

Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

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Conventional and Hazardous Air Pollutants
from Coal-Fired Power Plants

Prepared For:

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Table of Contents

Executive Summary	1
Introduction.....	5
Transport Rule	5
Air Toxics Rule.....	7
Overview of Air Pollution Control Technologies.....	8
Methods for Controlling SO ₂ Emissions.....	8
Lower Sulfur Coal.....	9
Flue Gas Desulfurization (FGD) or “Scrubbing”	10
Wet Scrubbers.....	10
Dry Scrubbers	11
Upgrades to Existing Wet FGD Systems.....	12
Dry Sorbent Injection (DSI).....	13
Methods for Controlling NO _x Emissions	14
Combustion Controls	15
Post-Combustion NO _x Controls	16
Methods for Controlling Hazardous Air Pollutant Emissions	18
Control of Mercury Emissions.....	18
Acid Gas Control Methods	21
PM Emissions Control	23
Control of Dioxins and Furans.....	25
Labor Availability.....	26
Conclusion	27

Executive Summary

To implement requirements adopted by Congress in the federal Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) is developing new rules to reduce air pollution from fossil fuel power plants. Power plants that burn coal will bear a large responsibility for reducing their emissions further, as the majority of air pollutants from the electric generation sector come from coal combustion.

The major rules addressing power plant pollution that EPA recently proposed are the Clean Air Transport Rule (Transport Rule), and the National Emission Standards for Hazardous Air Pollutants from Electric Utility Steam Generating Units (Air Toxics Rule). The Transport Rule will address the long-range interstate transport of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) in the eastern United States. Both these types of pollutants contribute to formation of small particles (“fine particulates”) in the atmosphere that can be transported long distances into downwind states. These small particles can be inhaled deep into the lungs, causing serious adverse health impacts. Nitrogen oxides also contribute to the formation and long-range transport of ground-level ozone, another pollutant with significant health impacts. The Air Toxics Rule will address emissions of hazardous air pollutants (HAPs) such as mercury, lead, arsenic, along with acid gases such as hydrogen chloride and hydrogen fluoride and organic air toxics (e.g., dioxins and furans). HAPs are chemical pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive problems or birth defects, and that adversely affect the environment.

These regulations will require coal-fired power plants that have not yet installed pollution control equipment to do so and, in some cases, will require plants with existing control equipment to improve performance.

Over the last several decades, state and federal clean air rules to address acid rain and ground-level smog led to power plant owners successfully deploying a range of advanced pollution control systems at hundreds of facilities across the country, providing valuable experience with the installation and operation of these technologies. In addition, many states adopted mercury reduction requirements in the absence of federal rules, leading to new controls and significant reductions of this air toxic from a number of coal power plants over the past several years. This has provided industry with a working knowledge of a suite of air pollution control devices and techniques that can comply with EPA’s proposed Transport Rule and Air Toxics Rule.

This report provides an overview of well-established, commercially available emission control technologies for SO₂ and NO_x, and HAPs, such as mercury, chromium, lead and arsenic; acid gases, such as hydrogen chloride and hydrogen fluoride; dioxins and furans; and other toxic air emissions.

The key findings of the report include:

- **The electric power sector has a range of available technology options as well as experience in their installation and operation that will enable the sector to comply with the Transport Rule and the Air Toxics Rule.**
 - The electric power sector has long and successful experience installing many of the required pollution control systems.

- The first flue gas desulfurization (scrubber) system was installed in 1968 and more than 40 years later, the plant is still in operation and undergoing a performance upgrade.
 - To reduce SO₂ emissions, about 60 percent of the nation's coal fleet has already installed scrubber controls, the most capital intensive of the pollution control systems used by coal-fired power plants.
 - About half of the nation's coal fleet has already installed advanced post-combustion NO_x controls, with the first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. placed in service in 1993 and the first retrofit in the U.S. placed in service in 1995.
- **Modern pollution control systems are capable of dramatically reducing air pollution emissions from coal-fired power plants.**
- Although scrubbers installed in the 1970s and 1980s typically obtained 80-90 percent SO₂ removal, innovation has led to modern systems now capable of achieving 98 percent or greater removal.
 - SCR can achieve greater than 90 percent NO_x removal.
 - Coal-fired power plants, equipped with baghouse systems, report greater than 90 percent removal of mercury and other heavy metals.
- **Pollution controls that significantly reduce mercury emissions from coal-fired power plants have already been installed, demonstrated, and in operation at a significant number of facilities in the United States. This experience demonstrates the feasibility of achieving the mercury emissions limits in the proposed Air Toxics Rule.**
- In 2001, under cooperative agreements with the Department of Energy, several coal plant operators started full-scale testing of activated carbon injection (ACI) systems for mercury control.
 - Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for coal power plants that require mercury capture rates ranging from 80 to 95 percent. Power plants in a number of these states have already installed and are now successfully operating mercury controls that provide the level of mercury reductions sought in EPA's proposed Air Toxics Rule.
 - At present, about 25 units representing approximately 7,500 MW are using commercial technologies for mercury control. In addition, the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources, has reported about 55,000 MW of new bookings.

- **A wide variety of pollution control technology solutions are available to cost-effectively control air pollution emissions from coal-fired power plants, and many technologies can reduce more than one type of pollutant.**
- A variety of pollution control solutions are available for different plant configurations.
 - The air pollutants targeted by the Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution controls, and, in many cases, technologies to control one pollutant have the co-benefit of also controlling other pollutants. For example, scrubbers, which are designed to control SO₂, are also effective at controlling particulate matter, mercury, and hydrogen chloride.
 - Dry sorbent injection (DSI) has emerged as a potential control option for smaller, coal-fired generating units seeking to cost-effectively control SO₂ and acid gas emissions.
 - As highlighted below in Table ES-1, because of these “co-benefits,” in many cases it may not be necessary to add separate control technologies for some pollutants.

Table ES-1. Control Technology Emission Reduction Effect

	SO ₂	NOx	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
SNCR	N	Y	N	N	N	N
SCR	N	Y	C	N	N	C
Particulate Matter Controls	N	N	C	N	Y	C
Low Sulfur Fuel	Y	C	N	C	N	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Scrubber	Y	N	C	Y	C*	N
DSI	Y	C	C	Y	N	C
ACI	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect

Y = Technology reduces emissions

C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect

* When used in combination with a downstream particulate matter control device, such as a baghouse

- **The electric power sector has a demonstrated ability to install a substantial number of controls in a short period of time, and therefore should be able to comply with the timelines of the proposed EPA air rules.**
 - Between 2001 and 2005, the electric industry successfully installed more than 96 gigawatts (GW) of SCR systems in response to NOx requirements.
 - In response to the Clean Air Interstate Rule (CAIR), about 60 GW of scrubbers and an additional 20 GW of SCR were brought on line from 2008 through 2010. Notably, most companies were “early movers,” initiating the installation process before EPA finalized its rules.

- Available technologies that are less resource and time-intensive will provide additional compliance flexibility. For example, DSI and dry scrubbing technology design and installation times are approximately 12 and 24 months, respectively.
- **The electric power sector has access to a skilled workforce to install these proven control technologies.**
- In November 2010, ICAC sent a letter to U.S. Senator Thomas Carper confirming the nation’s air pollution control equipment companies repeatedly have successfully met more stringent NO_x, SO₂ and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements.
 - Also in November 2010, the Building and Construction Division of the AFL-CIO sent a letter to Senator Carper indicating that “[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development.”
 - Actual installation of pollution control equipment far exceeded EPA’s earlier estimate of industry capability that it made during the Clean Air Interstate Rule (CAIR) rulemaking.
 - In response to CAIR, boilermakers increased their membership by 35 percent in only two years (between 1999 and 2001) to meet peak labor demand.

In summary, a range of available and proven pollution control technologies exists to meet the requirements of EPA’s proposed Transport Rule and Air Toxics Rule. In many cases, these technologies, some of which have been operating for decades, have a long track record of effective performance at many coal-fired power plants in the U.S.

The electric power sector has shown that it is capable of planning for and installing pollution controls on a large portion of the nation’s fossil fuel generating capacity in a relatively short period of time. Suppliers have demonstrated the ability to provide pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well. Examples of successful pollution control retrofits are provided throughout this report.

Introduction

The U.S. Environmental Protection Agency (EPA) is currently developing two major air quality rules under the Clean Air Act (“CAA” or “the Act”) to reduce air pollution from power plants: (1) the Transport Rule, and (2) the Air Toxics Rule. These regulations will require certain power plants that have not installed pollution control equipment to do so and others to improve their performance. The discussion that follows provides an overview of these regulations, including a discussion of the sources regulated by the rules and the air pollutants the rules address. Both rules are being developed in response to court decisions overturning prior EPA regulatory programs and have long been anticipated by the electric power sector.

