: 82

P. DeBarber, *HORIBA Instruments, Inc., Irvine, CA*; D. Dearmon, G. Starnes, *EPRI, Harriman, TN*; A. Hulen, *TVA, Chattanooga, TN*.

Efficient operation and control of an SCR depends on monitoring both inlet and outlet NO<sub>x</sub> concentrations at the catalyst bed. In the past, such measurements were effected by extractive continuous emissions monitoring systems (CEMS). The drawbacks of using CEMS are the cost associated with the purchase, installation and maintenance. These drawbacks make it difficult to justify monitoring at both inlet and outlet. Furthermore, by only monitoring at one or the other, valuable catalyst performance information is lost. HORIBA and the EPRI Instrumentation and Control Center have developed and tested an economical, low-maintenance, *in situ* instrument for simultaneously monitoring SCR inlet and outlet NO<sub>x</sub> concentrations. Results from tests of this new approach for *in-situ* NO<sub>x</sub> measurements at the inlet and outlet to the catalyst bed of an SCR system at the TVA's Kingston plant will be presented. Comparisons to existing FGAS shelter data will be made.

### **Ammonium Bisulfate (ABS) Measurement for SCR NO<sub>x</sub> Control and Air Heater Protection**

Paper #: 51

C. Chothani, *Breen Energy Solutions, Carnegie, PA*; R. Morey, *AES Cayuga LLC, Lansing, NY*.

Ammonia Slip from SCR/SNCR NO<sub>x</sub> control systems combines with H<sub>2</sub>SO<sub>4</sub> to form AbS, which has a higher dewpoint and condenses deeper into the Air Heater (AH) resulting in pluggage. This could lead to loss of ID Fan capacity, unit derate and a shutdown to wash the AH.

The AbSensor AbS measurement technology directly measures the temperatures at which AbS condenses. Some utilities have installed AH bypass dampers and steam/glycol heating coils to control the AH outlet temperature to avoid plugging. Breen Energy has partnered with EPRI to license and integrate their AH model to strike a balance between Heat Rate and NO<sub>x</sub> reduction.

This paper will present the results from the first full commercial installation of a dual control solution based on this measurement that controls the Ammonia Injection Rate and AH temperature at the AES Cayuga generating station while balancing the cost of NO<sub>x</sub> reduction and heat rate.

## **SCR Catalyst Regeneration - 10 years of R&D Development and Commercial Application**

Paper #: 104

M. Ehrnschwender, *Evonik Energy Services LLC, Kings Mountain, NC*; A. Freeman, *Southern Company, Birmingham, AL*.

With year round SCR operation a widespread use of catalyst regeneration will minimize catalyst replacement costs. Evonik has more than 10 years of R&D and full scale catalyst regeneration experience. The paper explains developments over the last 10 years in catalyst regeneration to the current most advanced state-of-the-art regeneration process.

Full scale regeneration results for all types of commercially available catalyst including:

- Full activity recovery for an application burning high sulfur Southern Illinois Basin coal.
- Opportunities to increase activity above the original value for an application burning world market compliance coal.
- SO<sub>2</sub>/SO<sub>3</sub> conversion rate reduction for an application burning high sulfur Southern Illinois Basin coal.
- Mercury oxidation for an application burning mid-sulfur Southern Appalachian coal.
- Catalyst longevity (number of regeneration cycles) covering catalyst that was regenerated for the fourth time after about 100,000 SCR operating hours.
- Maintaining mechanical catalyst strength and structural integrity.

## **Benefits of Combining SCR Systems and Optimization**

Paper #: 125

R. Johnson, J. James, *NeuCo, Inc., Boston, MA*; J. Naberhaus, *Plum Point Energy Station, Dynege, Osceola, AK*.

While SCR systems are extremely effective at NO<sub>x</sub> reduction, they have turned out to be more expensive to build and operate than initially anticipated. They also have the potential to introduce operating challenges such as ammonia slip, the formation of ammonium sulfate and ammonium bisulfate, and excess SO<sub>3</sub>. This paper will discuss the benefits of applying real-time optimization software to units with SCR systems to address tightening emissions regulations while improving the efficiency of SCR operations. These comparatively inexpensive optimization systems reduce NO<sub>x</sub> at the source and allow power generators to run SCRs less aggressively.

This paper will present results of combining boiler and SCR optimization at Dynege's Baldwin Energy Complex, implemented as part of NeuCo's US Department of Energy Clean Coal Power Initiative Phase 1 project. It examines how optimization has reduced SCR-related costs by reducing ammonia consumption, mitigating negative SCR-related side-effects and simultaneously improving combustion and sootblowing operations.

## Session 6a: Mercury: Sorbents (cont.)

### **Options for High Mercury Removal at PRB-fired Units Equipped with Fabric Filters with Emphasis on Preserving Fly Ash Sales**

Paper #: 163

R. Dutton, J. Conn, *Xcel Energy, Amarillo, TX*; R. Chang, *EPRI, Palo Alto, CA*; J. Paradis, C. Richardson, *URS Corporation, Austin, TX*; S. Morrow, *Xcel Energy, Earth, TX*; R. Rosvold, *Xcel Energy, Minneapolis, MN*; K. Fisher, *Apogee Scientific, Englewood, CO*.

Tests were conducted at two plants firing Powder River Basin coal equipped with fabric filters to evaluate mercury control options that provide high levels of removal while maintaining fly ash salability. Full-scale sorbent injection and boiler chemical injection tests were selected as the most viable options. Parametric tests were conducted to screen promising sorbents on the basis of mercury removal and fly ash cement replacement properties. Following the parametric trials, several options were evaluated during extended duration trials (two to four days) to evaluate performance variability during normal plant operation, and to generate representative ash samples for subsequent concrete additive testing. This paper presents the mercury removal results for the various sorbents and their impact on fly ash cement-replacement properties.

### **Initial Commercial Experience with Gas-Phase Brominated Mercury Sorbents and Injection System Hardware**

Paper #: 159

R. Landreth, *Sorbent Technologies Corporation, Twinsburg, OH*; K. Wanninger, *Midwest Generation, Chicago, IL*.

A number of power plants are now injecting Sorbent Technologies' gas-phase brominated mercury sorbents into their flue gases on a day to day basis and using the company's injection systems. Sorbent Technologies began selling B-PAC™ on a commercial basis in 2007. Initial customers had fabric filters and burned both bituminous and subbituminous coals. In 2008 Sorbent Technologies added power plant customers with electrostatic precipitators. Data from some of these various plants will be presented, including for concrete-friendly C-PAC™ and high-temperature H-PAC™ sorbents. It is becoming clear that the design of the mercury sorbent injection systems themselves can be critical to maximizing mercury reduction performance and cost-effectiveness. Sorbent Technologies delivered four such systems in 2007 and will be installing more in 2008, including some of an advanced design. The initial commercial experience with injection system hardware, the options available, and lessons learned are discussed.

## **PAC Characterization Tests for Coal-Fired Utility Applications**

Paper #: 175

J. Cichanowicz, *Consultant, Saratoga, CA*; R. Stewart, K. Baldrey, S. Sjostrom, J. Bustard, *ADA-ES, Inc., Littleton, CO*; R. Chang, *EPRI, Palo Alto, CA*; C. Richardson, J. Paradis, *URS, Austin, TX*; M. Rostam-Abadi, *ISGS, Urbana, IL*.

Activated carbon injection into flue gas is the most promising near-term approach for controlling mercury emissions from power plants. The technology continues to evolve rapidly as new suppliers of activated carbon and “improved” versions of activated carbon are introduced. There is no clear method to specify activated carbon physical and chemical properties to ensure that the carbon supplied will meet expected performance standards, the quality of the carbon is consistent from batch to batch, and that the carbons supplied will not have adverse balance-of-plant impacts. This paper will describe the effort to develop a list of key activated carbon specifications needed for power plant mercury control applications. Field mercury removal performance data and activated carbon samples from four to six field test sites will be gathered and samples shipped to selected laboratories for measurement of specific activated carbon properties. Correlations will be made between specific carbon properties and field performance.

## **Onsite PAC Production Using Hot Oxygen and Utility Supplied Coals**

Paper #: 35

L. Bool, *Praxair, Tonawanda, NY*; D. Smith, *SaskPower, Regina, SK, Canada*.

Over the last several years Praxair has developed a novel process to produce powder activated carbon (PAC) from pulverized coal. This process, described in detail in previous Mega Symposiums, uses patented oxygen-based technology to rapidly produce PAC. This PAC has been shown to be very effective in capturing mercury during small slipstream and 1 MW-scale trials. Recently three large samples were produced for full-scale trials. These samples were produced using utility supplied coals. Although results from the full-scale trials will be presented elsewhere, slipstream and 1 MW-scale results for these samples are presented here. As discussed in this paper production of the large samples demonstrated the robust nature of the process and solidified the design criteria for a commercial system capable of processing 2400 lb/hr of coal.

## **Session 6b: Mercury: TOXECON and Other Structures**

### **TOXECON™ Demonstration for Mercury and Multi-Pollutant Control at We Energies**

Paper #: 79

S. Derenne, *We Energies, Milwaukee, WI*; R. Stewart, *ADA-ES, Littleton, CO*.

We Energies and DOE, under a Clean Coal Power Initiative program, have been working together for the past three years to design, install, evaluate and demonstrate the EPRI-patented TOXECON™ air pollution control process. The primary goal of this project is to reduce mercury emissions from three 90-MW units that burn Powder River Basin coal at the We Energies Presque Isle Power Plant in Marquette, Michigan. Additional goals

are to reduce nitrogen oxide (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM) emissions, allow for reuse and sale of fly ash, and demonstrate a reliable mercury continuous emission monitor (CEM) suitable for use in the power plant environment. Demonstration of TOXECON™ began in February 2006. This paper will discuss the overall design of the installation, balance of plant issues, and results from mercury optimization testing, mercury long-term testing, and SO<sub>2</sub> and NO<sub>x</sub> removal testing.

### **TOXECON II™ and Other Options for Preserving Ash Sales**

Paper #: 172

S. Sjoström, T. Campbell, C. Sapp, *ADA-ES, Inc., Littleton, CO*; J. Hantz, C. Carmena, *Entergy, Woodlands, TX*; A. O'Palko, *U.S. Department of Energy/NETL, Morgantown, WV*; R. Chang, *EPRI, Palo Alto, CA*.

TOXECON II™ testing has been underway at Entergy's Independence Steam Electric Station (ISES), Unit 2 since 2005 through funding from DOE NETL, EPRI, Entergy, ADA-ES, and other industry partners. EPRI and Entergy have funded additional tests to evaluate other options to preserve ash sales. Independence fires Powder River Basin (PRB) coal and is configured with a cold-side ESP for particulate control.

TOXECON II™ testing to date indicates very promising results. However, testing has also shown that the TOXECON II™ system design is critical to achieving the expected results. Tests of other alternatives are scheduled to begin in February 2008. This paper will provide a summary of results from mercury control evaluations at Entergy's Independence Station, including mercury removal performance and the impacts of sorbent injection on ESP performance, particulate emissions, and projected impacts on ash sales.

### **Field Investigations of Fixed-bed Sorbents for Mercury Capture from Coal-fired Flue Gas**

Paper #: 106

T. Machalek, C. Richardson, J. Noblett, *URS Corporation, Austin, TX*; R. Chang, *EPRI, Palo Alto, CA*; B. Looney, M. Berry, B. Whittemore, *Southern Company, Birmingham, AL*; R. Merritt, *Randy Merritt Consulting, Birmingham, AL*; W. Harrison, *PCT Inc., Birmingham, AL*.

The use of fixed-structure sorbents for mercury capture from flue gas may offer several advantages over injection technologies related to sorbent utilization, byproduct contamination, and particulate emissions. Previous testing of EPRI's MerCAP™ process demonstrated the operational feasibility of using fixed sorbents in coal-derived flue gas. A new fixed-structure technology, based on the MerCAP™ concept, uses a fixed (activated) carbon bed to remove flue gas mercury of a particulate control device. EPRI's MercScreen™ has demonstrated effective performance in a number of flue gas slipstream tests and is currently being evaluated at pilot scale.

