United States
Environmental Protection
Agency

EPA-600/R-03-110
October 2003

Research and Development

Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers

Prepared for

Office of Research and Development

Prepared by

National Risk Management
Research Laboratory
Research Triangle Park, NC 27711

EPA-600/R-03/110
October 2003

Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers

Prepared by:

James E. Staudt
Andover Technology Partners
112 Tucker Farm Road
North Andover, MA 01845

Wojciech Jozewicz
ARCADIS Geraghty & Miller
4915 Prospectus Drive, Suite F
Durham, NC 27713

EPA Contract No. 68-C-99-201, Work Assignment 4-028
EPA Project Officer: Ravi K. Srivastava
National Risk Management Research Laboratory
Research Triangle Park, NC 27711

U.S. Environmental Protection Agency
Office of Research and Development
Washington, DC 20460

ABSTRACT

Under the Clean Air Act, as amended, the Environmental Protection Agency (EPA) has determined that mercury emissions from coal-fired power plants should be regulated. Based on this determination, EPA is to propose Maximum Achievable Control Technology Standards for these emissions by December 2003. To aid in this regulatory effort, estimates of the performance and cost of powdered activated carbon (PAC) injection-based mercury control technologies and multipollutant control technologies that may be useful in controlling mercury emissions have been developed. This report presents these estimates.

Estimates cost range for PAC injection, based on currently available data, is 0.03-3.096 mills/kWh. However, the higher costs are usually associated with the minority of plants using Spray Dryer Absorbers and Electrostatic Precipitators (SDAs plus ESPs) or the small number of plants using hot ESPs (ESPhs). Excluding the minority of plants using SDAs plus ESPs or ESPhs, current cost estimates are from 0.03 to 1.903 mills/kWh. At the low end of these cost ranges, 0.03 mills/kWh, it is assumed that no additional control technologies are needed, but mercury monitoring will be necessary. In these cases, high mercury removal may be the result of the type of particulate matter, nitrogen oxide, and sulfur dioxide control measures currently employed, such as combinations of ESP, selective catalytic reduction (SCR), and wet flue gas desulfurization (FGD) on bituminous coal-fired boilers.

Multipollutant control methods evaluated in this program that may provide cost effective mercury control and control of other pollutants include Electro Catalytic Oxidation (ECO), Advanced Dry FGD, and a coal beneficiation method. ECO and Advanced Dry FGD are flue gas treatment methods and are estimated to have costs ranging from 3.28 to 12.33 mills/kWh over a range of fuel types and conditions. A coal beneficiation method called K-Fuel was shown to provide about 60% or greater reduction in mercury from Powder River Basin coal on a heating value basis.

Based on this work, it is expected that future efforts in R&D are likely to focus on improved understanding of mercury speciation across SCRs leading to beneficial effects of combinations of SCR with wet FGD and developing sorbents that can improve performance and cost of sorbent-based mercury control technologies. Multipollutant control technologies, which are more costly than single-pollutant mercury control technologies but offer other environmental benefits, will be another area for further development that could improve the cost of reducing emissions from coal-fired power plants. Finally, removing mercury from the coal, along with other fuel quality improvements, may prove to be a very cost effective approach for reducing emissions.

Foreword

The U.S. Environmental Protection Agency (EPA) is charged by Congress with protecting the Nation's land, air, and water resources. Under a mandate of national environmental laws, the Agency strives to formulate and implement actions leading to a compatible balance between human activities and the ability of natural systems to support and nurture life. To meet this mandate, EPA's research program is providing data and technical support for solving environmental problems today and building a science knowledge base necessary to manage our ecological resources wisely, understand how pollutants affect our health, and prevent or reduce environmental risks in the future.

The National Risk Management Research Laboratory (NRMRL) is the Agency's center for investigation of technological and management approaches for preventing and reducing risks from pollution that threaten human health and the environment. The focus of the Laboratory's research program is on methods and their cost-effectiveness for prevention and control of pollution to air, land, water, and subsurface resources; protection of water quality in public water systems; remediation of contaminated sites, sediments, and ground water; prevention and control of indoor air pollution; and restoration of ecosystems. NRMRL collaborates with both public and private sector partners to foster technologies that reduce the cost of compliance and to anticipate emerging problems. NRMRL's research provides solutions to environmental problems by: developing and promoting technologies that protect and improve the environment; advancing scientific and engineering information to support regulatory and policy decisions; and providing the technical support and information transfer to ensure implementation of environmental regulations and strategies at the national, state, and community levels.

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.

Hugh W. McKinnon, Director
National Risk Management Research Laboratory

EPA REVIEW NOTICE

This report has been peer and administratively reviewed by the U.S. Environmental Protection Agency and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

ACKNOWLEDGMENTS

The authors would like to acknowledge the many contributors to this document, without whose efforts this report would not be complete. In particular, we wish to acknowledge the technical guidance and insights provided by Dr. Ravi Srivastava of EPA's National Risk Management Research Laboratory, Office of Research and Development. The authors also appreciate many helpful discussions with vendors of control technologies discussed in this document.

TABLE OF CONTENTS

Section **Page**

Abstract ii
Foreword iii
Acknowledgments iv
List of Figures vii
List of Tables viii
List of Acronyms and Abbreviations x

1.0 Introduction 1
2.0 Mercury Speciation and Capture 5
3.0 Mercury Control with Existing Technologies 7
3.1 Mercury Removal in PM Equipment 8
3.2 Impacts of NO_X Controls on Mercury Speciation and Capture 9
3.2.1 SCR Impact on Mercury Speciation 9
3.2.2 Mercury Removal Though Combustion NO_X Controls 15
3.3 Mercury Removal in SO_2 Control Equipment 16
3.3.1 Mercury Removal in Wet FGD 16
3.3.2 Mercury Removal in SDA 17
3.4 Mercury Removal in Other Control Devices 18
3.5 Models of Mercury Removal by Existing Equipment 18
4.0 Emerging Control Technologies 21
4.1 PAC Injection-Based Technologies 21
4.1.1 Mercury Removal Models 22
4.1.2 Mercury Reduction by PAC Injection 23
4.2 Emerging Control Technologies 25
4.2.1 Electro Catalytic Oxidation (ECO 26
4.2.2 Advanced Dry FGD 32
4.2.3 K-Fuel 38
5.0 Technologies Currently under Development 43
5.1 Oxidation Technologies 43
5.2 Sorbent Technologies 44

5.3 Other Technologies 46
6.0 Costs of Reducing Mercury Emissions 49
6.1 Mercury and Multipollutant Control Cost Models 49
6.2 Fuel Types, Plant Characteristics, and Model Plant Cases 53
6.3 Cost Model Results 57
6.3.1 High Sulfur Bituminous Coals (Model Plants 1-10, 26-28) 57
6.3.2 Low Sulfur Bituminous Coals 66
6.3.3 Low Sulfur Subbituminous Coals including Powder River Basin Coals 71
6.4 Cost Impacts of Selected Variables 80
6.5 Summary of Mercury and Multipollutant Control Costs 86
7.0 Summary 89
8.0 References 91

Appendices

A Appendix A Description of Mercury and Multipollutant Control Performance and Cost Model A-1
B Description of PAC Injection Algorithms Used in the Mercury and Multipollutant Control Performance and Cost Model B-1
C Summary of Mercury Control Cases Analyzed C-1
D Results of Model Runs D-1

LIST OF FIGURES

Figure **Page**

1. Mercury oxidation without a catalyst as a function of residence time, gas temperature, and HCl content 10
2. Mercury oxidation across SCR catalysts and without SCR catalyst 11
3. Oxidation of mercury across C-1 SCR catalyst in PRB-derived flue gas 12
4. Effect of flue gas exposure time on C-1 SCR catalyst oxidation of elemental mercury at 700 °F and space velocity of 1,450 hr^{-1} 12
5. Location of ECO installation in a power plant 26
6. Detailed process flow diagram of ECO 27
7. ECO power consumption versus NO_X 31
8. F.L. Smidth Airtech AirTech Gas-Solids Absorber (GSA). 33
9. Installation of an advanced dry FGD upstream of an existing ESP 33
10. Installation of an advanced dry FGD downstream of an existing ESP 34
11. Advanced dry scrubber SO_2 removal performance 35
12 Advanced dry scrubber performance 35
13. Overall schematic of K-Fuel processing plant 39
14. K-Fuel thermal processing plant 39
15. SO_2 and NO_X emissions from test burns of K-Fuel and untreated fuels 40
16. Estimated Effect of K-Fuel Cost on Generation Cost. 77
17. Cost of PAC Injection for 500 MW Coal Fired Boilers with existing ESPc or FF 81
18. Cost of PAC Injection for 500 MW Coal Fired Boilers with Existing ESPc—Effect of Medium Versus High Performance PAC 82
19. Effect of Capital Cost on 90 Percent Mercury Control with PAC on Boiler with Existing ESPc and Retrofit of Downstream PJFF. 83
20. Effect of Fertilizer Value on Cost of Emissions Control with ECO on a 500 MW Bituminous Coal Boiler 84
21. Effect of Power Value on Cost of Emissions Control with ECO on a 500 MW Bituminous Coal Boiler 85
22. Effect of Reagent Cost on Cost of Emissions Control with Advanced Dry FGD on a 500 MW Boiler Firing Low Sulfur Bituminous Coal 85

LIST OF TABLES

Table		Page
1.	Average Mercury Capture by Existing Post-Combustion Control Configurations Used for PC-Fired Boilers	7
2.	Summary of Results from Full-Scale SCR Mercury Oxidation Tests	14
3a.	Parameters Used for Equations 1 and 2 Which Estimate Mercury Removal by Existing Equipment	19
3b.	Parameters Used for Equations 1 and 2 Which Estimate Percent of Remaining Mercury in Gas that Is Elemental Mercury	20
4.	ECO Pollutant Removal Efficiencies	30
5.	Estimated Cost of CFB-FGD System for a 500 MW Plant Burning PRB Coal	38
6.	Comparison of Typical PRB Coal with K-Fuel	41
7.	Fuels Used In Model Plant Analysis	54
8.	Power Plant Characteristics	55
9.	Mercury Control Technology Applications and Co-benefits	56
10a.	High Sulfur Coal, ESP plus FGD Without SCR Co-benefit (Model Plants 1, 6)	59
10b.	High Sulfur Coal, ESP plus FGD With SCR Co-benefit (Model Plants 1, 6)	60
11a.	High Sulfur Coal, ESPh plus FGD Without SCR Co-benefit (Model Plants 3, 8)	61
11b.	High Sulfur Coal, ESPh plus FGD with SCR Co-benefit (Model Plants 3, 8)	61
12.	Advanced Dry FGD on High Sulfur Coal (Model Plants 4, 9), Sensitivity to Capital Cost	62
13.	ESP and ECO on High Sulfur Coal (Model Plants 5 and 10), Sensitivity to Capital Cost	63
14.	High Sulfur Coal, 100 MW SDA, and ESPc (Model Plant 26)	64
15.	High Sulfur Coal, 100 MW SDA, and FF (Model Plant 27)	65
16.	High Sulfur Coal, 100 MW ESPh, and FGD (Model Plant 28)	66
17.	Low Sulfur Coal, ESPc, and No SO_2 Controls (Model Plants 11 and 29)	67
18.	Low Sulfur Coal, FF, and No SO_2 Controls (Model Plants 12 and 30)	68
19.	Low Sulfur Coal, ESPh, and No SO_2 Controls (Model Plants 13 and 31)	69
20.	ECO Installed After Particulate Removal (Model Plants 14–16, 32–34), Sensitivity to Capital Cost	70
21.	Advanced Dry FGD (Model Plants 17–19, 35–37), Sensitivity to Capital Cost	71

22. Low Sulfur Subbituminous Coals, ESPc, and No SO_2 Control (Model Plants 20, 38) 73
23. Low Sulfur Subbituminous Coals, FF, and No SO_2 Control (Model Plants 21, 39) 74
24. Low Sulfur Subbituminous Coals, ESPh, and No SO_2 Controls (Model Plants 22, 40) 75
25. Low Sulfur Subbituminous Coals with ECO (Model Plants 23–25, 41–43) Sensitivity to Capital Cost 76
26. Comparison of Estimated Mercury Emissions from PRB and K-Fuel Boilers Equipped with Particulate Control and No Additional Mercury or SO_2 Controls . 77
27. K-Fuel, ESPc and No SO_2 Control (Model Plants 44, 47) 78
28. K-Fuel, FF, and No SO_2 Control (Model Plants 45, 48) 79
29. K-Fuel, ESPh, and No SO_2 Controls (Model Plants 46, 49) 80
30. Estimated Cost of Mercury Control—Current and Potential Cost Estimates 87
31. Estimated Costs of Multipollutant Controls 88

LIST OF ACRONYMS AND ABBREVIATIONS

ACRONYM	DEFINITION
ADP	acid dew point
ATS	approach to saturation
CAAA	Clean Air Act Amendments of 1990
CEMS	continuous emission monitoring system
COHPAC	compact hybrid particulate collector
CRF	capital recovery factor
ECO	electro catalytic oxidation
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
ESPc	cold-side electrostatic precipitator
ESPh	hot-side electrostatic precipitator
FF	fabric filter
FGD	flue gas desulfurization
GSA	gas suspension absorber
HCl	hydrogen chloride
Hg	mercury
$HgCl_2$	mercuric chloride
Hg^0	elemental mercury
Hg^{++}	oxidized mercury
Hg^p	particle-bound mercury
Hg_T	total mercury
HgO	mercury oxide
ICR	information collection request
IPM	integrated planning model
kWh	kilowatt hour
LOI	loss of ignition
LNB	low NO_X burner
LSFO	limestone forced oxidation
MACT	maximum achievable control technology
MEL	magnesium enhanced lime
MW	megawatt
MWCs	municipal waste combustors
NETL	National Energy Technology Laboratory

LIST OF ACRONYMS AND ABBREVIATIONS (continued)

ACRONYM	DEFINITION
NO_X	oxides of nitrogen
OAR	EPA's Office of Air and Radiation
OFA	overfire air
OH	Ontario Hydro
O&M	operation and maintenance
PAC	powdered activated carbon
PC	pulverized coal
PFF	polishing fabric filter
PJFF	pulse jet fabric filter
PM	particulate matter
PPPP	Pleasant Prairie Power Plant
PRB	Powder River basin
PS	particle scrubber
RGFF	reverse-gas fabric filter
RAP	rapid absorption process
R&D	research and development
SC	spray cooling
SCR	selective catalytic reduction
SDA	spray dryer absorber
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
TCLP	toxicity characteristic leaching procedure
UBC	unburned carbon
WESP	wet electrostatic precipitator

1.0 INTRODUCTION

In the atmosphere, mercury exists in two forms: elemental mercury vapor (Hg^0) and ionic mercury (Hg^{++}). Hg^0 can circulate in the atmosphere for up to one year and, consequently, can undergo dispersion over regional and global scales. Hg^{++} in the atmosphere either is bound to airborne particles or exists in gaseous form. This form of mercury is readily removed from the atmosphere by wet and dry deposition. After deposition, mercury is commonly re-emitted back to the atmosphere as either a gas or a constituent of particles and redeposited elsewhere. In this fashion, mercury cycles in the environment.[1]

A number of human health and environmental impacts are associated with exposure to mercury. Mercury is known to bio-accumulate in fish and animal tissue in its most toxic form, methylmercury. Human exposure to methylmercury has been associated with serious neurological and developmental effects. Adults exposed to methylmercury show symptoms of tremors, loss of coordination, and memory and sensory difficulties. Offspring exposed during pregnancy show atrophy of the brain with delayed mental development. The incidence and extent of such effects depend on the level of exposure to methylmercury. Hg^0 is readily absorbed through lungs and, being fat-soluble, is rapidly distributed throughout the body. Subsequently, it slowly oxidizes to Hg^{++}, which accumulates in the brain and can lead to tremors, memory disturbances, sensory loss, and personality changes. Hg^{++} is absorbed through the digestive tract, accumulates in the kidneys, and can lead to immune-mediated kidney toxicity. Adverse effects of mercury on fish, birds, and mammals include reduced reproductive success, impaired growth, behavioral abnormalities, and even death. Details of the risks associated with exposure to mercury are discussed in the literature.[1] A severe case of human exposure occurred in Minamata, Japan in the 1950s.[2]

Under the Clean Air Act as amended the Environmental Protection Agency (EPA) has determined that mercury emissions from coal-fired power plants should be regulated.[3] Based on this determination, EPA is to propose Maximum Achievable Control Technology (MACT) Standards for these emissions by December 2003. To aid in this regulatory effort, this report has been prepared as an update of a previous report (EPA 600/R-00-083)[4] that presented preliminary estimates of the performance and cost of promising mercury control technologies applicable to coal-fired electric utility boilers. Although most of these technologies are based on injection of powdered activated carbon (PAC) into boiler flue gas, additional technologies that offer promise in control of mercury and other pollutants are also discussed in this report.

The report layout is as follows. First, the general principles of mercury speciation and capture are discussed. Second, mercury removal by existing equipment on coal-fired boilers is discussed. Third, promising mercury control technologies for coal-fired electric utility boilers are identified, and the performance characteristics of these technologies are estimated. These include characterization of mercury removal performance possible as a function of various parameters. Fourth, model plants representing the spectrum of retrofit possibilities are identified and a matrix of cases to be studied is developed. Next, costs of controlling mercury emissions from these model plants with the technologies of interest are examined. Finally, potential future improvements in these costs are discussed. During discussion of cost and potential improvements, research and development (R&D) areas are identified for near-term emphasis.

Two multipollutant air pollution control technologies were evaluated as well as a coal beneficiation technology that offers pollution control advantages. The two air pollution control technologies include electro catalytic oxidation (ECO) and advanced dry flue gas desulfurization (FGD). ECO is a unique technology without any full-scale commercial experience on utility boilers. However, commercial-scale demonstrations are being built, and this technology has been studied extensively by the U.S. utility industry and the Department of Energy[5]. So, results are presented here for ECO technology; however, they should be considered preliminary. Advanced Dry FGD has extensive experience in waste incineration applications and some limited commercial experience on coal-fired boilers. Moreover, advanced dry FGD is similar in many respects to spray dryer absorber (SDA) technology—a well established sulfur dioxide (SO_2) control technology used on utility boilers. However, data regarding the control of mercury using this technology is limited, so the results presented here may be preliminary with regard to mercury control but are expected to be more reliable with regard to control of SO_2 and particulate matter (PM) and with respect to cost. Coal beneficiation through the K-Fuel process has been demonstrated on the pilot scale, and the first commercial plant for coal beneficiation through the K-Fuel process is planned. In addition to enhancing coal heating value for low-rank fuels, this process can reduce the content of mercury, sulfur, and nitrogen in the coal, providing multipollutant benefits. The costs are estimated in terms of increased fuel cost.

Use of sorbent injection technologies to control mercury emissions from electric power plants would result in mercury-impregnated sorbent waste, which would need to be disposed of either by itself or in mixture with flyash. One of the more commonly practiced solid waste disposal options is landfilling. However, there is limited information available on the stability of mercury in ash and sorbent residue. Therefore, it is unclear whether any potential exists for the release of mercury back into the environment from landfilled mercury-impregnated solid waste. Further research

is needed on ash and sorbent residue to evaluate mercury retention and the potential for release back into the environment. Due to lack of information, this report does not address any potential costs that may result if mercury has to be stabilized in sorbent waste.

2.0 MERCURY SPECIATION AND CAPTURE

Mercury is volatilized and converted to Hg^0 in the high temperature regions of combustion devices. As the flue gas cools, Hg^0 is oxidized to Hg^{++}. The rate of oxidization is dependent on the temperature, flue gas composition and properties, and amount of flyash and any entrained sorbents. In coal-fired combustors, where the concentrations of hydrogen chloride (HCl) are low, and where equilibrium conditions are not achieved, Hg^0 may be oxidized to mercuric oxide (HgO), mercuric sulfate ($HgSO_4$), mercuric chloride ($HgCl_2$), or some other mercury compound.[6] The oxidization of Hg^0 to $HgCl_2$ and to other ionic forms of mercury is abetted by catalytic reactions on the surface of flyash or sorbents and by other compounds that may be present in the flue gas. Applications of nitrogen oxides (NO_X) control technologies such as selective catalytic reduction (SCR) can assist in oxidation of Hg^0.

Hg^0, $HgCl_2$, and HgO are primarily in the vapor phase at flue gas cleaning temperatures. Therefore, each of these forms of mercury can potentially be adsorbed onto porous solids such as flyash, PAC, and other sorbents for subsequent collection in a PM control device. These mercury forms may also be captured in carbon bed filters or other reactors containing appropriate sorbents.

Mercury removal with wet scrubbers also appears to be possible. $HgCl_2$ is water-soluble and reacts readily with alkali metal oxides in an acid-base reaction; therefore, conventional acid gas scrubbers used for SO_2 control can also effectively capture $HgCl_2$. However, Hg^0 is insoluble in water and must be adsorbed onto a sorbent or converted to a soluble form of mercury that can be collected by wet scrubbing. HgO has low solubility and probably has to be collected by methods similar to those used for Hg^0. Therefore, the form of mercury that is most easily removed is $HgCl_2$, and this form of mercury is most readily formed when burning coals that are higher in chlorine content, such as Eastern bituminous coals. Furthermore, as will be described in Sections 3.1 and 3.2, the equipment on the boiler also plays an important role in determining mercury speciation. For this reason coal type, coal chlorine content, and the boiler equipment all play a significant role in determining the ease with which mercury can be removed from coal combustion flue gas streams.

The following sections will describe mercury removal technologies pertinent to coal-fired boilers. For many technologies described in the following sections, the coal properties and the existing equipment on the boiler will have an impact on the total mercury removal when that facility is retrofitted with mercury removal equipment. This is because mercury speciation is important in

determining the ease or difficulty of removing mercury from the exhaust gas. Additionally, fuel and the equipment used in the facility play role in determining the mercury speciation.

3.0 MERCURY CONTROL WITH EXISTING TECHNOLOGIES

Data derived from an EPA Information Collection Request (ICR) showed that mercury released from coal combustion may be partly removed from the exhaust gases by existing equipment without additional retrofit technology.[7] This chapter discusses the mercury control achieved with existing technologies utilized for control of PM, NO_X, and SO_2 emissions at electric utility coal-fired boilers.

Table 1 shows the average reduction in total mercury (Hg_T) emissions from ICR data for coal-boiler-control classes that burn pulverized coal (PC). Plants that employ only post-combustion PM controls display class average Hg_T emission reductions ranging from 1 to 90 percent. Units with fabric filters (FFs) obtain the highest average levels of control. Decreasing average levels of control are generally observed for units equipped with a cold-side electrostatic precipitator (ESPc), hot-side ESP (ESPh), and particle scrubber (PS). For units equipped with dry scrubbers, the class average Hg_T emission reductions ranged from 2 to 98 percent. The estimated class average reductions for wet FGD scrubbers were similar and ranged from 10 to 98 percent.

Table 1. Average Mercury Capture, in Percent, by Existing Post-Combustion Control Configurations Used for PC-Fired Boilers.[8]

Post-Combustion Control Strategy	Post-Combustion Emission Control Device Configuration	Coal Burned in PC-Fired Boiler Unit		
		Bituminous	Subbituminous	Lignite
PM Control Only	ESPc	36	9	1
	ESPh	14	7	not tested
	FF	90	72	not tested
	PS	not tested	9	not tested
PM Control and SDA	SDA+ESP	not tested	43	not tested
	SDA+FF	98	25	2
	SDA+FF+SCR	98	not tested	not tested
PM Control and Wet FGD System[a]	PS+FGD	12	10	not tested
	ESPc+FGD	81	29	48
	ESPh+FGD	46	20	not tested
	FF+FGD	98	not tested	not tested

[a] Estimated capture across both control devices

For PC-fired boilers, the amount of Hg captured by a given control technology is greater for bituminous coal than for either subbituminous coal or lignite. For example, the average capture of Hg, based on Ontario Hydro (OH) inlet measurements in PC-fired plants equipped with an ESPc, is 36 percent for bituminous coal, 9 percent for subbituminous coal, and 1 percent for lignite.

3.1 Mercury Removal in PM Control Equipment

Approximately 77 percent of the coal-fired utility boilers currently operating in the United States are equipped with only an ESP or an FF. Gaseous mercury (both Hg^0 and Hg^{++}) can potentially be adsorbed on fly ash and be collected in a downstream ESP or FF. The modern ESPs and 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. It is currently believed that mercury is primarily adsorbed onto the unburned carbon in fly ash. Approximately 80 percent of the coal ash in PC-fired boilers is entrained with the flue gas as fly ash. PC-fired boilers with low-NO_X burners have higher levels of carbon in the fly ash with a correspondingly higher potential for mercury adsorption. Cyclone and stoker boilers tend to have high levels of carbon in the fly ash but have lower flue gas concentrations of fly ash than PC-fired boilers. Fly ash concentrations in fluidized-bed combustors tend to be higher than those in PC-fired boilers. Also, the carbon content of fluidized-bed combustor fly ash is generally higher than that of PC-boiler fly ash.

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^{++} 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. As indicated in Table 1, the ICR data showed that, for both bituminous and subbituminous coals, mercury collection in boilers equipped only with FFs is much higher than for boilers equipped only with ESPs. As will be shown later in this

document, this effect also contributes to much more efficient collection of mercury when 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.

ICR data reflected that plants which employ only post-combustion PM controls display average Hg emission reductions ranging from 0 percent to 89 percent.[8] 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 an ESPc was 35 percent for bituminous coal, 3 percent for subbituminous coal, and near zero for lignite.

3.2 Impacts of NO_X Controls on Mercury Speciation and Capture

Several NO_X control technologies, including low NO_X burners (LNBs), overfire air (OFA), reburning, selective noncatalytic reduction (SNCR), and SCR, are employed at utility coal-fired boilers to control NO_X emissions. Of these control technologies, SCR has an impact on the speciation of mercury in flue gas and, therefore, subsequent capture in wet FGD systems. Based on recent data, combustion controls such as LNBs, OFA, and reburning may also have the potential to increase mercury capture in flyash. The effects of SCR and combustion controls on mercury capture are described in the following sections.

3.2.1 SCR Impact on Mercury Speciation

The speciation of mercury is known to have a significant impact on the ability of air pollution control equipment to capture it. In particular, the oxidized form of mercury, mercuric chloride ($HgCl_2$), is highly water-soluble and is, therefore, easier to capture in wet FGD systems than the elemental form of mercury which is not water-soluble. SCR catalysts can act to oxidize a significant portion of the elemental mercury, which makes it easier to remove in downstream wet FGD.

