

Multipollutant Emission Control Technology Options for Coal-fired Power Plants



Foreword

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This publication has been produced as part of the laboratory's strategic long-term research plan. It is published and made available by EPA's Office of Research and Development to assist the user community and to link researchers with their clients.

Sally Gutierrez, Director
National Risk Management Research Laboratory

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Abstract

This report presents and analyzes various existing and novel control technologies designed to achieve multi-emission [sulfur dioxide (SO₂), nitrogen oxide (NO_x), and mercury (Hg)] reductions. Summary descriptions are included of 27 multi-emission control technologies that have reached a stage of development beyond pilot scale. These can broadly be divided into: environmental control options (post-combustion controls), advanced power generation options, and power plant upgrading and operating options. For each evaluated technology, the report includes background information, applicability, status of commercialization, any secondary environmental impacts of the technologies, identification of primary process variables that impact performance relative to NO_x, SO₂, and Hg, as well as capital and operation and maintenance costs.

More than half of the technology options listed are in the commercial or early commercial stage (15 out of 27). However, nearly all the technology options in the commercial stage are proven SO₂ control technologies, which also appear to remove Hg. Some technologies, such as Advanced Silicate and Confined Zone Dispersion, have been tested in either the pilot or demonstration scale in the early phase of the U.S. Department of Energy's Clean Coal Technology program, but have not been adopted by industry. Some of these technologies could become more cost-effective as environmental requirements evolve. Activated coke, electro-catalytic oxidation, EnviroScrub, and the combination of flue gas desulfurization with LoTOx or selective catalytic reduction exhibit the potential to significantly control (above 80 percent) all three pollutants (SO₂, NO_x, and Hg).

Although the report is limited to addressing technologies with a certain level of maturity, the authors expect a rapid technological evolution in the development and commercialization of several multi-emission control technologies not addressed in this report.

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List of Acronyms

AC	Activated carbon
ACI	Activated carbon injection
ADVACATE	Advanced Silicate
AFBC	Atmospheric fluidized bed combustor
APCD	Air pollution control device
BOP	Balance of plant
Btu	British thermal unit
CAAA	Clean Air Act Amendments of 1990
CCT	Clean Coal Technology
CDS	Circulating Dry Scrubbing
CEDF	Clean Environment Development Facility
CFB	Circulating fluidized-bed
CFD	Computerized Fluid Dynamics Modeling
CO ₂	Carbon dioxide
COHPAC	Compact hybrid particulate collector
CZD	Confined-zone Dispersion
DBA	Dibasic Acid
DOE	Department of Energy
ECO	Electro-catalytic Oxidation
EdF	Electricite de France
EIA	Energy Information Administration
EOY	End of year
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
E-SO _x	ESP enhanced for SO ₂ removal
ESP	Electrostatic precipitator
ESP-CS	Cold-side electrostatic precipitator
ESP-HS	Hot-side electrostatic precipitator
FF	Fabric filter
FGD	Flue Gas Desulfurization
GSA	Gas Suspension Absorption
HALT	Hydrate Addition at Low Temperature
HAP	Hazardous air pollutant
Hg	Mercury
HHV	Higher heating value
HP	Horse power
HRSG	Heat recovery steam generator
HYPAS	Hybrid pollution abatement system
ICR	Information collection request
IDS	In-duct scrubbing
IGCC	Integrated gasification combined cycle
IPM	Integrated planning model
kWh	Kilowatt hour
KRW	Kellogg Rust Westinghouse
lb	Pound-mass

LOI	Loss-on-ignition
MM	Million (10 ⁶)
MSW	Municipal solid waste
MW	Megawatt (electric)
NAAQS	National Ambient Air Quality Standards
NO _x	Nitrogen oxides
NSPS	New source performance standards
NSR	New source review
OFA	Overfire Air
O&M	Operation and maintenance
PAC	Powdered activated carbon
PC	Pulverized coal
PEESP	Plasma-enhanced ESP
PFBC	Pressurized fluidized-bed combustion
PM	Particulate matter
PS	Particulate scrubber
PSD	Prevention of significant deterioration
RAP	Rapid absorption process
RCFB	Reflux circulating fluidized bed
ROFA	Rotating opposed air
SCR	Selective catalytic reduction
SDA	Spray dryer absorber
SIP	State implementation plan
SNCR	Selective non-catalytic reduction
SO ₂	Sulfur dioxide
SRG	SO ₂ -rich gas
TAG	Technical assessment guide
TVA	Tennessee Valley Authority
TOXECON	ACI combined with COHPAC
UNFCCC	United Nations Framework Convention on Climate Change
WESP	Wet electrostatic precipitator
WSA	Wet gas sulfuric acid condenser

Conversion of Units

<i>Multiply</i>	<i>By</i>	<i>To Obtain</i>
<i>POWER</i>		
Watts	1	Newton-meter/second or Joule/second
Watts	0.05692	Btu/minute
Watts	1.341×10^{-3}	Horsepower
<i>ENERGY</i>		
Joules	1	Watt-seconds or Newton-meters
Kilowatt-hours (kWh)	3415	Btu
Kilowatt-hours	1.341	Horsepower-hours
Kilowatt-hours	3.60×10^6	Joules
Btu	1,054	Joules
<i>MASS</i>		
Kilograms	2.2046	Pounds
Pounds	0.4536	Kilograms
Ton (short or US)	2000	Pounds
Tonne (metric ton)	1.1023	Ton (short or US)

Metric Prefixes

<i>Prefix</i>	<i>Symbol</i>	<i>Value</i>
Tera	T	10^{12}
Giga	G	10^9
Mega	M	10^6
Kilo	k	10^3
Hecto	h	10^2
Deka	da	10
Deci	d	10^{-1}
Centi	c	10^{-2}
Milli	m	10^{-3}
Micro	μ	10^{-6}

Chapter 1

Introduction

Recent changes in the structure of the electric utility industry, including the shift towards restructuring, the growing demand for electricity generation, and environmental needs, are driving additional reductions of multiple pollutants. Historically, industry has developed and implemented control technologies in incremental steps to mitigate emissions of sulfur dioxide (SO₂), oxides of nitrogen (NO_x), particulate matter (PM), and other pollutants, as driven by air pollution requirements. Control technologies that are capable of simultaneously reducing emissions of multiple pollutants may offer the potential to achieve this at lower cost and reduced footprint when compared to conventional controls.

This report presents and analyzes various existing and novel control technologies designed to achieve multi-emission reductions. Having up-front knowledge of environmental performance, cost, and limitations of multi-emission control technologies can help power companies select effective and less expensive compliance strategies at individual plants, compared with compliance choices made when the requirements are addressed individually.

1.1 Intended Use and Organization of this Report

The intended use for this report is to provide the current state-of-the art information on the multi-emission control technologies and options that are available for coal-fired power plants with a capacity of 25 megawatts-electric (MW) or larger in the United States. For the purposes of this report, multi-emission control technologies are those capable of simultaneously controlling emissions of at least two of these three pollutants, NO_x, SO₂, and mercury, from electric utility sources. This evaluation includes background information, applicability, status of commercialization, any secondary environmental impacts of the technologies, identification of primary process variables that impact performance relative to NO_x, SO₂, and mercury, as well as capital and operation and maintenance (O&M) costs, if available. In addition to simultaneously controlling at least two of the SO₂, NO_x, and mercury emissions, some technologies reviewed under this study promise to enable reductions of the carbon emissions that result from coal-based electricity production. Such capability is viewed as an additional benefit and discussed for each applicable technology, given that reducing carbon emissions would be advantageous to the fulfillment of U.S. commitments under the United Nations Framework Convention on Climate Change (UNFCCC) and would further the President's commitment to reduce greenhouse gas intensity in the United States by 18 percent over the next decade.¹

The audience for this report is expected to comprise persons: (1) engaged in air pollution related research and development (R&D) efforts, (2) responsible for developing and implementing emission control strategies at sources, (3) and involved in developing air regulations, as well as (4) the interested public. The report is organized into four chapters. The first chapter provides general background information on air emissions from coal-fired power plants and multi-emission control technologies. The second chapter characterizes U.S. power plants of 25 MW or greater and their respective air emissions. Chapter 3 presents evaluation summaries of 27 multi-emission control technologies. These summaries include details on the technology, commercial readiness and industry experience, emission control performance, future outlook, as well as capital and O&M costs. Chapter 4 is a summary of the report.

1.2 Background

Electricity is critical to the well functioning of the residential, commercial, and industrial sectors in the United States. More than 3,170 traditional electric utility plants and 2,110 non-utility power plants are responsible for ensuring an adequate and reliable source of electricity to consumers in their service territories.² While electricity plays a critical role in sustaining the nation's economic growth, the unintended by-products of electricity generation can have an undesirable effect on the environment and public health. Most of these health impacts result from emissions produced through the combustion of fossil fuels (coal, oil, and natural gas), which supply about 70 percent of the nation's requirements for electricity generation.

As a result, the focus of recent regulatory actions has been to require power plants to reduce emissions of NO_x and SO₂. The revisions of the National Ambient Air Quality Standards (NAAQS) for PM and ozone may also limit power plant emissions. These revisions may require electric utility sources to adopt control measures designed to reduce concentrations of fine PM in the atmosphere. Fine PM is PM at or below 2.5 micrometer in size (PM_{2.5}). In addition, EPA has recently proposed a rule that calls for regulation of mercury emissions from electric utility coal-fired plants. Concurrently, legislation has been proposed in both the previous and current Congresses that would require simultaneous reductions of multiple emissions, and the Administration's National Energy Policy³ recommends the establishment of "mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury."

This report focuses on control technologies that promise to simultaneously control more than one pollutant from coal-burning power plants. The report focuses on emissions from coal-fired power plants since these plants generate about 50 percent of the electricity used in the United States. The coal-burning electric power industry is a major source of various air pollutant emissions including SO₂, NO_x, and mercury. In addition, the combustion of fossil fuels contributes to CO₂ emissions to the atmosphere.

1.3 Human Health and Environmental Impacts

Over the last 30 years, the reduction of emissions from the electric power sector has led to significant human health and environmental benefits. Title IV of the Clean Air Act Amendments of 1990 (CAAA), for example, has reduced acid deposition by approximately 25 percent and substantially reduced airborne particulate matter.¹ At the same time, the U.S. economy has expanded, and the amount of electricity supplied to consumers has grown significantly. In spite of the progress made to date, the electric power industry is still a significant source of SO₂, NO_x, and mercury emissions (see Chapter 2). These pollutants continue to pose threats to human health and the environment as described below.

1.3.1 Fine Particles

Emissions of SO₂ and NO_x lead to the formation of fine particles (particles less than 2.5 micrometers). Most fine particles, namely sulfates and nitrates, are formed when SO₂, NO_x and volatile organic compounds and ammonia react in the air. Fine particles can travel for long distances in the air before

¹ Title IV of the Clean Air Act Amendments of 1990, Acid Deposition Control, sets a goal of reducing annual SO₂ emissions by 10 million tons below 1980 levels and a 2 million ton annual reduction in NO_x emissions by the year 2000 from fossil fuel-fired power plants. The program affects existing utility units serving generators with an output capacity of greater than 25 megawatts and all new utility units. To achieve these reductions, the law required a two-phase tightening of the restrictions. Phase I was from 1995-1999 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing over 2,000 units in all.

being deposited far away from where the emissions took place. Fine particles pose serious threats to public health because their size allows them to easily reach the most sensitive parts of the lungs. Scientific studies have linked fine particles (alone or in combination with other air pollutants) with a series of significant health problems, including premature death.

1.3.2 Ground-Level Ozone

Ozone is formed when emissions of NO_x and volatile organic compounds (VOCs) react in the presence of sunlight. Ground-level ozone is the primary component of smog and tends to be a problem over broad regional areas, particularly in the eastern United States and some urban areas including Los Angeles and Houston. Ozone can damage lung tissue, reduce lung function, and adversely sensitize the lungs to other irritants. Long-term exposures to ozone can cause repeated inflammation of the lung, impairment of lung defense mechanisms, and irreversible changes in lung structure, which can lead to premature aging of the lungs or chronic respiratory illnesses such as emphysema and chronic bronchitis. Ozone can also aggravate asthma, causing more frequent and severe asthma attacks.

1.3.3 Acid Deposition

Acid deposition results from the reaction of SO₂ and NO_x air-borne emissions with water, oxygen, and oxidants to form various acidic compounds. It occurs both as wet deposition through acidic rain, fog, and snow and as dry deposition through acidic gases and particles. Acid deposition lowers the pH of sensitive lakes and streams to toxic levels. Lower pH can impact entire ecosystems through changes in the food chain. Acid deposition causes release of aluminum from soil, which is also very toxic to fish. It can directly affect forest ecosystems by damaging plant tissue involving leaching of foliar calcium² in certain plants. In other cases, multiple pollutants such as ozone, SO₂, and NO_x can combine to weaken trees and make them vulnerable to other threats, such as pests, that cause mortality.

Atmospheric deposition is a rapidly growing anthropogenic source of biologically available nitrogen in estuarine and near-coastal ecosystems. Depending on the location, from 10 to 80 percent of new nitrogen inputs to coastal waters along the east and Gulf coasts of the United States are of atmospheric origin.⁴ This nitrogen contributes to eutrophication of these waters, which results in one or more undesirable ecological impacts. These impacts include algae blooms, massive die-offs of estuarine and marine plants and animals (including fish), loss of biological diversity, and degradation or loss of essential coastal ecosystem habitat (such as sea grass beds). These ecological changes impact commercial and recreational fisheries and reduce our ability to use and enjoy coastal ecosystems. Recent studies also link atmospheric nitrogen deposition, coastal eutrophication, and harmful algal blooms with human health impacts.⁵⁻⁸

1.3.4 Visibility

Visibility impairment is another undesirable by-product of air pollution. Visibility is generally defined as the degree to which the atmosphere is transparent to visible light; visibility impairment is a reduction in visual range and atmospheric discoloration. Regional haze obscures the clarity, color, texture, and form of what is seen. The same fine particles that adversely affect human health are the primary cause of regional haze. Visibility is of more concern in national parks and wilderness areas.

² Leaching of foliar calcium from the needles of red spruce, which reduces the cold tolerance of individual trees, has contributed to the decline of high-altitude red spruce forests throughout eastern North America. Recent studies indicate that foliar calcium loss may occur with other species as well.

1.3.5 Mercury

Mercury cycles in the environment as a result of natural and human activities. Most anthropogenic mercury emissions to the air come from stationary combustion sources, including waste and fossil fuel combustion. About 64 percent (48 tons) of the mercury in the coal burned in power generation plants in 1999 was emitted to the atmosphere.⁹ The percent contribution to total anthropogenic mercury emissions from power generation is expected to become even greater as coal-fired generation increases and the final mercury standards for municipal waste combustors and medical and hazardous waste incinerators are fully implemented. Current releases are adding to the mercury that already exists in land, water, and air, both naturally and as a result of previous human activities.

Mercury in combustors exists in elemental, ionic, or particulate forms. Elemental mercury can be widely dispersed and transported for many miles, whereas ionic mercury, which is soluble in aqueous solutions, and particulate mercury are typically deposited close to the emissions source. Once mercury is deposited in lakes, rivers, and oceans, it is converted to methylmercury by aquatic organisms and bioaccumulates in the food chain, resulting in high concentrations in predatory fish. In the United States, most human exposure to mercury is the result of consumption of fish contaminated with methylmercury. Adverse effects of mercury on fish, birds and mammals include death, reduced reproductive success, impaired growth and development, and behavioral abnormalities.

While EPA has already taken action to reduce mercury emissions from other major sources such as municipal waste combustors, medical waste incinerators and hazardous waste combustors, coal-fired power plants' mercury emissions into the air remain uncontrolled. The EPA took the first step towards controlling mercury emissions from the power generation sector on December 14, 2000 by issuing a finding that mercury emissions from the coal-fired power plants should be controlled. Based on this determination, the agency proposed the "Utility Mercury Reductions Rule" in December 2003, which calls for significant reductions of mercury from the utility coal-fired power plants.

1.4 Multi-emission Control Options

This report addresses multi-emission control technologies that have reached a stage of development beyond pilot scale. It includes those technologies that integrate in-situ or post-combustion controls of at least two of the SO₂, NO_x, and mercury pollutants, either in one process or a combination of coordinated and complementary processes. In addition, the report includes new coal-fired electricity-generating technologies, which are inherently more efficient than conventional coal-fired power plants or have the potential to generate lower emission of air pollutants and CO₂. The report also looks at power plant improvements capable of reducing emissions and producing higher energy efficiencies.

It is envisioned that the report will assist the electric power industry in selecting emission control options for power plants. Information on environmental performance, cost, commercialization barriers, and other relevant factors on these technologies could enable power companies to choose less expensive air pollution compliance approaches, compared to controlling individual emissions through a series of controls in succession, each targeting a different pollutant. In certain cases, such as in a constrained plant layout, multi-emission control technologies may represent the most practical method of providing the necessary environmental benefits.

This report is limited to coal-fired power plant emission controls and power generation technologies and does not include consideration of other power generating options such as systems based on renewable energy sources. The authors do recognize that these latter options do offer tremendous potential in reducing air pollution, and suggest they be addressed under separate efforts.

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Chapter 2

Characterization of U.S. Power Plants and Associated Emissions

As a preview to discussing multi-emission control technologies, it is beneficial to characterize the magnitude and sources of the emissions that drive the need for these technologies. Sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury are generated not only from electricity generation but also from a number of sectors of the economy. Figure 2-1 presents the 2001 estimates of SO_2 and NO_x and 1998 estimates of mercury emissions from major economic sectors in the United States.¹ During 2001, fuel combustion-electric utilities contributed 69 percent of the total SO_2 emitted and 22 percent of the NO_x .

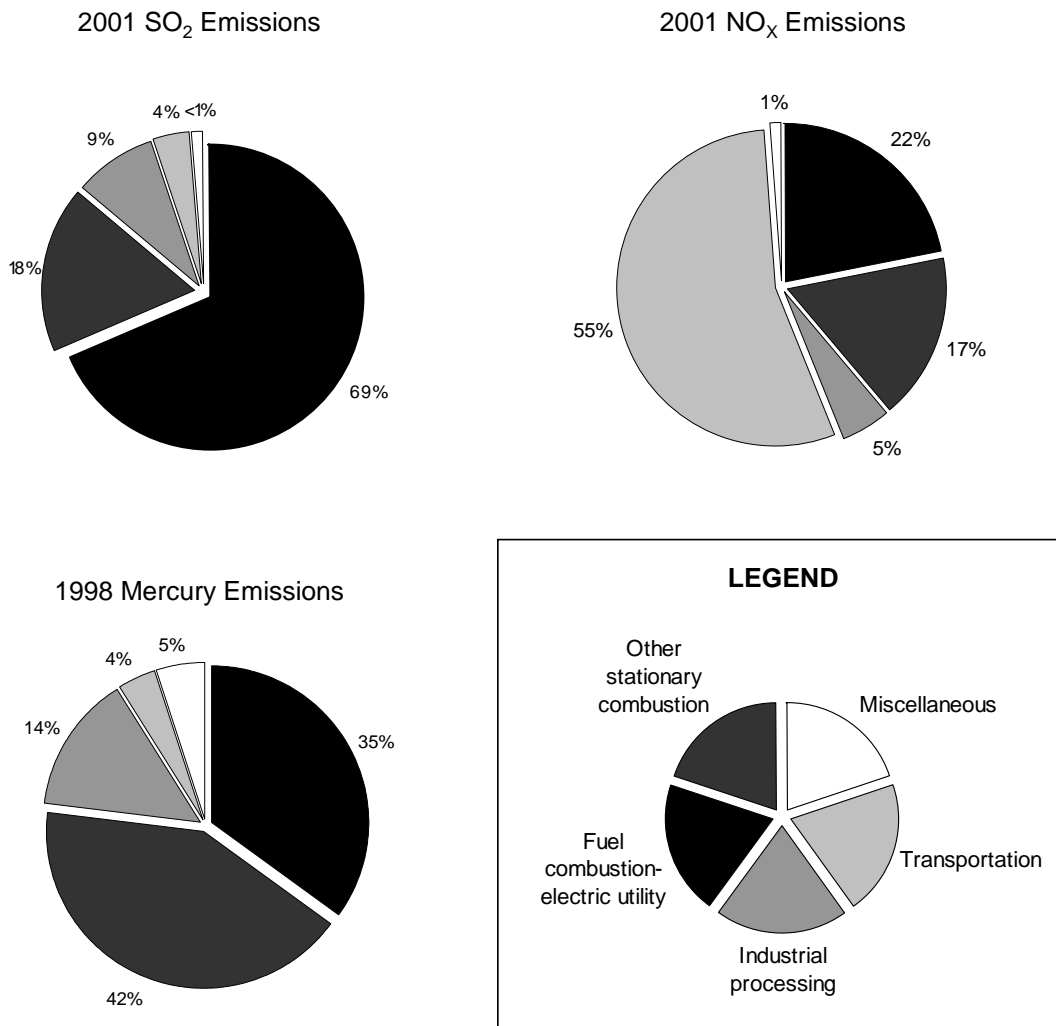


Figure 2-1. Major sources of SO_2 and NO_x emissions in 2001 and of mercury emissions in 1998.

Since the majority of U.S. power plant capacity is regulated under Title IV of the CAAA,^{2,3} the data for NO_x, SO₂, and CO₂ collected under this title provide a good representation of these emissions. Title IV of the Clean Air Act covers all boiler units with capacity greater than 25 MW, excluding a small percentage of units classified as co-generating units. Title IV affected a total of 2,638 units in 2001, from which 1,089 are considered coal-fired units based on burning over 50 percent coal as the primary fuel. Emissions data for Title IV affected units is available at EPA Clean Air Market Division's website.⁴

Table 2-1 summarizes the 2001 total emissions data for all Title IV affected units, apportioned by two broad primary fossil fuel type categories (coal and non-coal). Non-coal units affected by Title IV include those that burn liquid or gaseous fossil fuel (oil, diesel, natural gas, etc.) or other solid fuel, such as wood, as their primary fuel. The data reflect the predominance of coal use by U.S. facilities. Of the totals in 2001, coal accounts for 95 percent of SO₂ emissions, 90 percent of NO_x emissions, and 86 percent of CO₂ emissions. Note that data on mercury emissions is not collected under Title IV. Coal units also account for 79 percent of the total heat input.

Table 2-1. Emissions in 2001 from Coal and Non-coal Units⁵

	Coal	Non-Coal	Total
SO ₂ (Tons)	10,052,279	581,799	10,634,077
NO _x (Tons)	4,235,104	464,770	4,699,874
CO ₂ (Tons)	2,049,776,430	344,080,879	2,393,857,309

However, in 1999, the EPA conducted an Information Collection Request (ICR)⁶ to obtain information on mercury emissions from the U.S. coal-fired electric utility steam generating facilities. The ICR collected general information and data on quantity of fuel consumed, quantity of mercury of that fuel, and mercury speciation in flue gas before and after air pollution control devices upstream of the stack. This ICR identified 1140 boilers of 25 MW or greater capacity including cogenerators that supplied more than one-third of their potential electric output capacity to utility distribution systems for sale. The ICR effort further identified the breakdown of these units as 979 pulverized coal-fired, 87 cyclone-fired, 42 fluidized-bed combustors, and 32 stoker-fired boilers. The information on mercury emissions presented in this report is based on EPA's 1999 ICR.

2.1 SO₂ Emissions from Coal-Fired Power Plants

SO₂ emissions from coal-fired power plants increased slightly between 1996 and 1997 by about 400,000 tons. Despite this emissions increase, a sharp decrease of about 2,650,000 tons or 21 percent occurred between 1997 and 2001. Sulfur dioxide emissions from 1996 to 2001 are illustrated in Figure 2-2.¹

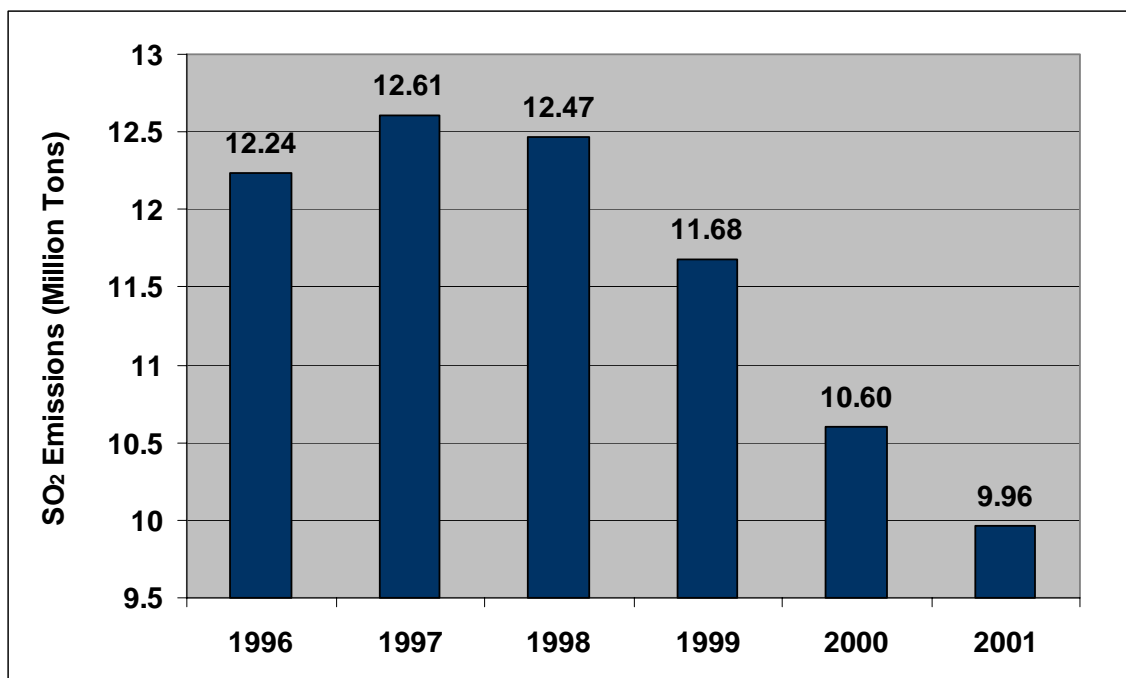


Figure 2-2. Annual SO₂ emissions for coal-fired units.

Emissions of SO₂ are highly dependent on the sulfur content in the coal burned and the emissions control system employed. Emissions control systems are typically based on dry or wet flue gas desulfurization (FGD). FGD technologies are based on the use of sorbents to scrub SO₂ from the flue gas and are conventionally classified as throwaway and regenerable depending on how the sorbent is treated, and further into wet or dry FGDs. In wet processes, wet slurry waste or by-product is produced, and flue gas leaving the absorber is saturated with moisture. In dry processes, dry waste material is produced and flue gas leaving the absorber is not saturated.

SO₂ emission rates for 60 units that had FGD technologies installed between 1990 and 1999 are presented in Table 2-2.⁷⁻⁹ Wet limestone and wet lime FGDs were the two most installed control technologies for these units. Emission rates varied widely among the different technologies and coal types.

Table 2-2. SO₂ Emissions from Units with FGD Installed in 1990-1999

FGD Type	Number of Units ^a	Fuels Burned ^b	Average SO ₂ Emission (lb/MMBtu)	Maximum SO ₂ Emission (lb/MMBtu)	Minimum SO ₂ Emission (lb/MMBtu)	Annual SO ₂ Emission (tons)
Dry Lime	2	Bit.	0.32	0.47	0.17	1,848
Dry Lime	4	Lignite	0.61	1.09	0.40	36,818
Dry Lime	8	Subbit.	0.28	0.61	0.09	36,477
Dual Alkali	2	Bit.	0.65	0.84	0.46	11,253
Dual Alkali	1	Lignite	1.02	1.02	1.02	21,863
Sodium Based	8	Bit.	0.70	1.93	0.05	18,878
Sodium Based	1	Subbit.	0.43	0.43	0.43	1,858
Wet Lime	24	Bit.	0.55	1.12	0.08	163,936
Wet Lime	4	Bit./petcoke	0.47	0.53	0.37	30,912
Wet Lime	2	Bit./subbit.	0.39	0.57	0.20	8,896
Wet Lime	4	Lignite	0.89	1.15	0.35	78,118
Wet Lime	8	Subbit.	0.42	0.51	0.14	49,743
Wet Limestone	50	Bit.	0.59	3.02	0.05	369,087
Wet Limestone	9	Bit./petcoke	0.45	0.73	0.05	65,006
Wet Limestone	5	Bit./subbit.	0.53	0.89	0.22	50,883
Wet Limestone	3	Bit./subpetcoke	0.45	0.57	0.22	16,320
Wet Limestone	1	Bit./tires	0.24	0.24	0.24	978
Wet Limestone	5	Lignite	0.89	1.14	0.56	120,824
Wet Limestone	3	Lignite/subbit.	1.06	1.16	0.87	101,745
Wet Limestone	23	Subbit.	0.39	0.76	0.08	178,358

^a FGD units under construction in 1999, or known not to be operating, were not included in the unit counts. This included 3 wet limestone, 2 dry lime FGD, and 1 dry limestone FGD.

^b Data from EPA's 2001 ICR; bit. = bituminous coal; subbit. = subbituminous coal; petcoke = petroleum coke.

2.2 NO_x Emissions from Coal-Fired Power Plants

Annual NO_x emissions for coal-fired units regulated under Title IV are shown in Figure 2-3.¹ These emissions steadily declined from 1997 to 2001 by about 1,470,000 tons.

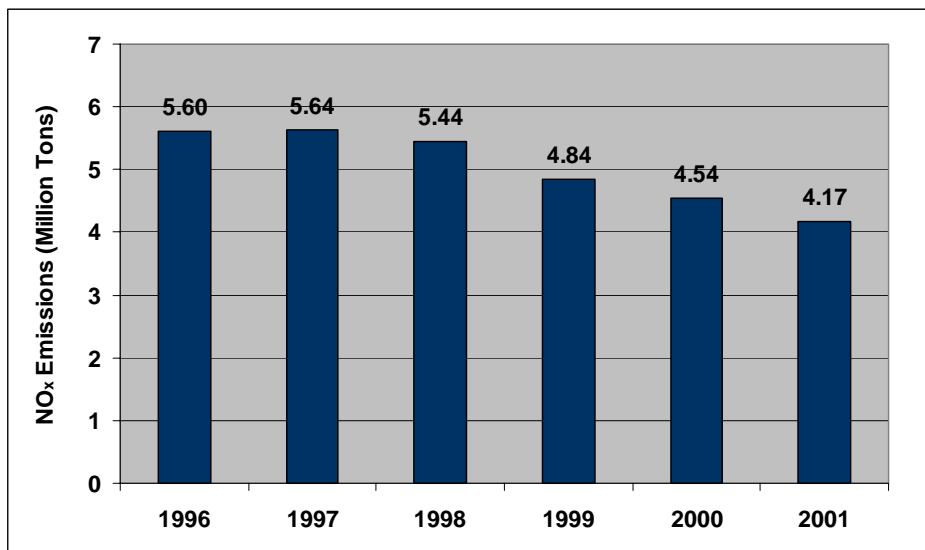


Figure 2-3. Annual NO_x emissions for coal-fired units.

NO_x is formed during most combustion processes by one or more of three chemical mechanisms: (1) “thermal” NO_x resulting from oxidation of atmospheric molecular nitrogen, (2) “fuel” NO_x resulting from oxidation of chemically bound nitrogen in the fuel, and (3) “prompt” NO_x resulting from reaction between atmospheric molecular nitrogen and hydrocarbon radicals. In fuel-lean combustion of nitrogen-free fuels, thermal NO_x is the primary component of NO_x emissions. Thermal NO_x formation is quite sensitive to temperature and can be controlled by appropriately controlling peak temperature in the furnace. In fuel-lean combustion of fuels containing nitrogen, fuel NO_x contributes significantly to total NO_x emissions, depending on the percentage of nitrogen in the fuel. Formation of fuel NO_x depends on the availability of oxygen to react with the nitrogen during coal devolatilization and the initial stages of combustion. Under fuel-rich conditions, the formation of NO_x may compete with the formation of molecular nitrogen (N₂) and may result in a reduction of NO_x emissions. Prompt NO_x contributes a relatively minor fraction of total NO_x emissions for both nitrogen-free and nitrogen-containing fuels.

The factors described above that dictate NO_x formation (devolatilization of fuel-bound nitrogen, oxygen concentration, and flame temperature) can all be adjusted by controlling the rate at which the fuel and air mix. This allows staging the combustion process, such that an initial fuel-rich zone is followed by a burnout zone that is high enough in oxygen to complete the combustion process, but low enough in temperature to minimize thermal NO_x production. Combustion modification NO_x controls utilize this combustion staging.

In general, NO_x control technologies are categorized as being either *primary control technologies* or *secondary control technologies*. Primary control technologies reduce the formation of NO_x in the primary combustion zone. In contrast, secondary control technologies destroy the NO_x present in the flue gas from the primary combustion zone. Primary control technologies being used in the United States are low NO_x burner (LNB) and overfire air (OFA).

The secondary NO_x control technologies in use on U.S. coal-fired utility boilers include reburning, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). More than 100 boilers either have used, or will use, these technologies to achieve the desired NO_x reductions. The NO_x

reductions achieved, or projected, at these applications range from 20 to more than 80 percent. Table 2-3 summarizes the 1999 NO_x emissions and emission rates for units regulated under Title IV.¹⁰

Table 2-3. 1999 NO_x Emissions for Title IV Affected Units

Boiler Type (Coal Units Only)	Number of Units	NO _x Control	Average NO _x Emission (lb/MMBtu)	Maximum NO _x Emission (lb/MMBtu)	Minimum NO _x Emission (lb/MMBtu)	Annual NO _x Emission (tons)
Arch-fired	9	Uncontrolled	0.74	0.91	0.25	11,170
Cell burner	2	Low NO _x Burner Technology	0.62	0.71	0.52	39,125
	3	Low NO _x Burner Technology for Cell Burners	0.46	0.46	0.46	20,067
	1	Low NO _x Burner Technology with Overfire Air (Dry Bottom Boilers Only)	0.39	0.39	0.39	8,089
	1	Other	0.61	0.61	0.61	13,044
	29	Uncontrolled	0.75	1.41	0.43	464,518
Circulating fluidized bed	2	Other	0.21	0.22	0.20	2,536
	4	Uncontrolled	0.37	0.47	0.19	1,368
Cyclone	1	Combustion Modification with Fuel Reburning	0.77	0.77	0.77	2,831
	1	Other	0.93	0.93	0.93	3,259
	1	Overfire Air	1.12	1.12	1.12	23,579
	1	Selective Catalytic Reduction	0.47	0.47	0.47	4,627
	1	Selective Non-catalytic Reduction	0.69	0.69	0.69	3,226
	84	Uncontrolled	0.96	1.81	0.26	708,760
Dry bottom turbo- fired	2	Low NO _x Burner Technology	0.39	0.40	0.37	16,110
	3	Low NO _x Burner Technology with Overfire Air (Dry Bottom Boilers Only)	0.59	0.62	0.54	18,078
	2	Overfire Air	0.43	0.44	0.42	13,128
	5	Uncontrolled	0.41	0.43	0.37	18,813
Dry bottom vertically-fired	2	Low NO _x Burner Technology	0.48	0.73	0.22	4,316
	3	Overfire Air	0.51	0.51	0.51	3,855
	21	Uncontrolled	0.77	1.16	0.37	64,234

(continued)

Table 2-3 (concluded)

Boiler Type (Coal Units Only)	Number of Units	NO _x Control	Average NO _x Emission (lb/MMBtu)	Maximum NO _x Emission (lb/MMBtu)	Minimum NO _x Emission (lb/MMBtu)	Annual NO _x Emission (tons)
Dry bottom wall-fired	153	Low NO _x Burner Technology	0.43	0.81	0.18	848,965
	41	Low NO _x Burner Technology with Overfire Air (Dry Bottom Boilers Only)	0.45	0.71	0.30	182,191
	1	Low NO _x Burner Technology with Overfire Air & Selective Catalytic Reduction	0.17	0.17	0.17	1,641
	3	Other	0.36	0.37	0.36	16,083
	4	Overfire Air	0.46	0.51	0.37	25,737
	5	Selective Non-catalytic Reduction	0.36	0.40	0.30	4,003
	213	Uncontrolled	0.57	1.11	0.20	539,907
Stoker (coal and wood)	15	Uncontrolled	0.40	0.57	0.32	2,008
Tangentially-fired	5	Combustion Modification with Fuel Reburning	0.42	0.44	0.37	6,893
	45	Low NO _x Burner Technology	0.34	0.45	0.13	202,120
	31	Low NO _x Burner Technology with Close-coupled and Separated OFA	0.36	0.63	0.16	146,046
	40	Low NO _x Burner Technology with Close-coupled OFA	0.37	0.67	0.17	181,774
	26	Low NO _x Burner Technology with Separated OFA	0.38	0.71	0.18	104,590
	22	Other	0.41	0.72	0.23	163,214
	10	Overfire Air	0.34	0.49	0.23	70,431
	2	Selective Non-catalytic Reduction	0.39	0.47	0.30	2,795
	254	Uncontrolled	0.43	0.86	0.24	800,505
Wet bottom turbo-fired	1	Low NO _x Burner Technology	0.53	0.53	0.53	6,242
	2	Overfire Air	0.46	0.47	0.45	5,606
	2	Uncontrolled	0.93	1.13	0.73	15,496
Wet bottom vertically-fired	2	Uncontrolled	0.90	0.93	0.86	456
Wet bottom wall-fired boiler	3	Low NO _x Burner Technology	0.37	0.47	0.32	23,852
	1	Other	0.45	0.45	0.45	10,351
	2	Selective Non-catalytic Reduction	0.79	0.82	0.76	12,759
	18	Uncontrolled	0.73	0.86	0.43	80,549

2.3 Mercury Emissions from Coal-Fired Power Plants

Coal-fired power plants represent a significant source of mercury emissions into the atmosphere. EPA has estimated that a total of 48 tons of mercury was emitted from coal-fired power plants in the United States in 1999.¹¹ Another analysis has estimated the total amount of mercury emissions from U.S. coal-fired plants to be 45 tons in 1999. This weight consists of 18 tons of oxidized mercury, 26 tons of elementary mercury (Hg^0), and less than 1 ton of particulate-bound mercury.¹² This latter analysis also estimates the total amount of mercury in the fuel entering these power plants at 75 tons in 1999.