Transport Rule

The Transport Rule—proposed by EPA in July 2010—is designed to reduce the interstate transport of harmful air pollution from power plants in the eastern U.S. as required by the CAA. The “good neighbor” provisions of the Act require states to prohibit air pollution emissions that “contribute significantly” to a downwind state’s air quality problems.¹ For example, EPA found that power plants in West Virginia significantly affect the air quality status of counties in Ohio, Indiana, Pennsylvania, Kentucky, and Michigan—hindering these states from achieving or maintaining federal air quality standards.²

In keeping with the purpose of the “good neighbor” provisions in the Act, the Transport Rule will assist states and cities across the eastern U.S. in complying with the national, health-based fine particulate, or PM_{2.5}, and 8-hour ozone standards by limiting SO₂ and NO_x emissions from power plants in the region. Fine particulates can be inhaled deep into the lungs, and have been linked to increased hospital admissions and emergency room visits for various respiratory or cardiovascular diseases, respiratory illness and symptoms, lung function changes, and increased risk of premature death. Ground-level ozone is a respiratory irritant that adversely affects both people with respiratory disease and healthy children and adults. Exposure to ozone through inhalation can result in reduced lung function and inflamed airways, aggravating asthma or other lung diseases. As with fine particulate matter, ozone exposure is also linked to increased risk of premature death.

The Transport Rule will replace the earlier Clean Air Interstate Rule (CAIR) that EPA had issued in March 2005.³ Under CAIR, EPA limited NO_x and SO₂ emissions from 28 states and the District of Columbia, and directed each state to file a plan for meeting those limits, or emission caps. In July 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit struck down CAIR after finding several flaws in the rule.⁴ In a subsequent ruling, the court determined that CAIR could remain in place until EPA developed a replacement program.⁵

Table 1. The Clean Air Transport Rule

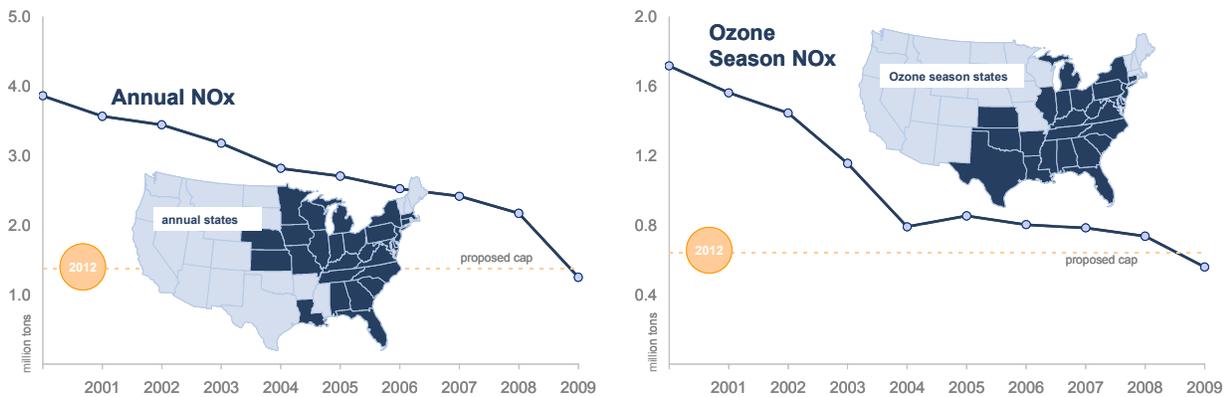
Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Sulfur dioxide (SO ₂) Nitrogen oxides (NO _x)	Fossil fuel-fired power plants 25 MW and larger in 31 eastern states and DC	Phase 1: 2012 Phase 2: 2014	EPA’s preferred approach would allow intrastate trading among covered power plants with some limited interstate trading

EPA's proposed emissions caps for SO₂ and NO_x are summarized in the following figures. EPA notes in the proposed rule that additional ozone season (May 1 to September 30) NO_x reductions will likely be needed to attain the national ozone standards.⁶ Therefore, the agency plans to propose a new transport rule in 2011, to become final in 2012, to reflect the revised National Ambient Air Quality Standards (NAAQS) for ozone when they are promulgated. While the Transport Rule only proposes to require reductions from the power sector, EPA notes, "it is possible that reductions from other source categories could be needed to address interstate transport requirements related to any new NAAQS."⁷

EPA estimates that the proposed rule would yield \$120 billion to \$290 billion in annual health and welfare benefits in 2014,⁸ which exceed the estimated \$2.8 billion in annual costs that EPA estimates power plants will incur to comply with the rule by a factor of more than 30.⁹ To meet the new requirements, EPA expects plants will employ a wide range of strategies, including operating already

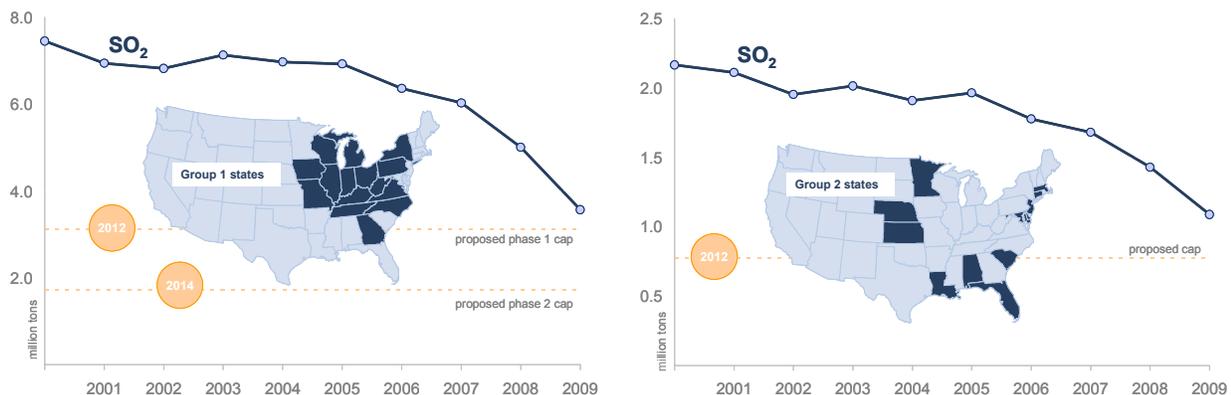
Clean Air Transport Rule: Proposed NO_x Emissions Caps

EPA's proposed Transport Rule would establish two NO_x programs: (1) an annual NO_x program, and (2) an ozone season (summer time) NO_x program (see map below). Annual NO_x emissions would be capped at 1.4 million tons per year beginning in 2012. The 2012 cap represents a 10 percent increase over 2009 emissions levels. Ozone season NO_x emissions would be capped at 0.6 million tons beginning in 2012. The ozone season cap represents a 15 percent increase over 2009 emissions levels.



Clean Air Transport Rule: Proposed SO₂ Emissions Caps

EPA's proposed Transport Rule would establish two independent trading programs for SO₂: (1) group 1 states; and (2) group 2 states (see maps below). SO₂ emissions from group 1 states would be capped at 3.1 million tons per year beginning in 2012 and 1.7 million tons per year beginning in 2014. The 2012 cap represents a 13 percent reduction below 2009 emissions levels. SO₂ emissions from group 2 states would be capped at 0.8 million tons beginning in 2012. The 2012 cap for group 2 states represents a 29 percent reduction below 2009 emissions levels.



installed pollution control equipment more frequently, using low sulfur coal, or installing new control equipment.

Air Toxics Rule

The U.S. EPA’s proposed Air Toxics Rule will establish, for the first time, federal limits on hazardous air pollutant (HAP) emissions from coal- and oil-fired power plants. The HAPs covered include mercury, lead, arsenic, hydrogen chloride, hydrogen fluoride, dioxins/furans, and other toxic substances identified by Congress in the 1990 amendments of the CAA. The rule establishes “maximum achievable control technology” (MACT) limits for many of these.

The U.S. EPA’s prior effort to regulate HAP emissions from power plants was overturned by court challenges. On February 8, 2008, a federal court held that EPA violated the CAA when it sought to regulate mercury-emitting power plants through the Clean Air Mercury Rule (CAMR), an interstate cap-and-trade program issued by EPA in March 2005.¹⁰ The court concluded that EPA violated the CAA by failing to make a specific health-based finding to remove electric generating units from regulation under CAA section 112.^a

On March 16, 2011, EPA proposed its replacement for CAMR that would establish numerical MACT emission limits for existing and new coal-fired electric power plants that would cover mercury, particulate matter (as the surrogate for non-mercury toxic metals), and hydrogen chloride (as the surrogate for toxic acid gases). The proposed rule would also establish work practice standards for organic air toxics (e.g., dioxins and furans).¹¹ EPA projects the proposed rule will reduce mercury emissions from covered power plants by 91 percent, acid gas emissions by 91 percent, and SO₂ emissions by 55 percent.¹² The projected mercury reductions are in the range of what a number of states already require for coal-fired power plants.¹³ A consent decree with public health and environmental groups requires EPA to finalize the standards by November 16, 2011. Table 2 summarizes elements of the proposed Air Toxics Rule.

EPA estimates that the Air Toxics Rule would yield \$140 billion in annual health and welfare benefits in 2016.¹⁴ The estimated annual cost of the program is \$10.9 billion.¹⁵ EPA emphasizes that the proposed rule would cut emissions of pollutants that are of particular concern for children. Mercury and lead can adversely affect developing brains—including effects on IQ, learning, and memory.