The results of studies have suggested that oxidation of elemental mercury by SCR catalyst may be affected by[9–12]

- The space velocity of the catalyst
- The temperature of the reaction
- The concentration of ammonia
- The age of the catalyst
- The concentration of Cl in the gas stream

Tests on a laboratory combustor has shown that mercury oxidation without a catalyst was enhanced with higher Cl concentration (higher HCl at inlet) and that oxidation increased with residence time and at lower temperatures, as shown in Figure 1.[9] Reference 9 also describes the results of laboratory tests of oxidation of mercury across different types of SCR catalysts. The results of these tests, shown in Figure 2, demonstrated that the catalyst significantly increased the amount of elemental mercury that oxidized to mercuric chloride.

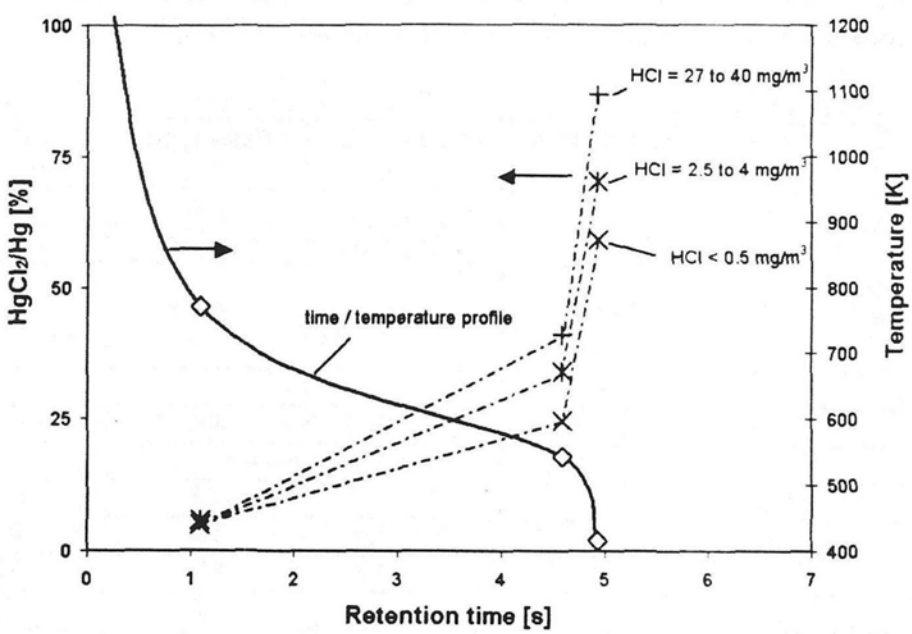

Figure 1. Mercury oxidation without a catalyst as a function of residence time, gas temperature, and HCl content.[9]

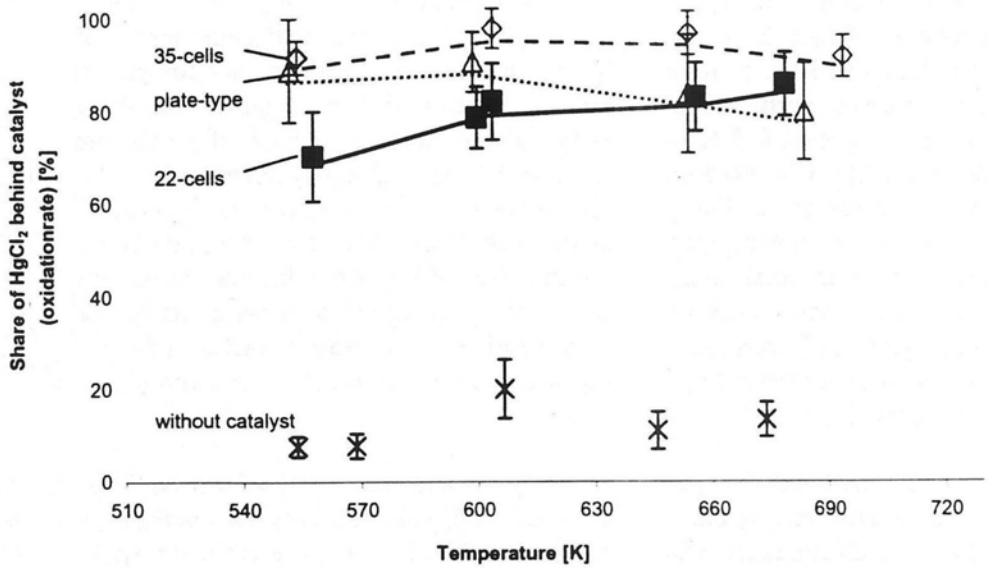

Figure 2. Mercury oxidation across SCR catalyst unit with and without catalyst.[9]

Tests of mercury oxidation by SCR catalyst have been conducted using simulated flue gas and slip-streams from actual units.[10] Results showed similar trends for both simulated flue gas and slip-streams from actual units with the exception that the effect of increasing space velocity appeared somewhat more significant with the slip streams. Multiple catalyst types were tested with similar results obtained. According to Reference 10, it was determined that mercury oxidation was in the range of about 80–90 percent for fresh catalyst and space velocities in the range of 1000 hr^{-1}. However, the oxidation rate falls off with increased space velocity such that oxidation might be in the range of 30–80 percent at a space velocity of 4000 hr^{-1}. Apparently, the wide range of oxidation performance at a space velocity of 4000 hr^{-1} is the result of the influence of other factors—temperature, ammonia, and possibly other effects. As shown in Figure 3, Reference 10 showed that oxidation of mercury across fresh SCR catalyst was relatively higher at temperatures in the vicinity of 700 °F and relatively lower in the vicinity of 800 °F. This may be consistent with the fact that oxidation of mercury to mercuric chloride is greater at lower temperatures.

The presence of ammonia, which is the NO_X reducing reagent normally used in SCR systems, appeared to inhibit the oxidation of elemental mercury, as reported in Reference 10. This effect appeared to be most pronounced with catalyst that had been exposed to boiler exhaust gases for a number of months. As shown in Figure 4, mercury oxidation without ammonia present remained between 80 and 90 percent after 4200 hours (about six months of continuous operation) of exposure

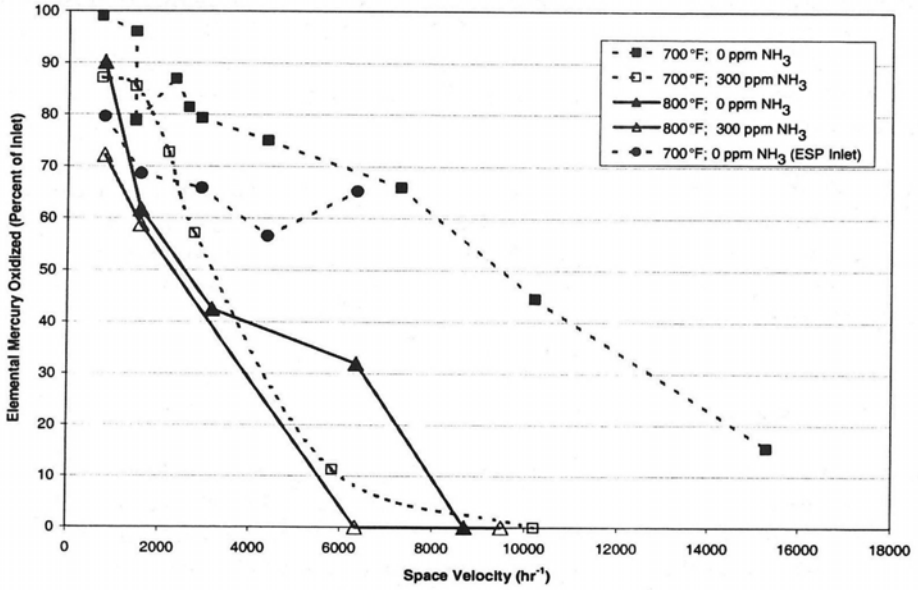

Figure 3. Oxidation of mercury across C-1 SCR catalyst in PRB-derived flue gas.[10]

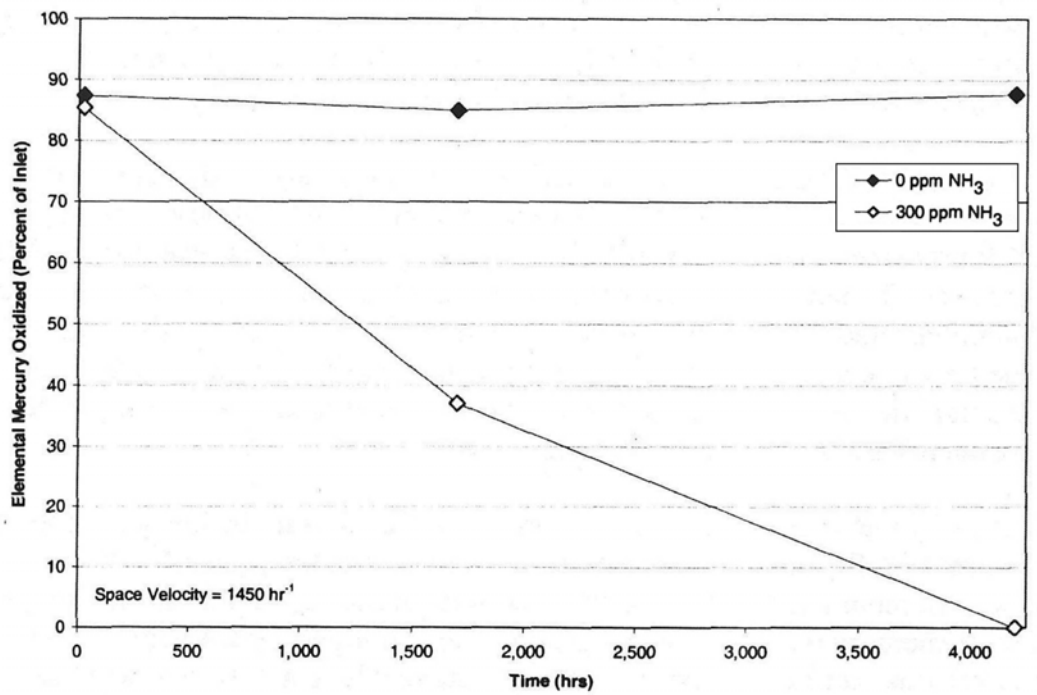

Figure 4. Effect of flue gas exposure time on C-1 SCR catalyst oxidation of elemental mercury at 700 °F and space velocity of 1,450 hr^{-1}.[10]

to boiler gases at a space velocity of 1450 hr^{-1}. When exposed to 300 ppm of ammonia, fresh catalyst continued to oxidize 80 to 90 percent of the elemental mercury. However, after 4200 hours of exposure, no oxidation was measured across the catalyst when ammonia was present, suggesting that ammonia may play a role in suppressing mercury oxidation.

Oxidation of elemental mercury to mercuric chloride across an SCR catalyst, therefore, may be a function of space velocity, temperature, ammonia concentration, and catalyst life. Other factors, such as fly ash characteristics, are also believed to play a role.

Reference 11 describes the results of a program that evaluated mercury oxidation across full-scale utility boiler SCR systems. A summary of the results of the tests conducted in 2001 is shown in the first four entries in Table 2. Testing was performed at four coal-fired electric utility plants having catalyst age ranging from around 2500 hours to about 8000 hours. One plant fired subbituminous coal, and three other plants fired Eastern bituminous coal. The test results showed high levels of mercury oxidation in two of the three plants firing eastern bituminous coal and insignificant oxidation at the other two plants (one firing bituminous coal and the other subbituminous). However, it should be noted that for both of the plants where little or no mercury oxidation was measured (S1 and S3), over 85 percent of the mercury at the particle control device inlet was already in the non-elemental form. For the one bituminous coal-fired plant with low mercury oxidation (S3), over 50 percent of the mercury at the SCR inlet was already in the oxidized form. At the plant firing subbituminous coal (S1), mercury oxidation was fairly low. But, due to the high carbon in that plant's fly ash, it is believed that the elemental mercury was adsorbed onto the ash, resulting in high particulate mercury levels. Finally, in contrast with the findings of Reference 10, ammonia appeared to have little or no effect on mercury oxidation on these actual, full-scale facilities.

Subsequent tests on sister units at those plants and at other plants are shown in the second four entries in Table 2. All of the units fired bituminous coal and showed that mercury oxidation was generally enhanced to high levels of oxidized mercury at the SCR outlet. In each case where a scrubber was installed, the mercury removal was high. For the unit with an ESP and no scrubber, mercury removal was not improved by the SCR.

Table 2. Summary of Results from Full-Scale SCR Mercury Oxidation Tests.[13 a]

Power Plant	Catalyst		Coal			Flue Gas Hg^{++} Content (SCR in/out)	Flue Gas Hg^{++} Content at PM Inlet without:with SCR	Total Hg Removal across PM+FGD without:with SCR	Effect of NH_3 on Hg Oxidation (SCR in/out)
	Type Space Velocity (hr^{-1})	Age	Type	Sulfur[b] (%)	Cl[b] (ppm)				
S1: 650 MW[c] Cyclone, ESP	Honeycomb 1800	8000 hr	PRB	0.2	<60	(1 OH sample) 8%/18% (Unit 2)	(1 OH sample each) 5%:8%	(1 OH sample each) 60%:65% (within experimental error)	No effect
S2: 1360 MW[c] Wall, ESP+FGD (MEL[d])	Plate 2125	3.5 months	OH bit.	3.9	1640	(2 OH samples) 48%/91% no effect of alkali injection (Unit 1)	(2 OH samples each) 73%:97%	(2 OH samples each) 51%:88% FGD removed 94% of Hg^{++}	Not tested
S3: 750 MW[c] Tangential, ESP	Honeycomb ~3930	1 ozone season	PA bit. blend	1.7	1150	(2 OH samples) 55%/65% (2 OH samples) 35%/61% for 2nd coal in sister unit	77%:67% (possible filter effect due to reactive ash) 2nd coal/sister unit not tested	(2 OH samples each) 16%:13% (within experimental error) 2nd coal/sister unit not tested	small neg. effect. Not tested in 2nd coal/ sister unit
S4: 704 MW[c] Cyclone, Lime Venturi Scrubber	Honeycomb 2275	1 ozone season	KY bit.	2.9	360	(2 OH samples) 9%/80%	(2 OH samples each) 56%:87%	(2 OH samples each) 46%:90%	Small negative effect
684 MW[c] Wall, ESP+FGD	"corregated" ~3750?	2 months	PA/ WV bit.	3.6	470	Oxidation to >80% (+38% net)	Oxidation to 95% (+15%net) (using data from sister unit w/o SCR)	Oxidation to >90% (+40% net)	Not tested
800 MW[c] Tangential, ESP	Honeycomb 3800	2 seas. 2 layers repl. after 1st seas.	KY/ WV bit.	1	1000	Oxidation to >80% (+21% net)	Oxidation to 89% (~0% net) (using data from sister unit w/o SCR)	No effect; actually lower Hg removal in ESP (-6% vs 23%)	Not tested
1360 MW[c] Wall, ESP+FGD (MEL)	Plate 2125	2 ozone seasons	OH bit.	3.9	520	Oxidation to >80% (+33% net)	Oxidation to >95% (did not test w/o SCR)	~85% Hg removal (did not test w/o SCR)	Not tested
Cyclone, Lime Venturi Scrubber	Honeycomb 2275	2 ozone seasons	KY bit.	3.1	750 bypass 250 w/SCR	Oxidation to 60% (+20% net) (more oxidation if 1 data outlier not used)	Oxidation to >90% (+39% net) (Cl in coal changed between tests)	Oxidation to >90% (+47% net)	Not tested

[a] NH_3, Cl, SO_3 sampled at SCR outlet unless noted
[b] Based on Energy Environmental Research Center's analyses
[c] Gross MW
[d] MEL = magnesium-enhanced lime scrubber

Bench scale testing strongly suggests that HCl is an important exhaust gas constituent that is necessary for providing the chlorine for oxidation of Hg^0 to HgCl across the SCR catalyst.[12] This important result provides a scientific base for explaining the differences observed between coals in field-testing. Subbituminous coals tend to have lower chlorine levels and higher calcium in the ash than bituminous coals. Hence, they would be expected to produce exhaust gas with lower HCl concentrations than bituminous coals.

It is acknowledged that, at this point in time, the understanding of the effects of SCR catalyst on mercury oxidation is not complete. There is a great deal to learn with regard to the science of this phenomenon. However, apparently significant mercury oxidation by SCR catalyst occurs with bituminous coal, and oxidation is less certain with other coals. In this work, when evaluating this effect, it is assumed that when bituminous coals are being used, 90 percent of the mercury after the SCR is in the non-elemental form and is captured by a downstream wet FGD. It is also assumed that the SCR catalyst has no effect on mercury oxidation when other coals are fired.

3.2.2 Mercury Removal Though Combustion NO_X Controls

The staged introduction of fuel and combustion air is a common practice for reducing formation of nitrogen oxides. This is often achieved within the burner in LNBs and also through the use of OFA when deeper staging and greater NO_X reduction than afforded by LNBs alone is desired. Air staging reduces NO_X formation by causing fuel-bound nitrogen to be released from the fuel at high-temperature and fuel-rich conditions. The fuel subsequently burns out under lower-temperature, oxygen-rich conditions to ensure high combustion efficiency with low formation of nitrogen oxide (NO). In the case of reburning (or fuel staging), a secondary, fuel-rich combustion zone is introduced after the initial combustion zone to reduce the NO that was formed in the initial combustion zone to nitrogen (N_2). A downstream burn-out zone—effectively an OFA zone after the reburn zone—provides complete combustion of the reburning fuel under oxygen-rich conditions. Because all of these staged combustion methods used for minimizing NO_X formation result in delayed combustion when compared with combustion methods that do not try to minimize NO_X formation (and therefore burn the fuel only with maximum efficiency in mind), they also tend to reduce combustion efficiency and increase the amount of unburned fuel—in the form of unburned carbon (UBC), also known as loss of ignition (LOI). The UBC ends up in the fly ash that is collected in the PM control device. This carbon in the fly ash may act to adsorb Hg^0 and Hg^{++}. Therefore, existing combustion controls might be expected to enhance removal of mercury from the exhaust gases by downstream PM collection devices.

Combustion of bituminous and low-rank (subbituminous and lignite) coals have been tested at pilot-scale under simulated air staging conditions.[14-16] In that effort, it was found that mercury removal efficiencies by the downstream ESP improved with air staging. Up to 90 percent mercury removal was achieved with bituminous coals through air staging. With low-rank coals, air staging improved mercury removal from about 20 percent removal (without air staging) to about 40 percent removal (with air staging). These tests confirmed the expectation that combustion NO_X controls can improve the mercury capture by the PM control devices.

3.3 Mercury Removal in SO_2 Control Equipment

Both wet and dry flue gas desulfurization technologies are being used in the United States to control SO_2 emissions from coal-fired boilers. SDA is being used at the majority of the plants employing dry FGD technologies. Available data reflects that some mercury capture occurs in wet FGD and SDA systems.

3.3.1 Mercury Removal in Wet FGD

More than 20 percent of coal-fired utility boiler capacity in the United States uses wet FGD systems to control SO_2 emissions. In such systems, a PM control device is installed upstream of the wet FGD scrubber. The PM control device used in combination with a wet FGD scrubber may be a PS, ESPc, ESPh, or a FF baghouse. Wet FGD systems remove gaseous SO_2 from flue gas by absorption. In wet scrubbers, gaseous species are mixed with a liquid in which they are soluble. For SO_2 absorption, gaseous SO_2 is mixed with a caustic slurry, typically water and limestone or water and lime.

Gaseous compounds of Hg^{++} are generally water-soluble and can absorb in the aqueous slurry of a wet FGD system. However, gaseous Hg^0 is insoluble in water and therefore does not absorb in such slurries. When gaseous compounds of Hg^{++} are absorbed in the liquid slurry of a wet FGD system, the dissolved species are believed to react with dissolved sulfides from the flue gas, such as H_2S, to form mercuric sulfide (HgS); the HgS precipitates from the liquid solution as sludge. In the absence of sufficient sulfides in the liquid solution, a competing reaction that reduces/converts dissolved Hg^{++} to Hg^0 is believed to take place. When this conversion takes place, the newly formed (insoluble) Hg^0 is transferred to the flue gas passing through the wet FGD system. The transferred Hg^0 increases the concentration of Hg^0 in the flue gas passing through the wet FGD (since the incoming Hg^0 is not absorbed), thereby resulting in a higher concentration of gaseous Hg^0 in the

flue gas exiting the wet FGD compared to that entering. Transition metals in the slurry (originating from the flue gas) are believed to play an active role in the conversion reaction since they can act as catalysts and/or reactants for reducing oxidized species.

The capture of Hg in units equipped with wet FGD scrubbers is dependent on the relative amount of Hg^{++} in the inlet flue gas and on the PM control technology used. As described in Reference 8, ICR data reflected that average Hg captures in wet FGD scrubbers ranged from 23 percent for one PC-fired ESPh plus FGD unit burning subbituminous coal to 97 percent in a PC-fired FF plus FGD unit burning bituminous coal. The high Hg capture in the FF plus FGD unit was attributed to increased oxidization and capture of Hg in the FF followed by capture of any remaining Hg^{++} in the wet scrubber.

3.3.2 Mercury Removal in SDA

More than 10 percent of coal-fired utility boiler capacity in the United States uses SDA systems to control SO_2 emissions.[8] An SDA system operates by the same principle as a wet FGD system using a lime scrubbing agent, except that the flue gas is mixed with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate. The heat of the flue gas evaporates the water in the mist leaving dry solid particles of calcium sulfite and calcium sulfate. Entrained particles (unreacted sorbent particles, reaction products, and fly ash) are captured in the downstream PM control device (either an ESP or FF).

The performance of SDA systems in controlling SO_2 emissions is dependent on the difference between the SDA outlet temperature and the corresponding flue gas water vapor saturation temperature. SDA systems on coal-fired boilers typically operate about 20 °F (11 °C) above the saturation temperature (i.e., a 11 °C approach to saturation temperature). The relatively low flue gas temperatures afforded by SDA systems increase the potential for mercury capture. The caking, or buildup, of moist fly ash deposits, which can plug the SDA reactor and coat downstream surfaces, dictates the minimum flue gas temperatures which can be employed at the outlet of SDAs.

Hg^p is readily captured in SDA systems. Both Hg^0 and Hg^{++} can potentially be adsorbed on fly ash, calcium sulfite, or calcium sulfate particles in the SDA. They can also be adsorbed and captured as the flue gas passes through the ESP or FF, whichever is used for PM control. In addition, gaseous Hg^{++} may be absorbed in the slurry droplets and react with the calcium-based sorbents within the droplets. Nearly all of the Hg^p can be captured in the downstream PM control device. If the PM

control device is a FF, there is the potential for additional capture of gaseous mercury as the flue gas passes through the bag filter cake composed of fly ash and dried slurry particles.

As described in Reference 8, ICR data reflected that units equipped with lime spray dryer absorber scrubbers (SDA/ESP or SDA/FF systems) 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 resulted from low levels of Hg^0 oxidization.

3.4 Mercury Removal in Other Control Devices

Some units use particulate scrubber systems, primarily venturi scrubbers, to control PM emissions. Capture of Hg in these systems is limited to soluble Hg compounds such as $HgCl_2$. PS systems are typically poor collectors of fine PM, and capture of Hg^p by such scrubbers may be poor if the Hg^p in the flue gas is associated with fine PM. Hg^0 is insoluble and will not typically be captured by the scrubber. It is possible to capture Hg^{++} in the wet scrubbers, but the scrubber chemistry and the manner in which the scrubber is operated will determine whether it is effectively removed, or whether it is stripped, from the scrubbing liquor. Stripping can occur if the Hg^{++} is not adsorbed on the particles or reacted chemically with liquid-phase reactants within the scrubber.

Mechanical collectors such as cyclones do a poor job of capturing fine PM, and, in general, mercury capture in these control devices should be limited to the capture of Hg^p associated with particles larger than 10 μm.

3.5 Models of Mercury Removal by Existing Equipment

As noted in the preceding sections, there are a number of parameters that impact the mercury removal by existing equipment. Chlorine is widely acknowledged as having a role in mercury removal. SO_2 is also expected to have a role as well. Fly ash characteristics and the temperature of the exhaust gas leaving the air preheater exit have also demonstrated a strong influence on mercury removal. Of course, the equipment type plays an important role as well.

Expressions approximating the effects of equipment type, coal chlorine content, and SO_2 level on mercury removal have been developed through statistical analysis of ICR data.[18] Data used by the Reference included equipment type, coal chlorine, and sulfur information but not some

of the other parameters expected to influence mercury removal from existing equipment. Since these expressions do not include other effects expected to be significant, such as ash characteristics and gas temperature, they should only be used for approximations. These algorithms are

Algorithm 1 (ESPc):

$$f_{\text{existing equipment}} = C_1 \times \ln\left[(\text{coal Cl, ppm})/(SO_2\text{, in lb/MMBtu})\right] + C_2 \qquad \text{Eq. 1}$$

Algorithm 2 (all other categories):

$$f_{\text{existing equipment}} = C_1 \times \ln(\text{coal Cl, ppm}) + C_2 \qquad \text{Eq. 2}$$

Where $f_{\text{existing equipment}}$ is the fraction of mercury removed by existing equipment. These same algorithms were shown in Reference 18 to also provide a means to approximate the remaining mercury that is in the elemental form. There are minimum and maximum allowable values that set the allowable range for the results of Equations 1 and 2. Tables 3a and 3b show values for C_1 and C_2 and minimum and maximum values to use in Equations 1 and 2 for estimating fraction of mercury removed by existing equipment (Table 3a) and the fraction of remaining mercury that is elemental (Table 3b).

Table 3a. Parameters Used for Equations 1 and 2 Which Estimate Mercury Removal by Existing Equipment[18]

Existing Equipment	C_1	C_2	Minimum (%)	Maximum (%)
ESPc	0.1233	-0.3885	0.0	55.0
ESPc + wet FGD	0.1157	-0.1438	24.0	70.0
ESPh	0.0927	-0.4024	0.0	27.0
ESPh + WET FGD	0.2845	-1.3236	4.0	65.0
FBC[a] + FF	0.1394	0.1127	66.0	99.0
FF	0.1816	-0.4287	40.0	85.0
FF + wet FGD	0.1943	-0.2385	79.0	96.0
SDA + ESP	-0.1087	0.6932	5.0	25.0
SDA + FF	0.2854	-1.1302	0.0	99.0

[a] FBC = fluidized bed combustor

Table 3b. Parameters Used for Equations 1 and 2 Which Estimate Percent of Remaining Mercury in Gas that Is Elemental Mercury[18]

Existing Equipment	C_1	C_2	Minimum (%)	Maximum (%)
ESPc	-0.1283	1.23	12.0	85.0
ESPc + wet FGD	-0.039	1.11	81.0	98.0
ESPh	-0.1639	1.55	34.0	91.0
ESPh + WET FGD	-0.0945	1.45	80.0	99.0
FBC[a] + FF	-0.1198	1.2	44.0	68.0
FF	-0.1182	0.88	30.0	33.0
FF + wet FGD	-0.426	3.1	45.0	84.0
SDA + ESP	-0.0355	1.13	91.0	98.0
SDA + FF	-0.1125	1.48	64.0	99.0

[a] FBC = fluidized bed combustor

The correlations of Reference 18 should be used only for making approximate estimates.[19] Although the algorithm will provide reasonable estimates in most cases, Reference 19 showed that factors not addressed by these algorithms, such as fly ash characteristics or gas temperature, can have a significant effect on the mercury capture in existing facilities.