The air pollution control technologies now used on pulverized-coal-fired utility boilers exhibit average levels of Hg control that range from 0 to 98 percent, as shown in Table 2-4.⁴ The best levels of control are generally obtained by emission control systems that use fabric filters (FF). The amount of Hg captured by a given control technology is better for bituminous coal than for either subbituminous coal or lignite.

The lower levels of Hg capture in plants firing subbituminous coal and lignite are attributed to low fly ash carbon content and the higher relative amounts of Hg^0 in the flue gas from combustion of these fuels. The average capture of Hg based on inlet measurements in pulverized coal (PC)-fired plants equipped with a cold-side electrostatic precipitator (ESP) is 35 percent for bituminous coal, 3 percent for sub-bituminous coal, and near zero for lignite.

Plants that employ only post-combustion PM controls display average Hg emission reductions ranging from 0 to 89 percent. The highest levels of control were observed for units with FFs. Lower levels of control were shown for units with ESPs and other controls.

Table 2-4. Mean Mercury Emission Reduction for Pulverized-coal-fired Boilers

Post-Combustion Emission Controls Used for PC Boiler		Average Mercury Emission Reduction (%) ^a		
		Bituminous Coal-fired	Subbituminous Coal-fired	Lignite Fired
PM Control Only	ESP-CS ^b	35	3	0
	ESP-HS	14	12	Not tested
	FF	89	73	Not tested
	PS	12	0	33
PM Control and Spray Dryer Adsorber	SDA and ESP	Not tested	50	Not tested
	SDA and FF	98	23	17
	SDA, FF, and SCR	97	Not tested	Not tested
PM Control and Wet FGD System	ESP-CS and FGD	81	30	42
	ESP-HS and FGD	45	25	Not tested
	FF and FGD	97	Not tested	Not tested

^a Mean reduction from 3-run test averages for each PC boiler unit in ICR Phase III database.

^b Refer to Acronyms, page vii for definitions.

Units equipped with lime spray dryer absorber scrubbers and with ESP or FF exhibited average Hg captures ranging from 98 percent for units burning bituminous coals to 3 percent for units burning subbituminous coal. The predominance of Hg^0 in stack gas units that are fired with subbituminous coal and lignite results from low levels of Hg^0 oxidization.

The capture of Hg in units equipped with wet FGD scrubbers is dependent on the relative amount of Hg^{2+} in the inlet flue gas and on the PM control technology used. Average Hg captures in wet FGD scrubbers ranged from 23 percent for one PC-fired hot-side ESP (ESP-HS) and FGD unit burning sub-bituminous coal to 97 percent in a PC-fired FF and FGD unit burning bituminous coal. The high Hg capture in the FF and FGD unit is attributed to increased oxidization and capture of Hg in the FF.

Mercury captures in PC-fired units equipped with spray dry scrubbers and wet limestone scrubbers appear to provide similar levels of control on a percentage reduction basis. However, this observation is based on a small number of short-term tests at a limited number of facilities. Additional testing will be required to characterize the effects of fuel, combustion conditions, and air pollution control device (APCD) conditions on the speciation and capture of Hg.

2.4 CO₂ Emissions from Coal-Fired Power Plants

Carbon dioxide emissions from the combustion of fossil fuels are mainly driven by the source of energy and its carbon content. Sources of energy include natural gas, diesel oil, biomass, and coal. The amount of carbon in fuels varies significantly by fuel type, and coal contains the highest amount of carbon per unit of useful energy, resulting in the highest rate of CO₂ emissions per kilowatt-hour of electricity.

Title IV does not require control of CO₂ emissions; it only requires that they be measured and reported. Figure 2-4 summarizes emissions from these units for 1996 to 2001.⁴ Emissions of CO₂ from all Title IV affected units increased by 2.5 percent from 1996 to 1997. In 1998, CO₂ emissions increased by 1.5 percent. The CO₂ emissions remained the same between 1998 and 1999, but in 2000, CO₂ emissions rose by 1.9 percent. In 2001, CO₂ emissions fell below the 1997 level.

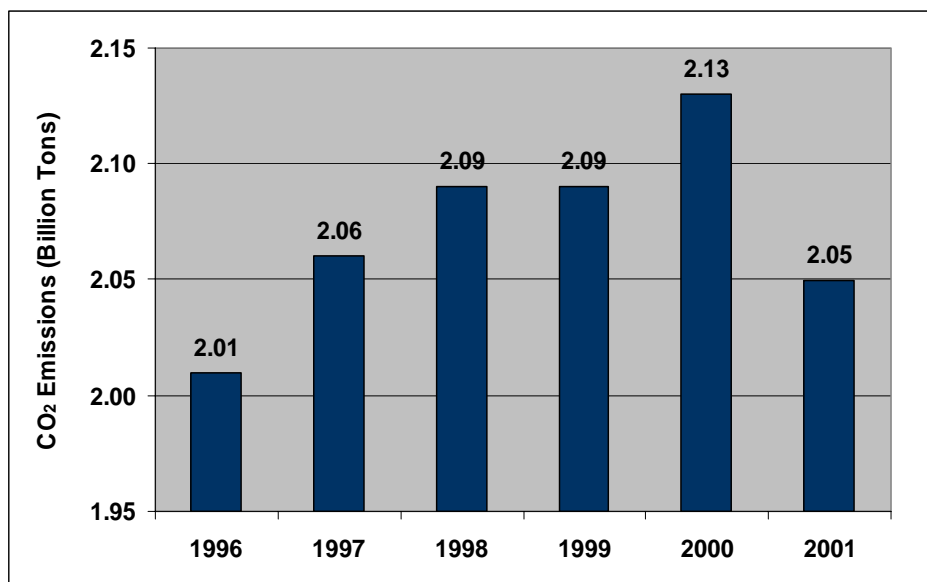


Figure 2-4. Annual CO₂ emissions for coal-fired units.

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Chapter 3

Multi-emission Control Technologies and Options for Coal-fired Power Plants

3.1 Introduction

This section provides a summary description of the technologies identified as multi-emission control technologies and which have reached a stage of development beyond pilot scale. The technologies selected satisfy the following definition established for this report: *Multi-emission control technologies are defined as options which integrate pre-combustion, in-situ or post-combustion controls of at least two of the SO₂, NO_x, and mercury pollutants, either in one process or a combination of coordinated and complementary (synergistic) processes.*

There were no constraints set as to the percentage reduction of each emission, such as: there should be a significant reduction of more than 80 or 90 percent. As a result, options such as advanced power generation technologies, power plant rehabilitation or upgrading, fuel switching or blending and power plant optimization were included in the multi-emission control category. These technologies were included to emphasize that there are multiple options a power company may use to control multiple pollutants in addition to the post-combustion control options, which are the focus in most cases. For example, utilizing a high plant efficiency technology, such as supercritical pulverized coal firing, is beneficial for all emissions (compared to the conventional subcritical pulverized coal technology), even though, by itself, it does not reduce emissions by more than 10-12 percent.

In addition to the above definition, two other criteria were applied in selecting the technologies described in this report. These were: (1) there should be at least one installation in operation in a power plant worldwide as of July 1, 2001, and (2) while it is acceptable for the technology to be used even in a slip-stream (not the entire power plant), the size of the technology installation should be at least 5 MW or equivalent.

Using the above definition and criteria, a literature search was done (using technical papers from conferences, the internet, technical reports by organizations such as DOE, EPA, and EPRI, and contacting vendors and utilities) and the technologies presented in this section were identified. The technologies were grouped into:

- environmental control options (in-situ and post-combustion controls),
- advanced power generation options, and
- power plant upgrading and operating options.

Environmental controls include processes that control SO₂-mercury, SO₂-NO_x, and SO₂-NO_x-mercury emissions. Injection of activated carbon in front of electrostatic precipitators (ESPs) and fabric filters (FFs) was also included, because of the significant role it may play in controlling mercury from existing power plants. Activated carbon can also be combined with other technologies, such as sorbent injection, to provide multiple emissions control.

Advanced power generation technologies include circulating fluidized bed combustion (CFB), integrated gasification combined cycle (IGCC), pressurized fluidized bed combustion (PFBC) and supercritical pulverized coal. In the category of plant upgrading and operating changes, the report includes: fuel

blending or cofiring, plant upgrading and efficiency improvements, and optimization. Some of these options require extensive plant modifications, such as boiler conversion from coal to natural gas or repowering of an existing coal-fired power unit to combined cycle unit burning natural gas. Others, such as optimization, are strictly plant-operating adjustments. Most of these options are very site-specific, especially with regard to the potential emission reduction and the required costs. As such, this report generically describes plant upgrading to raise the awareness about its potential and provides general guidelines with regard to its potential. More site-specific analyses are needed (beyond the scope of this document) to develop more accurate estimates.

A number of technologies did not satisfy the above definition and selection criteria. Many of these are under investigation at the laboratory or pilot scale. For others, adequate information is not available. Examples of such technologies include: Pioneer Technologies' Non-thermal Plasma Arc technology, Consummator's plasma arc by-product recovery, Phoenix's retrofit slagging combustor, ISCA's Cl_2 injection, and BioDeNO_x, which uses bacteria to reduce NO_x emissions in FGDs by adding FeEDTA and ethanol. These, and other technologies, may emerge in a relatively short period of time depending on the results of on-going laboratory and pilot tests, as well as the demand for multi-emission controls. Others may never reach commercial stage either because of technical problems they will face or because of unfavorable economics relative to competing options. Finally, there are technologies which were demonstrated in the past and for which recent information is not available. These technologies, such as LIMB, NOXSO, or Milliken Clean Coal, are not discussed in this report.

For each technology, the following information is provided wherever possible:

- brief technology description,
- commercial readiness and industry experience,
- emission control performance,
- O&M impacts,
- costs,
- issues associated with the technology, and
- references.

The description of each technology included in this section is brief, but references are provided if the reader is interested in more detailed information. Performance and cost of selected technologies for mercury and multipollutant control have been discussed in more detail elsewhere.¹

A significant effort was made to obtain costs, both capital and O&M. Cost ranges were provided for technologies that have reached maturity because significant information is available. If no adequate information was available in the literature, cost estimates that are provided are based on the authors' experience.

The costs reflect End of Year (EOY) 2000 US dollars, unless otherwise indicated. When the basis is different from EOY2000, the costs are adjusted using the Chemical Engineering Annual Plant Index (CEI). Considering that the cost data are based on literature reviews and other publicly available information, it should be noted that the level of uncertainty is of the order of -30 to +80 percent, as noted in EPRI's Technical Assessment Guide (EPRI TAG) when referring to the accuracy of estimates based on development stage of the technology and the design and cost basis.

In addition to the costs, an attempt is made in the report to provide also a size (in MW) to which the costs correspond. No scale-up correlations are provided (costs vs plant size), because some of the technologies may not follow the standard scale-up rules. Furthermore, there are other factors that may affect costs equally or more than plant size. Some of these factors include coal composition and emission reduction requirements.

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3.2 Environmental Control Options

3.2.1 *SO₂ and Mercury Control*

3.2.1.1 Dry Scrubbers

Dry scrubbing technology is a flue gas desulfurization (FGD) method capable of reducing multiple pollutants (specifically SO₂ and mercury) and is typically used in low- to medium-sulfur coal-fired power plants. “Dry” refers to the fact that the flue gas and the refuse (ash and solid reaction products) leaving the scrubber are *not* saturated with water vapor as in wet FGD (wet scrubbers). The technology is suitable for new and retrofit applications. Dry scrubbers have been installed on utility and industrial boilers, as well as hazardous and municipal waste incinerators. In general, dry scrubbers fall into several categories associated with the type of vessel or reactor used. The following sections describe the most common and available technologies – conventional spray dryer and fluidized bed.

3.2.1.1.1 *Conventional Dry Scrubbers*

Conventional Dry FGD (Spray Dryer Absorbers) Summary

Status	Commercial
SO₂ Reduction (%)	90 to 95
NO_x Reduction (%)	---
Hg Reduction (%)	0 to 95
Cost	
Capital (\$/kW)	150 - 230 for a 300 MW plant
Fixed O&M (\$/kW-yr)	1.5 – 7
Variable O&M (mills/kWh)	0.2 - 0.7
Applicability	SO ₂ and Hg control for low- to-medium-sulfur coals
Issues	Hg removal can vary significantly with coal type, operating conditions, and other pollution control devices present in the plant

Technology Description

In conventional spray dryer technology, a slurry of alkaline reagent (most often lime slurry or hydrated lime) is atomized via rotary atomizers or, alternatively, pneumatic nozzles and injected into a vessel where it reacts with the SO₂ in the flue gas to produce calcium sulfate or sulfite products. The vessel must be appropriately sized to allow sufficient residence time (~ 10 seconds) for droplet evaporation and SO₂ capture to take place.

In addition, spray dryers have been shown to reduce mercury in the flue gas.¹⁻³ In this case, the more complex chemistry and speciation forms of the mercury make it more difficult to fully understand the processes and reactions that take place. However, fly ash, lime and activated carbon-based sorbents all provide varying degrees of affinity to adsorb vapor-phase mercury present in the flue gas.

The relatively simple designs of the spray dryers include a cylindrical vessel with conical bottom. The atomizer may be located either at the top or the bottom and spraying into the moving flue gas flow. Flue gas exiting the spray dryer is directed to a downstream ESP or FF, where the dry material is then either collected in its entirety for disposal or may be partially re-introduced into the absorber as part of the slurry mixture to enhance the overall efficiency of process.

This technology has been used predominantly on low- and medium-sulfur coals, but can be applied to plants burning higher-sulfur coal, too. The reason for this application flexibility is mainly economic; spray dryers have lower costs and can achieve reasonable SO₂ removal for low- and medium-sulfur coal. For high-sulfur coal, the costs (both capital and O&M) increase substantially and cannot compete easily with wet FGDs. In all cases, two factors need to be considered. The capacity of the existing particulate control device (in retrofit situations) needs to be checked to make sure that the increase in particulate loading can be accommodated (the quantity of sorbent is proportional to the SO₂ concentration and the desired reduction sought, therefore it increases with higher sulfur and reductions required). Also, the existing ash handling system may not be able to handle the increased amount of ash and adjustments may be required because of the properties of the ash (unreacted CaO combined with water and moisture releases heat and may create handling problems).

The quantity of sorbent for a given application is typically referred to in terms of calcium-to-sulfur ratio or stoichiometry and ranges from about 1.0 to >2.0 for SO₂ removals of 75 to 95 percent. For 80 percent SO₂ removal, calcium-to-sulfur ratio is in the lower end of this range. Also, when a baghouse is used downstream of the spray dryer, it reduces further the required sorbent (lower calcium-to-sulfur ratio), as it provides more residence time (in some cases up to 10-15 minutes) for the unreacted sorbent to react further.

Commercial Readiness and Industry Experience

Spray dryers are a commercial and well-established technology in the United States and abroad, with over 11,000 MW and 7,000 MW of installed capacity, respectively.⁴ The technology was first used in the early 1980's, and has been deployed in bituminous, subbituminous, and lignite applications. Significant experience was gained in the United States through extensive testing programs such as those conducted at TVA's Shawnee Station, EPRI's Environmental Control Technology Center, Northern States Power's Riverside Station, and B&W's Alliance Research Center.⁵

Emission Control Performance

Spray dryers are capable of very high SO₂ reductions (up to 95 percent). Data from IEA's coal research indicate SO₂ reductions from 70 to 96 percent with a median value of 90 percent, comparable to that of wet FGD technology. This performance reflects applications with coals less than 2 percent sulfur.⁴ Most U.S. applications of dry scrubbing (spray dryer or baghouse) have been for western subbituminous coal with sulfur contents of <1 percent.

Information and experience with mercury is less available than for SO₂. However, a number of test programs as well as the recent EPA's Mercury Information Collection Request (ICR) program have yielded some insight into the potential mercury reductions in spray dryers.¹⁻³ It is important to recognize that the performance of the spray dryers is typically reported together with the associated particulate control device (ESP or FF). In other words, mercury reductions are reported from the inlet to the spray

dryer to the outlet of the ESP or FF. In a 1994 study,⁶ spray dryers were documented to capture mercury in a wide but not fully understood range (6 – 96 percent) based on data for seven installations on coal-fired power plants. Although at that time, mercury speciation was not measured, the amount of mercury removal increased with coal chlorine content suggesting that spray dryers preferentially remove oxidized mercury. The wide range in the reduction values indicates more research is needed to understand completely the physical and chemical processes taking place in the control devices.

More recently, EPA's ICR has documented mercury reductions from spray dryer-ESP-FF systems using different rank coals (from bituminous to lignite). Figure 3-1 presents the results for spray dryer and ESP-FF combinations from the ICR test program. Total mercury reductions across the system are plotted against chlorine content of the coal (an indicator of the likely fraction of elemental vs oxidized gas-phase mercury in the flue gas). The large variation in the data is evident. Mercury reduction ranges from a low of less than 10 to over 95 percent at the high end. Factors that impact overall performance are not yet fully understood. Table 3-1 presents average reductions for spray dryer and ESP-FF system by coal rank from the ICR data.

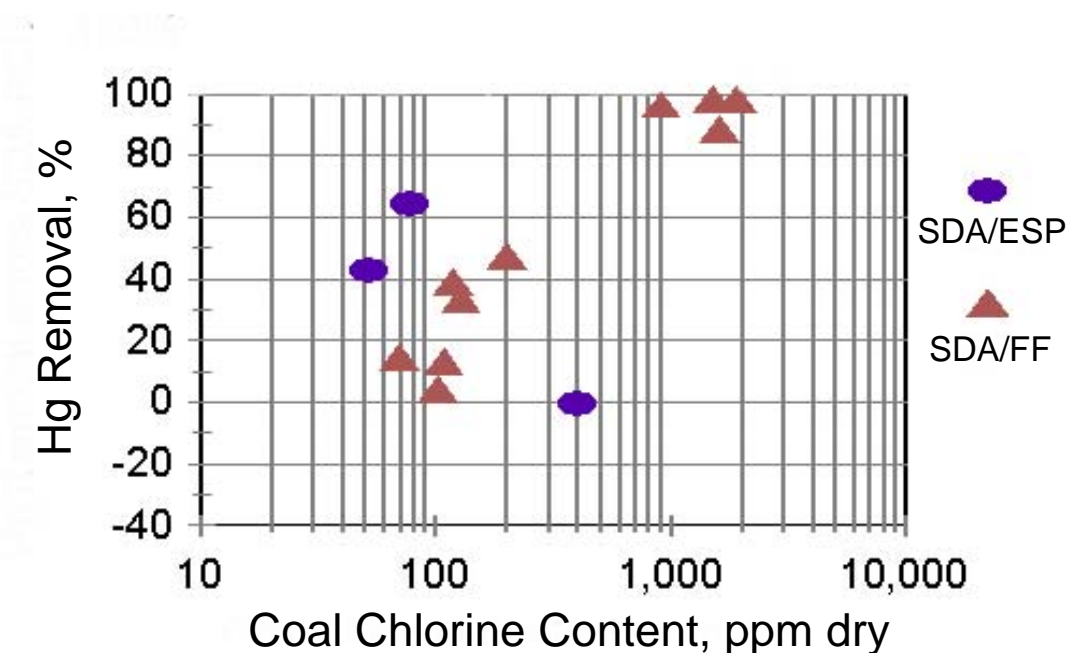


Figure 3-1. Mercury removal across spray dryer and ESP-FF from ICR data.²

Table 3-1. Average Mercury Reductions for Spray Dryer and ESP-FF per Coal Rank from ICR Data

Configuration	Coal Rank		
	Bituminous	Sub-Bituminous	Lignite
SDA-ESP	Not available	53%	Not available
SDA-FF	83%	22%	25%

O&M Impacts

O&M impacts include: 1. additional pressure loss associated with the spray dryer vessel and associated auxiliary power; 2. increased solids loading, which impacts the performance of the downstream particulate collector (mainly ESP) and ash handling system, and may increase the corrosion of the particulate collector and downstream ductwork; and 3. stack corrosion due to low approach-to-saturation temperatures. The magnitude of these impacts is a function of the specific design and operating conditions, and whether the ESP or FF is new or existing. Also, water usage is increased mainly for conditioning of the ash.

Capital Costs

Spray dryers represent a significant capital cost addition to a power plant. Costs have been reported in the 150 to 230 \$/kW range.⁷⁻⁹ For example in 1996 EPRI's TAG¹⁰ provided capital costs for a 300 MW unit ranging from 154 to 232 \$/kW and representing a variety of coals as well as geographical locations in the United States. As with other technologies, prices have tended to decrease as improvements to the technology have occurred.

O&M Costs

Fixed O&M costs are reported in the 1.5 - 7 \$/kW-yr range¹¹⁻¹³ for a range of coal sulfur contents of about 0.4 to 1 percent.

Variable O&M are reported,¹¹ in the range of about 0.2 to 0.7 mills/kWh, for the same sulfur content range.

Issues Associated with Dry Scrubbing; Future Outlook

The efficiency of mercury removal by dry scrubbers is related to mercury speciation, as well as a number of other factors. Additional information on mercury speciation and operating parameters in spray dryer-equipped power plants is necessary to better understand and predict mercury reduction performance. "Dedicated" mercury sorbents such as activated carbon should increase mercury capture potential.

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3.2.1.1.2 Advanced Dry Scrubbers

Advanced Dry FGD (CFB Absorbers) Summary

Status	Pilot to Commercial
SO₂ Reduction, %	90 - 98
NO_x Reduction, %	---
Hg Reduction, %	0 to 95
Cost	
Capital (\$/kW)	50 – 150 (depending on the type of technology used)
Fixed O&M (\$/kW-yr)	<1 – 3 (based on 1- 2 percent of capital)
Variable O&M (mills/kWh)	0.2 - 0.7
Applicability	SO ₂ -Hg control for low to medium sulfur coals (same as spray dryers)
Issues	Hg removal may vary significantly with coal type, operating conditions, and other pollution control devices present in the plant (similar to spray dryers)

Technology Description

Advances in dry scrubbing technology have focused on the general concept of increasing gas-solids mixing, hence reducing residence times in the absorber and allowing for more rapid evaporative cooling (1-2 seconds vs about 10 seconds in the conventional spray dryer). From a configuration perspective, these designs, for the most part, represent variations of Circulating Fluid Bed (CFB) technology with differentiating design features specific to each vendor. As in conventional spray dryers, lime slurry or hydrated lime are the typical sorbents used. A generic description is presented below, followed by brief descriptions of specific technologies offered by the major vendors. They include Circulating Dry Scrubbing (CDS) offered by LURGI, Gas Suspension Absorbers by FLS Miljo, Reflux Circulating Fluidized Bed Absorbers (RCFB) by WULFF GmbH, and Rapid Absorption Process (RAP) by Beaumont Environmental.

CFB Absorber Technology

The CFB absorber is a vertical reactor where a dense material bed of recycle products (ash and sorbent) ensures high gas-solids contact and more rapid cooling. The flue gas flows upward through the bed, with sorbent typically being sprayed as a slurry into the gas upstream of the bed. Product recycle is accomplished through a dedicated cyclone integral to the system, or directly from the final particulate collection device (ESP or FF).

CDS – LURGI¹⁻³

This technology uses a circulating fluid bed to establish a zone of high particle density. This bed is enhanced with activated carbon for mercury adsorption. Carbon utilization is enhanced due to the high residence time in the bed, while fine particles tend to agglomerate through "collisions" in the bed, facilitating their subsequent capture in a conventional ESP or FF. The technology is used with hydrated lime injection for control of acid gases.

GSA – FLS Miljo^{4,5}

Gas Suspension Absorption (GSA) uses a cyclone (designed for about 90 percent particulate removal) to recycle products into a dense bed which allows for rapid evaporative cooling as with the other technologies. This, in turn allows for lower temperatures [less than 11 °C (20 °F) approach to saturation

temperatures]. Flue gas from the boiler flows directly into the bottom of the GSA vessel. Simultaneously, lime-slaked slurry is atomized into the reactor, flowing upward with the flue gas. The lime content of the slurry is varied, depending on the SO₂ removal objectives.

GRAF – WULFF GmbH^{6,7}

The RCFB introduces an internal reflux within the circulating fluidized bed designed to increase the gas-solid mixing and sorbent residence time. This reflux (recirculation) within the RCFB reactor is equivalent to approximately 30 – 50 percent of the external product recirculation (from the downstream ESP or FF). As with the other technologies, gas temperature is controlled via internal water injection and SO₂ reduction via the amount of sorbent supply.

RAP - Beaumont^{8,9}

The Rapid Absorption Process uses a flash drying reactor technology combined with an external mixing chamber. In the flash drying process, recycle is accomplished through the final particulate control (ESP or FF). This reduces total pressure drop through the system. Differently from circulating fluid beds, lime slurry is introduced into a recycle transfer bin where it is mixed with recycle products, and then introduced into the reactor. Rapid cooling occurs as the products are introduced into the reactor, allowing for close-to-saturation temperatures and lower residence times.

Commercial Readiness and Industry Experience

While not widely used in the U.S. at present, the four CFB-based technologies are commercial, with installations in the U.S. and abroad. The RAP technology has undergone pilot-scale tests and has been demonstrated at a facility in Ohio combined with a low temperature NO_x removal system.

CDS - LURGI

The first commercial installation in the U.S. was deployed in 1995 at Black Hills Power and Light's Neil Simpson Station, Unit 2 on Powder River Basin coal. This is an 80 MW, coal-fired unit. The CFB was installed in a system arrangement with an ESP for particulate control. A 55 MW unit was installed in 1995 at the Roanoke Valley Energy Facility on eastern bituminous coal. The CFB reactor has been tested for multi-emission control in pilot scale at the 321 MW coal-fired boiler at PSE&G's Mercer Station, using activated carbon and lime for mercury and SO₂ control, respectively. Testing was carried out daily during a three-month period.

GSA – FLS Miljo

FLS Miljo offers GSA commercially, with over 35 installations worldwide in operation since 1986. In the U.S., GSA was demonstrated as part of DOE's Clean Coal Technology (CCT) program, at TVA's Center for Emissions Research. This program evaluated GSA and ESP as well as GSA and FF system configurations. More recently, a GSA retrofit was implemented to a 130 MW boiler at the Xiaolongtan power station in China. Demonstration of GSA on Boiler #9 (500,000 lbs.hr of 1,275 psig, 950 °F steam) at the City of Hamilton, OH showed SO₂ control exceeding 90 percent.¹⁰

GRAF – WULFF GmbH

WULFF GmbH commercially offers the RCFB. The technology is in full commercial use in plants ranging from 3 to 300 MW and firing various fuels for the simultaneous removal of SO₂ and mercury. Commercial Single module 660 MW system for a coal-fired plant is available.¹¹

RAP - Beaumont

The technology is currently being demonstrated at the SRI's combustion test facility. In addition, a full-scale demonstration program at the Medical College of Ohio is currently proceeding.

SO₂ and Mercury Emission Control Performance

In general, the advanced scrubbers are capable of >90 percent SO₂ reduction.^{12,13} With respect to mercury control, less information is available, but high removal rates (such as in conventional spray dryers) have been reported. Results will vary (as seen from the spray dryer data) depending on many operational factors such as solids concentration, temperatures, type of sorbent, or downstream particulate control device (ESP vs FF).

CDS - LURGI

Results from the Neil Simpson Station retrofit indicated around 95 percent SO₂ reduction in the CFB and ESP system, using coal with sulfur content varying from 0.2 percent to 1.2 percent. EPA-sponsored tests¹⁴ at the Roanoke Valley unit in September of 2000 indicated total mercury removal of 97 percent. At the Mercer Station, results for the CFB without activated carbon injection, indicated 50 percent capture of the mercury vapor. Mercury was reduced by 80 percent when the CFB was injected with iodine-impregnated activated carbon (at 1000:1 AC-to-Hg ratio).

GSA – FLS Miljo¹⁵

Results from the demonstration project at TVA under the CCT showed overall SO₂ removal efficiency of about 95 percent in the GSA and FF configuration at Ca to S ratio of 1.4, and about 90 percent in the GSA and ESP configuration with the same Ca to S ratio. The results of mercury removal tests in the GSA ranged from about 41.5 to 89.5 percent, without the use of activated carbon. The significant difference in removal efficiencies was attributed to variations in the residual carbon in the fly ash and the chlorine content of the coal.

GRAF – WULFF GmbH

SO₂ removal efficiency in the RCFB is reported from several plants to be in the 85 to 99 percent range. At the Dessau Heat and Power Station (operating on brown coal), SO₂ reduction was 90 – 96 percent. At the Strakonice plant in the Czech Republic, the desulfurization efficiency ranged between 85 and 95 percent. At the Theiss 2000 Power Station in Austria, SO₂ capture ranged from 90 to 99 percent. All three projects were carried out during the late 1990s through 2000. According to WULFF GmbH, mercury reduction using activated carbon in the RCFB can reach 98 percent. Mercury removal without activated carbon injection can reach up to 80 percent.

RAP - Beaumont

The technology is currently being piloted at a combustion test facility. Initial results were as high as 95 percent removal, but formal testing and demonstration on various coals and varying conditions will be part of a continuing program. According to Beaumont, at the Medical College of Ohio, the test program will investigate SO₂ reductions from 70 to 95 percent and sorbent utilization will be documented. Recycle rates and other variables for various coals are planned.

O&M Impacts

O&M impacts are similar to those of conventional spray dryers. For example, increased pressure loss, increased auxiliary power, increased solids loading, and its impact on the downstream particulate collector (ESP or FF) and ash handling equipment, corrosion of the downstream equipment, ductwork and stack due to low approach-to-saturation temperatures, and increased water requirements for ash conditioning. Because of better drying capability, the RAP technology, with lower exit moisture content, may minimize low temperature corrosion concerns. The magnitude of these impacts is a function of specific designs and operating conditions and whether the ESP or FF is new or existing.

Capital Costs

Capital costs vary from a low of 50 \$/kW (for a 150 MW plant) estimated by Beaumont, to about 150 \$/kW as reported for GSA from the CCT program.¹⁶ Capital cost for Lurgi CDS were estimated to be 140

\$/kW.¹⁶ According to GRAF GmbH, the capital cost for the RCFB at the 275 MW Theiss 2000 plant in Austria was 90 \$/kW.

O&M Costs

Fixed O&M costs are not well documented but should fall in the general area of about 1 – 2 percent of capital cost (EPRI TAG Guidelines). This would translate to a range of about 1 - 3 \$/kW-yr.

Variable O&M costs are expected to be similar or lower than those for spray dryers, therefore about 0.2-0.7 mill/kW-hr,^{10,12,17,18} corresponding to a sulfur content range of 0.4 – 1 percent.

Issues Associated with Advanced Dry Absorbers; Future Outlook

Similar to spray dryers, SO₂ performance is well documented for the three CFB-based absorbers. Mercury capture can potentially be >90 percent but is not well understood at present. Opportunity to add “dedicated” mercury sorbent will increase overall mercury removal potential.

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3.2.1.2 Sorbent Injection

Sorbent injection processes refer to the use of sorbent materials, typically in a powder or slurry form, which are injected into the flue gas upstream of a particulate control device. A key difference between these processes and those described in the previous section (dry scrubbers) is that in the latter, a dedicated reactor (the scrubber) is used to maximize the desired reactions, whereas in sorbent injection, the reactions occur in the flue gas duct and the downstream particulate control device. Inherently, performance of sorbent injection is directly related to the type of particulate control used with it (ESP or FF), as these devices offer additional “opportunity” for the reactions to take place, through residence or “contact” time.

Sorbent injection technologies can be characterized by the type of sorbent they utilize and by the type of pollutant they address. For example, activated carbon may be used for mercury control or calcium-based sorbent may be used for SO₂ control. Other differentiating features may include details on sorbent preparation, injection approach, and integration with the particulate control device, etc.

Sorbent injection technologies received significant “attention” in the US in the 1980’s, being developed as lower-cost and lower efficiency alternatives for SO₂ control. More recently, the technology has seen renewed interest, development and demonstration activities, driven by EPA’s December 2000 determination to control emissions of mercury from power plants.

The following sections describe several sorbent injection processes using different sorbents to achieve mercury or SO₂ reductions.

3.2.1.2.1 *Activated Carbon with Particulate Controls*

Activated Carbon with Particulate Controls Summary

Status	Pilot to commercial
SO₂ Reduction	None
NO_x Reduction	None
Hg Reduction	50 – 90 %
Cost	
Capital (\$/kW)	3 to >8 (for the carbon injection system only, low end of range for FF and COHPAC, high end for ESP application)
Fixed O&M (\$/kW-yr)	1 – 2
Variable O&M (mills/kWh)	0.2 – 2
Applicability	Retrofit and new units with ESP or FF
Issues	Not widely demonstrated at full scale on coal-fired plants, ash salability, particulate control effect on performance, impact of coal type

Technology Description

The technology involves the injection of an activated carbon (or alternative non-carbon sorbent) powder into the flue gas duct, somewhere between the air preheater and the ESP or FF. This is typically in the 120-175 °C (250-350 °F) range. Vapor-phase mercury is adsorbed onto the activated carbon, which is then collected in the ESP or FF. The mercury-activated carbon interaction continues to occur in the ESP or FF, where, in fact, the majority of the adsorption takes place. The technology can be used in conjunction with flue gas temperature control, usually accomplished through the injection of water droplets (spray cooling) into the flue gas. This can be done to optimize the temperature at which the activated carbon-mercury adsorption occurs. Lower approach-to-saturation temperatures favor the process.

A variation of this technology was developed and patented by EPRI. Named TOXECON, it is based on the combination of an ESP and a high air-to-cloth pulse-jet baghouse with sorbent injection technology (ACI plus COHPAC). This approach applies to retrofit situations where an ESP already exists and focuses on improving the efficiency of sorbent injection by providing high efficiency particulate collection as well as a good "contact" scheme for the sorbent and mercury, such as in the FF.

The most commonly studied sorbent for mercury control has been activated carbon. This material has been successfully used as a sorbent in municipal and hazardous waste combustors.¹ Activated carbon is carbon that has been “treated” to reflect certain properties such as surface area, pore volume, and pore size. Activated carbon can be manufactured from a variety of sources, including lignite, peat, coal, and wood. More commonly, steam is used for activation, which requires carbonization at high temperatures in an oxygen-lean environment. As some carbon atoms are vaporized, the desired highly porous activated carbon is produced. Commercially, activated carbon is available in a range of particle sizes, as well as other performance characteristics.² Furthermore, special activated carbon products such as iodine and sulfur impregnated are also available, and have been studied.^{3,4} Sorbents are often compared in terms of “capacity” and “reactivity.” These are a function of many parameters including surface area and porosity. Reactivity refers to the initial rate of reaction. Capacity refers to its ability to adsorb mercury in terms of mass of mercury captured per mass of sorbent.

Commercial Readiness and Industry Experience

To date, several pilot scale test programs and demonstrations have been conducted. Also, full-scale demonstration programs were completed to evaluate the performance, cost, and impacts of activated carbon injection. The program, sponsored by DOE, investigated several plant configurations, coals, and sorbents. This experience, combined with the experience gained in the 1980's with sorbent injection for SO₂ control, provides a sound basis for designing and implementing the technology.

