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WHITE PAPER

SELECTIVE CATALYTIC REDUCTION (SCR) CONTROL OF NO_X EMISSIONS FROM FOSSIL FUEL-FIRED ELECTRIC POWER PLANTS

PREPARED BY:

NO_x CONTROL TECHNICAL DIVISION

INSTITUTE OF CLEAN AIR COMPANIES, INC.

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ICAC

The Institute of Clean Air Companies (ICAC) is the national association of companies that supply stationary source air pollution monitoring and control systems, equipment, and services. It was formed in 1960 as a nonprofit corporation to promote the industry and encourage improvement of engineering and technical standards.

The Institute's mission is to assure a strong and workable air quality policy that promotes public health, environmental quality, and industrial progress. As the representative of the air pollution control industry, the Institute seeks to evaluate and respond to regulatory initiatives and establish technical standards to the benefit of all.

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EXECUTIVE SUMMARY

Nitrogen oxide (NO_x) emissions contribute significantly to national environmental problems, including acid rain, photochemical smog (ozone), and elevated fine particulate levels. Ozone exposure has also been linked to a number of health effects, including significant decreases in lung function, inflammation of the airways, and increased respiratory symptoms. In 2004, EPA designated the areas of the U.S. that have ground level ozone concentrations that are higher than the new standard and estimates that 160 million Americans live in areas with unhealthy ozone levels.

The regulations that were developed in response to ozone issues spurred the application of selective catalytic reduction (SCR) on a broad range of industrial sources of NO_x emissions. In the U.S., SCR has been applied on utility and industrial boilers, gas turbines, process heaters, internal combustion engines, chemical plants, and steel mills. First patented by a U.S. company in 1959, SCR is a proven technology. The largest application of SCR technology is on coal-fired power plants with more than 300 coal-fired power plants having installed the technology. Emissions reductions of nitrogen oxides on coal-fired power plants and other applications of greater than 90 percent are common with SCR, although this technology may be used economically for lower removal efficiencies as well.

More stringent regulations and successful operating experience have led to a sharp increase in the number of SCR systems installed in the U.S. Given a large and growing installed base and the increasing tendency of owners and operators of regulated units to choose SCR, authorities with extensive NO_x control experience have concluded that SCR technology is proven, safe, reliable, and economical. With increased operating experience owners and manufacturers are focusing their attention on reducing operating costs and improving SCR performance.

In the decade since this white paper was first issued, many changes have occurred regarding SCR technology. There are thousands of SCRs installed across the world today providing a breadth of manufacturer and end user experience. This experience has led to the development of a segment of the air pollution control industry to provide optimization and maintenance services. Some of these recently developed technologies and regulatory drivers are discussed in the whitepaper including: how regulatory requirements drive technology change, broadening of technology applications due to advances in catalyst development, new vendor maintenance services such as catalyst cleaning and regeneration, and optimization of technology performance through catalyst management strategies.

What are the regulatory and legislative drivers for NO_x control technologies?

Recent regulations developed in response to new ambient ozone standards have been the primary driver for the installation of NO_x control technologies on sources such as coal-fired power plants. Coal-fired power plants, as an industry sector, historically make up close to one-third of the NO_x emissions in the U.S.

In response to the emissions from power plants, one of the first regulatory drivers was the Acid Rain Program that was established through Title IV of the amendments to the 1990 Clean Air Act (CAA). This program included a two-phased strategy to reduce NO_x emissions from coal-fired power plants. Phase I began in January 1, 1996, regulating NO_x from the largest coal-fired boilers while Phase II began in January 1, 2000 affecting the vast majority of the remaining boilers. The Acid Rain Program was implemented through boiler specific NO_x emission rates ranging from 0.40 to 0.86 lb/MMBtu on an annual average. The primary method of compliance for the Acid Rain Program was through the application of Low NO_x burner (LNB) technology and emissions averaging across multiple boilers within a company's fleet of boilers.

Another driver for the installation of NO_x control technologies was established under Title I of the CAA, the National Ambient Air Quality Standards (NAAQS) for ozone, which led to the development of the NO_x SIP Call Rule of 1998. The NO_x SIP Call required 23 eastern states and the District of Columbia to participate in a regional cap-and-trade program in order to address regional transport of ozone across state boundaries. The NO_x cap for the program was based upon an equivalent NO_x emissions rate of 0.15 lb/MMBtu and was to be implemented during the summer ozone season from May 1st to September 30th of each year beginning in 2003-04. At the time, conventional technologies such as low NO_x burners were unable to achieve this level of emissions reduction spurring the application of SCR technology to control NO_x emissions in the United States.

The most recent regulatory driver for NO_x control at coal-fired power plants was U.S. Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR). Several lawsuits were filed against CAIR leading to the U.S. Court of Appeals' December 2008 decision to remand the rule back to EPA for revisions. The Court directed EPA to leave CAIR in place until a replacement rule is promulgated requiring compliance with the rule through NO_x control installations. EPA determined that 28 eastern states and the District of Columbia significantly contributed to nonattainment of the NAAQS for $PM_{2.5}$ and/or 8-hour ozone in downwind states. The rule reduces SO_2 and NO_x emissions as they are precursors or contribute directly to fine particle pollution and ground level ozone. Similar to the NO_x SIP Call, CAIR implements a market-based cap-n-trade program to reduce NO_x emissions. CAIR consists of two independent NO_x control programs including an ozone season program and an annual program. Both programs will be implemented in two phases. The first NO_x phase begins in 2009 and sets an annual NO_x cap of 1.2 million tons. The second NO_x phase begins in

2015 and sets an annual NO_x cap at 1.3 million tons. The total NO_x ozone season budget is approximately 570,000 tons beginning in 2009 and 480,000 tons beginning in 2015. The NO_x emissions caps were calculated using emissions rates of 0.15 lb/MMBtu for 2010 and 0.125 lb/MMBtu for 2015. EPA's Integrated Planning Model (IPM) estimates that a total of 150 GW of SCR, approximately 35 GW of new retrofits, will be needed on coal-fired power plants by 2015 to meet CAIR's NO_x emission caps.

In addition to CAIR, EPA recently amended its 1999 Regional Haze Rule to improve visibility in the national parks and wilderness areas. The rule would require further reductions in power plant NO_x and SO_2 emissions as one strategy for improving visibility in the national parks and wilderness areas by 2064. The regional haze rule requires the installation of Best Available Retrofit Technologies (BART) for existing power plants that began operating between 1962 and 1977, which were built prior to the development of NO_x standards for new sources under the New Source Performance Standards. The Best Available Retrofit Technology standards could require the installation of advanced in-furnace or post combustion NO_x controls, like SCR on these power plants. The implementation of BART NO_x controls would occur between 2014 and 2018. However, in 2005, EPA published amendments to the Regional Haze rule called the Clean Air Visibility Rule (CAVR) to clarify BART emission control requirements. The Clean Air Visibility Rule allows states covered under CAIR to use their CAIR NO_x and SO_2 control programs as a substitute for BART requirements. As a result, the regional haze rule primarily affects power plants in the west not covered under CAIR.

While the previously discussed regulatory drivers have set the stage for significant NO_x reductions resulting from technological advances in SCR, EPA is required by the Clean Air Act to review the ozone ambient requirements every five years with the trend to be continually lowering the ambient standard. There are also regional initiatives by states to achieve deeper cuts in NO_x emissions in order to satisfy their requirements to meet EPA's more stringent ambient ozone standards. Regional planning organizations such as the Ozone Transport Commission (OTC) have proposed more stringent plans that would layer additional control requirements over EPA's CAIR rule. The OTC's initiative, called CAIR-Plus, would set an annual cap based on an emission rate of 0.12 lb/MMBtu in 2009 and 0.08 lb/MMBtu in 2012. CAIR-Plus in 2009 as compared to phase I of CAIR is 20 percent more stringent and 36 percent more stringent that CAIR in phase II.

In addition to regional efforts to reduce NO_x emissions, there are several states that have implemented more stringent NO_x control requirements than what is required under federal rules. One case in point is North Carolina, which enacted its Clean Smokestacks Act in 2002. The regulation requires coal-fired power plants to reduce NO_x emissions by 77 percent from their 1998 emissions baseline beginning in 2009. Texas is another state that has adopted additional NO_x requirements with revisions to its 2002 plan for the Houston/Galveston eight-county area to reduce NO_x emissions by 88 percent from their 1997 baseline emissions. The reductions have been phased in between April 2003 and April 2007 and implemented through a NO_x cap-and-trade program. The NO_x emissions rate equates to 0.045 lb/MMBtu for a tangential-fired boiler and 0.05 lb/MMBtu for wall-fired boilers resulting in the installation of SCR on four boilers in the Houston/Galveston nonattainment area to meet compliance.

Clean air regulations are important for the development and advancement of emissions control technologies. The application of SCR on coal-fired power plants in the U.S. is a good example of the application of a technology that was driven by stringent yet flexible regulatory requirements. SCR had been applied in Europe and Asia on coal-fired power plants in the decades prior to being applied in the U.S. Not only has SCR been applied on coal-fired power plants in the U.S. but it has been applied to a broad range of industry sectors due to the confidence that regulators have in the reliability and performance of the technology.

SELECTIVE CATALYTIC REDUCTION (SCR) CONTROL OF NO_X EMISSIONS

Why Should We Control NO_x Emissions?

NO_x harms human health and the environment directly and contributes to photochemical smog, atmospheric fine particulate, acid rain, nitrogen deposition, and visibility impairment.

Nitrogen oxides (NO_x) include nitric oxide (NO) and nitrogen dioxide (NO_2), and are produced by the oxidation of atmospheric and fuel-bound nitrogen in combustion processes, including those in motor vehicles and combustion processes found in many industry sectors. Nitric oxide is a colorless gas that is converted in the atmosphere to NO_2 that can be detected in the atmosphere as a yellow-brown plume.

In 2006, EPA estimates national emissions of NO_x to be 18.2 million tons. Electric utility and industrial fuel combustion contributed 5.7 million tons with most of the remainder of the annual NO_x emissions being attributed to mobile sources. Nitrogen oxides harm human health and the environment both directly and indirectly, as summarized below.

Nitrogen dioxide can cause adverse human health effects, including bronchitis, pneumonia, lung irritation, and susceptibility to viral infection. Animal studies show that intermittent, low-level NO_2 exposures also can induce alterations in the kidney, liver, spleen, red blood cells, and cells of the immune system.

NO_x emissions lead to the formation of ground-level ozone (photochemical smog). Unlike ozone in the stratosphere, ozone at ground level has a strong negative impact on human health and the environment. Ozone impairs lung function and aggravates heart disease and respiratory diseases such as asthma and bronchitis. EPA estimates that more than 160 million Americans live in areas exceeding the national ozone air quality standard, making ozone a pervasive air problem.

NO_x reacts to form fine particulate in the atmosphere. Nitrogen oxides react with oxygen and other components of air to form nitrates, which coalesce into fine particles. Studies of collected $PM_{2.5}$ (particulate with a diameter less than 2.5 micrometers) suggest that nitrate makes up more than 10 percent of the mass of fine particulate in the western two-thirds of the country. Recent research showing that fine particulate increases human death rates and exacerbates respiratory and circulatory diseases highlights the importance of lowering the concentration of fine particulate and its precursors.

NO_x emissions contribute to acid rain and nitrogen deposition. Nitrogen oxides contribute to the formation of acid rain, which has been shown to destroy fish and other forms of fresh and coastal water life, and to damage buildings and materials, forests, and agricultural crops. In some western areas of the United States, NO_x emissions are the primary cause of acid deposition. In the East, NO_x emissions are responsible for about one-third of rainfall's acidity over the full year, and one-half during the winter. NO_x also contributes to nitrification of rain, which may "over-fertilize" the soil, leaving foliage more vulnerable to damage from cold, insects, and disease. Nitrification can also upset the ecological balance on both land and water.

What is SCR?

In the SCR process, a catalyst facilitates a chemical reaction between NO_x and ammonia to produce nitrogen and water. An ammonia-air or ammonia-steam mixture is injected into exhaust gases containing NO_x. The gases mix thoroughly in a turbulent zone, and then pass through the catalyst where the NO_x is reduced. The catalyst promotes the reaction, but is not consumed by it.