This paper summarizes results of both slipstream and pilot tests conducted at two host power plants firing bituminous and PRB coal. Tests have evaluated the impact of sorbent type and space velocity on mercury removal performance. Longer-term pilot tests have

evaluated pressure drop behavior, particulate emission, and optimization of flow dynamics. A preliminary economic analysis has been conducted.

### **Session 7: SO<sub>2</sub>**

#### **Duke Energy-Carolinas' WFGD Retrofit Program: Operation at Marshall and Belews Creek Stations**

Paper #: 48

R. Laws, *Duke Energy Carolinas, Charlotte, NC*; E. Byers, *Duke Energy-Carolinas, Walnut Cove, NC*; J. Dopatka, R. Mardini, *Alstom Power Environmental Control Systems, Knoxville, TN*; J. McCarthy, *Shaw Stone & Webster, Charlotte, NC*.

Duke Energy-Carolinas committed to a multiphase fleet-wide SO<sub>2</sub> emissions reduction. Four of eight coal-fired stations are being retrofitted with high efficiency WFGD by 2012. Two stations are already operating, one is being commissioned, and another being constructed.

The state-of-the-art WFGD systems at Marshall and Belews Creek Stations have been in operation between 8-20 months. Performance testing on the absorbers and overall systems has been completed. Operating experience, maintenance requirements, and performance results are the main focus of this paper. Specifics include:

- Absorber performance without spare spray levels
- Damperless open-bypass system employing unique materials
- Selection of FRP outlet flues and stack liners
- HDPE piping: engineering, construction, operation
- Duke's Gypsum Recycling Program: Gypsum quality, contract approach, transportation arrangement, dedicated supply.
- Biological and wetlands removal of selenium and mercury from WFGD blowdown
- Overall operating and maintenance experience, including O&M provisions and equipment reliability.

#### **WKE Coleman Station: Two Years of Operation with a Multiple Dual Flow Tray Absorber**

Paper #: 126

M. Hoydick, *Siemens Environmental Systems & Services, Pittsburgh, PA*; D. Braunecker, *Western Kentucky Energy, Louisville, KY*.

The Coleman Generating Station has three boiler units, each approximately 160 megawatts. Siemens Environmental Systems and Services (SESS) supplied a limestone based, single absorber module (~ 485 MW gross capacity) capable of meeting 95 percent SO<sub>2</sub> removal. Due to the high inlet sulfur loading design condition, the absorber is equipped with two levels of dual flow trays and five spray levels. The chemistry is limestone based, in-situ forced oxidation with no performance additives. Commercial, wallboard quality gypsum is produced.

Operation began in February 2006. The multiple tray arrangement has consistently

achieved SO<sub>2</sub> removal rates in excess of 98% and subsequent low outlet SO<sub>2</sub> concentrations. The outlet SO<sub>2</sub> typically ranges from 30 - 50 ppmv at all boiler loads (and all inlet fuel sulfur levels). This paper will review the FGD system design, examine historical and current emission and pressure drop data of the multiple tray arrangement.

### **800 MWe Single FGD System for Five Boilers at Elektrownia Kozenice Power Station**

Paper #: 136

T. Nakamoto, A. Katagawa, *Babcock Hitachi, K.K., Kure, Japan*; S. Mosch, T. Muramoto, *Hitachi Power Systems America, Basking Ridge, NJ*; M. Rozycki, *Elektrownia Kozenice S.A., Kozenice, Poland*.

A new FGD II at Elektrownia Kozenice (Poland) has been commissioned and started commercial operation in December 2006. The FGD plant was supplied by Hitachi Ltd and Poltegor (Poland) in consortium. This FGD is connected to five 200 MWe units and able to clean the flue gases of four units at full load simultaneously (800 MWe, 3,480,000 Nm<sup>3</sup>/h, wet), which makes it one of the largest FGD plant in Europe with a single module absorber. The plant can operate also with only one 200 MWe unit in operation. The FGD project also features a low cost, integrated wet stack mounted on top of the absorber and made of fiber reinforced plastic (FRP). The full EPC based FGD II project at Elektrownia Kozenice was handed over to owner within 30 months which is more than 2 months ahead of schedule of the contract.

### **Installation and Start-up of a Modern Wet Flue Gas Desulfurization System at the Ghent Generating Station Unit 3**

Paper #: 93

M. Jasinski, C. Erickson, *Babcock Power Inc., Worcester, MA*; E. Saunders, *E.ON US, Louisville, KY*.

In August of 2007, Babcock Power Environmental Inc. in conjunction with E.ON US and Fluor completed the start-up of a modern wet flue gas desulfurization (WFGD) system. The Ghent Unit 3 WFGD system was designed to remove 98.5% of a 6.9 lbs/MBtu inlet SO<sub>2</sub> while producing a wallboard quality gypsum by-product.

In order to meet all of the above requirements, Babcock Power used its cumulative experience and innovative scrubbing technology enhancements. In addition, a feed forward control system was used to minimize the excess reagent added. The resultant system, when tested, removed greater than 98.5% of a high inlet SO<sub>2</sub> loading while maintaining the removal on average within  $\pm 0.5\%$  of the set point.

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## **FGD System Foaming - Operational Issues and Design Considerations**

Paper #: 129

M. Hoydick, *Siemens Environmental Systems & Services, Pittsburgh, PA*; I. Brodsky, *URS Washington Group, Philadelphia, PA*; J. Smolenski, *Tampa Electric Company, Tampa, FL*; P. Kutzora, *We Energies, Milwaukee, WI*.

SESS has several FGD systems that have experienced periodic recycle tank foaming. Two sites include Tampa Electric's Big Bend Station and We Energies Pleasant Prairie Power Plant (P4).

P4 began operation in November 2006. Initial operation went smoothly and was uneventful. After about four weeks, questionable results from the recycle tank level transmitters were reported. Investigation revealed foaming was the root cause. Foam was also later observed in the trenches, sump, hydroclone, and various tanks throughout the system. A defoaming agent was added to the recycle tank to reduce the issues.

We Energies' South Oak Creek, a P4 replicate, is currently in design. Several design modifications have been incorporated to minimize the operational impacts caused by foaming. This paper discusses the potential foaming causes and design modifications incorporated to reduce operational impacts at both the Big Bend Station and the future South Oak Creek plant.

## **Jet Air Sparger System (JAS) Commercial Application and Development of Larger JAS**

Paper #: 24

J. Hashimoto, T. Nagayasu, *Mitsubishi Heavy Industries, Ltd., Yokohama, Japan*; T. Shinoda, S. Sugita, Y. Nakayama, *Mitsubishi Heavy Industries America, Inc., Austin, TX*; K. Maki, Y. Tokunaga, *Nippon Petroleum Refining Co., Ltd., Osaka, Japan*.

Mitsubishi Heavy Industries, Ltd. (MHI) has a unique forced oxidation system for Flue Gas Desulfurization (FGD) scrubber called Jet Air Sparger system (JAS). The JAS has been supplied in nearly 7,000MW of FGD in 17 units. This MHI proprietary design is highly efficient in terms of reducing oxidation air and power requirements.

The JAS uses the discharge from the recirculation pumps, with pipeline orifice plates, to induce ambient air and disperse the air into extremely fine bubbles, for oxidation of the circulating slurry in the Absorber. This paper presents the feature of the JAS and its successful commercial result.

MHI has further and newly developed larger JAS suitable for increased capacity absorbers. This paper presents as well the performance and durability results of larger JAS from FGD at Nippon Petroleum Refining Co., Ltd. in Japan.

## **Design, Construction & Commissioning for Lined Concrete Wet FGD Absorber Vessels**

Paper #: 141

J. Murphy, J. Wiinkler, *Siemens Environmental Systems & Services, Pittsburgh, PA*; R. Glaser, *PPL Generation, LLC, Pittsburgh, PA*.

After extensive economic and technical evaluations, PPL Generation LLC selected absorber vessels of lined concrete construction for installation as part of the Wet FGD System retrofits at their Montour and Brunner Island facilities. As the selected Wet FGD System supplier for both facilities, Siemens Environmental Systems & Services worked closely with the end user, PPL and the absorber vessel shell erector, Stebbins Engineering to ensure that contract requirements were maintained throughout the project.

Due to the unique design and construction requirements of lined concrete absorber vessels, special directions and procedures were practiced by Siemens Environmental Systems & Services and Stebbins Engineering throughout the project execution schedule. This paper will examine the design features, construction techniques and commissioning practices followed for the lined concrete absorber vessels at the PPL sites and also compares them to those utilized for alloy absorber vessels typically supplied for Wet FGD System retrofits.

### **Session 8: Mercury: Additives & SO<sub>3</sub> Countermeasures**

#### **Modeling Mercury Behavior in Coal-Fired Boilers with Halogen Addition**

Paper #: 150

C. Senior, A. Fry, B. Adams, *Reaction Engineering International, Salt Lake City, UT*.

In order to prepare for compliance with upcoming mercury regulations, such as the Clean Air Mercury Rule (CAMR), utilities must have useful tools and information for compliance planning. With EPRI support, REI has developed an integrated process model, MerSim, for predicting mercury behavior in coal-fired utility boilers and through air pollution control devices. This model uses fundamental mechanisms that allow for meaningful extrapolation to new plant configurations and conditions. This assessment tool has been modified to include bromine chemistry using a set of elementary, gas-phase (homogeneous) reactions as well as heterogeneous reactions involving bromine and mercury species. Validation has been performed against published data from a demonstration program at TXUs Monticello Unit 3. The model was able to accurately predict mercury speciation and concentration for eight baseline and halogen addition conditions. For six of the eight cases, mercury removal was predicted within 7% and for all cases within 15%.

## **Identifying the Best Options for Hg Control With MercuRator™**

Paper #: 58

S. Niksa, Y. Hou, *Niksa Energy Associates LLC, Belmont, CA.*

MercuRator™ is a computational tool to forecast Hg emissions over broad ranges of fuel quality, gas cleaning conditions, and dedicated Hg control technologies. Previous work validated the predictions for inherent controls in systems with SCRs, ESPs, and FGDs, and for dedicated Hg control with ACI, although most of the test data represented bituminous coals. This paper expands the validation database to better cover low-rank fuels for all cleaning configurations, and a wider range of sorbent injection conditions, including the impact of SO<sub>3</sub> adsorption on ACI performance; sorbent capture with SDA/FF combinations; and the performance of TOXECON II systems. In total, Hg speciation datasets from more than a dozen new test sites are interpreted with a single selection of chemical reaction mechanisms for in-flight Hg oxidation and sorption on unburned carbon in suspended flyash and injected sorbents; Hg oxidation along SCR catalysts; and Hg retention in FGD scrubber solutions.

## **Simultaneous Injection of HBr and Adsorbents (Activated Carbon, Fly Ash or Non-carbon-based Adsorbent) for Mercury Abatement in Coal-fired Utility Boilers**

Paper #: 71

Y. Cao, Q. Wang, J. Li, M. Cohron, W. Pan, *Institute for Combustion Science and Environmental Technology, Western Kentucky University, Bowling Green, KY*; E. Morris, *Pleasant Prairie Power Plant, We Energies, Pleasant Prairie, WI*; S. Derenne, *We Energies, Milwaukee, WI.*

Activated carbon injection in the utility boiler burning sub-bituminous coal causes some concerns on the re-use of fly ash in cement industry. Intensive tests were conducted in a subbituminous-coal-fired utility boiler for mercury abatement by simultaneous injection of HBr and several adsorbent candidates, such as activated carbon, fly ash or non-carbon-based adsorbent. HBr was indicated an effective mercury oxidant in lower temperature range under the subbituminous-coal-fired flue gas atmosphere. Simultaneous injection of HBr, which was firstly oxidize the elemental mercury in the flue gas, likely makes the mercury more easily be captured by either activated carbon or other adsorbents by synergetic effects. Benefits for simultaneous injection of both HBr and adsorbents will make adsorbent to capture mercury more efficient and also likely use alternative low cost adsorbents, such as fly ash. Corrosion tests with two desired temperature at 350 °C or 150 °C were also conducted to evaluate corrosion-resist performance.