Table 2. The Air Toxics Rule

Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Mercury Non-mercury metals, such as arsenic, chromium, cadmium, and nickel Organic HAPs (e.g., dioxins/furans) Acid gases (HCl, HF)	Coal- and oil-fired power plants 25 MW and larger	Early 2015 Note: EPA can grant a one year extension for a source to install controls	Numerical emission limits for mercury, other toxic metals, and acid gases; work practice standards for organic air toxics (e.g., dioxins/furans)

^a “EPA’s removal of these [electric generating units] from the section 112 list violates the CAA because section 112(c)(9) requires EPA to make specific findings before removing a source listed under section 112; EPA concedes it never made such findings. Because coal-fired [electric generating units] are listed sources under section 112, regulation of existing coal-fired [electric generating units] mercury emissions under section 111 is prohibited, effectively invalidating CAMR’s regulatory approach.” *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

Overview of Air Pollution Control Technologies

There are a wide range of technologies available for controlling air pollution emissions from coal-fired power plants. The most appropriate combination of control technologies will vary from plant-to-plant depending on the type and size of the electric generating unit, age, fuel characteristics, and the boiler design.

Many of the air pollutants targeted by the proposed Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution control devices. Table 3 summarizes the various pollutants and the technologies that are currently being applied or may be applied in the future to control them. In many cases, technologies designed to control one pollutant will also control others. These “co-benefits” may or may not be adequate to achieve compliance with the Transport Rule or the Air Toxics Rule. As a result, in some cases, it may be necessary to add separate control technologies for some pollutants.

Table 3. Control Technology Emission Reduction Effect

	SO ₂	NO _x	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
Selective Non-Catalytic Reduction (SNCR)	N	Y	N	N	N	N
Selective Catalytic Reduction (SCR)	N	Y	C	N	N	C
Particulate Matter Controls (i.e., ESP or baghouse)	N	N	C	N	Y	C
Lower Sulfur Fuel	Y	C	N	C	N	N
Dry Scrubber	Y	N	C	Y	C*	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Sorbent Injection (DSI)	Y	C	C	Y	N	C
Activated Carbon Injection (ACI)	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect

Y = Technology reduces emissions

C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect

* When used in combination with a downstream particulate matter control device, such as a baghouse

Methods for Controlling SO₂ Emissions

SO₂ is a highly reactive gas linked to a number of adverse effects on the human respiratory system. In 2008, power plants accounted for 66 percent of the national SO₂ emissions inventory,¹⁶ with the vast majority of this contribution (more than 98 percent) coming from coal-fired power plants.¹⁷

There are two basic options for controlling SO₂ emissions from coal-fired power plants, which is formed from the oxidation of sulfur in the fuel: (1) switching to lower sulfur fuels; and (2) SO₂ capture, including Flue Gas Desulfurization (FGD), or more commonly referred to as “scrubbing.” Table 4 shows the various methods for controlling SO₂ emissions. These methods include those that have been widely used on power plants, such as low sulfur coal and scrubbing, as well as less costly technologies that may be more attractive for smaller boilers, such as dry sorbent injection (DSI).

Table 4. SO₂ Emissions Control Methods

Methods of Control	
Lower Sulfur Fuel	Method – Lower sulfur fuel reduces SO ₂ formation Reagent – None Typical fuel types – Powder River Basin coal and lower sulfur bituminous coal Capital Cost – Low Co-benefits – May reduce NO _x , HCl, and HF emissions
Dry Sorbent Injection	Method – Dry Sorbent Injection captures SO ₂ at moderate rates, downstream PM control device captures dry product Reagent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels (i.e., coals – lignite, sub-bituminous, bituminous) Capital Costs- Low to moderate Co-benefits – NO _x and HCl and HF reduction, Hg reduction, removal of chlorine, a precursor to dioxins/furans
Dry Scrubber with Fabric Filter	Method – Reagent + water react to capture acid gases and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Coal Capital Costs – High Co-benefits – High SO ₂ and Hg capture (esp. bituminous coals), high PM and HCl capture
Wet Scrubber	Method – Reagent + water react to capture acid gases Reagent – Limestone, lime, caustic soda Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – High Co-benefits – Highest SO ₂ capture, high oxidized Hg and high HCl capture, PM capture
Wet Scrubber Upgrades	Method – Upgrade older scrubbers to provide performance approaching those of new scrubbers Reagent – Limestone, lime, etc. Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – Low to moderate Co-benefits – Same as wet scrubber
Co-benefit Methods of Control	
None	SO ₂ is a key pollutant that often is the major driver in emission control technology selection

Lower Sulfur Coal

Changing to lower sulfur coal was the most widely used approach for compliance with the Acid Rain Program (Title IV of the 1990 Clean Air Act Amendments). Certain coal types are naturally low in sulfur, such as sub-bituminous coal mined in the Powder River Basin (PRB) of Montana and Wyoming.^b

Some facilities cannot burn 100 percent PRB coal without substantial modifications to the boiler or fuel handling systems. These facilities can blend PRB or another lower sulfur coal with a bituminous coal to reduce emissions. Facilities that are not able to burn lower sulfur coals or facilities needing greater SO₂ emissions reductions may need some form of flue gas treatment.

^b Coal is classified into four general categories, or “ranks.” They range from lignite through sub-bituminous and bituminous to anthracite. Sub-bituminous and bituminous coals are the most widely used coal types, and the SO₂ emissions from burning these fuels can vary by a factor of 10 or more, depending upon the fuel sulfur content and the heating value of the fuel. Lignite fuels have low heating values, making them uneconomical to transport, and are generally limited in use to mine-mouth plants. Anthracite coal is used in very few power plants.

Co-benefits of low sulfur coal – PRB coal is relatively low in nitrogen, which results in lower NO_x emissions. It is also very low in chlorine, so hydrogen chloride (HCl) emissions are low for PRB coal.

Flue Gas Desulfurization (FGD) or “Scrubbing”

As EPA and states have further limited SO₂ emissions, an increasing number of coal-fired power plants have installed FGD systems. FGD controls enable a plant operator to use a wider variety of coals while maintaining low SO₂ emissions. There are two basic forms of FGD – wet and dry. As shown in Table 5, nearly two-thirds of the coal-fired power plant capacity in the United States is scrubbed or is projected to be scrubbed in the near future. Most plant operators have opted for wet FGD systems, particularly on larger coal-fired power plants. In response to the Clean Air Interstate Rule, coal-fired power plants added about 60 gigawatts (GW) of scrubbers in the three year period from 2008 through 2010.¹⁸

Scrubber Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
FGD (wet)	170 GW (52%)	371	457
FGD (dry)	22 GW (7%)	114	196
Total Scrubbed	192 GW (59%)	485	396
No scrubber	134 GW (41%)	788	171
Total	326 GW	1,273	256

Wet Scrubbers

Wet scrubbers are capable of high rates of SO₂ removal. In a wet FGD system, a lime or limestone slurry reacts with the SO₂ in the flue gas within a large absorber vessel to capture the SO₂, as shown in Figure 1.²⁰ Wet FGD systems may use lime or limestone. Lime is more reactive and offers the potential for higher reductions with somewhat lower capital cost; however, lime is also the more expensive reagent. As a result, limestone-forced oxidation (LSFO) wet scrubber technology is the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO₂ removal – on the order of 98 percent or more.

The first wet scrubber system in the U.S. was designed by Black & Veatch and installed in 1968 at the Lawrence Energy Center in Kansas. More than 40 years later, the system is still in operation, and the facility is undertaking a major upgrade to improve the system’s performance. The facility is also adding a pulse jet fabric filter.²¹

In the absorber, the gas is cooled to below the saturation temperature, resulting in a wet gas and high rates of capture. Modern wet scrubbers typically have SO₂ removal rates of over 95 percent and can be in the range of 98 percent to 99 percent.²² The reacted

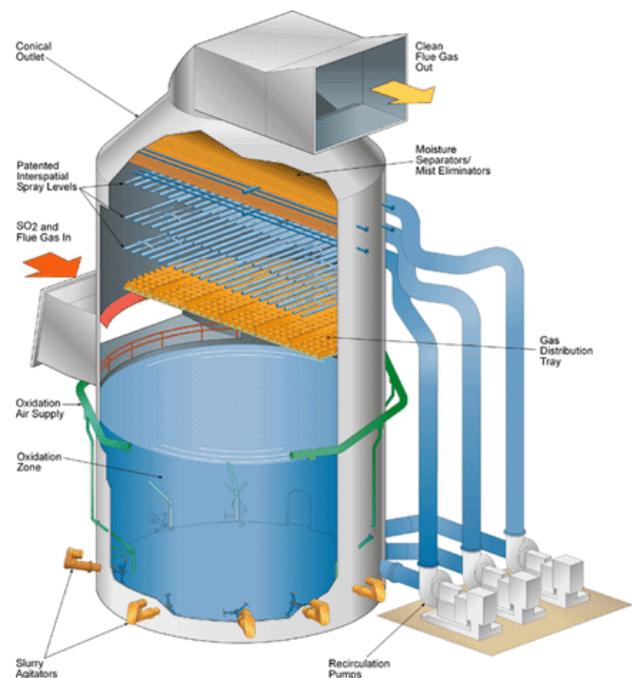


Figure 1. Wet Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

limestone and SO₂ form a gypsum by-product that is often sold for the manufacturing of wallboard.