SCR is a process for controlling emissions of nitrogen oxides from stationary sources. The basic principle of SCR is the reduction of NO_x to nitrogen (N_2) and water (H_2O) by the reaction of NO_x and ammonia (NH_3) within a catalyst bed. The primary reactions occurring in SCR are given below.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Several different catalysts are available for use for different applications and operating conditions. In use the longest are base metal catalysts, which typically contain titanium and vanadium oxides, and which also may contain molybdenum, tungsten, and other elements. Base metal catalysts are typically applied to mid-temperature range applications. For high temperature operation, zeolite catalysts are often used. In clean, low temperature applications, catalysts containing precious metals such as platinum and palladium are often applied. (Note that these compositions refer to the catalytically active phase only; additional ingredients may be present to give thermal and structural stability, to increase surface area, or for other purposes.)

The mechanical operation of an SCR system is quite simple as there are not moving parts. It consists of a reactor chamber with a catalyst bed that is composed of catalyst modules and an ammonia handling and injection system. With the ammonia handling and injection system, ammonia (NH_3) is injected into the flue gas upstream of the catalyst as shown in Figure 1. For certain applications, a fluidized bed of catalyst pellets is used. In utility boiler applications in the U.S., the catalyst is typically placed in a separate housing upstream of the air preheater and of any particulate collection device as shown in Figure 2. This configuration is referred to as a "high-dust" hot-side configuration as the SCR is installed prior to both the air preheater and particulate control device.

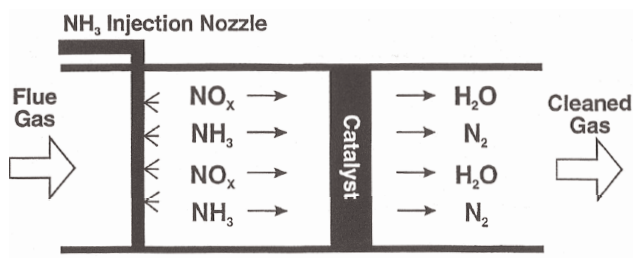

Figure 1. Schematic Diagram of a Generic SCR System

In combined-cycle gas turbine applications, the catalyst normally is placed after the superheater in the heat recovery steam generator (HRSG), where the temperature is in the range suitable for base metal operation (see Figure 3). At several sites in the U.S., high-temperature (zeolite) catalyst has been installed upstream of the HRSG or at the turbine exhaust in simple-cycle applications, where the temperature may be as high as 950-1050 °F.

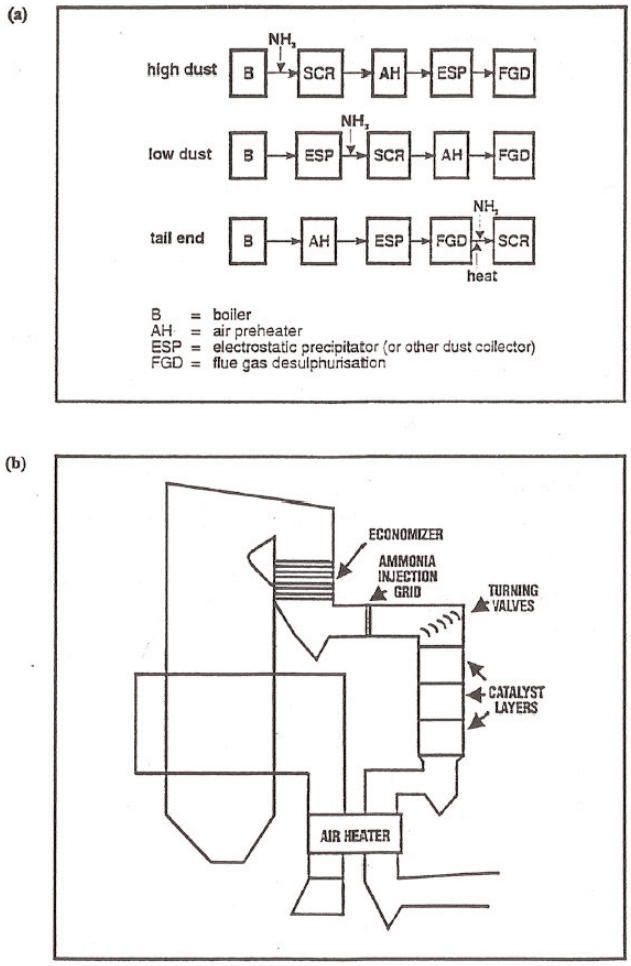

Figure 2. (a) SCR System Configuration for Utility Boiler Applications; (b) Schematic Diagram of a High-Dust Hot Side SCR System

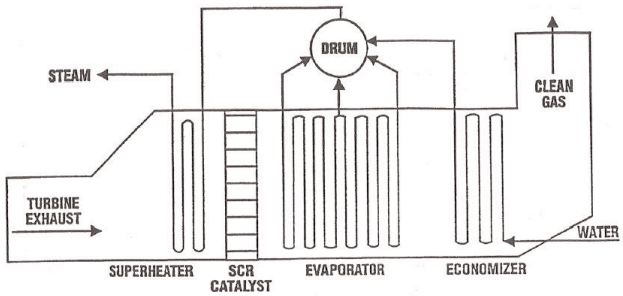

Figure 3. SCR Catalyst Placement for Gas Turbine Applications

How Much NO_x Can SCR Remove?

By proper catalyst selection and system design, NO_x removal efficiencies exceeding 90 percent may be achieved. In practice, SCR systems designed for a wide range of NO_x removal efficiencies have proven to be cost effective.

In principle, SCR can provide reductions in NO_x emissions approaching 100 percent. Simple thermodynamic calculations indicate that a reduction of well over 99 percent is possible at 650 °F. In practice, commercial SCR systems often meet control targets of over 90 percent.

A prerequisite to high removal efficiencies is effective mixing of NO_x with a precisely determined amount of ammonia, which is readily achieved in current systems. Physical modeling and computational fluid dynamic modeling are used to optimize the mixing for best SCR performance. Urea is converted to ammonia prior to injection with one mole of urea producing two moles of ammonia. To better understand the volume of reagent used, reducing one pound of NO_x will require roughly 0.176 kg of ammonia or about 0.312 kg of urea. This estimate for reagent usage includes a half percent increase in reagent demand due to ammonia slip and a five percent increase to account for a small amount of nitrogen dioxide (NO_2) in the flue gas.

In addition to achieving high percentage NO_x reductions, reducing NO_x to very low concentrations has proven cost effective using SCR. Since 1998, there have been more than 300 SCR systems installed on utility coal-fired boilers in the U.S. primarily on bituminous coal-fired boilers but also on other coal types. Regulatory drivers are also expected to require the installation of SCR technology on certain utility boilers in Texas that are being designed to achieve NO_x emission rates of 0.04 lb/MMBtu burning subbituminous coal. Reductions in coal-fired utility boiler emissions under the NO_x SIP Call have resulted in SCR retrofit installations that are achieving NO_x emission rates ranging from 0.04 lb/MMBtu to 0.15 lb/MMBtu.

Significant NO_x reductions are not limited to coal-fired boilers as natural gas fired utility boilers across the U.S. are achieving NO_x emission reductions of 95-99 percent to well below 0.01 lb/MMBtu. On gas turbines, reductions greater than 95 percent, with guaranteed outlet emissions below 5 ppm, are common with ammonia slip less than 5ppm. SCR has been used to reduce emissions from reciprocating engines by greater than 95 percent, with emissions from diesel engines reduced to well below 2 g/bhp-hr, and from dual fuel engines to below 0.5 g/bhp-hr.

Is SCR Commercially Demonstrated in the U.S.?

SCR is installed on more than 1,000 sources in the U.S., including utility and industrial boilers, process heaters, gas turbines, internal combustion engines, chemical plants, and steel mills.

Retrofit SCR systems are in operation on more than 50 **gas-fired utility boilers** ranging in size from 147 to 750 MW. SCR systems are operating on more than 300 **coal-fired boilers** in the U.S. alone not counting the experience gained in both Europe and Asia. In

addition to the installation experience on gas and coal-fired boilers, a number of oil-fired boilers in the U.S. have installed SCR systems with considerably more experience abroad. The SCR design and installation experience on the various fossil fuel-fired boilers indicate that SCR is a viable retrofit control technology for boilers used in electricity generation.

SCR is used to control NO_x emissions from more than 50 **industrial boilers and process heaters** in the U.S. These include both field-erected and small packaged boilers. Typical control levels on these units are 80-90 percent with single digit parts per million, outlet NO_x concentrations.

SCR has found growing use for the control of NO_x emissions from combined cycle **gas turbines**, with more than 650 systems installed in the U.S. Removal efficiencies of over 80 percent are common in this application, and SCR has been used alone or in combination with other control technologies to achieve outlet NO_x levels below 5 ppm. The development of the high-temperature SCR catalyst has allowed the use of SCR on simple cycle turbines with over 150 installations in the U.S. alone.

Another growing use of SCR is the control of NO_x emissions from stationary **reciprocating internal combustion engines**. SCR systems have been used to control emissions from dozens of internal combustion engines burning natural gas, diesel fuel, and mixtures of these in the U.S. For these applications, an SCR catalyst is often placed downstream of an oxidation catalyst to allow for simultaneous removal of NO_x, hydrocarbons, and carbon monoxide.

SCR also has been used on other types of sources, for example, **nitric acid plants** throughout the U.S. employ SCR systems to achieve reductions exceeding 90 percent. Selective Catalytic Reduction systems have been installed on annealing furnaces at **steel mills** in Illinois, Indiana, and California, and at an electric arc furnace to name a few other examples.

Is SCR Feasible on Lignite-Fired Power Boilers?

Yes. SCR has been operated successfully on several lignite-fired units worldwide. For all SCR applications, the fuel being burned dictates the catalyst and system design. Here are some of the factors to be considered for a successful SCR design for units firing lignite.

Lignite from different mines has some common characteristics but also differs in some significant ways. Lignite is the lowest rank coal, just above peat in heating value. The quality of the fuel is non-homogeneous. It has a high moisture content ranging from 25 percent to 45 percent, but sometimes as high as 65 percent. Most lignites have a high ash content as well. They are also typically high in silica and alumina. On the positive side, they are low in arsenic, which is the most common catalyst poison found in bituminous coals.

Lignite characteristics important to SCR design that may differ from region to region are sulfur content, sodium content, potassium content, and calcium content.

These fuel characteristics impact SCR design as follows:

1. *Heterogeneous quality* – May result in difficulty of the ammonia feed system to follow the NO_x loading quickly. Mismatch of NO_x loading to ammonia feed results in either insufficient NO_x reduction or high ammonia slip. A well-designed ammonia feed and control system is always important for efficient SCR operation and is particularly important for lignite-fired boilers.
2. *High ash content* – Ash content and characteristics determine minimum catalyst pitch, which is the catalyst cell dimension defined from centerline to centerline of one wall to an adjacent wall. Selection of the most appropriate catalyst pitch is important to assure that ash will not deposit and bridge over the catalyst openings, thus reducing the effective catalyst surface area and causing increased pressure loss. The higher ash content may drive a larger pitch than required for bituminous or PRB fuels. Excellent flow distribution is even more important than usual to prevent plugging. Similarly, proper specification and operation of soot blowers and sonic horns is critical.
3. *High silica or alumina content* – Silica and alumina are abrasive particles. Large quantities of these constituents "sandblast" the catalyst, removing active materials. Catalyst type should be robust. The catalyst supplier may recommend a thicker/harder wall than is usually used for less abrasive fuels.
4. *High sulfur and calcium content* – Sulfur content varies greatly among lignites. High sulfur content in lignite requires the same considerations given to high sulfur bituminous units. Specifically, the unit's tolerance for SO_3 downstream of the SCR. A correspondingly high level of calcium may result in the formation of gypsum ($CaSO_4 \cdot 2H_2O$), which masks catalyst pores resulting in loss of activity. This is also a common deactivation mechanism of PRB coal.
5. *High sodium (Na) and potassium (K) content* – Na and K are water soluble catalyst poisons. These poisons are not an issue as long as the catalyst stays above dew point conditions. Cold starts should be minimized. With year round operation of U.S. SCRs beginning in 2009, SCRs will be laid up less frequently, minimizing the concern with water soluble poisons.

In summary, every combustion byproduct stream has specific characteristics that must be considered in the design of a successful SCR for the application and lignite fuel is no different. With proper design, lignite applications can be successful.

What are the Impacts and Consideration of SO_2 to SO_3 Conversion in an SCR?