The capacity of PAC to adsorb mercury is large enough that it should not be limiting except at temperatures of about 350 °F (177 °C) or more, which is greater than the gas temperature at the exit of most air preheaters. So, with the possible exception of lignite coals, cooling usually has little or no beneficial effect on mercury absorption by PAC. However, the ability of fly ash and unburned carbon in the fly ash to absorb mercury is far less than that of PAC and may be enhanced by cooling. Therefore, although spray cooling may enhance mercury adsorption by fly ash and downstream capture in the ESP or FF, it is not expected to enhance mercury capture by PAC except in the case where lignite coals are burned. According to Reference 8, over 90 percent of the coals burned in the United States are bituminous, subbituminous, or blends of bituminous and subbituminous, which are not likely to use spray cooling with PAC injection. Therefore, spray cooling, which was evaluated in Reference 4, is not evaluated here.

4.0 EMERGING CONTROL TECHNOLOGIES

Based on published literature,[1,4,19-30] control technologies using injection of PAC into the flue gas appear to hold promise for reducing mercury emissions from utility boilers. These technologies have been applied successfully on municipal waste combustors (MWCs). Despite differences between MWCs and utility boilers (e.g., mercury concentration and speciation in the flue gas), full-scale and pilot-scale tests indicate that these technologies may be able to provide significant mercury removal from the flue gas of coal-fired utility boilers. Accordingly, this evaluation focused on the characterization of performance and costs of PAC injection-based technologies.

Other technologies have shown promise for control of mercury and other pollutants such as SO_2, NO_X, and PM. These multipollutant control technologies may offer cost-effective mercury control when considering the combined control of mercury with control of other pollutants. Multipollutant control technologies evaluated in this effort include ECO, advanced dry FGD, and a coal treatment technology known as K-Fuel.

This section begins with the description of PAC injection-based control technologies that can be retrofitted to existing boilers for control of mercury emissions, PAC injection estimates for these technologies, multipollutant control technologies that control mercury and other pollutants, and model plants used in this work. Subsequently, control technology applications on model plants used to develop cost estimates are discussed. Finally, this section discusses ECO, advanced dry FGD, and K-Fuel.

4.1 PAC Injection-Based Technologies

Injection of PAC for mercury emissions control has been developed and tested at the full scale on coal-fired utility boilers. Test programs have been performed on a utility boiler firing subbituminous coal with a downstream cold-side electrostatic precipitator (ESPc), on utility boilers firing bituminous coal with a downstream ESPc, and on a utility boiler firing bituminous coal with a Compact Hybrid Particle Collector (COHPAC) arrangement (upstream ESPh with downstream baghouse after the air preheater).[19,25–29] Using the data from these test programs and from pilot-scale testing, performance models were developed for PAC injection based mercury control applications.[19,30] These models are in a form where they can be updated as new information is developed on these applications and for other boiler applications.

4.1.1 Mercury Removal Models

If $f_{equipment}$ is equal to the fraction of mercury removed from the boiler gases by a specific piece of equipment, then $(1 - f_{equipment})$ equals the fraction of mercury remaining in the gases after that specific equipment. The fraction of mercury remaining after n pieces of equipment is equal to

$$[(1 - f_{equipment\ 1}) \times (1 - f_{equipment\ 2}) \times (1 - f_{equipment\ 3}) \times \ldots \times (1 - f_{equipment\ n})] \qquad \text{Eq. 3}$$

Therefore, the total mercury removal fraction, f_{Total}, is

$$f_{Total} = 1 - [(1 - f_{equipment\ 1}) \times (1 - f_{equipment\ 2}) \times (1 - f_{equipment\ 3}) \times \ldots \times (1 - f_{equipment\ n})] \qquad \text{Eq. 4}$$

If one of the pieces of equipment is PAC injection, then the total mercury removal fraction is

$$f_{Total} = 1 - [(1 - f_{equipment\ 1}) \times (1 - f_{equipment\ 2}) \times (1 - f_{equipment\ 3}) \times \ldots \times (1 - f_{PAC\ injection}) \times \ldots \times (1 - f_{equipment\ n})] \qquad \text{Eq. 5}$$

where $f_{PAC\ injection}$ is the fraction of mercury removed by PAC injection.

If PAC injection is simply added to existing equipment and the removal effects of the existing equipment are combined into one term, then we can represent Equation 5 as

$$f_{Total} = 1 - [(1 - f_{existing\ equipment}) \times (1 - f_{PAC\ injection})]$$

and, solving for $f_{PAC\ injection}$

$$f_{PAC\ injection} = 1 - [(1 - f_{Total}) / (1 - f_{existing\ equipment})] \qquad \text{Eq. 6}$$

where $f_{existing\ equipment}$ is the removal fraction associated with the existing equipment and may be approximated by Equations 1 and 2 in Section 3.5 of this document if the removal by existing equipment is not known. Given a total mercury reduction requirement and knowing the reduction by existing equipment, it is possible to determine how much additional reduction is necessary from PAC injection.

In this research, data from full-scale and pilot-scale tests of mercury reduction were used to formulate models for mercury reduction from existing equipment and from PAC injection. Full-scale

data for mercury removal by existing equipment are available from the ICR data. Full-scale testing results of mercury reduction from PAC injection are available from the Department of Energy's field testing programs at Southern Company's Gaston Plant, Wisconsin Electric Power Company's Pleasant Prairie Power Plant (PPPP), and at PG&E Corp. National Generating Group's Brayton Point and Salem Harbor Plants.[19]

4.1.2 Mercury Reduction by PAC Injection

Reference 4 has algorithms developed from pilot-scale data for mercury reduction on boilers equipped with PAC injection. The following model improvements, discussed in Reference 19, have been made:

1. The algorithms of Reference 4 were developed from pilot-scale tests and characterize total mercury reduction from both PAC injection and existing equipment as a function of PAC injection concentration. When using the algorithms of Reference 4, it is necessary to have a different PAC injection algorithm for each type of equipment configuration, including upstream and downstream equipment. These PAC injection algorithms may have to be updated as new information regarding mercury control from existing equipment becomes available. As described in Reference 19, the mercury reduction from PAC injection was isolated from that of the other equipment in Equation 5. Therefore, as more information on reduction of mercury from equipment other than PAC injection is developed, it should not be necessary to perform new regressions on the PAC injection models. Also, using Equation 5, it will also be possible to assess the fate of mercury in equipment that is either upstream or downstream of the PAC injection system.

2. The algorithms of Reference 4 are of a form in which it is possible to approach 100 percent mercury removal by injection of very high concentrations of PAC. As demonstrated at a full-scale demonstration at the Pleasant Prairie Power Plant, under some circumstances the mercury reduction by PAC injection can be limited to something well below 100 percent.[28] Therefore, the algorithm for mercury reduction from PAC injection was modified as described in Reference 19 and in the following paragraphs to permit an upper limit to mercury removal that may be less than 100 percent.

3. Because the algorithms of Reference 18 for mercury reduction from existing equipment are based on the full-scale ICR data, it is desirable to use them to characterize mercury reduction from existing equipment. However, it is not possible to integrate the algorithms of Reference

4 into the approach used in Reference 18. By treating the mercury reduction from PAC injection independently from mercury reduction from other equipment, it is possible to use the algorithms of Reference 18 to characterize mercury reduction from existing equipment.

Because mercury reduction by PAC injection may be limited to a value well below 100 percent, as identified in the second point, the equation that is used in Reference 4 to characterize the relationship between mercury reduction and PAC injection

$$\% \text{ reduction} = 0 = 100 \times f_{\text{from PAC injection}} = 100\text{-}[A/(M+B)^{C}] \qquad \text{Eq. 7}$$

where M is the mass injection rate of PAC (in lb/MMacf) so that

$$M = \{[A/(100 - 0)]^{(1/C)}\} - B \qquad \text{Eq. 8}$$

was modified in Reference 19 to be

$$M = \{[A/((100\times D) - 0)]^{(1/C)}\} - B \qquad \text{Eq. 9}$$

where D is the fraction of mercury reduction that is asymptotically approached.

A set of constants A, B, C, and D are specified for a given existing plant configuration, coal type (bituminous or subbituminous), PAC sorbent type, and retrofit configuration (PAC alone or PAC plus retrofit fabric filter). These constants are based upon full-scale data where available and based upon pilot-scale data or input from experts in this technology where full-scale data are not available. Reference 19 showed that, for systems with FFs, all of the PAC-based sorbents appeared to offer similar performance in terms of PAC injection concentration (in lb/MMacf) necessary for a given mercury reduction. On the other hand, for units with ESPs and without a fabric filter, PAC selection did have a significant effect on performance.

The constants A, B, C, and D are determined based upon a PAC injection matching key, which is a five-digit number composed of the following elements:

- Existing Particle Control Equipment (10000, 20000, 30000 for FF, ESPc, ESPh, respectively)
- The SO_2 control technology, if any (0, 1000, or 2000, or 3000, for none, FGD, SD, or advanced dry FGD, respectively)

- The fuel type: (100 for Bituminous or 200 for Subbituminous)
- Whether an additional FF will be retrofit (0 or 10 for none or FF, respectively)
- The PAC capacity (1 for high, 2 for medium, and 3 for low—In Reference 19, PAC selection appeared to make a difference for facilities with ESPs but not for facilities with FFs)

For example, ESPc SD Bituminous FF med (Matching Key # 22112) indicates a Bituminous coal-fired boiler currently equipped with a spray dryer absorber and an ESPc that will retrofit PAC injection (medium capacity) and a fabric filter. The list of constants used for Equation 9 in this work is shown in the Appendix 2. The matching key above will be used to determine the set of constants used for Equation 9 to estimate the PAC injection concentration.

Equation 9 is used to determine PAC injection rate is the following manner. If $f_{\text{existing equipment}}$ is greater than or equal to f_{Total}, then no additional mercury removal is necessary, and addition of PAC injection or any other technology to remove mercury is unnecessary. However, if $f_{\text{existing equipment}}$ is less than f_{Total}, additional mercury removal is necessary through retrofit of another technology, in this case PAC injection. Using Equation 6, it is possible to determine the amount of mercury reduction that must be performed by injection of PAC. Keeping in mind from Equation 7 that

$$0 = 100 \times f_{\text{from PAC injection}},$$

Equation 9 is then used to determine the injection concentration (M) of PAC (in lbs/MMacf). M is then multiplied by the total gas flow rate to determine the injection rate of PAC (in lbs per hour).

4.2 Emerging Control Technologies

Certain emerging technologies appear to offer significant potential for the combined reduction of mercury and SO_2, or of mercury, NO_X, and SO_2. The technologies of interest that are evaluated in this report include

- Electro catalytic oxidation (ECO)
- Advanced dry FGD
- K-Fuel

These technologies generally have limited commercial experience on coal-fired utility boilers, but experience with the technologies in other applications or experience with related technology may be extensive. In the case of ECO, for example, this is a unique technology with limited experience beyond the development and demonstration efforts currently underway in the United States. Some elements of the ECO process—ammonia scrubbing and wet ESPs—are well-established technologies, however. Wet ESP's, while not used widely in the utility industry, have a large experience base in other industries. Advanced dry FGD has experience on other applications and is also closely related to spray dryer absorber technology, which has extensive experience on coal-fired utility boilers. K-Fuel is an approach for beneficiating western fuels, especially Powder River Basin coals. K-Fuel removes moisture (increasing heating value), nitrogen (reducing NO_X), sulfur (reducing SO_2 emissions), and mercury (reducing mercury emissions). K-Fuel has been tested on utility boilers and a commercial production plant is under construction. Therefore, each of these technologies appears to have promise, may be used in the near term, and can be analyzed with some confidence. However, because of the limited experience with these technologies in coal utility applications, the results of the analysis shown here should be considered preliminary.

4.2.1 Electro Catalytic Oxidation (ECO)[31–34]

ECO technology has been developed by Powerspan. It is expected that the ECO system would be installed downstream of the existing ESP or FF, as shown in Figure 5.

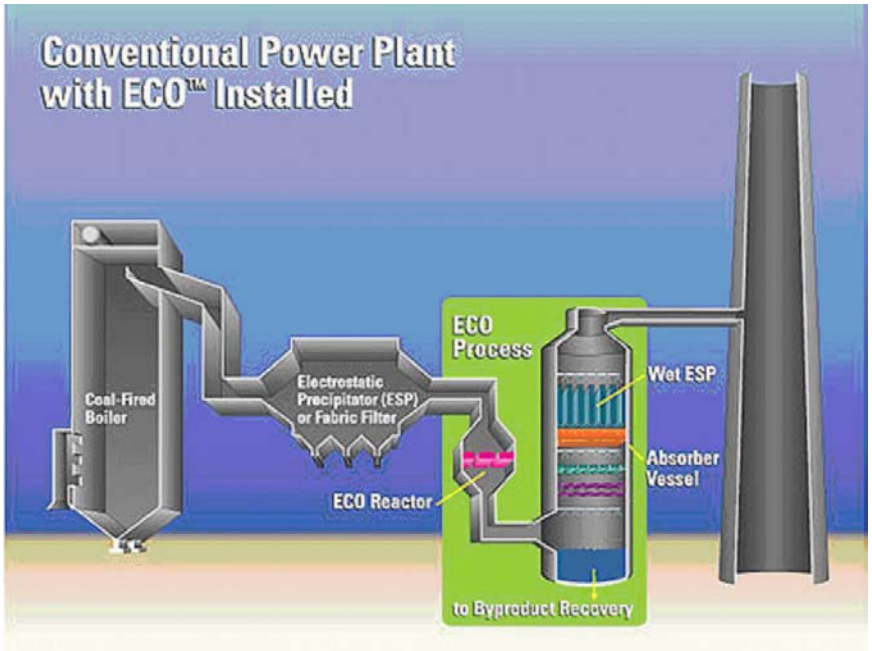

Figure 5. Location of ECO installation in a power plant.[31]

This technology consists of

- A dielectric barrier discharge reactor that induces oxidation of pollutants
- A two-loop ammonia scrubber tower that removes SO_2 and water-soluble oxidized forms of the pollutants
- A wet ESP that removes acid mist and fine particles
- A co-product (saleable fertilizer by-product) processing and mercury removal system that removes mercury with carbon filters and crystallizes the ammonium nitrate and ammonium sulfate fertilizers from the scrubber tower.

In the dielectric barrier discharge reactor, the following happens:

- NO gas forms nitrogen dioxide (NO_2) gas and nitric acid (HNO_3) aerosol mist.
- SO_2 gas forms sulfur trioxide (SO_3), leading to the formation of sulfuric acid (H_2SO_4) aerosol mist.
- Hg^0 vapor forms HgO particles.

Figure 6 shows a detailed process flow diagram for an ECO application.

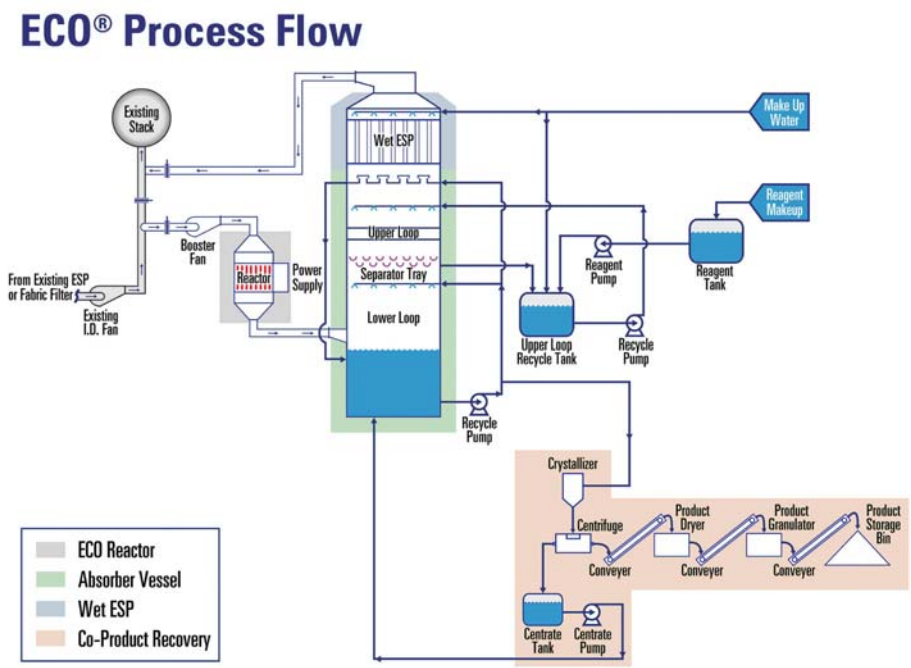

Figure 6. Detailed process flow diagram of ECO.[33]

The water-soluble forms of the oxidized pollutants—HNO_3 and H_2SO_4—are removed in an absorber tower that is equipped with a wet ESP. The absorber tower is a two-stage process with an absorption stage (at the top of the tower) for absorbing the pollutants and a concentrating stage at the bottom. An aqueous ammonia solution is used as the scrubbing agent to absorb SO_2 and convert the absorbed SO_2, nitric acid and sulfuric acid to ammonium nitrate and ammonium sulfate, respectively. NO_2 reacts with ammonium sulfite [$(NH_4)_2SO_3$], which forms in the scrubbing liquor, to form ammonium sulfate [$(NH_4)_2SO_4$] and N_2. With 90 percent NO_X reduction, about 40 percent of the NO_X becomes nitrate and about 50 percent becomes NO_2 and ultimately N_2. Thus, some of the NO_X is ultimately converted to ammonium nitrate and the remainder is ultimately converted to N_2. All of the SO_2 removed is ultimately removed in the form of ammonium sulfate. Mercury collected in the absorber tower water is removed from the liquid stream by an activated carbon filter. Acid mist and fine particles removed in the wet ESP drain into the absorber tower and are removed in the liquid discharge of the lower loop. Due to chemistry considerations of the absorber tower, the ECO process works best if the SO_2 to NO_X ratio in the flue gas is equal to 3 or more on a molar basis.

The consumables and the by-products of the ECO process include

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.[33]
- Heat for the by-product crystallizer.[33]
- Ammonia reagent, which can be estimated as roughly two moles of ammonia per mole of SO_2 removed. Additional amine is provided by other chemicals discussed below.
- Make-up water for the absorption tower—about 1 gal/min per MW—no special quality specification.[33]
- Carbon filters for mercury removal from the liquid discharge of the absorber.[33]
- Additional, proprietary chemicals that provide the balance of the amine for the conversion of NO_X to ammonium nitrate and SO_2 to ammonium sulfate. These are estimated at around \$150/ton of NO_X removed and \$15/ton of SO_2 removed.[33]

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 one mole of ammonium sulfate is produced for every mole of SO_2 reduced.[33]
- Mercury captured on the activated carbon (a waste to be disposed of) at a cost of about \$1000/lb of mercury captured.[33]

- 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.[33]
- Water vapor.[33]

Experience

The ECO technology has been demonstrated in the laboratory and on a 2000 scfm pilot at First Energy's Burger Plant. The pilot has been operating since March 2002. A 50 MW commercial demonstration system is currently being built at Burger Station. The commercial demonstration unit at Burger Plant is designed to handle 110,000 scfm of gas flow.[34]

Capital Cost

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 $114,500,000, inclusive of process equipment, general facilities, owner's costs, and contingencies. This also included the fertilizer plant and balance of plant modifications.[35] It is the only comprehensive, full-scale cost analysis that has been made available publicly. Therefore, a cost of $200/kW is a reasonable estimate to use. Reference 33 confirmed this estimate.

Operating Cost

Variable operating cost is the cost of power and other consumables. Ammonia consumption is determined by the molar ratio described above under Consumables. Specialty chemical costs are estimated at $150/ton of NO_X removed and about $15/ton of SO_2 removed, based upon information from Reference 33. Reference 33 also provided information on power consumption requirements for both the ECO reactor and auxiliaries, described in the next section. 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.[33] 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 3 operators and one maintenance person per shift.[33] The manpower needs are not expected to be a significant function of unit size.[33]

Pollutant Removal Efficiencies and Power Consumption

Because ECO is a true multipollutant process that can remove NO_X, SO_2, mercury, and fine particles, the effectiveness of the process can depend upon several variables, and there may be some interrelationships. However, a typical coal system would be designed for the removal efficiencies shown in Table 4.[33]

Table 4. ECO Pollutant Removal Efficiencies[33,35]

Pollutant	Removal Rate	Conditions
SO_2	98%-99%	Any inlet condition
NO_X	90%	Up to 250 ppm or up to about 0.450 lb/MMBtu[a]
Hg	80%-90%	Any inlet condition
Fine Particles	95%	(Outlet to less than 0.004 lbm/MMBtu)

[a] At higher NO_X levels, 90% reduction is achievable at higher ECO reactor power levels.

The ECO system tends to operate best when the molar SO_2 to NO_X ratio is 3.0 or greater.[33] Although ECO can operate at lower ratios, the reliability of both performance and cost predictions may be somewhat less.

The power for the dielectric barrier discharge reactor is largely determined by both 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 information from Reference 33, this work assumes that reactor power (in watts/scfm) is equal to the lesser of 20 watts/scfm or $58.220(NO_X) - 6.2431$ (see Figure 7), where NO_X is measured in lb/MMBtu. 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.

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. Although the fertilizer auxiliary costs are more closely related to the SO_2 being removed, a single percentage is used for simplicity.[33]

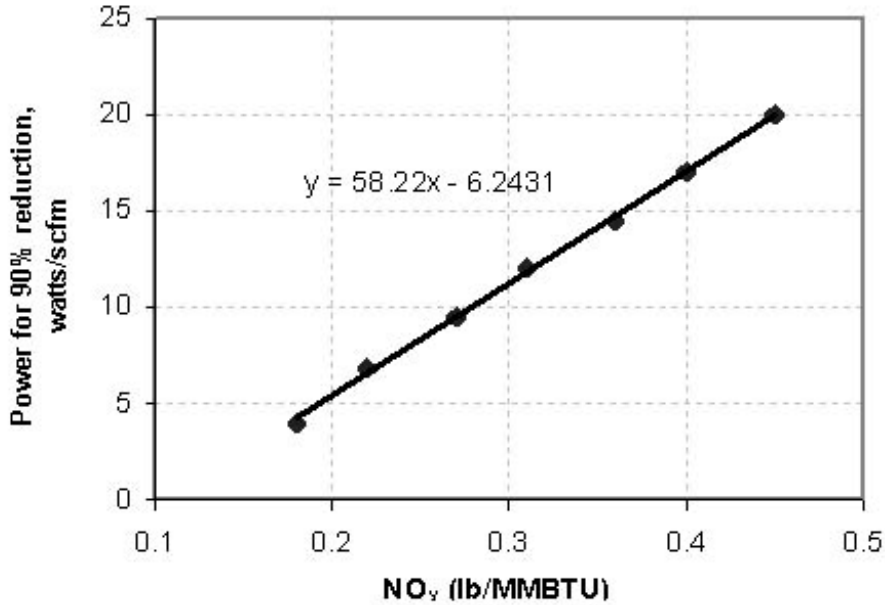

Figure 7. ECO power consumption versus NO_X.[33]

Calculation Methods

A worksheet titled ECO Cost and Performance was developed. Inputs for other calculations were largely taken from CUECost worksheets and the Plant Configuration Inputs and the Constants_CC worksheets. Inlet gas conditions are taken as the outlet of the air preheater except for particle loading, which is reduced due to the ESP or FF. Relationships for mass balances were developed from the information provided above regarding consumables, and relationships for power consumption were developed from information discussed regarding power consumption.

As noted earlier, the reliability of the algorithms used for predicting ECO system performance and cost may be somewhat reduced for molar SO_2 to NO_X ratios below 3.0. Therefore, the worksheet includes warnings when the inlet SO_2 to NO_X ratio is below this value. Low SO_2 to NO_X does not mean that the output is incorrect or that ECO cannot be used. It simply means that the calculations are somewhat less reliable, and it would be advisable to consult with the technology supplier for more information.

4.2.2 Advanced Dry FGD[36-39,41-47]

Dry FGD reacts hydrated lime slurry with exhaust gases in an absorber vessel to capture SO_2, SO_3, HCl, and mercury that may be present in the exhaust gases. The exhaust gases are maintained above saturation temperature to avoid condensation. The by-product of dry scrubbing can usually be landfilled safely or, in some cases, reutilized for another purpose.

Advanced dry scrubbing is intended to improve performance over conventional spray dryer absorbers. Advanced dry scrubbing utilizes a fluidized bed or a flash dryer for the reactor with recycle loops to enhance lime utilization. Figure 8 shows a diagram of the FLS AirTech Gas-Solid Absorber installed upstream of an ESP. Many systems use venturi mixers to introduce the sorbent slurry. The high solids loading in the reactor provides high gas-solids interaction and high solids-solids interaction. The high solids-solids interaction allows reactive particle surface to continuously be exposed as the particles impact one another. The solids-solids interaction also causes some agglomeration of fine particles to form larger particles that are easier to capture in downstream equipment. Because the reactions occur more efficiently in the reactor and because the particles are larger, Advanced dry scrubbing does not require a downstream fabric filter for the SO_2 removal reaction to be completed. When a cyclone is used for recycle to produce a lower outlet particle concentration, a smaller downstream particle collection device is needed. In this case, the technology can often be installed upstream of the existing ESP, as shown in Figure 9. Without the cyclone, it is likely that the existing ESP will require some modifications to improve collection efficiency, or a new particle collection device may be necessary. However, in many cases it is envisioned that the absorber will be installed downstream of the existing ESP so that fly ash does not get contaminated and can continue to be sold. In this case, an additional particle removal device will be necessary, as shown in Figure 10.

Some fly ash is beneficial to mercury capture in the absorber, especially for subbituminous coal.[36] Reference 36 also indicated that 98 percent mercury capture is possible for bituminous coal. The fly ash also helps to improve the qualities of the solid by-product, making it more suitable for use as fill or for sale of cement-like products.