Because a wet FGD system operates at low temperatures, it is usually the last pollution control device before the stack. The wet FGD absorber is typically located downstream of the PM control device (most often an electrostatic precipitator though many power plants have baghouses) and immediately upstream of the stack. Wet FGD is frequently used to treat the exhaust gas of multiple boilers with the gases being emitted through a common stack. A single absorber can handle the equivalent of 1,000 megawatts (MW) of flue gas.

Wet scrubber retrofits are capital intensive due to the amount of equipment needed, and recent installations for the Clean Air Interstate Rule have been reported to have an average cost of \$390/kW.²³ EPA estimates a capital cost of about \$500/kW (\$2007) for a wet scrubber (limestone forced oxidation) on a 500 MW coal unit.²⁴ There can be, however, a significant variation in costs depending upon the size of the unit and the specifics of the site. Generally, smaller boilers (under 300 MW) have been shown to be significantly more expensive to retrofit with wet scrubbers (capital cost normalized to a \$/KW basis) than larger boilers due to economies of scale. The economies of scale become less significant as boiler size increases.²⁵ As a result, wet scrubbers are a less attractive alternative for controlling SO₂ on small units. Companies can sometimes offset the cost of installing wet scrubber technology by switching to less expensive high sulfur coal supplies. Because of the high capital costs of the technology, wet scrubbers are generally only installed on power plants where the owner expects to operate the plant for an extended number of years.

Due to their complexity and the size of the equipment, EPA estimates that the total time needed to complete the design, installation, and testing of a wet FGD system at a typical 500 MW power plant with one FGD unit is 27 months, and longer if multiple boilers or multiple absorbers are necessary. Actual installation times will vary based upon the specifics of the plant, the need to schedule outages with FGD hook up, and other factors.

Co-benefits of wet FGD – FGDs have been shown to be effective at removing other pollutants including particulate matter, mercury, and hydrochloric acid. For this reason, facilities that are equipped with wet or dry FGD systems may avoid the need to install additional controls for hazardous air pollutants.

Dry Scrubbers

Dry scrubber technology (dry FGD) injects hydrated lime and water (either separately or together as a slurry) into a large vessel to react with the SO₂ in the flue gas. Figure 2 shows a schematic of a dry scrubber.

The term “dry” refers to the fact that, although water is added to the flue gas, the amount of water added is only just enough to maintain the gas above the saturation (dew point) temperature. In most cases, the reaction products and any unreacted lime from the dry FGD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of SO₂. Modern dry FGD systems typically provide SO₂ capture rates of 90 percent or more.

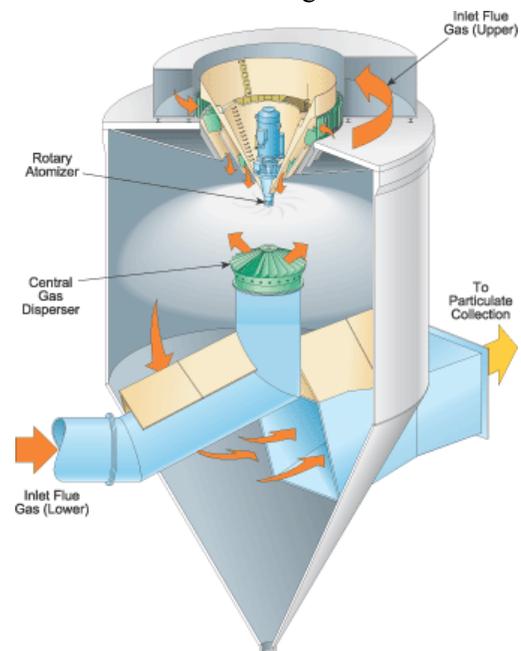


Figure 2. Dry Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

Historically, dry FGDs have been used primarily on low sulfur coals because the reagent, lime, is more expensive than reagents used in wet FGD systems. Also, because the systems are designed to maintain the flue gas temperatures above the dew point, this limits the amount of SO₂ that can be treated by a spray dryer. Another form of dry FGD, circulating dry scrubber systems (CDS), inject the water and lime separately, and have been shown to achieve high SO₂ removal rates in excess of 95 percent on higher sulfur coals. Lime is more costly than limestone, the most commonly used reagent for wet scrubber systems.

Case Study: Dry Scrubber

In Massachusetts, First Light's Mt. Tom Power Plant, a 146 MW coal-fired unit that went into service in 1960, installed state-of-the-art pollution control equipment in 2009 to meet state and federal environmental regulations. In December 2009, the plant installed a circulating dry scrubber to reduce SO₂ and mercury emissions during a routine outage. A precipitator and baghouse were also installed to remove particulate matter emissions. Total project costs were \$55 million, or \$377/kW. The project has reduced the plant's SO₂ emissions by approximately 70 percent, with the plant's 2009 SO₂ emission rate of 0.73 lbs SO₂/mmBtu dropping to 0.22 lbs SO₂/mmBtu in 2010.

Source: U.S. Environmental Protection Agency, Clean Air Markets-Data and Maps; <http://camdataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard> (accessed March 17, 2011).

Dry FGD systems tend to be less expensive than wet FGD systems because they are less complex and generally smaller in size. They also use less water. The lower reagent cost of wet FGD and the ability to burn lower cost, higher sulfur coals make wet FGD more attractive for large facilities. EPA estimates a capital cost of about \$420/kW (\$2007) for a dry scrubber (lime spray dryer) on a 500 MW coal unit.²⁶ The Turbosorp system installed at the AES Greenidge plant in New York cost \$229/KW (\$2005).²⁷ Depending upon the specifics of the facility to be retrofit, the cost could be higher in some cases.

Dry FGD systems are less complex and generally require less time to design and install than wet FGD systems. The Institute to Clean Air Companies (ICAC) estimates that dry scrubbers can be installed in a time frame of 24 months.²⁸

Co-benefits of Dry FGD – Dry FGD pollutant co-benefits include greatly enhanced capture of hazardous air pollutants, especially PM, mercury and HCl (as discussed later in the report).

Upgrades to Existing Wet FGD Systems

Modern wet FGD systems are capable of SO₂ removal rates in the range of 98 percent or more. Limestone wet scrubber removal efficiencies have improved dramatically since the 1970s as shown in Figure 3.²⁹ As a result, there are opportunities to improve scrubber performance from many existing scrubbers that were built in the 1970s and 1980s. An advantage of this approach is that substantial SO₂ reductions are possible at a far lower cost than installing a new scrubber and in a much shorter period of time. Each scrubber upgrade is unique, so cost and schedule will vary. Depending upon the scope of a scrubber upgrade, a scrubber upgrade could be implemented in under a year as opposed to three to four years for a new scrubber installation. All key areas of many older FGD systems (absorber, reagent preparation, and dewatering) can benefit from modern upgrades. Because each system is unique, an

effective FGD system-wide upgrade process is most successful after an extensive system review and diagnostics.

There have been numerous examples of FGD upgrades over the last several years that have improved SO₂ removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO₂ removal efficiency of 95.5 percent.³⁰ In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO₂ removal efficiency.³¹ In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009.³² The scrubber upgrades increased SO₂ removal efficiency from 91 percent to 97 percent.³³

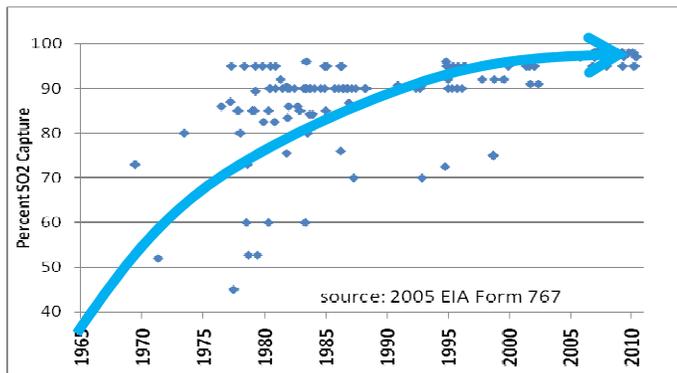


Figure 3. Historical Trends in Limestone Wet Scrubber SO₂ Removal Efficiency of Limestone Wet Scrubbing Systems

Dry Sorbent Injection (DSI)

DSI is the injection of dry sorbent reagents that react with SO₂ and other acid gases, with a downstream PM control device to capture the reaction products.

The most common DSI reagent in use is Trona, a naturally occurring mixture of sodium carbonate and sodium bicarbonate mined in some western states. Other reagents have also been used, such as sodium bicarbonate and hydrated lime. Sodium bicarbonate is capable of higher SO₂ removal efficiencies than Trona because it is more reactive. Trona can achieve varying levels of SO₂ reductions, from a range of 30-60 percent when injected upstream of an ESP, or up to 90 percent when injected upstream of a fabric filter. Fabric filters allow greater contact between the gas and the injected sorbent than ESPs, enabling better removal for any given reagent treatment rate. The level of removal will vary depending upon the circumstances of the facility and the injection system.

DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.³⁴ Unlike scrubbers that require additional reaction chambers to be installed, in DSI the reaction occurs in the existing ductwork and air pollution control equipment. The basic injection system with storage silo costs around \$20/kW; however, in some cases additional storage and material handling may be necessary that will add cost. But, even with the additional equipment, the capital cost of a DSI system will be substantially less than that of a full wet or dry scrubber, which can cost as high as \$400/kW. Reagents used in DSI are more costly than those used in wet or dry scrubbers, and the reagent is not as efficiently utilized, which can contribute to a higher cost of control in terms of dollars per ton of SO₂ reduced.

Case Study: Dry Sorbent Injection

Conectiv Energy installed a DSI Trona system at Edge Moor Units 3-4 to comply with Delaware's multi-pollutant emissions control rule. The project was several years in planning and operated from 2009 to mid-2010. The emission rates went from 1.2 lbs SO₂/mmBtu to 0.37 lbs SO₂/mmBtu with the use of Trona. Since the purchase of the facility by Calpine in mid-2010, coal is no longer burned thus eliminating the need for the Trona system. In New York, NRG installed a Trona system at its Dunkirk (530 MW) and Huntley stations (380 MW). This project is the first of its kind in the U.S. in which Trona and powder-activated carbon (PAC) are simultaneously injected into the flue gases to control both SO₂ and mercury emissions. The DSI system included several Trona storage and injection systems with equipment buildings, 6000 feet of transport piping, Trona railcar unloading and transfer systems, and associated bulk storage silos. Performance tests indicate that emissions of SO₂ have been reduced by over 55 percent, mercury levels have been reduced by over 90 percent, and particulate levels have been reduced to less than 0.010 lbs/mmBtu.

Source: Pietro, J. and Streit, G. (NRG Energy). "NRG Dunkirk and Huntley Environmental Retrofit Project." Presented to Air & Waste Management Association – Niagara Frontier Section, September 23, 2010.

Co-benefits of DSI – DSI has been shown to be very effective in the capture of the acid gases, HCl and HF. DSI has been shown to enhance mercury capture for facilities that burn bituminous coal by removing sulfur trioxide (SO₃) that is detrimental to mercury capture through ACI. In the case of PRB coals, the impact on mercury capture might be negative. Injection of Trona or sodium bicarbonate can also remove NO_x in the range of 10-20 percent, although NO_x removal is generally not a principal objective of DSI.³⁵ If DSI is installed at a point in the gas stream that is upstream of the dioxins/furans formation temperature, it is expected to remove the precursor chlorine that leads to their production.

Methods for Controlling NO_x Emissions

Nitrogen oxides (NO_x) are an acid rain precursor and a contributor to the formation of ground-level ozone, which is a major component of smog. In 2008, power plants accounted for 18 percent of the national NO_x emissions inventory. Most of the NO_x formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NO_x; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NO_x. Controlling NO_x emissions is achieved by controlling the formation of NO_x through combustion controls or by reducing NO_x after it has formed through post-combustion controls. Table 6 summarizes key NO_x control technologies.

Table 6. NOx Emissions Control Methods

Methods of Control	
Combustion Controls	Method – Reduce NOx formation in the combustion process itself for levels of reduction that vary by application Reagent – None Typical fuel types – All fuels Capital Cost – Low to moderate Co-benefits – Potential impacts on Hg, CO and precursors of dioxins/furans
Selective Non-Catalytic Reduction	Method – Reagent injected into furnace reacts with and reduces NOx at moderate removal rates of about 30% Reagent – Urea or ammonia Typical Fuel Types – Most often solid or liquid fuels Capital Costs- Low Co-benefits - None
Selective Catalytic Reduction	Method – Reagent reacts with NOx across catalyst bed and reduces NOx at high rates of about 90% Reagent – Ammonia (or urea that is converted to ammonia) Typical Fuel Types – Any fuel Capital Costs – High Co-benefits – Oxidation of Hg for easier downstream capture in a wet scrubber, reduction of dioxins/furans
Co-benefit Methods of Control	
Low Sulfur Coal	Conversion to PRB coal for SO ₂ reduction will also reduce NOx due to lower fuel nitrogen in PRB coal
Dry Sorbent Injection	DSI with Trona can provide NOx reduction of about 10-15%

Combustion Controls

Combustion controls minimize the formation of NOx within the furnace and are frequently the first choice for NOx control because they are usually lower in cost than post-combustion controls. For most forms of combustion control, once installed there is little ongoing cost because there are no reagents or catalysts to purchase. Combustion controls reside within the furnace itself, not in the exhaust gas stream, and include such methods as low NOx burners (LNB), over-fire air (OFA), and separated over-fire air (SOFA). Reburning technology is another combustion control option, but it chemically reduces NOx formed in the primary combustion zone. Reburning technology may also utilize natural gas.

Most utilities have already achieved substantial reductions in NOx emissions from implementation of combustion controls, sometimes in combination with post-combustion controls. There are some facilities that can still benefit from combustion controls, but these are generally the smaller units where utilities have not yet invested in NOx controls.

The capital cost of these combustion controls will vary; however, the capital cost is generally far less than that of more costly post-combustion control options, such as Selective Catalytic Reduction (SCR). The capital costs of combustion controls could be anywhere from about \$10/kW to several times that, but generally fall below \$50/kW. Except for gas reburning, there is little or no increase in operating or fuel costs.

Co-benefits of Combustion NOx Controls – Combustion controls may enhance mercury capture at coal-fired power plants because they can increase the level of carbon in the fly ash. While higher carbon in the

fly ash is generally viewed negatively because it is the result of incomplete combustion, it does provide a real benefit in enhancing mercury capture. Combustion controls can also have a positive impact on CO emissions and on concentrations of organic precursors to dioxins/furans.

Post-Combustion NOx Controls

There are limits to the level of NOx control that can be achieved with combustion controls alone. Therefore, post-combustion controls are necessary to achieve very low emissions of NOx. Combustion NOx controls and post-combustion NOx controls can, and often are, used in combination. About half of the nation’s coal fleet has already installed advanced post-combustion NOx controls (Table 7).

Table 7. Coal-Fired Power Plant Post-Combustion NOx Controls³⁶			
Control Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
SCR	129 GW (40%)	259	499
SNCR	29 GW (9%)	172	166
Total Post-Combustion NOx	158 GW (49%)	431	366
No Post-Combustion NOx	842 GW (51%)	842	198
Total	324 GW	1,273	255

Selective Catalytic Reduction (SCR)

SCR technology, which has been in use at coal-fired power plants for more than 15 years in the United States, is a post-combustion NOx control system that is capable of achieving greater than 90 percent removal efficiency.³⁷ The first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. was placed in service in 1993 in New Jersey, and the first retrofit in the U.S. went into service in 1995 at a power plant in New Hampshire.³⁸ About 130 GW of the total coal-fired generating capacity in the U.S. is now equipped with SCR, and more SCRs are planned for existing units. Between 2001 and 2005, the electric industry installed more than 96 GW of SCR systems in response to the NOx SIP Call. Coal plant operators installed an additional 20 GW of SCR from 2008 through 2010 in response to the Clean Air Interstate Rule.³⁹

SCR utilizes ammonia as a reagent that reacts with NOx on the surface of a catalyst. The SCR catalyst reactor is installed at a point where the temperature is in the range of about 600°F-700°F, normally placing it after the economizer and before the air-preheater of the boiler. The SCR catalyst must periodically be replaced. Typically, companies will replace a layer of catalyst every two to three years. Multiple layers of catalysts are used to increase the reaction surface and control efficiency (Figure 4).

SCR system capital costs will vary over a wide range depending upon the difficulty of the retrofit. Some retrofits have been reported to cost under \$100/kW, while others have been reported to cost over \$200/kW.⁴⁰ Operating costs include ammonia reagent, periodic catalyst replacement, parasitic power, and fixed operating costs.

The EPA estimates that the total time needed to complete the design, installation, and testing at a facility with one SCR unit is about 21 months, and longer for plants that have multiple units to be retrofitted with SCR.⁴¹

Selective Non-Catalytic Reduction (SNCR)

SNCR is another post-combustion NO_x control technology. It typically achieves in the range of 25-30 percent NO_x reduction on units equipped with low NO_x burners. SNCR reduces NO_x by reacting urea or ammonia with the NO_x at temperatures around 1,800°F-2,000°F. Therefore, the urea or ammonia is injected into the furnace post-combustion zone itself and, like SCR, reduces the NO_x to nitrogen and water.

The capital cost of SNCR is typically much less than that of SCR, falling in the range of about \$10-\$20/KW, or about \$4 million or less for a 200 MW plant. The operating cost of SNCR is primarily the cost of the ammonia or urea reagent. SNCR is most commonly applied to smaller boilers. This is partly because the economics of SCR are more challenging for small boilers. Furthermore, when emissions regulations allow averaging or trading of NO_x emissions among units under a common cap, installing an SCR on a large boiler allows utilities to over-control the large unit and use less costly technology, such as SNCR or combustion controls, for NO_x control on smaller units.

SNCR systems are relatively simple systems that can be installed in a period of about 12 months.