Background

As a result of the fossil fuel combustion process, SO_2 and SO_3 are generated due to the presence of sulfur in the fuel. As a rule of thumb approximately 600 ppmv of SO_2 is generated for each one percent by weight of sulfur in the coal. Sulfur trioxide typically represents one percent of the SO_x generated, for example, 6 ppmv for a one percent sulfur coal. With the addition of high sulfur petcoke to the combustion process, this level may increase due to the influence of vanadium deposition.

The use of SCR systems for NO_x emission control can have a negative impact on the concentration of SO_3 in the flue gas at the air preheater (APH) and through the stack. This is caused by an undesired side reaction that oxidizes SO_2 to SO_3 ($SO_2 + ½ O_2 \rightarrow SO_3$). The magnitude of this oxidation depends on SCR design conditions, operating parameters, and catalyst formulation. Generally, higher temperature and higher performance requirements will lead to higher levels of SO_3. If starting with medium to high sulfur coal (>1.5 percent weight sulfur), the resultant higher levels of SO_3 can cause operational issues related to air preheater fouling and/or corrosion and may lead to more visible emissions due to sulfuric acid mist. Conversely, if starting with low sulfur fuel (<1 percent), the additional SO_3 generated by the SCR may enhance electrostatic precipitator (ESP) performance through a positive effect on the ash resistivity properties.

SCR catalyst is most typically composed of vanadium pentoxide and tungsten trioxide or molybdenum trioxide dispersed on a high surface area titanium dioxide. Vanadium pentoxide, in particular, is the active catalytic material for reducing NO_x. Vanadium pentoxide also oxidizers SO_2 to SO_3 as an undersired side reaction. Therefore, there is a trade-off between NO_x reduction activity and SO_2 oxidation activity.

Catalyst manufacturers typically formulate their catalyst to achieve a low SO_2 to SO_3 oxidation. Therefore, the reaction is rather slow compared to the NO_x reduction reaction; and thus, is reaction rate limited, utilizing the full mass of catalytic components. Conversely, at typical SCR temperatures, the NO_x reduction reaction is diffusion limited, utilizing the surface of the catalyst. Catalyst suppliers design the chemical composition and geometry (i.e. surface to mass ratio) of the catalyst to provide a low SO_2 conversion, while achieving the required NO_x reduction and resistance toward deactivation, erosion, and plugging by fly-ash.

During initial deployment of SCR technology in the U.S. market, typical levels of SO_2 to SO_3 conversion for SCR catalyst ranged from 0.5 percent to 2 percent for the initial charge of catalyst for most bituminous coals and up to 3 percent for sub-bituminous coal. In some cases, utilities proactively addressed the expected increased potential for air preheater operational issues by utilizing enameled, cold-end elements and/or modified layer geometry/arrangement to enhance on-line cleaning capabilities and general reliability.

At the same time, many bituminous coal-fired units were installing flue gas desulfurization systems (FGD) that are wet scrubbing processes designed to remove SO_2 from the flue gas stream. The installation of an FGD results in more condensation of sulfuric acid at the stack due to cooling of the flue gas. The combination of firing high sulfur bituminous coals, SO_2 oxidation from SCR catalysts, and installation of FGDs has resulted in higher than expected visual emissions for some boilers.

Current

Driven primarily by issues related to visual impact caused by SO_3 emissions and secondarily by actual tonnage emission limits and/or APH issues, the utility industry desired a lower SO_2 conversion SCR catalyst. The catalyst suppliers responded by utilizing their understanding of the governing factors which balance NO_x reduction, deactivation resistance, SO_2 conversion and in some cases mercury oxidation to create advanced products to reduce the contribution of SO_3 from the SCR. These advancements primarily take advantage of reducing the bulk density of the catalyst and utilizing the existing catalytic components [Vanadium (V), Tungsten (W), Molybdenum (Mo)] in order to create a more optimized balance between performance features. Currently, an SO_2 conversion level as low as 0.2 percent for initial catalyst charge is feasible in some cases.

For units outfitted with a Flue Gas Desulfurization (FGD) system, SO_3 stack emissions are targeted at less than 5 ppmv in order to avoid visual emissions. If burning a high sulfur fuel, catalyst advancements alone are not likely to achieve the desired level of SO_3 in the stack. It is very case specific but Table 1 presents rules of thumb for the generation or reduction of SO_3 in a system.

As seen in the example above, additional mitigation techniques include additives (Calcium oxide, Sodium bisulfite (SBS), Trona, etc.) or fuel blending (PRB blend) and would be required to reach the desired level of SO_3 emissions. The effectiveness of such changes must be 70 percent to achieve a value of < 5 ppmv at the stack. Reduction of the contribution from the SCR to near zero would still require some additional mitigation under the example provided above; however, may reduce the mitigation costs. Therefore the understanding of actual emissions, the contributions of each of the system components and the economics and flexibility of each mitigation technique must be evaluated to determine the best course of action.

Future

Focus by the air pollution control industry and end users on the balance of all features desired from the SCR and potential combination with other technologies such as fuel changes and additives to minimize SO_3 emissions are ongoing. Items range from catalytic re-

Table 1. SO_3 Generation Across Coal-Fired Boiler Process

Generation of SO_3	*Reduction of SO_3*
~ 1% → of Furnace SO_2 Concentration	0-30% → In furnace Additive or Prior to SCR
0.2-2% → of SCR Inlet SO_2 Concentration	20-50% → Air Preheater (APH)
	50+% → Pre or Post Air Preheater additive
	10-30% → Dry Electrostatic Precipitator (ESP)
	0-20% → Flue Gas Desulfurization (FGD)

Example:

3% Sulfur Coal	***Generation*** →	*Furnace* SO_2 = 1800 ppmv SO_3 = 18 ppmv		*1% conversion by SCR:* SO_3 = 36 ppmv	
SCR outlet: 36 ppmv	***Reduction*** →	APH at 35% SO_3 = 23 ppmv	ESP at 15% SO_3 = 20 ppmv	FGD at 20% SO_3 = 16 ppmv	Stack SO_3: 16 ppmv

duction of SO_3 to allowing SCR oxidation to increase while utilizing additives for overall control.

Each power plant example is case specific and must be evaluated considering multiple factors including site requirements, utility requirements, economics, stability SO_3 mitigation and, duration of method employed, etc.

What Are the Design and Operational Issues Around a Shift from Ozone Season to Annual Compliance?

There are numerous design and operational issues impacting the shift from ozone to annual NO_x compliance. These issues include but are not limited to catalyst management, ammonia system optimization, insulation, and SCR system considerations.

Most SCR systems installed in the U.S. were designed for operation during the five month ozone season, which is from May 1st to September 30th of each year, as that was the compliance period designated in the NO_x SIP Call regulation that initially drove the installation of many of the SCR systems. For the other seven months of the year, the SCR was not required to operate. Due to this part-year operating scenario, the SCR systems installed to meet ozone season regulatory requirements were often equipped with a bypass duct which diverts boiler flue gas stream around the SCR system and allows the boiler to operate at all loads. This preserves catalyst life since exposure to flue gas with or without ammonia injection will degrade the catalyst.

Starting on January 1, 2009, the CAIR rule will require many SCR systems to operate the entire calendar year from January 1 – December 31 as opposed to the summer ozone season that runs from May 1 – September 30. This annual requirement is primarily driven by the promulgation of EPA's Clean Air Interstate Rule that established annual NO_x requirements on top of the ozone season NO_x requirements. Due to this change in operation from ozone season to annual operation, there are certain issues that should be addressed with SCR systems designed for seasonal operation so that they can successfully operate the entire year.

Catalyst Management

The catalyst management plan for the seasonal SCR must be reviewed since the catalyst will degrade faster with constant operation. The catalyst degrades during all times when the flue gas passes over it regardless of whether ammonia is injected for NO_x reduction purposes or not. The ultimate catalyst life time in hours will not change, just the rapidity with which those hours will add up. A seasonal SCR could expect a little over four years to be required for the accumulation of 16,000 operating hours, if the system operates every day during the ozone season. For an SCR system operating every day of a year, the 16,000 hours of catalyst life would be accumulated before two years had passed. Full time operation of an SCR will result in a shorter calendar life for the catalyst. Thus, more frequent catalyst changes will be required.

This is especially true for applications with relatively rapid catalyst deactivation due to arsenic poisoning. Diligent planning and preparation (i.e. having a spare catalyst layer) may be necessary to maintain NO_x removal targets and minimize outage times.

During periods of catalyst handling and maintenance, it is important to avoid wetting the catalyst in a freezing environment. Wetting a catalyst in a freezing environment may cause the catalyst to freeze and weaken the catalyst structure and degrade catalyst performance. Care and planning should be taken to avoid this situation.

Ammonia System Optimization

The ammonia system may require some optimization to provide adequate service in the cold winter

months as the system was designed for operation during the ozone season. The ozone season occurs during the summer months, which in most areas of the U.S. is a much warmer time of the year than the winter months.

The anhydrous ammonia vaporization system can take advantage of the warmer ambient temperature and solar flux to aid in the vaporization. During the winter, the ambient temperatures are much lower and the amount of solar flux is notably less. The vaporization system for anhydrous ammonia should be reviewed to make sure that it can provide the amounts of ammonia demanded by the SCR in the cold of a winter night when temperatures are usually at their lowest. The ammonia transport pipe may require heating and insulating to prevent moisture from freezing and plugging the lines during cold winter operation.

The ammonia supply system will have a lower ammonia vapor pressure during the colder winter months. This will result in lower tank and supply line pressures which might affect system pumping or other delivery capacities. The higher density and viscosity of the liquid ammonia feed may also reduce the delivery system capacity.

Anhydrous tanks will require annual or possibly more frequent draining of the water that is always present in the ammonia supplied for most SCR systems. This water can accumulate in the tanks and at some point prevent adequate ammonia from being vaporized. Systems that are "once through" and send all the vaporizer output to the injection grid rather than back to the tank and then to the injection grid will require frequent draining of the vaporizer. This draining of the water could be a maintenance problem unless the equipment has spare capability so one can be out of service while the draining takes place.

Most anhydrous tanks are equipped with a fogging system to minimize the effects of a large ammonia leak. These fogging systems will require heat tracing to maintain their effectiveness during the winter months. If a fogging system is triggered during freezing weather, a considerable amount of ice can form and this impact should be reviewed from both a safety and operational hazards consideration.

Those SCR systems that use aqueous ammonia or urea will require a review of the equipment insulation since the ambient temperatures for winter operation could be lower than those values used in the initial design for seasonal operation. The heat required for the processes would remain the same but additional heat may be required to account for thermal losses due to ambient temperature.

Ammonia Injection System

In some instances the ammonia injection is carried out with unheated dilution air. This air carries the ammonia into the flue gas duct. In some cases, large quantities of cool air have caused some issues but many SCR systems operate without heated dilution air. The much lower ambient air temperatures encountered in the winter months may require heating of this dilution air to prevent corrosion, deposits, and plugging of the ammonia injection grid during winter operation.

The ammonia supply lines may need to be heat traced, especially any vapor lines, to avoid condensation from forming in cold piping sections.

Dilution air blower's service requirements should be reviewed for any minimum incoming air limitations.

Insulation Coverage

Insulation on the SCR and flue gas ducts should also be reviewed to assure adequate thickness for operation during the winter months since other seasonal ambient values may have been used during the initial system design.

Damper Operation

The damper that is included in those SCR systems with a bypass duct may not operate frequently with a system used year round. The design of the damper and operator should be reviewed to assure that it could operate successfully after long time periods of non-operation.

If the bypass is taken out of service, then it should be secured so that there is no leakage of exhaust. This may require maintenance of seals and sealing mechanisms.

SCR System Capacity

During cold winter months, the boiler may be capable of producing more exhaust gas and/or a greater NO_x demand than during warmer summer months. Both the ammonia supply side and the catalyst side of the system should be assessed to ensure that the entire system capacity can satisfy winter operation expectations.

The colder incoming air temperature entering the air preheater can result in lower exhaust gas temperatures and cooler metal surfaces. This situation can exacerbate ammonia bisulfate formation and SO_3 corrosion.

How Long Do SCR Catalysts Last?

Initial catalyst loadings are generally guaranteed by the manufacturers for 8,000 to 24, 000 operating hours depending on design and operating conditions. Catalyst regenerations service providers may be able to restore some or all of the original performance for less cost than new a catalyst, extending the service life of the catalyst.