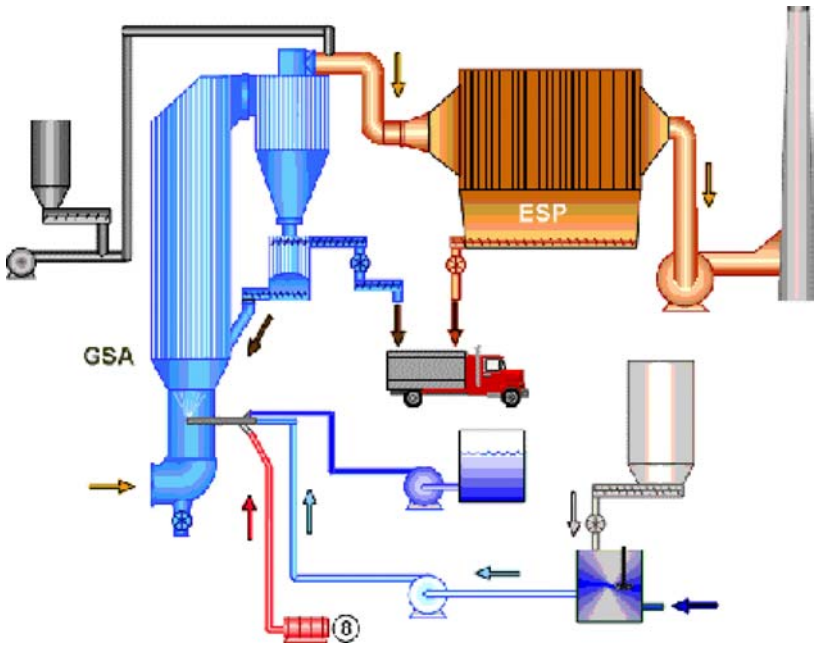

Figure 8. F.L. Smidth AirTech Gas-Solids Absorber (GSA).[37]

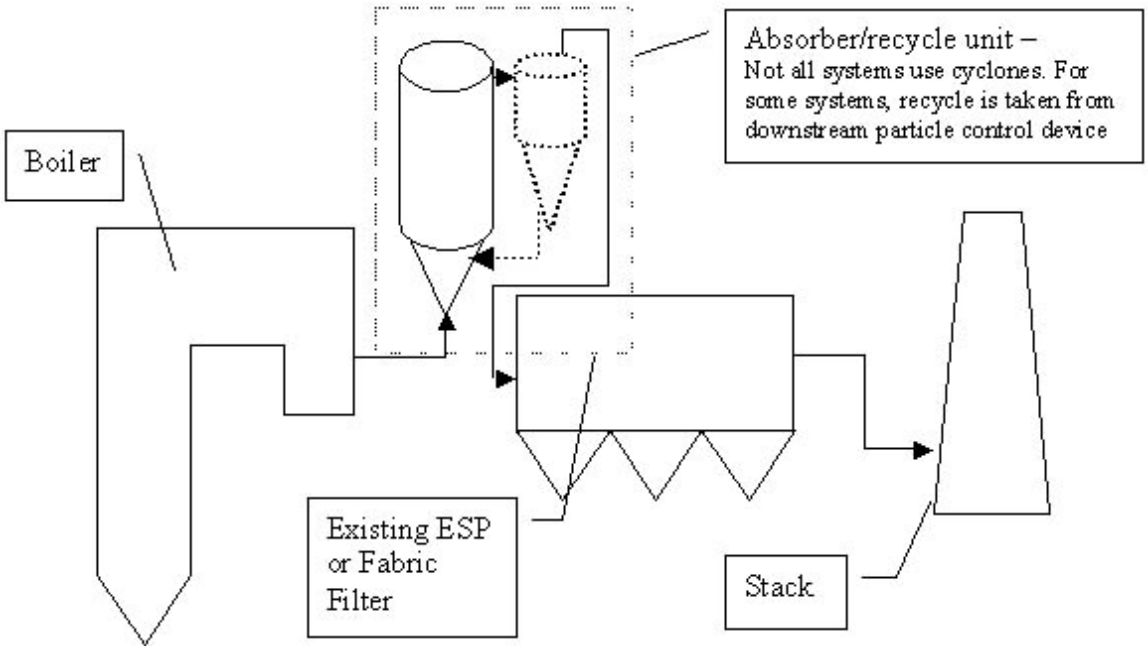

Figure 9. Installation of an advanced dry FGD upstream of an existing ESP.

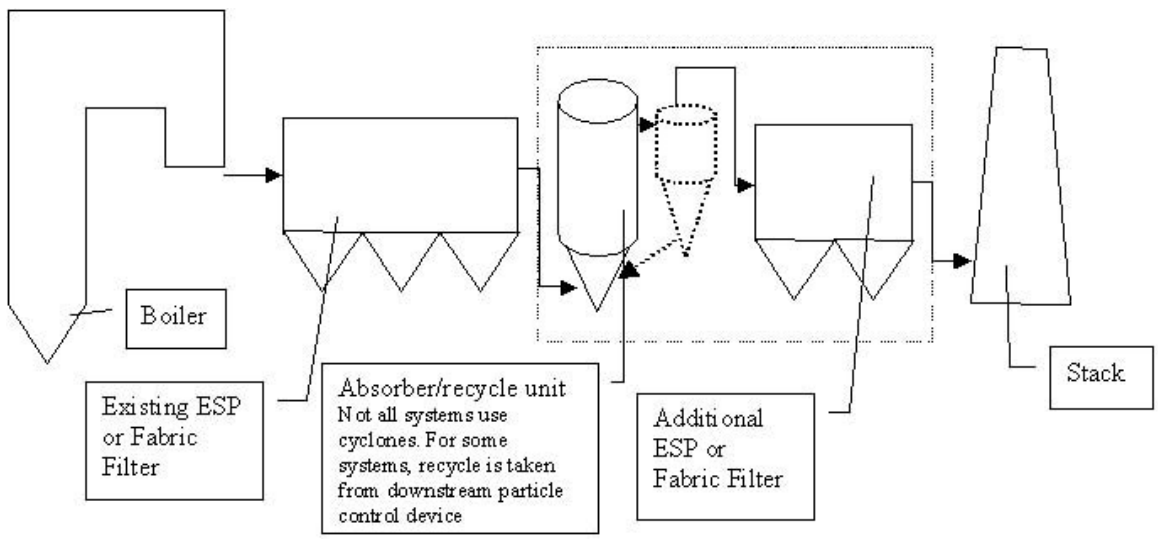

Figure 10. Installation of an advanced dry FGD downstream of an existing ESP.

There are a number of companies that supply different versions of advanced dry FGD technology: Lurgi Lentjes, F.L. Smidth AirTech's Gas Suspension Absorber (GSA), RJM Beaumont's Rapid Absorption Process (RAP), and WULFF. The advanced dry scrubbing systems all use hydrated lime slurry as the principal reagent to remove SO_2 and can remove mercury as well. Figure 11, which is the published performance of three different advanced dry scrubber systems,[40,43,46] shows that the SO_2 removal efficiency is a strong function of stoichiometric ratio, approach-to-saturation (ATS, expressed in degrees Fahrenheit), and chlorine content. Data is shown for chlorine contents of 0.04 percent (400 ppm) and 0.12 percent (1200 ppm). Stoichiometric ratio is defined as moles Ca/molesSO_2. As shown, ATS, fuel chlorine content and lime stoichiometry determine the SO_2 removal efficiency. For any given ATS, chlorine level, and stoichiometric ratio, all technologies offer similar SO_2 removal. For example, note that the GSA 18 deg and 1200 ppm Cl line, if continued, would closely follow the RAP 18 degree line. Since all versions of advanced dry FGD offered by the different suppliers rely on the same chemistry, similar performance would be expected for a specific set of conditions.

Although advanced dry FGD has not been as widely used as SDA technology, there is significant operating data on it for pulverized coal-fired applications. Moreover, the chemistry of SO_2 capture is very similar to that of SDA technology. For the analysis of this report, algorithms were developed to predict performance. To calculate lime feed necessary for a particular level of SO_2 reduction, Figure 11 was re-plotted as stoichiometry versus SO_2 reduction, and curves were fit based on ATS and chlorine content of the coal. The results are shown in Figure 12.

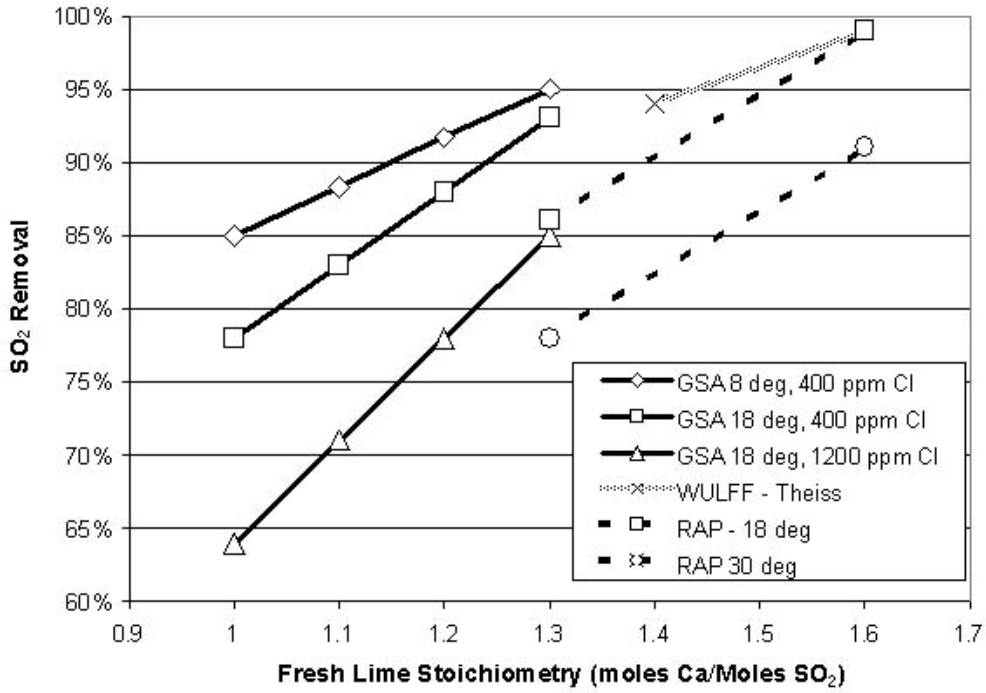

Figure 11. Advanced dry scrubber SO_2 removal performance.

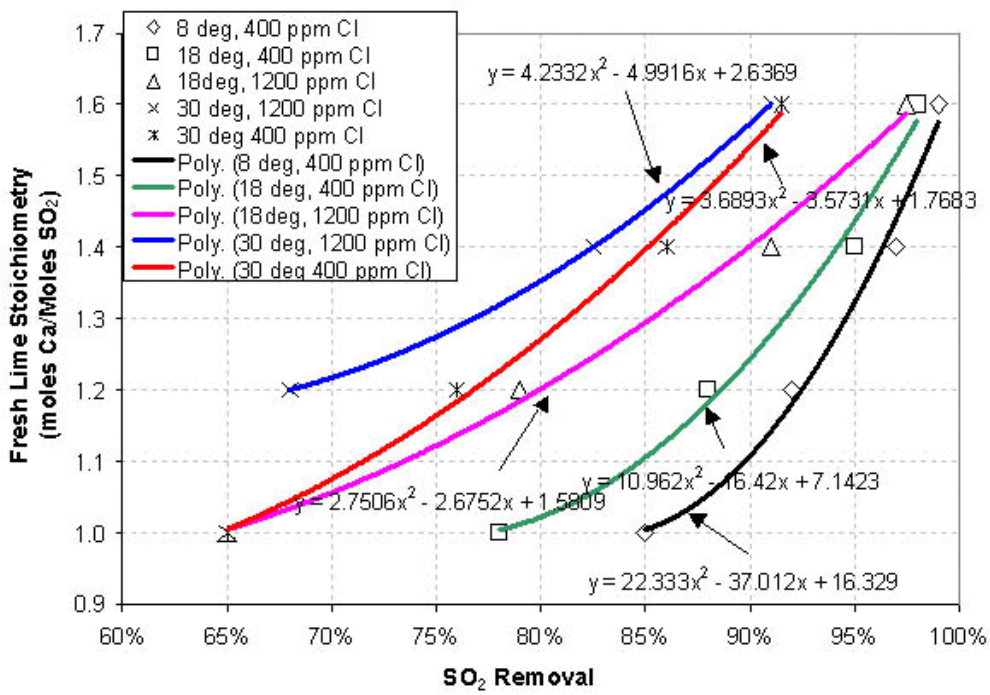

Figure 12. Advanced dry scrubber performance.

At this time, some suppliers of this technology limit the gas-flows per reactor to an equivalent of around a 125-150 MW plant.[38] On the other hand, Lurgi has supplied single-reactor systems as large as 250 MW and expects to be able to supply single reactor systems as large as about 400 MW.[39] WULFF has supplied single-reactor systems as large as 300 MW.[40] As a result, in some (but not all) cases it may be necessary to have more absorber towers than for conventional spray dryers. For this reason, a design of a RAP system for a 500 MW boiler may require as many as four reactors and a 250 MW system may require as many as two reactors.[41] Some other suppliers may not require as many reactors.

Limited experience has shown high mercury removal rates. Testing of mercury control from the Roanoke Valley Energy Facility showed that the Lurgi-designed system provided in excess of 95 percent mercury removal from the 55 MW Unit #2 while firing eastern bituminous coal.[42] For subbituminous coals, where there is lower chlorine content and a greater proportion of elemental mercury versus total mercury as compared to bituminous coals, lower capture efficiencies may be expected with normal lime sorbent. However, activated carbon or other specialized sorbents may offer the potential to capture more mercury. RJM-Beaumont Environmental Systems offers oxidized calcium sorbent that they claim is effective in removal of SO_2 and mercury.[43]

The consumables and the by-products of the ECO process include

<u>Consumables</u>

- Electric power for the booster fan, pumps, blowers, and reagent preparation
- Lime – normally delivered as dry lime and hydrated to hydrated lime
- Water – for producing hydrated lime and for gas cooling
- Costs associated with downstream particle removal (energy, fabric filters, etc.)

The algorithms of Figure 19 are used to calculate lime feed necessary for a particular level of SO_2 reduction.

<u>By Products</u>

- Calcium sulfate, calcium sulfite, a small amount of unreacted sorbent, ash and other solids collected in the downstream particle collection device. Based upon review of process designs from different suppliers, the approximate amount of this is 2.5-2.8 lbs/lb of sorbent injected. Most often the by-products are landfilled, but they can occasionally be re-used.
- Water vapor that goes up the stack

Experience

This technology has been widely used on incineration systems and to a lesser degree on coal-fired boilers. Lurgi has supplied the technology to a 250 MW plant in Puerto Rico, to the 55 MW Roanoke Valley facility in North Carolina, to the Black Hills Power & Light (Gillette, WY) plant, and to nine coal-fired plants in Europe.[44] WULFF has supplied the technology for the 300 MW coal- and oil-fired Theiss plant in Austria. There is significant commercial experience on coal as a result of these installations.[40]

Capital Cost

Information from technology providers suggests that the installed cost of a reactor and all material handling equipment excluding any downstream particle control device (ESP, FF, or cyclone) is roughly $35/kW for 250 MW or 500 MW systems.[41,45] It may then be necessary to add the cost of the equipment and installation of a FF or an ESP, associated material handling equipment, ductwork, fans, and other equipment, which could cost up to an additional $60/kW. Total cost of process capital, therefore, is in the range of $100/kW. Additional costs associated with the project, such as engineering and construction management, allowance for funds during construction, contingency, and general facilities would increase the total cost to above $100/kW. This is consistent with Reference 46, which estimates the cost of an F.L. Smidth AirTech Gas Suspension Absorber system at $149/kW (1990 dollars) for a 300 MW plant. It is unclear from Reference 46 whether or not this cost includes the downstream ESP, but it does include the cost of the cyclone separator in the recycle system. Table 5 provides a cost estimate for a Lurgi Lentjes CFB-FGD system at a 500 MW plant and shows a $150/kW cost estimate. Therefore, a cost of about $150/kW appears to be consistent among several sources and will be used here.

Operating Costs

The principal variable operating costs are for lime reagent, water, power, and solid disposal. The preceding discussion described how lime consumption is determined. Water consumption (city water is considered adequate quality—demineralized water is not required) is determined by the slurry concentration. Booster fan power for the reactor and cyclone is estimated from gas flow rate (actual cubic feet per minute) and pressure drop assuming a blower efficiency of 65 percent, and material handling power is estimated at 0.1144 hp/lb/h of lime feed.

Table 5. Estimated Cost of CFB-FGD System for a 500 MW Plant Burning PRB Coal

Subsystem	Cost, U.S. $	$/kW
Reagent Feed Syatem	5,000,000	10.0
SO_2 Removal System	7,000,000	14.0
Particulate Collector	16,000,000	32.0
Flue Gas System	7,000,000	14.0
Waste Handling and Recycle System	7,000,000	14.0
General Support Equipment	4,000,000	8.0
Miscellaneous Equipment	6,000,000	12.0
Total Process Capital (TPC)	52,000,000	104
General Facilities (A, 5% of TPC)	2,600,000	5.2
Engineering and Construction Management (B)	5,200,000	10.4
Project Contingency (15% of TPC+A+B))	8,970,000	17.9
Total Plant Cost (TC)	68,770,000	137.5
Allowance for Funds (3.2% of TC)	2,201,000	4.4
Owner's Cost (5% of TC)	3,439,000	7.0
Total Plant Investment (TPI)	74,410,000	148.9
Inventory Capital (spare, 1 % of TPI)	744,000	1.5
Royalties	0	0
Total Capital Requirement	**75,154,000**	**150**

4.2.3 K-Fuel

K-Fuel is a beneficiated coal that is derived from western 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 combustion, the need for post-combustion controls may be reduced.

The K-Fuel Coal Beneficiation Process[48,49,50]

The K-Fuel process employs both mechanical and thermal means to increase the quality of the coal by removing moisture, rock, sulfur, mercury, and other heavy metals. To begin the process, coal is delivered to the K-Fuel processing plant from the mine. The coal enters the first stage separator, developed using conventional coal cleaning technology, where it is crushed and screened

to remove the large rock and rock material. The processed coal is then passed on to an intermediate storage facility prior to being sent to the next stage in the process, as shown in Figure 13.

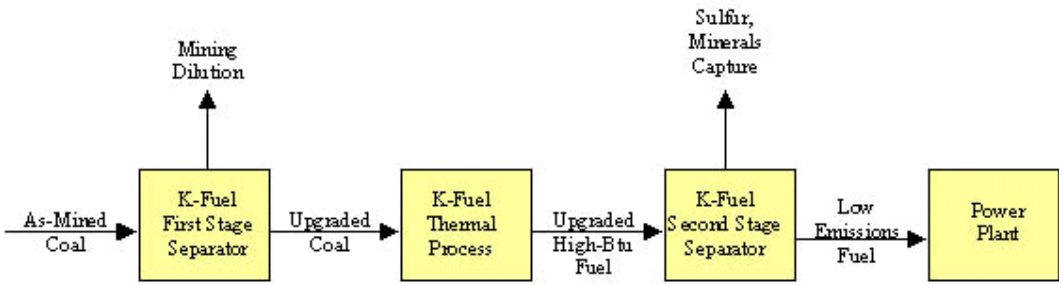

Figure 13. Overall schematic of K-Fuel processing plant.[48]

From the intermediate storage facility the coal is sent via a distribution system to the K-Fuel thermal processing unit (Figure 14). This process employs Lurgi Mark IV vessels under high pressure and temperature to place thermal stress on the coal. The coal passes through pressure locks into the processors, and then steam at 460 °F (238 °C) and 485 psi is injected into the processors. While the coal is maintained at these conditions, the mineral inclusions are fractured under the thermal stress, removing both the included rock (which contains some mercury) and sulfur-forming pyrites. The inherent moisture of the coal is liberated as well.

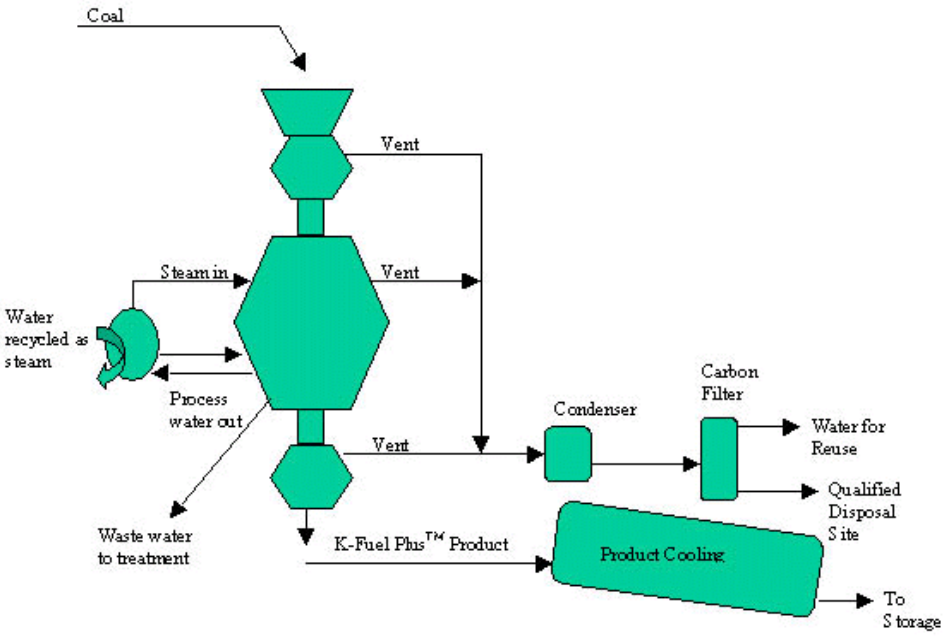

Figure 14. K-Fuel thermal processing plant.[48]

After it has been treated in the main processor, the processed coal is discharged into a second pressurized lock, which is then sealed off from the primary reactor. After sealing, the processor pressure is vented into a water condenser to return the processor to atmospheric pressure, and to flash cool the coal to approximately 200 °F (93 °C). The coal is then discharged onto a belt and further cooled by convection and indirect cooling. After cooling, the coal is sent on to a second stage separator for additional screening to remove sulfur- and mercury-containing mineral matter which has been liberated by the thermal process. Mercury that is released from the coal during thermal treatment is captured in a carbon filter. The carbon filter can then be disposed.

Pollutant Reduction Performance

Test burns of coal treated with the K-Fuel Process showed reductions in NO_X and SO_2 emissions. Figure 15 shows SO_2 and NO_X emissions for two coals that were tested—with and without K-Fuel treatment—and emissions from an eastern bituminous coal.[48]

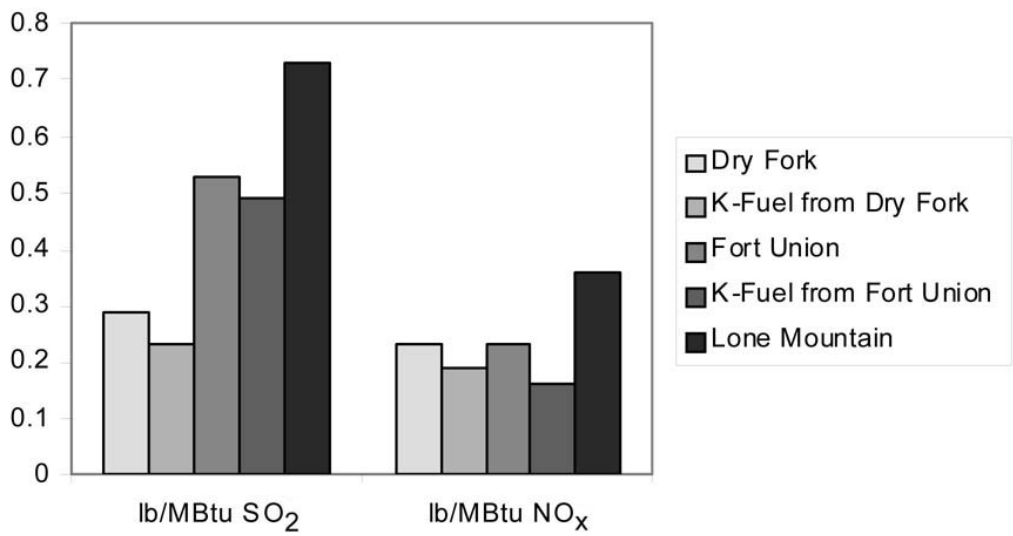

Figure 15. SO_2 and NO_X emissions from test burns of K-Fuel and untreated fuels.

Because the K-Fuel process simultaneously reduces the mercury content of the coal and increases its Btu value, there is a significant overall mercury emission reduction on a heating value basis. Table 6 below compares the fuel analysis of a typical PRB coal used for the analysis of this report

and a similar analysis of K-Fuel that was assembled from information provided by KFx Corporation.[49] The table shows that mercury content of the K-Fuel derived from Cordero Mine is about 43 percent lower on a mass basis and about 60 percent lower on a Btu basis than the PRB coal used in this comparison. This is consistent with the roughly 65 to 70 percent mercury reduction reported in Reference 48 for the K-Fuel process when applied to different PRB coals.

Table 6. Comparison of Typical PRB Coal with K-Fuel

Contents	Coal Type	
	PRB	K-Fuel
Proximate Analysis (ASTM, as received)		
Volatile Matter (wt%)	30.79	40.20
Fixed Carbon (wt%)	32.41	45.50
	100.00	99.62
Ultimate Analysis (ASTM, as received)		
Moisture (wt%)	30.40	7.50
Carbon (wt%)	47.85	66.70
Hydrogen (wt%)	3.40	4.80
Nitrogen (wt%)	0.62	1.00
Chlorine (wt%)	0.03	0.03
Sulfur (wt%)	0.48	0.38
Ash (wt%)	6.40	6.42
Oxygen (wt%)	10.82	13.20
Total (wt%)	100.00	100.03
Mercury (mg/kg)	0.07	0.04
Modified Mott Spooner HHV (Btu/lb)	8304.	11,718.
Coal Ash Analysis (ASTM as received)		
SiO_2 (wt%)	31.60	28.40
Al_2O_3 (wt%)	15.30	17.30
TiO_2 (wt%)	1.10	1.60
Fe_2O_3 (wt%)	4.60	6.00
CaO (wt%)	22.80	23.50
MgO (wt%)	4.70	4.00
Na_2O (wt%)	1.30	1.40
K_2O (wt%)	0.40	0.27
P_2O_5 (wt%)	0.80	2.43
SO_3 (wt%)	16.60	13.63
Other Unaccounted for (wt%)	0.80	1.47
Total (wt%)	100.00	100.00

Experience

The K-Fuel Process has been tested at the pilot stage, and construction of a commercial plant is planned for this year.[48,50] Lurgi is providing much of the process reactor technology. The first commercial plant is to be built at the Black Thunder mine in Wright, WY. Construction is currently scheduled to start in mid-2003, with completion expected in the first half of 2004. The plant is expected to produce more than 700,000 tons per year of K-Fuel Plus. This plant is intended to not only prove the commercial value of the technology but to also provide a basis for optimizing the technology, and thus, it is designed for the possibility of future expansion on site.[48,50]

Technology Cost

For the purpose of this program, the cost of the K-Fuel is going to be assessed on the basis of incremental fuel cost. K-Fuel may be utilized on any facility where it can be economically transported to the site.[50] According to Reference 50, some interior eastern bituminous fuel-fired boilers might consider K-Fuel over PRB because K-Fuel will avoid retrofits that may be necessary to avoid derates that might otherwise occur when switching from bituminous coal to PRB coal. Reference 50 discusses possible delivered prices ranging from $20 to $32 per ton of coal. At this price range and a heating value of about 11,700 Btu/lb, the K-Fuel has an estimated price of about $1.20-$1.36/MMBtu, which makes it competitively priced on a Btu basis with many bituminous coals and somewhat more expensive than PRB coals. $20/ton would equate to only about $0.85/MMBtu, which makes it cost competitive with (and in some cases less expensive than) PRB coals according to the fuel cost information in Reference 50. There is a chance that some retrofit costs might be incurred by switching from bituminous or PRB coals to K-Fuel, but these capital costs will be relatively small and will be dominated by the fuel costs in most cases. As a result, the cost analysis performed here will focus on incremental fuel cost as the major cost of using K-Fuel. Incremental costs of control may be incurred if mercury removal technologies, such as PAC injection, are retrofit to reduce mercury emissions further.