Hybrid SNCR/SCR

SNCR and SCR may be combined in a “hybrid” manner. In this case, a small layer of catalyst is installed in ductwork downstream of the SNCR

system. With the downstream catalyst, the SNCR system can be operated in a manner that provides higher NO_x removal rates while using the SCR catalyst to mitigate the undesirable ammonia slip from the SNCR system. Although some NO_x reduction occurs across the SCR catalyst, its function is primarily as a means to reduce ammonia slip to an acceptable level. This approach has been demonstrated at the Greenidge power plant in upstate New York, but has not been widely adopted.⁴² For some smaller boilers that can accommodate the needed ductwork modifications necessary for “hybrid” SNCR/SCR, this may be an attractive technology for reducing NO_x emissions beyond what SNCR is able to achieve.

The hybrid SNCR/SCR system installed at Greenidge was part of a multi-pollutant control system designed to demonstrate a combination of controls that could meet strict emissions standards at smaller coal-fired power plants.⁴³ The multi-pollutant control system was installed on AES Greenidge Unit 4, a 107 MW, 1953-vintage tangentially-fired boiler. The facility fires high sulfur eastern U.S. bituminous coal. The multi-pollutant control system consists of a hybrid SNCR/SCR technology to control NO_x, a circulating fluidized bed dry scrubbing technology to control SO₂, mercury, SO₃, hydrogen chloride, and

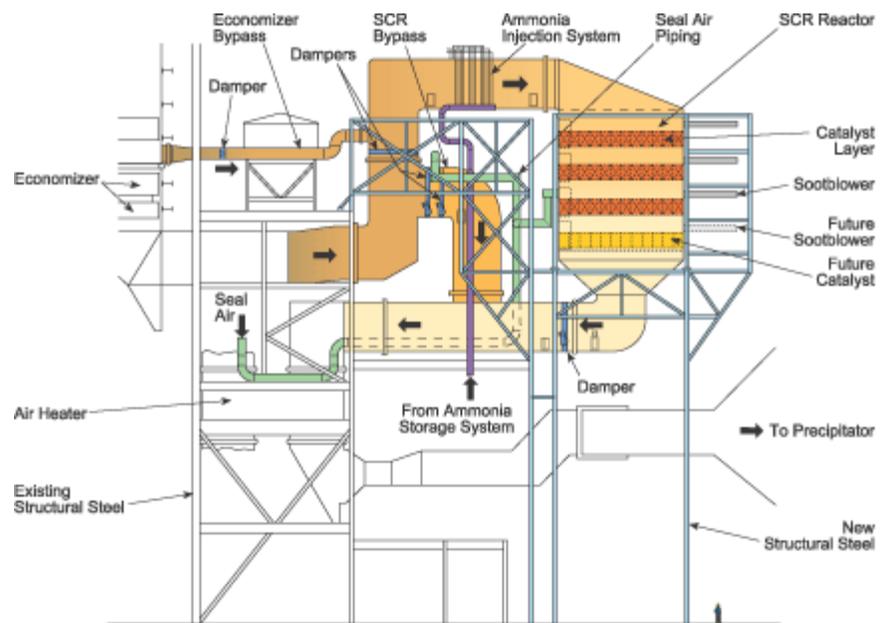


Figure 4. Selective Catalytic Reduction (Retrofit Installation)
Image courtesy of Babcock and Wilcox Company

particulate matter, and an activated carbon injection system to control mercury emissions. Total capital cost of the system was \$349/kW (2005\$), about 40 percent less than the estimated cost of full SCR and wet scrubbers—\$114/kW for the hybrid SNCR/SCR system, \$229/kW for the circulating dry scrubber system and \$6/kW for the activated carbon injection system. The plant has achieved 95 percent SO₂ control, 98 percent mercury removal, and 95 percent SO₃ and HCl removal.⁴⁴

Co-benefits of post-combustion NOx controls – SNCR has no known co-benefit effects on other pollutants. SCR, on the other hand, has the co-benefit effect of enhancing oxidation of elemental mercury, especially for bituminous coals. The effect of mercury oxidation is to enhance mercury capture in a downstream wet FGD because the resulting ionic mercury is extremely water soluble. Several field and pilot studies conducted in the U.S. have found increases in oxidized ionic mercury with the use of SCR controls.^{45,46,47,48} For example, testing conducted at the Mount Storm coal-fired power plant in West Virginia evaluated the effect of the unit’s SCR system on mercury speciation and capture.⁴⁹ The facility fires a medium sulfur bituminous coal. The test program found that the presence of an SCR catalyst can significantly affect the mercury speciation profile. Measurements showed that the SCR catalyst improved the mercury oxidation to levels greater than 95 percent, almost all of which was captured by the downstream wet FGD system. In the absence of the SCR catalyst, the extent of oxidation at the inlet of the FGD system was only about 64 percent. This effect, however, is much reduced with PRB coals because halogen content in PRB coals is low. SCR catalyst can also mitigate emissions of dioxins and furans.^{50,51}

Methods for Controlling Hazardous Air Pollutant Emissions

HAPs from power plants include mercury, acid gases (HCl and HF), heavy metals (nickel, chromium, arsenic, selenium, cadmium, and others), and organic HAPs (dioxins and furans). Many HAPs emitted by power plants are captured to some degree by existing air pollution control technologies. However, EPA’s proposed Air Toxics Rule will establish emissions standards that will require additional controls be installed. For each of these HAPs, the potential methods for capture are discussed below.

Control of Mercury Emissions

Mercury is found within coal, with its concentration varying widely by coal type and even within coal types. The mercury is released during combustion and becomes entrained in a power plant’s flue gas in one of three forms; particle-bound mercury, gaseous elemental mercury, and gaseous ionic mercury. Table 8 lists available methods to control mercury emissions for coal units.

Table 8. Mercury Emissions Control Methods

Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous Hg, converting to particle Hg that is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Some capture of dioxins/furans
Halogen Addition	Method – Halogen (bromine) addition to flue gas increases oxidized Hg that is easier to capture in a downstream scrubber or in PM control device Reagent – Halogen containing additive Capital Costs – Negligible Co-benefits – None
Co-benefit Methods of Control	
PM Controls (ESP, FF, multicyclone)	Method – Captures particle-bound mercury
Dry Sorbent Injection	Method – Increases co-benefit and ACI Hg capture by removing SO ₃ , which suppresses mercury capture
Dry Scrubber with Fabric Filter	Method – Hg captured in downstream fabric filter
Wet Scrubber	Method – Oxidized mercury captured in wet scrubber
NOx Catalyst	Method – Catalyst in SCR increases oxidation of Hg that is more effectively captured in downstream wet scrubber

Activated Carbon Injection (ACI)

Mercury is often captured using injection of powdered activated carbon (activated carbon injection – ACI) and capture of the injected carbon on a downstream PM capture device (ESP or a baghouse). An ACI system is relatively simple and inexpensive, consisting of storage equipment, pneumatic conveying system, and injection hardware (“injection lances”). Under cooperative agreements with the U.S. Department of Energy, several coal plant operators conducted full-scale testing of ACI systems in 2001.⁵²

ACI has been used to capture mercury by effectively converting some of the gaseous ionic and elemental mercury to a particle-bound mercury that is captured in a downstream particulate matter control device, such as an ESP or fabric filter. ACI is very effective at removing mercury except if high sulfur coals are used, or if SO₃ is injected for flue gas conditioning for ESPs, or if the facility has a hot-side ESP and no downstream air pollution controls. SO₃ interferes with mercury capture by ACI; however, upstream capture of SO₃ by DSI, if one is in place, should enable ACI to be more effective at capturing mercury. Fortunately, most of the installed capacity of boilers firing high sulfur fuels is scrubbed and may not need ACI.

Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for power plants that require mercury capture rates ranging from 80 to 95 percent.⁵³ At present, about 25 units representing about 7,500 MW are using commercial ACI technologies for mercury control. In addition, about 55,000 MW of new bookings are reported by the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources.⁵⁴

ACI systems cost in the range of \$5/kW and can be installed in about 12 months or less, assuming a baghouse is installed. PSEG’s Bridgeport Harbor Generating Station completed the construction and

installation of a baghouse and ACI system in under 2 years. The final connection of the controls was completed during a six to eight week outage.

Case Study: ACI Controls

In response to a 2006 Minnesota state mercury law, Xcel Energy agreed to install an ACI system on the 900 MW Unit 3 at its Sherburne County plant (Sherco 3). The unit, which burns low sulfur western coal from Montana and Wyoming, already had a dry scrubber operating to reduce SO₂ emissions. Once it has been tuned to the unit's operational specifications, the ACI system is expected to reduce the plant's mercury emissions by about 90 percent. The system was completed in December 2009 for a total capital cost of \$3.1 million, or \$3.46/kW. Wisconsin Power and Light installed ACI controls at its Edgewater Generating Station. The system was operational in the first quarter of 2008. Edgewater Unit 5 is a 380 MW plant that fires PRB coal and is configured with a cold-side ESP for particulate control. The total installed costs of the Edgewater Unit 5 ACI system was approximately \$8/kW, or approximately \$3.04 million.

Source: Southern Minnesota Municipal Power Agency. "Sherco 3: Environmental Controls." August 2010, <http://www.smmpa.com/upload/Sherco%203%20brochure%202010.pdf> (accessed March 17, 2011).