SCR systems have been operating on coal-fired power plants in the U.S. since the first unit went commercial in 1990's. Early projections assumed a one year life before catalyst replacement would be necessary, subsequent operating experience showed these projections to be unduly pessimistic. Today, with catalyst regeneration, catalyst lives have been extended, providing catalyst cost savings while helping to keep the environment healthy as spent catalysts are now being recycled rather than being disposed of in a landfill.

Further, with proper catalyst management techniques, there is no need to replace all of the catalyst at once. Selective Catalytic Reduction reactors are designed to hold several layers of catalyst. During the ini-

tial fill of catalyst, one layer will often be left vacant. When NO_x conversion decreases or ammonia slip increases to the permit level, fresh or regenerated catalyst may be placed into the vacant space, leaving the remainder of the catalyst intact. After the fresh or regenerated catalyst is added to the vacant space, periodic replacement or regeneration of a portion of the total catalyst inventory is usually sufficient to maintain the desired catalyst activity.

Management schemes coupled with regeneration may result in reduced need for replacement catalyst. For example, catalyst replacement schemes at units in New Jersey and Florida would result in the annual purchase of the equivalent of between 1/14 and 1/8 of the initial catalyst charge over a 15-year period, i.e., an effective life of 8 to 14 years. By using regeneration what was new catalyst can now be regenerated, not once but several times depending upon the catalyst.

Regeneration allows recycling of the SCR catalyst. Catalysts that are weaker structurally, especially those with thin walls can be regenerated 0-2 times. Stronger thick walled catalyst and plate type catalyst can and have been regenerated in Europe up to four times. For example, if four regenerations are used, then the life of 8 to 14 years may be extended to several decades. It is anticipated that catalysts used for other applications besides coal-fired boilers will also lend themselves to regeneration.

What are some of the Means for Optimizing Catalyst Performance?

Most SCRs for coal-fired boilers are designed for about 90 percent NO_x removal and very low ammonia slip (typically less than 2 ppm).

Competition to keep the SCR as small and inexpensive as possible has pushed SCR design margins to very tight levels leaving little room for error. Three areas in particular that have proven essential for maintaining top SCR performance include:

1. Maintaining Good Ammonia Distribution
2. Catalyst Maintenance
3. Catalyst Management

Ammonia Distribution

Uneven ammonia distribution across the catalyst reactor is a frequent cause of poor SCR performance and may be mistaken for low catalyst activity. If the ammonia is not properly distributed throughout the exhaust gas, some parts will be over-treated; resulting in high ammonia slip and other parts may be under-treated, resulting in poor NO_x reduction.

At high NO_x reduction rates even small imbalances in ammonia distribution can cause local peaks in ammonia slip and higher average ammonia slip. If average ammonia slip must be maintained below 2 ppm, poor distribution will cause more frequent catalyst replacement. In fact, with even modestly poor distribution (root-mean-square variation at 6.8 percent versus about 4.9 percent), peak ammonia slip can reach levels that are sure to cause problems as shown in Figure 4. This may be the most common cause of high ammonia slip on SCR systems because at high NO_x removal rates there is so little room for error in the distribution of ammonia. When parts of the exhaust gas have more ammonia than NO_x to react with, all of that excess ammonia will pass through as ammonia slip.

Since the NO_x distribution will change with boiler firing conditions, it is not possible to achieve ideal mixing under all conditions. Mixing devices will certainly help improve the spatial distribution of ammonia and NO_x to minimize unevenness. Even with mixing devices, regular testing should be performed to confirm proper ammonia distribution. This can be done by measuring NO_x in a multi-point grid at the exit of the SCR, and sometimes between levels. Proper ammonia distribution should show little variation of NO_x at the SCR exit grid. A high variation in NO_x measured at the exit grid means that the ammonia-to-NO_x molar ratio at the inlet to the SCR may be uneven.

If catalyst is replaced when average slip reaches 2 ppm (arrows show time of catalyst addition or replacement), better distribution, indicated by lower root-mean-square (RMS) variation, will result in longer times between catalyst replacement because of the lower average ammonia slip. Better distribution will also result in much lower peak ammonia slip. The peak ammonia slip can reach levels that are certain to cause problems, such as localized ammonium bisulfate deposits in the air preheater or high ammonia in the fly ash.

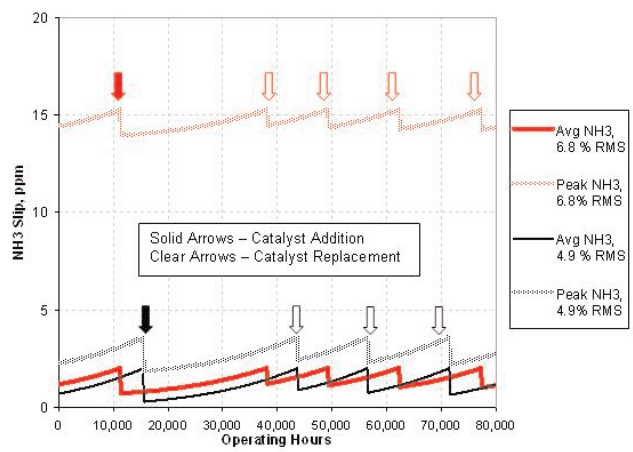

Figure 4. Average and Peak Ammonia Slip

Catalyst Maintenance

Maintaining properly working catalyst is part of a larger catalyst management program, which includes other priorities such as periodic catalyst sampling and testing and replacement/exchange evaluations based on NO_x reduction efficiency; regular ammonia slip monitoring; evaluation of catalyst physical condition; considering unit outage schedules, and other factors.

On-line catalyst cleaning is performed on a regular basis with soot blowers or sonic horns while off-line cleaning occurs during a unit outage and may become imperative if the catalyst becomes plugged. Keeping the catalyst clean is important for maintaining catalyst activity and also for avoiding flow restrictions which will reduce boiler output and can induce accelerated catalyst erosion.

Some units equipped with SCR systems have experienced severe catalyst plugging problems as a result of low-density, large-particle ash ("popcorn ash") formation in the boiler and carry-over into the SCR reactor. Unfortunately, this type of ash is not readily cleaned with on-line cleaning methods since it lodges in the catalyst channels. Therefore, when this type of plugging happens, it is necessary to take the SCR off-line for cleaning. Prevention is the best method for dealing with this type of plugging. It is desirable to have the popcorn ash fall out of the gas flow and be collected prior to the SCR in order to avoid plugging. Ash screens located near the economizer outlet hopper have proven to be helpful in this regard.

Catalyst Management

Catalyst management involves monitoring the catalyst activity, planning for future activity additions, and then making a decision to either replace or regenerate the catalyst as needed. Catalyst will lose its activity over time due to deposits of material that block active sites, by chemical poisoning of the active components, and by physical erosion and damage.

Arsenic is a particularly bad SCR catalyst poison because it chemically binds to the catalyst and can rapidly deactivate the catalyst. Arsenic is of greatest concern for boilers that reinject fly ash or boilers that fire certain coals that have moderate to high arsenic content with free lime in the ash under two percent. As shown in Figure 5, lime (CaO) helps to bind the gaseous arsenic that acts as a poison into harmless calcium arsenate. Some facilities have found it useful to inject limestone into the furnace to reduce arsenic poisoning and improve catalyst lifetime. Due to its volatility at high temperature, arsenic has proven to be difficult to measure in coals using some older lab procedures. So, owners should take care to ensure that their coal analysis is properly measuring arsenic.

If there's adequate CaO in the flyash, the gaseous arsenic trioxide gas released from burning the coal will be converted to calcium arsenate that is collected in the ESP or in the bottom ash. If there is not adequate CaO in the flyash to scavenge the gaseous arsenic, then the arsenic may deposit and chemically react with the catalyst, poisoning it. Flyash reinjection as practiced in some cyclone boilers will also concentrate the gaseous arsenic.

SCR catalyst is typically replaced during planned outages and would incur significant expense to replace during a forced outage. At the very least, a comprehensive catalyst management effort involves minimizing the catalyst costs while simultaneously optimizing the

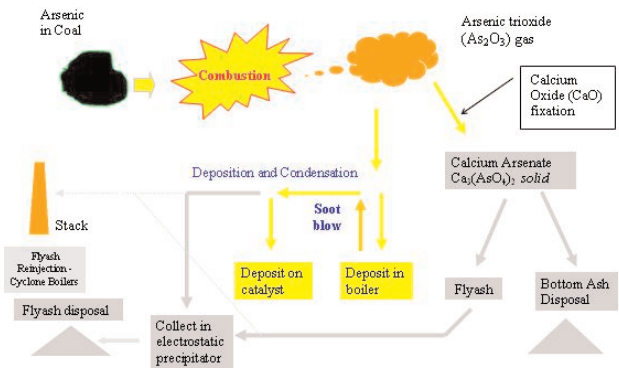

Figure 5. Pathways for Arsenic Poisoning

operation of the facility to achieve the lowest cost impact to generation. As a result, it involves making trade-offs between catalyst consumption, the frequency, timing and duration of outages taken for catalyst work, ammonia slip, NO_x reduction, baseline NO_x, parasitic pressure loss, and of course, comparing catalyst regeneration versus catalyst replacement.

Some of the trade-offs include:

1. *Outage timing and duration* – Ideally, outages for catalyst replacement can be timed to coincide with other work so that they don't impact plant generation. But this isn't always the case. If the planned catalyst replacement doesn't coincide with an outage for other work, it may be necessary to choose between replacing catalyst early, taking an unplanned outage, or delaying catalyst replacement and risking higher ammonia slip.

2. *NO_x reduction* – With NO_x allowances having a marketable value, increasing the NO_x reduction of the SCR may be worth exploring. But, it comes at the risk of increased ammonia slip, increased ammonia consumption, and possibly increased frequency of catalyst replacement.

3. *Baseline NO_x level* – Reducing NO_x from the furnace into the SCR inlet can help reduce ammonia consumption, reduce ammonia slip, and permit longer times between SCR-imposed outages.

4. *Catalyst loading volume* – It may be possible to further extend time between catalyst outages through increasing the catalyst loading beyond the initial design level. The decision will need to be balanced with other factors as increased catalyst loading adds catalyst cost, increases SO_2 to SO_3 conversion, and increases parasitic loads due to pressure drop across the catalyst.

5. *Pressure drop* – In some catalyst management scenarios, some layers in the catalyst reactor are left empty. This approach has the advantage of reducing catalyst loading and pressure drop and avoids additional SO_2 to SO_3 oxidation versus a traditional approach that fills the SCR reactor

and later replaces catalyst as the catalyst loses activity.

6. *Regeneration of catalyst versus new catalyst* – If physically in good shape, catalyst can be cleaned and reactivated, saving cost on new catalyst and on disposal of used catalyst.

Each SCR reactor is designed to provide a minimum specified NO_x reduction performance with a maximum ammonia slip under a given set of conditions after the catalyst has lost some portion of its initial activity. Therefore, once catalyst activity drops below a level necessary to provide desired performance, it is necessary to replace some of the catalyst, add more catalyst to the reactor, or regenerate the catalyst.

Figure 6 shows the most common approach to increasing catalyst activity over time. First, catalyst is added to fill any empty layers in the SCR reactor. Then, activity additions are performed by replacing catalyst with new or regenerated catalyst. When the SCR catalyst activity drops to a point where ammonia slip increases to an unacceptable point, then new catalyst is added to level 4. After the SCR reactor is full, it is necessary to replace catalyst levels with new or regenerated catalyst to increase total SCR catalyst reactor activity. Operators of SCR systems should consult their SCR system suppliers and their catalyst suppliers for more information that is specific to their equipment.

There are several key parts of this effort:

1. Monitoring catalyst activity
2. Projecting future catalyst activity and needs for activity additions
3. Choosing between replacing catalyst with new catalyst or with regenerated catalyst

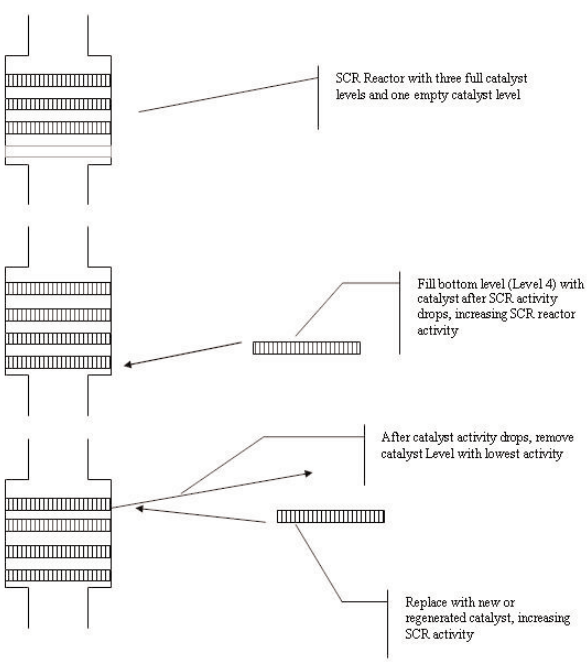

Figure 6. Typical Catalyst Replacement Sequence in SCR Reactor

Monitoring Catalyst Activity

The catalyst supplier will typically provide projected deactivation curves. However, regular testing of catalyst activity is recommended and is typically conducted on an annual basis. There are also new systems designed to provide on-line catalyst activity indication. It is necessary to have these evaluations of catalyst health on a regular basis in order to help plan for when the next catalyst replacement or regeneration is needed.