5.0 TECHNOLOGIES CURRENTLY UNDER DEVELOPMENT

There are several multipollutant control technologies that are currently under development or nearing commercial status in the United States. These, and other technologies, may emerge in a relatively short time depending on the results of on-going tests as well as the demand for mercury and multipollutant controls. Others may never reach commercial stage either because of technical problems or because of unfavorable economics relative to competing technologies.

For the purpose of this report, technologies currently under development were divided into three groups: employing oxidation (other than SCR), utilizing sorbents, and other technologies.

5.1 Oxidation Technologies

Oxidation technologies aim at oxidizing mercury in order to facilitate its subsequent removal in wet FGD or wet ESP. Examples of these technologies include LoTOx, PEESP, and ESP modification discussed below.

LoTOx

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 N_2O_5, and mercury to HgO. Subsequently, these compounds are removed in a wet FGD because they are water soluble. The LoTOx system consists of an integrated oxygen/ozone generation unit complete with ozone injection system either into the LoTOx 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. It is produced in response to the amount of NO_X present in the flue gas generated by the combustion or process source. 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 and Hg reactions.

PEESP

Plasma-Enhanced Electrostatic Precipitators (PEESP) technology offers the potential to enhance the ability of wet ESP to remove elemental mercury. 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. Greater than 80 percent total mercury removal is projected at pilot and full scale; bench scale testing demonstrated mercury removal of up to 83 percent.

ESP Modification for Mercury Oxidation

In this arrangement, a catalyst, most likely in honeycomb form, is inserted into the flue gas path upstream of the FGD system (last section of the ESP). This placement provides for low velocity and a relatively particulate-free flue gas. As a result, a close-pitched catalyst can be used. Downstream of the catalyst, the oxidized mercury is scrubbed in the FGD absorber, and co-precipitates with the calcium sulfite or gypsum byproduct. Preliminary cost estimates show that a catalytic process, if installed upstream of a wet FGD system, should allow plants to achieve 90 percent overall mercury control at a cost that is 50 percent less than by injecting activated carbon. However, the cost of the process will depend largely on the catalyst life and required catalyst volume. So far, only catalysts produced at a laboratory scale have been tested.

5.2 Sorbent Technologies

Sorbent technologies utilize improved dry sorbents to accomplish mercury removal in systems without wet FGD. Additionally, improvements in sorbents may help reduce the cost of controlling mercury. Novel sorbents discussed here include Amended Silicate, MerCAP, and Pahlmanite.

Amended Silicate

Amended silicate sorbents use a commodity substrate material impregnated with a chemical additive that binds mercury to the surface of the particles. The sorbents have been prepared in a number of formulations tailored to provide economic mercury recovery in multiple applications. In packed-bed tests these sorbents showed mercury removal of several times that of activated carbon. Pilot plant tests demonstrated 70–96 percent mercury capture at injection rates of 1.6–9.1 lb/MMacf, respectively. Out of the total removal, the injected amended silicate removed 40 percent or more of the mercury in the first one second of contact time in the pilot tests. Good stability of captured mercury on the sorbent was observed. When samples of sorbent mixed with fly ash were collected

from the pilot fabric filter hopper and subjected to Toxicity Characteristic Leaching Procedure (TCLP) tests; the leachate mercury levels were below the limit of detection. Preliminary process design and analysis indicate that amended silicates can be cost competitive with activated carbon for mercury control.

Mercury Control Adsorption Process

Mercury Control Adsorption Process (MerCAP) deploys a mercury adsorbing sorbent-coated cartridge placed in the flue gas duct at temperatures of 400 °F (204 °C) or less. Mercury is removed from the flue gas as it flows past the rigid structure. Once the cartridge is saturated with mercury, it can then be removed or regenerated in-situ. Sorbent materials that have been considered for MerCAP configuration include activated carbon or metals which can amalgamate with mercury, such as gold and silver. Pilot scale experiments indicated that a MerCAP with gold coated plates approximately 10 ft long and spaced 0.5 inches apart was placed downstream of the spray dryer/fabric filter could remove more than 80 percent of mercury from a low-rank fuel flue gas. In preliminary tests, MerCAP did not perform as well in nonscrubbed flue gas.

Pahlman Process

The Pahlman Process is a dry sorbent system comprised of two discrete steps. One step involves capturing 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 the 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 (MnO_2) in the form of fine black powder. The sorbent is injected in a reactor, which operates at temperature between ambient and 320 °F (160 °C). 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. Testing indicated above 99 percent SO_2, 93.6–96.6 percent NO_X, and up to 67 percent mercury reduction.

ROFA and ROTAMIX

ROFA (rotating opposed fire air) is a combustion control technology that employs staged combustion to reduce NO_X emissions. In the staged combustion, fuel is initially burned in a fuel-rich zone for low NO_X generation. The fuel-rich zone is followed by an OFA system that induces rapid mixing of burn-out air with furnace gases in the upper furnace region using highly-turbulent, rotating flow to complete fuel combustion while minimizing NO_X formation. When sorbent or NO_X-reducing chemicals (such as ammonia or urea) are added to the OFA ports, the technology is referred to as ROTAMIX. The NO_X-reducing chemicals reduce NO_X through selective non-catalytic reduction

reactions. The sorbent may be added for adsorption of SO_2 or mercury. Full-scale tests at Cape Fear Unit 5, firing eastern bituminous coal, showed that, in addition to the NO_X removal provided by the staged combustion and the baseline mercury removal from the existing ESP, up to 89 percent removal of mercury, 64 percent removal of SO_2 and 4 percent removal of NO_X was achieved by limestone injection. Addition of Trona produced results of up to 67 percent removal of mercury, 69 percent removal of SO_2 and 11 percent removal of NO_X. Slagging of the superheater by sorbent and ash was found to be a problem during the tests. However, it is believed that this problem might be avoided in the future through selection of injection locations at a lower temperature where ash softening is not as great.

5.3 Other Technologies

This group of technologies includes hybrid processes that accomplish mercury removal in a modified baghouse (Promoted MB Felt), by a combined dry and wet process (multipollutant control process), or in a regenerable sorbent bed (activated coke). These processes are presented below.

Promoted MB Felt

This process is centered on a proprietary, low-pressure, mercury-capturing filter fabric (Promoted MB Felt) incorporated into a pulse-jet baghouse. The fabric is designed in a way that allows for mercury capture to be segregated from particulate control, thereby avoiding fly ash contamination. Bench-scale experiments at 185 °C demonstrated approximately 75 mg Hg/(g filter medium) were captured. High mercury capture was later confirmed in a pilot plant over the course of seven weeks.

Multipollutant Control Process

This process involves sequential injection of dry sorbent and liquid oxidant to accomplish SO_2 removal and oxidation/removal of NO_X, and Hg in a multipollutant control reactor. The reactor consists of three sequential tubular sections followed by a fabric filter. The first vertical section is a humidifier, which is followed by two vertical sorption sections. Dry sorbent injection is located approximately one third from the top of the first sorption section. Liquid oxidant is dispersed into the flue gas at the top of the same section. Preliminary results from a 1 MW slipstream of a 300 MW low sulfur coal-fired boiler indicated SO_2, NO_X, and mercury removals across the reactor of up to 92, 80, and 68 percent, respectively. The extent of oxidation and subsequent removal of NO_X and mercury was a function of the type and amount of oxidizer used.

The Activated Coke Process

This process involves three steps: adsorption, desorption, and (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 [NH_4HSO_4]. Mercury can also be removed by adsorption on the coke at a rate of up to 1.7 mg/g of activated coke at a temperature below 180 °C and condensation in the middle of desorber where the coke is about to be heated for regeneration. Therefore, mercury can be removed by extracting the coke in the middle of desorber. One method being considered for removing mercury is the use of a selenium filter, which absorbs the mercury from the flue gas and forms HgSe, a chemically stable compound. The selenium filter is expected to have 98 percent Hg collection efficiency during the filter life (usually 4-5 years).

6.0 COSTS OF REDUCING MERCURY EMISSIONS

The costs of controlling any pollutant are composed of capital costs associated with installation of the equipment and the operating costs associated with operating the equipment. In this report, these costs are estimated and assessed on a mills/kWh (or $/MWh) basis. In this effort, costs are determined on a constant dollar basis—that is to say that the costs are represented in 2003 dollars and the effects of general inflation are, therefore, normalized. We also assume that the escalation of operating costs equals the general inflation rate. Therefore, inflation is assumed to offset escalation so that the levelization factor for operating costs is equal to 1.0.

The approach to assess costs included the use of EPA's CUECost model and additional worksheets that are specific to the technologies of interest. EPA's CUECost model was used to estimate flue gas conditions, establish basic economic parameters, and perform cost and performance calculations for those technologies already integrated into CUECost. This approach was used to first estimate the costs for model plants under specific conditions. Then, the cost impacts of some selected variables are determined.

6.1 Mercury and Multipollutant Control Cost Models

For this work, mercury removal is from existing air pollution control equipment as well as from additional equipment such as PAC injection. These models were described in Sections 3.5 and 4.1, and the PAC injection rate algorithm constants for each equipment configuration are provided in the Appendices.

Costs are comprised of capital and operating costs. These costs are assessed to develop a total annual cost of pollution control expressed in mills/kWh or $/MWh.[a] The total installed capital cost is annualized to produce an annual charge. This is done by multiplying the total installed capital charge by a capital recovery factor (CRF). The CRF is a function of variables such as project life, cost of capital, tax rate, depreciation methods, and others. In this analysis, a CRF of 0.133 (or 13.3 percent) was chosen to be consistent with Reference 4. The annualized capital charge is then divided by the total power output of the plant for the year to determine the annual capital cost contribution to electric cost in mills/kWh (or $/Mwh).

---

[a]Costs expressed in mills/kWh and $/MWh are numerically equal.

Operating costs are estimated by determining the sum of the annual cost of consumables—reagents, power, water, etc. that contribute to variable operation and maintenance (O&M) and the annual cost of additional operators, maintenance, or parts (that contribute to fixed O&M) and dividing that sum by the total power output of the plant for the year to determine the operating cost contribution to electric cost in mills/kWh (or $/MWh).

The total annual cost of pollution control (in mills/kWh) is determined by adding all of the cost components—annual capital cost, annual variable O&M, and annual fixed O&M.

It is important to note that the costs of the multipollutant control technologies are likely to be greater than those for mercury control only. However, these technologies are providing additional pollution control benefits over and above mercury control.

In the tables that follow, estimates of capital and total annual cost for mercury and multipollutant control technology applications on model plants are shown. These estimates were determined with the cost model discussed. It is noted that these estimates are based on currently available data.

While developing the cost estimates for the model plant applications, the following specifications were used with the cost model.

1. Mercury concentration in the coal was taken to be 0.10 mg/kg for eastern bituminous coal and 0.07 mg/kg for subbituminous coal. These concentrations are in the range of concentration reported for utility boilers in Reference 72.

2. PAC injection rate correlations (see Section 4.1, Appendices and Reference 19) generally reflect that PAC injection requirements increase nonlinearly with an increase in mercury removal efficiency. To characterize the impact of this behavior, model plant cost estimates were obtained for mercury removal efficiencies of 50, 60, 70, 80, and 90 percent wherever possible. In some cases existing equipment provided in excess of 50 percent removal and PAC injection was not needed to achieve the specified level of reduction. For PAC injection with a downstream ESP, 90 percent reduction may not be possible with subbituminous coals without retrofit of a downstream pulse jet fabric filter (PJFF). For bituminous coal fired boilers with an ESP, 90 percent removal may not be cost effective by PAC injection alone when compared to PAC injection and retrofit of a downstream PJFF to achieve 90 percent mercury removal.

3. Spray cooling was not used in any of these model runs because PAC has sufficiently high capacity for most temperatures of interest—air preheater (APH) exit temperature under 350 °F— that any temperature effect is expected to be small. Moreover, spray cooling may have adverse effects on high-sulfur fuel boilers [due to acid dew point (ADP) effects] and PRB fuel boilers (due to cement-like properties of the ash). However, at lignite coal-fired plants, which are not evaluated here, spray cooling might be used to improve mercury removal. No data are currently available for recycling of sorbent in technology applications utilizing PAC injection and PJFF. Accordingly, no sorbent recycle was used.

4. Wet FGD performance for mercury control is determined by Equation 2 if no SCR exists or 90 percent removal if the boiler fires bituminous coal and is equipped with an SCR. No oxidation (or co-benefit) by SCR is assumed for subbituminous coals. If PAC is added to provide additional reduction of mercury, then PAC is added upstream of the ESP or FF.

5. In each of the model plant cost determinations, a plant capacity factor of 65 percent was used.

6. The cost of PAC was taken to be $1,000/ton of carbon.

7. In some cases, it is assumed that PAC is added upstream of the existing particulate control equipment. In others, particularly for high removal rates, it is assumed that a downstream FF is added. In the case of spray dryer absorbers, it is assumed that PAC is added upstream of the spray dryer, and a fabric filter may be added between the upstream PAC injection point and the downstream spray dryer. This is because the removal of HCl by the spray dryer will adversely affect the ability of PAC to achieve reasonable removal rates. This will require a larger fabric filter than if the fabric filter were installed downstream of the existing particulate control device because, in the upstream arrangement, the fabric filter would need to be sized to capture all of the fly ash as well as the injected PAC.

8. The multipollutant control technologies evaluated—ECO, advanced dry FGD, and K-Fuel—were designed to provide other benefits (e.g., reduction of NO_X or SO_2 emissions, improvement in fuel heating value) besides mercury reduction. Therefore, the higher cost of these multipollutant control approaches over control methods

developed solely for mercury control should be considered with special attention to the greater environ-mental and other benefits associated with multipollutant control approaches. For ECO, it was assumed that 98 percent SO_2 removal and 90 percent NO_X removal were provided in addition to 85 percent mercury reduction. For advanced dry FGD, it was assumed that 90 percent SO_2 removal was achieved in addition to about 95 percent mercury reduction. For K Fuel, the reduction of emissions of other pollutants, especially SO_2 and NO_X, will depend upon how the K-Fuel compares to the base fuel. For example, the K-Fuel has 44 percent lower sulfur content on a heating value basis than the base DOE PRB. Therefore, the environmental benefits of these methods—over and above mercury reduction—can be very significant.

9. Costs include capital and operating costs associated with the retrofit and the expected cost of a continuous emission monitoring system (CEMS). The cost of existing technology is not included in the cost estimate. However, the effect of existing technology is included in the total mercury removal performance. In some cases, existing technology will provide adequate mercury removal and no additional mercury removal technology is required. In these cases, a small cost associated with the expected cost of the mercury CEMS will be shown.

10. In this analysis it was assumed that the percent mercury removal possible from additional controls was not affected by the mercury removal from existing controls. While it is possible that there may be some interaction, this is not expected to be a significant effect for the cases evaluated here.

11. In all of the cases evaluated here, the cost calculations assumed that all collected fly ash is currently sold. Therefore, calculations for PAC injection configurations in which fly ash and PAC are collected together include incremental costs to landfill fly ash at a cost of $30/ton. In many cases these costs will not be incremental because fly ash may currently be landfilled or because fly ash may not be rendered completely unacceptable for re-use. The large majority of plants currently landfill their flyash,[30] and PAC injection would increase disposal costs only in proportion to PAC usage for them. Also, in situations where flyash is currently sold, fly ash contaminated with some used PAC might still be beneficially reused depending upon the amount of PAC added, the properties of the fly ash, and the intended use of the sold ash. According to ASTM Standard C618-03, coal fly ash with carbon contents as high as 6 percent may be acceptable as a concrete additive.[73] There are other criteria that may determine

acceptability of the fly ash as an additive to a buyer. However, the presence of small amounts of carbon in the fly ash will not necessarily render it unacceptable for beneficial re-use. Disposal costs can be a significant portion of total costs. As will be shown in a sensitivity analysis, elimination, or at least a reduction, of disposal costs can significantly improve economics of PAC injection from what is presented in this section. The ash content of the coal (on a heating value basis) largely determines the magnitude of this cost impact. So, coals with higher or lower ash contents will have higher or lower ash disposal costs, respectively. Based upon the characteristics of the fuels used in this program, the cost of landfilling fly ash at $30/ton is estimated to be about 0.37 mills/kWh for the low sulfur bituminous cases with PAC injection. Similarly, for the subbituminous and high-sulfur bituminous cases with PAC injection, the cost of landfilling fly ash at $30/ton is estimated to be about 1.01 mills/kWh and about 0.93 mills/kWh, respectively. Because these costs, which may not apply in some cases, are included as incremental costs in the results shown whenever a PJFF is not added to segregate the fly ash from the injected PAC, the cost estimates shown here should be regarded as likely to overestimate the cost in this respect.

6.2 Fuel Types, Plant Characteristics, and Model Plant Cases

Four different fuel types were evaluated for estimating costs of mercury control options presented in the following chapter:

1. A high sulfur bituminous coal
2. A low sulfur bituminous coal
3. A PRB Coal
4. A special, subbituminous fuel from K-Fuel.

The first three fuels are taken from Reference 4, where the fuel information was developed by NETL of the Department of Energy. The properties of these fuels are identified in Table 7 below.

Table 7. Fuels Used In Model Plant Analysis

Contents	Coal Type			
	High Sulfur Bituminous	Low Sulfur Bituminous	PRB Subbituminous	K-Fuel
Proximate Analysis (ASTM, as received)				
Volatile Matter (wt%)	40.40	44.00	30.79	40.20
Fixed Carbon (wt%)	47.50	50.00	32.41	45.50
	100.00	100.00	100.00	99.62
Ultimate Analysis (ASTM, as received)				
Moisture (wt%)	3.10	2.20	30.40	7.50
Carbon (wt%)	69.82	78.48	47.85	66.70
Hydrogen (wt%)	5.00	5.50	3.40	4.80
Nitrogen (wt%)	1.26	1.30	0.62	1.00
Chlorine (wt%)	0.12	0.12	0.03	0.03
Sulfur (wt%)	3.00	0.60	0.48	0.38
Ash (wt%)	9.00	3.80	6.40	6.42
Oxygen (wt%)	8.70	8.00	10.82	13.20
Total (wt%)	100.00	100.00	100.00	100.03
Mercury (mg/kg)	0.10	0.10	0.07	0.04
Modified Mott Spooner HHV (Btu/lb)	12,676.	14,175.	8304.	11,718.
Coal Ash Analysis (ASTM, as received)				
SiO_2 (wt%)	29.00	51.00	31.60	28.40
Al_2O_3 (wt%)	17.00	30.00	15.30	17.30
TiO_2 (wt%)	0.74	1.50	1.10	1.60
Fe_2O_3 (wt%)	36.00	5.60	4.60	6.00
CaO (wt%)	6.50	4.20	22.80	23.50
MgO (wt%)	0.83	0.76	4.70	4.00
Na_2O (wt%)	0.20	1.40	1.30	1.40
K_2O (wt%)	1.20	0.40	0.40	0.27
P_2O_5 (wt%)	0.22	1.80	0.80	2.43
SO_3 (wt%)	7.30	2.60	16.60	13.63
Other Unaccounted for (wt%)	1.01	0.74	0.80	1.47
Total (wt%)	100.00	100.00	100.00	100.00

Costs for installing and operating the mercury control technologies described in previous sections are estimated with model plants. Approximately 75 percent of the existing coal-fired utility boilers in the United States are equipped with ESPs for the control of PM.[8] The remaining boilers employ FFs, particulate scrubbers, or other equipment for control of PM. Additionally, units firing medium-to-high sulfur coals may use FGD technologies to meet their SO_2 control requirements. Generally,

larger units firing high sulfur coals employ wet FGD, and smaller units firing medium sulfur coals use spray dryers. While developing the model plants, these PM and SO_2 control possibilities were taken into account.

Several model plants, with various flue gas cleaning equipment configurations and firing either bituminous or subbituminous coal, were used in this work. Table 7 exhibits fuels used in model plants. Power plant characteristics are given in Table 8, and model plants are shown in Table 9. Note that boiler sizes of 100 and 975 MW used in this work were selected to approximately span the range of existing boiler sizes and to be consistent with the size of the model plants used in previous work.[4] It was also envisioned that use of SCR can enhance oxidation of mercury in flue gas and result in the "co-benefit" of increased mercury removal in wet FGD. Since SCR is a capital-intensive technology, generally its use is cost-effective on larger boiler sizes. Accordingly, in this work, the mercury co-benefit resulting from SCR use was evaluated for model plants utilizing large (975 MW) boilers and wet FGD.

Table 8. Power Plant Characteristics

Characteristic	Units	Value
MW Equivalent of Flue Gas to Control System	MW	100, 300, 500, 975
Net Plant Heat Rate	Btu/kWh	10,500
Plant Capacity Factor	%	65
Total Air Downstream of Economizer	%	120
Air Heater Leakage	%	12
Air Heater Outlet Gas Temperature	°F	300
Inlet Air Temperature	°F	80
Ambient Absolute Pressure	in. of Hg	29.4
Pressure after Air Heater	in. of H_2O	-12
Moisture in Air	lb/lb dry air	0.013
Ash Split		
Fly Ash	%	80
Bottom Ash	%	20
Seismic Zone	integer	1

Table 9. Mercury Control Technology Applications and Co-benefits

Model Plant	Size (MW)	Coal		Existing Controls	Additional Controls	Co-benefit Case(s) with
		Type[a]	% S			
1	975	Bit	3	ESP+FGD	PAC, PAC +PJFF	SCR
2	975	Bit	3	FF+FGD	PAC, PAC +PJFF	SCR
3	975	Bit	3	ESPh+FGD	PAC, PAC +PJFF	SCR
4	975	Bit	3	ESP	Adv Dry FGD	
5	975	Bit	3	ESP	ECO	
6	300	Bit	3	ESP+FGD	PAC, PAC +PJFF	SCR
7	300	Bit	3	FF+FGD	PAC, PAC +PJFF	SCR
8	300	Bit	3	ESPh+FGD	PAC, PAC +PJFF	SCR
9	300	Bit	3	ESP	Adv Dry FGD	
10	300	Bit	3	ESP	ECO	
11	975	Bit	0.6	ESP	PAC, PAC +PJFF	
12	975	Bit	0.6	FF	PAC, PAC +PJFF	
13	975	Bit	0.6	ESPh	PAC +PJFF	
14	975	Bit	0.6	ESP	ECO	
15	975	Bit	0.6	FF	ECO	
16	975	Bit	0.6	ESPh	ECO	
17	975	Bit	0.6	ESP	Adv Dry FGD	
18	975	Bit	0.6	FF	Adv Dry FGD	
19	975	Bit	0.6	ESPh	Adv Dry FGD	
20	975	Subbit	0.5	ESP	PAC, PAC +PJFF	
21	975	Subbit	0.5	FF	PAC, PAC +PJFF	
22	975	Subbit	0.5	ESPh	PAC +PJFF	
23	975	Subbit	0.5	ESP	ECO	
24	975	Subbit	0.5	FF	ECO	
25	975	Subbit	0.5	ESPh	ECO	
26	100	Bit	3	SD+ESP	PAC, PAC +PJFF	
27	100	Bit	3	SD+FF	PAC, PAC +PJFF	
28	100	Bit	3	ESPh+FGD	PAC +PJFF	
29	100	Bit	0.6	ESP	PAC, PAC +PJFF	
30	100	Bit	0.6	FF	PAC, PAC +PJFF	
31	100	Bit	0.6	ESPh	PAC +PJFF	
32	100	Bit	0.6	ESP	ECO	
33	100	Bit	0.6	FF	ECO	
34	100	Bit	0.6	ESPh	ECO	
35	100	Bit	0.6	ESP	Adv Dry FGD	
36	100	Bit	0.6	FF	Adv Dry FGD	
37	100	Bit	0.6	ESPh	Adv Dry FGD	
38	100	Subbit	0.5	ESP	PAC, PAC +PJFF	
39	100	Subbit	0.5	FF	PAC, PAC +PJFF	
40	100	Subbit	0.5	ESPh	PAC +PJFF	
41	100	Subbit	0.5	ESP	ECO	
42	100	Subbit	0.5	FF	ECO	
43	100	Subbit	0.5	ESPh	ECO	
44	975	K-Fuel	0.4	ESP	PAC, PAC +PJFF	
45	975	K-Fuel	0.4	FF	PAC, PAC +PJFF	
46	975	K-Fuel	0.4	ESPh	PAC +PJFF	
47	100	K-Fuel	0.4	ESP	PAC, PAC +PJFF	
48	100	K-Fuel	0.4	FF	PAC, PAC +PJFF	
49	100	K-Fuel	0.4	ESPh	PAC +PJFF	

[a] Bit = bituminous coal; Subbit = subbituminous coal

6.3 Cost Model Results

Three costs are typically shown in the following tables. One is the capital cost expressed in $/kW. This is the one-time capital charge for the equipment, installation, start-up, and such. Total annualized cost (Total Cost in the tables) and the Variable Cost, both expressed in mills/kWh, are also shown. Total Cost includes the annualized capital cost as well as annual variable and fixed operating cost. The Variable Cost is only the portion of the Total Cost that is attributable to variable operating and maintenance costs. In the following tables and discussion, the Model Plant numbers are noted so that more detailed cost information can be reviewed in the model plant tables of Appendix 4.