The following are some of the pilot and full-scale demonstrations that were conducted:

- Public Service of Colorado, Comanche Station – pilot scale ESP, FF, and COHPAC and TOXECON⁵
- PSE&G Hudson Station – pilot scale COHPAC and TOXECON⁶
- Alabama Power, Gaston Plant – full scale COHPAC and TOXECON⁷
- WEPCO, Pleasant Prairie – full scale ESP⁷
- PGE NEG, Salem Harbor Station – full scale ESP⁷
- PGE NEG, Brayton Point Station – full scale dual ESPs⁷

The other component of the technology – activated carbon – is a commercially available product widely used in industry. Another source of carbon-based sorbent may be coal fly ash. Coal ash with varying carbon levels has shown utility as a mercury sorbent.⁸ However, properties of unburned carbon that contribute to mercury sorption are still not well understood. It is expected that fly ash-derived sorbents may become, in some cases, a cost-effective alternative to activated carbon. In addition, sorbents for mercury may also be produced from other inexpensive materials, such as corn-derived biomass and waste tires.⁹

Emission Control Performance

Approximately 86 percent of the coal-fired utility boilers currently operating in the United States are equipped with only an ESP or an FF, with ESP as the predominant PM emission control device. Gaseous mercury (both Hg⁰ and Hg²⁺) can potentially be adsorbed on fly ash and be collected in a downstream ESP or FF. The modern ESPs or FFs that are now used on most coal-fired units achieve very high capture efficiencies for total PM. As a consequence, these PM control devices are also effective in capturing PM-bound mercury (Hg^p) in the boiler flue gases. The degree to which mercury can be adsorbed onto fly ash for subsequent capture in PM control is dependent on the speciation of mercury, the flue gas concentration of fly ash, the properties of fly ash and the temperature of the flue gas in the PM control device. Gas-phase mercury in units equipped with an ESP can be adsorbed on the entrained fly ash upstream of the ESP. The gas-phase mercury in units equipped with a FF can be adsorbed by entrained fly ash or it can be adsorbed as the flue gas passes through the filter cake on the surface of the FF. The degree

to which gaseous mercury adsorbs on the filter cake typically depends on the speciation of gaseous mercury in the flue gas; in general, gaseous Hg^{2+} is easier to adsorb than gaseous Hg^0 . The very intimate contact between the gas and collected PM (which can act as a sorbent for the gas-phase mercury) that occurs in a FF significantly enhances the gas-phase mercury collection efficiency of the FF over what is possible with an ESP.¹⁰

The Information Collection Request (ICR) data showed that, for both bituminous and subbituminous coals, mercury collection in boilers equipped only with FFs was much higher than for boilers equipped only with ESPs. ICR data reflected that plants which employ only post-combustion PM controls display average Hg emission reductions ranging from 0 percent to 89 percent. The highest levels of control were observed for units with FFs. Decreasing levels of control were shown for units with ESPs, particulate scrubbers, and mechanical collectors. The average mercury reduction for two PC-fired units equipped with a FF baghouse and burning bituminous coal averaged 90 percent while two similarly equipped units burning subbituminous coals displayed an average mercury reduction of 72 percent. The average capture of Hg for PC-fired plants equipped with a cold-side ESP was 35 percent for bituminous coal, 3 percent for subbituminous coal, and near zero for lignite.¹¹

This effect also contributes to much more efficient collection of mercury when powdered activated carbon (PAC) is injected for additional mercury control upstream of a FF as opposed to injection upstream of an ESP. New hybrid ESP-FF technologies, such as the Combined Hybrid Particle Collector (COHPAC), offer ways to cost-effectively retrofit ESP's with FF and realize this benefit. The COHPAC approach also offers the benefit enabling segregation of injected PAC from much of the collected fly ash. The overall performance of the activated carbon injection technology is a function of many factors, including sorbent characteristics as well as plant configuration and operating conditions. Mercury reductions of 80 – 90 percent were documented at Alabama Power, Gaston Station for activated carbon with COHPAC.^{12,13} Reduction levels from 50 to 90 percent are possible for the range of technology configurations and activated carbons available. Model predictions¹⁴ for various configurations, sorbent characteristics, and operating conditions confirm this range of performance. If COHPAC is added to an existing ESP, in addition to the mercury reduction, particulates (including $\text{PM}_{2.5}$) are reduced, too.¹⁵

Laboratory, pilot scale, and modeling programs¹⁶⁻¹⁸ have indicated that the following parameters can affect the ultimate performance of the technology:

- sorbent type and properties,
- gas-phase mercury species (Hg^0 or HgCl_2),
- temperature,
- concentration of acid gases (HCl , SO_2 , NO , NO_2) in the flue gas,
- overall residence time, and
- dispersion of the sorbent in the flue gas.
- Further, the overall performance of the technology is a function of the quantity of sorbent required to achieve a desired result as can be observed below. Figure 3-2 contrasts pilot-scale ESP data (open symbols) with baghouse data (closed symbols) for sorbent injection and the same eastern bituminous coal burned at PSE&G's Hudson Station.¹⁹ As expected, given the better contact between sorbent and gas in a FF, the data confirm a higher mercury capture for the same sorbent loading.

Recent review and modeling²⁰ of full-scale data obtained during field tests at Gaston, Pleasant Prairie, Brayton Point, and Salem Harbor power plants produced the following findings:

- PAC injection followed by a FF results in much lower injection concentrations being necessary for a given level of mercury reduction than for PAC injection followed by a cold-side ESP.
- Sorbent selection appears to have little effect on performance when PAC injection is followed by a FF, but it appears to have a significant effect when PAC injection is followed by an ESP.
- Loss-on-ignition (LOI) and temperature can have a significant effect on the mercury removal by existing equipment.
- In some cases PAC injection without a downstream FF may not be able to achieve mercury removal rates of 90 percent or more regardless of PAC injection concentration.

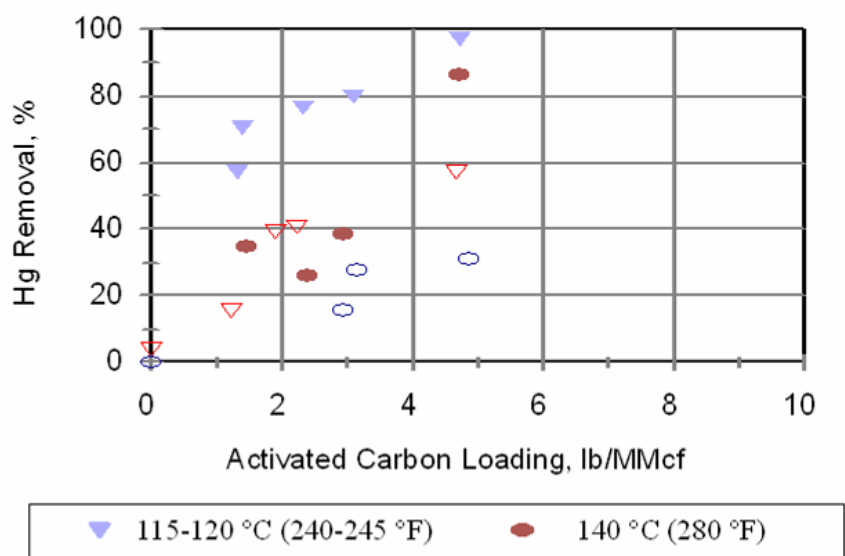


Figure 3-2. Mercury removal versus activated carbon loading in a pilot scale ESP (open symbols) and baghouse (closed symbols).¹⁹

O&M Impacts

The major potential O&M impacts associated with the activated carbon injection involve the following:

- increased particulate loading to the ESP or FF; this is not expected to be significant enough to affect performance, especially for the case of the FF,
- increased carbon content and different particle size distribution which may affect ESP and FF performance or operation factors such as entrainment, dust cake pressure loss,
- increased carbon content of fly ash may affect its salability,
- low flue gas temperatures (if spray cooling is used) affecting SO₃ dew point and, thus, intensifying corrosion and reducing bag life,
- auxiliary power for activated carbon injection, even though the amount is relatively small, and
- disposal and utilization of ash; testing at a number of DOE-funded demonstration projects indicates that AC injection does not affect the leaching properties of the ash to require changes in its disposal. However, if the ash is utilized or sold for construction applications, the increased concentration of carbon may affect the ability of the utility to sell it.

Capital Costs

Capital costs will vary significantly for applications with a FF or COHPAC vs those with an ESP. This is because of the significantly higher activated carbon requirements (may be a factor of 10) for ESP applications and the associated costs for sorbent storage. According to ADA-ES,⁷ the costs for the carbon injection system will vary from about \$2/kW for a FF and COHPAC configuration, to >\$6/kW for ESP applications. If spray cooling is used, the additional cost is estimated at \$1 - 2/kW. COHPAC's capital costs are estimated to be between 57 and 59 \$/kW for mercury removal between 50 and 90 percent, respectively.²⁰

O&M Costs

Fixed O&M costs are estimated to be in the range of \$1-2/kW-yr for a nominal plant size of 100 - 200 MW. Variable O&M will be driven by sorbent cost. Hence FF and COHPAC applications are estimated at 0.15-0.2 mills/kWh, with ESP potentially up to 2 mills/kWh. Variable O&M costs for COHPAC are estimated to be between 0.24 and 0.39 mills/kWh for mercury removal between 50 and 90 percent, respectively.²⁰

Issues Associated with Activated Carbon Injection; Future Outlook

At present, the technology is being demonstrated at full scale in several different applications. No significant "setbacks" have been identified. Due to its low capital cost, ease of retrofit, and compatibility with both ESP's and FF's, it is expected that carbon injection may become an efficient approach for retrofit in power plant applications without a combination of NO_x controls and scrubbers that may provide significant mercury capture of their own.

If the technology were used on a wide scale basis, deployment of new kilns and furnaces would be necessary to increase the production of activated carbon to meet the potential market for coal-fired boilers. The current market for activated carbon is 250,000 tons per year. Once mercury regulations are fully implemented, this could increase the demand.

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3.2.1.2.2 *SO₂ Sorbents*

SO₂ Sorbents Summary

Status	Pilot scale to pre-commercial demonstration
SO₂ Reduction	40 – 85 %
NO_x Reduction	None
Hg Reduction	NA
Cost	
Capital (\$/kW)	25 – 120 for 500 MW plant
Fixed O&M (\$/kW-yr)	1.6 – 7
Variable O&M (mills/kWh)	0.5 – 1
Applicability	Units with ESP or FF for particulate control
Issues	Calcium-based compounds not used commercially in coal fired plants. Waste disposal issue with sodium-based compounds. Potential impacts on ESP or FF.

Technology Description

SO₂ sorbent injection technologies include several variations based on the point of injection (furnace, economizer, ductwork upstream of an ESP or FF) and the sorbent type (calcium vs sodium based). In all cases, the major premise is that, by using the existing system as the “reactor,” significant cost savings can be achieved in situations where the SO₂ reductions of 40 – 50 percent are appropriate. In this section, the focus is on technologies involving the injection of a calcium- or sodium-based sorbent into the flue gas duct, somewhere between the air preheater and the ESP or FF (commonly referred to as “dry duct injection”). This is typically in the 120-175 °C (250-350 °F) range. SO₂ reacts with the sorbent to produce a mixture of sulfate and sulfite salts, which are then collected in the ESP or FF. The sorbent is either injected as atomized slurry, or as a powder separate from the water injection. Low approach-to-saturation temperatures enhance the ensuing reactions, therefore maximizing the SO₂ reductions. Several different approaches to the technology have been developed and are described briefly below.¹

Duct Injection - Lime Slurry

The duct injection of lime slurry is a process similar to a conventional spray dryer. The main difference is the elimination of the large reaction vessel by the direct spraying of lime slurry into the ductwork between

the air heater and the particulate control device. To offset the fact that the ductwork provides a much shorter residence time than the spray dryer vessel, slurry is atomized into very fine droplets in the duct injection process. The slurry droplets in such a fine mist dry out before reaching the particulate control device or prior to coming into contact with the duct walls, as required for proper operation. Two-fluid (air and slurry) atomizing spray nozzles are commonly used to provide the small droplets. Lime slurry injection was shown to provide slightly higher SO₂ removals than duct injection of dry hydrated lime.

Specialized processes and additives to improve the performance of the lime slurry injection process were developed at several commercial enterprises. They include Bechtel's Confined-Zone Dispersion (CZD) process, using pressure-hydrated dolomitic lime; General Electric's In-Duct Scrubbing (IDS) process, an in-duct spray drying system based on a rotary atomizer; and EPA's E-SO_x process, consisting of an array of spray nozzles fitted into a cavity created by removing the internals from the first field of an ESP.

Duct Injection - Dry Lime with Humidification

The use of dry hydrated lime requires separate injection of water, upstream or downstream of the lime injection point, to activate the lime. The water is finely atomized to enhance evaporation and to avoid wetting the duct walls. As with lime slurry, a number of commercial processes were developed including:

- Dravo's HALT Process – the Hydrate Addition at Low Temperature process which included the addition of NaOH to the water spray to enhance the lime-SO₂ reaction
- CONSOL's Coolside Process – similar to the HALT
- EPA's ADVACATE Process – ADVACATE uses an advanced sorbent produced by reacting lime and fly ash at elevated temperature
- EPRI's HYPAS – the Hybrid Pollution Abatement System injects hydrated lime and water between an ESP and a downstream FF

Duct Injection - Sodium Compounds

The use of sodium-based processes not requiring water was developed primarily for water-scarce regions such as in certain western states. Tests of various sodium compounds, including nahcolite, trona, soda ash, sodium bicarbonate, and sodium sesquicarbonate were conducted at a number of locations. The sodium sorbent is pulverized and injected into the flue gas through an array of nozzles located in the ductwork.

Commercial Readiness and Industry Experience

These technologies were tested or demonstrated extensively during the mid 1980's but never gained wide commercial acceptance. However, significant experience was gained regarding various sorbents as well as several injection approaches. Tables 3-2, 3-3, and 3-4 identify some of the test or demonstration and commercial programs.

Table 3-2. Duct Injection of Lime Slurry

Process	Developer	Test Site	Reference
Confined-Zone Dispersion (CZD)	Bechtel	Seward Station	2
In-Duct Scrubbing (IDS)	General Electric	Muskingum River Station	3
E-SO _x	U.S. EPA	Burger Station	4

Table 3-3. Duct Injection of Dry Lime

Process	Developer	Test Site	Reference
Hydrate Addition at Low Temperature (HALT)	Dravo Lime Company	Toronto Station	5
Coolside	Conoco	Edgewater	6
Advanced silicate (ADVACATE)	U.S. EPA	Edgewater Station (sorber) TVA Shawnee (process)	7
Hybrid Pollution Abatement System (HYPAS)	EPRI	EPRI High-Sulfur Test Center	8

Table 3-4. Duct Injection of Sodium

Utility or Operator	Plant and Location	Reference
Public Service Company of Colorado	Cameo Unit No. 1 Grand Junction, CO	9
City of Colorado Springs	Ray D. Nixon Unit No. 1 Fountain, CO	10
Public Service Company of Colorado	Cherokee Unit No. 4 Denver, CO	11
Wisconsin Electric Power Company	Port Washington Unit No. 3 Port Washington, WI	12

Emission Control Performance

The results from the various programs indicated SO₂ reductions in the range of 40 to about 85 percent, depending on sorbent type and stoichiometry, amount of recycle, temperature, and plant configuration. Little information is available on mercury reduction from these programs.

O&M Impacts

The major potential O&M impacts associated with SO₂ sorbent injection involve the following:

- increased particulate loading to the ESP or FF,
- different particle size distribution which may affect ESP and FF performance because of entrainment or dust cake pressure loss,
- impact of sodium injection reaction products or lowered gas temperatures on particulate resistivity, mostly resulting in an improved ESP performance,
- low flue gas temperatures (if spray cooling is used) affecting SO₃ dew point and, thus, intensifying corrosion and reducing bag life,
- impact on plume visibility from formation of NO₂ (for sodium-based sorbents),
- increased solid waste flow rate and associated auxiliary power; potentially, more operating problems may be experienced in the ash handling system if the right precautions are not taken to address the different properties of the ash when it includes unreacted sorbent,
- In case of sodium-based sorbents, disposal of solid waste needs to take into account the solubility of sodium compounds in water and associated concerns with the handling of sodium-containing leachate from the landfills, and
- increased water consumption mainly due to ash conditioning.

Capital Costs

Capital costs for these processes vary over a wide range from \$25 to 50/kW (FY 1990)¹³⁻¹⁵ to 70-120 \$/kW (FY 1990) for a 500 MW plant. Because there is no commercial application of these technologies, it is difficult to address the accuracy of these projections.

O&M Costs

O&M costs are not readily available. Fixed O&M is expected to be similar to or lower than spray dryers. Therefore, the same range of \$1.6-7/kW-yr is presented.¹⁶ Variable O&M costs are expected to be somewhat higher than those for conventional spray dryers (lower reagent effectiveness), therefore in the range of 0.5-1 mills/kWh for the same range of coal sulfur content of 0.4 to 1 percent.

Issues Associated with SO₂ Sorbent Injection; Future Outlook

The technology did not gain commercial acceptance as part of the compliance strategies for Phase I and II of the CAAA of 1990. In the future, broad compliance strategies and increased use of low sulfur coals may make this technology an attractive option for smaller units, plant or system "bubble" strategies, or in combination with activated carbon or other multipollutant sorbents to address mercury emissions.

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3.2.1.2.3 Combined Mercury and SO₂ Sorbents

Combined Mercury and SO₂ Sorbents Summary

Status	Pilot scale to commercial
SO₂ Reduction, %	40 – 85
NO_x Reduction	NA
Hg Reduction, %	Up to 90
Cost	
Capital (\$/kW)	28 – 58 for a nominal 500 MW plant
Fixed O&M (\$/kW-yr)	2.6 – 9
Variable O&M (mills/kWh)	0.7 – 3
Applicability	Units with ESP or FF for particulate control
Issues	Not used commercially, potential impacts on ESP or FF

Technology Description

As described in Sections 3.2.1.2.1 and 3.2.1.2.2, the basic technologies for sorbent injection involve the injection of a sorbent into the flue gas at temperatures in the range of 120-175 °C (250-350 °F) and before the particulate collection device (ESP or FF). Several actual methods of injection, such as dry powder and atomized slurry, have been developed to optimize the processes as a function of specific requirements and conditions. The technologies for combined or multipollutant sorbent injection involve the same approaches as described in the previous sections. The approaches may involve using sorbents together (activated carbon plus hydrated lime) or single, multipollutant-capability sorbents. In this section, a brief summary of combined and multipollutant sorbents is provided.

Commercial Readiness and Industry Experience

Data from the mercury ICR¹⁻³ program demonstrated that dry scrubbers remove mercury and SO₂, suggesting the ability of calcium-based sorbents to enhance mercury capture in addition to SO₂. Pilot test programs have documented the performance of combined sorbents.⁴⁻⁷ Much laboratory activity has focused on the development of novel and enhanced sorbents.^{8,9} Based on this experience, sorbent injection technology for combined SO₂-mercury reduction represents a viable, although not fully quantified approach for multi-emission control.

Emission Control Performance

Calcium-based sorbents have been characterized most extensively.^{8,10} Co-injection of activated carbon and calcium-based sorbents in air pollution control equipment has been known to increase the removal of mercury from flue gas. This was first demonstrated in spray dryer absorber (SDA) systems on full-scale coal-fired power plants.¹¹ There has been pilot work on injection of calcium-based sorbents upstream of a baghouse⁴ and into a specialized fluidized bed reactor.⁶ Combining activated carbon with hydrated lime can reduce the amount of carbon required (for an equivalent mercury removal) by one-half to one-third. Pilot tests of limestone furnace injection, followed by a cyclone separator, also showed good removal of mercury from flue gas in a pilot-scale unit burning eastern bituminous coals.¹²

Laboratory investigations of calcium-based sorbents for mercury control^{8,10} have shed light on the mechanisms involved that offer the potential for more efficient use of such sorbents across a range of applications. Fly ash, hydrated lime, and ADVACATE (a trademarked, pressurized fly ash-lime mixture) have been tested for mercury sorption in a fixed-bed reactor.¹⁰ All calcium-based sorbents captured HgCl₂ from simulated flue gas at 100 °C (although less than commercial activated carbon). Addition of SO₂ to

the gas mixture decreased the sorption of HgCl_2 , suggesting that there is competition for the same alkaline sites between the two species. In contrast, the calcium-based sorbents showed little or no removal of Hg^0 in the absence of SO_2 . Addition of SO_2 to the gas greatly enhanced the uptake of elemental mercury, suggesting the possibility of some chemical reaction on the surface. Increased sorbent surface area and internal pore volume also increased the capture of elemental mercury by calcium-based sorbents. More recently, hydrated lime and silicates have been evaluated for mercury, NO_x , and SO_2 capture in bench-scale tests. Oxidant-enhanced silicate sorbents indicated enhanced mercury capture. The practical significance of these results is that it is possibly more effective to separate the injection of sorbents dedicated to bulk acid gas removal (lower cost alkaline sorbents) from the higher porosity, oxidant-enhanced sorbents for mercury control.^{8,9} Unfortunately, while these studies offer a great deal of new understanding about the chemical and physical interactions between the flue gas, mercury, and sorbent, the results cannot yet be directly translated to full-scale performance.

Pilot-scale testing at PSE&G Hudson Station^{4,7} with activated carbon, sodium, and calcium sorbents in a COHPAC and TOXECON configuration has shown the ability to inject activated carbon simultaneously with other sorbents. Activated carbon performance was enhanced when tested with hydrated lime. Similar mercury capture of >80 percent was obtained with much lower levels of activated carbon (about a factor of 4) when combined with hydrated lime. In other tests using sodium sesquicarbonate and sodium bicarbonate injection, SO_2 reduction was up to about 90 percent for the bicarbonate and about 20 percent for sesquicarbonate. In other tests at PSE&G's Mercer Station,⁶ injection of activated carbon and hydrated lime into a fluid bed reactor resulted in mercury removals of up to 80 percent with iodine-impregnated carbon at a ratio of 1000:1 and about 67 percent for non-impregnated carbon at a ratio of 2000:1. SO_2 removal with hydrated lime was about 70 percent with 100 percent sorbent utilization.

In summary, combined and multipollutant sorbent use with sorbent injection technology is neither used nor quantified in full-scale applications. However, based on information from activated carbon and SO_2 sorbent technologies, it is expected that combined performance will be similar to that of the individual technologies, while the development of new sorbents may optimize the utilization and efficiency of future technology applications.

O&M Impacts

The major potential O&M impacts associated with combined and multipollutant sorbent injection include the following:

- increased particulate loading to the ESP or FF,
- impact of reaction products on particulate resistivity and associated ESP performance,
- low flue gas temperatures (if spray cooling is used) affecting SO_3 dew point and, thus, intensifying corrosion and reducing bag life,
- impact on plume visibility from formation of NO_2 (for sodium-based sorbents),
- increased carbon content and different particle size distribution which may affect ESP and FF performance (entrainment, dust cake pressure loss), and
- impact of increased carbon content on fly ash salability.

Capital Costs

No information on capital costs is available for multipollutant sorbent injection technologies. However, it can be extrapolated that at one extreme the combination of activated carbon and SO_2 sorbent injection technologies would cost no more (likely less) than the sum of the two. In this case, the range of about \$28-58/kW would apply. In practice, economies would exist in design, construction, and installation of such multipollutant control technologies.

O&M Costs

O&M costs are not directly available. However, following the same rationale as above, the combined technologies would have costs as follows:

- Fixed O&M in the range of \$2.6 – 9/kWh
- Variable O&M in the range of 0.7 – 3 mills/kWh.

These are predicated on a coal sulfur range of 0.4 to 1 percent.¹³

Issues associated with Combined Mercury and SO₂ Sorbent Injection; Future Outlook

The same issues apply as for the application of the individual activated carbon and SO₂ sorbent injection technologies.

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3.2.1.3 Wet Scrubbers

Wet desulfurization refers to the most widely used SO₂ control technology worldwide (approximately 220 GW of installed capacity) and in the United States (approximately 84 GW of installed capacity),¹ commonly known as wet scrubbers or wet FGD. Wet scrubbers have been shown to be efficient devices in capturing oxidized mercury in the flue gas.¹⁻⁷ This fact has triggered a number of developments geared towards understanding and promoting the oxidation of elemental mercury in the flue gas of wet-scrubber-equipped plants as a means of maximizing the mercury capture within the wet scrubber. These efforts have focused mostly on catalyst-enhanced oxidation and reagent injection approaches for mercury oxidation. In addition, and as a result of developments in wet precipitator technology (WESP) and the compatibility of WESPs with wet scrubbers, the wet scrubber-WESP combination represents another system approach to combined SO₂ and mercury capture. Because these various processes are predicated on well-known, conventional and widely used wet scrubber technology, the basic wet scrubber technology description is presented in this section to avoid repetition. The “add-on” technology components are discussed in their respective sections.

Technology Description - Wet Scrubber

The most commonly used wet scrubber technology uses a wet limestone process to remove SO₂ from the flue gas with in-situ forced oxidation to produce a gypsum-grade by-product. This is typically accomplished in a vertical vessel with flue gas cooling and reaction with limestone slurry to produce a mix of calcium sulfite and sulfate. Through controlled oxidation of the reaction products, a salable by-product in the form of commercial grade gypsum (hydrated calcium sulfate) may be produced. The intimate contact between gas and liquid is ensured through different design approaches, usually involving several counter flow spray levels and mass transfer “trays” to optimize gas-liquid interactions. The technology has evolved over the years through “mechanical” improvements, which have included better gas and liquid distribution within the scrubber, droplet size and size distribution, as well as “chemistry” improvements such as the addition of organic acids [adipic acid or dibasic organic acid (DBA) used most often], which not only improve overall SO₂ capture but also help the settling characteristics of the waste

products. Several commercial variations of the technology exist based on reagent type, vessel design, etc. Because oxidized vapor-phase mercury is water soluble (whereas, elemental mercury is not), the intense gas-liquid mass transfer in wet scrubbers is potentially an excellent mercury control mechanism.

3.2.1.3.1 *Wet Scrubbers with Mercury Oxidation Processes*

Wet FGD with Mercury Oxidation Processes Summary

Status	Under development, Pilot-scale testing
SO₂ Reduction, %	95
NO_x Reduction	NA
Hg Reduction, %	>80
Cost	
Capital (\$/kW)	160 – 275 for a nominal 400 MW plant
Fixed O&M (\$/kW-yr)	1.2 – 14 (scrubber only)
Variable O&M (mills/kWh)	0.1 – 1
Applicability	Wet Scrubber Plants
Issues	Full scale demonstration underway, insufficient information at present

The two major areas of development underway in the area of mercury oxidation in the flue gas, upstream of wet scrubbers involve catalytic oxidation^{5,7} and oxidation resulting from reagent injection.^{6,8} One other approach injects chlorine into the flue gas to form HgCl₂ upstream of the wet scrubber.

Catalytic Oxidation

This approach involves the deployment of a catalyst in the flue gas (similar to the use of SCR for NO_x control) to oxidize elemental mercury. While catalyst development and testing are at the laboratory scale, full-scale application would likely involve a conventional support structure (honeycomb) placed between the particulate control device and the wet scrubber. A number of catalyst materials have been investigated at several test sites including carbon, palladium, iron, and high carbon fly ash⁸ with varying degrees of success. Full-scale application of the technology envisions the catalyst to be exposed to flue gas in an area of low velocity [~ 1.5 m/s (5 ft/s)], possibly downstream of the last field of an ESP.^{5,9}

Reagent-based Oxidation

This technology involves the introduction of dedicated reagents into the flue gas or the scrubber itself. In both cases, the objective is to promote the conversion of elemental mercury to an oxidized form (most often HgCl₂). The flue gas injection approach is expected to promote the conversion of HCl to Cl₂ in the flue gas, thereby providing a pathway for the formation of HgCl₂. The direct scrubber injection approach involves the addition of small amounts of a proprietary reagent into the scrubber recirculation system.⁶ Details are not publicly available at present.

Commercial Readiness and Industry Experience

Catalytic Oxidation

At present, the technology is at laboratory- and pilot-scale development. Laboratory- and pilot-scale tests funded by the DOE and EPRI have identified several catalyst materials successful in oxidizing elemental mercury. Further testing of these catalysts has focused on two issues associated with the catalytic oxidation process: (1) catalyst life and (2) the applicability of the process for the U.S. electric utility industry.^{5,7} Results to date suggest that larger scale testing is warranted at this time.

Reagent-based Oxidation

Reagent tests have been conducted for wet scrubber enhancement at B&W's Clean Environment Development Facility (CEDF). In the course of several tests, a reagent was found which allowed for over 80 percent mercury removal while having no negative effects on scrubber operation.⁶ The technology was later demonstrated at the 55 MW Endicott Station (limestone forced oxidation system). Further tests of the technology at Zimmer Station (magnesium enhanced lime) demonstrated average Hg removal across wet FGD of 51 percent.¹⁰

Emission Control Performance

Catalytic Oxidation

In laboratory- and pilot-scale tests, several of the catalysts tested exhibited levels of elemental mercury oxidation in the 70 to 95 percent range. In particular, palladium, carbon, and high-carbon fly ash-based catalysts exhibited high levels of oxidation. Further, tests to address catalyst longevity, while preliminary, indicate that the palladium catalyst, and three of the five catalysts tested retained better than 70 percent oxidation of the inlet elemental mercury at the end of the 5-month test period.⁵ Palladium catalyst showed little deactivation after approximately 4,000 hours of operation.

Reagent-based Oxidation

Results from two series of testing indicated that high levels of mercury removal (up to 86 percent) were repeatedly achieved with small amounts of proprietary reagents with no adverse effects on scrubber operation or SO₂ removal. This is in comparison to baseline (no reagent) removal of mercury across the scrubber of about 72 percent.¹⁰

O&M Impacts

There is not sufficient information at present to assess the impacts of the oxidation process itself. In the case of catalytic oxidation, the presence of the catalyst could have a minimum impact on flue gas pressure loss. The wet FGD adds additional pressure drop and increases the auxiliary power consumption by up to 1.5-2.5 percent.

Capital Costs

Wet scrubber: \$160-273/kW;¹¹ as low as \$103/kW reported¹²

Catalytic oxidation: estimated for 400 MW plant to be about \$5/kW⁵

Reagent Injection: NA

O&M Costs

Wet scrubber

- Fixed O&M: \$1.2-14/kW-yr¹³ (for a range of coal sulfur from 0.4 to about 3.5 percent)
- Variable O&M: 0.1-1 mill/kWh¹³ (for a range of coal sulfur from 0.4 to about 3.5 percent)

Catalytic oxidation: estimated for 400 MW plant to be about \$3.5/kW-yr.⁵ This is total O&M and includes the catalyst cost, which is treated as an O&M expense, projected as catalyst replacement every 3 years.

Issues Associated with the Technology; Future Outlook

Catalytic Oxidation

Further pilot-scale testing is needed for periods of 1 to 3 years to more clearly understand catalyst life, as several catalyst candidates appear to warrant such testing. Further testing of the potential for oxidation of other flue gas elements, including SO₂ and NO, should be carried out. Parallel research to characterize the stability and fate of mercury in the FGD sludge or gypsum is ongoing.

Reagent-based Oxidation

Potential for re-emission of elemental mercury from the scrubber's tank, and means to prevent it, are being investigated.¹⁴

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3.2.1.3.2 *Wet Scrubbers with Wet ESP*

Wet FGD with Wet ESP Summary

Status	Commercially available, being tested in power plant applications
SO₂ Reduction, %	99
NO_x Reduction	NA
Hg Reduction, %	Up to 80
Cost	
Capital (\$/kW)	10 – 25 (WESP only) for a nominal 400 MW plant
Fixed O&M (\$/kW-yr)	0.5 – 1.5
Variable O&M (mills/kWh)	---
Applicability	Integration with wet scrubbers, retrofit dry ESPs, new units
Issues	Few applications in power industry, potentially expensive alloys required

Technology Description

Wet ESP

Wet Electrostatic Precipitators (WESPs), like dry ESPs, operate in a three-step process: charging of the entering particles, collection of the particles on the surface of an oppositely charged surface, and finally, cleaning the collection surface. Both technologies employ separate charging and collection systems. However, unlike dry ESPs, in the WESP the collecting surface is cleaned with water as opposed to mechanically. As a result, the two technologies differ in the nature of particles that can be removed, the overall efficiency of removal, and the design and maintenance parameters.¹ While dry ESPs are typically limited to power levels of 100-500 watts per 0.47 m³/s (1,000 cfm), WESPs can handle power levels as high as 2,000 watts per 0.47 m³/s (1,000 cfm). As a result, WESPs can handle a wide variety of pollutants and flue gas conditions and are highly efficient on submicrometer particles and acid mist. WESPs have also been found to be most efficient in treating flue gases with high moisture content or sticky particulate matter. As a result of the wet cleansing of the collection system, particulate matter does not accumulate on the ESP collection electrodes, therefore mitigating particle re-entrainment.^{1,2}

WESPs can be configured for vertical or horizontal gas flows in tubular or plate designs. Tubular designs offer smaller footprints and, in general, are more efficient than the plate type.

WESP Integration with Wet Scrubber

WESPs are compatible and easily integrated into a system design with a wet scrubber.³ In fact, integration of the WESP within the wet scrubber is a design option with many synergisms and attractive features,⁴

- compact footprint, considering that the scrubber and the WESP could share a common casing,
- ability to integrate the handling of the wash water and solids from the WESP with scrubber slurry, avoiding the need for separate tank and blowdown system, and
- ability to collect the fine sulfuric acid mist that typically escapes the scrubber due to its very small droplet size.

Commercial Readiness and Industry Experience

WESPs have been used for almost a century as standard technology in abating the submicrometer particle SO₃ mist in sulfuric acid plants.⁵ It was until recently, however, a relatively unknown technology to the electric power industry. An up-flow tubular design WESP has been retrofit at Northern States Power Company's Sherco Station in a wet scrubber-WESP configuration. In addition, a horizontal flow, plate WESP system was recently installed at Potomac Electric Power Company's Dickerson Generating Station, converting an existing dry ESP to hybrid operation by replacing the third field of the existing ESP to wet operation.¹

In 1986, the first commercial WESP application on a U.S. power plant took place when AES Deepwater, a 155 MW cogeneration plant firing petroleum coke as the primary fuel, was equipped with a WESP. The other air pollution control equipment included a dry ESP and a wet scrubber. The WESP was installed mainly for removing relatively high levels of sulfur trioxide. With the WESP in operation, the plume opacity at the plant is generally 10 percent or less.⁶ Two more power plant applications are underway presently: (1) 2.35 m³/s (5,000 cfm) slipstream at the Bruce Mansfield Station and (2) a plate type WESP for integration with Powerspan's ECO technology to be demonstrated at First Energy's R.E. Burger plant. The WESP at the Mansfield Station is achieving greater than 95 percent removal of SO₃ and PM_{2.5} and stack flow with near-zero opacity.^{7,8}

Emission Control Performance

When integrated with upstream technology, including wet scrubbers, multiple pollutants can be removed by WESPs. A hazardous waste facility fit with a two-stage tubular WESP following a scrubber achieved 99.9 percent removal of acid gases, dioxins, furans, PM_{2.5}, and metals. It achieved 78 percent removal of mercury.^{1,2} At a mining operation, a combined scrubber and WESP system achieved an SO₂ removal of 99 percent.^{1,2}

Tests at the Sherco Station (WESP retrofit to the outlet section of the wet scrubber) allowed the scrubber to maintain a 70 percent SO₂ reduction, while keeping particulate emissions at 0.01 lb/MMBtu and opacity under 10 percent. Full conversion of all the plant's scrubber modules with WESPs is now underway.

In pilot scale tests at Southern Research Institute,⁹ a plate type WESP yielded the following removal results:

- SO₂: 10 – 25 percent
- SO₃: ~ 65 percent
- PM: 90 – 99 percent
- Hg: ~ 30 percent

O&M Impacts

When WESP is integrated with a wet FGD, there are no significant O&M impacts other than auxiliary power requirements; in this case, the wastewater from the WESP is handled together with the FGD wastes. Auxiliary power is higher than dry ESPs by a factor as WESP operating power could reach 2,000 Watts per 1,000 cfm, while dry ESP power ranges from 100 to 500 watts per 1,000 cfm.^{10,11}

Capital Costs

According to vendors,¹² capital costs are estimated in the range of \$10 - 25/kW depending on unit size, flue gas conditions, and overall design configuration. If special alloys are necessary, due to acid gas concentrations, the costs could be considerably higher. Non-metal materials are being investigated with the potential for cost reduction. Note that these costs refer to the WESP only, not the SO₂ scrubber.

O&M Costs

According to vendors, there is no appreciable increase in O&M costs. O&M for WESP is estimated to be less than half when compared to a dry ESP. A general estimate of about \$1/kW-yr was provided for fixed O&M cost including the increased power consumption.

Issues Associated with the Technology; Future Outlook

Several conditions determine the efficiency of a WESP system and should be considered in each specific design. These include air distribution, sparking, and corona current suppression. Integration with wet scrubbers can offer significant advantages to wet scrubber operations, specifically in sulfuric acid mist control. Material performance will be key to overall cost of the technology. Expensive alloys may reduce market appeal.