Whether choosing to replace or regenerate catalyst, it is important to identify the layer with the lowest activity and replace or regenerate that layer. It may seem obvious but this is because the net activity addition to the SCR reactor is the activity of the new or regenerated catalyst minus the activity of the catalyst that is removed. The greatest net activity addition will occur if the catalyst with the lowest activity is replaced or regenerated. So, regular catalyst activity testing by a qualified laboratory is important for maximizing time between catalyst activity additions.

Projecting future catalyst needs

Software programs are available for assessing trade-offs in catalyst management approaches that make planning ahead much easier. These programs project future dates for catalyst activity additions and associated cash flows. These software programs can also be used to troubleshoot SCR system problems because they normally have design and reactor analysis tools built in. The test data from annual catalyst testing can be used to update the SCR models in these programs to provide more accurate predictions for the future.

Regular catalyst testing and updating of projected catalyst needs with software will help to reduce overall compliance costs and avoid unplanned outages. It will also help assess methods to potentially improve performance. Moreover, new catalyst technologies under development and new regeneration approaches may offer significant improvements and cost savings. End users should remain aware of these developments and should maintain flexibility in their approach.

Catalyst Replacement or Regeneration?

Most SCR reactors are designed with up to four available levels of catalyst, depending on structural design. In some cases each level may hold more than one layer (two layers of catalyst essentially stacked on top of one another). When the system is new, with fresh catalyst, at least one level is typically empty. When the SCR catalyst activity drops to a point where ammonia slip increases to an unacceptable point (typically >2ppm), then new catalyst is added to the empty level. After the SCR reactor is full, it is necessary to replace catalyst levels with new or regenerated catalyst to recover total SCR catalyst reactor activity. Since the top level usually loses activity faster than the others, it is normally the first catalyst level to be replaced.

The advantages of regenerating catalyst are:

1. If the catalyst is physically intact, it is not necessary to purchase new catalyst and since regeneration of a unit of catalyst is typically less expensive than buying new catalyst, savings are possible.
2. Regeneration may reduce concerns regarding the cost and liability of used catalyst disposal. When spent catalyst can no longer be reactivated, it can be disposed of in approved landfills. At this time, EPA has determined that spent catalyst is not a hazardous waste.

There are also some limitations to regeneration, such as:

1. There is a risk that when catalyst is reactivated with new active material, the catalyst may not behave in the same way with respect to SO_2 to SO_3 oxidation and with respect to deactivation as the original catalyst.
2. If the catalyst is badly eroded, or otherwise physically damaged, regeneration cannot be performed and replacement with new catalyst is necessary. After cycles of exposure and regeneration, the catalyst is likely to be so eroded from normal flyash abrasion during operation that the catalyst cannot be effectively regenerated due to lack of remaining surface area or mechanical strength. This limits the number of times the same catalyst can be regenerated. The number of times a catalyst can be regenerated will be determined by the particular catalyst and the environment it has been exposed to.
3. Regeneration may reduce the structural integrity of the catalyst. Manufacturers of SCR catalyst may void any remaining warranty if their catalyst is cleaned or regenerated in a wet process.

What Are Application Temperature Ranges for Major Types of SCR Catalyst?

Operating temperature is a key design input for SCR catalyst. It dictates the appropriate catalyst formulation and materials of module construction for the application in order to meet performance requirements of NO_x reduction, ammonia slip, pressure loss, and SO_2 oxidation over a given catalyst operating period. Lower temperature applications are typically limited by the potential for formation of ammonium sulfates or ammonium nitrates. Higher temperature applications are typically limited by ammonia oxidation, SO_2 oxidation, and catalyst operating life. Table 2, presented below, provides basic categories of catalyst materials used for various temperature ranges.

Can Ammonia Slip Be Controlled?

Ammonia "slip" is the emission of unreacted ammonia from SCR systems. Ammonia slip can be controlled to levels low enough that effects on plant operation, ash properties, and health will be insignificant.

Ammonia slip, caused by the incomplete reaction of injected ammonia, has been cited as a potential environmental and health hazard. Slip may be minimized by designing SCR systems to ensure good distribution and mixing of injected ammonia.

In practice, ammonia slip is a design parameter for catalyst sizing, just as is the level of NO_x reduction. Thus, the amount of catalyst used in a given system will be selected to meet permitted slip and outlet NO_x limits. In cost effective systems, NO_x removal efficiencies of up to 90 percent commonly are achieved with ammonia slip values below 5 ppm. In fact, slip has been controlled to below 2 ppm through proper design and use of sufficient catalyst. Ammonia slip levels at 2 ppm has no effect on fly ash disposability or sale.

In the United States, permitted ammonia slip levels typically are in the 2-10 ppm ranges. Some permits have called for ammonia slip levels of 5-10 ppm on gas turbines, and 2-5 ppm on coal-fired boilers. In actual practice, ammonia slip levels much lower than these are achieved. For example, at coal-fired boilers in New Jersey and Florida, SCR systems designed for 5 ppm ammonia slip have actual slip values of 0.16 ppm or below. Only when the catalyst is near the end of its service life will slip values approach permitted levels. According to an EPA study, the ammonia slip at 14 coal-fired units with data available, ammonia slip

Table 2. SCR Catalyst Temperature Ranges

Composition	*Type*	*Application Range*	*Normal Range*
Vanadia-Titania Based Catalyst (with Tungsten or Molybdenum)	Plate	500-850 °F	650-800 °F
	Corrugated	300-870 °F	500-850 °F
	Homogeneous and Coated Honeycomb	300-870 °F	500-850 °F
	Pellet	300-750 °F	300-450 °F
Tungsten-Titania Based Catalyst	Homogeneous and Coated Honeycomb	850-1100 °F	900–1050 °F
Zeolite Based Catalysts	Homogeneous and Coated Honeycomb	700-1100 °F	>900 °F

ranges from below 0.1 ppm to below 5 ppm. Seven of these units report slip below 1 ppm. Any operational effects of ammonia slip on these units, in terms of air heater maintenance requirements and the ability to sell fly ash, are negligible.

Even permitted levels for ammonia slip in the U.S., which may not be reached during normal operation, are well below health and odor thresholds. For example, in permitting a pulverized coal cogeneration plant in New Jersey, state officials predicted that the project's 24-hour average and maximum one-hour contributions to ambient ammonia levels would be 0.16 $\mu g/m^3$ and 1.7 $\mu g/m^3$, both well below the chronic health effect criterion of 34 $\mu g/m^3$.

Can Ammonia Be Handled Safely?

Yes.

Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 2006, 17 billion pounds of ammonia were produced in the U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine.

To avoid the risk of handling anhydrous ammonia, many current applications of SCR technology use aqueous ammonia or urea. Aqueous ammonia is typically over 70 percent water so that end users avoid nearly all of the safety issues associated with anhydrous ammonia gas. Most utility SCR installations on coal-fired boilers in the east use either aqueous ammonia or urea.

What Are the Reagent Quality Considerations?

What are the water quality considerations where urea or aqueous ammonia is utilized for SCR Systems?

Water quality and product handling are important components of the overall successful operation of the emissions control system when urea or aqueous ammonia reagents are used in post-combustion applications. Water quality is important in order to minimize system fouling and corrosion that can result in reduced SCR system on-line time, higher maintenance costs, and the inability to meet emissions targets. Proper product handling and storage equipment is necessary in order to assure that the quality of the reagents have the optimum characteristics for industrial emissions control applications.

With urea-based SCR systems, urea is generally shipped as a 50 percent solution but is also available and shipped from a range of concentrations from 32 percent to 70 percent solution. Depending on the urea manufacturer, the water used to ship urea may be demineralized for quality purposes. Prior to injection, urea solution is diluted in-line anywhere from 50 percent to 80 percent. Water quality for this dilution step is important to the success of the application because urea (as well as ammonia) is highly alkaline in water and will precipitate hardness and other minerals. Demineralizing water will remove any potential suspended solids which may lead to plugging of injection lances and other components of the SCR system. The dilution water for SCR remains stable if: (1) urea is purchased from suppliers who supply "NO_x grade urea liquor" whereby stabilizers have been mixed into the solution, or (2) otherwise the dilution water should be of high quality with deminieralized or reverse osmosis quality providing maximum insurance. Table 3 provides a list of components and acceptable concentration ranges for SCR reagents used in post combustion emissions control applications.

Table 3. Range of Properties for SCR Grade Urea Liquor from Demineralized Water

Characteristic	*Range*
Urea Concentration	32 to 70
Free Ammonia (at loading)	<0.2% to <0.5 %
Biuret (at loading)	<0.3 % to <0.7 %
Magnesium (Mg) ppm	<0.5 to <0.8
Calcium (Ca) ppm	<0.5 to <0.8
Phosphates as PO_4 ppm	<0.5 to <1.5
Iron (Fe) ppm	<0.5 to <0.8

Ammonia and urea supply chain and storage is important in order to assure the quality assurance and quality control of the liquor used for SCR systems. The vast majority of anhydrous ammonia and urea manufactured in North American is produced for agricultural purposes where water quality in the make-up and dilution water is less of an issue. For anhydrous ammonia and urea that is produced domestically, between 85-90 percent is used for fertilizer. Agricultural applications place a higher priority on the nitrogen value and certain physical characteristics of the urea to ensure that the fertilizer is evenly distributed when fertilizing fields.

Urea and anhydrous ammonia that is produced for SCR grade applications has a higher standard for the quality of the water used for the make-up and dilution processes. Although supply is available in most locations in North America, the actual distance between point of production and final use can add up to tens of thousands of miles of transport by road, rail, ship, and pipeline involving material handling at each step of the delivery process. Some manufacturers have dedicated supply and storage systems for SCR grade urea and anhydrous ammonia in order to ensure that there is no contamination between agricultural and industrial

grade products. Although not mandatory, minimizing the risk of contamination of the urea or anhydrous ammonia during the supply chain will ensure that the supply of reagent meets the tight quality control requirements demanded in emissions control systems.

Can SCR Suppliers Meet the Current Compliance Needs of the U.S.?

SCR system suppliers and catalyst manufacturers have enough capacity to install SCR systems for any future regulatory requirement or surge in new power plant development projects.

The air pollution control (APC) industry has extensive experience both in the US and worldwide with the installation of NO_x control technologies across many industrial sectors. For coal-fired power plant SCR installations in the U.S., a few installations were in place in the mid-1990s with the majority of the close to 100 GW of SCR installations taking place from 2001 to 2004.

After EPA finalized the NOx SIP Call rules that would require the first wave of SCR installations in the U.S., concerns were raised about whether or not there was enough skilled labor, catalyst production capacity, large cranes, and engineers to design and construct the SCR systems. The air pollution control industry was able to meet the challenging demands of the first wave of SCR installations. The National Association of Construction Boilermaker Employers (NACBE) recruited and trained new boilermakers, catalyst companies opened and expanded operations in the U.S., new construction methods were implemented to better coordinate usage of large hydraulic cranes, and air pollution control companies provided additional resources into engineering of SCR systems. In the end, the air pollution control industry started-up 55 GW of SCR on coal-fired power plants on approximately 100 units from 2001 through 2003. The overall experience gained from SCR installations equate to fifteen years of operational and installation experience with SCR systems on coal-fired power plants in the U.S. alone.

Outside of the US, there is also extensive experience with the installation of SCR systems on coal-fired boilers. Close to 90 GW of SCR installations have been completed in Japan and Europe. SCR installations in Germany were completed in large numbers over another very short period of time as 97 of their 137 units were started-up during two consecutive years (1989-1990). This pattern of installations demonstrates that the air pollution control industry is able to quickly respond to environmental regulations that require a surge of control installations in a short period of time.