For those applications, particularly PAC injection, in which multiple mercury control levels were evaluated (i.e., 50 through 90 percent), several columns are shown in the tables presented. Each column indicates the estimated capital cost ($/kW) and total annual cost (mills/kWh) for the plant size indicated and whether or not a PJFF was added. In some cases, existing controls provided adequate mercury reduction, so the only items added were mercury emissions monitoring equipment (no PAC injection or PJFF). Estimated mercury emissions on mg/kWh basis are also indicated in the tables. This estimated mercury emissions number may be useful for estimating total mercury mass emissions for particular configurations.

Only one level of mercury removal is shown for ECO and advanced dry FGD. Multiple columns and costs are estimated for sensitivity to different variables, such as capital cost.

6.3.1 High Sulfur Bituminous Coals (Model Plants 1–10, 26–28)

For all of the model plants in which high sulfur bituminous coal is fired, it was assumed that the boiler was equipped with an FGD technology that might include limestone forced oxidation (LSFO), SDA, ECO, or advanced dry FGD. In the case of boilers equipped with wet FGD (LSFO), it was assumed any necessary additional mercury control was performed through injection of PAC upstream of the existing particulate removal device or between the existing particulate removal device and a new downstream PJFF. The co-benefit of SCR was also evaluated assuming that the combination of SCR with LSFO would result in the greater of 90 percent mercury removal or the amount of mercury removal from the existing particle removal equipment and LSFO.

For high sulfur units in which the co-benefit of SCR with LSFO (or wet FGD) is evaluated, the size range chosen was 300 MW to 975 MW. The reason 300 MW rather than 100 MW was selected as the low end of the size range is that SCR plus LSFO is a capital-intensive approach for combined SO_2 and NO_X control. Therefore, it would be unlikely to be selected over other approaches for SO_2 and NO_X control on a unit as small as 100 MW. For ECO and advanced dry FGD, the same size range was evaluated for consistency with the LSFO cases. On the other hand, SDA was not assessed for large, high-sulfur fuel boilers because it would rarely be economical for SO_2 removal on such large boilers when compared to LSFO.

High Sulfur Coal ESP plus FGD (Model Plants 1, 6)

As shown in Tables 10a and 10b, existing equipment (ESPc and wet FGD) are expected to provide 68 percent mercury removal under the conditions of Model plant #1. Mercury removal by PAC injection is necessary for higher mercury removal. Under these conditions, to achieve 90 percent mercury removal, a PJFF downstream of the ESP and PAC injection will permit more economical removal through PAC injection. With the SCR, PAC injection is not expected to be necessary for achieving over 90 percent removal of mercury, but PAC injection may be necessary for higher than 90 percent mercury removal.

High Sulfur Coal FF plus FGD (Model Plants 2, 7)

When a facility is equipped with a fabric filter and an FGD system, it is expected that no additional mercury removal will be necessary because 96 percent mercury removal is expected from existing equipment. In this case SCR co-benefit is not significant because mercury removal is expected to be high already.

Table 10a. High Sulfur Coal, ESP plus FGD Without SCR Co-benefit (Model Plants 1, 6)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	67.7	67.7	67.7	67.7	67.7
Hg Reduction by PAC (%)	none	none	7.3	38.2	69.1
Total Outlet Hg (mg/MWh)	12.2	12.2	11.3	7.5	3.8
975 MW and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$0.094	$1.601	$2.437	$4.304
Variable Cost (mills/kWh)	0.000	0.000	1.195	1.447	2.175
Total Cost[b] (mills/kWh)	0.003	0.003	1.242	1.520	2.303
975 MW with PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.094	$0.094	$36.216	$36.322	$36.538
Variable Cost (mills/kWh)	0.000	0.000	0.215	0.234	0.278
Total Cost (mills/kWh)	0.003	0.003	1.122	1.144	1.195
300 MW and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.126	$0.126	$2.370	$3.600	$6.330
Variable Cost (mills/kWh)	0.000	0.000	1.195	1.447	2.175
Total Cost[b] (mills/kWh)	0.004	0.004	1.265	1.554	2.363
300 MW with PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.126	$0.126	$45.989	$45.147	$46.467
Variable Cost (mills/kWh)	0.000	0.000	0.215	0.234	0.278
Total Cost (mills/kWh)	0.004	0.004	1.352	1.376	1.430

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the situation with the most conservative assumption. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 0.93 mills/kWh. In many cases these costs will not apply because either ash may currently be landfilled or it may not be rendered completely unacceptable for re-use.

Table 10b. High Sulfur Coal, ESP plus FGD With SCR Co-benefit (Model Plants 1, 6)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	90.	90.	90.	90.	90.
Hg Reduction by PAC (%)	none	none	none	none	none
Total Outlet Hg (mg/MWh)	3.8	3.8	3.8	3.8	3.8
975 MW					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$0.094	$0.094	$0.094	$0.094
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.000
Total Cost (mills/kWh)	0.003	0.003	0.003	0.003	0.003
300 MW					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$0.126	$0.126	$0.126	$0.126	$0.126
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.000
Total Cost (mills/kWh)	0.004	0.004	0.004	0.004	0.004

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

High Sulfur Coal ESPh plus FGD (Model Plants 3, 8)

If an ESPh is used in combination with FGD, it is assumed that a low temperature PJFF will follow the ESP and air preheater. Tables 11a and 11b show the results of cost estimates. As shown, the co-benefit of SCR has substantial cost impacts because, without SCR, PAC must be added with a downstream PJFF.

Table 11a. High Sulfur Coal, ESPh plus FGD Without SCR Co-benefit (Model Plants 3, 8)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	65.0	65.0	65.0	65.0	65.0
Hg Reduction by PAC (%)	none	none	14.3	42.9	71.4
Total Outlet Hg (mg/MWh)	13.2	13.2	11.3	7.5	3.8
975 MW					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.094	$0.094	$36.236	$36.345	$36.566
Variable Cost (mills/kWh)	0.000	0.000	0.218	0.239	0.284
Total Cost (mills/kWh)	0.003	0.003	1.126	1.149	1.201
300 MW					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.126	$0.126	$46.018	$46.180	$46.508
Variable Cost (mills/kWh)	0.000	0.000	0.218	0.239	0.284
Total Cost (mills/kWh)	0.004	0.004	1.357	1.382	1.437

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

Table 11b. High Sulfur Coal, ESPh plus FGD with SCR Co-benefit (Model Plants 3, 8)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	90.	90.	90.	90.	90.
Hg Reduction by PAC (%)	none	none	none	none	none
Total Outlet Hg (mg/MWh)	3.8	3.8	3.8	3.8	3.8
975 MW					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$0.094	$0.094	$0.094	$0.094
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.000
Total Cost (mills/kWh)	0.003	0.003	0.003	0.003	0.003
300 MW					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$0.126	$0.126	$0.126	$0.126	$0.126
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.000
Total Cost (mills/kWh)	0.004	0.004	0.004	0.004	0.004

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

ESP plus AdvDry FGD (Model Plants 4, 9)

Because of the high levels of mercury reduction that are assumed to occur with advanced dry FGD on bituminous coals (over 95 percent mercury removal was measured at the Roanoke facility),[42] additional mercury removal by PAC injection is not necessary. As will be shown later, this technology is more cost effective on low sulfur coals than on high sulfur coals as shown here. It should also be kept in mind that this technology, while more costly than PAC injection, provides SO_2 removal. An SO_2 removal of 90 percent was assumed for each of these cases.

Due to the limited experience with this technology on utility plants in the United Ststes, capital cost estimates may be uncertain. Sensitivity of the total cost with respect to capital cost is shown in Table 12. The base estimated cost for the size range is shown in bold on Table 12. Sensitivity analysis in a later section of this report and the appendices also show cost sensitivity with respect to reagent price.

Table 12. Advanced Dry FGD on High Sulfur Coal (Model Plants 4, 9), Sensitivity to Capital Cost[a]

Parameter	Capital Cost Category[b]				
	-20%	-10%	Projected	+10%	+20%
Hg Reduction of Existing Equipment (%)	29.4	29.4	29.4	29.4	29.4
Hg Reduction of Advanced Dry FGD[c](%)	95.0	95.0	95.0	95.0	95.0
Total Hg Removal (%)	96.5	96.5	96.5	96.5	96.5
Total Outlet Hg (mg/MWh)	1.327	1.327	1.327	1.327	1.327
975 MW					
Capital Cost ($/kW)	$115.46	$129.80	$144.23	$158.65	$173.07
Variable Cost (mills/kWh)	5.323	5.323	5.323	5.323	5.323
Total Cost (mills/kWh)	7.940	8.265	8.592	8.919	9.246
300 MW					
Capital Cost ($/kW)	$127.47	$143.30	$159.23	$175.15	$191.07
Variable Cost (mills/kWh)	5.323	5.323	5.323	5.323	5.323
Total Cost (mills/kWh)	8.212	8.571	8.932	9.293	9.654

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] Capital Cost (115.28–173.07 $/kW for a 975 MW plant and 127.47–191.07 $/kW for a 300 MW plant) is the variable.

[c] Advanced dry FGD is a technology developed primarily for SO_2 removal; however, it can also provide mercury control for bituminous coal.

ESP plus ECO (Model Plants 5 and 10)

ECO is an emerging technology that appears to be capable of high pollution reduction. Because it is an emerging technology, the sensitivity of total cost to capital cost was assessed and is shown in Table 13. The economics rely, in part, on the revenue from fertilizer product sales and on the value of power. Sensitivity analyses for the effect of fertilizer product value and for power cost are shown in a later section of this report and in the appendices. For high sulfur coals, a high amount of fertilizer product is possible, which makes the economics of the process appear more favorable than for lower sulfur applications.

Table 13. ESP and ECO on High Sulfur Coal (Model Plants 5 and 10), Sensitivity to Capital Cost[a]

Parameter	Capital Cost Category[b]				
	-20%	-10%	Projected	+10%	+20%
Hg Reduction of Existing Equipment (%)	29.4	29.4	29.4	29.4	29.4
ECO Hg Reduction FGD[c](%)	85.0	85.0	85.0	85.0	85.0
Total Hg Reduction (%)	89.4	89.4	89.4	89.4	89.4
Total Outlet Hg (mg/MWh)	3.98	3.98	3.98	3.98	3.98
975 MW					
Capital Cost ($/kW)	$150.28	$169.05	$187.83	$206.60	$225.38
Variable Cost[d] (mills/kWh)	-0.820	-0.820	-0.820	-0.820	-0.820
Total Cost (mills/kWh)	3.276	3.764	4.252	4.740	5.228
300 MW					
Capital Cost ($/kW)	$190.23	$214.00	$237.76	$261.53	$285.29
Variable Cost[d] (mills/kWh)	-0.820	-0.820	-0.820	-0.820	-0.820
Total Cost (mills/kWh)	4.741	5.359	5.977	6.595	7.212

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] Capital Cost (150.28–225.38 $/kW for a 975 MW plant and 190.23–285.29 $/kW for a 300 MW plant) is the variable.

[c] ECO is a technology developed primarily for NO_X and SO_2 removal; however, it can also provide mercury control.

[d] Variable Cost includes a credit for fertilizer by-product sale. Negative numbers imply a net credit. Variable Cost also includes the cost of power for the barrier discharge reactor—estimated at about 4.8% of plant output for this case.

100 MW SDA and ESPc (Model Plant 26)

For high sulfur fuels, a SDA with a downstream ESP is not expected to be very effective for mercury removal. Therefore, most of the mercury removal must be performed by additional PAC injection. In this case, a PJFF may be installed upstream of the SDA and must be sized for collection of the full ash loading plus the PAC injection. Alternatively, a smaller polishing PJFF may be installed downstream of the existing ESP. As will be shown later, a SDA with a downstream PJFF is expected to achieve relatively high mercury removal and will only require moderate PAC injection to achieve the additional reduction necessary for 90 percent removal. Therefore, it may be more economical to install a polishing PJFF downstream of the ESP (COHPAC conversion) and still inject the PAC upstream of the SDA than to install a PJFF sized for collection of the full ash loading plus the PAC injection. However, because data is not available on mercury removal from an SDA with a downstream COHPAC, it is uncertain if an SDA with a downstream COHPAC arrangement would be as effective in removing mercury as an SDA with downstream PJFF.

Table 14. High Sulfur Coal, 100 MW SDA, and ESPc (Model Plant 26)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	5.0	5.0	5.0	5.0	5.0
Hg Reduction by PAC (%)	47.4	57.9	68.4	78.9	89.5
Total Outlet Hg (mg/MWh)	16.8	13.5	10.1	6.7	3.4
100 MW no PJFF					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$6.014	$7.235	$8.996	$11.818	$17.266
Variable Cost (mills/kWh)	0.659	0.877	1.226	1.861	3.309
Total Cost (mills/kWh)	0.838	1.092	1.493	2.211	3.821
100 MW and Full Size PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$110.342	$110.891	$111.094	$111.413	$112.065
Variable Cost (mills/kWh)	0.242	0.255	0.275	0.308	0.383
Total Cost (mills/kWh)	2.907	2.934	2.960	3.002	3.096
100 MW with PJFF (COHPAC conversion)					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$57.612	$57.970	$58.174	$58.495	$59.149
Variable Cost (mills/kWh)	0.243	0.257	0.277	0.310	0.385
Total Cost (mills/kWh)	1.657	1.680	1.706	1.749	1.843

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

100 MW SDA and FF (Model Plant 27)

As shown in Table 15, a SDA with a downstream fabric filter is expected to provide high mercury removal, approaching 90 percent. A small amount of PAC might be added upstream of the SDA to provide some more mercury reduction at a relatively low cost.

Table 15. High Sulfur Coal, 100 MW SDA, and FF (Model Plant 27)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	89.3	89.3	89.3	89.3	89.3
Hg Reduction by PAC (%)	none	none	none	none	6.3
Total Outlet Hg (mg/MWh)	4.0	4.0	4.0	4.0	3.8
100 MW, no PJFF					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$0.165	$0.165	$0.165	$0.165	$3.388
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.270
Total Cost (mills/kWh)	0.005	0.005	0.005	0.005	0.370

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

100 MW ESPh and FGD (Model Plant 28)

In this case, the ESPh followed by a wet FGD (LSFO) will provide about 65 percent mercury removal, and additional mercury removal will, therefore, be necessary to achieve 90 percent. As shown in Table 16, it is more economical for 90 percent mercury removal to install a polishing fabric filter after the air preheater and upstream of the flue gas desulfurization than to only inject PAC without the fabric filter. But for 70 percent removal, it may be most economical to inject PAC in the ductwork between the air preheater and the FGD.

Table 16. High Sulfur Coal, 100 MW ESPh, and FGD (Model Plant 28)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	89.3	89.3	89.3	89.3	89.3
Hg Reduction by PAC (%)	none	none	none	none	6.3
Total Outlet Hg (mg/MWh)	4.0	4.0	4.0	4.0	3.8
100 MW without PJFF					
Retrofit PJFF?	no	no	no	no	no
Capital Cost ($/kW)	$0.165	$0.165	$3.751	$5.595	$9.657
Variable Cost (mills/kWh)	0.000	0.000	1.236	1.510	2.287
Total Cost (mills/kWh)	0.005	0.005	1.347	1.675	2.573
100 MW with PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.165	$0.165	$57.533	$57.767	$58.241
Variable Cost (mills/kWh)	0.000	0.000	0.217	0.237	0.282
Total Cost (mills/kWh)	0.005	0.005	1.627	1.654	1.714

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

6.3.2 Low Sulfur Bituminous Coals

These coals are represented by Model Plants 11–19 and 29–37 in Table 9 and have a 0.6 wt% sulphur content as shown in Table 7. The existing controls on these plants are either a cold- or hot-side ESP or FF. Plants with ESPc or FF would need additional controls that consist of PAC, PAC with a PJFF, ECO, or advanced dry FGD. Plants with an ESPh would need PAC with a PJFF, ECO, or FF.

With ESPc and No SO_2 controls (Model Plants 11 and 29)

For these cases, PAC injection is expected to be necessary for mercury reduction in excess of 50 percent. As shown in Table 17, addition of a PJFF for the 975 MW plant case improves overall economics for removal in excess of 70 percent. However, for a smaller 100 MW plant, the addition of a polishing PJFF is more economical only for the 90 percent mercury removal case.

Table 17. Low Sulfur Coal, ESPc, and No SO_2 Controls (Model Plants 11 and 29)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	50.6	50.6	50.6	50.6	50.6
Hg Reduction by PAC (%)	none	19.0	39.2	59.5	79.7
Total Outlet Hg (mg/MWh)	16.601	13.452	10.089	6.726	3.363
975 MW and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$1.855	$2.467	$3.490	$5.711
Variable Cost (mills/kWh)	0.000	0.709	0.901	1.277	2.282
Total Cost[b] (mills/kWh)	0.003	0.764	0.974	1.381	2.451
975 MW with PJFF					
Retrofit PJFF?	no	yes	yes	yes	yes
Capital Cost ($/kW)	$0.094	$36.248	$36.324	$36.445	$36.690
Variable Cost (mills/kWh)	0.000	0.220	0.234	0.258	0.311
Total Cost (mills/kWh)	0.003	1.128	1.144	1.171	1.233
100 MW and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.165	$3.791	$5.271	$7.430	$12.057
Variable Cost (mills/kWh)	0.000	0.709	0.901	1.277	2.282
Total Cost[b] (mills/kWh)	0.005	0.827	1.057	1.497	2.639
100 MW with PJFF					
Retrofit PJFF?	no	yes	yes	yes	yes
Capital Cost ($/kW)	$0.165	$57.563	$57.729	$57.989	$58.518
Variable Cost (mills/kWh)	0.000	0.220	0.234	0.258	0.311
Total Cost (mills/kWh)	0.005	1.631	1.650	1.682	1.751

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the situation with the most conservative assumption. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 0.93 mills/kWh. In many cases these costs will not apply because either ash may currently be landfilled or it may not be rendered completely unacceptable for re-use.

With FF and No SO_2 controls (Model Plants 12 and 30)

Due to the high mercury removal expected from existing equipment in these cases, PAC injection is only expected to be necessary for mercury reduction in excess of 85 percent. As shown in Table 18, installation of a PJFF is expected to be economically beneficial for neither the 975 nor the 100 MW plant cases.

Table 18. Low Sulfur Coal, FF, and No SO_2 Controls (Model Plants 12 and 30)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	85.0	85.0	85.0	85.0	85.0
Hg Reduction by PAC (%)	none	none	none	none	33.3
Total Outlet Hg (mg/MWh)	5.0	5.0	5.0	5.0	3.4
975 MW and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$0.094	$0.094	$0.094	$0.821
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.458
Total Cost[b] (mills/kWh)	0.003	0.003	0.003	0.003	0.482
975 MW with PJFF					
Retrofit PJFF?	no	no	no	no	yes
Capital Cost ($/kW)	$0.094	$0.094	$0.094	$0.094	$36.299
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.229
Total Cost (mills/kWh)	0.003	0.003	0.003	0.003	1.139
100 MW and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.165	$0.165	$0.165	$0.165	$1.752
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.458
Total Cost[b] (mills/kWh)	0.005	0.005	0.005	0.005	0.510
100 MW with PJFF					
Retrofit PJFF?	no	no	no	no	yes
Capital Cost ($/kW)	$0.165	$0.165	$0.165	$0.165	$57.674
Variable Cost (mills/kWh)	0.000	0.000	0.000	0.000	0.229
Total Cost (mills/kWh)	0.005	0.005	0.005	0.005	1.644

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the situation with the most conservative assumption. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 0.93 mills/kWh. In many cases these costs will not apply because either ash may currently be landfilled or it may not be rendered completely unacceptable for re-use.

With ESPh and No SO_2 Controls (Model Plants 13 and 31)

Due to the low mercury removal possible from existing equipment in these cases, PAC injection is expected to be necessary for all of the conditions, and a polishing PJFF must be added because PAC injection would normally be added downstream of the ESPh and air preheater. Table 19 shows the economics of this type of installation for 975 MW and 100 MW plants.

Table 19. Low Sulfur Coal, ESPh, and No SO_2 Controls (Model Plants 13 and 31)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	25.5	25.5	25.5	25.5	25.5
Hg Reduction by PAC (%)	32.9	46.3	59.7	73.2	86.6
Total Outlet Hg (mg/MWh)	16.8	13.5	10.1	6.7	3.4
975 MW					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$36.162	$36.360	$36.447	$36.584	$36.865
Variable Cost (mills/kWh)	0.229	0.241	0.258	0.287	0.353
Total Cost (mills/kWh)	1.135	1.152	1.172	1.205	1.280
100 MW					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$57.458	$57.805	$57.994	$58.290	$58.893
Variable Cost (mills/kWh)	0.229	0.241	0.258	0.287	0.353
Total Cost (mills/kWh)	1.638	1.659	1.682	1.720	1.804

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

ECO Installed after Particulate Removal (Model Plants 14–16, 32–34)

Since the most common location for installation of ECO is likely to be after an ESPc and because the economics are similar regardless of the existing PM removal equipment, only the results of analysis for ECO installed after an ESPc are shown in Table 20. ECO is a capital-intensive technology, and there remains some uncertainty regarding its actual capital cost because it is an emerging technology. Therefore, the cost was evaluated for a range of capital costs plus or minus 20 percent of the projected cost for the size unit. The sensitivity analysis of Section 6.4 shows estimated ECO economics while varying the fertilizer product value and the power cost for a 500 MW plant. Additional information is available in the Model Runs in the appendices. For a given coal, unit size, and cost of consumables, the economics of ECO are estimated to be roughly the same regardless of the type of upstream particulate control device.

Table 20. ECO Installed After Particulate Removal (Model Plants 14–16, 32–34), Sensitivity to Capital Cost[a]

Parameter	Capital Cost Category[b]				
	-20%	-10%	Projected	+10%	+20%
Hg Reduction of Existing Equipment (%)	50.6	50.6	50.6	50.6	50.6
ECO Hg Reduction FGD[c](%)	85.0	85.0	85.0	85.0	85.0
Total Hg Reduction (%)	92.6	92.6	92.6	92.6	92.6
Total Outlet Hg (mg/MWh)	2.49	2.49	2.49	2.49	2.49
975 MW					
Capital Cost ($/kW)	$150.28	$169.05	$187.83	$206.60	$225.38
Variable Cost[d] (mills/kWh)	1.243	1.243	1.243	1.243	1.243
Total Cost (mills/kWh)	5.340	5.828	6.316	6.804	7.292
100 MW					
Capital Cost ($/kW)	$236.99	$266.59	$296.20	$325.80	$355.41
Variable Cost[d] (mills/kWh)	1.243	1.243	1.243	1.243	1.243
Total Cost (mills/kWh)	9.521	10.021	10.790	11.560	12.329

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] Capital Cost (150.28–225.38 $/kW for a 975 MW plant and 236.99–355.41 $/kW for a 100 MW plant) is the variable.

[c] ECO is a technology developed primarily for NO_X and SO_2 removal; however, it can also provide mercury control. Data shown is for retrofit on a boiler with existing ESPc. For boilers with existing ESPh or FF, costs would be very similar, but outlet mercury would differ somewhat from what is shown here. See appendices for details

[d] Variable Cost includes a credit for fertilizer by-product sale. Negative numbers imply a net credit. Variable Cost also includes the cost of power for the barrier discharge reactor—estimated at about 4.8% of plant output for this case.

Advanced Dry FGD (Model Plants 17–19, 35–37)

Advanced Dry FGD is another technology that is somewhat capital intensive and controls SO_2 and mercury. Like ECO, the economics are a strong function of capital cost and sulfur level and less affected by the type of upstream particulate control technology. Shown in Table 21 are the results of analysis for advanced dry FGD downstream of an existing ESPc.

Table 21. Advanced Dry FGD (Model Plants 17–19, 35–37), Sensitivity to Capital Cost[a]

Parameter	Capital Cost Category[b]				
	-20%	-10%	Projected	+10%	+20%
Hg Reduction of Existing Equipment (%)	50.6	50.6	50.6	50.6	50.6
Hg Reduction of Advanced Dry FGD[c](%)	95.0	95.0	95.0	95.0	95.0
Total Hg Removal (%)	97.5	97.5	97.5	97.5	97.5
Total Outlet Hg (mg/MWh)	0.830	0.830	0.830	0.830	0.830
975 MW					
Capital Cost ($/kW)	$115.46	$129.80	$144.23	$158.65	$173.07
Variable Cost (mills/kWh)	1.071	1.071	1.071	1.071	1.071
Total Cost (mills/kWh)	3.688	4.013	4.340	4.667	4.994
100 MW					
Capital Cost ($/kW)	$162.17	$182.31	$202.57	$222.82	$243.08
Variable Cost (mills/kWh)	1.071	1.071	1.071	1.071	1.071
Total Cost (mills/kWh)	4.747	5.203	5.662	6.122	6.581

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] Capital Cost (115.28–173.07 $/kW for a 975 MW plant and 162.17–243.08 $/kW for a 100 MW plant) is the variable.

[c] Advanced dry FGD is a technology developed primarily for SO_2 removal; however, it can also provide mercury control for bituminous coal. Data shown is for retrofit on a boiler with existing ESPc. For boilers with existing ESPh or FF, costs would be very similar, but outlet mercury may differ somewhat from what is shown here. See appendices for details.

6.3.3 Low Sulfur Subbituminous Coals Including Powder River Basin Coals

Mercury removal with existing equipment is typically lower for subbituminous coals than for bituminous coals. As a result, mercury reduction is more dependent on PAC injection for high levels of mercury removal. In the case of boilers currently equipped with ESPs, it may not be possible to achieve 80 or 90 percent reduction without addition of a downstream PJFF as indicated in Model Plants 20–22 and 38–40. ECO is examined on Model Plants 23–25 and 41–43. The effectiveness and cost of K-Fuel as a mercury control technology is examined in Model Plants 44–49. The K-fuel process is primarily designed to improve fuel-heating value, but it also provides some SO_2 reduction, may provide NO_X reduction, and provides mercury reduction.

Boilers with Particulate Control and No SO_2 Control (Model Plants 20–22, 38–40)

As shown in Table 22 for the cases without a downstream PJFF, estimates for 80 or 90 percent mercury reduction show high costs due to high predicted injection rates. It is recognized that, despite the high injection rates, the specified Hg reduction may not be achievable without addition of a PJFF after the ESP. However, it should be noted that the algorithms used for PAC injection here (Equation 9 and the associated constants for this case) were developed from test results at the Pleasant Prairie Power Plant, which had a coal chlorine content of only 15 ppm, which is lower than typically expected for this type of fuel.[19] So, it is possible that other PRB fueled boilers may be easier to control with PAC than those shown here.