Starns, T., Martin, C., Mooney, J., and Jaeckels, J. "Commercial Operating Experience on an Activated Carbon Injection System, Paper #08-A-170-Mega-AWMA." Power Plant Air Pollutant Control MEGA Symposium. Baltimore, MD. August 25-28, 2008.

Co-benefits of ACI – ACI co-benefits include the reduction of dioxins and furans.

Halogen Addition

For applications where there is inadequate halogen for conversion of elemental mercury to ionic mercury, such as some western coals, the addition of halogen will increase mercury conversion to the ionic form and will permit higher capture efficiency through co-benefit capture or by ACI. Addition of halogen to PRB coals or to activated carbon injected for mercury capture has been shown to make mercury capture from PRB fired boilers with halogen addition generally high.⁵⁵

Co-Benefit Methods for Mercury Capture

Of the three mercury forms previously mentioned, particle-bound mercury is the species more readily captured as a co-benefit in existing emission control devices, such as fabric filters (also called "baghouses") or electrostatic precipitators (ESPs). Ionic mercury has the advantage that it is extremely water soluble and is relatively easy to capture in a wet FGD/scrubber. Ionic mercury is also prone to adsorption onto fly ash or other material, and may thereby become particle-bound mercury that is captured by an ESP or fabric filter. Elemental mercury is less water soluble and less prone to adsorption, thus remains in the vapor phase where it is not typically captured by control devices unless first converted to another form of mercury more readily captured.

Fabric filters generally provide much higher co-benefit mercury capture than ESPs. Bituminous coal-fired boilers with fabric filters can have high rates of mercury capture based on data collected by the U.S. EPA during its Information Collection Request (ICR) supporting the development of the Air Toxics Rule.⁵⁶

Wet scrubbers with SCR controls upstream have been shown to be very effective in removing oxidized (ionic) mercury. Therefore, when a wet scrubber is present, it is beneficial to take measures to increase the oxidation of mercury upstream of the wet scrubber. Catalysts in SCR systems promote oxidation of mercury, and SCR controls upstream of a wet FGD system have been shown to provide high mercury capture in the range of 90 percent when burning bituminous coals.⁵⁷ The precise level of oxidation and capture will vary under different conditions. In a study by the Southern Company, five of its plants with SCR and scrubbers captured an average of 87 percent of mercury over a period of several months.⁵⁸

Co-benefit capture rates of mercury in ESPs, fabric filters, scrubbers, or other devices for bituminous coals are generally greater than that for PRB coals. This is because the higher halogen content (e.g., chlorine) found in eastern coals promotes formation of oxidized mercury.⁵⁹

Acid Gas Control Methods

Strong acids, such as hydrogen chloride (HCl) and hydrogen fluoride (HF), result from the inherent halogen content in the coal that is released during combustion to form acids as the flue gas cools. As with mercury content, the concentration of halogens in the coal varies widely by coal type and even within coal types. Chlorine is of greatest concern because it is usually present in higher concentrations than other halogens in U.S. coals. The U.S. EPA's proposed Air Toxics Rule for power plants sets a numerical emission limit for HCl. The HCl limit also functions as a surrogate limit for the other acid gases, which are not given their own individual emission limits under the proposed rule.

Table 9 shows HCl emission control methods for coal boilers. In principle, wet and dry SO₂ scrubbers can be used for the control of HCl and HF on power plant boilers; however, these are not likely to be necessary because lower cost methods exist. For those facilities with wet or dry scrubbers for SO₂ control, these units will likely provide the co-benefit of HCl capture. For those units that are unscrubbed, these will likely be adequately controlled through retrofit with DSI systems, and a fabric filter.

Table 9. HCl Emissions Control Methods

Methods of Control	
Dry Sorbent Injection	Method – Dry sorbent captures HCl, downstream PM control device captures dry product Regent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels with PM control Capital Costs – Low to moderate Co-benefits – NO _x and SO ₂ reduction, Hg reduction, removal of chlorine precursor leading to lower dioxins/furans formation
Dry Scrubber with fabric filter	Method – Reagent + water react to capture acid gas and dry product captured in downstream fabric filter Regent – Hydrated lime Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – High Hg capture (esp. bituminous coal), high SO ₂ capture, high PM capture
Wet Scrubber	Method – Reagent + water react to capture acid gas Regent – Limestone, lime, caustic soda Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Highest SO ₂ capture, high oxidized Hg capture, some PM capture
Co-benefit Methods of Control	
Wet or Dry Scrubbers	Method – SO ₂ scrubber has high HCl removal efficiency
Coal Change	Low sulfur PRB coal is also low in chlorine content

Dry Sorbent Injection

Data from DSI commercial projects or pilot testing has indicated that acid gases can be very effectively captured by DSI using Trona, sodium bicarbonate, or hydrated lime. Although DSI is a technology that has not yet seen the wide deployment of other technologies for acid gas controls, like wet or dry scrubbers, data suggest that DSI is an effective technology for controlling emissions of acid gases, including HCl and HF. For example, as shown in Table 10, HCl capture rates of 98 percent have been measured at Mirant’s Potomac River station with sorbent injection upstream of the air preheater.⁶⁰ Testing of DSI systems has shown that HCl capture is consistently well above the SO₂ capture rate, and that capture rate of HCl on an ESP was in the mid to upper 90 percent range with SO₂ capture in the 60 percent range. With fabric filters, similar HCl capture efficiencies are possible but at lower sorbent treatment rates.⁶¹ Hydrated lime has also been shown in pilot tests to potentially achieve substantial HCl removal at low capital cost.⁶²

Table 10. HCl and HF Capture at Mirant Potomac River Station

	Trona Injection	Sodium Bicarbonate Injection
HCl (%)	98.8	97.8
HF (%)	78.4	88.0

DSI may be sufficiently effective in removing acid gases in combination with the existing PM control device. In some cases, however, it may be necessary to modify the existing PM control device or to install a new PM control device. If a fabric filter is installed for PM control, this will also facilitate capture of acid gases with DSI, and mercury and dioxins/furans with ACI. Such an approach will be far

less expensive than installing a wet scrubber. As indicated above, DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.

PM Emissions Control

Toxic metals other than mercury are normally in the particle form and are therefore controlled through particulate matter controls, such as ESPs and fabric filters. The proposed Air Toxics Rule for power plants sets numerical PM emission limits as a surrogate for non-mercury toxic metal emission limits. Table 11 lists PM emission control methods for pulverized coal units.

Table 11. PM Emissions Control Methods	
Methods of Control	
ESP	Method – Electrostatic capture of PM, high capture efficiency Reagent – None Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Capture particle-bound mercury
Baghouse	Method – Filtration of PM, highest capture efficiency Reagent – None Typical Fuel Types – Gaseous fuels Capital Costs – High Co-benefits – High capture of mercury and other HAPs
Co-benefit Methods of Control	
Scrubber (wet or dry)	Method – Captures PM

Electrostatic Precipitator

An electrostatic precipitator (ESP) uses an electrical charge to separate the particles in the flue gas stream under the influence of an electric field. More than 70 percent of existing coal-fired power plants are reported to have installed ESPs.⁶³

In brief, an ESP works by imparting a positive or negative charge to particles in the flue gas stream. The particles are then attracted to an oppositely charged plate or tube and removed from the collection surface to a hopper by vibrating or rapping the collection surface. An ESP can be installed at one of two locations. Most ESPs are installed downstream of the air heater, where the temperature of the flue gas is between 130°C-180°C (270°F-350°F).⁶⁴ An ESP installed downstream of the air heater is known as a “cold-side” ESP. An ESP installed upstream of the air heater, where flue gas temperatures are significantly higher, is known as a “hot-side” ESP.

The effectiveness of an ESP depends in part on the electrical resistivity of the particles in the flue gas. Coal with a moderate to high amount of sulfur produces particles that are more readily controlled. Low sulfur coal produces a high resistivity fly ash that is more difficult to control. The effectiveness of an ESP also varies depending on particle size. An ESP can capture greater than 99 percent of total PM, while capturing 80 to 95 percent of PM_{2.5}.⁶⁵

Depending upon the particular ESP and the applicable MACT standards, there may not be any need for further controls; however, many ESPs are decades old and were built for compliance with less stringent emission standards in mind. As a result, these facilities may need to make one or both of the following modifications to comply with new MACT standards:

- Upgrade of existing ESP – The existing ESP could be upgraded through addition of new electric fields, use of new high frequency transformer rectifier technology, or other changes. The applicability of this option will depend upon the condition and performance of the existing ESP.
- Replacement of ESP with fabric filter – A fabric filter may be installed in place of the existing ESP. In some cases, the existing ESP casing and support structure could be utilized for the baghouse. A booster fan is likely to be necessary because of the increased pressure drop across the fabric filter.

In recent years, there has been more focus on fabric filters for PM control than ESPs because of the PM capture advantages of fabric filters. As a result, there is not a great deal of available information on recent cost or installation time for ESPs. In general, however, an ESP will likely cost somewhat more and take more time to construct than a fabric filter built for the same gas flow rate because ESPs are somewhat more complex to build than a fabric filter system.