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3.2.1.3.3 Plasma-Enhanced ESP (PEESP)

PEESP Summary

Status	Bench scale
SO₂ Reduction, %	(>90 with FGD)
NO_x Reduction, %	NA
Hg Reduction, %	Up to 90
Cost	
Capital (\$/kW)	< \$5/kW for retrofit of Wet ESP
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	NA
Applicability	Both new and retrofit applications
Issues	Early stage of development; demonstration and further assessment of the technology is needed

Technology Description

Wet Electrostatic Precipitators (Wet ESP) have demonstrated that they can remove multiple pollutants. For example, pilot scale dry-wet ESP (addition of a wet ESP field in a dry ESP without PEESP) funded by the Electric Power Research Institute (EPRI)¹ in a 1995 demonstrated the following removals: 95 percent particulate, 20 percent SO₂, 35 percent hydrogen chloride, 45 percent hydrogen fluoride, and 50 percent oxidized mercury. In 2001, a wet ESP pilot unit funded by Croll-Reynolds and First Energy demonstrated greater than 90 percent removal of PM_{2.5} and SO₃ mist in a two-field electrical configuration² with the ESP after an FGD system. In addition, 40 percent removal of elemental mercury and greater than 70 percent removal of particulate and oxidized mercury were achieved in a single electrical field configuration.

The ability of Wet ESP to remove elemental mercury can be enhanced further through Plasma-Enhanced ESP (PEESP) technology. PEESP oxidizes vapor phase elemental mercury into oxidized form and then removes it within the Wet ESP process. This technology involves injection of a reagent gas mixture, through a corona discharge needle that is attached to the central electrode within an electrostatic field. Injection into the area surrounding the sharp discharge point results in generation of hydroxyl radicals, ozone and other reactive compounds. These react with elemental mercury vapor to form oxidized mercury particles. These negatively charged particles are attracted to the positively charged collecting electrode where they are collected. The mercuric oxide particles and other absorbed pollutants are removed during the wash-down cycle of the Wet ESP.

PEESP can be incorporated in an existing Wet ESP by modifying the central electrode to inject the reagent gas.

Commercial Readiness and Industry Experience

The technology has been tested at bench scale. Scale-up to pilot scale size of 5,000 actual cubic feet per minute (ACFM) is planned and testing will commence later in 2004.

Emission Control Performance

The supplier projects that up to 90 percent total mercury removal can be achieved at pilot and full scale. Bench scale testing³ demonstrated mercury removal efficiencies up to 83 percent.

O&M Impacts

O&M impacts are not known, mainly because of the lack of information, but are expected to be minimal since the PEESP technology is a passive device retrofitted within a wet ESP. There are no significant impact expected on pressure drop and performance of upstream equipment.

Costs

Capital costs for Wet ESPs are estimated at \$20-\$35 per kW depending upon the difficulty of the installation at a site. The cost to retrofit the PEESP technology within a wet ESP is less than \$5 per kW, as it requires only modification of the central discharge electrode.

O&M costs are not available presently because of the technology is at an early stage of development.

Issues Associated with the Technology; Future Outlook

There has been limited mercury removal experience with Wet ESPs. What has been reported shows some oxidation of elemental mercury and capture of particulate and oxidized forms of mercury similar to that for PM_{2.5}.⁴ The PEESP technology seeks to enhance oxidation of elemental mercury to improve total mercury removal. The technology is still at an early development stage (bench scale towards pilot plant) and requires further demonstration and techno-economic assessment to develop a more comprehensive picture of its cost-effectiveness. Additionally, further investigation is needed regarding the water chemistry within the wet ESP to keep the oxidized mercury from being reduced back to elemental mercury.

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3.2.1.4 MerCAP

MerCAP Process Summary

Status	Early pilot plant testing
SO₂ Reduction, %	Existing scrubber
NO_x Reduction, %	NA
Hg Reduction	>80% for 10 ft long plates spaced 0.5 inches apart
Cost	
Capital (\$/kW)	18.8 \$/kW for a 250 MW plant
Fixed O&M (\$/kW-yr)	0.46 – 0.87 mills/kWh
Variable O&M (mills/kWh)	0.19 mills/kWh
Applicability	New power plants and retrofits
Issues	Did not perform well in unscrubbed gas

Mercury Control via Adsorption Process (MerCAP) concept is to place fixed sorbent-coated structures into a flue gas stream at temperature below 400 °F to adsorb mercury and then periodically regenerate them and recover the captured mercury. Slip-stream field tests of this concept were conducted at four different sites with the in-situ probes with various spacing and gold coatings (different thickness and support plates). The in-situ probes were designed and fabricated to allow testing of full-length (10-foot long) plates. Table 3-5 summarizes the test conditions and results at the four sites. The sites included two PRB units, one equipped with an ESP (probe located downstream of the ESP) and one with a wet particulate scrubber (WPS) (probe located upstream of the WPS in full dust loading) and two North Dakota lignite units, one equipped with an ESP (probe located downstream of ESP) and one with a spray dryer-baghouse (probe located downstream of spray dryer-baghouse).^{1,2}

Table 3-5. Summary of MerCAP Field Sites

Site ID	Plant	Coal Type	Fuel Composition		Test Location	HCl at Test Location (est. ppm)	SO ₂ at Test Location (ppm)	Initial Mercury removal, %
			S (%)	Cl (ppm)				
S2	Pleasant Prairie	Subbituminous	0.5	14	ESP Outlet	< 10	280-340	0-24
S9	Laskin	Subbituminous	0.4	<50	WPS Inlet	0.7	200-400	20
L1	Coal Creek	ND Lignite	1	20	ESP Outlet	<10	1000	10
L2	Stanton	ND Lignite	0.06	30	FF Outlet	<10	100	55-89

Two long-term slip-stream tests are planned for a period August 2004 through January 2005. At Great River Energy's Stanton Station, which burns North Dakota lignite, sorbent structures will be retrofitted into a single compartment in the Unit 10 baghouse enabling reaction with a 6 MW equivalence of flue gas. At Southern Company Services' Plant Yates, which burns Eastern bituminous coal, gold-coated plates will be configured as a mist eliminator located downstream of a 1 MW pilot wet absorber, which receives flue gas from Unit 1.¹

Additional tests will evaluate the ability to thermally regenerate the gold-coated plates. The results of this study will provide data required for assessing the feasibility and estimating the costs of a full-scale MerCAP process for flue gas mercury removal. The study will provide information about optimal operating conditions for different flue gas conditions, the effectiveness of sorbent regeneration, and the ability of the gold sorbent to hold up to flue gas over an extended period. In addition, if successful, the novel approach of incorporating MerCAP structures in existing baghouse compartments will demonstrate a cost-effective means for achieving mercury control using existing baghouse technologies.

Commercial Readiness and Industry Experience

The technology has been tested at pilot scale.

Emission Control Performance

Tests indicate that given the right flue gas conditions, MerCAP with gold coated plates around 10 ft long and spaced 0.5 inches apart can remove more than 80 percent of mercury. In the tests conducted to date in flue gas derived from low rank fuels, this performance was achieved downstream of a spray dryer-baghouse. Similar results have recently been obtained in other tests conducted downstream of a wet absorber in bituminous-derived flue gas. Developer claims that higher removals (>90 percent) for the short term should be achievable by increasing plate length, decreasing plate spacing, or reducing gas velocities.²

O&M Impacts

A factor that may reduce cost is the use of sorbent material that is cheaper or has higher mercury capacities than gold. Development work is needed to evaluate these options to reduce costs as well as to establish sorbent capacity, regeneration frequency, and sorbent life expectancy for the range of power plant configurations and coals burned. Projected additional pressure drop is less than 2" of H₂O for plate-to-plate spacing of 1-inch and a gas velocity of 60 ft/s.

Costs

The capital costs for a MerCAP system with 90 percent mercury control, 3-month regeneration, and 100 percent redundancy is estimated at \$4.7 million for a 250 MW unit (this corresponds to \$18.8/kW). Of the

capital cost, \$2.3 million is the gold media and its substrate. For 1-year regeneration and lower mercury capacity (10 percent compared to 15 percent of the weight of gold), the costs are \$14.9 million for a 250 MW unit (this corresponds to \$59/kW) with \$12.6 million in gold media and substrate cost.²

O&M costs are estimated by a preliminary engineering economic study to range from 0.46 to 0.87 mills/kWh and 0.19 mills/kWh for fixed and variable component, respectively. The amount and cost of the sorbent media is the major cost component for a MerCAP installation.²

Issues Associated with the Technology; Future Outlook

MerCAP with gold as the sorbent surface did not perform well in non-scrubbed flue gas. Mercury removal effectiveness, although low in non-scrubbed gases, also did not appear to degrade over time in flue gas. It is uncertain at this point whether the low effectiveness is due to specific flue gas components, which reduced the gold capacity for mercury in the gases tested, or due to an effect of temperature, or to a combination of both. Sorbent materials other than gold are also being tested as alternate coatings. Some of the materials may be more effective or offer a cost-effective alternative to gold for specific flue gas conditions.²

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3.2.2 SO₂ and NO_x Control

3.2.2.1 Electron Beam Process

Electron Beam Process Summary

Status	Early commercialization stage
SO₂ Reduction, %	>95
NO_x Reduction, %	Up to 90
Hg Reduction	NA
Cost	
Capital (\$/kW)	180 – 250 for 100 – 300 MW
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	NA
Applicability	New power plants and retrofits
Issues	Demonstration is required. High auxiliary power requirement is the main barrier.

Technology Description

The electron beam (E-beam) process is capable of removing simultaneously SO₂ and NO_x and involves cooling of the flue gas, injection of ammonia, and then irradiation by high-energy electrons.¹⁻⁵ As Figure 3-3 shows, the E-beam process equipment is placed after the ESP. The first component is an evaporative spray cooler, where the flue gas is cooled to 60-66 °C (140-150 °F). The spray cooler is operated with a

dry bottom (all the water injected into the flue gas is evaporated). In addition, gaseous ammonia is injected into the flue gas either before or after the spray cooler.

The main component of the E-beam process is a chamber where the flue gas is irradiated by a beam of high-energy electrons, while water is added to counteract the temperature rise. The irradiation also generates hydroxyl radicals and oxygen atoms, which oxidize the SO_2 and NO_x . These oxidized species mix with water in the flue gas to form sulfuric acid and nitric acid, which are neutralized by the ammonia. The by-products of the E-beam process are solid ammonium sulfate and ammonium sulfate-nitrate, which are collected downstream of the E-beam chamber by an ESP or a baghouse, and can be used as fertilizer after processing into a granular product. The by-product particles are small and sticky and pose some problems to both ESPs and FFs. A combination of ESP-FF has been proposed as more effective. In addition, use of inert materials has been considered to make it easier to clean the bags of the baghouse.

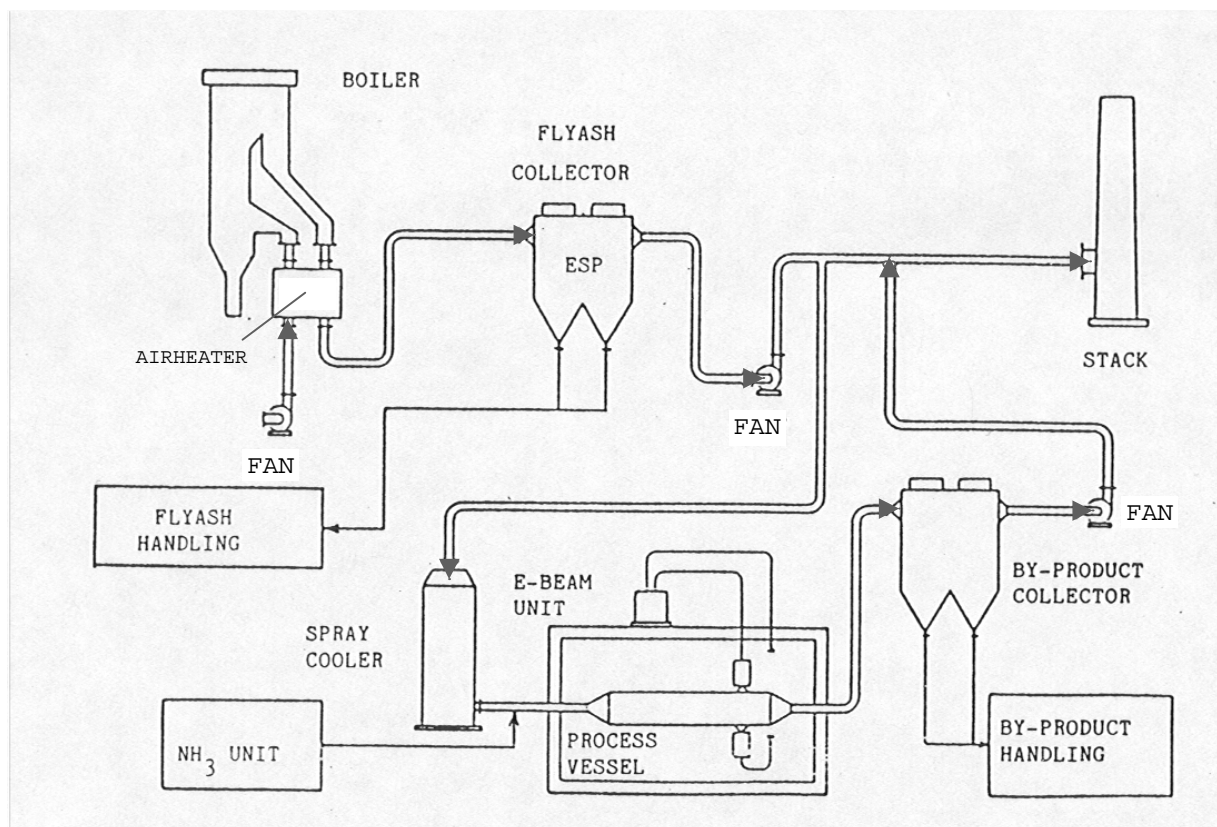


Figure 3-3. E-Beam process schematic.

Commercial Readiness and Industry Experience

The technology is in an early commercialization stage with a number of demonstration plants in operation, but no operating commercial applications. Ebara International Corp. is actively promoting this technology, but others are preparing to offer related systems (primarily different methods for producing the ionization energy). The main reason for limited acceptance of the technology is that it is more expensive (relative to other competing options such as FGDs) as an SO_2 removal process only. Future market acceptance of this technology will depend on whether it is cheaper than the combination of individual SO_2 and NO_x controls for the levels of SO_2 and NO_x emissions required. Another major factor

will be the price that can be obtained for the fertilizer by-product. Should it be possible to sell the fertilizer by-product, this revenue stream would possibly help partially offset O&M costs.

Pilot-scale testing was conducted at Indianapolis Power & Light's Stout station in an 8 MW slipstream in 1986. Similarly, the process was tested in 1992 at Chubu Electric Power Company's Nishi-Nagoya plant on a slipstream (12,000 Nm³/h) of the 200 MW boiler firing Australian coal. The emission reductions achieved were: 92 percent SO₂ and 60 percent NO_x. After the successful operation of this plant, Chubu decided to install the E-beam process in the Nishi-Nagoya 1 unit, which burns high-sulfur residual oil.

Also, the E-beam process was demonstrated at the Chengdou Power Plant in Sichuan Province, China. The plant is 90- MW and has been operating since July 1997. SO₂ removals have been in the mid-80 percent range and NO_x removal was between 15 and 20 percent using low-to-high-sulfur bituminous coal (600 – 2500 ppm inlet SO₂).⁶

Emission Control Performance

The E-beam process is capable of achieving SO₂ removals of 95 percent or greater and NO_x removals of about 90 percent. High SO₂ removals require a minimal E-beam dose, generally much lower than the E-beam dose necessary for NO_x removal. Once the minimum E-beam dose is achieved, the primary factors affecting SO₂ removal are flue gas temperature and ammonia stoichiometry. The E-beam dosage required for 90 percent SO₂ removal is a minimum of 1.0 mrad.

The removal of NO_x depends primarily on the E-beam dosage; temperature and SO₂ concentration are of secondary importance. Higher NO_x removals require higher radiation dosages. A dose of about 0.3–0.6 mrad is required to achieve 50 percent NO_x removal, and 90 percent NO_x removal requires at least 2.7 mrad according to the data obtained to date.^{7,8} Higher NO_x removals are obtained at higher temperatures, contrary to SO₂ removal. Higher SO₂ concentrations also improve NO_x removal, making the process better suited for high-sulfur applications. Furthermore, additional particulates are removed in the new ESP or FF.

O&M Impacts

The energy requirement for E-beam depends greatly on the NO_x reduction being sought; when significant NO_x reduction is not required, the auxiliary power for the E-beam process may range from 2 to 3 percent of the total plant output. The Chengdou demonstration plant consumed about 2 percent of the plant energy for an SO₂ removal of 80 percent and NO_x removal of 10 percent. When NO_x reduction is above 60 percent, the auxiliary power may reach 5 percent.

Particulate collection by either ESP or baghouse can be problematic if appropriate steps are not taken to overcome the stickiness of the particulates.

Capital Costs

Ebara projects capital costs for a 100-300 MW plant in the \$180-250/kW range.¹

O&M Costs

The main O&M costs are related to the auxiliary power requirements and the ammonia injection. Early studies project that the total O&M costs are 11-15 mills/kWh resulting in levelized costs (including cost of capital) of 16 to 22 mills/kWh.¹

These costs do not include capital and O&M costs associated with by-product treatment, such as granulation, or revenue from the sale of the by-products. A concept has been proposed for the fertilizer production companies to provide the ammonia needed to the power plant and receive the “upgraded” solid nitrogen granular fertilizer (net credit of \$1 million per year or 3-4 mills/kWh). Ebara claims that

this concept would result in significant savings, but detailed cost estimates have not been developed and it has not been applied anywhere.

Issues Associated with the Technology; Future Outlook

The technology has yet to reach commercial stage and there is uncertainty regarding its cost and long-term reliability. Also, the process currently uses a significant amount of electricity, up to 5 percent of the plant output depending on the required NO_x removal.

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3.2.2.2 ROFA-ROTAMIX (Mobotec)

ROFA-ROTAMIX Summary

Status	ROFA and ROTAMIX commercially available for NO _x reduction; ROTAMIX demonstrated on a 150 MW coal-fired unit
SO₂ Reduction, %	69 with Trona, 64 with limestone 40 – 60 with ROFA;
NO_x Reduction, %	up to 80 with ROTAMIX Additional removal with Trona (11) or limestone (4)
Hg Reduction, %	67 with Trona, 89 with limestone
Cost	
Capital (\$/kW)	ROFA: \$20-25/kW for 100 and 200 MW plants ROTAMIX: \$25-30/kW for units in the 100 - 200 MW range
Fixed O&M (\$/kW-yr)	0.5 - 1.0
Variable O&M (mills/kWh)	Depends on the use of ammonia or SO ₂ control absorbent
Applicability	Existing plants, especially older units less than 300 MW ROFA has been demonstrated up to 175 MW scale. Also, the potential increases in boiler slagging and fouling and erosion of boiler tube surfaces with the injection of sorbents for SO ₂ and Hg control have not been resolved.
Issues	

Technology Description

Mobotec offers three NO_x control technologies: (1) the Rotating Opposed Fire Air (ROFA) system, (2) the ROTAMIX, and (3) in-duct SCR that may be used in conjunction with the previous two systems. This report includes description of the ROFA and ROTAMIX. According to the vendor, these two technologies are generally designed as one system; therefore, they are considered a multi-emission control option. The in-duct SCR is an independent NO_x control option.

ROFA System

The ROFA system incorporates asymmetrically placed ROFA air nozzles (in concept similar to overfire air), which contribute to mixing of the flue gas in the furnace by introducing turbulence. One or more levels of nozzles are placed asymmetrically in opposite walls, usually higher than those used in conventional overfire air systems. The ROFA system is designed for 20-40 percent of the total airflow and uses a booster fan to provide the required pressure and achieve adequate air penetration into the furnace.¹

ROTAMIX

ROTAMIX is used in conjunction with ROFA and involves injection of various chemicals or additional fuel (for example, reburn gas) to remove NO_x, SO₂, and heavy metals (including mercury). In addition to the ROFA ports, lances are provided to inject the chemicals. So far, Mobotec has used urea and ammonia for NO_x reduction, CaCO₃ for SO₂ control, and is considering adsorbents for mercury control.

Computational fluid dynamic (CFD) modeling is used to take into account site-specific considerations, determine the optimal design characteristics for each boiler, and determine the placement of the ROFA boxes.

Commercial Readiness and Industry Experience

The ROFA-ROTAMIX system is considered commercial. There are 18 installations in the U.S. and 17 in Sweden (mainly stoker-fired, fluidized-bed, and dry-bottom boilers burning coal, heavy fuel oil, wood wastes, and municipal waste). In the U.S., ROFA-ROTAMIX has been recently installed at Carolina Power & Light's (CP&L) Cape Fear 5 and 6, T-fired boilers burning pulverized eastern bituminous coal. Cape Fear 5 is a single furnace boiler generating 154 MW. Cape Fear 6 is a twin furnace generating 172 MW.² In Sweden, the combination of ROFA-ROTAMIX has been installed in a 78 MW coal-fired stoker boiler (Jordberga plant of Danisco Sugar Ltd.). In the Jordberga plant, a 90 percent reduction of SO₂ was achieved using CaCO₃.

Emission Control Performance

The 17 ROFA retrofits in Sweden (mainly stoker-fired, fluidized-bed, and dry-bottom boilers burning coal, heavy fuel oil, wood wastes, and municipal waste) achieved an average of 50 percent NO_x reduction with ROFA, while maintaining CO emissions and reducing excess O₂.

As Figure 3-4 shows, CP&L's Cape Fear 5, a T-fired boiler burning pulverized eastern bituminous coal and generating 154 MW of power, achieved 55 percent NO_x reduction at full load and up to 69 percent at low loads. Also, the level of excess oxygen was reduced from 5.5 to 3.7 percent at full load resulting in higher boiler and plant efficiency. This reduction of the excess oxygen did not adversely affect CO emissions. They were also reduced from 50-90 ppm to less than 20 ppm. Adverse impacts included a small increase in unburned carbon in the fly ash or LOI (from 3 to 5 percent), approximately 11 °C (20 °F) superheat and reheat temperature reduction and increased auxiliary power due to the high-volume ROFA fan [820 kW (1100 HP)].

The combination of ROFA-ROTAMIX at Jordberga (78 MW coal-fired stoker boiler in Sweden) achieved 40 percent NO_x reduction and 90 percent SO₂ reduction.¹ The same performance (especially with regard to the SO₂ reduction) has not been confirmed in pulverized coal boilers, which operate at significantly higher temperatures than stokers.

The combination of ROFA-ROTAMIX has been installed in CP&L's 154 MW coal-fired Unit 5 at the Cape Fear Generating Station for the multipollutant technology evaluation program. The program included injection of CaCO₃ to determine the effect on SO₂ and Hg reduction and injection of trona to determine the effect on NO_x, SO₂, HCl, and Hg reduction. SO₂ reductions of 69 percent were achieved with trona and 64 percent with CaCO₃. Mercury reductions of 89 percent were achieved with limestone and 67 percent with Trona.³⁻⁶

Key factors affecting the performance of the ROFA and ROTAMIX systems are:

- height between top burner and furnace outlet which determines whether the ROFA system can be accommodated and there is adequate residence time for complete combustion,
- furnace dimensions, which will impact the degree of penetration of the air into the furnace, and
- temperature at the top of the boiler.

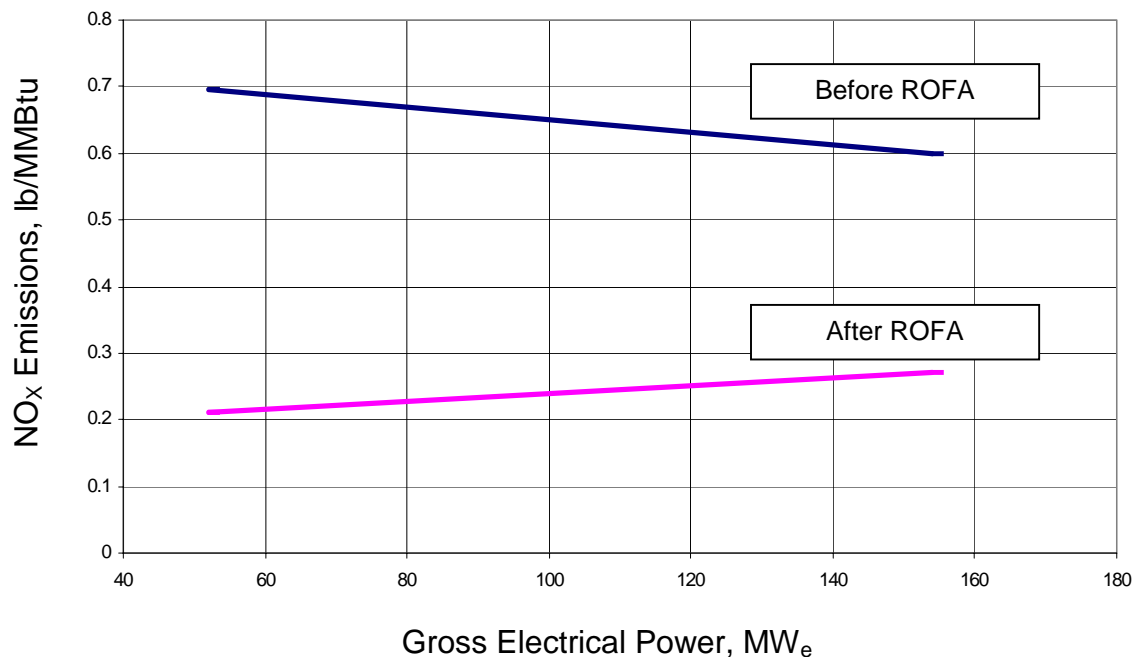


Figure 3-4. NO_x emissions from Cape Fear Unit 5: comparison before and after ROFA.

O&M Impacts

The limited experience with ROFA systems in the U.S. indicates that there are positive and negative O&M impacts. On the positive side, combustion efficiency and CO emissions have improved. Also, excess oxygen has been reduced resulting in higher boiler and plant efficiency. On the negative side, reduction in superheat and reheat temperatures have been experienced. At Cape Fear, outlet steam temperatures declined by 11 °C (20 °F) (an equivalent of 0.40 percent reduction in plant efficiency). However, the O&M impacts are very site-specific (usually depend on the boiler design, operating condition, and fuel characteristics), and one site is not adequate to generalize the potential impacts of ROFA for coal-fired boilers.

Impact that needs to be taken into account is the increased auxiliary power due to the high-volume ROFA fan, estimated (by the vendor) to be approximately 0.3 percent of the plant output. A 150- MW boiler requires a fan with a 450-750 kW (600-1,000 HP) motor.

There will be a similar increase in auxiliary power due to ROFA-ROTAMIX, plus there will be the use of chemicals such as ammonia, urea, or CaCO₃.

Costs

Typical costs for ROFA average around \$20 – 25/kW for boilers between 100 and 200 MW.² The retrofits take approximately 8 months from order to final installation. A 2-week outage is expected for installation of the system.

Capital costs of ROFA-ROTAMIX range between \$25 and 30/kW for boilers between 100 and 200 MW. The installation costs (\$/kW) are projected to be lower for larger boilers.

Issues Associated with the Technology; Future Outlook

The performance of ROFA in large boilers may degrade, as the boiler dimensions increase and either the air penetration will be less efficient or a more powerful fan would be required to achieve the same efficiency. CFD modeling completed for boiler sizes up to 550 MW indicate satisfactory performance. Presently, ROFA has been demonstrated up to the 172 MW scale. Slagging of the superheater by sorbent (CaCO_3 and Trona) and ash was found to be a problem during the Unit 5 Cape Fear Generating Station tests. Also, the effect of long-term injection of such sorbents on boiler tube erosion is not known.

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3.2.2.3 SNO_xTM

SNO_x Summary

Status	Early commercial stage; two commercial plants in operation in Europe
SO₂ Reduction, %	Above 90
NO_x Reduction, %	Above 90
Hg Reduction, %	Zero
Cost	
Capital (\$/kW)	270 – 315 for 300 – 500 MW plant
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	NA
Applicability	Both new and retrofit applications
Issues	Cost-effectiveness

Technology Description

As shown in Figure 3-5, the SNO_x process involves removing particulates from the flue gas that leaves the boiler in a high-efficiency fabric filter (baghouse) to minimize the cleaning frequency of the sulfuric acid catalyst in the downstream SO₂ converter.¹⁻³ The ash-free gas is reheated to 725-752 °F (385-400 °C) mainly in a gas to gas heat exchanger, and NO_x is reduced with small quantities of ammonia in the first of two catalytic reactors where the NO_x is converted to nitrogen and water vapor. If the heat available in the gas stream is not adequate, supplemental heating maybe used (see preheat burner in front of the baghouse or the SO₃ reactor). The SO₂ is oxidized to SO₃ in a second catalytic converter (SO₃ Reactor). Then, the gas passes through a novel glass-tube condenser (WSA: Wet gas Sulfuric Acid condenser) that allows the SO₃ to hydrolyze to concentrated sulfuric acid.

Because the SO₂ catalyst follows the NO_x catalyst, any unreacted ammonia (slip) is oxidized in the SO₂ catalyst to nitrogen and water vapor. According to the supplier, downstream fouling by ammonia compounds is eliminated, permitting operation at higher than normal stoichiometry. These higher stoichiometries allow smaller catalyst volumes and higher reduction efficiencies.

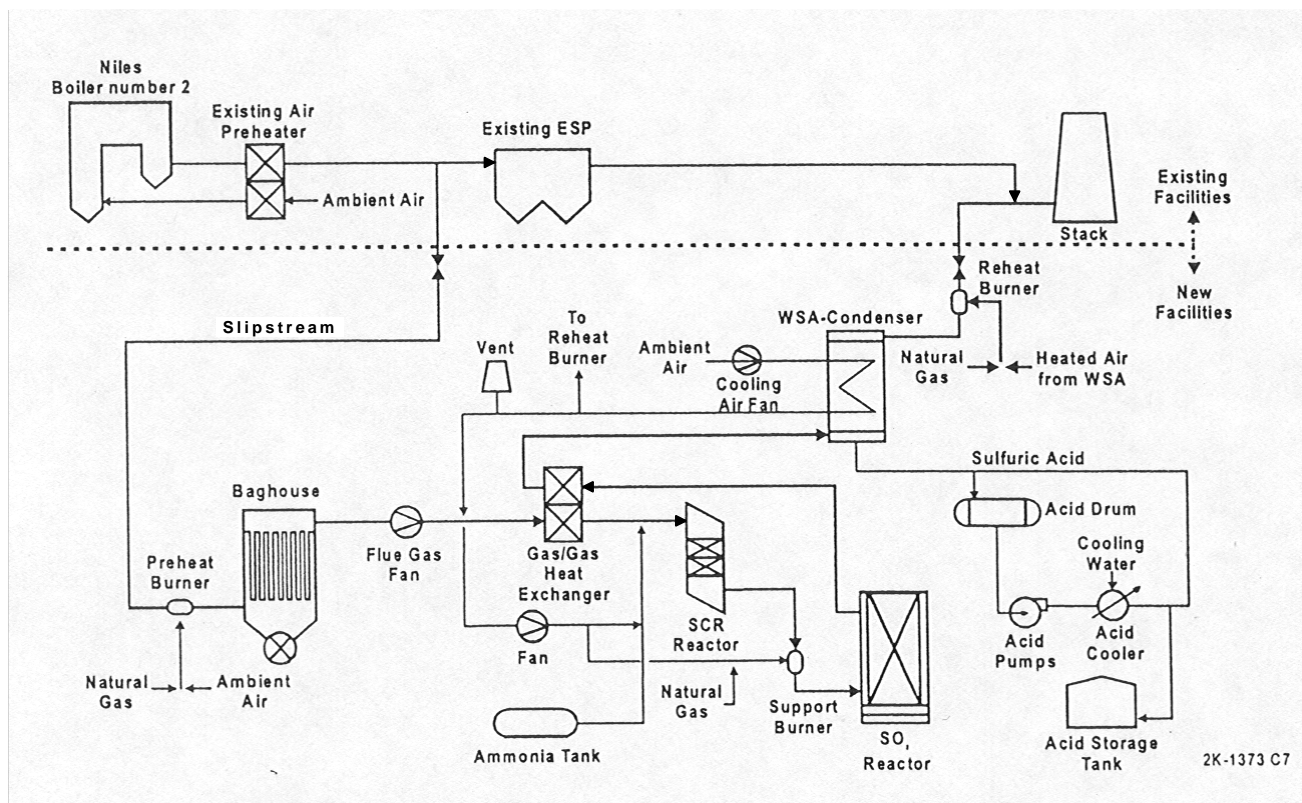


Figure 3-5. SNO_x process schematic.

Commercial Readiness and Industry Experience

The technology is in an early commercial stage with five demonstration projects completed in the early- and mid-1990s.⁴⁻⁷ The first commercial plant started operation in 1999. Initially, the technology was tested at a pilot plant of Elsam (Danish utility) in a flue gas stream of 10,000 Nm³/h. From 1991 to 1993, the following demonstrations took place:

- Gela (Italy) of Enichem SpA; Gas: 100,000 Nm³/h with 600-4,000 ppm SO₂ and 500 ppm NO_x in the inlet
- Vodskov (Denmark) of ELSAM; Gas: 1,000,000 Nm³/h (approximately 305 MW) with 200-2,000 ppm SO₂ and 550 ppm NO_x in the inlet
- Niles (USA) of Ohio Edison; Gas: 132,000 Nm³/h with 2,000 ppm SO₂ and 500-700 ppm NO_x in the inlet
- Vresova (Czech Republic) of Sokolovska Uhelna A.G.; Gas: 54,000 Nm³/h with 2.4-3.6 H₂S and 200 ppm NO_x in the inlet
- Kawasaki plant (Japan) of Asahi Chemical Industry Ltd; Gas: 50,000 Nm³/h with 5.7 percent SO₂ and 100 ppm NO_x in the inlet

The U.S. demonstration was conducted at Ohio Edison's Niles Station in Niles, OH in a 35- MW equivalent slipstream of flue gas from the 108- MW Unit No. 2 boiler, which burned a 3.4 percent sulfur Ohio coal.

In addition to the Vodskov plant, which has been operating for several years, a new commercial size plant was built and started operation in 1999 at AGIP Petroli SAP's Gela plant in Italy. It treats 1,000,000 Nm³/h of flue gas from a petroleum-coke-firing facility having 2,380 - 4,600 ppm SO₂ and 330 ppm NO_x in the inlet of the SNO_x process.³ The Gela plant is designed for 94 percent SO₂ removal and 90 percent NO_x removal.

Emission Control Performance

SO₂ and NO_x removal efficiencies above 90 percent have been achieved. At Ohio Edison's Niles demonstration, SO₂ removal was approximately 94 percent with inlet concentrations averaging about 2,000 ppm SO₂ and NO_x removal was 95 percent with inlet NO_x in the 500 - 700 ppm range.⁴ In addition, particulates are expected to be reduced, relative to the original system with ESP.

SO₂ removal is controlled by the efficiency of the SO₂-to-SO₃ oxidation, which occurs as the flue gas passes through the oxidation catalyst beds. Control is accomplished through the space velocity and bed temperature. Space velocity governs the amount of catalyst necessary at design flue gas flow conditions, and the gas and bed temperatures have to be high enough to activate the SO₂ oxidation reaction.

Particulates are very low, usually below 1 mg/Nm³. At Niles, air toxics were tested and showed high capture efficiency of some trace elements in the baghouse. A significant portion of the boron and almost all of the mercury escaped to the stack. Selenium and cadmium were effectively captured in the acid drain, as were organic compounds.

O&M Impacts

While no systematic assessment of O&M impacts has been carried out, it is expected that the following impacts would need to be taken into account:

- Fuel (most likely natural gas) requirements for the heaters
- Increased auxiliary power which is going to affect the plant efficiency and heat rate
- Safety issues associated with ammonia storage and feed system

Costs

Costs for retrofitting a 500 MW plant with the SNO_x process are projected to be 305 \$/kW (EOY 1995 dollars) resulting in 6.1 mills/kWh levelized costs³ (over a 15-year period). Using the CEI (Chemical Engineering Annual Plant Index), the adjusted cost in EOY 2000 dollars is 315 \$/kW. Presently, the supplier projects that the SNO_x process could be retrofitted on a 300 MW power plant in the US for approximately 270 \$/kW.

Issues Associated with the Technology; Future Outlook

The main issue associated with the technology is its cost-effectiveness in reducing SO₂ and NO_x relative to competing technologies.