## **The Balance-of-Plant Impact of Calcium Bromide Injection as a Mercury Oxidation Technology in Power Plants**

Paper #: 27

K. Dombrowski, C. Richardson, J. Paradis, *URS Corporation, Austin, TX*; R. Chang, *EPRI, Palo Alto, CA.*

The use of calcium bromide as a mercury oxidizing agent may result in elevated concentrations of bromine (as HBr or Br<sub>2</sub>) in the fly ash, FGD byproducts, and/or flue gas.

We have initiated a project to evaluate the fate of bromide/bromine in coal-fired power plants and its potential balance of plant impacts. Data for this project are gathered from bromine injection tests completed recently and from on-going calcium bromide injection testing where samples are obtained from flue gas, ash, and the wet scrubber. Samples are analyzed for impact of bromine on flue gas bromine emissions, ash use, bromine leaching, bromine related corrosion in the boiler and in the scrubber, and the partitioning of bromine and mercury between the FGD liquor and solids. This paper will summarize the results from the various field tests and their implications on the use of bromide boiler injection for mercury control.

### **Activated Carbon Injection with SO<sub>3</sub> Flue Gas Conditioning Test at Gulf Power's Mercury Research Center**

Paper #: 78

B. Looney, *Southern Company, Birmingham, AL*; W. Marchant, *Particulate Control Technologies, Helena, AL*; M. Tuck, *Mississippi Power Company, Escatawpa, MS*.

Various field tests have identified an interference mechanism between the ability of activated carbon to readily adsorb mercury and the presence of sulfur trioxide (SO<sub>3</sub>) in the flue gas stream. This interference presents a substantial challenge for using activated carbon as a mercury control on boiler units currently using SO<sub>3</sub> Flue Gas Conditioning for ESP performance. This paper summarizes the results from a test conducted at Gulf Power Company's Mercury Research Center to quantify the effects SO<sub>3</sub> has on the ability of activated carbon to capture mercury when burning Colombian bituminous coal.

The test results include an evaluation of the effect of injection locations of both the activated carbon and SO<sub>3</sub>. Results of particulate collection are presented for various parametric tests. Additionally, an evaluation of alternative ESP power supplies, including high frequency and pulsing, and their effect on activated carbon capture are included.

### **Cost Effective Mercury Control System at the Newmont TS Power Plant**

Paper #: 72

J. Brown, *Fluor Corporation, Greenville, SC*; J. Seeliger, *Newmont Mining Corporation, Dunphy, NV*; P. Williams, K. Redinger, S. Brown, B. Jankura, *The Babcock & Wilcox Company, Barberton, OH*.

In early 2004, prior to issuance of the Clean Air Mercury Rule, Newmont Mining Corporation took a proactive stance in addressing mercury emissions when developing the greenfield 200 MW TS Power Plant. The power plant air permit application proposed Powdered Activated Carbon (PAC) injection with brominated carbon to achieve low mercury emissions. In development of the final plant design, enhanced mercury removal and reduction of operating costs were achieved through the use of a cost-effective technology to maximize the co-benefit mercury control features of the FGD system. This paper discusses the emissions control system design, presents supporting mercury emissions control performance data, reviews the initial system operating experience and presents the life cycle cost savings of the combination of B&W's CaCl<sub>2</sub> injection

technology with PAC injection upstream of the spray dry adsorber and fabric filter baghouse at this full-scale, operating power facility.

### **Mercury Removal Enhancement via SO<sub>3</sub> Removal: Pilot and Full-Scale Test Results**

Paper #: 133

J. Jarvis, S. Wells, *URS Corporation, Austin, TX*; J. Wilson, *Southern Company Services, Birmingham, AL*.

Mercury co-removal with the unburned carbon in fly ash, or through activated carbon injection, may be critical for meeting future compliance requirements. However, there is a growing consensus that the presence of SO<sub>3</sub> in the flue gas from coal-fired boilers significantly reduces the capacity of these carbon-containing materials to adsorb gaseous mercury species.

The relationship between SO<sub>3</sub> and mercury removal was explored in detail during testing at the Mercury Research Center in Pensacola, Florida. The results illustrate both the relationship between SO<sub>3</sub> and mercury adsorption and the ability to significantly enhance mercury capture by reducing the SO<sub>3</sub> concentration to very low levels. Results include mercury speciation and SO<sub>3</sub> concentration measurements along the gas path and estimates of mercury emissions reductions resulting from SO<sub>3</sub> control and wet scrubbing.

### **Mercury Control with Activated Carbon: Results from Evaluations at Plants with High SO<sub>3</sub>**

Paper #: 174

T. Campbell, S. Sjoström, M. Dillon, J. Bustard, P. Brignac, *ADA-ES, Inc., Littleton, CO*; P. Raichle, *PSNH, Bow, NH*; T. Orscheln, *Ameren, St. Louis, MO*; A. O'Palko, *U.S. Department of Energy/NETL, Morgantown, WV*; R. Chang, *EPRI, Palo Alto, CA*.

The presence of SO<sub>3</sub> in flue gas, whether a result of the combustion of high-sulfur coal, the presence of an upstream SCR, or of SO<sub>3</sub> injection for flue gas conditioning, can impair the effectiveness of activated carbon for mercury removal. Full-scale evaluations of sorbent injection for mercury removal have been conducted over the past two years to characterize the impact and assess alternatives to enhance mercury removal. These tests have been funded by DOE NETL, EPRI, and industry partners.

This paper will present results from testing including the effectiveness of traditional and alternative sorbents on mercury emissions, the influence of SO<sub>3</sub> concentration and flue gas temperature on mercury removal efficiency, and the effectiveness and economics of dual injection for SO<sub>3</sub> and mercury control.

## **Session 9: SO<sub>2</sub> (cont.)**

### **Evaluation and Management of the Impact of FGDs on Wastewater**

Paper #: 105

P. Chu, N. Goodman, *EPRI, Palo Alto, CA*; D. Fink, *CH2M Hill, Oakland, CA*; T. Higgins, *CH2M Hill, Chantilly, VA*; D. Wallschläger, *Trent University, Peterborough,*

ON, Canada; D. Orr, G. Behrens, C. Braman, *URS, Austin, TX*; B. Park, *MSE Technology Applications, Inc., Butte, MT*.

Volatile trace elements such as mercury and selenium may be captured in the wet FGD, and would be eventually discharged in either the FGD solids and/or water discharge. EPRI R&D is characterizing trace element concentrations in FGD water. Mercury can be present as either dissolved and/or particulate phase. The “dissolved” mercury may include mercury associated in the fines, and the fraction of dissolved mercury may vary significantly from site to site. This is critical in developing water treatment options for mercury. Selenium may be present in several forms, including selenite, selenate, as well as several unknown selenium compounds. Selenate and these unknown selenium compounds appear to be more difficult to treat using traditional iron coprecipitation. EPRI is evaluating various treatment options to remove all the selenium compounds as well as for mercury. Laboratory results with a metallic iron approach indicate promising removal of all forms of selenium.

### **Preliminary Results from a WFGD Effluent Characterization Study and Their Impact on Scrubber Operations and Waste Water Treatment**

Paper #: 140

S. Winter, M. Sandell, M. Hoydick, J. Murphy, *Siemens Environmental Systems & Services, Pittsburgh, PA*.

Currently, the USEPA along with industry groups, UWAG and EPRI, are conducting waste water studies at designated coal-fired power plants to determine if effluent guidelines should be revised. In parallel to these studies, Siemens Environmental Systems & Services (SESS) will present results from an in-house wet flue gas desulphurization (WFGD) effluent water sampling and analysis program from current SESS wet scrubber installations. Characterization of these waters will target elements such as mercury, selenium, arsenic, and boron, as well as other water quality parameters, such as organics, chlorides, and suspended solids. The data will be presented with respect to developing solutions for WFGD operators to maintain removal performance, while minimizing the impact on plant water quality, and to identify cost effective waste water treatment technologies when water discharge is required.

### **Wastewater Treatment for FGD Purge Streams**

Paper #: 33

P. Kutzora, *We Energies, Milwaukee, WI*; K. Braunstein, *Washington Division of URS Corporation, Princeton, NJ*; M. Riffe, B. Heimbigner, *Siemens Water Technologies Corp., Warrendale, PA*.

Characteristics of FGD Purge streams will be identified and items affecting those characteristics will be discussed, including the coal source, limestone quality, scrubber design, and makeup water quality. Key elements affecting the design and sizing of FGD wastewater treatment systems will be discussed. A number of case studies will be presented to illustrate different wastewater treatment systems that resulted from the combination of the FGD Purge characteristics and the final treated effluent requirements

and permits. Materials of construction, redundancy of parts/components, operation & maintenance procedures, and system flexibility for future changes will be covered. Lessons learned will be presented on systems that are currently in operation, as well as some under construction or design.

#### **Multi-Pollutant Control Project at Cholla Unit 4**

Paper #: 156

J. Jones, J. Mashek, *Burns & McDonnell Engineering Company, Kansas City, MO*; B. Gifford, *Arizona Public Service Company, Phoenix, AZ*.

The 380 MW Unit 4 at the Cholla Station, which is owned by PacifiCorp and operated by Arizona Public Service, is the site of an ongoing full-scale multi-pollutant control project featuring several unique features. The goals of the project are to simultaneously implement modifications to reduce emissions of particulate and SO<sub>2</sub> while providing improved inherent mercury control and capability for further mercury reductions. This paper will provide an update on the progress of the project, which includes the replacement of a hot-side electrostatic precipitator with a pulse-jet fabric filter, installation of a wet lime FGD system utilizing inhibited oxidation, significant upgrades to the existing lime reagent preparation and waste slurry disposal systems and conversion of the existing stack to accommodate operation in the “wet stack” mode. Performance test data will be incorporated and discussed.

#### **Testing and Model-based Optimization of SO<sub>2</sub> Removal With Trona in Coal-fired Utility Boilers**

Paper #: 137

M. Cremer, D. Wang, C. Senior, *Reaction Engineering International, Salt Lake City, UT*.

In response to continuing SO<sub>2</sub> regulations, a number of removal technologies are being tested at utility boilers. Although large boilers often employ wet or dry scrubbers, smaller units may have performance or scheduling flexibility to utilize lower-cost solutions such as sorbent injection. Successful application requires appropriate injection system design and operation. This presentation describes the development, application and field verification of a CFD-based model for SO<sub>2</sub> reduction with trona. The model implementation of the chemistry, mass transfer and chemical adsorption factors for capture of SO<sub>2</sub> on trona is described. Predicted reductions are shown to compare well with field data from two utility boilers, 75 MW and 175 MW, firing bituminous coal. Sensitivity to injection rate, particle size, injection location and economizer gas temperature are summarized. Predicted reduction ranges from 45-80% for both units and is highly dependent on NSR and trona distribution.

#### **Dry Sorbent Injection for Low Cost SO<sub>2</sub> Control and SO<sub>3</sub> Mitigation**

Paper #: 6

K. Day, *O'Brien & Gere, Greene, NY*; D. Quenan, *AES Somerset, LLC, Barker, NY*.

This presentation will demonstrate the effectiveness of using "Duct Injection" or DI technology as a low cost SO<sub>2</sub> control process and for SO<sub>3</sub> mitigation. Duct Injection is

the process of injecting dry sorbents, Trona, Hydrated Lime or Sodium Bicarb. into the duct at various locations after the economizer.

Results and analytical data from several demonstrations and operating systems will be discussed. DI applications, system design innovation's and economics will be presented. Additional Advantages of DI; CO<sub>2</sub>, NO<sub>x</sub> and mercury control results will be discussed also.

### **Session 10: SO<sub>3</sub>**

#### **SO<sub>3</sub> and Fine Particulate Mitigation at AES Deepwater**

Paper #: 57

R. Snyder, A. Silva, A. Morretti, D. Tonn, *Babcock & Wilcox, Barberton, OH*; S. Kumar, *Babcock & Wilcox, Houston, TX*; A. Lau, *AES Deepwater, Houston, OH*.