Are Low NO_x Burners and Other Combustion Controls Preferable to SCR?

While low NO_x burners and other combustion controls are appropriate tools for controlling NO_x emissions, additional post combustion control may be needed in order to meet stringent NO_x limits.

In many cases, combustion control options such as the use of low NO_x burners, over-fire air, low NO_x combustors, and flue gas recirculation are the most cost-effective ways to control NO_x emissions. Unfortunately, NO_x combustion technologies are often unable to meet the increasingly stringent emission limits.

Relying on low-NO_x technologies may be inappropriate as emission limits are likely to change over time. Incurring the costs of two retrofits by installing low NO_x burners followed by a second NO_x control technology a short time later clearly is a questionable strategy, given the availability of a technology like SCR which allows cost-effective compliance with a broad range of emission limits.

For some units, such as cyclone and other wet-bottom boilers, low NO_x technologies are available, but these may change operating conditions in unacceptable ways. Low NO_x burners also may cause significant operating problems when retrofit in existing boilers. These problems may include localized furnace and watertube corrosion, lower boiler efficiency, and increased particulate emissions.

Although SCR may have advantages over many other technologies for given operating conditions, engineering cost studies should be conducted in order to determine the best control application prior to choosing a particular technology solution.

What Are Some Recent Developments in SCR?

SCR suppliers are continuing to reduce the relative cost of SCR systems further through improvements in catalyst technology and system design, and to exploit the capabilities of SCR catalysts for the removal of multiple pollutants.

Catalyst manufacturers have continued to improve catalysts and extend SCR catalyst capabilities. Current SCR catalyst designs are more resistant to poisoning and erosion than previous designs, and thus have longer operating lives. Catalysts for high-temperature operation, e.g., in simple cycle turbines, are finding expanded use. Catalysts which reduce dioxin and furan emissions, as well as NO_x emissions, are being installed on units such as incinerators. In addition, SCR catalyst formulations are being developed to increase the oxidation of elemental mercury for improved capture in down stream emissions control equipment.

SCR suppliers also are working to expand the capabilities and reduce the cost of SCR. Use of sophisticated flow modeling allows the design of systems with very uniform gas flows and NH_3/NO_x ratios, thus reducing required catalyst volumes and minimizing ammonia slip.

Suppliers also have developed hybrid selective non-catalytic reduction (SNCR) and SCR systems. These hybrids rely on reaction with urea or ammonia in the boiler to destroy a portion of the NO_x, followed by further reaction in a reduced-size catalyst reactor to destroy most of the remaining NO_x. The hybrids provide high removal efficiencies and low ammonia slip, but with reduced capital costs.

Are Mercury Reductions a Co-Benefit of Using an SCR?

Although SCR catalyst reduces NO_x, it also has the dual ability of oxidizing mercury. This can be a significant co-benefit as SCR installed upstream of an FGD will result in a higher overall mercury capture.

Many plants are expected to be operating with SCR/FGD control combinations due to the requirements of EPA's Clean Air Interstate Rule that requires significant SO_2 and NO_x reductions from power plants. For bituminous firing boilers, 80 percent to over 95 percent overall mercury capture has been observed in full-scale plant tests where SCR followed by wet FGD is employed. A large bituminous-fired plant equipped with SCR and wet FGD showed sustained high Hg capture performance over multiple ozone operating seasons.

SCR catalysts are effective in converting elemental mercury to oxidized mercury in bituminous coal-fired boilers, in addition to reducing NO_x emissions. Downstream flue gas desulfurization (FGD) equipment for SO_2 pollution control, if installed, can effectively capture the oxidized mercury which is soluble in water. Wet FGD systems are installed downstream of SCR systems and completely saturate the flue gas in the FGD reactor. When both SCR and wet FGD are installed on bituminous-fired units, the result is substantial reductions in stack emissions of mercury. The reduced stack emissions of mercury have been referred to as a "co-benefit" of boilers equipped with both SCR and FGD.

SCR system oxidation of mercury can be enhanced by the addition of catalysts to specifically convert elemental mercury to oxidized mercury. This can include addition of an extra SCR catalyst layer, a mercury-specific oxidation catalyst added after (or in lieu of) the SCR catalyst layers in a hot flue gas location, or the addition of a mercury-specific oxidation catalyst in a relatively cool flue gas location. For subbituminous and lignite firing, the hot-side catalysts may require augmentation of flue gas chlorine or bromine to be effective whereas the cold-side catalysts are effective without chlorine augmentation.

Can SNCR be used in combination with selective catalytic reduction (SCR)?

Hybrid SNCR-SCR systems have been demonstrated at a number of utility plants and are being commercially installed to meet RACT NO_x limits.

SNCR may be combined with selective catalytic reduction (SCR). While achievable NO_x reductions using SNCR normally are limited by ammonia slip requirements, in a combined SNCR/SCR system, ammonia slip is generated intentionally as the reagent feed to the SCR catalyst, which provides additional NO_x removal. The quantity of catalyst required in a hybrid system is reduced from that in an SCR-only application, so that the hybrid system will have lower capital requirements. This hybrid approach has been demonstrated in several full-scale utility applications.

Reasonably Available Control Technology (RACT) is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas). For areas not meeting the national ambient air quality standards for ozone, additional NO_x reductions may be required. Hybrid SNCR-SNCR systems offer a cost effective solution. For example, at two gas-fired utility boilers in Southern California, hybrid systems gave emissions reductions of 72-91 percent. At a wet bottom coal-fired boiler in New Jersey, a hybrid system reduced NO_x emissions by up to 98 percent. In a DOE Clean Coal Technology installation, the combination of SNCR with smaller SCR will reduce NO_x below 0.15 lb/MMBtu at less than two-thirds the cost of full SCR.

Can SCR be applied to simple cycle turbines?

Yes, the application of SCR to simple cycle combustion turbines has increased in recent years.

This is primarily due to the increased installation and utilization of the turbines for meeting peak power demand. A reference list of typical units with power output and key design inputs is shown in Table 4.

As shown in Table 4 there is a wide operating temperature range for the machines listed. Further, the range represents an area where there has not been widespread experience with SCR, namely above 800 ºF.

Table 4. Simple Cycle Turbine Reference List

Unit Type	*Capacity (MW)*	*Flue Gas Flow (lb/hr)*	*Exhaust Gas Temperature (°F)*
GE LM6000	45	1,051,200	840
GE LMS100	99	1,642,000	820
GE Frame 7EA	85	2,400,000	997
GE Frame 7FA	172	3,531,800	1113
SGT6-5000F	198	3,967,200	1070
MW-701D	144	3,595,300	991
MW-501D	150	2,810,000	1112

Experience in this range has been limited due to the lack of requirements for SCR in the past and the relatively low operating hours that are naturally accumulated on a simple cycle application. However, experience is growing fast and the catalyst and system design issues and evaluation methodology is available. Operating experience has been achieved with temperatures up to 1100 °F and up to 95 percent NO_x reduction with slip values ranging from 2-10 ppm.

Reactions and Catalyst Design Features

As mentioned previously the key difference between standard SCR and that applied for simple cycle SCR is temperature. Temperature must be considered in the catalyst design to assure proper performance features are achieved. Specific features include NO_x reduction, limited ammonia slip, limited ammonia oxidation, and adequate performance life. The basic reaction network is shown below:

Reaction Network

(1) $4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$

(2) $4\ NH_3 + 3\ O_2 \rightarrow 2\ N_2 + 6\ H_2O$

(3) $4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O$

Equation (1) represents the SCR reaction under standard operating temperatures. Equations (2) and (3) show the pathway for ammonia oxidation which must be managed in order to achieve desired performance. Management is performed by modifying the catalyst formulation. Figure 7 shows an example of how catalyst formulation is modified to manage ammonia oxidation.

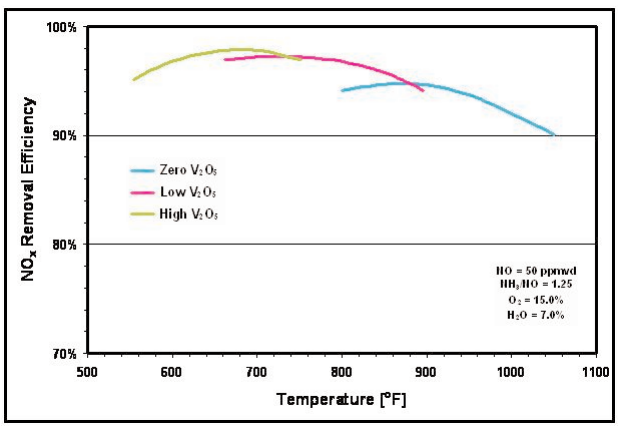

Figure 7. Catalyst Formulation

The performance characteristics shown represent a homogeneous honeycomb catalyst. Other types may include impregnated corrugated or coated honeycomb and may also include formulations which include or depend on zeolites instead of vanadium and tungsten. Figure 7 shows three basic ranges in which the vanadium:tungsten (V:W) ratio is modified to tailor the catalyst performance features to the application. Basically, the V:W ratio is reduced as temperature is elevated to achieve the following key performance properties: a) Stronger NH_3 adsorption, b) Lower NH_3 oxidation rate, c) Higher $DeNO_x$ rate, and d) Lower sintering rate

Design Optimization

As described above there are proven catalyst design methods to manage the higher operating temperature that comes with simple cycle combustion turbine operation. However, the methods do have tradeoffs that must be evaluated on a case by case basis. For example, the catalyst volume, inherent material cost, and module material cost all increase at elevated temperatures as compared to standard SCR temperature for a given design life. However, the flue gas must be cooled to a standard temperature regime in order to take advantage of the benefits related to standard SCR. Therefore an evaluation process, as shown in Figure 8, can be followed to determine which option(s) should be considered to meet the particular application goals.

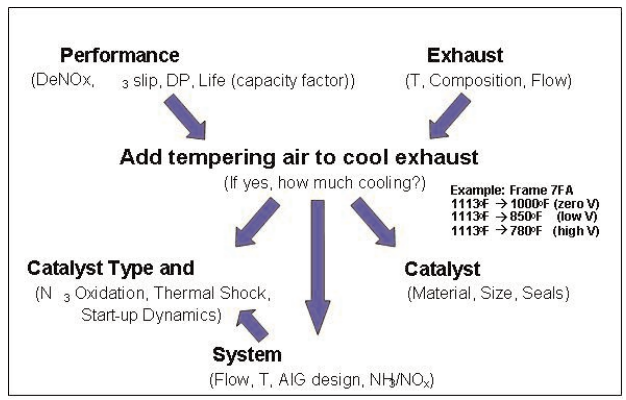

Figure 8. Design Option Evaluation

Tables 5 and 6 show the qualitative results of the analysis. Assigned costs will be case specific and depend on the performance goals, economic life, operator philosophy, etc.

Table 5. Simple Cycle with Tempering Air Considerations

Benefits	*Costs*
Use catalyst with higher V:W ratio	Fans required (capital, operating costs; added space)
Less volume	Catalyst can overheat if fan failure occurs
Lower pressure loss	
Longer catalyst life guarantees	
Module design	
May be able to use carbon steel; larger modules	

Table 6. Simple Cycle without Tempering Air Considerations

Benefits	*Costs*
No fans required (save capital,operating costs; less space)	Requires a catalyst with lower V:W ratio
No risk of catalyst overheating	More volume; Higher DP
	Shorter catalyst life guarantees if >1000°F
	Management plan (extend life, reduce total volume)
	Module design
	Chrome-moly steel; Smaller modules

Summary Experience

Multiple catalyst vendors provide products for the market segment. Table 7-9 and Figure 9 show a list of the vendors, and experience information.