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³ Other assumptions: credit was assumed for sale of sulfuric acid at 25 \$/ton and for heat recovery from the SNO_x process for use in the boiler at 2.00 \$/MMBtu

3.2.2.4 SO_x-NO_x-Rox Box (SNRBTM)

SNRB Summary

Status	Pilot stage
SO₂ Reduction, %	80 – 90
NO_x Reduction, %	90
Hg Reduction, %	Zero
Cost	
Capital (\$/kW)	253 for 150 MW retrofit
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	NA
Applicability	Both new and retrofit applications
Issues	Requires demonstration

Technology Description

The SNRB process combines the removal of SO₂, NO_x, and particulates in one unit - a high-temperature baghouse.^{1,2} It operates in the 425-455 °C (800-850 °F) temperature range and is placed before the air heater. SO₂ removal is accomplished using either calcium- or sodium-based sorbent, sodium carbonate (Na₂CO₃), and sodium bicarbonate (NaHCO₃), injected into the flue gas upstream of the baghouse. NO_x removal is accomplished by injecting ammonia (NH₃) to selectively reduce NO_x in the presence of a selective catalytic reduction (SCR) catalyst, which is placed on the high-temperature ceramic filter bags of the baghouse. Also, the baghouse removes particulates, its primary design function.

Commercial Readiness and Industry Experience

The SNRB technology requires further demonstration on a 50-100 MW scale. It has been demonstrated successfully on a 5- MW slipstream at Ohio Edison's Burger No. 5 (a 156- MW boiler burning high-sulfur bituminous coal) boiler.

Emission Control Performance

Four different sorbents were tested at the Burger pilot project including hydrated lime, sugar-hydrated lime, lignosulfonate-hydrated lime, and sodium bicarbonate. The results achieved can be summarized as follows:^{1,2}

- SO₂ removal efficiency of 80 percent with commercial-grade hydrated lime at a calcium-to-sulfur (Ca-to-S) molar ratio of 2.0 and temperature of 425-455 °C (800-850 °F),
- SO₂ removal efficiency of 90 percent with sugar-hydrated and lignosulfonate-hydrated lime at a Ca-to-S ratio of 2.0 and temperature of 425-455 °C (800 - 850 °F),
- SO₂ removal efficiency of 80 percent with sodium bicarbonate at a sodium-to-sulfur (Na₂-to-S) molar ratio of 1.0 and temperature of 220 °C (425 °F),
- SO₂ emissions were reduced to less than 1.2 lb/MMBtu, 80-85% SO₂ reduction, with 3-4 percent sulfur coal with a Ca-to-S molar ratio as low as 1.5 and Na₂-to-S ratio of 1.0,
- Injection of calcium-based sorbents directly upstream of the baghouse at 440-480 °C (825-900 °F) resulted in higher overall SO₂ removal than injection farther upstream at temperatures up to 650 °C (1,200 °F),
- NO_x reduction of 90 percent was achieved with an NH₃-to-NO_x ratio of 0.9 and temperature of 425-455 °C (800-850 °F), and

- Also, 99.9 percent particulate removal has been demonstrated.

In summary, 80 - 90 percent SO₂ removal, 90 percent NO_x removal, and similar levels of control for some air toxics were demonstrated. However, a demonstration on a larger scale (50 - 100 MW) is needed to assess the performance and economics of this technology.

O&M Impacts

The only potential O&M impact relates to effects on the FFs (mainly life expectancy). The SNRB filters are ceramic, incorporating a catalyst for NO_x control, and their reliability is affected by both mechanical and thermal stresses due to cycling (changing operating conditions) and cleanup of the bags. To address these concerns, a 3,800-hour durability test of three fabric filters was completed² at the Filter Fabric Development Test Facility in Colorado Springs, CO, in December 1992. No signs of failure were observed. All of the demonstration tests were conducted using 3M Company Nextel ceramic fiber filter bags or Owens Corning Fiberglas S-Glass filter bags. No excessive wear or failures occurred in over 2,000 hours of elevated-temperature operation.

In most cases, SNRB is expected to be placed before the air heater, where the flue gas temperature is adequate [425-455 °C (800-850 °F)]. In case, the temperature is lower, flue gas heating may be required and the consumption of natural gas or oil needs to be taken into account, as an additional O&M impact.

Costs

The supplier estimates that capital costs for a 150- MW retrofit would be \$253/kW (constant US\$ 1994), assuming 3.5 percent sulfur coal, baseline NO_x emissions of 1.2 lb/MMBtu, 65 percent capacity factor, and 85 percent SO₂ and 90 percent NO_x removal. Levelized cost over 15 years (constant U.S.\$, 1994) is estimated to be 12.1 mills/kWh or equivalent to \$553/ton of SO₂ plus NO_x removed.

Issues Associated with the Technology; Future Outlook

Considering that the technology has not been demonstrated, there are some uncertainties associated with both the emission control potential and its economics. Since the Burger pilot program in the mid-1990s, the supplier has not pursued further development of the technology because there was no demand for multi-emission control technologies. With the pending multipollutant control regulation, demand may increase for technologies such as SNRB.

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3.2.2.5 THERMALNO_x and FLU-ACE Process

THERMALNO_x and FLU-ACE Process Summary

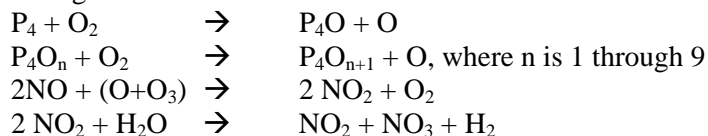
Status	In demonstration
SO₂ Reduction, %	Up to 95
NO_x Reduction, %	Up to 90
Hg Reduction, %	NA
Cost	
Capital (\$/kW)	THERMALNO _x : \$35/kW for 500 MW; FLU-ACE: Not available
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	1.43*
Applicability	Applicable to both new plants and retrofits
Issues	Need demonstration to confirm performance and reliability on large scale, as well as economics.

*Assumed to be only for the THERMALNO_x process

Technology Description

The THERMALNO_x and FLU-ACE process is a two-step process.^{1,2} The first step is the gas phase chemical reaction converting nitrogen monoxide (NO) into nitrogen dioxide (NO₂). This is accomplished by direct phosphorus (P₄) liquid injection into the flue gas, which causes the release of ozone (O₃) that oxidizes NO into NO₂. This NO to NO₂ conversion takes place in a specially designed reactor normally placed upstream of a wet scrubbing process.

The prevailing chemical reactions are:



In the second step the NO₂ is removed, as a water-soluble gas in the wet FGD process. In addition, as in the phosphoric acid manufacturing process, the solid P₄O₁₀ particles that are formed in the duct from the first step, upon entering the wet FGD process are instantly hydrated and hydrolyzed to form the dibasic phosphate (H₂PO₄⁻) and the mono-basic phosphate (HPO₄²⁻) anions.

This second step could be accomplished by a wet FGD process (especially if it already exists) or the FLU-ACE process, a condensing reactive scrubber, which is also offered by Thermal Energy. The supplier projects 90 percent nitrogen dioxide removal efficiency by wet FGD and 98 percent by FLU-ACE. If the FGD cannot achieve the required NO_x reduction, a FLU-ACE reactor can be added to boost the NO_x reduction above 90 percent and remove other pollutants such as mercury, VOCs, and fine particulates.

The by-products of the THERMALNO_x process are non-toxic nitrogen and phosphate compounds used as fertilizers and animal food additives.

The P₄ liquid is maintained at a constant temperature of 60 °C (140 °F) in the P₄ injection tank and is pumped continuously through a steam-traced closed piping circuit connecting the P₄ injection tank to the P₄ atomization nozzle injection location in the flue gas duct. The P₄ injection rate is individually controlled to each nozzle via corresponding P₄ liquid flow control valves and atomizing steam pressure

control valves to maintain optimum P₄ droplet size, physical dispersion, and chemical reaction in the duct. Atomization is done using steam, compressed air, or an aqueous emulsion of phosphorus.

When THERMALONO_x is used, the existing wet FGD process must absorb the additional nitrogen and phosphorus compounds generated. The system must also deal with the additional nitrogen and phosphorus species in solution. These compounds must be controlled to maintain proper scrubber operation to optimize NO₂ and SO₂ absorption and to control and maintain the by-product quality, whether it is for gypsum production or landfill.

Commercial Readiness and Industry Experience

The technology is in the early demonstration stage. There were plans to install it at American Electric Power's Conesville plant (a 375 MW unit), but the project was suspended on September 27, 2001, during initial start-up. Tests were expected to last for 8-12 weeks with the target NO_x reduction of 75 percent.

In parallel with the Conesville demonstration, Thermal Energy is carrying out an R&D program to test the THERMALONO_x process with an existing FLU-ACE scrubber near Ottawa, Canada.

Emission Control Performance

Thermal Energy projects 80-90 percent NO_x removal for THERMALONO_x with conventional FGD.¹ A combination of THERMALONO_x and FLU-ACE is projected to achieve 98 percent NO_x removal. In both cases, SO₂ removal is projected to be in the 90 – 95 percent range.

Key parameters affecting the THERMALONO_x process are the flue gas temperature and oxygen concentration, which affect the reaction rate for converting NO to NO₂, and therefore the reaction time required to achieve the desirable conversions (usually 99 percent). For a typical coal-fired power plant with flue gas at 140-160 °C (280-320 °F) and 4-5 percent excess oxygen, the required reaction time is about 1 second. The NO_x to P₄ ratio is projected by the supplier to be in the 3.0 - 4.0 range.

O&M Impacts

Potential O&M impacts are associated with the ability to control the spontaneous reaction of the phosphorus and flue gas to produce ozone. Also, if there is no market for the wastes, the ability to dispose of phosphate compounds needs to be assessed.

Costs

Thermal Energy projects the cost of THERMALONO_x for a 500 MW coal-fired plant to be approximately \$35/kW.¹

Variable O&M are projected to be 1.43 mills/kWh.¹

Issues Associated with the Technology; Future Outlook

The main issues and uncertainties associated with the technology are:

- Confirmation of pilot scale results and projected economics in utility scale demonstration and subsequently commercial projects.
- The ability to control the spontaneous reaction of the phosphorus and ability of the flue gas to produce ozone in large scale needs to be demonstrated.
- Disposal of phosphate compounds needs to be assessed including the impact of phosphorus injection on by-product properties and economics.

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3.2.3 SO₂, NO_x, and Mercury Control

3.2.3.1 Activated Coke

Activated Coke Summary

Status	Commercial
SO₂ Reduction, %	90 – 98
NO_x Reduction, %	15 – 80 (depends on SO ₂ reduction)
Hg Reduction, %	90 – 99
Cost	
Capital (\$/kW)	120 – 200 for 300 – 1,000 MW
Fixed O&M (\$/kW-yr)	8 – 13
Variable O&M (mills/kWh)	1.3 – 2.1
Applicability	Both new and retrofit applications
Issues	Demonstration of the combined SO ₂ -NO _x -Hg control is needed in the United States

Technology Description

The activated coke process,¹⁻³ shown in Figure 3-6, involves three steps: (1) adsorption, (2) desorption, and (3) (optional) by-product recovery. In the first step (adsorption), flue gas passes through a bed of activated coke slowly moving downwards in a two-stage adsorber. The activated coke consists of carbon with large porous inner surface area. In the first stage, sulfur dioxide is removed by adsorption into the activated coke where it forms sulfuric acid or ammonium hydrogen sulfate (NH₄HSO₄); the latter in case ammonia is injected in addition to the presence of activated coke. These compounds are maintained in the coke inner surface at temperatures ranging from 100 to 180 °C (212 to 356 °F). The adsorber acts also as a particulate control device reducing particulates below 30 mg/Nm³ (0.0124 grain/scf) when the inlet is kept below 200 mg/Nm³ (0.0827 grain/scf).

In the second stage of the adsorption process, the activated coke acts as a catalyst in the decomposition of NO_x to nitrogen and water after injection of ammonia in the activated coke bed. The chemical reaction occurs in the 100-180 °C (212-356 °F) temperature range.

Activated coke is a carbonaceous material produced by steam activation (at approximately 900 °C). It has high mechanical strength against abrasion and crushing. Its surface area is 150-250 m²/g, less than the conventional activated carbon but much higher than the metallurgical coal.

As the activated coke is loaded with sulfuric acid, its adsorption capacity declines. To regenerate the activated coke, it is conveyed by a bucket elevator to a desorber. In the desorber the sulfuric acid or ammonium hydrogen sulfate (NH₄HSO₄) is decomposed to nitrogen, sulfur dioxide, and water. The regenerator is heated to 380-500 °C (716– 932 °F) temperature range through an external air heater, which consumes either oil or natural gas. Utilization of flue gas for this purpose is possible to reduce fuel requirements and associated costs, but has not been implemented. After cooling, the activated coke passes through a vibrating screen to eliminate smaller particles (fines) and then it is recycled back into the adsorber.

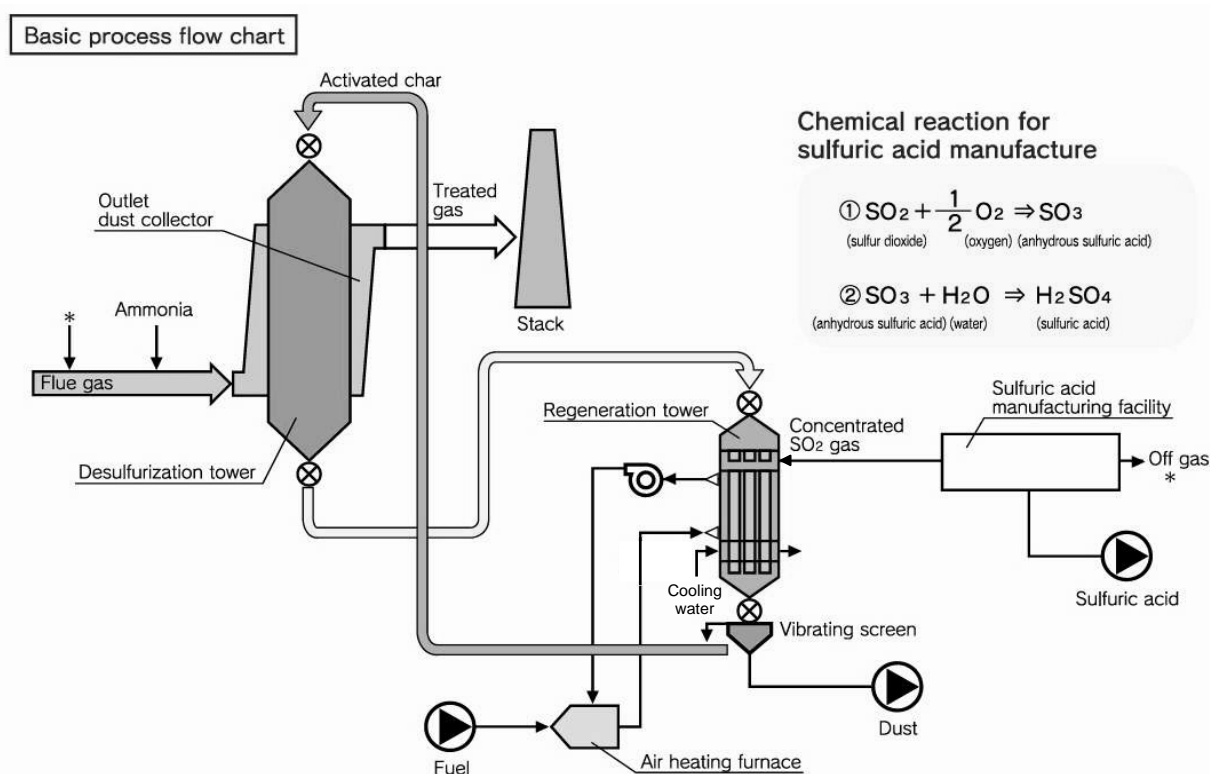


Figure 3-6. Activated coke process flow diagram⁷

SO₂-rich gas can be reduced to H₂S in a reduction column and then elemental sulfur can be produced in a Claus unit (typical process for sulfur production). Alternatively, sulfuric acid can be produced.

Mercury can be removed also by adsorption. Once adsorbed on the coke, mercury must be collected in a form suitable for disposal or recovery. Mercury is absorbed on the coke up to 1.7 mg/g-coke at the temperature below 180 °C. Due to the temperature profile within the regenerator, mercury-rich coke can be found in the middle section of the regenerator. The mercury concentration in this area increases over time and removal of the mercury-rich coke is required once every few years (1-3 years depending on the percentage sulfur and mercury in the coal). The coke removed, representing approximately 1 percent of

the total coke in the system, is sent to special facilities, which recover the mercury and sell it for commercial applications.

The mercury recovery facilities use various methods one of them being the use of a selenium filter, which absorbs the mercury from the flue gas and forms HgSe, a chemically stable compound. The selenium filter technology is commercial and can achieve up to 98 percent Hg collection efficiency during the filter life (usually 4-5 years). Once spent, the selenium filter has to be disposed of in a hazardous waste facility. Other methods of mercury removal or disposal are also considered, such as SO₂-rich gas (SRG) off-gas, sulfuric acid plant off-gas, and SRG scrubber waste water.

Commercial Readiness and Industry Experience

The process is commercially available in Japan and Germany. It was originally developed by Deutsche Montan Technologie (formerly Bergbau-Forschung GmbH) and demonstrated at a 158,000 m³/s (93,000 scfm) plant, the Kellerman generating station of STEAG GmbH. Mitsui Mining Co., Ltd. of Japan obtained a license from Deutsche Montan Technologie and tested it in a pilot facility from 1981 to 1983.⁴ Installations of the Mitsui activated coke process in Japan^{5,6} and Germany include the following (designed for both SO₂ and NO_x control unless otherwise indicated):

- 31,775 Nm³/h at Mitsui's power generating station (1984)
- 236,000 Nm³/h at Idemitsu Kosan's refinery on a residual fluidized bed catalytic cracking process (1987)
- 451,000 and 659,000 Nm³/h boilers at EVO GmbH's Arzberg power station in Germany (1987)
- 323,000 Nm³/h at Hoechst AG's power station in Frankfurt, Germany (1989)
- 10,000 Nm³/h at Electric Power Development Corp.'s (EPDC) Wakamatsu power station (1990)
- 1,157,000 Nm³/h (350 MW) AFBC boiler at the Electric Power Development Corp. Takehara power station (1995), designed only for NO_x reduction and achieved above 80 percent NO_x reduction

Sumitomo of Japan has also developed its own activated coke technology and provided a commercial system for the Electric Power Development Corp. Isogo station, a 600 MW power plant burning low-sulfur coal (flue gas flow rate of 1,806,000 Nm³/h). The activated coke process is designed for 95 percent SO₂ removal and 30% NO_x reduction.

Sumitomo also has utilized this technology in sintering plants of steel-making industry for SO₂, NO_x and dioxin control. The following Table 3-5 provides the size and start-up year for sintering plants utilizing Sumitomo's process.

Table 3-5 Sintering Plants Utilizing Activated Coke

Customer	Emission Removed	Gas Volume [Nm ³ /h]	Start up
A	SO ₂	900,000	1987
B	SO ₂ , NO _x , Dust	1,300,000	1999
C	Dioxin, Dust	1,552,000	2003
D	SO ₂ , NO _x , Dust	1,300,000	2003
E	SO ₂ , NO _x , Dust, Dioxin	1,350,000	2004
F	SO ₃ , NO _x , Dust	1,650,000	2004

Emission Control Performance

SO₂ control efficiency has ranged from 90 to 98 percent and the NO_x control efficiency from 15 to 80 percent.^{1,5,6} NO_x reduction is higher for lower SO₂ concentrations at the inlet of the adsorber. For example, 1000 ppm SO₂ concentration may result in NO_x reduction in the 15 – 40 percent range, while 200 ppm SO₂ concentration will raise NO_x reduction to above 70 percent. NO_x reduction is also affected by the amount of ammonia injected (NH₃-to-NO_x ratio typically in 0.5-1.0 range results in above 70 percent NO_x reduction), the oxygen concentration of the flue gas (lower excess O₂ results in lower NO_x reduction), and the inlet gas temperature.

Based on pilot-scale tests carried out by Sumitomo and measurements by EPDC at its Matsushima power station, 90 – 99 percent mercury removal is projected. These tests resulted in >99 percent mercury reduction at operating temperatures of 150 to 180 °C. Mercury reduction data from the remaining installations are not available, because these systems were not designed with mercury control in mind, but rather for SO₂ and NO_x control; hence, mercury was removed, but no data were kept regarding mercury capture efficiencies.

O&M Impacts

Due to the high heat capacity of the activated coke system, it takes longer than a conventional plant to reach the operating temperature of the de- NO_x process, which means that either NO_x emissions will be higher during start up or the ramp-up rate of the plant will be limited. Other O&M impacts are not known, mainly because of the lack of information and experience in the United States. Required auxiliary power is estimated to be 0.70 percent of the gross output, compared to 1.0-2.5 percent for a wet FGD.

Capital Costs

According to the suppliers, capital costs (including by-product equipment) are projected to be in the \$120 – 200/kW range for a unit 300 – 1,000 MW in capacity, gas temperature 150-165 °C (300-330 °F), and gas inlet conditions: SO_x 500 – 1,000 ppm, NO_x 170 – 260 ppm and dust 140 – 200 mg/Nm³. The capital costs include all equipment (including mercury control and acid production) fully installed and operational.

O&M Costs

Fixed costs are expected to be in the \$8-13/kW-yr range. Operating costs (including electricity, active coke, NH₃, and fuel) are projected to be 1.3-2.1 mills/kWh (assumptions: activated coke: \$833 per ton; ammonia: \$223 per ton; electricity: 35 mills/kWh; cost of labor: 50,000 \$/year-person). As the sulfur content in the coal increases above the 2 percent level, the O&M costs may increase substantially mainly due to the increase in activated coke costs.

Issues Associated with the Technology; Future Outlook

During start-up, it takes longer to bring up the temperature in the De-NO_x system; so, NO_x reduction in cycling units may suffer during start-up unless they are designed to utilize an external heat source to preheat the De-NO_x reactor.

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3.2.3.2 Electro-Catalytic Oxidation (ECO)

ECO Summary

Status	In demonstration
SO₂ Reduction, %	98
NO_x Reduction, %	90
Hg Reduction, %	90
CO₂ Change, %	5 increase
Cost	
Capital (\$/kW)	200 for 500 MW plant
Fixed O&M (\$/kW-yr)	6.83
Variable O&M (mills/kWh)	1.5 projected
Applicability	Both new and retrofit applications
Issues	50 MW demonstration in progress

Technology Description

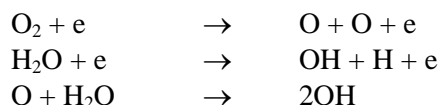
The ECO process, shown in Figure 3-7,¹ treats flue gas in three steps to achieve multipollutant removal. First, a majority of the ash in the flue gas stream is removed in a conventional dry ESP. Following the ESP, a barrier discharge reactor oxidizes the gaseous pollutants to higher oxides. For example, nitric oxide is reacted to form nitric acid, sulfur dioxide is converted to sulfuric acid, and mercury is oxidized to mercuric oxide. Products of the oxidation process are then captured in a wet electrostatic precipitator (WESP) that also collects fine particulate matter. Liquid effluent from the WESP may be treated to remove collected ash and then delivered to a system to produce concentrated sulfuric and nitric acids for sale. The ECO system is designed for retrofit into the last fields of an existing ESP. If the ESP does not have adequate space to fit the ECO system, some or all components could be built downstream of the ESP. In the latter case, the downtime of the plant is reduced, but additional space (footprint) is needed.

The sulfuric and nitric acids produced and captured in the WESP effluent can be made into salable by-products such as concentrated acids, gypsum, or fertilizer.

Oxidation of gaseous pollutants in the barrier discharge reactor is the key component of the ECO process. Oxidation is accomplished through generation of a non-thermal discharge or plasma. In a dielectric barrier discharge, energetic electrons are produced throughout the reactor without heating the gas stream to high temperatures, requiring considerably less energy than plasma discharges. Dielectric barrier discharges can be operated over a wide range of temperatures and pressures and have been widely used for commercial ozone (O₃) generation.²⁻⁵

To form a barrier discharge, a dielectric insulating material is placed between two discharge electrodes. Typically, the material (glass or ceramic) has a high dielectric strength and high dielectric constant and covers one of the two electrodes. High voltage applied to the electrodes causes the gas in the gap to break down. Presence of the dielectric barrier prevents this breakdown from forming an arc with its resulting energy consumption. Instead, breakdown is in an array of thin filament current pulses, or “microdischarges.” They are well distributed spatially over the discharge gap. Typical duration of a microdischarge is of the order of a few nanoseconds, and electron energies range from 1 to 10 electron volts.

The electron energies formed in the microdischarge are ideal for generating gas-phase radicals, such as hydroxyl (OH) and atomic oxygen (O) through collision of electrons with water and oxygen molecules present in the flue gas stream:



In a flue gas stream, these radicals simultaneously oxidize NO_x, SO₂, and Hg to form nitric acid (HNO₃) and NO₂, sulfuric acid (H₂SO₄), and mercuric oxide (HgO), respectively. The above reactions leading to radical formation and the subsequent oxidation reactions can be made to occur at a low temperature 65-150 °C (150-300 °F).

The presence of a dielectric barrier allows for several possible electrode configurations, including coaxial cylinders, cylindrical electrodes with plates, and parallel plate electrodes. Different reactor designs have little effect on overall conversion efficiency. This allows for spacing that reduces the potential for plugging of the reactor and results in a minimal pressure drop across the reactor. Aerosols formed by the oxidation reactions, including HgO, HNO₃, and H₂SO₄, exit the barrier discharge reactor in the flue gas stream. At this point the gas enters a condensing WESP where collection of the aerosols, fine PM, and other air toxic compounds is accomplished.

The by-products of the ECO process are raw sulfur and nitric and sulfuric acids, which can be used in the industry for fertilizer and gypsum production. Of course, the extent to which these by-products would be actually used depends on economics (supply and demand of competing products) in the local market (around the power plant).

Commercial Readiness and Industry Experience

The technology is in the demonstration stage. It was originally tested at laboratory scale (1 and 100 scfm). Then, it was tested at pilot scale at First Energy’s R.E. Burger No. 5 unit^{6,7} (a 156 MW unit), where a slipstream of equivalent to approximately 1 MW was used to assess the performance of the ECO process. The 1 MW pilot scale tests have been carried out since early 2002.

Presently, Powerspan has installed and begun testing a commercial demonstration unit at First Energy's R.E. Burger plant.⁸ The technology is being tested at a slipstream (110,000 scfm or 7.4 percent of the total flue gas) equivalent to 50 MW. The unit burns a variety of fuels including Ohio coal with 2-4 percent sulfur.⁹

Emission Control Performance

At First Energy's R.E. Burger No. 5 unit (1 MW slipstream), the technology achieved the following emission reductions:⁹

- 90 percent NO_x reduction,
- 98 percent SO₂ reduction, and
- 90 percent mercury reduction.

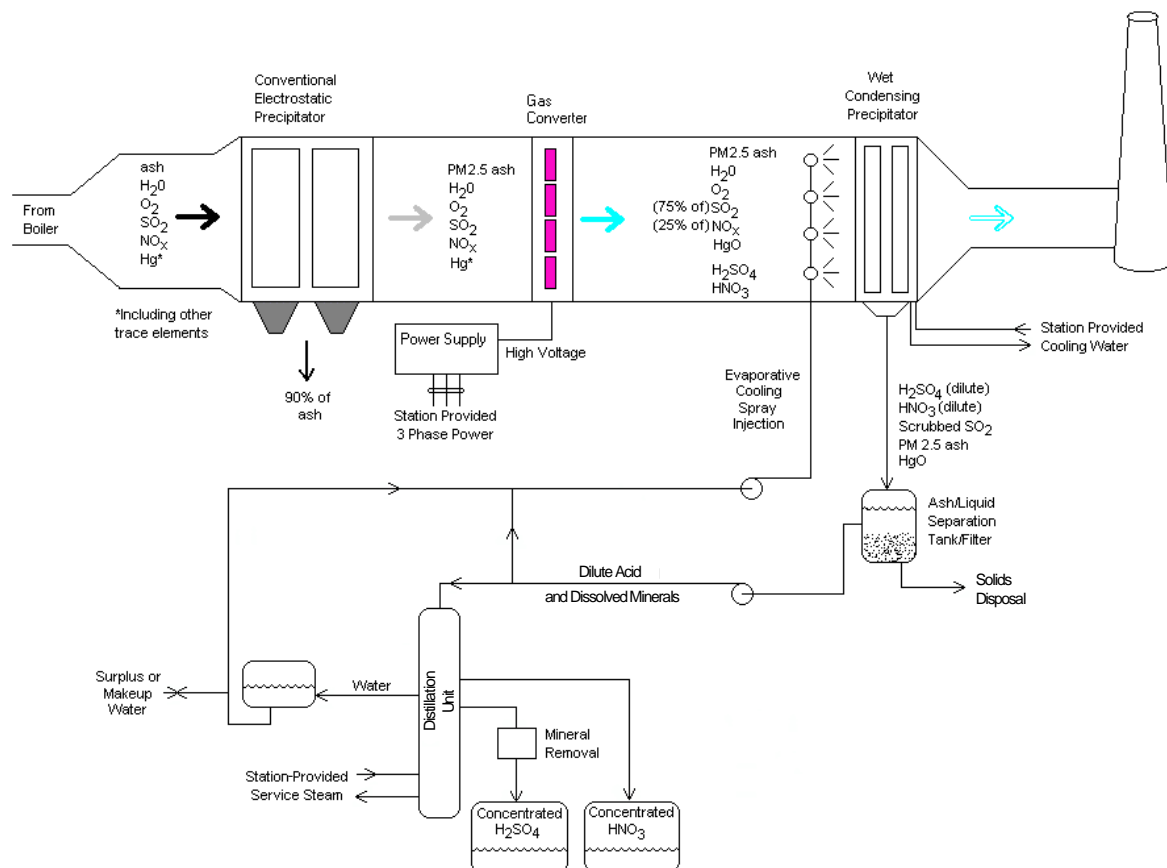


Figure 3-7. ECO process flow diagram.

It should be pointed out that these results were achieved with 337 ppm NO_x in the inlet of the ECO system, approximately 40 percent higher than a similar installation with low-NO_x burners.

The early results from 50 MW demonstration (by Powerspan Corp.) achieved the following:

- Greater than 90 percent NO_x conversion in the reactor, total reduction of 65 percent, hindered by absorber performance
- Greater than 98 percent SO₂ reduction, often >99 percent
- Mercury measuring equipment being installed

O&M Impacts

The main O&M impact of the ECO process is the auxiliary power consumption. Powerspan estimates that approximately 3 percent of the plant's output is needed for the ECO process to reduce inlet NO_x of 0.30 lb/MMBtu down to 0.05 lb/MMBtu.⁸

Also, cooling water is required for the WESP and is assumed to be provided by the cooling water system of the plant. Finally, heating for the acid recovery and ash drying is required and is expected to be provided by the plant's auxiliary system. While these do not present any technical challenge, they will have some impact on the plant mass and energy balances, as well as the plant's overall efficiency. At this point, there is not enough information to assess the magnitude of this impact, but it is not expected to be substantial.

The list of consumables and the by-products of the ECO process is given below.¹⁰

Consumables:

- Electric power for the barrier discharge reactor, pumps and blowers. The power for the discharge reactor is related to the NO_x reduction desired.
- Heat for the by-product crystallizer.
- Ammonia reagent – this can be estimated as roughly two moles of ammonia per mole of SO₂ removed. Additional amine is provided by other chemicals discussed below.
- Make-up water for the absorption tower – about 1 gpm per MW – no special quality specification.
- Carbon filters for mercury removal from the liquid discharge of the absorber.
- Additional, proprietary chemicals that provide the balance of the amine for the conversion of NO_x to ammonium nitrate and SO₂ to ammonium sulfate. These are estimated at around \$150/ton of NO_x removed and \$15/ton of SO₂ removed.

By Products:

- Ammonium nitrate and ammonium sulfate crystals that can be sold as fertilizer. Typically, for 90 percent reduction for every mole of inlet NO_x, 0.40 moles of ammonium nitrate are produced and for every mole of SO₂ reduced, one mole of ammonium sulfate is produced.
- Mercury captured on the activated carbon (a waste to be disposed of) at a cost of about \$1000/lb of mercury captured.
- A small amount of coal fly ash that was not captured by the ESP is filtered out of the liquid stream to the fertilizer crystallizer.
- Water vapor.

Costs

The cost of the demonstration project at First Energy's R.E. Burger (equivalent 50 MW scale) was \$18 million.⁸ This is equivalent to \$200/kW for 500 MW unit. AmerenUE, Sargent & Lundy,

Wheelabrator, The Andersons, and Powerspan performed a detailed cost estimate of an ECO unit at AmerenUE's Sioux plant. The capital cost of an ECO system for this 510 MW installation was estimated at \$120,400,000, inclusive of process equipment, general facilities, owner's costs, and contingencies. This also included the fertilizer plant and balance of plant modifications. It is the only comprehensive, full-scale cost analysis that has been made publicly available. Therefore, a cost of \$200/kW is a reasonable estimate to use.^{10,11}

Variable operating cost for ECO is the cost of power and other consumables such as ammonia and specialty chemicals. Ammonia consumption is determined by the molar ratio and specialty chemical costs are estimated at \$150/ton of NO_x removed and about \$15/ton of SO₂ removed. Carbon filter replacement costs and the costs of disposal of used carbon filters are estimated at \$1000/lb of mercury removed. Fertilizer value, which produces a revenue stream that offsets a portion of the cost, is approximated at \$110/ton of fertilizer produced. The ammonium sulfate and ammonium nitrate fertilizer are widely traded commodity chemicals and their value will depend largely on market conditions at the time and transport costs. Fixed operating costs include an estimated 1.5 percent of process capital per year plus three operators and one maintenance person per shift. The manpower needs are not expected to be a significant function of unit size.¹⁰

The power for the dielectric barrier discharge reactor is largely determined by the amount of NO oxidation needed and the gas flow. To increase the amount of NO_x removed by the ECO process, it is necessary to increase reactor power. So, for a given percent of NO_x reduction, the reactor power is roughly proportional to the NO_x mass flow. Therefore, to achieve a low outlet NO_x level while minimizing power demand, it is best to start with a low NO_x level from the boiler. As a result, one would typically use an ECO system in combination with low NO_x burners or other devices to minimize NO_x into the ECO reactor. Based upon available information, reactor power (in W/scfm) can be assumed to be equal to the lesser of 20 W/scfm or $58.22 \cdot (\text{NO}_x) - 6.2431$, where NO_x is measured in lb/MMBtu. This is shown in Figure 3-8 below. Reactor power could potentially be higher than 20 watts/scfm. However, this would likely be unattractive when compared to reducing NO_x by other means such as low NO_x burners.¹⁰

Other power demands include fan power to overcome about 9 inches of water total pressure drop (calculated as actual volume flow times pressure drop with an assumed fan efficiency of 65 percent) and another estimated 0.75 percent of plant output for auxiliary loads for the absorber and fertilizer plants.¹⁰

Issues Associated with the Technology; Future Outlook

As the process is scaled up, the main uncertainties are whether it can achieve the performance (emission reduction), which was achieved at smaller scale. Also, the costs and cost-effectiveness of the process is uncertain and may be adversely impacted by relatively high auxiliary power requirements. Finally, some uncertainty exists with regard to the scalability of the by-products both in terms of their suitability in meeting market specifications and price. Technology remains in the demonstration phase; therefore, performance and costs remain uncertain, especially for large-scale projects.

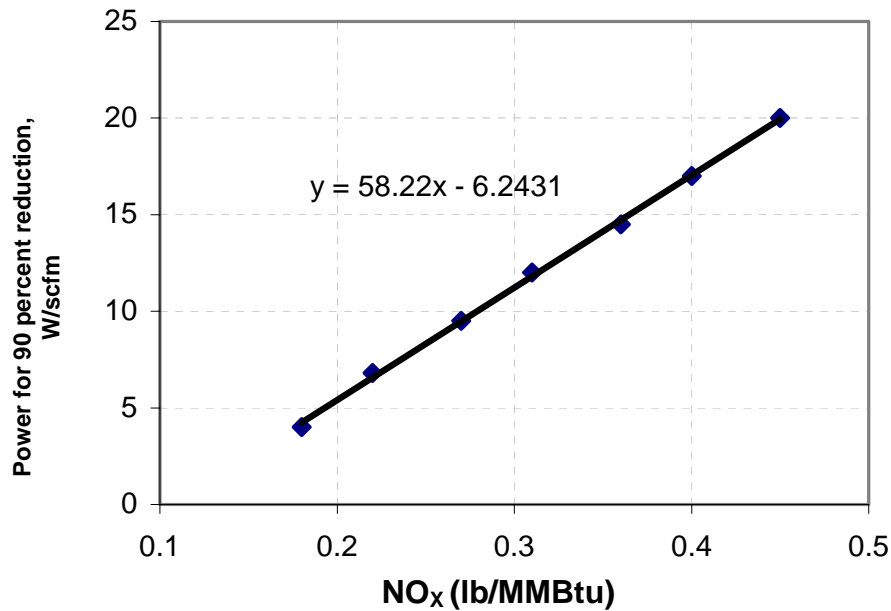


Figure 3-8. ECO power consumption versus NO_x.