The AES Deepwater Plant installed upgrades to the existing Wet ESP's and added a new SCR. The nature of the fuel, being petroleum coke, coupled with the new SCR requires high SO<sub>3</sub> capture across the WetESP. The performance of the Wet ESP is similar to those of high sulfur coal applications which strive to achieve low outlet emissions. This paper will describe the plant equipment configuration, Wet ESP upgrade, SCR overview and performance issues related to Wet ESP operation. In late 2007, a series of tests were conducted across the SCR and Air Heater for SO<sub>3</sub> and at the exit of the Wet ESP measuring SO<sub>3</sub> and PM. The results of the tests and description of the test methods will be presented. A comparison of similarities and differences between the AES Deepwater installation and typical high sulfur coal fired plant will be discussed.

#### **An Emissions Approach to SO<sub>3</sub> Mitigation**

Paper #: 69

D. Tonn, A. Moretti, R. Snyder, *Babcock & Wilcox, Barberton, OH*; A. Lau, *AES Deepwater, Pasadena, TX*.

Total particulate emissions are being set near detection limits on new or revised plant operating permits. Acid gas emissions, like SO<sub>3</sub>, which form particulate and make up a portion of total particulate must be controlled to even lower values. Thus, the selected acid gas control technologies must be based on meeting the required emissions. This paper provides the results of investigations that have been performed and demonstrates achievable SO<sub>3</sub> emissions utilizing an emissions control system approach for a range of fuel sulfur contents. Available total particulate emission results on both high and low sulfur fuels with multiple control technologies are presented as demonstration of SO<sub>3</sub> mitigation. Consideration of multiple SO<sub>3</sub> mitigation technologies and reagents is included. The conclusions of this analysis can be utilized in the economic selection of the proper control technologies for the selected primary fuel and sulfur content to achieve the total particulate emissions.

### **Ultra-High SO<sub>3</sub> Removal: SBS Injection™ as an Alternative to W-ESP**

Paper #: 132

S. Gray, *URS Corporation, Austin, TX*; M. Harpenau, *Duke Energy, Owensville, IN*; P. Copsey, *Dayton Power & Light, Dayton, OH*.

With increased scrutiny of proposed coal-fired power plants, the electric utility industry is faced with ever more stringent limits on sulfuric acid mist (SAM) emissions. Until recently, these very low limits have only been achievable with wet electrostatic precipitators (W-ESP). This paper will describe and present a relatively new sorbent injection process, SBS Injection™, which can achieve ultra-high SO<sub>3</sub> removal. Performance data will be presented from several commercial applications that demonstrate greater than 98% SO<sub>3</sub> removal and SAM emissions of less than 0.005 lb/MMBtu.

The paper will also describe how ultra-high SO<sub>3</sub> removal at the boiler exit can produce valuable benefits for a power plant. These benefits include enhanced environmental performance by making other emission control technologies work better to further reduce NO<sub>x</sub>, Hg, particulate, and CO<sub>2</sub> emissions. In addition, ultra-high removal of SO<sub>3</sub> can enhance plant operational performance by improving energy efficiency and reducing back-end equipment corrosion and fouling.

### **Ammonia Injection for Control of SO<sub>3</sub> - Effectiveness and Secondary Impacts On Fly Ash and FGD Process Streams**

Paper #: 26

J. Smolenski, *Tampa Electric Company, Tampa, FL*.

Tampa Electric Company has recently installed SCR systems on coal fired Units 3 and 4 of its Big Bend Station. These units were already equipped with wet FGD systems and burning eastern medium to high sulfur bituminous coal. In anticipation of the need to control sulfuric acid mist emissions from the projected high SO<sub>3</sub> concentrations Tampa Electric installed ammonia injection systems downstream of the air preheaters of these two units. This paper will discuss the results of the field testing of the effectiveness of the ammonia injection systems at reducing SO<sub>3</sub> concentrations in the flue gas. The secondary impacts of the injected ammonia upon the marketability of the resulting fly ash and the environmental implications of the increased nitrogen content of the FGD chloride purge stream discharge will be discussed. The design and operation of the ammonia injection system will also be discussed.

### **AEP's Protocol for Qualifying Trona Suppliers**

Paper #: 101

D. Ritzenthaler, *American Electric Power, Columbus, OH*.

A growing number of utilities are utilizing the dry sorbent injection of Trona as a cost effective solution to SO<sub>3</sub> mitigation. Trona suppliers entering the market have different product characteristics and, as a result, a thorough investigation is required to ensure that the end product offered by the supplier is compatible with the material handling

equipment and that, ultimately, it performs as advertised.

This paper will discuss AEP's efforts to develop and implement testing protocols to evaluate and approve Trona suppliers for SO<sub>3</sub> mitigation systems used throughout the AEP fleet. Qualification efforts included: establishing critical parameters such as free moisture, particle size, etc.; mill testing in both laboratory and in the field; producing test material in sufficient volumes; and performance testing at a plant. This paper will discuss the results of the full scale testing as well as the final material specifications that were developed from this effort.

### **Next Generation Wet Electrostatic Precipitators**

Paper #: 30

H. Shah, J. Caine, *Southern Environmental Inc., Pensacola, FL*; R. Henningsgaard, *Xcel Energy Co., Becker, MN*.

Multi-pollutant control technologies are becoming more important. This paper will document the advantages of a Membrane WESP to remove PM<sub>2.5</sub>, SO<sub>3</sub> and Hg+2 emissions after limestone WFGD scrubbers, and present performance results of various full-scale and pilot installations.

The operation and performance of the first commercial size, two-module, upflow, single-field unit, being operated at the downstream of boilers firing No. 6 oil with 4% sulfur and vanadium content will be detailed.

The other advantage of the membrane WESP is its capability to cool the saturated gas stream and operate as a condensing WESP. The WESP performance is enhanced by condensing water out of the gas stream and this unit requires no make-up water which allows the use of lower grade stainless steels for materials of construction. The details of this capability will be described.

Cost estimates comparing the membrane design WESP to conventional (metal plate) Wet ESP's will be presented.

### **Field Experience with On-line Measurement of SO<sub>3</sub> and Sulfuric Acid Dewpoint**

Paper #: 68

C. Lockert, *Breen Energy Solutions, Carnegie, PA*.

The negative effects of varying and elevated levels of SO<sub>3</sub> in utility flue gas streams have been well documented. Air Heater fouling and corrosion, diminished unit heat rate, compromised ESP performance, compromised mercury capture through ACI and Blue Plume release have all captured center stage in technical conferences and research investigations.

To effectively mitigate these problems several viable technologies have been introduced and field tested. However, only recently has an equally viable method for measurement and control of these processes been introduced.

This presentation will document the field experience of the Breen AbSensor technology for on-line measurement of SO<sub>3</sub>/Sulfuric Acid Vapor in full scale plant settings. The presentation will cover control of mitigation chemical injection, on-line heat rate improvement, high sulfur baghouse experience and control of ESP Gas Conditioning systems.

### **Session 11: Multi-Pollutant Controls**

#### **ReACT Process Demonstration at Valmy Generating Station**

Paper #: 123

C. Dene, *Electric Power Research Institute, Palo Alto, CA*; J. Gilbert, *Sierra Pacific Resources, Valmy, NV*; K. Jackson, *Shaw Environmental and Infrastructure, Knoxville, TN*; S. Miyagawa, *J-Power EnTech Inc., Tokyo, Japan*.

An advanced process for removing pollutants from coal-fired power plant emissions - Regenerative Activated Coke Technology (ReACT) was tested at the Valmy Generating Station in northern Nevada in 2007. The purpose of the demonstration project at Valmy was to verify ReACT's performance with U.S. coals. The ReACT process can reduce emissions of sulfur oxides (SO<sub>2</sub> and SO<sub>3</sub>) by more than 98 percent, nitrogen oxides (NO<sub>x</sub>) by up to 40 percent and mercury emissions by more than 90 percent.

This paper will cover the results of demonstration testing at the Valmy Generating Station over a period of five months. During the testing both sub-bituminous and western bituminous coals were used to validate the application on low sulfur US coals, and a series of parametric tests were conducted to explore the ReACT technology performance over a range of operating parameters and conditions.

#### **Field Testing of Advanced Air Quality Control System for Multi-pollutant Control**

Paper #: 127

T. Nakamoto, H. Kikkawa, M. Iwatsuki, Y. Taguchi, *Babcock Hitachi, K. K., Kure, Japan*; S. Mosch, S. Wu, *Hitachi Power Systems America, Basking Ridge, NJ*; G. Mues, T. Orscheln, D. Harley, *Ameren Services, St. Louis, MO*.

An Advanced AQCS has been developed to help the power industry to meet new environmental requirements by controlling SO<sub>3</sub>, condensable PM and mercury emissions at significantly lower cost than current systems, and to reduce CO<sub>2</sub> emissions through plant efficiency improvement. The new AQCS includes a) SCR with high mercury oxidation / low SO<sub>2</sub> - SO<sub>3</sub> conversion catalyst; b) gas cooler; c) PJFF or dry ESP; d) advanced wet scrubber.

Following extensive laboratory and pilot plant testing, the development work has entered the field testing phase. A slipstream AQCS test facility of 1 MW equivalent heat input has been installed at Ameren's Duck Creek Power Station. This paper describes the configuration of the advanced AQCS, the test facility arrangement, and slipstream test data firing Illinois bituminous coal. A full-scale conceptual design of the advanced

AQCS and its performance, capital and operation costs will be discussed and compared with current commercial systems.

### **Cliffside Unit 6 Integrated Air Quality Control System**

Paper #: 9

G. McGinnis, *Duke Energy, Charlotte, NC*; P. Rader, R. Gansley, *Alstom Power, Knoxville, TN*.

Duke Energy anticipates a final air permit soon and, at the time of the Mega Symposium, expects to be constructing a new nominal 800 MW unit as part of a modernization of their existing Cliffside, NC facility. This paper focuses on the advanced Integrated Air Quality Control System (AQCS) that will be supplied by Alstom. The Integrated AQCS combines Alstom's dry and wet FGD systems in an innovative way that will reliably achieve stringent emission requirements at a lifecycle cost well below that of competing technologies. Major cost savings are achieved by replacing a wet electrostatic precipitator with a spray dryer absorber and eliminating the need for wastewater treatment equipment for the WFGD system. Other advantages include reduced water consumption and the ability to employ low cost materials for construction for the WFGD absorber. In addition to describing the process, a lifecycle cost comparison will be made with competing technologies.

### **The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation**

Paper #: 15

D. Connell, J. Locke, *CONSOL Energy Inc., Research & Development, South Park, PA*; D. Roll, *AES Greenidge LLC, Dresden, NY*; R. Abrams, R. Beittel, *Babcock Power Environmental Inc., Worcester, MA*; W. Huber, *U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA*.

The Greenidge Project is being conducted at the 107-MW AES Greenidge Unit 4 as part of DOE's Power Plant Improvement Initiative to demonstrate a combination of technologies that is well-suited for reducing emissions from the nation's large fleet (~60 GW) of smaller coal-fired units. The technologies, which include a hybrid SNCR/SCR system and a Turbosorp<sup>®</sup> circulating fluidized bed dry scrubber, were installed in 2006 at a cost of ~\$340/kW, substantially less than the cost for a conventional SCR and wet scrubber.

Testing in 2007 with 2.4-3.2% sulfur coal demonstrated the system's ability to reduce NO<sub>x</sub> emissions to 0.10 lb/mmBtu and emissions of SO<sub>2</sub>, SO<sub>3</sub>, and HCl by 96-97%. All tests performed to-date have demonstrated 93-99% mercury removal without activated carbon injection. Additional parametric testing is being conducted through mid-2008. The effects of operating conditions on system performance will be discussed, and process economics incorporating first-year operating data will be presented.

## **Pilot Scale Testing of the Indigo MAPS Technology at Alabama Power's Gadsden Plant**

Paper #: 161

R. Truce, R. Crynack, *Indigo Technologies, Pittsburgh, PA*; M. Berry, *Southern Company, Birmingham, AL*; R. Altman, *EPRI, Chattanooga, TN*.