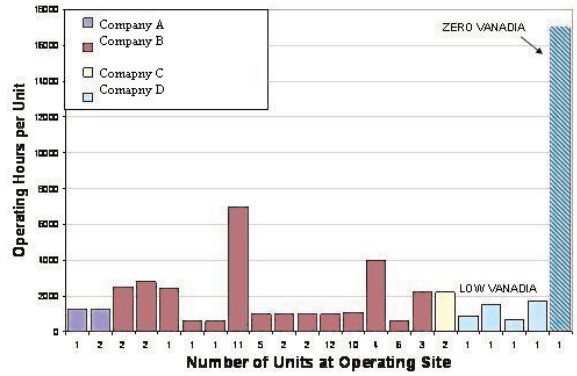

Figure 9. Select Simple Cycle Operating Experience

Table 7. SCR Catalyst Vendors

Manufacturers	*Operating Temperature Range*	*NO_x Reduction (%)*	*NO_x Limit (ppm@15% O2)*	*NH_3 Slip Limit (ppm @15% O_2)*
Manufacturer 1 (H)	700-500	75-95	2 - 5	2 - 10
Manufacturer 2 (H)	750-1100	75-95	2 - 5	2 - 10
Manufacturer 3 (WC)	850-1040	75-95	2 - 5	2 - 10
Manufacturer 4 (HY)	750-950	95	2	2
Manufacturer 5 (HY)	700-1025	71-95	2 - 5	2 - 10
Manufacturer 6 (WC)	850	80	5	10

(H) – Homogeneous Catalyst
(HY) – Hybrid Catalyst
(WC) – Wash-coated Catalyst
Source: WTUI 2006 – EPRI

Table 8. Experience without Dilution Air

Plant	*Location*	*Unit Type*	*Dilution Air*	*Catalyst Type*	*Operating Temp. (°F)*	*Operating Hours*	*Outlet NO_x (ppmvdc)*	*NH_3 Slip (ppmvdc)*
A	CA	Simple cycle LM6000	None	Zero vanadia	865	>17,000	5	20
B	CA	Simple cycle LM6000	Available	Low vanadia	828	<1,700	2.5	5
C	CA	Simple cycle LM6000	Available	Low vanadia	811	<1,450	2.5	10
D	NY	Simple cycle LM6000	Available	Low vanadia	840	>900	2.5	7
E	NY	Simple cycle LM6000	Available	Low vanadia	840	Initial start	2.5	7
F	CA	Simple cycle LM6000	Available	Low vanadia	805	>700	2.5	10
G	CA	Simple cycle 7EA	Available	Zero vanadia	1020	>200	4.2	10
H	CA	Simple cycle LM6000	Available	Low vanadia	841	Initial start	6	5
I	CA	Simple cycle LM6000	Available	Low vanadia	761	Construction	2.5	5
J	CA	Simple cycle LM6000	Available	Low vanadia	796	Construction	2.5	6
K	CA	Simple cycle LM6000	Available	Low vanadia	821	Construction	2	10
L	CA	Simple cycle LM6000	Available	Low vanadia	821	Construction	2	10
M	Japan	Simple cycle MW701F	None	Zero vanadia	1112	>3,000	NA	NA
N	Japan	Simple cycle MW501D	None	Zero vanadia	986	>4,000	NA	NA

Source: WTUI 2006 – Cormetech

Table 9. Experience with Dilution Air

Plant	*Location*	*Installation*	*Unit Type*	*Catalyst Type*	*Operating Temp. (°F)*	*Operating Hours*	*Outlet NO_x (ppmvdc)*	*NH_3 Slip (ppmvdc)*
A	NY	2002	LM6000	High Vanadia	720	>7,534	2.5	9
B	CA	2003	LM6000	High Vanadia	756	NA	2	10
C	CA	2003	LM6000	High Vanadia	756	NA	2	10
D	CA	2001	LM6000	High Vanadia	750	NA	2.5	9
E	CA	2001	LM6000	High Vanadia	750	NA	2.5	9
F	CA	2001	LM6000	High Vanadia	750	NA	2.5	9
G	CA	2002	LM6000	High Vanadia	750	NA	2.5	9
H	CA	2003	LM6000	High Vanadia	750	NA	2.5	9
I	CA	2003	LM6000	High Vanadia	750	NA	2.5	9
L	CA	2002	LM6000	High Vanadia	750	NA	2.5	9
K	CA	2002	LM6000	High Vanadia	750	NA	2.5	9
L	CA	2002	LM6000	High Vanadia	750	NA	2.5	9

Source: WTUI 2006 – Cormetech

As shown above there is a reasonable experience base for application of SCR to simple cycle combustion turbines. Table 10 shows a list of notable issues on simple cycle units which had performance issues and suggested methods to avoid problems and assure success.

Table 10. SCR Application Innovations for Simple Cycle Units

Issue	*Method to Assure Success*
Catalyst de-lamination and/or deactivation	Request detailed catalyst vendor experience and references for identical or similar units. Utilize industry user groups, technical conferences, etc. to learn of recent experience.
Poor reactor to module sealing	Confirm experience of system vendor on similar units. Confirm materials of construction are compatible.
Poor tempering air system (if applicable)	Materials of construction, start up sequence, redundancy and/or appropriate control logic for upsets.

Can SCR be applied to Integrated Gasification Combined Cycle (IGCC) power plants?

Background

Integrated Gasification Combined Cycle (IGCC) is an alternative method for generating energy by producing and burning syngas through coal gasification. IGCC competes primarily with Ultra Super Critical Pulverized Coal (USCPC) technology as the next generation of clean coal energy generation technology.

There is a vast experience base for the use of SCR on combined cycle combustion turbine applications firing natural gas and some additional limited experience firing distillate oil. However, the first SCR installations on IGCC application using coal derived syngas was built by Mitsubishi Heavy Industries (MHI) in Japan. The 250 MW Nakoso plant started up in September 2007. The basis of this design utilized experience from natural gas fired combustion turbine-heat recovery steam generator (CT-HRSG) and Mitsubishi Heavy Industries SCR experience at an IGCC plant utilizing asphalt derived syngas started in 2003.

If the syngas is as clean as natural gas the vast combustion turbine-HRSG experience base would be directly applicable. In some areas the applications do compare well, namely, NO_x reduction efficiency, ammonia slip, pressure loss requirements, applicable reagent, and temperature regime. There are a number of issues that must be addressed to assure successful operation in the areas of flue gas composition, downstream equipment considerations, and CO catalyst considerations.

Design Issues

The primary design issues to be addressed surround the flue gas composition and the resultant effects it has on the SCR and equipment design. Many

have interrelated effects; however, they are broken out into individual items below for discussion purposes:

1) Catalyst Poisons → levels and impact on catalyst design and life
2) Flue Gas SO_x → Allowable operating temperature window, applicability of CO catalyst and impact of sulfur compounds on downstream equipment
3) Particulate Loading → catalyst pitch selection, total particulate emissions

Particulate Loading

Starting with potentially the most straightforward item above, (3) Particulate loading and pitch selection. A direct comparison between catalyst pitch experience versus particulate loading, size, and characteristics should be completed to evaluate applicability. When comparing applications such as gas-fired CT-HRSG, oil-fired CT-HRSG, and coal IGCC; one should consider both the pitch of the SCR catalyst as well as CO catalyst to assess applicability. In general, it is believed that the catalyst pitch will have to be no larger than nominally three millimeters for coal based IGCC and the consideration of two millimeters is not unreasonable.

Particulate from the CT will be added to particulate created from sulfate formation (combination of NH_3 slip and SO_3) to create the total emission level. This level must be checked versus permit levels and consideration of limited ammonia slip may be required.

Catalyst Poisons

The level of "clean-up" that is performed on the syngas prior to combustion in the CT will dictate what elements/compounds and what concentration level will be seen in the CT exhaust stream and thus at the SCR catalyst. Given the compounds and level of contaminant, the SCR catalyst supplier can evaluate the potential impact on catalyst life and/or provide necessary margins or a management plan concept necessary to achieve the desired performance life, or provide recommendations for additional syngas treatment. At this time, based on the level of cleanup necessary for combustion in a CT it is expected that the SCR catalyst life will be manageable. Although sulfur, by itself, is not a direct catalyst poison it is believed that the efforts made to reduce sulfur in the syngas through carbonyl sulfide (COS) hydrolysis with Selexol or Rectisol, in order to reduce stack sulfur emissions, will further enhance the removal of other potential catalyst poisons thus minimizing catalyst deactivation concerns.

Flue Gas SO_x

The level of SO_x (SO_2 and SO_3) in the flue gas presents perhaps the largest overall issue.

Temperature: The SCR catalyst must be placed in a temperature regime which avoids potential for ammonia bisulfate formation over the load range in the catalyst and minimizes SO_2 conversion (typically < 5 percent). Ammonia bisulfate, when formed in the catalyst at sufficient levels can cause deactivation. Although reversible upon operation at temperatures above the ABS dew point, it is generally recommended to avoid ammonia bisulfate formation in the catalyst and thus avoid any temporary performance loss and/or spike in SO_3 emissions during thermal decomposition. In general it is relatively easy to select a location within the HRSG to avoid this issue.

CO catalyst: If carbon monoxide (CO) oxidation catalyst is required, strong consideration must be given to its impact on flue gas SO_3 concentrations and resultant potential impact on SCR operation and/or downstream equipment. CO catalyst may oxidize over 50 percent of SO_2 to SO_3 thus affecting SCR operating temperature regime, NH_3 slip limit recommendations and particulate emissions. Consideration of placing CO catalyst downstream of SCR may also be given provided NO_x reduction limits can still be maintained with the oxidation of ammonia slip back to NO_x.

Downstream Equipment: Formation of ammonia salts due to the presence of SO_3 and NH_3 (slip) can cause fouling issues in the downstream heat transfer equipment and contribute to particulate matter (PM) emissions. The amount of salt formation will be dictated by the concentration of NH_3 and SO_3. In most cases the quantity formed will be limited by the amount of SO_3; however, reduced NH_3 slip can also help limit the probability of formation. In order to limit the impact of sulfate formation, it is recommended to make the following considerations in the tube bundle design:

a) Utilize in-line or parallel tube arrangements instead of staggered
b) Minimize fin density (i.e. reduce fins per inch)
c) Minimize tube bundle depth such that typical cleaning methods can reach all internal tubes
d) Allow access to tubes for cleaning during outages
e) Consider on-line cleaning capability to minimize outage frequency/time

As mentioned above these issues may be further reduced by enhancing the syngas cleanup process.

Summary

The application of SCR to coal based IGCC appears feasible although it will require close attention to system design. This is supported by non-coal based IGCC SCR experience and is expected to be further supported by the first commercial operation of a Japanese plant that was scheduled for startup in 2007. Concerns related to operation temperature, downstream equipment design, maintainability, outage management can be addressed with proper design and performance expectations. Additional opportunities may exist in the enhanced understanding of syngas treatment capability and its impact on the resultant flue gas properties.

APPENDIX 1: U.S. UTILITIY APPLICATION OF SCR

STATE NAME	*PLANT NAME*	*CAPACITY (MW)*	*UNIT ID*	*START OF OPERATION*
New Jersey	Chambers Cogeneration LP	131	1	1994
New Jersey	Chambers Cogeneration LP	131	2	1994
New Jersey	Logan Generating Plant	200	GEN1	1994
Florida	Indiantown Cogeneration LP	330	GEN1	1995
New Hampshire	Merrimack	320	2	1995
New Jersey	Carney's Point	285	1	1995
New Jersey	PSEG Mercer Generating Station	310		1995
New Jersey	PSEG Mercer Generating Station	315		1995
Virginia	SEI Birchwood Power Facility	199	1	1997
New Hampshire	Merrimack	113	1	1999
New York	Kintigh (AES Somerset)	675	1	1999
Kentucky	Paradise	596	2	2000
Maryland	Brandon Shores	645	1	2000
Maryland	Brandon Shores	645	2	2000
Massachusetts	Canal	580	1	2000
Pennsylvania	Montour	745	2	2000
Georgia	Bowen	706	1BLR	2001
Georgia	Bowen	705	2BLR	2001
Kentucky	Paradise	596	1	2001
Missouri	Hawthorn	550	5	2001
Missouri	New Madrid	580	1	2001
Missouri	New Madrid	580	2	2001
New York	Milliken (AES Cayuga)	157	1	2001
North Carolina	Roxboro	350	4A	2001
North Carolina	Roxboro	350	4B	2001
Ohio	Gen J M Gavin	1300	1	2001
Ohio	Gen J M Gavin	1300	2	2001
Pennsylvania	Cheswick	570	1	2001
Pennsylvania	Homer City	620	1	2001
Pennsylvania	Homer City	614	2	2001
Pennsylvania	Homer City	650	3	2001
Pennsylvania	Montour	760	1	2001
Tennessee	Allen	248	3	2001
Texas	W A Parish	555	WAP8	2001
Alabama	Gorgas	737	10	2002
Florida	Stanton Energy	441	2	2002
Georgia	Hammond	505	4	2002
Illinois	Baldwin	581	2	2002