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3.2.3.3 SCR and Wet FGD

SCR and Wet FGD Summary

Status	Commercial
SO₂ Reduction, %	95
NO_x Reduction, %	90 – 95
Hg Reduction, %	40—90% depending on coal type
Cost	
Capital (\$/kW)	SCR: 50-140; Wet FGD: 160-275 for a nominal 400 MW plant
Fixed O&M (\$/kW-yr)	SCR: 0.5 – 1.4; Wet FGD: 1.2 – 14
Variable O&M (mills/kWh)	SCR: 0.75 – 4; Wet FGD: 0.1 – 1
Applicability	Plants with SCR and wet scrubber technologies
Issues	Need additional confirmation of mercury oxidation levels in the SCR

Technology Description

Selective Catalytic Reduction (SCR) – NO_x Control

SCR technology¹ reduces NO_x through a catalytically enhanced reaction of NO_x with ammonia, reducing NO_x to water and nitrogen. This reaction takes place on the surface of a catalyst, which is “housed” in a “reactor” vessel. The reactor ensures that the flue gas is uniformly distributed over the catalyst as well as determines the flue gas velocity. Typical catalyst materials are titanium-oxide and vanadium-oxide on a “coated” substrate structure that may take forms such as plate or honeycomb. SCR system configuration is generally referred to in accordance with the location of the SCR relative to the power plant:

- “high-dust” – SCR located between the economizer and the air preheater, upstream of the ESP
- “low-dust” – SCR located between a hot-side ESP and the air preheater
- “tail-end” – SCR located downstream of the air preheater, ESP, and FGD. This approach requires the flue gas to be reheated prior to entering the SCR

Ammonia (anhydrous or aqueous) is injected into the flue gas upstream of the SCR reactor through a nozzle grid designed to ensure its uniform distribution in the flue gas and then through the catalyst.

SCR – Mercury Control

The contribution of SCR technology to mercury reduction comes from the fact that SCRs have been shown (also discussed in Section 3.2.1.3) to oxidize elemental mercury.²⁻⁵ Thus, there is synergism with

wet scrubbers, which are effective in capturing oxidized mercury. In fact, the SCR-wet scrubber combination is conceptually similar to the approaches discussed in the wet scrubber section (catalytic- and reagent-based mercury oxidation upstream of a wet scrubber).

Wet Scrubber

As explained before in Section 3.2.1.3, the most commonly used wet scrubber technology uses a wet limestone process with *in-situ* forced oxidation to remove SO₂ from the flue gas while producing a gypsum-grade by-product. This is accomplished typically in a vertical vessel with flue gas contacting and reacting with limestone slurry to produce a mixture of calcium sulfite and sulfate. Through controlled oxidation of the reaction products, a salable by-product in the form of commercial grade gypsum may be produced. The intimate contact between gas and liquid is enhanced through different design approaches, usually involving several counterflow spray levels and mass transfer “trays” to optimize gas-liquid interactions. The technology has evolved over the years through “mechanical” improvements, which have included better gas and liquid distribution within the scrubber, better controlled droplet size and size distribution, as well as “chemistry” improvements such as the addition of organic acids which not only improve overall SO₂ capture but also help the settling characteristics of the waste products. Several commercial variations of the technology exist based on reagent type, vessel design, etc.

The intense gas-liquid mass transfer, combined with the fact that oxidized, vapor-phase mercury is water soluble (elemental mercury is not), is what allows wet scrubbers to be potentially an excellent means of mercury control. Wet FGD is a mature technology that offers potential for a very effective mercury control via minor process modifications.

Commercial Readiness and Industry Experience

Similar to wet FGD technology, SCR technology is widely used commercially worldwide. In Germany, for example, essentially all coal-fired boilers are quipped with SCR technology combined with wet scrubbers. Over 50,000 MW of capacity is deployed worldwide. In the United States the technology is being deployed at a rapid pace at present.⁶ Therefore, both SCR (for NO_x control) and wet scrubbers are readily commercially available.

With respect to SCR performance on mercury oxidation, testing is on-going at pilot- and full-scale sites.²⁻⁵ Efforts by B&W^{2,4} and EPRI³ are examples of pilot-scale activities. Full-scale testing is taking place at various sites as well.^{5,7}

Emission Control Performance (Mercury Oxidation)

SCR systems are widely used in conjunction with wet FGD technology, and the combination has yielded total mercury capture exceeding 80 percent.^{4,7} In tests conducted at Grosskraftwerk Mannheim AG in Germany, mercury oxidation across the SCR increased HgCl₂ content in the flue gas from 77 to 95 percent.⁵

Results from tests at B&W indicated that oxidized mercury increased from 50.9 to 93.4 percent in the presence of the SCR catalyst at typical SCR temperatures, while at lower (air preheater outlet) temperatures, oxidized mercury levels rose from 81.9 to 94.1 percent.²

Joint pilot- and full-scale tests³ by URS and EPRI showed a significant variation in results, suggesting that the fundamental mechanisms of mercury oxidation across the SCR catalyst may not be fully understood. Table 3-6, taken from Reference 3, summarizes some of the results. However, the mercury oxidation is highly depended on the coal type and could range from 40 to 90 percent.

Table 3-6. Selected SCR Test Results

Control Unit	Control Unit Status	Inlet Mercury Oxidation (% of total)	Outlet Mercury Oxidation (% of total)
Pilot SCR	No ammonia	8 – 12	2 – 10
Full scale SCR	Normal	10 – 18	4 – 7
Full scale SCR	No ammonia	10 – 18	50
NH ₃ injection system	Normal	50 – 87	67 – 85
NH ₃ injection system	No ammonia	50 – 87	70 – 90

O&M Impacts

No impacts are expected from the natural oxidation of elemental mercury across the SCR catalyst. Of course, as mentioned in the section on wet FGD, the FGDs and SCRs themselves have O&M impacts including increased auxiliary power and potential air preheater fouling due to ammonium bisulfate.

Capital Costs

No additional costs to the SCR-wet scrubber system are associated with the naturally occurring oxidation of elemental mercury on the catalyst and the subsequent capture in the scrubber. SCR costs are highly dependent on site-specific factors and range from about \$50 to 140/kW.⁸ Capital costs for wet scrubbers were provided in Section 3.2.1.3 and were in the range of \$160-275/kW.

O&M Costs

Fixed O&M:

SCR: \$0.5-1.4/kW-yr (based on 1 percent of capital costs).¹

Wet scrubber: \$1.2-14/kW-yr (for a range of coal sulfur from 0.4 to about 3.5 percent).

Variable O&M:

SCR: 0.75-4 mills /kWh.⁸ Wide range based on catalyst rate of replacement, number of air preheater washes.

Wet scrubber: 0.1-1 mill/kWh (for a range of coal sulfur from 0.4 to about 3.5 percent).

Issues Associated with the Technology; Future Outlook

Studying mercury oxidation has become a focus in efforts to enhance SCR, and in turn, wet FGD technology. Further testing on the speciation of mercury must be conducted to gain a better understanding of oxidation potential, oxidation vs catalyst age, as well as fundamental mechanisms. As SCR and wet FGD technologies are increasingly combined for NO_x and SO₂ reduction, this will result in a significant and inexpensive way to also control mercury emissions. Parallel research to characterize the stability and fate of mercury in the FGD sludge or gypsum is ongoing.

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3.2.3.4 EnviroScrub Pahlman

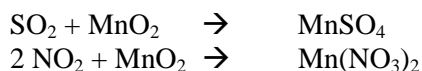
EnviroScrub Summary

Status	Pilot scale
SO₂ Reduction, %	>99
NO_x Reduction, %	93-97
Hg Reduction, %	Up to 67
Cost	
Capital (\$/kW)	150 for 500 MW plant
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	1.45
Applicability	Both new and retrofit applications
Issues	Early stage of development; demonstration and further assessment of the technology is needed.

Technology Description

EnviroScrub's Pahlman Process is a "closed-loop" dry sorbent system comprised of two discrete steps. One step involves capturing the target pollutants, such as NO_x, SO_x, mercury and particulates, using Pahlmanite dry mineral sorbent compounds. The other step involves the regeneration of the spent or partially spent sorbent compounds for reuse and separation and isolation of useful by-products such as nitrates and sulfates for use in fertilizers and industrial chemicals.

The Pahlmanite sorbents are low-density oxides of manganese (MnO₂) in the form of fine black powder. The sorbent is injected in a reactor, which operates at temperature between ambient and 320 °F. According to the supplier, different type of reactors are suitable including fluidized bed, baghouse, transport and cyclone. SO₂ and NO_x react with the sorbent according to the following reactions:



Mercury vapor reacts with the Pahlmanite sorbent, which promotes oxidation to HgO followed by sorption by MnO₂.

Sorbent regeneration is a wet chemical process, which involves the following steps:³

1. Reacted ("loaded") sorbent is transported into a regeneration vessel where it comes in contact with a hot, oxidizing, aqueous solution, which dissolves the nitrate and sulfate salts of manganese. The chemical composition and operating conditions of the regeneration vessel are controlled so that the dissolved manganese is precipitated to form fresh sorbent; also, the remaining solid sorbent is re-oxidized and re-activated.
2. The slurry consisting of nitrates and sulfates is transported from the regeneration vessel to a washing and filtration process, which separates the solids from the liquid fraction. The solids are subsequently dried and returned to the reactor for reuse.
3. The liquid fraction is separated by membrane technology or other means into concentrated solutions containing sulfate, nitrate and mercury compounds. These solutions may then be

precipitated or evaporated to be converted to a solid form for either disposal or by-products. Excess water is returned to the regeneration vessel.

4. Some of the sulfate-containing liquid from the washing and filtration system is sent to a chemical regeneration process to produce base and oxidizer chemical which can be used in the Pahlmanite sorbent regenerator.

Commercial Readiness and Industry Experience

The technology is in pilot scale stage; a trailer-mounted pilot plant is available which has been tested at a number of power plants using flue gas slipstreams (1,000 scfm):

- Ameren Energy's Hutsonville Power Station in Hutsonville, Illinois, which burns high-sulfur Eastern Bituminous coal, without the use of an emissions control system for SO₂ and NO_x.
- Minnesota Power's Boswell Energy Center located in Cohasset, Minnesota, which consists of four coal-fired steam boilers (total: 1000 MW) burning PRB (Powder River Basin) coal. The demonstration of the EnviroScrub process was conducted on the exhaust gas stream of Unit 1, a 75 MW boiler, which currently operates without any form of back-end emission control systems for NO_x and SO₂.
- Potlatch Corp. Northwest Paper Division's facility located in Brainerd, Minnesota. The demonstration of the EnviroScrub process was conducted on boiler #1, a Zurn Industries 75,000 lb/hr steam boiler, operating exclusively on natural gas with NO_x concentration output of approximately 133 ppm.⁴

Emission Control Performance

Results from Minnesota Power's Boswell testing indicate that the technology achieved above 99 percent SO₂ reduction and 94-97 percent NO_x reduction.¹ Also, the Hutsonville facility achieved over 99 percent SO₂ and 75 percent NO_x reduction⁴ on 1750 ppm SO₂ and 300 ppm NO_x inlet.

According to the supplier, the technology also controls mercury and particulates (PM_{2.5}). Testing at Boswell indicated mercury removal up to 67 percent.⁴

O&M Impacts

O&M impacts are not known, mainly because of the lack of information. At least auxiliary power is expected to increase, but no specific estimates are available.

Capital Costs

According to the supplier, capital costs for a 500 MW plant are projected to be in \$150/kW.²

O&M Costs

Variable O&M costs are projected by the supplier to be approximately 1.45 mills/kWh.²

Issues Associated with the Technology; Future Outlook

The technology is still at an early development stage (pilot plant) and requires further demonstration and techno-economic assessment to develop a more comprehensive picture of its cost-effectiveness. Also, removal efficiencies of mercury and particulates need to be demonstrated.

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3.2.3.5 LoTOx

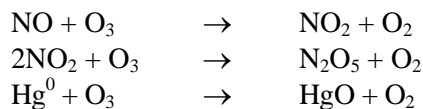
LoTOx Summary

Status	Early commercial (commercial in metal industry)
SO₂ Reduction, %	95% due to the FGD which is part of the system
NO_x Reduction, %	70-95%
Hg Reduction, %	Up to 90%
CO₂ Change, %	NA (1-2.5% increase due to auxiliary power requirements)
Cost	
Capital (\$/kW)	\$35-70/kW (for LoTOx only; not including FGD)
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	NA
Applicability	Both new and retrofit applications
Issues	Further demonstration is needed at utility scale.

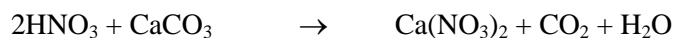
Technology Description

LoTOx is a gas phase low temperature oxidation system, which involves injection of ozone in the flue gas upstream of a wet FGD to oxidize NO_x to higher oxides of nitrogen such as N₂O₅, and mercury to HgO.¹⁻⁷ Subsequently these compounds are removed in a wet FGD, because they are water-soluble. As Figure 3-8⁸ shows, the LoTOx system consists of an integrated ozone-from-oxygen generation unit complete with ozone injection system into the LoTOx.

Ozone is injected into the reactor or directly into the exhaust duct prior to the wet FGD (if sufficient residence time can be provided). Ozone is produced in-situ and on demand by passing oxygen through a conventional industrial ozone generation system, in response to the amount of NO_x present in the flue gas generated by the combustion or process source. Upon injection of the ozone in the flue gas (typically below 300 °F), oxidation occurs according to the following simplified reactions:⁹⁻¹²



N₂O₅ and HgO are water soluble. In the presence of water, N₂O₅ forms HNO₃, which further reacts with alkali compounds or alkaline earth metals to form corresponding nitrates:



The selection of wet FGD type (lime, limestone or ammonia) does not impact the performance of the LoTOx process because the solubility of N₂O₅ is significantly higher than that of SO₂.

Theoretically, there is the potential for oxidation of SO_2 to SO_3 ; however, as proven in field testing, the reaction rates are very low compared to the predominant NO_x reactions.

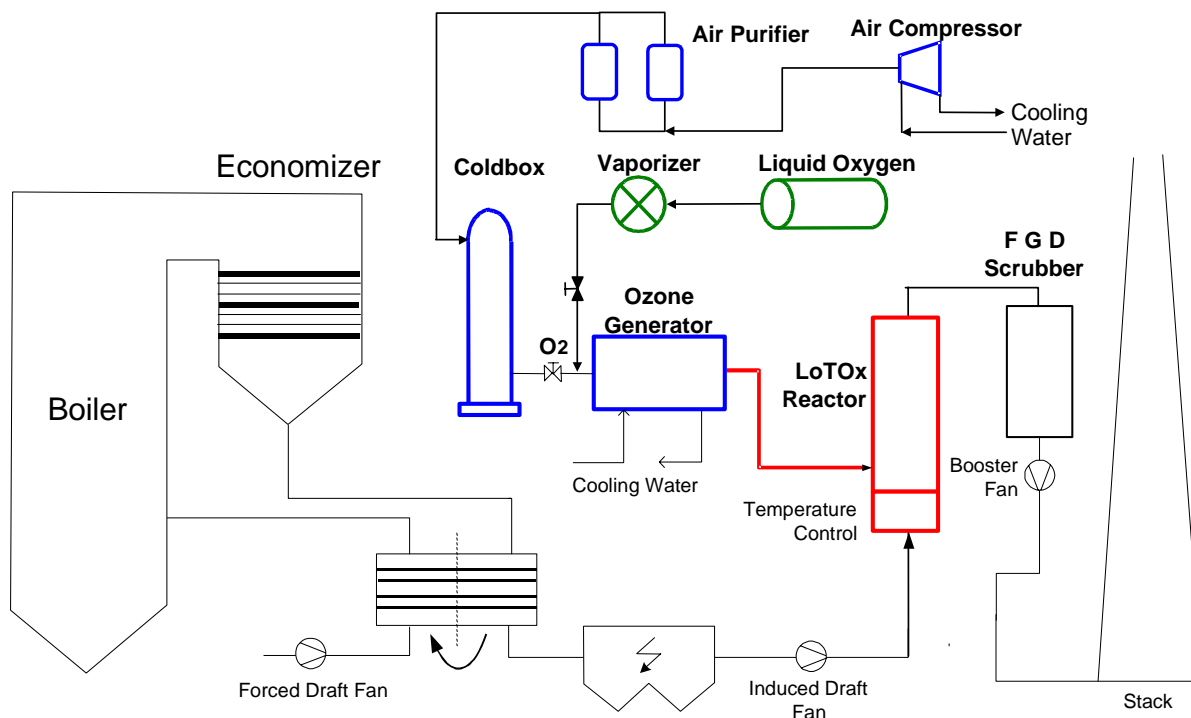


Figure 3-8. Schematic diagram of LoTOx™ system.⁸

Commercial Readiness and Industry Experience

The technology has been demonstrated up to a scale of 25 MW, at boiler #4 of the Medical College of Ohio (MCO) capable of burning high-sulfur Ohio coal.¹³ Commercial experience was also gained in the steel industry prior to the MCO demonstration. For example: a 4,500 scfm metal pickling process and a natural gas-fired boiler of 8,000 scfm are on-going applications. Also, LoTOx has been installed at a lead recovery furnace (25,000 scfm) which is operating presently.¹⁴ LoTOx technology for NO_x control is being considered by the refining industry to be used with wet SO_2 scrubbers and a number of commercial installations are expected to be operating by 2005-07. Based on these developments, the supplier (BOC) is prepared to provide the technology for commercial use with appropriate guarantees.

Emission Control Performance

Up to 95 percent NO_x reduction has been achieved and projected for large-scale applications. As Figure 3.9 shows, NO_x outlet levels of less than 5 ppm have been achieved. Similar NO_x reductions have been achieved in other facilities. For example, the 4,500 scfm metal pickling application achieved approximately 84 percent NO_x reduction from 1100 ppm inlet, while the natural gas-fired boiler of 8,000 scfm achieved nearly 98 percent NO_x reduction (4 ppm outlet NO_x emissions). Finally, LoTOx at the lead recovery furnace averaged 80 to 95 percent NO_x reduction.^{8,15}

BOC normally recommends installation of LoTOx alone when inlet NO_x is below 0.3 lb/MMBtu. Above 0.3 lb/MMBtu, LoTOx is recommended as part of an integrated control approach operating in series with an alternate control process that is capable of moderate NO_x removal. By combining the two

technologies, users may be able to avoid installing an SCR system, which is expected to have higher capital investment and operating costs.

Oxidized mercury species are removed in a forced oxidation wet FGD, which is downstream of the LoTOx system, and removal rates depend primarily on the coal characteristics. As the Table 3-7 shows, LoTOx is reported to have enhanced the mercury removal of FGD for all coals, especially subbituminous coal and lignite.¹⁶

According to the supplier, LoTOx enhances the SO₂ removal efficiency of the FGD by approximately 5 percent (depending on the FGD design) and has no impact on SO₃ emissions.

O&M Impacts

O&M impacts are expected to be minimal since the LoTOx technology is injecting ozone in the flue gas. According to the supplier, auxiliary power requirements for a 500 MW plant are projected to be approximately 5.0 – 12.5 MWs or 1-2.5 percent of the gross power output.

Also, cooling water is required; which for a 500 MW plant is estimated at 4,500 gal/min and assumed available at 70 °F.

Costs

Capital costs are estimated (by the supplier) to be in the \$35 to 70 per kW range depending on inlet NO_x level and unit size.

The supplier estimates the fixed O&M costs to be approximately 2.5 percent of the capital costs. In the electric utility industry, annualized costs are typically \$1,200-2,200 per ton of NO_x removed, inclusive of mercury removal.

Issues Associated with the Technology; Future Outlook

The technology has yet to be demonstrated at a utility scale plant based on which the performance and cost projections could be verified.

Table 3-7. Mercury Data for Various Coals⁸

Coal Type	Typical Hg ²⁺ as % of Total Hg	Hg Removal with FGD Alone	Hg removal with LoTOx and FDG
Bituminous	70-85%	76%	94%
Sub-Bituminous	15-45%	33%	92%
Lignite	10-30%	19%	91%

Performance of LoTOx System at MCO
December 6, 2001
Outlet NO_x Setpoint = 5 PPM Changed to 10 PPM

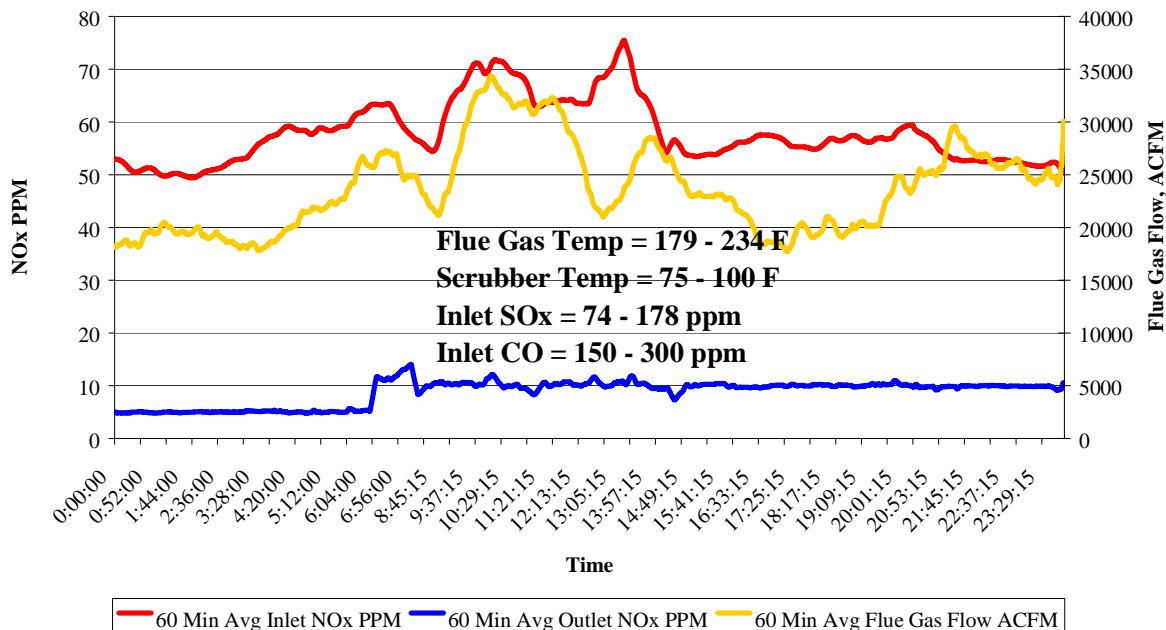


Figure 3-9. NO_x with LoTOx at MCO's 25 MW-thermal gas and coal fired boiler.¹³

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3.2.3.6 K-Fuel

K-Fuel Summary

Status	Components of technology commercial
SO₂ Reduction, %	Up to 30% (relative to raw PRB coal or lignite)
NO_x Reduction, %	Up to 45% (relative to raw PRB coal or lignite)
Hg Reduction, %	Up to 70% (relative to raw PRB coal or lignite)
Cost	Indicative prices: \$20 per ton for K-Fuel vs \$6.50 ton PRB, both FOB in Wyoming
Capital (\$/kW)	NA
Fixed O&M (\$/kW-yr)	NA
Variable O&M (mills/kWh)	NA
Applicability	The supplier is focusing on boilers burning subbituminous and lignite because the process is effective for coals with high ash and moisture. K-Fuel could apply to boilers burning bituminous coal too, but significant boiler modifications may be required as is the case of switching from bituminous to PRB.
Issues	A plant-specific evaluation is required to assess the cost effectiveness of a switch to K-fuel, especially when the overall benefit of the emission reductions is taken into consideration.

Technology Description¹

K-Fuel is a beneficiated coal that is derived from PRB coal or lignite coal. The resulting fuel is lower in ash, higher in Btu value and produces lower pollutant emissions than untreated western subbituminous or PRB coals. K-Fuel uses a pre-combustion process that improves the quality of the coal – including removing the mercury, moisture, ash, sulfur, and some of the fuel NO_x precursors – before the coal is burned at the power plant. Because these constituents are removed prior to burning the coal at the plant, the need for post-combustion controls may therefore be reduced. Technology may be applicable to bituminous coal. However, the supplier has focused exclusively on PRB and lignite applications, because the K-Fuel is a moisture and ash reduction process, which PRB and lignites are high in.

The K-Fuel pre-combustion multi-pollutant reduction technology (PMR) is a two-step process, illustrated in Figure 3-10.

1. *Physical Separation:* A gravity separation process – either wet or dry – is used to remove ash along with other pollutants (sulfur and mercury). This involves crushing and screening to remove the larger particles. Also, high-energy magnetic separation can be used, especially for coals with a higher percentage of fine particles. The processed coal is then passed on to an intermediary storage facility prior to being sent to the next step of the process. Wastes from physical cleaning are returned to the coal mine.
2. *Thermal Processing,* which follows, employs Lurgi Mark IV vessels operating under high temperature and pressure (460 °F and 485 psi). Mineral matter of the coal under thermal stress fractures in these vessels liberating moisture, as well as sulfur and mercury. Figure 3-11 shows the main components of the thermal processing unit.

The water and mercury vapors are condensed, and mercury is captured in a carbon-bed adsorption reactor. Water is recycled in the process. Mercury-laced activated carbon is disposed in a toxic landfill.

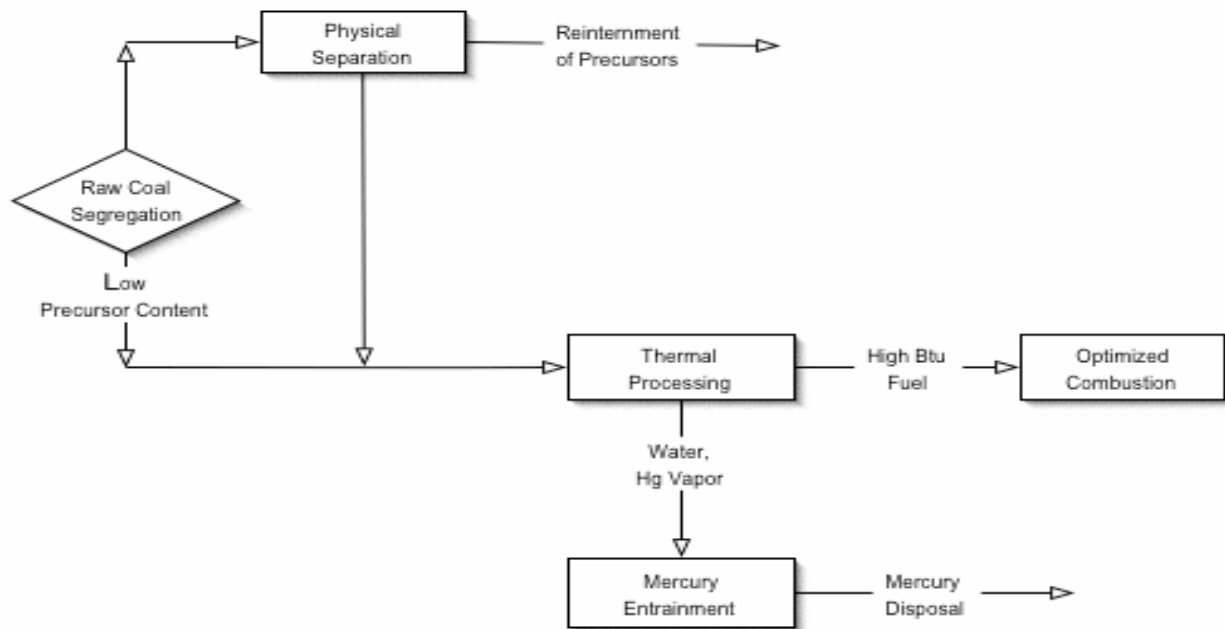


Figure 3-10. K-Fuel PMR technology.

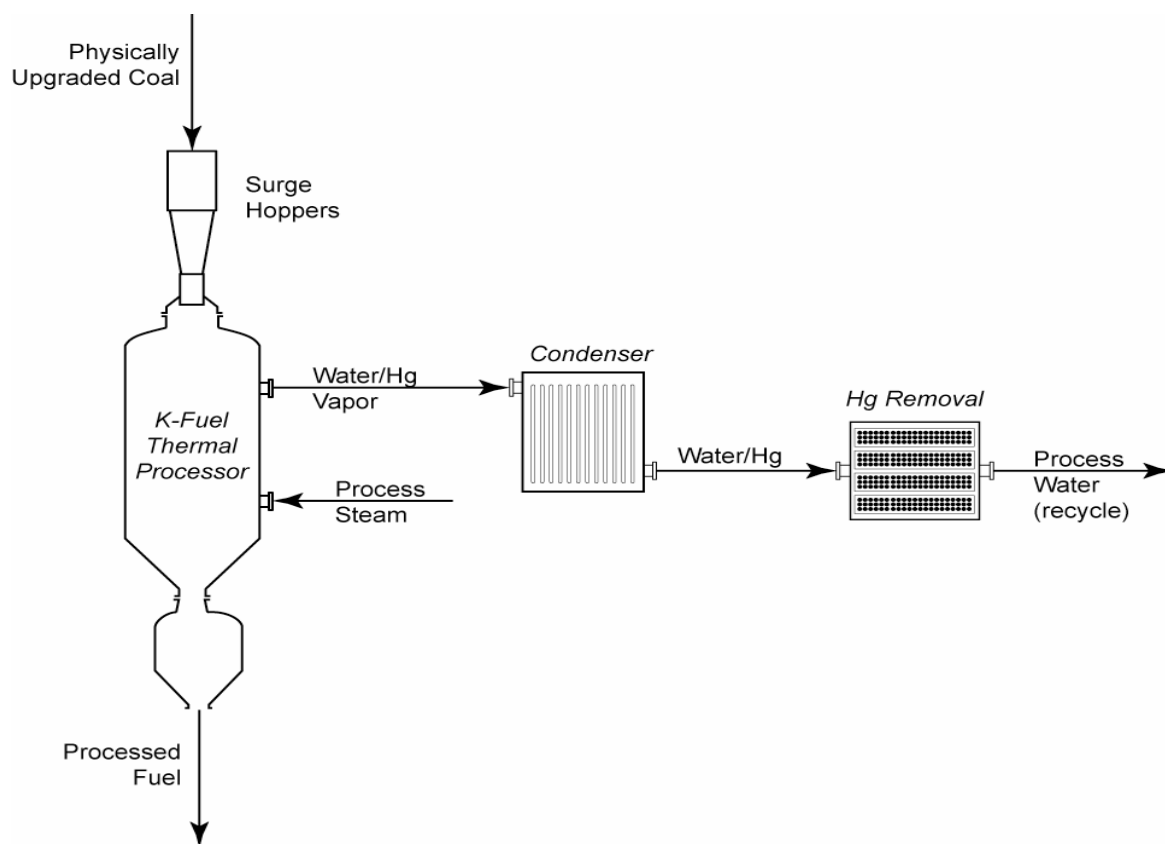


Figure 3-11. K-Fuel thermal separation unit.

Commercial Readiness and Industry Experience

The components of the PMR process are proven commercially. Physical cleaning is a well-proven technology and thermal separation is used worldwide, with Lurgi having approximately 160 thermal separation units in operation. In the U.S., thermal processing has been used since 1984.² The first commercial plant, 700,000 tons per year, is expected to be completed by the middle of 2004.

The K-Fuel has been tested in smaller scale facilities and a commercial plant, including Southern Research Institute (SRI) and at American Electric Power's (AEP) Clifty Creek Station in Indiana.

Emission Control Performance

According to KFx, the developer of K-Fuel, physical separation studies on a number of low rank coals, exhibited ash reduction in the 10-30 percent range, 10-36 percent sulfur reduction, and 28-66 percent mercury reduction. Thermal separation adds more mercury reduction; for example, testing by Rio Tinto Technical Services in Perth, Australia showed a 40 percent reduction³ in fuel mercury due to thermal separation alone. Total mercury reduction at the Energy & Environmental Research Laboratory of the University of North Dakota⁴ and the Western Research Institute⁵ were reportedly 66-67 percent. Also, NO_x reduction up to 46 percent has been experienced in tests at Southern Research Institute⁶ and 40 percent at AEP's Clifty Creek Station. All emission reductions are relative to similar type raw coal (PRB or lignite).

Finally, reduced moisture in the coal is expected to improve boiler efficiency. For a typical Wyoming coal, moisture is reduced from 20-30 percent to approximately 6 percent. Such a change may improve boiler efficiency by up to 2.0 percent.

O&M Impacts

Most O&M impacts are expected to be positive including reduced auxiliary power and O&M costs associated with the coal handling equipment, pulverizers, particulate collection, and ash handling equipment. Also, less ash reduces transportation and disposal costs. Finally, more consistent coal quality with lower ash would have a positive impact on plant reliability. However, there is inadequate information to quantify such impacts.

While the supplier is targeting mainly boilers burning PRB coal or lignites for this technology, K-Fuel could be used in boilers designed for bituminous coal, too. However, in the case of bituminous coal, the O&M impacts could be significant including lower steam temperatures, higher unburned carbon, slagging and potential de-rating (reduced output). Such impacts could be eliminated through boiler modifications, but some investment would be required.

Costs

It is envisioned that the coal produced by the PMR process will be sold to the power plants rather than the power plants having to set-up their own PMR process facility; if so, the price of the processed coal is the important parameter. Presently, there is no adequate information to estimate the price of the processed coal, but it would need to reflect the costs of selective mining, capital and operating costs of all components (physical and thermal separations and carbon bed absorber for mercury removal) and disposal costs of mercury and other wastes. Also, the price will have to be competitive with other coal; in other words, the price for K-Fuel may be based on the price of competing coal on heating value basis plus credits for environmental benefits (lower SO₂, NO_x and Hg reductions). Preliminary estimates suggest that K-Fuel may be available in the \$20-25 per ton range FOB Wyoming. Presently, this compares to raw Wyoming coal of \$6.50 per ton FOB Wyoming. However, the K-Fuel may also compete against Eastern bituminous coal.

Issues Associated with the Technology; Future Outlook

The technology is suitable mainly for western coals. Also, not adequate information is available to assess its cost-effectiveness. With the operation of the Black Thunder plant by mid-2004 more information is expected to become available.

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3.2.4 Advanced Power Generation Technology Options

3.2.4.1 Circulating Fluidized Bed Technology

Circulating Fluidized-bed Technology Summary

Status	Commercial up to 250 MW
SO₂ Reduction, %	>95
NO_x Reduction, %	30 – 70 depending on the coal [90 with SNCR (ammonia or urea)]
Hg Reduction, %	NA
CO₂ Change, %	Negligible
Cost	
Capital (\$/kW)	850 – 1100 (for a new CFB plant in the 100 – 250 MW range)
Fixed O&M (\$/kW-yr)	30 – 37
Variable O&M (mills/kWh)	2.0 – 5.5
Applicability	Mainly new power plants; also for replacement of old boilers while utilizing the existing turbine and balance of plant (BOP)
Issues	Successful scale-up to 400 – 600 MW while maintaining its cost-effectiveness and emission performance

Note: Emission reduction is based on comparison of this technology to a similar size subcritical pulverized coal boiler with low NO_x burners, but without FGD.

Technology Description

Circulating Fluidized Bed (CFB) combustion technology is one of the two variations of Atmospheric Fluidized Bed Combustion (AFBC), the other one being the bubbling AFBC. CFB has been the predominant design used in coal-fired power applications, especially in large-scale plants above 100 MW. Bubbling AFBC is used too, but the most recent plants are small, 10-50 MW, burning biomass and municipal solid wastes. CFB technology is described in this section because of its applicability for large power applications.

CFB boilers (see Figure 3-12) are very similar to conventional PC boilers in many respects. The majority of boiler components are similar, and hence manufacturing of the furnace and the back-pass can be done in existing manufacturing facilities. In addition, a CFB boiler utilizes the Rankine steam cycle with steam temperatures and pressures similar to PC boilers. CFB boilers can be designed for either subcritical or supercritical conditions. Most CFB boilers utilized so far are of the subcritical type mainly because the technology has been utilized in sizes up to 250 MW where subcritical operation is more cost-effective. As the technology is scaled up (above 400-500 MW), the supercritical design may be used depending on the site-specific environmental requirements or cost of fuel.