The Indigo MAPS technology is a multi-pollutant control system targeted at reducing the emissions of a range of pollutants including Mercury, NO<sub>x</sub>, SO<sub>x</sub> and particulate. This technology is ideal for application on smaller units as it has a relatively low capital cost and a small footprint allowing easy, cost effective retrofit on existing installations. Pilot-scale trials were carried out at Alabama Power's Gadsden Plant in December, 2007 to assess Mercury, SO<sub>x</sub> and NO<sub>x</sub> removal efficiencies. Removal efficiencies of over 95% for SO<sub>x</sub>, 90% for Mercury and 40% for NO<sub>x</sub> were measured. Further tests are planned for early 2008 following modifications aimed at improving NO<sub>x</sub> and Mercury removal efficiencies. This paper presents the results of these tests and estimates of capital and operational costs for the Indigo MAPS technology.

## **Operating Experience of a Coal-Fired Boiler Retrofit with an Advanced Hybrid of Coal Gasification for SO<sub>2</sub> & NO<sub>x</sub> Emissions Control and Reduced Operating Cost**

Paper #: 165

K. Moore, *Phenix Limited, LLC, Oxnard, CA*; M. Giberson, *Fernald Power Corp., Prunedale, CA*; W. Ellison, *Ellison Consultants, Monrovia, MD*.

Results are presented from the first commercial operation of a coal-fired boiler retrofit with an **advanced hybrid coal-gasification process** for SO<sub>2</sub> and NO<sub>x</sub> emissions compliance. Significant operating cost savings were demonstrated by firing a lower-cost, higher-sulfur Illinois bituminous coal in lieu of expensive compliance coals. The construction permit waived NSPS and PSD.

The Clean Combustion System™ (CCS) is an entrained-flow coal gasifier that replaces the boilers existing burners and wind box to control emissions of SO<sub>2</sub> and NO<sub>x</sub> [right within the combustion zone]. Limestone is the only "chemical required.

The presentation addresses:

- CCS Boiler retrofit, Operation, Start-up and Commissioning Experience,
- Control of SO<sub>2</sub> and NO<sub>x</sub> Emissions - to meet EPA CAIR,
- Improved Efficiency - Reduced CO<sub>2</sub> emissions,
- Capital, Operating Costs and Lessons Learned.

## **Session 12: Particulate**

### **A Review of Electrostatic Precipitator Upgrades and SO<sub>2</sub> Reduction at the Tennessee Valley Authority Johnsonville Fossil Plant**

Paper #: 52

C. Deye, C. Layman, *Alstom Power Inc., Knoxville, TN.*

This paper provides a detailed analysis of the precipitator (PPTR) power supply and controls upgrade made to the TVA Johnsonville Fossil Plant as part of a major plant fuel switch project. The plant was limited in lowering the coal sulfur content and thus, SO<sub>2</sub> reductions by precipitator performance and the resultant stack opacity. The new equipment enabled lower sulfur coal to be burned, resulting in reduced SO<sub>2</sub> emissions. Comparisons are made before and after the upgrade for the PPTR power supplies, power consumption, stack opacity, controls, supervisory system and system optimization. Boiler operating conditions and coal analyses are examined, including results from TVA's ongoing SO<sub>2</sub> reduction evaluation program. The installation included the first commercial demonstration of automatic back corona correction in HFPS. The information will be of use, as an option, to power plants that need to cost effectively reduce particulate emissions or facilitate SO<sub>2</sub> reduction through fuel switching.

### **Hot-Side Electrostatic Precipitator Advanced Power Supply Test**

Paper #: 81

B. Looney, M. Berry, *Southern Company, Birmingham, AL*; H. Herder, R. Guenther, *NWL, Bordentown, NJ*; J. Bunce, *Alabama Power Company, Bucks, AL*; R. Altman, *EPRI, Chattanooga, TN.*

In recent years Switch Mode Power Supplies (SMPS) have been introduced into the utility ESP market. This paper summarizes EPRI and Southern Company funded Switch Mode Power Supply testing on Alabama Power's Plant Barry Unit 4 Hot-Side ESP. For this test program, eight Switch Mode Power Supplies were installed parallel to the existing four T/R sets.

During the test program, the ESP was operated for a time using each power supply type and emission measurements were taken. Included are ESP Outlet Loading and Size Distribution Results as well as EPA Method 5 mass emission results. Additionally, the paper includes an analysis of the ESP electrical characteristics during the operation of both types of power supplies as well as any possible conclusions. An investigation into the benefit of Intermittent Energization is also included.

### **The Effect of SO<sub>3</sub> Sorbents on Electrostatic Precipitator (ESP) Performance**

Paper #: 75

R. Altman, *Electric Power Research Institute, Chattanooga, TN*; J. Bionda, *Clean Air Engineering, Pittsburgh, PA*; D. Rhoades, *Clean Air Engineering, Palatine, IL.*

Sulfuric acid gas control has in recent years become an increasingly important issue for the electric utility industry. The development of alkaline sorbent injection processes for the

reduction or removal of SO<sub>3</sub>, from coal-fired boiler flue gas streams has in some instances been hampered by a lack of a comprehensive understanding of the ancillary effects of these sorbents on the balance of plant, namely the performance of ESP particulate control devices. EPRI and Clean Air Engineering have investigated the effect of the injection of various sorbents on ESP performance. This paper will present field test results conducted on two coal-fired utility boilers. Field test results will be presented from: 1) a 1,300 MW supercritical coal-fired boiler which utilizes hydrated lime injection downstream of the airheater for SO<sub>3</sub> control, and 2) an 800 MW coal-fired boiler which injects Trona downstream of the airheater for SO<sub>3</sub> control.

### **Remedial Gas Flow Distribution Techniques Developed via CFD Modeling to Minimize Unburned Carbon Re-Entrainment From ESPs**

Paper #: 88

V. Belba, *BELBA & Associates, Boulder, CO*; C. Martin, *ADA-ES, Inc., Littleton, CO*; C. Senior, J. Valentine, M. Cremer, *Reaction Engineering International, Salt Lake City, UT*; R. Altman, *EPRI, Chattanooga, TN*.

The use of low-NOX burners can increase the amount of unburned carbon in fly ash, which can elevate particulate emissions. The unique properties of the carbon make it more difficult to collect than conventional mineral ash in an electrostatic precipitator (ESP). Recent field observations and testing indicate that the exceptionally large, low-density unburned carbon particles are easily re-entrained from the final row of ESP hoppers. A field test program conducted on five ESP installations recovered in-flight carbon and ash samples to determine percent carbon and mass loading into and out of each ESP. Laboratory analyses conducted on the recovered samples determined key particulate parameters, including: density, morphology and size distribution. Computational fluid dynamics (CFD) modeled the suspected re-entrainment mechanisms. This paper summarizes the unburned carbon properties determined by this work, the CFD modeling results and recommendations of remedial gas flow distribution devices that can minimize unburned carbon re-entrainment.

### **Long-Term COHPAC Baghouse Performance at Alabama Power Company's E. C. Gaston Units 2 and 3**

Paper #: 16

K. Cushing, *Southern Research Institute, Birmingham, AL*; T. Grubb, *Grubb Filtration Testing Services, Inc., Delran, NJ*; B. Corina, *Alabama Power Company, Birmingham, AL*; R. Chang, *Electric Power Research Institute, Palo Alto, CA*.

Following a successful pilot-scale baghouse testing program and after reviewing other successful full-scale performance experiences, Alabama Power Company (APCO) decided to install COHPAC baghouses (EPRI's patented **CO**mpact **H**ybrid **PA**rticulate **C**ollector technology) on Units 2&3 at its E. C. Gaston Steam Plant located near Wilsonville, Alabama beginning in 1996. Performance of these systems has been excellent during the past nine and twelve years, respectively. Recent filter drag values of 0.5 in. H<sub>2</sub>O/ft/min on Unit 3 and 0.3 in. H<sub>2</sub>O/ft/min on Unit 2 have been experienced at air-to-cloth values of 8.0 ft/min.. Bag lives have exceeded 35,000 hours. The COHPAC

baghouse installations have successfully reduced earlier stack opacity problems. COHPAC baghouse performance for Alabama Power Company has exceeded expectations and continues to provide an excellent air pollution control benefit. This presentation will highlight these and other important performance results from these COHPAC baghouse installations.

### **Session 13: Coal Combustion Products**

#### **Effects of Bromine Addition on Flyash Use in Concrete**

Paper #: 115

L. Larrimore, M. Berry, *Southern Company, Birmingham, AL*; R. Chang, *Electric Power Research Institute, Palo Alto, CA*; A. Gallet, D. Been, S. Renfroe, *Gallet & Associates, Birmingham, AL*.

As utilities plan for mercury control on boilers burning PRB coal, difficulties arise from the lack of chlorine in PRB coal. Chlorine can be replaced by a non-corrosive halogen such as bromine. However, many PRB plants depend on flyash utilization in concrete for revenue and as an alternative to disposal. Consequently, some emissions control additives may alter properties of ash and concrete, such that the resulting product does not meet performance requirements. If present, this effect could result in lost flyash markets or legal liabilities in construction projects.

This question has been evaluated during bromine addition tests at Alabama Power's Plant Miller. This includes comprehensive ash and concrete testing. Test conditions include bromine addition to ash in a laboratory environment, in addition to full-scale testing on ash samples from the boiler, where bromine was added to coal over a wide range of concentrations.

#### **Impact of Mercury Sorbents on Fly Ash Use for Cement Replacement**

Paper #: 164

J. Paradis, K. Dombrowski, *URS, Austin, TX*; R. Chang, *EPRI, Palo Alto, CA*; B. Boggs, *Headwaters, Taylorsville, GA*; S. Kabis, *LaFarge, Summit, MO*.

The use of activated carbon injection (ACI) for mercury control in coal-derived flue gas can compromise the ability to sell fly ash for use as a cement replacement in the production of concrete. EPRI is evaluating how various process parameters, such as sorbent type and injection rate, impact important fly ash reuse properties. This paper presents results from fly ash cement replacement testing conducted as part of several full-scale ACI test programs performed at four coal-fired power plants representing PRB and PRB/Texas lignite blended fired units and equipped with either an ESP or a fabric filter. Several activated carbons have been tested in parametric and longer-term ACI tests including novel sorbents projected to reduce the impact on fly ash cement replacement. Test parameters presented include sorbent impacts on fly ash foam index properties, concrete strength, concrete air entrainment, and selected ASTM C618 test results.

## **The Impact of Hg Control Technologies on Mobility Pathways of Hg, Ni, As, Se, Cd and Pb from Coal Utilization Byproducts**

Paper #: 85

A. Dahl, *Frontier GeoSciences, Inc., Seattle, WA*; C. Gilmour, *Smithsonian Institute, Edgewater, MD*; L. Brickett, *USDOE-NETL, Pittsburgh, PA*.

The US DOE is assessing the fate of mercury removed from flue gas by mercury capture technologies (Hg-CT) at coal-fired utilities. Control technologies are expected to impact the quality of the coal utilization by-products by increasing the concentration of mercury, cadmium, nickel, lead, arsenic and selenium. Results to date show that Hg-CT resulted in an increase of Hg in the ash for all facilities, Se for some, and As for one facility.

Thermal releases at 190°C over 1 hour were increased for Hg in some facilities using Hg-CT while others indicated a decrease, leading to speculation that the Hg is stabilized in some cases. At 1200°C for 5 minutes, Hg emissions are significantly increased with Hg-CT. Se emitted 100% for all but 3 facilities. The SPLP leached a very low amount of target metals. The microbial mobilization study showed an increase in Methyl-Hg production while other target metals were stabilized.

### **Poster Session**

#### **SOx**

### **Polypropylene Reduces FGD Cost and Improves Operation Flexibility**

Paper #: 4

A. Licata, *Babcock Power, Worcester, MA*; R. Modes, *Steuler, Hoehr-Grenzhausen, Germany*; G. Schwarz, *RWE Power, Bergheim, Greenland*.