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
Illinois	Coffeen	560	02	2002
Indiana	Gibson	630	2	2002
Indiana	Gibson	630	3	2002
Kentucky	East Bend	600	2	2002
Kentucky	H L Spurlock	500	2	2002
Kentucky	Trimble County	435	1	2002
Maryland	Herbert A Wagner	324	3	2002
North Carolina	Cliffside	562	5	2002
North Carolina	Roxboro	385	1	2002
Ohio	Miami Fort	500	8	2002
Tennessee	Allen	248	1	2002
Tennessee	Allen	248	2	2002
Texas	W A Parish	650	WAP5	2002
Texas	W A Parish	650	WAP6	2002
Virginia	Chesterfield	326	5	2002
West Virginia	Harrison	640	1	2002
West Virginia	John E Amos	1300	3	2002
West Virginia	Mountaineer	1,300	1	2002
Alabama	James H Miller Jr	675	3	2003
Alabama	James H Miller Jr	666	4	2003
Alabama	Widows Creek	477	7	2003
Georgia	Bowen	893	3BLR	2003
Georgia	Bowen	913	4BLR	2003
Georgia	Wansley	864	1	2003
Georgia	Wansley	868	2	2003
Illinois	Baldwin	575	1	2003
Illinois	Coffeen	340	01	2003
Illinois	E D Edwards	361	3	2003
Illinois	Havana	388	6	2003
Illinois	Kincaid	554	1	2003
Illinois	Kincaid	554	2	2003
Illinois	Marion	170	4	2003
Indiana	Clifty Creek	209	1	2003
Indiana	Clifty Creek	206	2	2003
Indiana	Clifty Creek	209	3	2003
Indiana	Clifty Creek	187	4	2003
Indiana	Clifty Creek	211	5	2003
Indiana	F B Culley	250	3	2003
Indiana	Gibson	615	4	2003

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
Indiana	Merom	507	1SG1	2003
Indiana	Merom	493	2SG1	2003
Indiana	Michigan City	469	12	2003
Kentucky	E W Brown	446	3	2003
Kentucky	Ghent	498	3	2003
Kentucky	H L Spurlock	300	1	2003
Kentucky	Mill Creek	386	3	2003
Kentucky	Mill Creek	480	4	2003
Kentucky	Paradise	977	3	2003
Michigan	Dan E. Karn	265	1	2003
Michigan	Monroe	750	1	2003
Michigan	Monroe	750	4	2003
North Carolina	Belews Creek	1120	1	2003
North Carolina	Roxboro	354	3A	2003
Ohio	Ashtabula	256	10	2003
Ohio	Bay Shore	218	4	2003
Ohio	Cardinal	500	1	2003
Ohio	Cardinal	585	2	2003
Ohio	Cardinal	630	3	2003
Ohio	J M Stuart	585	1	2003
Ohio	J M Stuart	585	2	2003
Ohio	J M Stuart	585	3	2003
Ohio	J M Stuart	585	4	2003
Ohio	Killen Station	600	2	2003
Ohio	Kyger Creek	211	1	2003
Ohio	Kyger Creek	198	2	2003
Ohio	Kyger Creek	205	3	2003
Ohio	Kyger Creek	199	4	2003
Ohio	Kyger Creek	201	5	2003
Ohio	W H Zimmer	1300	1	2003
Pennsylvania	Bruce Mansfield	781	1	2003
Pennsylvania	Bruce Mansfield	785	2	2003
Pennsylvania	Bruce Mansfield	805	3	2003
Pennsylvania	Keystone	850	1	2003
Pennsylvania	Keystone	850	2	2003
South Carolina	Cross	560	1	2003
South Carolina	Cross	540	2	2003
South Carolina	Wateree	350	WAT1	2003
South Carolina	Wateree	350	WAT2	2003

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
South Carolina	Winyah	270	2	2003
Tennessee	Bull Run	879	1	2003
Tennessee	Cumberland	1224	1	2003
Texas	W A Parish	560	WAP7	2003
Virginia	Chesterfield	166	4	2003
West Virginia	Harrison	640	2	2003
West Virginia	Harrison	640	3	2003
West Virginia	Mt Storm	533	1	2003
West Virginia	Mt Storm	533	2	2003
West Virginia	Pleasants	614	1	2003
West Virginia	Pleasants	614	2	2003
Wisconsin	Pleasant Prairie	600	2	2003
Wyoming	Wygen 1	70	3	2003
Alabama	Colbert	467	5	2004
Alabama	Widows Creek	467	8	2004
Illinois	Dallman	199	33	2004
Illinois	Dallman	87	32	2004
Illinois	Dallman	86	31	2004
Illinois	Duck Creek	366	1	2004
Illinois	Mano_Il_Stcoa	18		2004
Indiana	A B Brown	250	1	2004
Indiana	A B Brown	250	2	2004
Indiana	Bailly	320	8	2004
Indiana	Gibson	630	1	2004
Indiana	Gibson	619	5	2004
Indiana	Petersburg	407	2	2004
Indiana	Petersburg	510	3	2004
Indiana	R M Schahfer	431	14	2004
Indiana	Warrick	320	4	2004
Kentucky	D B Wilson	416	W1	2004
Kentucky	Ecoa_Ky_Stcoa	268		2004
Kentucky	Elmer Smith	141	1	2004
Kentucky	Ghent	476	1	2004
Kentucky	Ghent	485	4	2004
Kentucky	HMP&L Station 2	151	H1	2004
Kentucky	HMP&L Station 2	157	H2	2004
Kentucky	R D Green	231	G2	2004
Michigan	Dan E. Karn	265	2	2004
New Jersey	Hudson	600	2	2004

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
New Jersey	Mercer	321	2	2004
North Carolina	Belews Creek	1120	2	2004
Ohio	Miami Fort	500	7	2004
Pennsylvania	Mapp_Ia_Wc	520		2004
South Carolina	Williams	560	WIL1	2004
South Carolina	Winyah	270	1	2004
South Carolina	Winyah	270	3	2004
South Carolina	Winyah	270	4	2004
Tennessee	Cumberland	1224	2	2004
Tennessee	Kingston	136	1	2004
Tennessee	Kingston	136	2	2004
Tennessee	Kingston	136	3	2004
Tennessee	Kingston	136	4	2004
Tennessee	Kingston	178	5	2004
Tennessee	Kingston	178	6	2004
Tennessee	Kingston	178	7	2004
Tennessee	Kingston	178	8	2004
Virginia	Chesapeake	156	3	2004
Virginia	Chesapeake	217	4	2004
Virginia	Chesterfield	658	6	2004
West Virginia	Mt Storm	521	3	2004
Alabama	James H Miller Jr	670	1	2005
Alabama	James H Miller Jr	669	2	2005
Florida	Crist	477	7	2005
Indiana	Harding Street Station	428	70	2005
Kentucky	Big Sandy	800	BSU2	2005
Kentucky	R D Green	240	G1	2005
Massachusetts	Brayton Point	650	3	2005
New Jersey	Mercer	321	1	2005
North Carolina	Asheville	207	2	2005
North Carolina	Roxboro	670	2	2005
Ohio	Muskingum River	575	5	2005
Ontario	Lambton	490	3	2005
Ontario	Lambton	490	4	2005
Ontario	Nanticoke	490	7	2005
Ontario	Nanticoke	490	8	2005
West Virginia	John E Amos	800	1	2005
West Virginia	John E Amos	800	2	2005
Arizona	Springerville	400	3	2006

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
Kentucky	Cooper	225	2	2006
Massachusetts	Brayton Point	250	1	2006
Massachusetts	Mount Tom	144		2006
Michigan	J.H Campbell	871	3	2006
Montana	Hardin Generator Project	105	1	2006
New York	Greenidge	113	6	2006
North Carolina	Mayo	362	1A	2006
North Carolina	Mayo	362	1B	2006
Ohio	Eastlake Unit 5	680	5	2006
Alabama	E C Gaston	861	5	2007
Indiana	Bailly	175	7	2007
Iowa	Council Bluffs	790	4	2007
Kansas	La Cygne	890	1	2007
Maryland	Morgantown	582	1	2007
Michigan	Monroe	820	3	2007
Minnesota	Allen S King	571	1	2007
Minnesota	Koda Energy	23		2007
Missouri	Asbury	212	1	2007
Missouri	Sioux Units 1	510	1	2007
Missouri	Sioux Units 2	510	2	2007
Nevada	Newmont	200		2007
New Mexico	San Juan	506	4	2007
North Carolina	Allen Station Unit 4	270	4	2007
North Carolina	Asheville	207	1	2007
North Carolina	Buck 5	142	5	2007
North Carolina	Buck 6	142	6	2007
North Carolina	Marshall 2	350	2	2007
Ohio	Conesville	800	4	2009
Ohio	Conesville	375	5	2007
Ohio	Conesville	375	6	2007
South Carolina	Cross	600	3	2007
South Carolina	Cross	600	4	2007
Tennessee	Kingston	175	9	2007
Texas	AES Deepwater	140	1	2007
West Virginia	Mitchell	800	1	2007
West Virginia	Mitchell	800	2	2007
Wisconsin	Pleasant Prairie	600	1	2007
Wisconsin	Weston	515	4	2007
Wyoming	Wygen II	90		2007

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
Alabama	Barry	750	5	2008
Alabama	Charles R Lowman	238		2008
Alabama	Nucor	99		2008
Arkansas	Plum Point	665		2008
Florida	Big Bend	421	BB01	2008
Florida	Big Bend	421	BB02	2008
Florida	Big Bend	430	BB03	2008
Florida	Big Bend	439	BB04	2008
Florida	Crystal River	807	4	2008
Florida	Deerhaven Unit 2	228	2	2008
Maryland	Morgantown	582	2	2008
Michigan	J.H Campbell	385	2	2008
Missouri	Iatan	670	1	2008
Nebraska	Nebraska City	663	2	2008
New Mexico	San Juan	495	3	2008
New Mexico	San Juan	322	1	2008
New York	AES Greenidge LLC	27	4	2008
New York	AES Greenidge LLC	27	5	2008
New York	Westover	88	8	2008
North Carolina	Allen Station Unit 5	270	5	2008
North Carolina	Marshall 1	350	1	2008
Ohio	Burger 4 & 5	127		2008
South Carolina	Cope Station	410	1	2008
Texas	J K Spruce	750	2	2008
Arizona	Springerville	400	4	2009
Colorado	Comanche	750	3	2009
Florida	Crystal River	755	5	2009
Florida	Seminole Station	650	1	2009
Florida	Seminole Station	650	2	2009
Florida	St. Johns River	600	1	2009
Florida	St. Johns River	600	2	2009
Illinois	Dallman	200	34	2009
Kentucky	Ghent	469	2	2009
Maryland	Chalk Point LLC	342	2	2009
Maryland	Chalk Point LLC	341	1	2009
Minnesota	Clay Boswell	350	3	2009
Missouri	Thomas Hill	180	1	2009
Missouri	Thomas Hill	303	2	2009
Missouri	Thomas Hill	730	3	2009

STATE NAME	PLANT NAME	CAPACITY (MW)	UNIT ID	START OF OPERATION
Nevada	TS Power Plant	200		2009
New Mexico	San Juan	320	2	2009
North Carolina	Marshall	657	3	2009
Texas	Oak Grove	800	1	2009
Texas	Oak Grove	800	2	2009
Texas	Sandow 5	600		2009
Wisconsin	Elm Road Generating Station	615	1	2009
Wyoming	Two Elk Generating Station	300		2009
Arizona	J W Turk	600	1	2010*
Kentucky	Trimble Station (LGE)	732	2	2010*
Missouri	Iatan	850	2	2010*
Missouri	Southwest	300	2	2010*
New York	AES Westover	84	13	2010*
New York	AES Westover	22	12	2010*
New York	AES Westover	22	12	2010*
Ohio	W H Sammis Unit 6	600	6	2010*
Texas	Martin Lake	855	2	2010*
Texas	Martin Lake	855	3	2010*
Wisconsin	Elm Road Generating Station	615	2	2010*
Georgia	Scherer	875	3	2011*
Louisiana	Big Cajun II	626	1	2011*
North Carolina	Cliffside	800	6	2011*
Ohio	W H Sammis Unit 7	600	7	2011*
Texas	Sandow No 4	545	4	2011*
Texas	Martin Lake	855	1	2011*
West Virginia	Longview Power	695		2011*
Wisconsin	Edgewater	430	5	2011*
Illinois	Powerton	890	5	2012*
Wisconsin	Edgewater	330	4	2012*
Illinois	Powerton	890	6	2013*

*Anticipated start-up

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