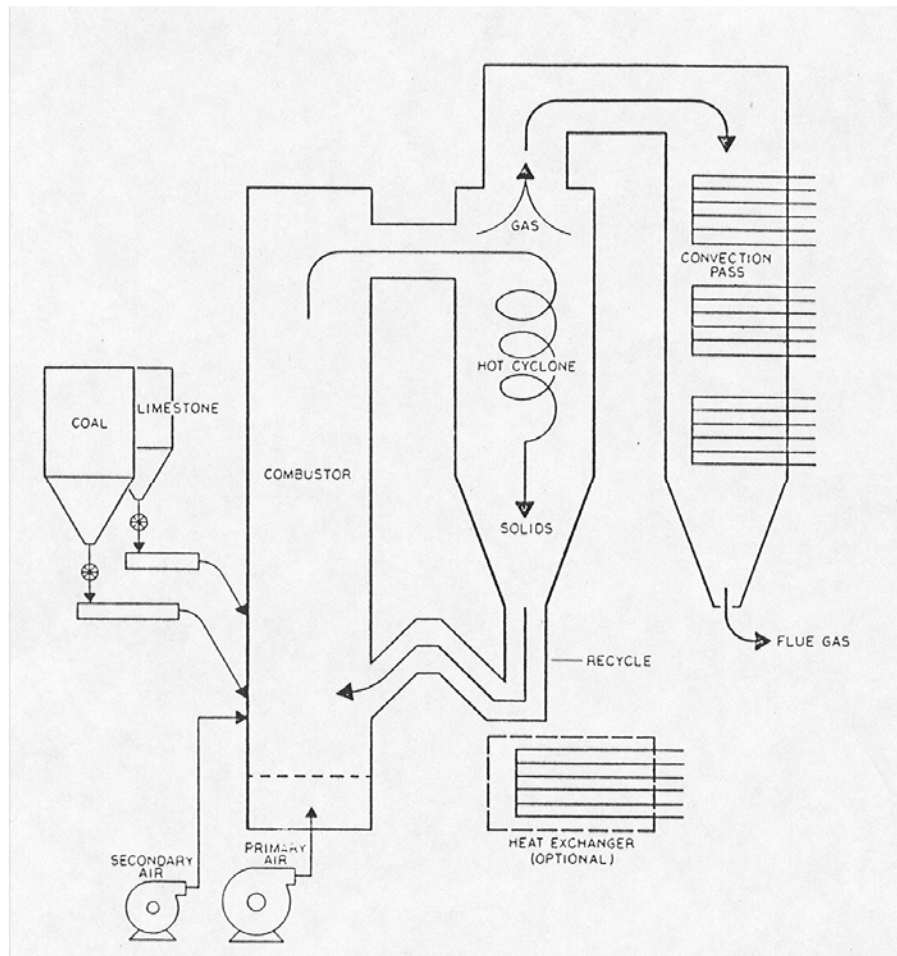


Figure 3-12. CFB process schematic.

The difference of CFB relative to PC boiler stems from the lower operating temperature and the injection of limestone in the furnace to capture SO_2 emissions. Typical maximum furnace temperature in a CFB boiler are in the 1500-1600 °F (820-870 °C) range, while conventional PC boilers operate at 2200-2700 °F (1200-1500 °C). This low combustion temperature limits the formation of NO_x and is the optimum temperature range for in-situ capture of SO_2 . The injected limestone is converted to lime, a portion of which reacts with SO_2 to form calcium sulfate (CaSO_4), a dry solid, which is removed in the particulate collection equipment (either ESP or FF). A cyclone is located between the furnace and the convection pass to capture unreacted lime and limestone present in the flue gases exiting the furnace. The solids collected in the cyclone are recirculated back to the furnace to improve the overall limestone utilization. Limestone injection can remove from 90 to >95 percent of the sulfur in the coal¹ eliminating the need for flue gas desulfurization (FGD) downstream of the boiler. CFBs have NO_x emissions 60-70 percent lower than conventional PC boilers with low NO_x burners

CFB boilers can efficiently burn low reactivity and low-grade fuels, which may not be burned in conventional PCs. Such fuels include anthracite, coal cleaning wastes, and industrial and municipal solid wastes. High-ash fuels, such as lignite, are particularly suitable for CFB technology.

Commercial Readiness and Industry Experience

Commercial applications of this technology exist in sizes up to 265 MW net (~300 MW gross) unit size, as demonstrated by hundreds of boilers operating throughout the world (Australia, China, Czech Republic, Finland, France, Germany, India, Japan, Poland, South Korea, Sweden, Thailand, and United States). Vendors are now offering boiler sizes for plants well over 300 MW in sizes. Foster Wheeler has signed a contract to supply a 460 MW boiler with super-critical steam conditions at the Lagisza plant in Poland.³ This plant is scheduled to be started up by the end of 2005. In 1996, EPRI estimated that there are approximately 300 CFB units (larger than 22 tons/hr of steam capacity each) in operation worldwide. Since then (1996), the number of CFB operating units has increased further. Experience from these units has confirmed performance and emissions targets, high reliability, and the ability to burn a variety of low quality fuels.

The most recent CFB projects on a scale larger than 200 MW are shown in Table 3-8.

Table 3-8. CFB Units larger than 200 MW

Company, Plant Name	Location	Supplier	Net MW	Start- up	Fuel Type
EDF, Gardanne	Provence, France	Stein (Lurgi)	232	1996	Subbituminous Coal (30% ash/4% S)
Turow Power Co., Turow Station	Silesia, Poland	Foster Wheeler	2 x 230	1999	Brown Coal (23% ash/44% H ₂ O/0.6% S)
KEPCO, Kangwon-do	Kangwon-do, South Korea	KHI and ABB-CE	2x200	1998	Korean Anthracite
AES, Warrior Run	Warrior Run, Maryland, USA	ABB-CE and Lurgi	2 x 200	1999	Bituminous Coal
JEA, Jacksonville	Jacksonville, Florida, USA	Foster Wheeler	265	2002	Bituminous Coal, Petroleum Coke
Sithe/Tractabel Red Hills	Red Hills, Mississippi, USA	Alstom (Stein)	2 x 220	2001	Lignite

Emission Control Performance

CFBs have demonstrated that they can remove up to 90 - 95 percent¹ of the sulfur in the coal without the need for flue gas desulfurization (FGD) downstream of the boiler. SO₂ removal is affected mainly by the bed temperature and by the Ca-to-S molar ratio. The bed temperature is designed for optimum sulfur capture [1500-1600 °F (820 - 870 °C)]. Ca-to-S molar ratio depends on the amount of CaO and MgO in the ash, as well as their reactivity. A Ca-to-S molar ratio of 2.0 - 2.5 is typical for 90 - 95 percent SO₂ removal.

NO_x emissions are 30 - 70 percent lower than conventional PCs with low NO_x burners;¹ CFB boilers have achieved consistently 0.12-0.16 lbs/MMBtu NO_x emissions, compared to pulverized coal plants which range from 0.2 to 0.5 lbs/MMBtu. Further NO_x reduction can be achieved by installing an SNCR (ammonia or urea) injection system in the CFB furnace. NO_x emissions in the 100 ppm level without ammonia or urea injection and below 20 ppm (0.027 lbs/MMBtu) with ammonia or urea injection have been demonstrated.¹ NO_x emissions are impacted by the bed temperature, the nitrogen and volatile matter in the coal, and the bed stoichiometry. Stoichiometry, defined as a ratio of available air (weight) to theoretical air needed for complete combustion, is affected by the excess air and air distribution across the

bed. The amount of ammonia or urea being injected (in case such system is available) also impacts the additional NO_x removed as a result of such an injection.

It is not clear whether CFB controls mercury, too. CFB plant efficiency is similar to new subcritical pulverized coal plants equipped with NO_x and SO₂ controls, typically 34-38 percent (higher heat value basis). Therefore, no significant CO₂ reduction is expected. Supercritical CFBs will have higher efficiency (38-40 percent) and proportionally lower CO₂ emissions.

O&M Impacts

None.

Capital Costs

Capital costs of large CFB plants (between 150 and 250 MW) range from \$850 to 1100/kW, similar to or slightly above the costs of pulverized coal plants with FGD, which range from \$800 to 1000/kW.¹

O&M Costs

O&M costs are projected to be \$30-37/kW-yr for fixed O&M and 2.0-5.5 mills/kWh for variable O&M costs depending on the O&M practices of the utility, labor costs, and cost of consumables (especially sorbent).¹

Issues Associated with the Technology; Future Outlook

The main barrier to widespread utilization of the technology is scale-up to larger sizes (present focus on 400 - 500 MW) while maintaining its cost-effectiveness and emission control performance. This barrier is expected to be overcome in the next 2-3 years as indicated by a number of studies and demonstration projects being planned.² One such effort is led by Electricite de France (EdF), which sponsored a study to develop a 600 MW CFB design. Participating in this study are Alstom and Foster Wheeler, two of the leading CFB vendors.

Presently, CFBs are being built worldwide, especially for solid fuels difficult to burn in a pulverized coal boiler such as anthracite, lignite, brown coal, and coal wastes. Also, industrial and municipal solid wastes, petroleum coke, and other waste fuels are being burned in most cases as supplemental fuels. CFB technology is expected to be used widely in the future, mainly in new power plant applications.

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3.2.4.2 Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle Summary

Status	Entrained and moving beds: commercial up to 500 MW; fluidized bed: in demonstration stage
SO₂ Reduction, %	Up to 99
NO_x Reduction, %	80-90 (compared to PC with low NO _x burners)
Hg Reduction, %	Needs characterization via measurements
CO₂ Change, %	10 to 20% potential reduction over a comparably-sized PC plant with FGD
Cost	
Capital (\$/kW)	1200 – 1600 (for new plant of 400 MW size)
Fixed O&M (\$/kW-yr)	30 – 45
Variable O&M (mills/kWh)	0.5 – 2.0
Applicability	New power plants or retrofits utilizing existing plant steam turbine-generators and balance of plant equipment
Issues	High costs are the main barrier to widespread utilization of entrained and moving bed IGCC. Fluidized bed IGCC requires demonstration.

Technology Description

The integrated gasification combined cycle (IGCC) involves gasification of coal with either oxygen or air, with the resulting syngas (an abbreviation for synthetic gas) cooled, cleaned, and fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine.^{1,2} Power is produced from both the gas and steam turbines; hence, combined cycle (CC).

The gasification plant could be designed to operate under atmospheric or pressurized conditions. Pressurized gasification is preferred to avoid large auxiliary power losses for compression of the syngas, which is required in an atmospheric IGCC, before the gas enters the gas turbine. Pressurized gasification also reduces the size of the gasifier. Most gasification processes currently in use or planned for IGCC applications are oxygen blown; however, the Piñon Pine Plant in the U.S. uses an air-blown fluid bed process [developed by Kellogg Rust Westinghouse (KRW)].

The electric output of an IGCC plant is mainly determined by the firing temperature of the gas turbine [typically: 1100 °C (2000 °F) or 1260 °C (2300 °F) for standard designs offered commercially] and by the frequency of the electricity produced. Typical net output for single-train IGCC plants is approximately 275 MW for 60-Hz markets and 400 MW for 50-Hz markets. Plant net efficiency is typically 40 – 44 percent on a higher heating value (HHV) basis. Utilization of the new gas turbines (G- and H-class) would increase the overall plant efficiency to 46 – 48 percent (HHV basis) with an output of 400-450 MW (in 60-Hz markets) and 500 - 550 MW in 50-Hz markets.

The IGCC design varies, especially in the degree of integration. For example, some IGCC plants such as the Buggenum (Netherlands) and Puertollano (Spain) are highly integrated designs with all the air for the air separation unit being taken as a bleed from the gas turbine compressor. In contrast, the U.S. plants at Tampa and Wabash River are less integrated, and the air separation units have their own separate air compressors. The more highly integrated design has higher plant efficiency, but lower plant availability and operating flexibility. Presently, the general consensus among IGCC plant designers is to have the air

separation unit derive part of its air supply from the gas turbine compressor and the remainder from a separate dedicated compressor.

Commercial Readiness and Industry Experience

In general, IGCC technology has been demonstrated up to 500 MW in size and offered commercially, but higher costs (relative to the conventional PC with FGD) limit its widespread utilization. Presently, there are six coal-based IGCC demonstration plants in operation (three in the U.S and three in Europe) with three more IGCC plants utilizing refinery wastes in Italy. Table 3-9 shows these plants, as well as the first IGCC demonstration, Cool Water IGCC in Barstow, CA, which operated from 1984 to 1989.

In addition, there are approximately 160 gasification facilities in 28 countries being utilized by the petrochemical industry. These are mainly gasifiers using heavy oil, petroleum bottoms, or petroleum coke. While this experience is not directly applicable to coal-fired IGCCs, it is clearly helpful because some of the technical problems and operating issues have been addressed.

Table 3-9. Commercial-Size IGCC Power Plants

Project name and location	Gasification Technology	MW (gross)	Startup Date
Cool Water, Mojave, CA, US	Texaco	120	1984
SEP-Demkolec, Buggenum, The Netherlands	Shell	253	1994
Wabash River, West Terre Haute, IN, US	Destec	296	1995
Tampa Electric, FL, US	Texaco	312	1996
Sierra Pacific Piñon Pine, NV, US	KRW fluid bed	107	1998
ELCOGAS, Puertollano, Spain	Krupp-Uhde Prenflo	335	1997
Schwartze Pumpe, Schwartze Pumpe, Germany	Lurgi moving bed	75	1999
ISAB Energy, Sicily, Italy	Texaco	512	2001
Sarlux, Sardinia, Italy	Texaco	548	2000
API Energia, Falconara, Italy	Texaco	280	2001

Note: Above gasifiers are of entrained type, unless otherwise indicated.

Samples of additional projects in the planning stage include:

- Vresova, Czech Republic: 385 MW lignite-firing; upgrading of existing facility and increase of plant output;
- Port Arthur, TX: 6,985 tonnes/day (7,700 U.S. ton/day) petroleum coke gasification plant; and
- Citgo's refinery at Lake Charles in Louisiana: 670- MW IGCC utilizing petroleum coke.

Actual efficiencies of IGCC plants have been measured in the 38-43.2 percent range (HHV-basis), mainly because their operation was designed in a conservative way to demonstrate the reliability of the technology and its ability to reduce acid rain pollutants rather than to achieve the highest efficiency. Utilization of parts of existing plants in IGCC repowering cases also contributed to keeping the efficiency on the low side. For example, the Wabash River IGCC repowering project achieved 39.7 percent efficiency (this was 20 percent higher than the plant's efficiency prior to repowering). Similarly, the Tampa (Polk) IGCC plant achieved 38 percent³ while Puertollano IGCC plant achieved 43.2 percent efficiency.⁴

Three types of gasification processes are available: moving-bed, fluidized-bed, and entrained-bed, each of them at a different stage of development.

Entrained-flow gasifiers operate at high temperatures (between 1300 and 1500 °C) where the ash is melted and removed from the bottom of the gasifier as slag. This type of gasification is suitable for low-ash coals (less than 10 – 15 percent ash) and is the most widely used IGCC process. The main suppliers are: Texaco (Tampa and Cool Water plants in the U.S., and three refinery waste IGCC plants in Italy) and Destec (Wabash plant in the U.S.) offering coal-water-slurry-fed processes, and Shell (Buggenum, Netherlands), Krupp-Uhde (Puertollano, Spain), GSP (Schwarze Pumpe, Germany), and Mitsubishi (Nakoso, Japan) offering a dry-coal-fed process.

In moving-bed dry ash gasifiers, steam is injected along with the oxygen to keep the coal ash well below its ash fusion temperature. This type of gasifier is offered mainly by Lurgi and has been used in many countries including China, the Czech Republic, Germany, South Africa, and the United States. Also, a slagging version of the Lurgi gasifier has been developed, and a commercial-sized unit based on this technology has been commissioned at Schwarze Pumpe in Germany.

Fluidized-bed gasification, which is more suitable for high-ash coals, is still in the demonstration stage. A number of small atmospheric-pressure Winkler gasifiers have been built in Germany, India, and Turkey. Also, the U-Gas gasifier developed by the Institute of Gas Technology (IGT) in the U.S. is utilized in the Shanghai Coking and Chemical plant in China. A high-temperature Winkler gasifier has been developed by Rheinbraun and used in Germany and Finland for methanol and ammonia manufacture. The same process is expected to be used in the Vresova IGCC plant in the Czech Republic. Presently, the largest plant is the 100- MW Piñon Pine in Reno, NV, utilizing the KRW fluid-bed process, but it is experiencing operating problems and is still in an extended commissioned program.

Emission Control Performance

By removing the emission-forming constituents (sulfur and nitrogen species and particulates) prior to combustion in the gas turbine, IGCC plants meet extremely stringent air emission standards. Sulfur emissions can be almost completely eliminated; SO₂ emissions are expected to be 0.03-0.1 lb/MMBtu, (40-115 mg/Nm³ at 6 percent O₂). NO_x emissions have been controlled to levels below 0.1 lb/MMBtu (125 mg/Nm³ at 6 percent O₂) at two of the demonstrations using steam or nitrogen dilution in the combustor and to half that level at two other sites operating at lower combustion turbine temperatures. Recently, General Electric (GE) has claimed that they can meet a NO_x level of 60 mg/Nm³ even with their 2300 °F (1260 °C) series FA gas turbine. Typical CO₂ emissions will be 12 – 15 percent lower than a comparably-sized PC plant with FGD, with further reduction possible with the utilization of the higher efficiency (G- and H-class) gas turbines. There are indications that IGCC plants equipped with carbon bed adsorption systems may be able to achieve 90 percent mercury removal.⁵

Emissions are affected mainly by the requirements of the gas turbine to maintain low particulates and SO₂ emissions. NO_x emissions are affected by the design of the gas turbine combustor and the environmental requirements of the plant site; most gas turbines utilize a dry low NO_x combustor design and have achieved NO_x emissions below 25 ppm(v) with the most recent turbine designs targeting below 10 ppm(v).⁶ Assuming 25 ppm NO_x emissions, this results in 80-90 percent reduction compared to pulverized coal boilers with low NO_x burners which experience 0.20-0.50 lbs/MMBtu.

Limited data available (mainly from Wabash River, Polk, and the Louisiana IGCC plants) suggest that mercury emissions at the stack are similar to pulverized coal-fired plants, ranging from 1.5 to 5 lb/trillion Btu. While the mass balance closure in these plants was not good, there is good evidence that mercury is removed by the amine solvent, accumulates in the acid gas scrubbing loop, or is stripped from the amine

solvent upon regeneration and partitions to the sulfur recovery unit. Some mercury, especially particulate-phase and oxidized forms, may be removed in the wet particulate scrubber and discharged with wastewater sludge. More testing is required to assess the level of mercury emissions from IGCC plants. It is also important to find out the fate of the mercury in IGCC wastes.

By-products of IGCC include production of elemental sulfur (usually in a Claus process) or sulfuric acid, as well as solid wastes in the form of inert slag, which can be disposed of or sold for a variety of construction applications.

O&M Impacts

The presence of toxic gases (CO and H₂S) between the gasifier and the gas turbine requires some additional precautions. However, such precautions are common in other industries and can be addressed by installing CO and H₂S sensors and appropriate design of the control system to manage plant start-up and especially transition from the start-up fuel to coal or coal-based syngas. Plant availability continues to be an issue especially during early start-up of most IGCC plants, as they experience operating problems. However, after the commissioning period, most IGCC plants have achieved high reliability (in the 75 – 95 percent range).

Capital Costs

While significant progress has been made in reducing the capital costs of IGCC plants, they remain more expensive than conventional PC with FGD. The typical range of IGCC capital costs of a 400 MW plant is \$1200 - 1600/kW¹ with the lower end of the range corresponding to IGCC plants with a minimum level of integration and, therefore, lower efficiency and the high end for maximum integration. The capital costs are projected to decline, as the industry gains more experience with IGCC technology and technological developments are incorporated (especially in higher efficiency gas turbines and hot gas clean-up technologies), but the timing and impact of these developments are uncertain.

O&M Costs

For a 400 MW IGCC, fixed O&M costs are projected to be in the \$30-45/kW-yr range. Variable O&M costs depend on whether some revenue can be obtained from by-product sales. Assuming no sales of by-products, the variable O&M costs are projected to be in the 0.5 - 2.0 mills/kWh range.¹

Issues Associated with the Technology; Future Outlook

For the entrained and moving bed IGCC processes, the main barrier to widespread utilization is the high capital costs relative to competing technologies. However, it should be pointed out that IGCC has much lower SO₂, NO_x, and CO₂ emissions than the conventional (subcritical) PC with FGD; furthermore, because they are more efficient, they have lower fuel costs. The fluidized-bed gasification process requires further development and demonstration. It has yet to demonstrate adequate reliability on a large scale (above 100 MW). The future of IGCC technology depends on the ability of the industry to reduce its costs and the environmental requirements associated with SO₂, NO_x, mercury, and CO₂ emissions.⁷

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3.2.4.3 Pressurized Fluidized Bed Combustion (PFBC)

PFBC Summary

Status	Commercially available up to 350 MW
SO₂ Reduction, %	Up to 98
NO_x Reduction, %	30 – 70 depending on the coal [90 with SNCR (ammonia or urea)]
Hg Reduction, %	NA
CO₂ Change, %	Reduction up to 12
Cost	
Capital (\$/kW)	1000 – 1300 (for new plants of 250 MW size)
Fixed O&M (\$/kW-yr)	40 – 70
Variable O&M (mills/kWh)	2.0 – 4.0
Applicability	Mostly new power plants– also applicable to retrofit applications
Issues	Some reliability problems and high costs (relative to conventional PC and FGD) limit its short-term acceptance. Also, scaling-up the technology to larger size (above 350 MW) has experience problems which are not clear how they will be overcome

Note: Emission reduction is based on comparison of this technology to a similar size subcritical pulverized coal boiler with low NO_x burners but without FGD.

Technology Description

Pressurized Fluidized-bed Combustion (PFBC) is similar to AFBC in that it utilizes the fluidized bed technology, but the PFBC boiler operates under pressure (typically 1.2–1.6 MPa).^{1,2} Also, it is a combined cycle plant (see Figure 3-13), as pressurized hot flue gas, after particulate removal, is expanded through a gas turbine (GT) to drive the combustion air compressor and generate additional electric power.

The main advantages of PFBC are:

- pressurized conditions result in a more compact boiler and therefore offers the potential to lower capital costs,
- utilization of the combined cycle concept increases the overall plant efficiency and will take advantage of future technological progress in gas turbine technology, and
- PFBC is able to accomplish sulfur removal at somewhat lower sorbent (Ca-to-S ratio) than AFBC.

As in the case of AFBC, there are two types of PFBCs, the bubbling and circulating. Also, an “advanced PFBC” design has been developed with a pyrolyzer added upstream of the PFBC combustor. The fuel gas generated in the pyrolyzer is burned with the flue gas from the main combustor in a topping cycle to raise the turbine inlet gas temperature and increase the power output and efficiency of the turbine. The char from the pyrolyzer is burned in the main combustor. Sorbent is added to both the pyrolyzer and the main combustor. The successful development of hot gas cleanup (HGCU) technology using ceramic particle filters and alkali vapor removal is crucial to protecting the gas turbine and the successful demonstration of advanced PFBC.

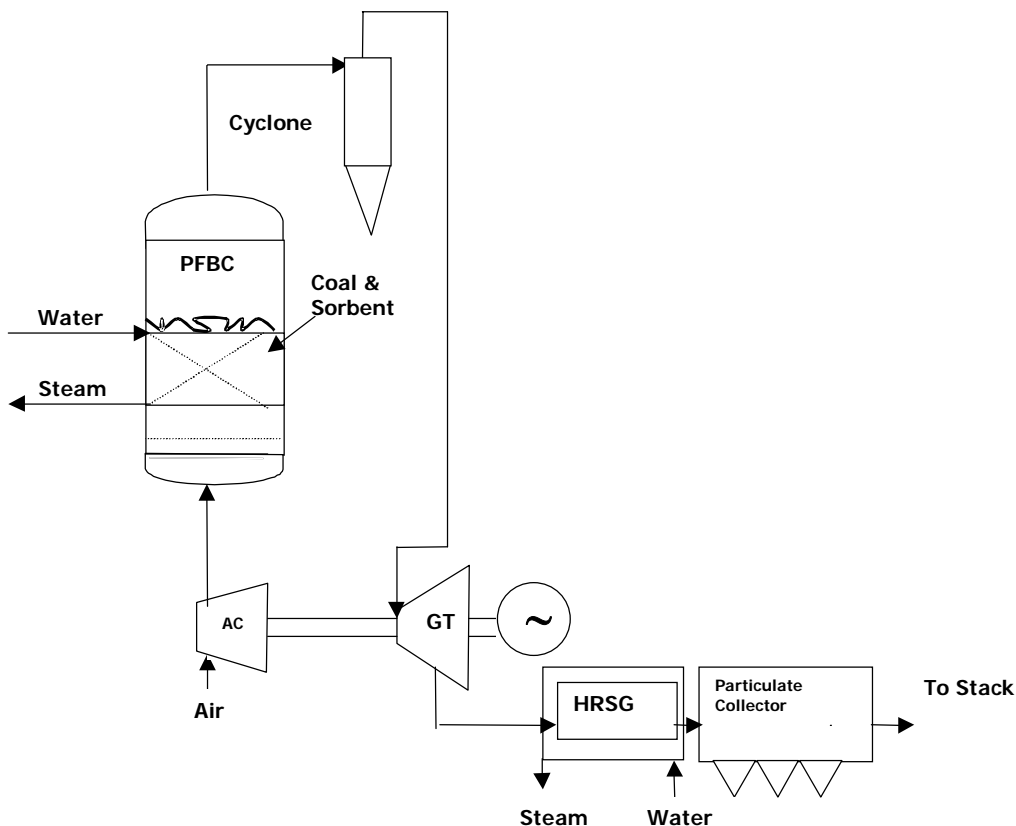


Figure 3-13. PFBC conceptual design.

Commercial Readiness and Industry Experience

The technology is offered commercially up to 350 MW^{3,4} but there are a number of technical issues still unresolved (see Issues below). As shown in Table 3-10,¹ six commercial-scale bubbling PFBC units (five plants, one with two units) have been put into service around the world. Most of these boilers are demonstration units, with financial support from government or international agencies, and all but one are less than 100 MW. A 360- MW supercritical unit (based on the ABB technology) and a 250- MW subcritical unit (based on the Hitachi technology) have been constructed in Japan at Karita for Kyushu Electric Power Company (KyEPCO) and at Osaki for Chugoku Electric, respectively. Both were commissioned in mid-2000. The operating experience obtained from these units will have a strong influence on the future of commercial PFBC technology.

Ishikawajima-Harima Heavy Industries (IHI), which recently obtained a worldwide license from ABB, Mitsubishi Heavy Industries (MHI), and Hitachi Ltd., are the main suppliers of bubbling PFBC. Five of the six operating PFBC units listed in Table 3-10 are based on ABB's P 200 PFBC module, designed for about 80 MW. The sixth unit, an 85- MW module designed by MHI, started up in early 1996.

The Karita PFBC plant, a 360- MW PFBC, replaces an old, conventional coal-fired power plant. It consists of one novel ABB P 800 module with a GT140P 75- MW gas turbine and a 290- MW steam turbine. The boiler is designed for supercritical steam conditions of 24.1 MPa/565 °C/593 °C. A wide range of coal qualities, from lignite to anthracite, will be used at this plant, and the fuel and sulfur sorbent mixture will be fed as paste. The order for the plant was placed with ABB Carbon's licensee, IHI, which has undertaken the engineering, manufacturing, erection, and commissioning of the plant. The GT140P turbine was supplied by ABB STAL and the steam turbine was supplied by Toshiba.

Table 3-10. PFBC Plants and Operating Experience

Technology	ABB	ABB	ABB	ABB	MHI
Facility Name	Escatron, Spain	Vartan, Sweden	Tidd, USA	Wakamatsu, Japan	Tomatoh-Atsuma, Japan
Gross Output, MW	79	135 plus 224 MW	73	71	85
Units	1	2	1	1	1
Coal Type	Lignite	Polish Bituminous	Ohio Bituminous	Australian	Various
Coal Sulfur, %	7	0.65	4	0.4	0.9
Coal Ash, %	36	15	10	10	Not Available
Coal Feed	Dry	Paste	Paste	Paste	Dry
Sorbent Feed	Dry	Paste	Dry or Paste	Paste	Dry
Sorbent	Limestone	Dolomite or Limestone	Dolomite	Limestone	Limestone
NO _x Control	None	SNCR and SCR	None	SCR	SCR
Cyclones	9 x 2	7 x 2	7 x 2	7 x 1	2 x 1
Hot Filter	1/9 Slipstream	None	1/7 Slipstream	Full Gas Flow (part time)	Full Gas Flow
Steam Pressure, bar	90	130	90	102	166
Steam Temperature, °C	510	530	496	593/593	566/538

Lurgi Lentjes Babcock (LLB, the Lurgi-Deutsche Babcock partnership) and Foster Wheeler (now incorporating Ahlstrom Pyropower) have been developing circulating PFBC. To date, development has been mainly on a pilot plant scale. However, a 137 MW circulating PFBC plant is under construction at the McIntosh plant of the City of Lakeland, FL.

PFBC technology is applicable for both retrofit (replacement of an existing boiler and utilization of the remaining equipment, especially the steam turbine and balance of plant) and new applications. However, most PFBC projects in the future are expected to be new applications.

Emission Control Performance

SO₂ removal up to 98 percent is possible, especially with high-sulfur coals. SO₂ removal is affected by the bed temperature and by the Ca-to-S molar ratio. A Ca-to-S molar ratio of approximately 1.5 is typical for an SO₂ removal of 90 – 95 percent. The excess sorbent is not calcined. While this increases the volume of solid wastes compared to an AFBC with the same Ca-to-S molar ratio, PFBC requires a lower Ca-to-S molar ratio, which counterbalances this disadvantage and results in about the same waste volume compared to an AFBC. Furthermore, the absence of lime makes the solid wastes easier to handle.

NO_x emissions are 30 – 70 percent lower than conventional PCs with low NO_x burners. Further NO_x reduction can be achieved by installing an SNCR or SCR system. NO_x emissions in the 100 ppm (0.13 lbs/MMBtu) level without SNCR have been demonstrated. NO_x emissions are impacted by the bed temperature, the nitrogen and volatile matter in the coal, and the bed stoichiometry, which is affected by the excess air and air distribution across the bed.

It is not clear whether PFBC controls mercury, too.

Typical PFBC design plant efficiency ranges from 38 to 46 percent (HHV basis) depending on the coal type, coal feed method, and steam cycle conditions. Compared to new subcritical pulverized coal plants, which typically have efficiency in the range of 34 to 38 percent, PFBC can potentially result (as these efficiencies indicate) in up to 10 - 12 percent lower CO₂ emissions.

O&M Impacts

Reliability problems have been experienced by the most recent demonstration plants, but eventually have been resolved. For example, Vartan and Wakamatsu reached the 80-90 percent reliability level, but others had lower reliability. The impact of small particulates and alkali on the gas turbine was one of the issues. ABB is offering a “ruggedized” gas turbine design, which is expected to improve reliability. The properties of the ash are critical in determining the potential impacts on the various PFBC plant components.

Capital Costs

Typical costs of PFBC plants are expected to be in the \$1000 - 1300/kW range.¹

O&M Costs

O&M costs are projected to be: \$40 - 70/kW-yr fixed O&M cost and 2.0 - 4.0 mills/kWh variable O&M cost¹ depending on the O&M practices of the utility, labor costs, and cost of consumables (especially sorbent). The high estimates are more typical of the 80 MW PFBC, while the lower estimates are for the 350 MW design.

Issues Associated with the Technology; Future Outlook

The PFBC plants in operation experienced a number of problems but, for the most part, they have been satisfactorily addressed. However, some uncertainty still remains in the following areas:

- Coal feed. Wet feed systems need proper size distribution and a better indicator of proper consistency; dry feed systems need designs that address erosion in transport pipes at high pressure and redundant systems for high availability.
- Gas turbine lifetime. High-cycle fatigue damage and erosion are on-going problems being addressed by the suppliers.
- Gas filter performance. Development continues on thermal shock-resistant ceramic candle filters. Development of this component is critical for achieving higher plant efficiencies and the wider acceptance of the technology.

- Coal and sorbent distribution in the bed. Fuel and sorbent distribution need to be optimized to achieve maximum sorbent utilization and uniform bed temperatures.
- Cyclone liner life. Proper application of select materials or unlined austenitic stainless steel cyclones may resolve this issue.

In conclusion, PFBC technology has been demonstrated and is commercially available up to a 350 MW plant size, but higher than conventional technology costs limit its widespread utilization, at least in the short term.

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3.2.4.4 Supercritical Pulverized Coal Plant

Supercritical Pulverized Coal Plant Summary

Status	Supercritical: commercial; ultra- supercritical: needs demonstration
SO₂ Reduction, %	4 – 12
NO_x Reduction, %	4 – 12
Hg Reduction, %	4 – 12
CO₂ Change, %	4 – 12 reduction
Cost	
Capital (\$/kW)	Supercritical: 825 – 1080; Ultra-supercritical: 1000 – 1150 (for 700 – 1000 MW plant size)
Fixed O&M (\$/kW-yr)	Supercritical: 25 – 32; Ultra-supercritical: 30 – 35
Variable O&M (mills/kWh)	3.0 – 5.0
Applicability	New power plants
Issues	Ultra-supercritical requires further demonstration

Note: Emission reduction is based on comparison of this technology to a similar size subcritical pulverized coal boiler with low NO_x burners, but without FGD.

Technology Description

Supercritical pulverized coal technology is similar to subcritical in terms of the conceptual plant design, but may operate at higher steam temperatures and higher pressures.¹ Subcritical plants operate below approximately 18 MPa (2600 psi) maximum steam pressure, while supercritical plants are designed to operate from 23 to 35 MPa (3200 to 5000 psi). Also, supercritical plants can be designed to operate at

steam temperatures (superheat and reheat) up to 650 °C (1200 °F) compared to 538 °C (1000 °F), which is the typical temperature in subcritical plants.

Typical pulverized plant designs used presently and their steam parameters are given below:

1. Subcritical: 16.7 MPa/538 °C/538 °C (2400 psi/1000 °F/1000 °F);
2. Supercritical: 24.2 MPa/538 °C/565 °C (3500 psi/1000 °F/1050 °F), which is about 4.0 percent more efficient than the subcritical; and
3. Ultra-supercritical with double reheat: 31 MPa/600 °C/600 °C/600 °C (4500 psi/1100 °F/1100 °F/1100 °F), which is about 8 percent more efficient than the subcritical design; or 35 MPa/650 °C/650 °C/650 °C (3500 psi/1200 °F/1200 °F), which would produce an efficiency gain of about 11 percent relative to the subcritical unit. Both these options are under development.

The high steam pressures and temperatures require higher grade materials for the furnace water walls, superheat and reheat sections of the boiler, headers, steam piping between boiler and turbine, and first stages of the superheat and reheat sections of the turbine. Availability of materials such as 1¼Cr-½Mo, 2¼Cr-1Mo, and 9–12 percent Cr class steels (T91 and T23) are critical for designing and manufacturing supercritical plants. In addition to materials, water chemistry (corrosion protection) and power plant controls are some of the most important aspects of supercritical plant design and operation. However, appropriate design and O&M practices have proven adequate to ensure reliable operation.

Commercial Readiness and Industry Experience

Supercritical plants are commercially available in many countries including China, Denmark, Germany, Italy, Japan, Russia, South Korea, and the United States.^{1,2,3} The ultra-supercritical unit is in the demonstration stage. Supercritical pulverized coal technology is commercial with approximately 462 units operating worldwide (see Table 3-11). There are at least 12 boiler manufacturers and 11 steam turbine suppliers that offer supercritical plant components.

Table 3-11. Power Plants with Supercritical Design Parameters⁴

Country or Region	Number of Units	Total Units (%)	Capacity, MW	Total Capacity (%)
Japan	108	23.4	67,900	25.2
USA	149	32.3	106,454	39.6
West European Countries	53	11.5	29,310	10.9
East European Countries	123	26.5	51,810	19.3
Other Countries	29	6.3	13,520	5.0
Total	462	100.0	268,994	100.0

The U.S. has the largest number of supercritical plants in operation, but all these plants were installed in the 1960s and 1970s. In recent years, no supercritical plants have been built in the U.S. This is mainly attributable to the perception that supercritical plants have lower reliability and the relatively low costs of fuels in the U.S., which make low-cost but also low efficiency options (in this case subcritical PC) economically more attractive. Indeed, there were some reliability problems experienced by the first supercritical plants built in the U.S., but, as Table 3-12 shows, the reliability (expressed as equivalent availability) of these plants improved significantly to the same level of subcritical plants. Similar experience is documented by VGB in Germany.⁴

Table 3-12. Equivalent Availability for Subcritical and Supercritical Power Plants⁴

U.S. Supercritical Plants

Size Range (MW)	300-399	400-499	500-599	600-799	>800
Subcritical	76.5	77.4	76.3	78.5	77.2
Supercritical	64.4	74.6	73.8	74.2	75.6

Germany's Supercritical Plants

Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Subcritical	84.2	82.5	84.1	84.9	84.5	82.0	83.8	83.7	86.6	88.5
Supercritical	80.2	74.9	84.2	85.2	87.1	89.8	83.0	84.7	79.5	90.3

Japan is one of the countries leading the development of supercritical technology. Until the early 1990s, most Japanese plants had steam conditions of 3500 psi/1000 °F/1050 °F (24.6 MPa/538 °C/566 °C), but starting in 1993 the steam temperatures of new plants are in the ultra-supercritical range, approaching 1100 °F (600 °C).