RWE Power is building two supercritical 1,100 MW units at their BOA station. BOA was being designed to burn local lignite coal. RWE's experience with FGD systems burning lignite has shown that both carbon steel/rubber lined and flaked glass lined vessels have a defined life, especially since the design criteria calls for > 70,000 ppm of Chlorides. Up until now only metal vessels have life of plant expectancy. However, the recent rise in the cost of alloys typically used in FGD vessels has led to the application of a new design system for FGD vessel construction. For the new BOA plants, RWE selected the patented Bekaplast FGD vessel technology developed by the Steuler Company. The Bekaplast FGD vessels utilize a concrete shell with a polypropylene (PP) liner.

The BOA is scheduled to begin commissioning December 2008 for unit 1 and January 2009 for unit 2.

### **Effect of Oxidation Agents on Se<sup>6+</sup> Formation in a Wet FGD**

Paper #: 20

H. Akiho, S. Ito, H. Matsuda, *Central Research Institute of Electric Power Industry, Yokosuka-shi, Kanagawa-ken, Japan.*

Selenium, designated as an item in effluent standards of the Water Pollution Control Law in Japan, exists as  $\text{Se(IV)O}_3^{2-}$  and  $\text{Se(VI)O}_4^{2-}$  in a wet-FGD solution.  $\text{Se(IV)O}_3^{2-}$  is generally removed in a conventional wastewater treatment method such as coagulation-sedimentation, but it is necessary for  $\text{Se(VI)O}_4^{2-}$  removal to reduce to  $\text{Se(IV)O}_3^{2-}$  before the wastewater treatment. To understand the behavior of selenium leads to the control of  $\text{Se(VI)O}_4^{2-}$  formation and the cost reduction of selenium treatment. Peroxodisulfuric acid ( $\text{S}_2\text{O}_8^{2-}$ ) was one of the most likely oxidation agents in desulfurization slurries.  $\text{Se(VI)O}_4^{2-}$  formation was greatly related to  $\text{S}_2\text{O}_8^{2-}$  concentration and the solution temperature. It was also found that some metal additives were effective to reduce  $\text{S}_2\text{O}_8^{2-}$  and control of  $\text{Se(VI)O}_4^{2-}$  formation.

### **Stainless Steel Selection for Wet Flue Gas Desulfurization Systems**

Paper #: 23

G. Carinci, *Outokumpu Stainless, Pittsburgh, PA.*

This paper discusses different stainless steel grades suitable for construction of flue gas desulfurization (FGD) systems on coal-fired power units. The majority of FGD units worldwide employ wet scrubbing processes using limestone. The materials of construction for wet scrubbers have to be selected with respect to the corrosive environment (chlorides, acidity, temperature) and plant design. The corrosion resistance of austenitic and duplex stainless steels is studied by electrochemical testing performed under laboratory conditions, which simulate FGD process conditions. In particular, the effect of chloride content, pH, and temperature on corrosion resistance is discussed. The intention is to present data that may assist in selecting the appropriate material for different parts of an FGD system. The excellent corrosion resistance of duplex stainless steels, combined with the increased mechanical properties and moderate alloy cost make these materials cost effective solutions for wet flue gas desulfurization applications.

### **Selection of Corrosion Resistant Materials & Linings for Flue Gas Desulfurization (FGD) Systems**

Paper #: 32

R. Jaworowski, A. Langeland, *DUROMAR, INC., Pembroke, MA.*

There are many considerations in the design of wet or dry FGD systems, including the selection of corrosion resistant materials, their initial costs, availability, schedules, and future O&M expenses.

Corrosion is a major concern in FGD's since the first large units when into service. Early FGD systems were fabricated using carbon steel lined with rubber, vinyl ester, epoxy, high alloy steels and borosilicate block. Steel or Nickel Alloys were used either as solid plate or wallpapered over carbon steel.

In the last 20 years, 100% solids, “0” VOC , epoxy products have been used to replace failing systems. These have demonstrated long term, maintenance free performance, ease, safety, and economy of application.

This paper will discuss each FGD problem area, the current major lining and cladding systems, their advantages, limitations and, applied cost comparisons.

### **Slurry and Air Do Mix: Interim Results of WFGD Absorber Slurry Aeration Studies**

Paper #: 36

S. Brown, K. Rogers, *The Babcock & Wilcox Company, Barberton, OH.*

The magnitude and distribution of air entrainment within the slurry of WFGD absorbers operating with forced oxidation is challenging to accurately estimate. Air dispersion and hold-up impacts slurry operating level and absorber recirculation pump performance. A method for measurement of entrained air in the recirculation pump suctions was developed and utilized at a number of field sites. In an effort to enhance accuracy of air entrainment prediction, preliminary comparison of this data to various design parameters is performed. Detailed herein are the methodology and interim results of slurry aeration sampling at the absorber recirculation pump suctions of various operating units; associated data and observations related to air hold-up, the discussion on the propensity for excessive air hold-up and foaming, spray nozzle performance with aerated fluids, as well as the impact of selected anti-foaming agents is also provided.

### **The Rapid Growth of Composite Use in FGD Applications**

Paper #: 56

D. Kelley, *Ashland Inc., Amarillo, TX.*

The demand for composites made from epoxy vinyl ester resins increased significantly in wet flue gas desulfurization (FGD) processes starting in 2006. Composites provided power engineers with a reliable, cost effective construction material that can be employed in numerous applications that have been traditionally made from metal alloys. Also, resin improvements and three decades of industry guideline and standard development have significantly improved the quality and reliability of composites in industrial applications. Years of experience have taught engineers and industry leaders that guidelines and standards alone are not enough to ensure long term success. Overall success requires that composite buyers employ best practices in operation, material selection, design, specifications, fabrication, inspection, shipping and installation.

The details of these keys to composite success in FGD applications will be the subject of this paper.

## **FGD Performance Capability**

Paper #: 62

C. Dene, *Electric Power Research Institute, Palo Alto, CA*; L. Anderson, R. Keeth, *Washington Group International, Denver, CO*.

Utilities continue to specify FGD system performance at higher SO<sub>2</sub> removal efficiencies in response to permit requirements, local consent decrees and the potential need to install CO<sub>2</sub> controls in the future. Environmental groups are also pressuring public utility commissions to push pulverized coal power plants to achieve emission levels similar to IGCC and NGCC. This paper summarizes FGD system design and operation upgrades that may be necessary to achieve 99+% SO<sub>2</sub> removal on a continuous basis, resulting in single digit SO<sub>2</sub> ppm emission rates. The presentation will also address several multi-pollutant emission control technologies that can achieve or show promise to achieve very high levels of SO<sub>2</sub> removal in addition to removal of NO<sub>x</sub> and/or mercury. The impacts of removal efficiency, site operating parameters, and consumables prices on operating costs for these multi-pollutant control technologies will also be addressed.

## **Stainless Steel Selection for FGD and Associated Pollution Control Equipments**

Paper #: 95

J. Peultier, J. Grocki, J. Gagnepain, *INDUSTEEL, Le Creusot, France*.

This paper presents the corrosion performance of the candidate stainless steels for wet flue gas desulphurization (WFGD) system and wet electrostatic precipitator (WESP). In a first part, the corrosion risk is discussed taking into account the local environments. Then the uniform, pitting and crevice corrosion resistances are studied under laboratory conditions which simulate process conditions. In addition to an intensive electrochemical study, the results of long term immersion tests with welded assemblies are also presented and the effect of chloride content, fluoride content, pH and temperature is discussed. The results show that duplex grade UNS S32205 is always better than the austenitic 317LMN. The superduplex UNS S32520/550 and the super austenitic UNS S34565 appear as very cost effective alternatives to standard 6Mo grades and, for the most aggressive conditions where Ni-base alloys are often specified, the super austenitic grade UNS S31266 can also be an alternative.

## **Considerations to Evaluate when Performing Wet Stack SO<sub>3</sub> Measurements by the Controlled Condensate Method**

Paper #: 111

A. Silva, *The Babcock & Wilcox Co., Barberton, OH*; C. Wiza, *Clean Air Engineering, Palantine, IL*.

The Controlled Condensation approach (CCM) has become the preferred method for measuring SO<sub>3</sub> from fossil-fired boilers. However, testing SO<sub>3</sub> in a wet stack, downstream on a WFGD, can produce varying results depending upon how one performs the test and interprets the data. Potential test result biases from WFGD carryover could occur since SO<sub>3</sub> is measured as total sulfate and carryover is a water soluble sulfate compound which is reported as SO<sub>3</sub> if appropriate corrections are not made. A procedure

for this correction is outlined in this report as are other important factors related to obtaining high quality data when using CCM. Other considerations related to sampling such as traversing the stack, probe temperature, QA, etc. are evaluated to make the test results most accurate. Data analyzed and presented in this study is from field data taken at numerous jobsites.

### **Performance Upgrades for Low-Sulfur Wet Scrubbers**

Paper #: 134

W. Siegfriedt, A. Carstens, R. Gaikwad, *Sargent & Lundy, LLC., Chicago, IL*; S. Escobedo, *CPS Energy, San Antonio, TX*.

Wet FGD systems installed in the late 1970s through early 1990s included a large number of units burning low-sulfur coal. The CAAA of 1977 required that these units achieve a minimum of 70% SO<sub>2</sub> reduction. Based on this requirement, these units typically included partial FGD bypass and only modest SO<sub>2</sub> removal in the wet absorber. The increasing value of emission allowances caused by the Clean Air Interstate Rule (CAIR) in the eastern US and the Clean Air Visibility Rule (CAVR) in the western US, are causing owners of these units to consider improving their performance. This paper explores candidate technologies that can be used to achieve these performance improvements at CPS Energy's JK Spruce Unit 1, the pros and cons of each and the expected capital and O&M cost necessary to capture additional SO<sub>2</sub>.

### **Initial Operating Results from the First Installations of CT- 121™ Wet FGD Technology in North America**

Paper #: 144

R. Solar, M. Meadows, J. Hubers, *Black & Veatch, Overland Park, KS*.

This paper will focus on the installation, startup, and initial operating results of the first eight installations of the CT-121™ wet FGD system in the US. These FGD systems - located at four different sites and owned by three different electric utilities - were commissioned between June 2007 and May 2008. They are designed to achieve SO<sub>2</sub> removal efficiencies of 97% or 98% when treating flue gas from eastern bituminous coals, and to produce gypsum byproduct for the reuse in the wallboard or cement markets. The paper will discuss the original design basis for the FGD systems and the actual performance results and operating results. Emphasis will be placed on the initial results during startup and commissioning of the eight units.

## Mercury

### **Mercury Oxidation With Electron Beam Irradiation**

Paper #: 45

J. Kim, *Konkuk University, Seoul, Republic of Korea*; A. Armendariz, *Southern Methodist University, Dallas, TX*; K. Kim, *Sejong University, Seoul, Republic of Korea*; M. Al-Sheikhly, *University of Maryland, College Park, MD*.

Mercury oxidation over SCR catalysts followed by wet scrubbing can reduce emissions by 20~80%, but results are variable and ultra-high removal (95%+) is unusual. The objective of this study was to investigate the effectiveness of electron beam irradiation to oxidize mercury vapor, to improve mercury removal with scrubbers. Metallic mercury vapor samples in air and other atmospheres were prepared at concentrations of 16 µg/m<sup>3</sup>. Samples were irradiated at energy levels of 2.5-10 kGy, equivalent to 3.1~12.4 kJ/m<sup>3</sup> stack gas. Results show that greater than 97% of mercury vapor was readily converted from metallic to oxide forms. Full-scale operating energy consumption was estimated to be 3000 kW for a 500 MW EGU, or 1000 kW for a 1 million ton/year cement kiln. Electron beam irradiation, as a primary or secondary mercury oxidation technique, could lead to high levels of mercury oxidation and improve mercury removal at plants with wet scrubbers.