For mercury reduction from boilers firing subbituminous coals and equipped with a downstream FF, PAC injection is necessary for greater than about 60 percent mercury reduction. Addition of a downstream PJFF provides the benefit of much lower waste disposal costs because fly ash is not contaminated. Therefore, although the cost of sorbent is similar regardless of whether or not a PJFF is added, the additional cost of waste disposal roughly compensates for the cost of the PJFF for the 975 MW case as shown in Table 23.

In the case where an ESPh is currently installed, it is necessary to install a downstream PJFF for mercury removal by PAC injection. As shown in Table 24, this can generally be performed at a cost of below 2 mills/kWh.

PRB Coals with ECO (Model Plants 23–25, 41–43)

Since the most common installation for an ECO is likely to be after an ESPc and the economics are similar regardless of existing particle removal equipment, only the ECO after an ESPc is shown in Table 25. ECO is a capital-intensive technology, and there remains some uncertainty regarding its capital cost because it is an emerging technology. Therefore, the cost was evaluated for a range of capital costs within 20 percent of the projected cost for the size unit. The model runs in the appendices show estimated ECO economics for various fertilizer product value and power value for 975 MW and 100 MW plants equipped with ESPc, FF, or ESPh. The lower NO_X level associated with PRB coals helps to reduce the power demand of the ECO barrier discharge reactor compared to the power demand of the ECO barrier discharge reactor when firing bituminous coals. However, because of the low fertilizer product revenue (due to low NO_X and SO_2 levels for PRB coals), economics of ECO on this application are estimated to be less favorable than for the bituminous coals that have higher NO_X and SO_2 levels.

Table 22. Low Sulfur Subbituminous Coals, ESPc, and No SO_2 Control (Model Plants 20, 38)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	29.7	29.7	29.7	29.7	29.7
Desired Hg Reduction by PAC (%)	28.9	43.1	57.3	71.5	85.8
Actual Hg Reduction by PAC (%) without PJFF[b]	28.9	43.1	57.3	69.3	69.3
Total Actual Hg Reduction without PJFF[b]	50.0	60.0	70.0	78.5	78.5
975 MW with ESPc and No PJFF[c]					
Retrofit PJFF?[c]	no	no	no	no	no
Capital Cost ($/kW)	$0.401	$1.238	$3.232	$27.744	$27.744
Variable Cost (mills/kWh)	1.027	1.181	1.811	20.102	20.102
Total Cost[c] (mills/kWh)	1.039	1.218	1.907	20.924	20.924
Total Outlet Hg (mg/MWh)	20.1	16.1	12.1	8.7	8.7
975 MW with ESPc and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$35.998	$36.258	$36.422	$36.666	$37.139
Variable Cost (mills/kWh)	0.209	0.231	0.262	0.315	0.435
Total Cost[c] (mills/kWh)	1.111	1.139	1.176	1.236	1.369
Total Outlet Hg (mg/MWh)	20.1	16.1	12.1	8.0	4.0
100 MW with ESPc and No PJFF[c]					
Retrofit PJFF?[c]	no	no	no	no	no
Capital Cost ($/kW)	$0.840	$2.651	$6.887	$55.806	$55.806
Variable Cost (mills/kWh)	1.027	1.181	1.811	20.102	20.102
Total Cost[c] (mills/kWh)	1.052	1.259	2.015	21.756	21.756
Total Outlet Hg (mg/MWh)	20.1	16.1	12.1	8.7	8.7
100 MW with ESPc and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$57.102	$57.585	$57.939	$58.466	$59.479
Variable Cost (mills/kWh)	0.209	0.231	0.262	0.315	0.435
Total Cost[c] (mills/kWh)	1.608	1.643	1.685	1.753	1.903
Total Outlet Hg (mg/MWh)	20.1	16.1	12.1	8.0	4.0

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] With PAC injection on subbituminous coals without a downstream fabric filter, Hg reduction at very high levels is not expected to be possible. Additional PAC injection will not improve Hg reduction.

[c] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the most conservative situation. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 1.01 mills/kWh. In many cases these costs will not apply because ash may currently be landfilled or because ash may not be rendered completely unacceptable for re-use.

Table 23. Low Sulfur Subbituminous Coals, FF, and No SO_2 Control (Model Plants 21, 39)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	60.7	60.7	60.7	60.7	60.7
Hg Reduction by PAC (%)	none	none	23.6	49.1	74.5
Total Outlet Hg (mg/MWh)	15.8	15.8	12.1	8.0	4.0
975 MW with FF and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$0.094	$0.616	$0.842	$1.259
Variable Cost (mills/kWh)	0.000	0.000	1.057	1.097	1.186
Total Cost[b] (mills/kWh)	0.003	0.003	1.075	1.122	1.223
975 MW with FF and PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.094	$0.094	$36.094	$36.320	$37.737
Variable Cost (mills/kWh)	0.000	0.000	0.203	0.243	0.332
Total Cost[c] (mills/kWh)	0.003	0.003	1.106	1.153	1.254
100 MW with FF and No PJFF[b]					
Retrofit PJFF?[b]	no	no	no	no	no
Capital Cost ($/kW)	$0.165	$0.165	$1.308	$1.799	$2.696
Variable Cost (mills/kWh)	0.000	0.000	1.057	1.097	1.186
Total Cost[c] (mills/kWh)	0.005	0.005	1.096	1.150	1.266
100 MW with FF and PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.165	$0.165	$57.230	$57.721	$58.618
Variable Cost (mills/kWh)	0.000	0.000	0.203	0.243	0.332
Total Cost[c] (mills/kWh)	0.005	0.005	1.604	1.659	1.774

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the most conservative situation. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 1.01 mills/kWh. In many cases these costs will not apply because ash may currently be landfilled or because ash may not be rendered completely unacceptable for re-use.

Table 24. Low Sulfur Subbituminous Coals, ESPh, and No SO_2 Controls (Model Plants 22, 40)[a]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	12.6	12.6	12.6	12.6	12.6
Hg Reduction by PAC (%)	42.8	54.2	65.7	77.1	88.6
Total Outlet Hg (mg/MWh)	20.1	16.1	12.1	8.0	4.0
975 MW with ESPh and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$36.119	$36.381	$36.550	$36.806	$37.305
Variable Cost (mills/kWh)	0.230	0.254	0.289	0.348	0.482
Total Cost (mills/kWh)	1.135	1.166	1.206	1.273	1.421
100 MW with ESPh and PJFF					
Retrofit PJFF?	tes	yes	yes	yes	yes
Capital Cost ($/kW)	$57.365	$57.852	$58.217	$58.766	$59.834
Variable Cost (mills/kWh)	0.230	0.254	0.289	0.348	0.482
Total Cost[c] (mills/kWh)	1.637	1.674	1.720	1.795	1.960

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

Table 25. Low Sulfur Subbituminous Coals with ECO (Model Plants 23–25, 41–43) Sensitivity to Capital Cost[a]

Parameter	Capital Cost Category[b]				
	-20%	-10%	Projected	+10%	+20%
Hg Reduction of Existing Equipment (%)	29.7	29.7	29.7	29.7	29.7
ECO Hg Reduction FGD[c](%)	85.0	85.0	85.0	85.0	85.0
Total Hg Reduction (%)	89.5	89.5	89.5	89.5	89.5
Total Outlet Hg (mg/MWh)	4.24	4.24	4.24	4.24	4.24
975 MW with ESPc					
Capital Cost ($/kW)	$150.28	$169.05	$187.83	$206.60	$225.38
Variable Cost[d] (mills/kWh)	0.442	0.442	0.442	0.442	0.442
Total Cost (mills/kWh)	4.539	5.027	5.515	6.003	6.491
100 MW with ESPc					
Capital Cost ($/kW)	$236.99	$266.59	$296.20	$325.80	$355.41
Variable Cost[d] (mills/kWh)	0.442	0.442	0.442	0.442	0.442
Total Cost (mills/kWh)	8.451	9.220	9.990	10.759	11.529

[a] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[b] Capital Cost (150.28–225.38 $/kW for a 975 MW plant and 236.99–355.41 $/kW for a 100 MW plant) is the variable.

[c] ECO is a technology developed primarily for NO_X and SO_2 removal; however, it can also provide mercury control. Data shown is for retrofit on a boiler with existing ESPc. For boilers with existing ESPh or FF, costs would be very similar, but outlet mercury would differ somewhat from what is shown here. See appendices for details

[d] Variable Cost includes a credit for fertilizer by-product sale. Negative numbers imply a net credit. Variable Cost also includes the cost of power for the barrier discharge reactor—estimated at about 4.8% of plant output for this case.

Beneficiated Western Coals—K-Fuel

Table 26 compares the estimated mercury emissions on a mg/MWh basis for the base PRB coal versus the K-Fuel beneficiated coal. The K-Fuel has about 60 percent less mercury than PRB on a unit of heating value basis. Mercury removal rates for the particulate removal equipment are similar, with the K-Fuel estimated to have a slightly higher removal with an ESPc due to the slightly lower sulfur level in the fuel. It is also important to note that K-Fuel provides a 44 percent reduction in SO_2 emissions from the base PRB fuel.

Figure 16 shows the economics of K-Fuel assuming that all of the incremental costs of using the fuel are born in an increased fuel cost over PRB fuel.

Table 26. Comparison of Estimated Mercury Emissions from PRB and K-Fuel[a] Boilers Equipped with Particulate Control and No Additional Mercury or SO_2 Controls

Characteristic	PRB	K-Fuel	PRB	K-Fuel	PRB	K-Fuel
Particulate Control System	ESPc	ESPc	FF	FF	ESPh	ESPh
Hg Reduction with Existing Equipment (%)	29.7	36.8	60.7	60.7	12.6	12.6
Hg from Coal (mg/MWh)	40.2	16.3	40.2	16.3	40.2	16.3
Total Outlet Hg (mg/MWh)	28.2	10.3	15.8	6.4	35.1	14.2

[a] The K-fuel process is primarily designed to improve fuel-heating value, but it may provide NO_X reduction, provides some SO_2 reduction, and provides Hg reduction.

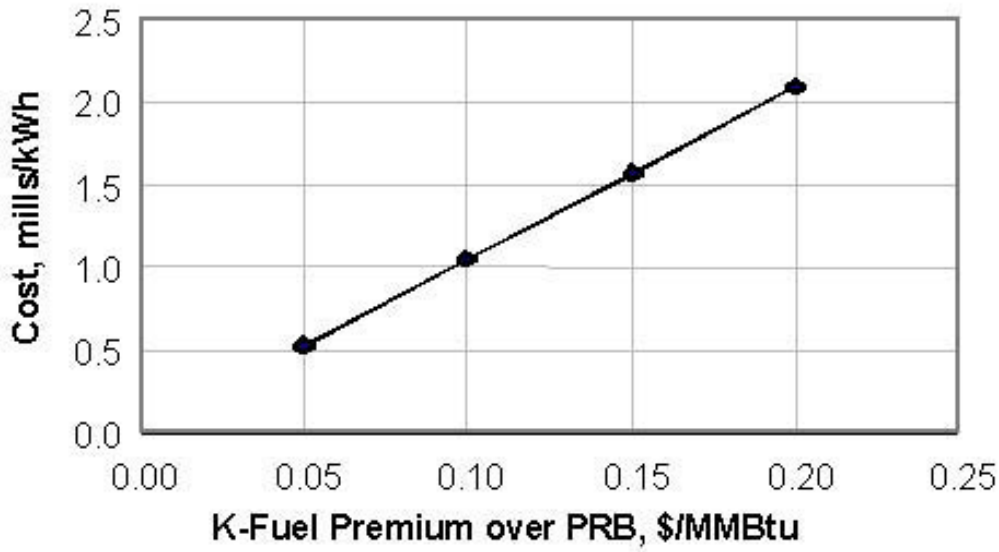

Figure 16. Estimated Effect of K-Fuel Cost on Generation Cost.

Model runs were performed for PAC injection on boilers equipped with K-Fuel. These are model runs 44 through 49, and Tables 27–29 summarize the results of these model runs. The economics of PAC injection for K-Fuel are similar to those for PAC injection for PRB, except that it may be appropriate to add to these costs the incremental cost of the K-Fuel over PRB. The major difference is that lower emissions rates are possible with K-Fuel than with PRB due to the lower initial mercury level.

Table 27. K-Fuel[a], ESPc and No SO_2 Control (Model Plants 44, 47)[b]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	36.8	36.8	36.8	36.8	36.8
Desired Hg Reduction by PAC (%)	20.9	36.7	52.5	68.3	84.2
Actual Hg Reduction by PAC (%) without PJFF[c]	20.9	36.7	52.5	68.3	69.3
Total Actual Hg Reduction without PJFF[c]	50.0	60.0	70.0	80.0	80.6
975 MW with ESPc and No PJFF[d]					
Retrofit PJFF?[d]	no	no	no	no	no
Capital Cost ($/kW)	$0.391	$0.673	$2.240	$14.462	$26.735
Variable Cost (mills/kWh)	0.745	0.785	1.180	8.237	18.846
Total Cost[d] (mills/kWh)	0.756	0.805	1.247	8.666	19.638
Total Outlet Hg (mg/MWh)	8.1	6.5	4.9	3.3	3.2
975 MW with ESPc and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$35.922	$36.177	$36.333	$36.565	$37.009
Variable Cost (mills/kWh)	0.190	0.209	0.238	0.285	0.393
Total Cost[d] (mills/kWh)	1.089	1.115	1.148	1.203	1.323
Total Outlet Hg (mg/MWh)	8.1	6.5	4.9	3.3	1.6
100 MW with ESPc and No PJFF[d]					
Retrofit PJFF?[d]	no	no	no	no	no
Capital Cost ($/kW)	$0.817	$1.431	$4.792	$29.800	$53.860
Variable Cost (mills/kWh)	0.745	0.785	1.180	8.237	18.846
Total Cost[d] (mills/kWh)	0.769	0.828	1.322	9.120	20.441
Total Outlet Hg (mg/MWh)	8.1	6.5	4.9	3.3	3.2
100 MW with ESPc and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$56.936	$57.409	$57.748	$58.248	$59.202
Variable Cost (mills/kWh)	0.190	0.209	0.238	0.285	0.393
Total Cost[d] (mills/kWh)	1.584	1.616	1.654	1.717	1.853
Total Outlet Hg (mg/MWh)	8.1	6.5	4.9	3.3	1.6

[a] The K-fuel process is primarily designed to improve fuel-heating value, but it may provide NO_X reduction, provides some SO_2 reduction, and provides Hg reduction.

[b] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[c] With PAC injection on subbituminous coals without a downstream fabric filter, Hg reduction at very high levels is not expected to be possible. Additional PAC injection will not improve Hg reduction.

[d] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the most conservative situation. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 1.01 mills/kWh. In many cases these costs will not apply because ash may currently be landfilled or because ash may not be rendered completely unacceptable for re-use.

Table 28. K-Fuel[a], FF, and No SO_2 Control (Model Plants 45, 48)[b]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	60.7	60.7	60.7	60.7	60.7
Hg Reduction by PAC (%)	none	none	23.6	49.1	74.5
Total Outlet Hg (mg/MWh)	6.4	6.4	4.9	3.3	1.6
975 MW with FF and No PJFF[c]					
Retrofit PJFF?[c]	no	no	no	no	no
Capital Cost ($/kW)	$0.094	$0.094	$0.598	$0.817	$1.219
Variable Cost (mills/kWh)	0.000	0.000	0.773	0.811	0.895
Total Cost[c] (mills/kWh)	0.003	0.003	0.791	0.835	0.931
975 MW with FF and PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.094	$0.094	$36.076	$36.295	$36.697
Variable Cost (mills/kWh)	0.000	0.000	0.193	0.230	0.315
Total Cost[c] (mills/kWh)	0.003	0.003	1.096	1.140	1.236
100 MW with FF and No PJFF[c]					
Retrofit PJFF?[c]	no	no	no	no	no
Capital Cost ($/kW)	$0.165	$0.165	$1.269	$1.744	$2.611
Variable Cost (mills/kWh)	0.000	0.000	0.773	0.811	0.895
Total Cost[d] (mills/kWh)	0.005	0.005	0.811	0.862	0.973
100 MW with FF and PJFF					
Retrofit PJFF?	no	no	yes	yes	yes
Capital Cost ($/kW)	$0.165	$0.165	$57.191	$57.666	$58.533
Variable Cost (mills/kWh)	0.000	0.000	0.193	0.230	0.315
Total Cost[c] (mills/kWh)	0.005	0.005	1.593	1.645	1.755

[a] The K-fuel process is primarily designed to improve fuel-heating value, but it may provide NO_X reduction, provides some SO_2 reduction, and provides Hg reduction.

[b] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

[c] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the most conservative situation. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 1.01 mills/kWh. In many cases these costs will not apply because ash may currently be landfilled or because ash may not be rendered completely unacceptable for re-use.

Table 29. K-Fuel[a], ESPh, and No SO_2 Controls (Model Plants 46, 49)[b]

Parameter	Specified Hg Reduction (%)				
	50	60	70	80	90
Hg Reduction of Existing Equipment (%)	12.6	12.6	12.6	12.6	12.6
Hg Reduction by PAC (%)	42.8	54.2	65.7	77.1	88.6
Total Outlet Hg (mg/MWh)	8.1	6.5	4.9	3.3	1.6
975 MW with ESPh and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$36.096	$36.353	$36.517	$36.764	$37.246
Variable Cost (mills/kWh)	0.219	0.242	0.275	0.331	0.457
Total Cost (mills/kWh)	1.123	1.153	1.191	1.254	1.395
100 MW with FF and PJFF					
Retrofit PJFF?	yes	yes	yes	yes	yes
Capital Cost ($/kW)	$57.315	$57.792	$58.145	$58.676	$59.707
Variable Cost (mills/kWh)	0.219	0.242	0.275	0.331	0.457
Total Cost (mills/kWh)	1.624	1.660	1.7.03	1.775	1.932

[a] The K-fuel process is primarily designed to improve fuel-heating value, but it may provide NO_X reduction, provides some SO_2 reduction, and provides Hg reduction.

[b] This table shows Total Cost and the portion of Total Cost that is variable (Variable Cost), both in mills/KWh. For a more comprehensive breakdown of costs, please see the model plant tables in the appendices.

6.4 Cost Impacts of Selected Variables

Sensitivity analysis was performed for certain variables of interest on specific model plants. These included the effects of new sorbents, capital cost on PAC injection, fertilizer cost/power cost on ECO, and lime cost on Advanced Dry FGD.

Effect of New Sorbents on Cost of Hg Control

In the future, cost of controlling mercury could be reduced by new sorbents, which could potentially eliminate disposal costs for spent sorbent/fly ash mixtures. To assess the effects of elimination of ash and sorbent disposal cost, Figure 17 was developed. Figure 17 shows the results of cost estimates comparing mercury control cost for 500 MW plants with and without disposal costs. For each configuration, the sorbent and fly ash are collected together in an existing FF or ESPc. As shown, the elimination of disposal costs can be quite significant, especially for the PRB fuels. Low sulfur bituminous coal, with a low ash level and high Btu content, has a lower component of ash disposal cost of the total cost, but it is nevertheless quite significant at about 0.38 mills/kWh (this is just for the fly ash; the sorbent contributes to additional disposal cost). The PRB fuel has

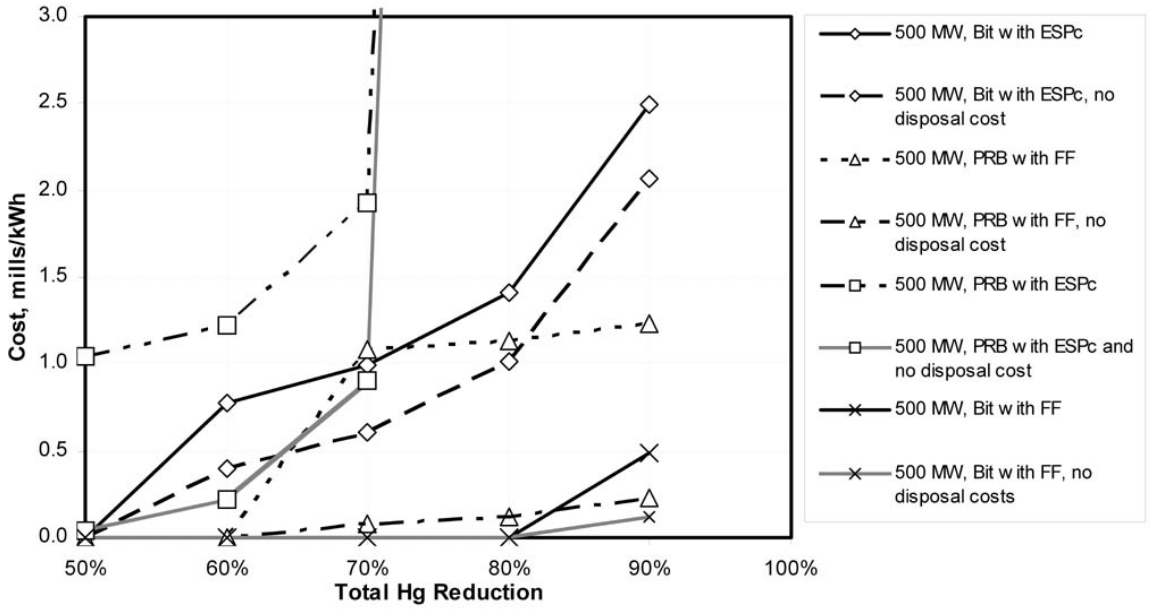

Figure 17. Cost of PAC Injection for 500 MW Coal Fired Boilers with existing ESPc or FF.

a higher ash loading and lower Btu content, causing ash levels to be much higher and disposal costs for contaminated ash much higher (about 1.0 mill/kWh for the ash alone). The exact savings in disposal cost for any particular application will depend upon the actual ash content and Btu value of the particular fuel being used. So, facilities with fuel having different ash content or Btu value will see a different impact on ash disposal costs.

It is also notable that the impact of disposal costs, as a percent of total cost, is much greater for facilities with FFs than for facilities that capture the PAC and fly ash in ESPs. This is because the much lower PAC injection rate for FF-equipped facilities makes ash disposal cost a very large fraction of the total cost. Figure 17 shows that if disposal costs can be avoided by use of cost-effective sorbents other than PAC, or by other means, then the cost of controlling mercury can be reduced by 75 to 80 percent in some cases (PAC injection upstream of existing FF).

There is extensive research ongoing in the field of improved sorbents for mercury control that may be more efficient in capturing mercury and potentially at a lower cost than PAC.[59,74,75] These improvements in sorbents may contribute to overall reductions in sorbent consumption, contributing to reduced costs for disposal, sorbents, and capital equipment. Improved sorbents could enable

users to avoid installation of fabric filters and will also reduce the sorbent storage and material handing equipment on site.

For example, Reference 19 showed that PAC usage for facilities that capture PAC sorbent in downstream ESPs was much more affected by selection of the type of PAC sorbent than facilities that captured the PAC sorbent in a FF. Reference 19 cited the results of several full-scale tests using different PAC materials available from manufacturers. Reference 19 developed three different performance curves for each of the two cases with downstream ESPs (one case with bituminous coal and the other case with a PRB subbituminous coal). The three different curves were characterized as high, medium, and low performance. Figure 18 shows estimates of total cost for PAC injection (inclusive of disposal costs) for the medium performance sorbents used in this study versus higher performance sorbents tested in field trials. The estimates assume that the higher performance PAC sorbents are available at the same price (the higher performance sorbents are PAC with some different physical characteristics—no additional chemicals). As shown in Figure

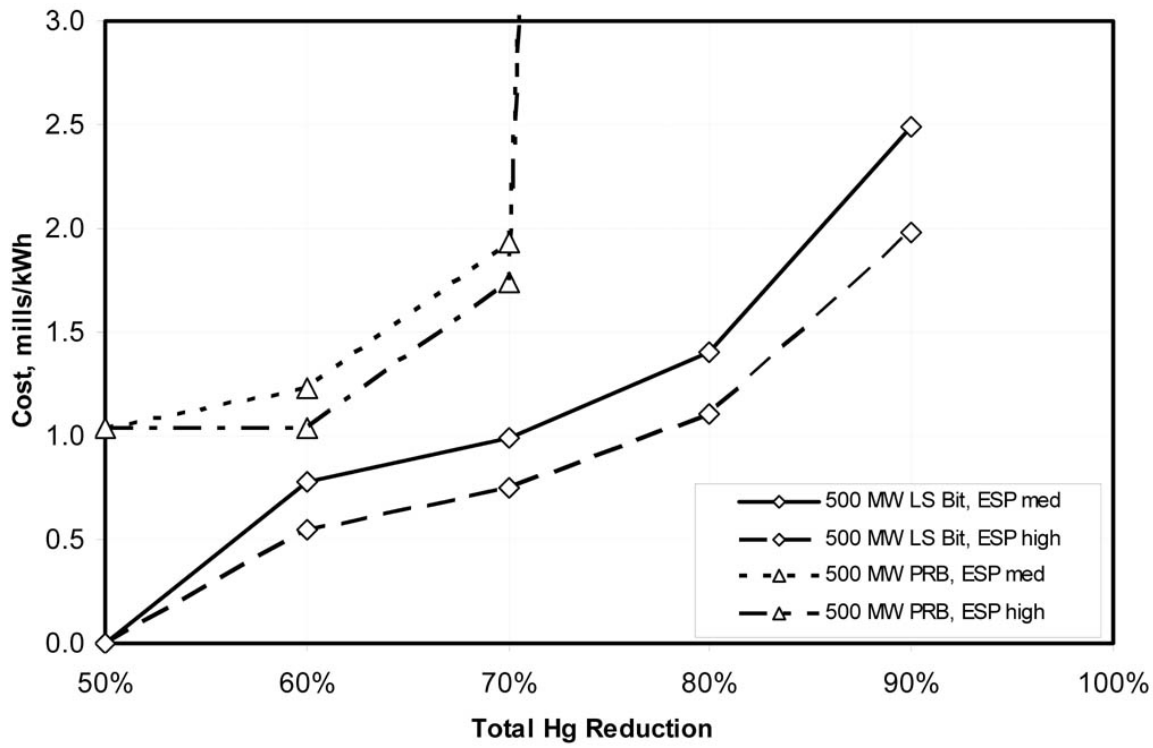

Figure 18. Cost of PAC Injection for 500 MW Coal Fired Boilers with Existing ESPc—Effect of Medium Versus High Performance PAC.

18, cost reduction of 20 percent is estimated for the bituminous coal fired facility when using the higher performance PAC. Because the sorbents used in the calculations to generate Figure 18 are conventional PAC sorbents, even greater cost improvements are likely if other improved sorbents are considered.

Effect of Capital Cost for PAC Injection

For facilities with ESPcs that may retrofit PAC injection and a PJFF downstream of the ESP, capital cost is a major contributor to control cost. As shown in Figure 19, for boilers firing either PRB or low sulfur bituminous coal, the total cost of control is expected to vary from about 1.2 to about 1.8 mills/kWh over the range of expected total capital costs.