Also, there are about 53 supercritical units in Europe, especially in Germany, Italy (mostly oil fired), and Denmark. The most recent European units (most of them coal-fired with one oil-biomass unit) utilize ultra-supercritical steam conditions.

Korea has built sixteen 500 MW supercritical units utilizing a standardized design for bituminous coal.⁵ Also, China has ten supercritical units in operation and 10 more in the planning stage.

Emission Control Performance

This technology is not an environmental control technology per se, but due to its higher efficiency it results in lower emissions prior to utilizing environmental controls such as SCR and FGD. The supercritical design improves plant efficiency by 4.0 percent relative to a similar subcritical plant.

If the ultra-supercritical design is used with double reheat, the efficiency increases by about 8 percent relative to a similar subcritical plant. Further potential exists (projected to increase efficiency by 10 - 12 percent) utilizing higher steam conditions, such as 35 MPa/650 °C/650 °C/650 °C (3500 psi/1200 °F/1200 °F), but this technology remains to be demonstrated.

O&M Impacts

There are no significant O&M impacts relative to subcritical PC technology. Supercritical PC requires more attention to water chemistry (requirements are tighter than for subcritical plants) and operation, especially during start-up and load following. However, power plant controls can be designed to include all the precautions and safeguards needed for safe and reliable operation.

Capital Costs

Many recent studies^{1,6} have estimated the costs of supercritical vs subcritical PC technologies. The general consensus is that the capital costs of a supercritical plant are equal to or up to 8 percent higher than a similar size subcritical plant. So, considering that the latter is projected to cost \$800 - 1000/kW, the

supercritical unit is projected to cost \$825 - 1080/kW and the ultra- supercritical unit \$1000 - 1150/kW (in all cases, the PC is equipped with FGD, but not SCR).^{1,6}

It should be noted also that supercritical plants are usually competitive in large sizes, above 500 MW. However, recently power plant suppliers have been developing smaller supercritical plants (in the 350 - 500 MW range) to address cases with high cost fuels and limited demand growth.¹

O&M Costs

Fixed O&M costs range from \$25 to 32/kW-yr for supercritical units and \$30 to 35/kW-yr for ultra-supercritical units. Variable O&M costs range from 3 to 5 mills/kWh.¹

Issues Associated with the Technology; Future Outlook

The supercritical PC technology is commercially available, and there are no issues associated with it. As more emphasis is placed on CO₂ emission reduction, it provides a proven technology (therefore low-risk option) to achieve significant plant efficiency improvement relative to conventional (subcritical) pulverized coal plants. An ultra-supercritical unit requires further demonstration, mainly to prove the reliability of new alloy materials.

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3.2.5 Power Plant Upgrading and Operating Options

3.2.5.1 Fuel Blending and Cofiring

Fuel Blending and Cofiring Summary

Status	Commercial except for fuel blending requiring on-line continuous control of emissions
SO₂ Reduction	Proportional to sulfur content of fuels; up to 100% reduction for switching from high- to low-sulfur coal or gas
NO_x Reduction	Up to 20 – 30% due to switching from bituminous to subbituminous coal or biomass cofiring. 50 – 80% due to gas cofiring and reburn or switching from coal to gas
Hg Reduction	Proportional to mercury content of fuels, as well as other fuel properties
Cost	
Capital (\$/kW)	Coal blending: 20 – 100; Fuel switching: Up to 200 – 300; Cofiring: 30 – 200
Fixed O&M (\$/kW-yr)	Project-specific
Variable O&M (mills/kWh)	Project-specific
Applicability	Both new and retrofit applications
Issues	Development of on-line coal quality monitoring is needed to enhance coal blending

Technology Description

The ability to alter the fuel characteristics has a significant impact on both the thermal performance of the unit and the resulting emissions of SO₂, NO_x, Hg, and CO₂. Table 3-14 lists the key fuel properties, which affect emissions. Therefore, altering the characteristics of the fuel by blending or cofiring could be viewed as a multi-emission control option.

While the feasibility and attractiveness of changing the fuel characteristics are very site-specific (affected significantly by plant design and fuel properties), in general the following options are available while maintaining the basic configuration and design of the plant:

- Blending with a fuel of the same type with different properties (blending coal of the same classification such as two eastern bituminous coals) or different classifications (eastern bituminous coal with subbituminous coal),
- Switching to a fuel of the same type; for example, switching from eastern bituminous to subbituminous coal,
- Switching to a fuel of different type; for example, switching from coal to natural gas, and
- Cofiring coal with fuels such as gas, biomass, and municipal solid wastes.

Blending and cofiring generally constitute operating changes (even though originally some hardware modifications may be necessary or required to mitigate O&M impacts), while switching to another fuel is a permanent change (at least until the decision is reversed) and includes hardware modifications.

Blending coals is very common in the utility industry worldwide with the primary focus being control of sulfur content.¹⁻⁵ The plant operator either mixes the coals in the coal yard or loads the coal silos partly with the one coal and then with the other with mixing occurring inside the silo. In some cases, blending

has been accomplished by mixing coals from two different conveyors on to a common one. The ability to monitor and control coal quality (beyond just sulfur) is very limited. Monitoring is based on periodic sampling of the coal and rough estimation of the average quality characteristics (mainly sulfur content), as well as SO₂ measurements using continuous emission monitors. Blending could be used to affect emissions other than SO₂ (NO_x and mercury). However, the exact coal quality resulting from such blending cannot be predicted; only an approximation of the average is possible with present technologies. More detailed fine-tuning of the coal analysis through blending needs on-line coal quality monitoring technologies, which are still under development.

Switching to another coal (from bituminous to subbituminous) is a common practice in the industry (again, mainly for sulfur control) and usually involves hardware changes. Such changes are very site-specific, but common areas, which are impacted by coal switching, are:

- Upgrading the coal crushing equipment and the pulverizers to avoid potential de-rating of the unit due to limited coal throughput into boilers,
- Modifying the heating surface of the boiler (superheater and reheat sections) to maintain the steam outlet temperatures over the load range without exceeding operating limitations set by materials (maximum metal temperatures or gas velocities to avoid excessive erosion),
- Replacing or modifying the soot blowing system to accommodate higher slagging or fouling,
- Incorporation of a flue gas conditioning system to modify the resistivity of the sub-bituminous, low-sulfur coal ash and make it suitable for collection in an existing precipitator originally designed for high-sulfur coal ash,
- Modification of the ash handling system to handle quick-setting characteristics of sub-bituminous coal ash, and
- Modification of the coal storage and conveying systems to meet the special handling characteristics of sub-bituminous coal.

On the positive side, coal switching may provide an opportunity to improve performance (plant efficiency) or at least minimize the adverse impacts on efficiency. For example, modifications in the economizer, air heater, and feed water heaters may increase plant efficiency or mitigate boiler efficiency reduction due to higher moisture of the new coal.

Switching from coal to a different fuel type such as natural gas is also possible. Hardware modifications may be required depending on the design of the existing plant. The types of changes required are as follows:

- The plant needs to be connected to a natural gas pipeline, in case gas is not available on site,
- The burners need to be modified to accommodate natural gas,
- The boiler heating surfaces may need to be modified to maintain proper steam conditions, and
- Boiler backend modifications may be required, depending on whether the plant elects to dismantle the existing pollution controls, bypass these controls and leave them in place, or continue to pass flue gases through the non-operating controls.

Cofiring involves utilization of more than one fuel, which represents a relatively small percentage (usually 5 - 15 percent) of the total heat input.^{6,7} Typically, fuels which have been cofired with coal are: natural gas, biomass, and municipal solid wastes (MSW).^{8,9} Depending mainly on the physical properties of the secondary fuel, it may be introduced in the boiler through a separate burner or injection port or mixed with the coal. Solid fuels may be pulverized together with the coal, but this limits the amount of

cofired fuel to about 5 percent. In most case, separate injection ports are added. Cyclones and fluidized bed boilers are better cofiring candidates than pulverized coal boilers, even though the latter have demonstrated adequate performance and reliability. Cofiring natural gas requires separate burners or ports within the existing coal burners.¹⁰

Commercial Readiness and Industry Experience

Fuel switching and cofiring are commercial options that have been used extensively worldwide both for new plants and retrofit applications. Coal blending is also a common practice. In cases, where the average coal quality needs to be adjusted to an approximate level or below a set level, coal blending is a well-demonstrated option. However, if on-line continuous monitoring and control of coal quality is needed, presently there is no available technology except monitoring of sulfur content. On-line coal quality monitoring technologies are under demonstration and have not achieved the level of reliability needed for widespread application.

Emission Control Performance

Blending of coals or switching to another coal clearly impacts all emissions, even though the impact at each plant is very site-specific and depends on the characteristics of the coals, the design of the power plant, and the operating conditions. Switching from a high-sulfur (4 - 5 percent sulfur content) coal to a low-sulfur (0.5 - 0.8 percent sulfur content) coal reduces the SO₂ emissions up to 80 - 90 percent. The impact of coal blending on SO₂ would be lower than this level and proportional to the percent of the low-sulfur coal being used. Switching from bituminous to subbituminous coal or blending also reduces NO_x emissions by up to 20-50 percent as demonstrated in a number of well-documented utility sites such as Arapahoe 4 of Public Service of Colorado,⁵ Genoa 3 of Dairyland, and Gibson 3 of PSI Energy.² Coal switching and blending is expected to have an impact on mercury emissions as each coal contains a different level of mercury. Also, changes in chlorine content resulting from coal blending may affect the speciation of mercury. Additionally, the ash composition and unburned carbon content may play a catalytic role affecting mercury speciation. Presently, no adequate data exist to predict such impact. Finally, coal switching and blending are expected to affect plant efficiency and CO₂ emissions mainly because of different moisture content of the coals, but also because of potentially different auxiliary power requirements. For illustration purposes, if the moisture content of the coal changes (as a result of switching or blending) from 8 to 20 percent, the impact is an approximately 1.2 percent lower boiler efficiency, which corresponds to approximately a 3 percent or higher increase of CO₂.

Switching from coal to another fuel has more drastic consequences to the performance and emissions. The most common fuel switch is from coal to natural gas provided that the economics are favorable. In this case, SO₂ and mercury emissions may be eliminated. NO_x emissions could be reduced by up to 70 - 80 percent. Finally, CO₂ is reduced by approximately 30 percent as a result of switching from coal to natural gas fuel. Boiler efficiency for natural gas is usually 2-3 percentage points lower than bituminous coal. Due to the high percentage of hydrogen in the natural gas, the CO₂ emission per fuel input is 200 lb/MMBtu for coal and 130 lb/MMBtu for natural gas based strictly on fuel carbon conversion.

The impact of cofiring on emissions is very site specific and depends on the characteristics of the fuels being cofired, the plant design, and the design of the cofiring system. Cofiring of gas in a coal-fired plant reduces SO₂ and mercury proportionally to its input (typically up to 30 percent), NO_x up to 50 - 70 percent, and CO₂ by up to 7 percent (assuming maximum heat input due to natural gas of 20 percent).¹¹⁻¹⁴ The characteristics of biomass and MSW vary significantly, but in general they are expected to reduce SO₂ and CO₂ proportionally to their inputs, and NO_x by up to 20 percent. It should be noted that these fuels are considered renewable energy sources, so any substitution of coal results in a proportional reduction of CO₂ emissions. However, some of the fuels contain a significant amount of moisture (wood wastes and wet MSW may contain 40 - 60 percent moisture), which reduces the plant efficiency and may counterbalance the benefit of using a renewable energy resource.

O&M Impacts

Changes in the fuel characteristics may have significant impacts on unit performance and reliability. Table 3-14 summarizes the main impacts of unfavorable changes in the values of the key fuel characteristics, as well as potential mitigation options.

In general, load reduction (de-rating) may be necessary to avoid high steam and metal temperatures or to accommodate lower steam temperatures at the steam turbine inlet. Also, load may be limited by the capacity of the existing fuel handling system pulverizers, or other boiler-related systems. In most cases, these impacts can be mitigated by modifying the boiler and other effected equipment. Other potential impacts include:

- Changes in the unburned carbon. This can be mitigated by design enhancements of the pulverizers (addition of dynamic classifiers) and the firing system (new burners).
- Increase or reduction of furnace slagging and fouling. In most cases, this can be mitigated through increased soot blowing, but in some cases de-rating may be needed.
- Depending on the fuel characteristics, pulverizer wear and reliability, as well as corrosion and erosion of boiler heating surfaces, may be affected. The impact of blending coals of different hardness on the final size distribution and compositional distribution of the pulverized coal is still not fully understood. Blending hard and soft coals may cause difficulties in pulverizing the blend, as the grinding requirements may not always be proportional to the mix of the two coals. In most cases, the characteristics of the poor coal dominate the blend.
- Very often fuel changes impact the performance of the ESP and may result in higher particulate emissions and opacity. If the ESP size is conservative, it may not require any modifications. However, many older plants represent tight designs and may need to be modified to meet particulate emissions and opacity requirements.
- Reliability and operating flexibility may be impacted, usually adversely because biomass and MSW are difficult fuels to handle. Also, some coals may be harder to grind (pulverize) or more corrosive. Of course, natural gas is easier to handle and would be expected to improve plant reliability and operating flexibility.
- Other impacts requiring consideration on a case-by-case basis include potential changes in the required excess air (which impacts plant efficiency), CO emissions, and unit turndown rate (speed at which the operator can change unit output).

Table 3-14. Main O&M Impacts and Potential Mitigations

Coal Property	Impact on Emissions				Potential Plant Equipment and O&M Impacts	Potential Mitigation
	SO ₂	NO _x	Hg	CO ₂		
Coal Type	X	X	X	X	Potential de-rating, lower reliability, and lower efficiency	De-rating may be avoided through hardware modifications, especially in the mills and boiler heating surfaces
% Sulfur	X				ESP performance and FGD system performance	ESP upgrading or SO ₃ flue gas conditioning and upgrading of the FGD system or increased reagent use
% Ash				X	ESP performance, ash handling system impacts, and erosion of mills and boiler surfaces	ESP upgrading, upgrading or more frequent operation of the ash handling system and more active maintenance of mills and boiler surfaces
Ash fusion temperature		X			Furnace slagging and backpass fouling	Sootblowing and fuel additives
% Nitrogen		X				Design or operation of NO _x controls for the increased baseline emissions
Volatile Matter		X			Potential impact on boiler heating surface performance	Design or operation of NO _x controls for the increased baseline emissions and boiler heating surface modification
% Moisture	X	X	X	X	Mill throughput, boiler efficiency, primary air system performance, and increased combustion air and flue gas volumes	Mill and primary air system upgrading, design or operation of pollution controls for the increased baseline emissions, and operation of draft fans at higher capacities
% Mercury			X			Depends on whether mercury controls would be present
% CaO or MgO	X					Increased reagent use, if SO ₂ controls are present
Grindability				X	Mill throughput	Mill upgrading

Costs

The costs, both capital and O&M, are very site specific. The following estimates are for illustration purposes only.

Coal blending is the least expensive option with regard to costs, which may range from \$20 to 100/kW depending on the amount of cofired coal, its characteristics, and the design of the existing power plant. Switching to another fuel is usually more expensive and may reach up to \$200 - 300/kW. Cofiring capital costs may range from \$30 to 200/kW. More specific examples⁶ (End of Year 1991 U.S.\$; however, capital costs of power plant equipment have been reduced significantly since then and it is expected that the same costs reflect FY2000 conditions):

- Wood cofiring: \$104/kW,
- Refuse Derived Fuel cofiring: \$128/kW, and
- Tire-derived fuel cofiring: \$37/kW.

Issues Associated with the Technology; Future Outlook

Fuel blending, switching, and cofiring are common industry practices and are expected to continue. In the past, the main driving force has been economics, but they have a role to play in emission control too, as emissions become commodities and emission control becomes an operating cost. The key technological barrier, especially with regard to coal blending, is the absence of reliable and commercially available on-line continuous coal quality monitors. However, if only a not-very-accurate control of emissions is required, all options are practical and commercially available.

Depending on site-specific constraints, not all options may be available to all power plants. Such constraints may include: lack of natural gas in the proximity of the plant, very high transportation and processing costs for biomass and waste fuels, and constraining power plant design with tight fuel specification requirements (cyclone and wet bottom boilers).

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3.2.5.2 Plant Efficiency Improvements (Upgrading, Newer Configurations, Technologies)

Plant Efficiency Improvements Summary

Status	Commercial
SO₂ Reduction	Heat rate improvement and upgrading: SO ₂ reduction proportional to heat rate improvement; Repowering with gas: close to 100% SO ₂ reduction
NO_x Reduction	Heat rate improvement and upgrading: NO _x reduction proportional to heat rate improvement; Repowering with gas: up to 70 – 80% NO _x reduction
Hg Reduction	Heat rate improvement and upgrading: Hg reduction proportional to heat rate improvement; Repowering with natural gas: 100% Hg reduction
CO₂ Change	Heat rate improvement: Up to 1.5% reduction at full load (up to 5% at low loads); Upgrading: up to 8% reduction; Repowering with natural gas: up to 50% reduction
Cost	
Capital (\$/kW)	Heat rate improvement: <20 – 40; Upgrading: 20 – 50; Repowering with natural gas: 100 – 400
Fixed O&M (\$/kW-yr)	Project-specific
Variable O&M (mills/kWh)	Project-specific
Applicability	Retrofit applications
Issues	Impact of environmental regulations pertaining to increased output of existing plants

Technology Description

Upgrading and efficiency improvement in a power plant are geared towards increasing the plant output or achieving higher efficiency. In the latter case, the same output can be produced utilizing less fuel and, in most cases, proportionally less emissions. Most options affecting plant output and efficiency are interrelated, but for simplicity they will be described separately in this document, grouped into three categories: (1) efficiency improvement, (2) plant upgrading and (3) power plant repowering. The third option involves significant changes in the plant design, usually by adding a gas turbine and converting the plant to a combined cycle.

Efficiency Improvements

Efficiency improvements can be achieved by both operating changes and minor hardware modifications,¹ such as:

- adjustment and tuning of the pulverizer to improve coal fineness for better combustion efficiency, resulting in lower CO and unburned carbon,
- reduction in excess air; this is accomplished by closer monitoring of excess air (usually by installing a CO monitor in the stack), combustion system tuning (adjustments of air registers and coal-air flow balancing), and pulverizer tuning,
- reduction in air leakage into the boiler, air heater, and pollution control equipment,
- reduction in water and steam leaks in valves and piping of the balance of plant, and
- cleaning of heating surfaces such as the boiler water walls, superheat and reheat sections, as well as the condenser and the feed water heaters to improve heat transfer.

Power Plant Upgrading

Usually upgrading is geared towards increased plant output,^{2,3} or increased plant remaining life, but invariably it improves plant efficiency, too. Examples of measures included in this category are:

- pulverizer upgrades including a dynamic classifier and increased capacity of the exhaust fans,
- replacement of the economizer or the air heater, resulting in lower stack temperature and better plant efficiency; this is usually a desirable option when the plant switches from high-sulfur to low-sulfur coal (either by coal switching or blending) and can afford to lower the stack temperature without concern about corrosion in the backend equipment due to condensation of sulfuric acid,
- replacement of steam turbine blades with new blades (usually improved three-dimensional profile) taking advantage of technological improvements in blade design and materials; this applies to all sections of the steam turbine (high, intermediate, and low pressure), but especially in the high pressure section where the economics are more favorable and more technological improvements have been made,⁴⁻⁶
- more efficient modifications of feed water heaters and addition of low-pressure preheating,⁷
- refurbishment of condenser with new and more efficient tubes (with regard to heat transfer), heating surface cleaning systems, and design modifications to reduce air in-leakage,
- installation of variable-speed drives on the main rotating equipment (forced- and induced-draft fans, boiler-feed pumps, and circulating water pumps) to reduce the plant auxiliary power consumption, and
- replacement of outdated controls with a state-of-the-art digital control system to improve overall plant operation and efficiency.

Power Plant Repowering

The general principle followed in repowering an existing coal-fired power plant is to add a gas turbine and associated equipment and convert it to a combined cycle plant burning natural gas. There are a number of alternative approaches to repowering (full repowering, topping or windbox repowering, and parallel repowering),⁸⁻¹² but they differ only by the degree to which the existing equipment is used. Topping or windbox repowering involves use of the flue gas from a new gas turbine as hot combustion air into the burners of the existing boiler and may increase plant output up to 40 percent. Parallel repowering⁸ utilizes the existing boiler as a heat recovery device for the flue gas of the gas turbine, but because the resulting outlet steam temperatures are lower, a new heat recovery steam generator is needed to ensure that the plant output is maintained. Full repowering utilizes mainly the existing steam turbine and balance of plant along with a new gas turbine and associated equipment to form a combined cycle. Power output of the plant may increase up to 200 percent as a result of full repowering.

Commercial Readiness and Industry Experience

All these options are commercially available, and the industry (both the utilities and the boiler vendors) has significant experience with such projects.

Emission Control Performance

In the case of heat rate improvement and upgrading, reduction of SO₂, NO_x, mercury, and CO₂ is proportional to the heat rate improvement achieved. There are some exceptions where the change may not be exactly proportional, but it is not significantly different. An example of such cases is the reduction of excess air, which benefits plant efficiency, but may benefit NO_x emissions more than indicated by the proportional change.

Heat rate improvements may result in up to 1.5 percent heat rate improvement at full load and up to 5 percent at low loads. Upgrading projects may achieve higher efficiency than heat rate improvements, but they are very site-specific.

In the case of repowering, there is a change in fuel from coal to natural gas, which results in significant changes in the emissions. In general, topping or windbox repowering improves plant heat rate by 5 – 10 percent. Full repowering may increase the plant efficiency of an old coal-fired power plant (in most cases: 28 – 34 percent efficient on an HHV-basis) to 45 – 50 percent. CO₂ reduction is achieved due to better heat rate if less fuel is burned and the fact that natural gas releases less CO₂ per unit heat input than coal. The end result from a repowering project may reach up to 50 percent CO₂ reduction, with parallel elimination of SO₂ and mercury.

O&M Impacts

Upgrading and repowering projects do not have significant adverse O&M impacts. In fact, the changes in plant design and operation are usually beneficial to both performance and reliability of the plant. There are cases, however, with heat rate improvements where a trade-off between emissions and heat rate may be involved. For example, an attempt to reduce NO_x emissions as much as possible through aggressive combustion staging (high overfire air flow rate) and low excess air, may affect heat rate adversely due to lower steam temperatures, high CO emissions, and high unburned carbon.

Costs

Costs of heat rate improvements are typically low, below \$20-40/kW. Upgrading and repowering costs are very site-specific, but they are typically in the following ranges:

- \$20 - 50/kW for upgrading and
- \$100 - 400/kW for repowering.¹²

Issues Associated with the Technology; Future Outlook

Repowering applications depend greatly on the availability of a reliable source of gas supply at a candidate plant location and cost differential between coal and gas. Considering that gas prices continue to be significantly above those of coal for most locations in the U.S., the attractiveness of repowering options is limited. Another reason is the significant reduction of prices of new natural gas combined cycle power plants (ranging from \$400 to 550/kW), which can achieve higher performance than repowered plants. However, if emission requirements are imposed on existing power plants, the cost-effectiveness of repowering will likely improve. The main issue associated with heat rate improvements and plant upgrading relates to environmental requirements, which may apply in case the plant increases its output even marginally.

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3.2.5.3 Power Plant Optimization

Power Plant Optimization Summary

Status	Commercial
SO₂ Reduction, %	Up to 1.5 at full load and up to 5 at low load
NO_x Reduction, %	5 – 35
Hg Reduction, %	Up to 1.5 at full load and up to 5 at low load
Cost	
	Stand-alone or one-time: \$25,000 – 50,000
Capital	Advisory: \$100,000 – 250,000
	Closed loop: \$150 – 300,000
Fixed O&M (\$/yr)	\$10,000 – 20,000
Variable O&M (mills/kWh)	None
Applicability	Both new and retrofit applications
Issues	None

Technology Description

Power plant optimization generally involves the use of a software program that can determine the set of operating conditions which optimize an “objective function” such as “maximize plant efficiency,” “minimize NO_x emissions,” or “maximize plant efficiency while maintaining NO_x, CO, and unburned carbon below certain limits.” The software resides in a separate personal computer, which is linked directly to the existing Data Acquisition System (DAS) of the power plant to monitor plant performance. With the data obtained from the DAS, it establishes a model of how the process works (usually by employing neural network-based technology) and then identifies the optimum operating conditions.

The optimum advice could be implemented automatically (without any action from the plant operator) through a direct link into the power plant control system (“closed-loop” system). Alternately, it could be shown on a computer screen in the control room and be left to the power plant operator to decide whether and how to implement it (“advisory” system). A third variation of the power plant optimization system is “stand-alone” or “one-time” optimization, in which case the software is linked temporarily to the DAS (usually a few weeks), optimum settings are identified, and the existing control system (mainly the “control set-points”) is adjusted to take advantage of the optimum settings. After the completion of the stand-alone or one-time optimization, the software may be removed from the plant or left on site so that optimization can be repeated in the future.

Commercial Readiness and Industry Experience

The technology is commercially available. Presently, there are more than 250 boilers with power plant optimization systems in operation or planned to be installed in the U.S.¹ More than 95 percent of these boilers are coal-fired, but there are a few gas- and oil-fired boilers, too. When the first optimization systems were installed (1993 - 95), most were stand-alone or one-time and advisory systems, because utilities wanted to gain experience and confirm their operation and reliability before putting them in automatic control. Presently, most of the optimization systems are of the “closed loop” type.

Optimization software is offered by a number of organizations such as: NeuCo (ProcessLink), Pegasus Technologies Corp. (offering NeuSIGHT), Pavillion (Process Insights software), Praxis Engineers/GE (PECOS), ULTRAMA_x,^{2,3} and URS (formerly Radian Corp. offering GNOCIS).⁴ Also, Lehigh University offers BoilerOP software,⁵ but this software is geared more for optimization through parametric testing.

Emission Control Performance

Industry experience has demonstrated that optimization can achieve 5-35 percent NO_x reduction, along with heat rate improvement (up to 1.5 percent at full load and up to 4 percent at low loads). Boilers that have more operating variables, have not been tuned recently, or have not been tuned with the objective to reduce emissions, fall in the middle to the high end of the 5-35 percent range. Boilers that have been recently tuned (following a low NO_x burner retrofit or a scheduled outage) are expected to achieve NO_x and heat rate improvement in the low end of the above range. SO₂ and mercury emissions are expected to be reduced proportionally to the heat rate improvement.

O&M Impacts

Significant O&M impacts are not expected in conjunction with power plant optimization. However, the right precautions need to be taken to avoid O&M impacts, especially long-term impacts which are difficult to monitor and quantify. Examples of such impacts are potential waterwall corrosion, which may be caused by aggressive combustion staging (high overfire air flow rate) and low excess air. Also, if the optimization program shows preference in using one specific pulverizer more than others, then precautions need to be taken so that pulverizer maintenance schedule is adjusted to avoid reliability problems.

Costs

Typical capital costs,¹ including installation but not including the time contributed by utility staff, are:

- For stand-alone or one-time optimization: \$25,000-50,000
- For advisory optimization: \$100,000-250,000
- For closed loop optimization: \$150,000-300,000

In most cases, O&M costs are limited to a small license agreement (up to \$10-20,000 per year) with the software supplier to provide technical support on an as-needed basis, as well as revised versions of the software.

Issues Associated with the Technology; Future Outlook

Increased competition due to deregulation and emission trading is expected to provide an additional impetus for more extensive use of optimization software. There are no major issues associated with their application.

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Chapter 4

Summary

During 2001, fuel combustion-electric utilities contributed 69 percent of the total SO₂ emitted, and 22 percent of the NO_x emitted in the United States. As demand for electricity generation and the need to address emissions of multiple pollutants grow, new emissions control technologies are emerging. In the past, these technologies have mainly addressed one pollutant at a time in harmony with individual environmental requirements. In light of the need to address emissions of multiple pollutants, the development of cost-effective and easily retrofittable emissions control technologies capable of simultaneously handling several pollutants is increasingly becoming necessary.

This report presents and analyzes various existing and novel control technologies designed to achieve multi-emission reductions. It provides an evaluation of multi-emission control technologies and options that are available for coal-fired power plants with a capacity of 25 MW or larger in the United States. The report addresses technologies and options that are capable of simultaneously controlling at least two of the following three pollutants: NO_x, SO₂, and Hg.

The selection of control technologies was limited to those for which at least one installation, no lower than 5 MW or equivalent, was in operation in a power plant worldwide as of July 1, 2001. Advanced power generation technologies, power plant rehabilitation-upgrading options, fuel switching or blending, and power plant optimization were also included due to their ability to reduce multiple emissions.

The technology reviews are based on several sources of information including technology vendors, technical papers, expert consultations, reports published by the Department of Energy, and trade publications. The results of this review reveal the following:

- The number of technologies under development, demonstration, or already commercially available is significant; most of them have been used already in power plants or industrial applications;
- Fifteen out of the 27 evaluated technologies are in commercial or early commercial stage;
- A couple of technologies (Activated Coke and E-BEAM), which are not commonly used in the United States, are already in use in other countries;
- Six of the evaluated control technologies (Activated Coke, ECO, wet FGD with SCR, EnviroScrub, LoTOx and K-Fuel) are capable of achieving reductions of SO₂, NO_x, and mercury; most of these exhibit the potential to significantly control (above 80 percent) all three pollutants (SO₂, NO_x, and Hg).;
- Some technologies, such as SNO_x, SNRB, ADVACATE, and CZD, have been tested either in pilot or demonstration scale in the early phase of the U.S. Department of Energy's Clean Coal Technology (CCT) program, but have not been adopted by industry. Some of these technologies could become more cost-effective as environmental requirements evolve.
- A number of technologies under early development (Pioneer Technologies' Non-thermal Plasma Arc technology, Consummator's plasma arc by-product recovery, Phoenix's retrofit slagging combustor, ISCA's Cl₂ injection, and BioDeNO_x), which were not evaluated in this report, may offer additional effective emission control of multiple pollutants in the near future.

For each evaluated technology, the report includes background information, applicability, status of commercialization, any secondary environmental impacts of the technologies, identification of primary process variables that impact performance relative to NO_x, SO₂, and mercury, as well as capital and operation and maintenance (O&M) costs. Table 4-1 includes summary descriptions of 27 technologies identified as multi-emission control technologies, which have reached a stage of development beyond pilot scale. These technologies can broadly be divided into:

- Environmental control (post-combustion controls),
- Advanced power generation, and
- Power plant upgrading and operating options.

For the purposes of this report, environmental controls include those processes that control SO₂-mercury, SO₂-NO_x, and SO₂-NO_x-mercury emissions. Injection of activated carbon upstream of electrostatic precipitators and bag filters was also included because of the significant role it may play in controlling mercury from existing power plants.

Advanced power generation technologies include circulating fluidized bed combustion (CFB), integrated gasification combined cycle (IGCC), pressurized fluidized bed combustion (PFBC), and supercritical pulverized coal. Plant upgrading and operating changes include fuel blending and cofiring, plant upgrading and efficiency improvements, and plant optimization.

Although the report is limited to addressing technologies with a certain level of maturity, the authors expect a rapid technological evolution in the development and commercialization of several multi-emission control technologies not necessarily addressed in this report.

Table 4-1. Summary Descriptions of 27 Multi-emission Control Technologies for Coal-fired Units

Technology	Status ^a	Emissions Reductions	Applicability	Issues
<u>SO₂ and Mercury Control</u>				
Dry scrubbers	C	SO ₂ : 90-98%; NO _x : NA ^b ; Hg: 0- 95%	Low-to-medium sulfur coal	Hg removal can vary significantly with coal type, operating conditions
SO ₂ sorbents	P/C	SO ₂ : 40-85%; NO _x : NA; Hg: NA	Units with ESP or FF for particulate control	Calcium-based compounds not used commercially in coal fired plants. Waste disposal issue with sodium-based compounds. Potential impacts on ESP or FF
Activated carbon with SO ₂ sorbent processes	P/C	SO ₂ : 40-85%; NO _x : NA; Hg: Up to 90%	Units with ESP or FF for particulate control	Not used commercially, potential impacts on ESP or FF
Activated carbon with particulate controls	P/C	Hg: 50-90%	Retrofit and new units with ESP or FF	Not widely demonstrated at full scale, ash salability, ESP and FF performance, impact of coal type (mercury speciation)
Wet FGD with mercury oxidation processes	P	SO ₂ : 95%; NO _x : NA; Hg: >80%	Wet scrubber plants	Full scale demonstration underway, insufficient information at present
Wet FGD with wet ESP	C/P	SO ₂ : 99%; NO _x : NA; Hg: Up to 80%	Integration with wet scrubbers, retrofit dry ESPs, new units	Few applications in power industry, potentially expensive alloys required
Advanced dry FGD	P/C	SO ₂ : 90-98%; NO _x : NA; Hg: 0-95%	SO ₂ -Hg control for low-to- medium sulfur coal (same as spray dryers)	Hg removal may vary significantly with coal type, operating conditions (similar to spray dryers)
PEESP	B/P	SO ₂ : >90% (with wet FGD); NO _x : NA; Hg: Up to 98%	New and retrofit	Early stage of development; demonstration and further assessment of the technology is needed
MerCAP	B/P	SO ₂ : NA; NO _x : NA; Hg: >80%	New and retrofit; scrubbed flue gas	Did not perform well in unscrubbed gas; >80% for 10 ft long plates spaced 0.5 inches apart
<u>SO₂ and NO_x Control</u>				
E-BEAM	C/D	SO ₂ : >95%; NO _x : Up to 90%; Hg: NA	New and retrofit	Demonstration is required. High costs and auxiliary power requirements
ROFA-ROTAMIX	C/D	SO ₂ : 90%; NO _x : 40-60%; Hg: 67% with Trona, 89% with CaCO ₃	Existing plants	Demonstration phase
SNO _x	C	SO ₂ : >90%; NO _x : >90%; Hg: 0%	New and retrofit	Cost-effectiveness
SNRB	P	SO ₂ : 80-90%; NO _x : 90%; Hg: NA	New power plants and retrofits	Requires demonstration
THERMALONO _x with wet FGD or FLU-ACE	D	SO ₂ : Up to 95%; NO _x : Up to 90%; Hg: NA	New and retrofit	In demonstration

(continued)

(Table 4-1 concluded)

Technology	Status ^a	Emissions Reductions	Applicability	Issues
<i>SO₂, NO_x, and Mercury Control</i>				
Activated coke	C	SO ₂ : 90-98%; NO _x : 15-80%; Hg: 90-99%	New and retrofit	Demonstration of the combined SO ₂ -NO _x -Hg control is needed in the United States
Electrocatalytic oxidation (ECO)	D	SO ₂ : 98%; NO _x : 90%; Hg: 90%	New and retrofit	Demonstration in progress
Wet FGD and SCR	C	SO ₂ : 95%; NO _x : 90-95%; Hg: 40-90% depending on coal type	Plants with SCR and wet scrubber technologies	Need additional confirmation of mercury oxidation levels in the SCR
EnviroScrub	P	SO ₂ : >99%; NO _x : 93-97%; Hg: Up to 67%	New and retrofit	Demonstration required
LoTO _x	D/C	SO ₂ : 95%; NO _x : 70-95%; Hg: Up to 90%	New and retrofit	Demonstration required
K-Fuel	D/C	SO ₂ : Up to 30%; NO _x : Up to 45%; Hg: Up to 70%	Mostly boilers burning PRB or lignite	Demonstration required
<i>Advanced Power Generation Options</i>				
Circulating fluidized bed combustion	C	SO ₂ : >95%; NO _x : 30-70%; Hg: NA	Mainly new	Successful scale-up to 400-600 MW while maintaining its cost-effectiveness and emission performance
Integrated gasification combined cycle	C/D	SO ₂ : 99%; NO _x : 80-90%; Hg: 90%	New	High costs. Fluidized bed IGCC requires demonstration
Pressurized fluidized bed combustion	C	SO ₂ : Up to 98%; NO _x : 30-70%; Hg: NA	Mostly new	Some reliability problems and high costs (relative to conventional PC and FGD). Also, scale-up issues.
Supercritical pulverized coal	C/D	SO ₂ : 4-12%; NO _x : 4-12%; Hg: 4-12%	New	Ultra-supercritical unit requires further demonstration
<i>Power Plant Upgrading</i>				
Fuel blending and cofiring	C	SO ₂ : Up to 100%; NO _x : 20-80%; Hg: flex%	New and retrofit	Development of on-line coal quality monitoring is needed to enhance coal blending
Plant upgrading	C	Depends on choice	Retrofit	Impact of environmental regulations pertaining to increased output of existing plants
Power plant optimization	C	SO ₂ : 1.5-5%; NO _x : 5-35%; Hg: 1.5-5%	New and retrofit	None

^a Status: B = Bench scale; P = pilot stage; C = commercial; D = demonstration^b NA = no removal reported

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