### **Full-Scale Test Results From a 600 MW PRB -fired Unit Using Alstom's KNX technology for Mercury Control**

Paper #: 73

M. Rini, *Alstom Environmental Control Systems, Knoxville, TN*; B. Vosteen, *Vosteen Consulting, Cologne, Germany*.

This paper reports the results of several full-scale tests using Alstom's KNX<sup>TM</sup> technology on a 600 MW plant. The KNX technology utilizes a patented process wherein a bromine-containing chemical is added to the fuel in a coal-fired boiler. The KNX coal additive technology is operated to enhance mercury oxidation, which in turn results in an augmentation of mercury collection in downstream air pollution control equipment. This unit fires 100% PRB fuel and is equipped with an SCR, ESP and WFGD. A series of full-scale tests were conducted in late 2007 and 2008 adding calcium bromide solution (KNX) to the coal prior to combustion. Mercury oxidation rates over 90% and mercury removal rates of up to 90% were obtained. This paper will also report on any effects of the KNX technology on ash, gypsum and wastewater.

### **Novel Mercury Abatement Technology for Coal-fired Power Plants**

Paper #: 80

P. Kuang, K. Gadkaree, B. Johnson, A. Liu, T. Wetherill, M. Owusu, J. Fagan, *Corning Inc., Corning, NY*.

Corning, Inc has developed a novel honeycomb based technology for mercury emission reduction. This concept has been confirmed to be a promising mercury control technology for the power industry, effectively capturing BOTH elemental mercury and

oxidized mercury. In a long term lab test (still in progress after 8 months), this technology continues to show 90% mercury removal efficiency without regenerating or replacing the honeycomb. Several field pilot tests were conducted at power plant facilities where 90% mercury removal efficiency was achieved for both bituminous and PRB coal types. This technology utilizes material more effectively than the standard ACI technology and has added benefit of preserving the value of fly ash. This standalone technology would be installed downstream of the PM device in the power plant and not require additional downstream equipment. The effectiveness of this technology would allow plants to meet the federal as well as more stringent state regulations.

### **A New Non-carbon Sorbent for Hg Removal from Flue Gases**

Paper #: 139

G. Alptekin, *TDA Research, Inc., Wheat Ridge, CO.*

Several physical adsorbents, particularly activated carbons, can remove mercury from flue gases produced by coal combustion. However, fly ash that contains carbon is not suitable for use in cement. If the fly ash is not salable for concrete, it has no use at all, and immediately becomes an expensive waste problem.

TDA Research, Inc. is developing a new sorbent/catalyst combination to carry out oxidation of mercury and subsequent capture and removal of all mercury species. The sorbent is made of non-carbon based materials and has a high mercury absorption capacity, thus will not alter the properties of the fly ash. This paper summarizes the bench-scale and field testing results of the new sorbent material.

### **Understanding Acid Gas Reactions When Injecting Sorbents**

Paper #: 145

J. Gilmour, V. Petti, M. Sandell, *Siemens Environmental Systems & Services, Pittsburgh, PA.*

Siemens Environmental Systems & Services has begun an extensive program to understand the reactions and interactions of sorbents with various acids in coal fired boiler flue gas duct work. When sorbents are injected into flue gas for acid gas removal and/or dew point control, understanding the interaction of the various acids is critical for proper sorbent selection and process design of the system.

This paper will present the laboratory work which is being done to understand reaction rates and sorbent capacities prior to scaling up to pilot and full scale testing. This work includes testing the effects of temperature, acid gas concentrations, sorbent concentration, sorbent type and residence time in the duct work.

### **Bench-Scale Kinetics Study of Mercury Reactions in FGD Liquors**

Paper #: 149

G. Blythe, J. Currie, D. DeBerry, *URS Corporation, Austin, TX*; R. Rhudy, *EPRI, Palo Alto, CA*; C. Miller, *US DOE-NETL, Pittsburgh, PA*.

DOE co-funded this project through 2007, but it continued in 2008 with EPRI funding. The project objective is to determine mercury reaction mechanisms and kinetics in wet FGD systems through bench-scale tests. Mercury species were initially measured by UV and CVAA spectroscopy to determine reactant and byproduct concentrations over time. These data were used to develop an empirically adjusted, theoretically based mercury reaction kinetics model. The model is being verified and extended through bench-scale wet FGD tests, with both gas- and liquid-phase mercury concentration measurements. Bench-scale results are used to determine if the model accurately predicts mercury re-emissions, and to extend the range of the model to conditions not previously tested. The model will be used to determine optimum wet FGD conditions to maximize mercury capture. Bench-scale testing should be complete by the time the manuscript is due, so full project results will be available for presentation.

### **Light Extinction-based Monitoring of Particle Size Distributions During Sorbent Injection for Mercury Emissions Control**

Paper #: 157

E. Lee, H. Clack, *Illinois Institute of Technology, Chicago, IL*.

Full-scale tests of powdered activated carbon (PAC) injection for mercury emissions control have occasionally yielded results that suggest the existence of significant sorbent particle dynamics, such as coagulation and agglomeration, within sorbent feeding lines under certain conditions. However, such tests have not measured sorbent particle size distributions (PSDs) dynamically and on-site, both of which are criteria for confirming the presence and severity of such phenomena. In this study, a simple light extinction model uses the Beer-Lambert law of light absorption within particle suspensions to demonstrate that a line-of-sight opacity measurement (i.e., light intensity ratio,  $I_o/I_i$ ) varies as the particle size distribution (PSD) changes. Using this model, light adsorption experiments using a HeNe laser and a photodiode positioned across the origin of a sorbent-laden jet provide results that confirm this method as a means for dynamically detecting changes in injected sorbent PSDs on-site and in real time.

### **Non-carbon Sorbents for Mercury Control: Recent Advancements with Amended Silicate Sorbent**

Paper #: 185

C. Turchi, J. Butz, B. Byers, *Amended Silicates, LLC, Littleton, CO*.

Sorbent injection systems are being installed for mercury control; however, there remains a strong need for non-carbon sorbents that effectively remove mercury but do not degrade by-product fly ash. Materials tested to date have either exhibited less than desired mercury capture efficiency or have deleteriously affected fly ash quality.

Unlike powdered activated carbon (PAC) or even “concrete-compatible” PAC, the non-carbon Amended Silicates™ sorbent is intrinsically compatible with fly ash. Amended Silicates sorbent does not degrade concrete physical properties, nor does it create a blackened concrete color or require additional air entrainment agents. Yet, demonstration tests held in 2006 and 2007 at power plant sites exhibited lesser mercury capture than seen in prior evaluations. Re-assessment and investigation of the sorbent manufacturing and injection procedures have led to a reformulated Amended Silicates sorbent that demonstrates superior performance. Comparison data from small-scale testing will be featured, as well as plans for power-plant demonstration.

### **Sorbent Injection: Taking the Technology from R&D to Commercial Launch**

Paper #: 188

N. Pollack, R. Vaughn, *Calgon Carbon Corporation, Pittsburgh, PA.*

There has been an incredible amount of information developed on sorbent injection to control mercury emissions from coal fired power plants over the past 10 years. In fact the work sponsored by NETL, EPRI and others has paved the way for sorbent injection to be the BACT for mercury capture. However there are still a number of questions that remain to be answered as the technology goes from the development stage to the commercial stage. This paper provides comprehensive summary of the commercial issues facing the utility industry including what product specifications are important when specifying the carbon in an RFP, what is the best way to preserve fly ash sales when carbon injection is implemented, and what steps can be taken to ensure an adequate supply of sorbent.

### **Factors Influencing High Temperature Capture of Mercury by the MinPlus Sorbent**

Paper #: 189

J. Biermann, *MinPlus BV, Eerbeek, Netherlands*; J. Wendt, S. Lee, *University of Utah, Salt Lake City, UT.*

High mercury capture whilst using the MinPlus sorbent at in-furnace temperatures in full-scale power-plant demonstrations as well as laboratory and bench-scale tests has been reported earlier. Recent full-scale power-plant demonstrations however showed low mercury capture, which results are contrasting these earlier findings. Hence, we initiated a research program to address factors influencing the sorbent’s efficacy for mercury capture and to further elucidate the underlying sorption mechanism. This contribution discusses first results of this program. Measured effects of varying oxygen and water partial pressures in the flue-gas reveal that although no mercury oxidation is expected at the conditions applied, high oxygen concentrations do stimulate mercury sorption on the MinPlus sorbent, which may be related to oxidation of the sorbent itself. Additionally, high water concentrations reduced mercury sorption, which may be related to interaction of the water with the sorbent’s mineral structure.

## Multi-Pollutant

### **Planning by New EU Member Nation, Romania, for Achieving Medium and Long Term Emission Abatement Goals for Air Pollutants and Carbon Dioxide**

Paper #: 13

I. Gheorgiu, *WEC Romania, Bucharest, Romania*; W. Ellison, *Ellison Consultants, Monrovia, MD*; C. Constantin, C. Tomescu, *ISPE, Bucharest, Romania*; V. Gorokhov, *Energy and Environmental Modeling and Solutions, Potomac, MD*.

Technical approach of cognizant Romanian officials is presented in pursuit of initiatives for fulfilling diverse emission limits per EU protocols. National emission inventory limits for stack gas pollutants and carbon dioxide are quantified /reviewed. Major considerations addressed: abating high-sulfur lignite fired electric generating units; utilization or disposal of massive amounts of flue gas cleaning residues; abating pollution of surface water and groundwater with preference for zero-effluent scrubbers.

Initiatives to be detailed include:

§ By-product yield of ammonium sulfate serving as agricultural plant nutrient sulfur compensating for continued radical reduction of SO<sub>2</sub> emission inventory throughout Europe

§ Advantageous use of low-cost, circulating fluid bed scrubbers providing dry solids by-product ideal for sub-standard land recovery via structural landfilling

§ “Carbon dioxide capture readiness” at selected, large-capacity units to be scrubbed in time for CO<sub>2</sub> isolation

§ Maximum utilization of the carbon dioxide yield in rejuvenation of indigenous oil field production.

### **Emission of Polycyclic Aromatic Hydrocarbons Associated with Particulate Matter from a Coal-Fired Power Plant in Vietnam**

Paper #: 44

D. Nghiem, *Hanoi University of Technology, Hanoi, Viet Nam*; L. Reutergårdh, *Stockholm University, Stockholm, Sweden*; K. Nguyen, *Asian Institute of Technology, Bangkok, Thailand*.

Integrated samples of particulate matter were taken iso-kinetically from the flue gas of the Bai Bang thermal coal-fired power plant, Vietnam, using glass fibre filters. The particulate matter was Soxhlet extracted with CH<sub>2</sub>Cl<sub>2</sub> and cleaned-up on SiO<sub>2</sub> column, prior to separation and quantification of PAHs by liquid chromatography with fluorescence detection (HPLC/FLD) and/or gas chromatography with mass spectrometer detection (GC/MS). Anthracene, benzo[a]anthracene, phenanthrene, fluoranthene, pyrene, chrysene and benzo[a]pyrene, were all present on the particulate matter, and the quantification of the latter five yielded concentrations of 12.1, 6.3, 4.8, 3.0, 0.20 ng/m<sup>3</sup> at normal conditions, emission factors of 111, 57, 43, 27, 2 ng/kg coal, and emission rates of 2207, 1122, 847, 535, 38 ug/h, respectively. The obtained concentrations, emission factors, as well as recoveries were reduced with increased molecular weight of individual PAHs compounds.

## **Using a Wet Scrubber System for Control of SO<sub>2</sub>, NO<sub>x</sub>, Hg<sup>2+</sup> and Hg<sup>0</sup> in Coal Flue Gas**

Paper #: 55

N. Hutson, *US EPA, Research Triangle Park, NC*; R. Krzyzyska, *US EPA (ORISE), Research Triangle Park, NC*; Y. Zhao, *Arcadis G&M, Inc., Research Triangle Park, NC*.