Fabric Filter or Baghouse

A fabric filter, more commonly known as a baghouse, traps particles in the flue gas before they exit the stack. Baghouses are made of woven or felted material in the shape of a cylindrical bag or a flat, supported envelope. The system includes a dust collection hopper and a cleaning mechanism for periodic removal of the collected particles.

According to EPA, a fabric filter on a coal-fired power plant can capture up to 99.9 percent of total particulate emissions and 99.0 to 99.8 percent of PM_{2.5}.⁶⁶ Thirty-five percent of coal-fired power plants in the U.S. have installed fabric filters.⁶⁷

A full baghouse retrofit would generally cost somewhat more than the addition of a downstream polishing baghouse (discussed later); however, because the material and erection of the baghouse is only a portion of the total retrofit cost of any baghouse, most of the costs are the same (ductwork, booster fans, dampers, electrical system modifications, etc.). Increasing the fabric filter size by 50 percent (equivalent to a change in air to cloth ratio of 6.0 to 4.0) would yield much less than a 50 percent impact to project cost over the cost of retrofitting a polishing baghouse, perhaps in the range of 15-20 percent. A fabric filter retrofit (full or polishing) would typically be achievable in 12-24 months from design to completion, depending upon the complexity of the ductwork necessary. For example, in 2009, the Reid Gardner generating station in Nevada completed the installation of three new pulse-jet baghouses in 17 months. The retrofit required the replacement of the plant's existing mechanical separators.⁶⁸

Rather than replacing an ESP with a fabric filter, a power plant with an existing ESP has the option of installing a downstream polishing baghouse (downstream of the existing ESP). This will capture particulate matter that escapes the ESP. Retrofit of a downstream polishing fabric filter will require addition of ductwork, a booster fan, and the fabric filter system. Costs will vary by application, particularly by the amount of ductwork needed. For example, the polishing fabric filter installed on three 90 MW boilers at Presque Isle Power Plant in Michigan cost about \$125/KW (2005\$). This project, however, had very long duct runs for each of the boilers and significant redundancy.⁶⁹ For a project on a single larger unit without the long duct runs, one would expect a lower cost.

Co-benefits of PM controls – PM controls, especially fabric filters, permit higher co-benefit mercury capture. Also, capture of other toxic pollutants through DSI is improved with a fabric filter. This is true

with any situation where sorbent is used to capture a pollutant because a fabric filter permits capture on the filter cake in addition to capture in-flight while ESPs permit only in-flight capture.

Control of Dioxins and Furans

Under the Air Toxics Rule, EPA has proposed a “work practice” standard for organic HAPs, including emissions of dioxins and furans, from coal-fired power plants. Power plant operators would be required to perform an annual tune-up, rather than meeting a specific emissions limit. EPA has proposed a work practice standard because it found that most organic HAP emissions from coal power plants are below current detection levels of EPA test methods. Therefore, it concluded that it is impractical to reliably measure emissions of organic HAPs. While EPA is not proposing numerical emission limits for organic HAPs, for completeness, we discuss below experience in controlling emissions of dioxins and furans from incinerators that may have relevance for co-benefits with coal power plant controls.

Emissions of dioxins and furans result from: (1) their presence in the fuel being combusted; (2) the thermal breakdown and molecular rearrangement of precursor ring compounds, chlorinated aromatic hydrocarbons; or (3) from reactions on fly ash involving carbon, oxygen, hydrogen, chlorine, and a transition metal catalyst. Because dioxins and furans are generally not expected to be present in coal, the second and third mechanisms are of most interest. In both of these mechanisms, formation occurs in the post-combustion zone at temperatures over 500°C (930°F) for the second mechanism or around 250-300°C (480-575°F) for the third mechanism.⁷⁰ Once formed, dioxins and furans are difficult to destroy through combustion. Therefore, it is best to prevent their formation, or alternatively, capture them once formed.

While emissions of dioxins and furans have long been a source of concern for municipal and other waste incinerators, their emissions have not generally been controlled from power plants. Emissions of dioxins and furans are generally expected to be lower in coal combustion than in municipal waste combustion because of the relatively lower chlorine levels and the higher sulfur levels of coal.⁵⁰ Sulfur has been shown to impede dioxins and furans formation.^{50,70,71} Table 12 lists the technologies for control of dioxins and furans and EPA’s previously proposed institutional, commercial, and industrial boiler limits for pulverized coal units.

The extensive experience with control of dioxins and furans at incinerators has provided insights that may be relevant for power plants, while recognizing the important differences between power plants and incinerators. Because dioxins and furans are formed from organic precursors, one way to avoid their formation is to have complete combustion of organics; hence, combustion controls or oxidation catalysts can contribute to their lower formation.⁷⁰ SCR has also been shown to mitigate emissions of dioxins and furans.^{50,51} Data indicate that capture of chlorine prior to the dioxins formation temperature will reduce dioxins/furans formation from municipal waste combustors.⁵⁸ Therefore, dry sorbent injection upstream of the air preheater of a coal boiler may be a means of reducing dioxins/furans formation.

Injection of activated carbon is a means that has been used to capture dioxins and furans emitted by municipal waste incinerators,^{50, 70} and has demonstrated over 95 percent capture of dioxins at a hazardous waste incinerator.⁷² Currently, there are not enough available data to form a definitive conclusion about how effective ACI will be at dioxins/furans capture from power plants because of the different conditions. The information available, however, suggests that it is likely to be useful in reducing dioxins and furans in the event other methods are not adequate in preventing their formation.

Table 12. Dioxins and Furans Emission Control Methods

Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous dioxins/furans, and is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Capture of Hg
Co-benefit Methods of Control	
Combustion Controls	Method – Destruction of organic dioxins/furans precursors
Dry Sorbent Injection	Method – Captures precursor chlorine prior to dioxins/furans formation
CO or NOx Catalyst	Method – Catalyst increases oxidation of organic dioxins/furans precursors

Labor Availability

The installation of air pollution control equipment requires the effort of engineers, managers, and skilled laborers, and past history has shown that the industry has substantial capacity to install the necessary controls. Between 2008 and 2010, coal-fired power plants added approximately 60 GW of FGD controls and almost 20 GW of SCR controls with a total of 80 GW of FGD controls installed under CAIR Phase 1. Between 2001 and 2005, the electric power industry successfully installed more than 96 GW of SCR systems in response to the NOx SIP Call.

Based on a retrospective study of actual retrofit experience, it was determined that EPA and industry dramatically underestimated the ability of the air pollution control industry to support the utility industry in responding to CAIR. The study offered several reasons for why EPA and industry underestimated the capabilities of the labor market: (1) boilermakers will work overtime during periods of high demand; (2) boilermakers frequently travel to different locations for work, supplementing local available labor; (3) boilermakers work in fields other than power, such as refining/petrochemical, shipbuilding, metals industries and other construction trades, and workers can shift industry sectors with appropriate training; and (4) new workers will enter the field—for example, in advance of the NOx SIP Call, boilermakers increased their ranks by 35 percent, mostly by adding new members.⁷³

In November 2010, the Institute of Clean Air Companies (ICAC), an association that represents most of the suppliers of air pollution control technology, sent a letter to U.S. Senator Thomas Carper confirming the nation’s air pollution control equipment companies repeatedly have successfully met more stringent NOx, SO₂, and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements. In its letter, the industry association stated, “based on a history of successes, we are now even more resolute that labor availability will in no way constrain the industry’s ability to fully and timely comply with the proposed interstate Transport Rule and upcoming utility MACT rules. Contrary to any concerns or rhetoric pointing to labor shortages, we would hope that efforts that clean the air also put Americans back to work.”⁷⁴ Also in November 2010, the Building and Construction Trades Department of the AFL-CIO issued a letter concluding that “[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development.”⁷⁵

The electric industry has long been aware that EPA would be regulating HAPs and other pollutants from coal-fired power plants. As a result, many companies started planning their compliance strategies before EPA even proposed its Air Toxics Rule in March 2011. For example, companies have been evaluating

control technology options and establishing capital budgets.⁷⁶ Similar advance planning occurred after the proposed CAIR rule was released in December 2003. In 2004, when EPA was still working to finalize the rule, companies placed orders for more than 20 GW of FGD controls (wet and dry scrubbers).⁷⁷ Southern Company, for example, had begun planning its FGD installations in 2003, well in advance of the final rule.⁷⁸

Conclusion

EPA's clean air rules—the Transport Rule and the Air Toxics Rule—address one of the nation's largest sources of toxic air pollution, providing important human health protections to millions of people throughout the country. Additionally, thousands of construction and engineering jobs will be created as companies invest in modern control technologies.⁷⁹

The electric power sector has several decades of experience controlling air pollution emissions from coal-fired power plants, which should serve the industry well as it prepares to comply with the Transport Rule and the Air Toxics Rule. Many companies have already moved ahead with the upgrades necessary to comply with these future standards, demonstrating that better environmental performance is both technically and economically feasible.

In most cases, the required pollution control technologies are commercially available and have a long track record of effective performance at many coal-fired power plants in the U.S., with some operating successfully for decades. The electric power sector has demonstrated that it is capable of installing pollution controls on a large portion of the nation's generating fleet in a relatively short period of time. Also, suppliers have demonstrated the ability to deliver pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well.

Endnotes

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