This paper discusses recent bench- and pilot-scale studies using an additive-enhanced wet flue gas scrubber system for control of SO<sub>2</sub>, NO<sub>x</sub> and Hg (both Hg<sup>2+</sup> and Hg<sup>0</sup>). Bench-scale tests were used to screen various additives. The most promising additive was then tested more extensively. In the pilot-scale tests, the oxidizing additive was introduced continuously at the top of scrubber through the spray nozzle. Both the bench- and pilot-scale tests showed that the additive is very effective in increasing the amount of Hg captured in the scrubber. Increased control of NO was also observed, though to a lesser extent than the Hg. It was also observed that the addition of the EPA additive resulted in a slight increase in Hg re-emission. The effects of varying concentrations of pollutants (NO and SO<sub>2</sub>) and the scrubber solution pH were also evaluated.

## **Potential Reuse for Fly-ash from Mexican Power Plants**

Paper #: 87

A. Rodas, R. Flores, G. Blass, *Instituto de Investigaciones Eléctricas, Cuernavaca, Mexico*.

In Mexico, power plants use carbon (21 %) or heavy fuel oil (39%) to generate electricity (Prospectiva del Sector Eléctrico. SENER. Mexico. 2006). High demand of energy requires burning more fossil fuels; therefore, higher emissions of air pollutants, such as SO<sub>x</sub>, NO<sub>x</sub>, CO<sub>x</sub>, and unburned particles are expected. The latest are transported by the flue gases to the atmosphere (fly-ash) or also are deposited in the bottom of the chimney (bottom-ash). Actually, these ashes are confined in open containers causing several ecological problems. According to their chemical characterization by SEM and atomic absorption spectroscopy (AAS), ashes from Mexican power plants have the potential of different applications to solve environmental problems. In this work are presented experimental results of using ashes as catalytic support for Fenton process, as an additive to the desulphurization of flue gases, and as an adsorbent for the treatment of industrial water to remove heavy metals.

## **Mercury Specie & Multi-Pollutant Control**

Paper #: 118

S. Piche, R. James, *NeuCo, Inc., Boston, MA*; T. Smitherman, J. Hudspeth, *NRG Limestone, Jewett, TX*.

NeuCo's Mercury Specie and Multi-Pollutant Control project, part of the Department of Energy's Clean Coal Power Initiative, entails using advanced sensors and artificial intelligence technologies to optimize the speciation of mercury, heat rate and other emissions control goals such as NO<sub>x</sub>, SO<sub>x</sub>, and Particulates. By optimizing the combustion, sootblowing, ESP and FGD processes, mercury removal from the flue gas in the backend systems is maximized.

In addition to identifying the “best” real-time operating condition for individual equipment, plant integration software will be used to arbitrate among the optimizers from each area to find the best balance among inputs, such as coal blend, temperature and air staging, to result in the optimum outputs, such as capturable mercury species and commercial-grade ash, while operating within regulatory and commercial constraints, such as emission and byproduct standards.

This paper presents a status of the project, the technical approach and the anticipated industry impact.

## CO<sub>2</sub>

### **Impacts of Flue Gas Impurities in Sequestered CO<sub>2</sub> on Groundwater Sources: A Process Analysis and Implications for Risk Management**

Paper #: 19

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This study analyzed the potential impacts of acid gases and mercury vapor in the separated CO<sub>2</sub> stream from monoethanolamine (MEA) absorption on groundwater aquifers in the case of the CO<sub>2</sub> leakage from its storage sites based on published information. When a wet flue gas desulfurization (FGD) system achieves 95% SO<sub>2</sub> removal, up to ~2,400 ppmw SO<sub>2</sub> could be included in the separated CO<sub>2</sub> stream. The estimated concentration was reduced to as low as 135 ppmw for the SO<sub>2</sub> of <10 ppmv in the flue gas entering the MEA unit. Heat-stable salts formation could also further reduce the SO<sub>2</sub> concentration below 40 ppmw. It is realized that the formation rates of heat-stable salts in MEA solution are not readily available in the literature, and critical to estimating the compositions of flue gas impurities. Mercury and other impurities could vary depending on pollutant removal and impose potential impacts on the groundwater.

### **Evaluation of Wet FGD Technologies to Meet Requirements for Post CO<sub>2</sub> Removal of Flue Gas Streams**

Paper #: 49

K. Smith, W. Booth, L. Benson, *Carmeuse North America, Pittsburgh, PA*.

The possibility of CO<sub>2</sub> emission reductions from existing coal fired power plants being mandated will cause electric utilities to begin studying their options. One option to reduce CO<sub>2</sub> emission that is likely to be considered is the use of regenerative (including amine) sorbents to scrub flue gas. One of several requirements to be met for power plant flue gas to be processed by amine scrubbing is for SO<sub>2</sub> concentration to be as low as or less than 10-ppmv. This paper discusses the results of a comparative study of typical wet FGD methods used to achieve extremely low emissions of SO<sub>2</sub> and other acid gases in flue gas. This study reveals the critical assumptions and inputs that are required to draw meaningful conclusions.

### **Site Specific Considerations for Carbon Dioxide Capture at Existing PC Plants**

Paper #: 112

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The advancement of the Lieberman & Warner Senate Bill has heightened the interest in understanding the control of carbon emissions from fossil power plants. Coal-based Power generation companies are actively investigating the impact that carbon capture technologies and storage facilities will have on their existing generation facilities.

Balance of plant considerations are very significant with impacts on heat rate, gross and net generation output, operability, and secondary environmental concerns. S&L has performed studies to identify and quantify these impacts on actual existing coal fired installations. Typical analyses include capital and O&M costs and cycle analysis using the GATE CYCLE modeling protocol.

This paper will present the types of issues that must be considered when evaluating the installation of CO<sub>2</sub> removal systems at a specific coal fired, nominal 650 MW unit. It will also show the impact on plant heat rate, carbon emissions, turndown, plant space requirements, and secondary environmental issues.

### **Using Low-Cost Optimization Technologies to Reduce Carbon Footprint**

Paper #: 131

P. Spinney, *NeuCo, Inc., Boston, MA*; D. Bloomfield, *Four Corners Generating Station, Arizona Public Service, Fruitland, NM.*

To survive the seemingly inevitable onslaught of climate change legislation, many power generators are looking towards intelligent optimization technologies.

This paper will examine how real-time intelligent optimization technologies can reduce CO<sub>2</sub> emissions as a function of improved boiler efficiency and heat rate. Compared with hardware-based alternatives and physical retrofits, intelligent optimization preserves existing assets, requires significantly lower capital investment and maintenance costs, minimizes installation lead time, and delivers a flexible solution platform. When combined with hardware-based approaches, intelligent optimization can make even greater contributions towards lowering CO<sub>2</sub>. Intelligent optimization also allows plants to lower CO<sub>2</sub> while continuing to achieve other important plant goals.

This paper will discuss how lowered CO<sub>2</sub> is being realized at plants using real-time intelligent optimization, particularly ones that combine solutions for soot, combustion, maintenance and performance.

### **CFD Modeling of a Pilot-Scale Oxy-Coal Combustion Retrofit**

Paper #: 153

A. Fry, K. Davis, *Reaction Engineering International, Salt Lake City, UT*; T. Gale, *Southern Research Institute, Birmingham, AL*.

Combustion of coal with pure oxygen and recycled flue gas produces exhaust gases that contain close to 100% CO<sub>2</sub>, which can be efficiently compressed, and transported. Technology developers in several countries are already pursuing this approach for greenhouse gas abatement. Oxy-combustion of pulverized coal with CO<sub>2</sub> capture and storage is the CO<sub>2</sub> mitigation technology most readily integrated into existing infrastructure and therefore may be implemented in the near-term. As this technology is yet in its infancy, little is known concerning the specific issues associated with retrofit on an existing coal-fired utility boiler. In this study, CFD modeling is used to investigate the impact of oxy-coal retrofit on Southern Research Institutes, 1 MW, pilot-scale pulverized coal furnace. The dependency of flame stability, heat distribution, coal particle combustion and pollutant emissions on operating conditions, combustion equipment and recycle ratio is elucidated.

### **Non-Amine Approaches for Carbon Dioxide Capture from the Power Plant Flue Gas**

Paper #: 186

R. Jain, *InnoSeptra LLC, Bridgewater, NJ*.

The current post-combustion CO<sub>2</sub> capture technology uses amine solvents and results in a 28-30% reduction in relative power plant efficiency, a 60-100% increase in the cost of power generation, and a greater than 30% decrease in the power output. This paper will discuss alternatives to amine technology with potential to significantly reduce the energy consumption associated with CO<sub>2</sub> capture. These include polymeric membranes, membrane contactors, pressure and temperature-swing adsorption, and reactive materials. We will also discuss the results of a novel process with potential to significantly reduce the power penalty associated with CO<sub>2</sub> capture. Preliminary bench scale testing with simulated flue gas indicates 75-80% CO<sub>2</sub> recovery at a CO<sub>2</sub> purity of over 98%. The power consumption is less than 50% of the amine process. Unlike the amine process this process does not require additional removal of NO<sub>x</sub> and SO<sub>x</sub> and is much easier to retrofit to an existing power plant.

### **NO<sub>x</sub>**

#### **NO<sub>x</sub> Control Strategies for Thermal Power Plants in Korea**

Paper #: 63

D. Kim, Y. Jo, G. Han, *Korea Western Power Company, Seoul, Republic of Korea*.

In Korea, stringent NO<sub>x</sub> emission standards for thermal power plants was in force from January 1, 2007 and started total amount emission permission of air pollutants in metropolitan.

Power Generation Companies(GENCOs) in Korea have promoted a variety of countermeasures to meet new stringent NOx emission standard.

GENCOs have been performing a diversity of NOx reduction measures such as combustion equipments, 2nd stage combustion and combustion technology to burn coals with diverse quality etc.

And, from 2000 to 2007 year, 50 thermal power units in total operate with SCR of which NOx reduction efficiency is around 76 ~ 80%.

GENCOs applied Honey Comb and Plate type of SCR catalyst, and used liquefied ammonia for reducing agent.

In recent days, 12 gas turbine units in a suburb of big cities operate with CH-SNCR developed by domestic company to remove yellow plume caused by NO<sub>2</sub> in gas turbine start-up.

### **The SCR Retrofit Design for the Seminole Generating Station**

Paper #: 121

W. Gretta, D. Harajda, A. Favale, *Hitachi Power Systems America, Ltd., Basking Ridge, NJ*; T. Wess, *Seminole Electric Cooperative, Inc., Tampa, FL*.

Units 1 and 2 at the Seminole Generating Station are each rated at 715 MW and burn a blend of eastern bituminous coal and petcoke. In 2006, the SCR retrofit of both units began, each designed to achieve 90% NOx reduction. Results of the fabrication and erection process will be provided highlighting the modular construction scheme. The SCR is equipped with low SO<sub>2</sub>-oxidation, plate-type catalyst, and AIG/static mixing system. Results of the physical flow modeling tests will be presented showing how the mixing system was optimized. Results of a CFD (Computational Fluid Dynamics) model study will be provided detailing how a large particle ash (LPA) screen designed to minimize the potential for premature wear. The reagent for the SCR utilizes a urea to ammonia based system, and unique features of the system including redundant, steam-heated process piping from the hydrolysers to the SCR will be presented.

### **CFD Modeling of ALTA in a 180 MW, Pulverized Coal Furnace for NOx Control**

Paper #: 152

A. Fry, K. Davis, M. Cremer, D. Wang, *Reaction Engineering International, Salt Lake City, UT*.

ALTA is the strategic combination of combustion modifications including deep staging of the lower furnace and burner modifications, Rich Reagent Injection (RRI) and Selective Non-Catalytic Reduction (SNCR) for NOx control. In cyclone boilers, ALTA has been shown to produce NOx emissions below 0.12 lb/MMBtu. A critical requirement for the success of RRI is the homogenization of the lower furnace, creating a hot, rich environment. ALTA has not previously been applied to pulverized coal (PC) units due to their typical stratified nature. Supported by CFD modeling and pilot-scale testing,

combustion conditions have been identified that produce a near burner environment suitable for the application of ALTA in a PC furnace. Pilot-scale data and CFD modeling results of ALTA in a 180 MW, wall-fired PC unit will be presented here. These results suggest reduction of NO<sub>x</sub> of up to 35% by RRI with a pre-SNCR emission rate of 0.19 lb/MMBtu.

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