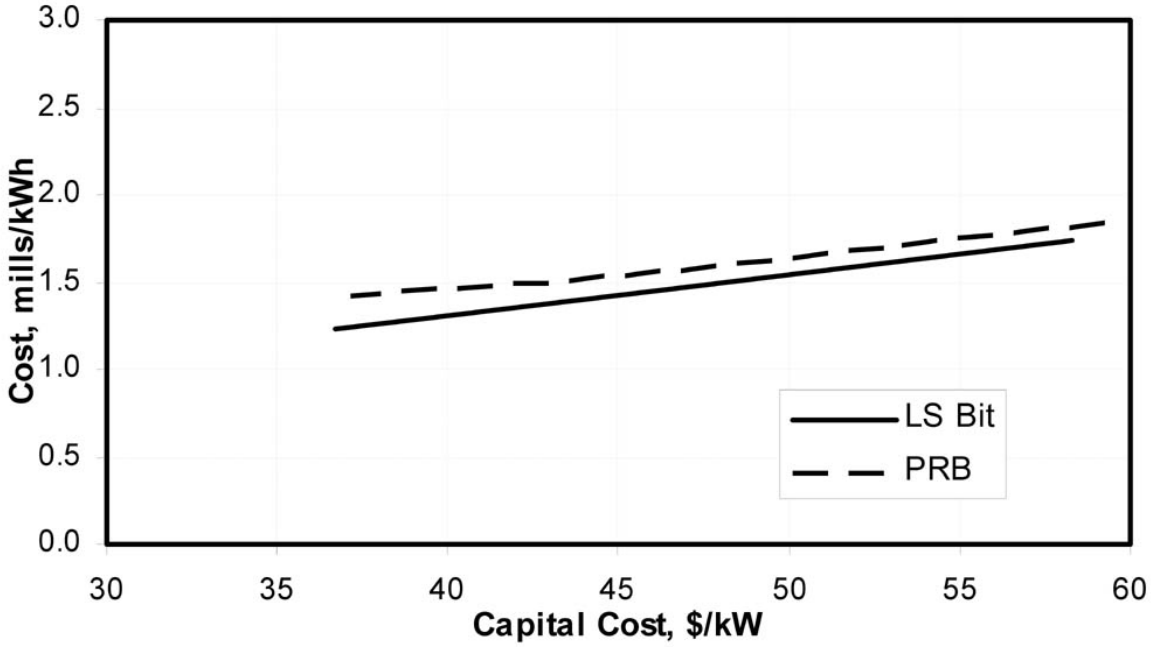

Figure 19. Effect of Capital Cost on 90 Percent Mercury Control with PAC on Boiler with Existing ESPc and Retrofit of Downstream PJFF.

Effect of Fertilizer Value and Power Cost on ECO

Figure 20 shows the estimated effect of the value of fertilizer product on the economics of ECO for a 500 MW plant firing either low sulfur or high sulfur bituminous coal. For a high sulfur coal

fired boiler, the impact of fertilizer value in reducing cost is greater because more fertilizer is produced from a high sulfur coal boiler. Also, for the high sulfur coal boiler, the net cost is lower due to the higher fertilizer revenues. Figure 21 shows the effects of the value of power needed by the ECO on the cost of controlling with ECO on a 500 MW plant firing either low sulfur or high sulfur bituminous coal. For a PRB coal fired boiler or a boiler with lower initial NO_X, the effect of power on total cost is less because power consumption is closely related to NO_X levels.

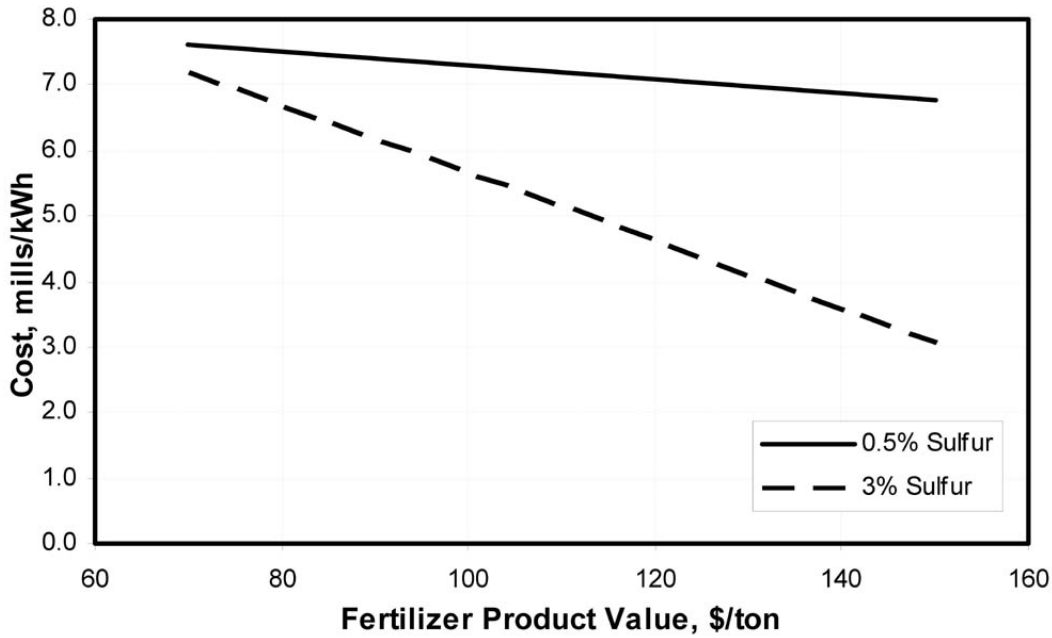

Figure 20. Effect of Fertilizer Value on Cost of Emissions Control with ECO on a 500 MW Bituminous Coal Boiler.

Effect of Lime Cost on Advanced Dry FGD

Figure 22 shows the effects of the cost of lime reagent, an important cost factor, on the total cost of control for advanced dry FGD. As shown, there is roughly !0.19 mills/kWh effect, or a roughly !4 percent effect on the total cost of control over the range evaluated.

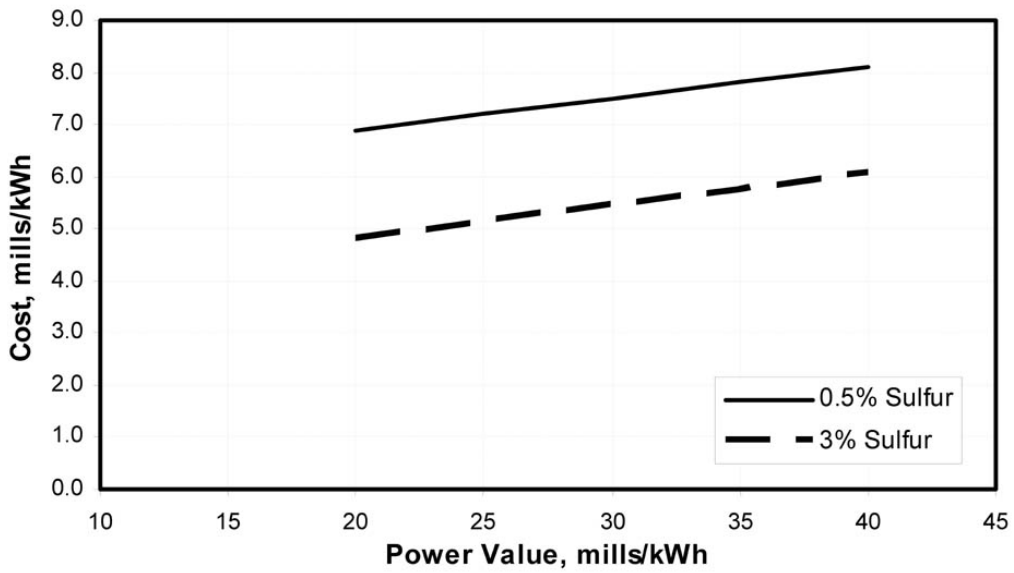

Figure 21. Effect of Power Value on Cost of Emissions Control with ECO on a 500 MW Bituminous Coal Boiler.

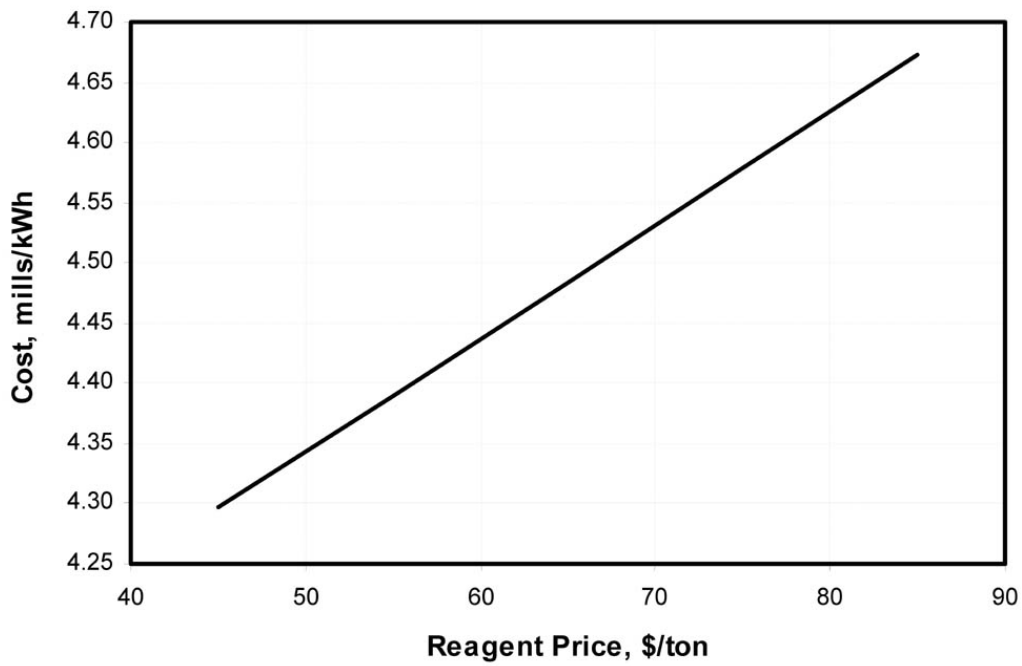

Figure 22. Effect of Reagent Cost on Cost of Emissions Control with Advanced Dry FGD on a 500 MW Boiler Firing Low Sulfur Bituminous Coal.

6.5 Summary of Mercury and Multipollutant Control Costs

Table 30 shows expected costs for control of mercury from coal-fired boilers. Listed are control costs for at least 80 percent and up to 90 percent reduction. The following assumptions were used in making the current and potential cost estimates.

- For situations where one approach seemed to be more attractive than another (such as PAC injection alone versus PAC injection plus a PJFF), it was assumed that the facility owner would normally select the more economically attractive approach.

- An approach that is not considered in the results of Table 27 is changing of fuels to lower mercury content fuels (such as conversion from PRB to K-Fuel, as described earlier). However, depending upon the incremental cost of these fuels relative to the current fuel, they could be more cost effective in the application than the additional controls shown.

- The Current Cost Estimates use PAC sorbent injection levels that have been measured in field tests or in pilot tests using currently available PAC sorbents[19,30] assume that all cases used PAC and that all fly ash that comes in contact with used PAC must be disposed of. As discussed earlier, the assumption that all fly ash currently is sold is a most conservative assumption. For the majority of plants that currently landfill their fly ash, the incremental costs of PAC injection are estimated to be from 0.37 mills/kWh to about 1.0 mills/kWh less than shown in Table 30. Moreover, current research programs offer the potential to reduce operating costs in one of two ways: (1) reduction of sorbent costs by development of less expensive sorbents, or sorbents that are more efficient in mercury capture than existing PAC sorbents or (2) reduction or elimination of disposal costs by utilizing sorbent materials that can be beneficially reused in the same manner as fly ash that may be captured with it. Sensitivity analysis showed that, if disposal costs caused by PAC injection could be avoided, the cost of control could be reduced by 15 to 17 percent for facilities where sorbent is collected in downstream ESPc's and by about 80 percent for facilities where sorbent is collected in downstream FFs. The reason the impact is greater for FFs than for ESPs is because PAC injection rates tend to be much lower for FFs, and the impact of ash disposal cost on total cost is therefore much greater.

Table 30. Estimated Cost of Mercury Control—Current and Potential Cost Estimates

Coal		Existing Controls	Additional Controls	Cost Estimates of Additional Controls (mills/kWh)
Type	S (%)			
Bitt	3	ESP + FGD	PAC + PJFF + CEMS PAC + CEMS	1.144–1.430
Bit	3	SCR + ESP + FGD	CEMS	0.03–0.04
Bit	3	FF + FGD	CEMS	0.03–0.04
Bit	3	SCR + FF + FGD	CEMS	0.03–0.04
Bit	3	ESPh + FGD	PAC + PJFF + CEMS	1.149–1.437
Bit	3	SDA + ESP	PAC + (PJFF) + CEMS[a]	2.211–3.096[a]
Bit	3	SDA + FF	PAC + CEMS	0.05–0.370
Bit	0.6	ESP	PAC + PJFF + CEMS PAC + CEMS[b]	1.171–1.751
Bit	0.6	FF	PAC + CEMS[b]	0.003–0.510
Bit	0.6	ESPh	PAC + PJFF + CEMS	1.205–1.804
PRB	0.5	ESP	PAC + PJFF + CEMS PAC + CEMS[b]	1.236–1.903
PRB	0.5	FF	PAC + CEMS[b]	1.122–1.266
PRB	0.5	ESPh	PAC + PJFF + CEMS	1.273–1.960

[a] For 80 percent control assumes no PJFF. For 90 percent control, assumes full-size PJFF (sized for full ash loading and much more expensive than if sized for downstream of an ESP or FF) being necessary for 90 percent control.

[b] The calculations performed to generate the results in this table assumed that all collected fly ash is currently sold, which is the most conservative situation. Therefore, these calculations include costs to landfill fly ash with an impact to total cost of around 0.37 mills/kWh for the low sulfur bituminous coal and around 1.01 mills/kWh for the low sulfur bituminous coal. In many cases these costs will not apply because ash may currently be landfilled or because ash may not be rendered completely unacceptable for re-use.

In this work, two multipollutant controls were also evaluated: ECO and advanced dry FGD. ECO is an emerging technology, and advanced dry FGD is a technology that is being introduced to the United States by several suppliers. There currently is no commercial experience with ECO at this time. There is limited commercial experience with advanced dry FGD on coal-fired boilers in the United States; however, there is more experience with the technology in Europe. Therefore, the cost information presented in Table 31 should be regarded as preliminary, especially for ECO. However, it should be kept in mind, when considering the higher costs associated with multi-pollutant controls over controls that remove only mercury, that other environmental benefits, such as SO_2 or NO_X control, are realized in addition to mercury reduction.

The universe of multipollutant controls is not limited to the technologies presented in this work. Therefore, other technologies that could offer lower control costs may become available to users.

Table 31. Estimated Costs of Multipollutant Controls

Coal		Existing Controls	Additional Controls	Cost Estimates of Additional Controls (mills/kWh)
Type	S (%)			
Bit	3	ESP	ECO + CEMS	3.28–7.21
Bit	3	ESP	Adv Dry FGD + CEMS	7.94–9.65
Bit	0.6	ESP	ECO + CEMS	5.34–12.33
Bit	0.6	ESP	Adv Dry FGD + CEMS	3.69–6.58
PRB	0.5	ESP	ECO + CEMS	4.54–11.53
PRB	0.5	ESP	Adv Dry FGD[a] + CEMS	3.89–6.79[a]

[a] Mercury control with advanced dry FGD on PRB fuels may be uncertain

K-Fuel, which is developed from low rank western fuels, was also evaluated. It was shown in this work that K-Fuel offers roughly 60 percent, sometimes more, reduction of mercury in the fuel (on a heating value basis). This is achieved by simultaneously reducing the mercury concentration in the fuel while increasing the fuel's heating value. K-Fuel may also offer the facility other environmental or operating benefits besides mercury reduction. Moreover, it was shown that mercury reductions beyond the 60 percent provided by K-Fuel (versus PRB) can be achieved with PAC injection. As the first commercial K-Fuel plant will be built soon, there is no commercial experience with this technology at this time. Costs are evaluated based on cost premium for K-Fuel over a facility's existing fuel. For example, if K-Fuel were available at an incremental cost of $0.12/MMBtu over a base fuel, then the incremental cost would be approximately 1.26 mills/kWh.

7.0 SUMMARY

Cost estimates of PAC injection-based mercury control technologies for coal-fired electric utility boilers have been determined. These estimates include those based on currently available data as well as projections for future applications of more effective sorbent. Estimates based on currently available data range from 0.03-3.096 mills/kWh. However, the higher costs are usually associated with the minority of plants using SDAs plus ESPs or the small number of plants using ESPhs. Potential costs, developed assuming improvements in sorbent technology for mercury removal, range from 0.03-1.69 mills/kWh excluding applications with SDAs plus ESPs or with ESPhs. At the low end of these cost ranges, 0.03 mills/kWh, it is assumed that no additional control technologies are needed but that mercury monitoring will be necessary. In these cases, high mercury removal may be the result of the type of NO_X and SO_2 control measures currently employed.

The estimates based on currently available data may be conservative for the following reasons: (1) They assume that prior to addition of controls all fly ash is sold, and after addition of controls, any fly ash that is combined with spent PAC must be disposed of; (2) The estimates of PAC injection rates for PRB-fired boilers with PAC collected by downstream ESP are based upon experience at Pleasant Prairie Power Plant, which fires a fuel with a lower chlorine content coal than is typical for a PRB fuel; (3) A 65 percent capacity factor is assumed for all cases. The first assumption is conservative because most plants do not currently sell their fly ash; furthermore, fly ash sales might be possible even with small amounts of PAC present. The impact of this assumption was estimated to be in the range from 0.37 mills/kWh to about 1.0 mills/kWh, depending upon fuel characteristics. Thus, for plants that do not currently sell their fly ash (most plants), the actual incremental cost of control would be lower than what we have estimated. Moreover, improved sorbents available in the future may eliminate, or at least mitigate, any impact of sorbent injection on disposal costs. The second estimate is conservative because, at the PPPP tests, mercury reduction by PAC injection was limited to around 70 percent. This is believed to be due, at least in part, to PPPP's unusually low chlorine content—much lower than for most PRB fuels. Therefore, other PRB fueled boilers with chlorine contents typical of a PRB coal, and equipped with a downstream ESP, may be more effectively controlled than what was demonstrated at PPPP. The final assumption is conservative particularly for larger plants that are likely to be base loaded with higher capacity factors.

Results of sensitivity analyses conducted on total annual cost of mercury controls reflect that: (1) Elimination of disposal costs could reduce costs by 80 percent for some cases (PAC injection upstream of an existing FF) and by 17 percent in others (PAC injection upstream of an existing

ESP); (2) Using a more effective PAC sorbent might reduce costs by 20 percent; (3) The cost of a retrofit PJFF has a significant impact on control costs and, over the expected cost range, may cause cost to vary from about 1.2 mills/kWh to about 1.8 mills/kWh; (4) Fertilizer product value and the value of process power requirement have a very significant impact on the cost of ECO, with fertilizer product value being most significant for high sulfur fuel applications; and (5) As expected, lime reagent cost has a large impact on the total cost of using advanced dry FGD.

Based on this work, it is expected that future efforts in R&D are likely to focus on improved understanding of both mercury speciation across SCRs and the beneficial effects of combinations of SCR with wet FGD, and on developing sorbents that can improve performance and cost of sorbent-based mercury control technologies. Multipollutant control technologies, which are more costly than single-pollutant mercury control technologies but offer other environmental benefits, will be another area for further development that could improve the cost of reducing emissions from coal-fired power plants. Finally, removing mercury from the coal, along with other fuel quality improvements, may prove to be a cost effective approach for reducing emissions.

8.0 REFERENCES

1. Keating, M.H.; Mahaffey, K.R. Mercury Study Report to Congress, Office of Air Quality Planning and Standards and Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1997, EPA-452/R-97-003 (NTIS PB98-124738). Also available at the web site http://www.epa.gov/ttn/oarpg/t3rc.html (Accessed October 2003).
2. Mishima, Akio. Bitter Sea: The Human Cost of Minamata Disease, Kosei Publishing Co., Tokyo, Japan, 1992.
3. Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam-Generating Units; *Federal Register* 2000, 65 (245).
4. Srivastava, R.K.; Sedman, C.B.; Kilgroe, J.D. "Performance and cost of Mercury Emission Control Technology Applications on Electric Utility Boilers," EPA-600/R-00-083, September 2000.
5. Boyle, P.; DoVale, A., "Commercial Readiness of Electro-Catalytic Oxidation (ECO) Multipollutant Control Technology, paper available from Powerspan and Wheelabrator.
6. Brown, T.D.; Smith, D.N.; Hargis, R.A.; O'Dowd, W.J. "1999 Critical Review, Mercury Measurement and Its Control: What We Know, Have Learned, and Need to Further Investigate," Journal of the Air & Waste Management Association, June 1999, pp. 1-97.
7. Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort, OMB Control No. 2060-0396, EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC.
8. Control of Mercury Emissions From Coal-Fired Electric Utility Boilers: Interim Report Including Errata Dated 3-31-02, EPA-600/R-01-109, April 2002.
9. Hocquel, M.; Unterberger, S.; Hein, K.; Bock, J. "Behavior of Mercury in Different Gas Cleaning Stages", International Conference on Air Quality, Crystal City, VA, September 9-12, 2002.
10. Richardson, C.; Machalek, T.; Miller, S.; Dene, C.; Chang, R. "Effect of NO_X Control Processes on Mercury Speciation in Utility Flue Gas", International Conference on Air Quality, Crystal City, VA, September 9-12, 2002.
11. Selective Catalytic Reduction Mercury Field Sampling Project, EPA-600/R-02-096, December 2002.
12. Lee, C.; Srivastava, R.; Ghorishi, S.B.; Hastings, T.W.; Stevens, F.M. "Study of Speciation of Mercury under Simulated SCR NO_X Emission Control Conditions," AWMA Paper 03-A-41-

AWMA, Presented at the Joint EPRI DOE EPA Combined Utility Air Pollution Control Symposium, The Mega Symposium, Washington, D.C., May 19-22, 2003.
13. Personal Communication, e-mail, from Ravi Srivastava, U.S. EPA, March 13, 2003.
14. Lissianski, V.; Zamansky, V.; Maly, P.; Seeker, R. "Control of NO_X and Mercury Emissions During Coal Reburning", 95th Annual A&WMA Conference and Exhibition, Baltimore, MD, June 23-27, 2002.
15. Lissianski, V.; Zamansky, V.; Maly, P.; Seeker, R. "Integration of Combustion Modifications with Mercury Control," Air Quality III Conference, Washington, DC., September 11, 2002.
16. Lissianski, V.; Maly, P.; Ho, L.; Zamansky, V.; Glenn, E.; Seeker, R. "Multi-Pollutant Control for Boilers Firing Low-Rank Coals," Presented at the Joint EPRI DOE EPA Combined Utility Air Pollution Control Symposium, The Mega Symposium, Washington, D.C., May 19-22, 2003.
17. Srivastava, R.K.; Jozewicz, W. Flue Gas Desulfurization: The State of the Art, *J. Air & Waste Manage. Assoc. 51(12), 1676-1688*, December 2001.
18. An Assessment of Mercury Emissions from U.S. Coal Fired Power Plants, EPRI, Palo Alto, CA, 2000. EPRI 1000608
19. Staudt, J.E.; Jozewicz, W.; Srivastava, R. "Modeling Mercury Control with Powdered Activated Carbon", AWMA Paper 03-A-17-AWMA, Presented at the Joint EPRI DOE EPA Combined Utility Air Pollution Control Symposium, The Mega Symposium, May 19-22, 2003, Washington, D.C.
20. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, Volume 1, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, February 1998, EPA-453R-98-004a (NTIS PB98-131774).
21. Waugh, E.G.; Jensen, B.K.; Lapatnick, L.N.; Gibbons, F.; Sjostrom, S. Ruhl, J.; Slye, R.; Chang, R. "Mercury Control in Utility ESPs and Baghouses through Dry Carbon-Based Sorbent Injection Pilot-Scale Demonstration," EPRI-DOE-EPA Combined Air Pollutant Control Symposium, Particulates and Air Toxics, Volume 3, EPRI TR-108683-V3, Electric Power Research Institute, Palo Alto, CA, August 1997, pp. 1-15.
22. Haythornthwaite, S.M.; Smith, J.; Anderson, G.; Hunt, T.; Fox, M.; Chang, R.; Brown, T. "Pilot-Scale Carbon Injection for Mercury Control at Comanche Station," presented at the A&WMA 92nd Annual Meeting & Exhibition, St. Louis, MO, June 1999.
23. Haythornthwaite, S.M.; Sjostrom, S.; Ebner, T.; Ruhl, J. Slye, R. Smith, J.; Hunt, T.; Chang, R.; Brown, T.D. "Demonstration of Dry Carbon-Based Sorbent Injection for Mercury Control in Utility ESPs and Baghouses," EPRI-DOE-EPA Combined Air Pollutant Control Symposium,

Particulates and Air Toxics, Volume 3, EPRI TR-108683-V3, Electric Power Research Institute, Palo Alto, CA, August 1997.

24. Redinger, K.E.; Evans, A.P.; Bailey, R.T.; Nolan, P.S. "Mercury Emissions Control in FGD Systems," EPRI-DOE-EPA Combined Air Pollutant Control Symposium, Particulates and Air Toxics, Volume 3, EPRI TR-108683-V3, Electric Power Research Institute, Palo Alto, CA, August 1997.
25. Durham, M.; Bustard, J.; Schlager, R.; Martin, C.; Johnson, S.; Renninger, S. "Field Test Program to Develop Comprehensive Design, Operating Cost Data for Mercury Control Systems on Non-Scrubbed Coal-Fired Boilers," AWMA 94th Annual Conference and Exhibition, Orlando, FL, June 24-28, 2001.
26. Bustard, J.; Durham, M.; Lindsey, C.; Starns, T.; Baldrey, K.; Martin, C.; Schlager, R.; Sjostrom, S.; Slye, R.; Renninger, S.; Monroe, L.; Miller, R.; Chang, R., "Full-Scale Evaluation of Mercury Control with Sorbent Injection and COHPAC at Alabama Power E.C., Gaston," DOE-EPRI-U.S. EPA-A&WMA Power Plant Air Pollutant Control Mega Symposium, Chicago, IL, August 20-23, 2001.
27. "Gaston Demonstrates Substantial Mercury Removal with Sorbent Injection," Power Engineering, vol. 106, no. 11, November 2002.
28. Starns, T.; Bustard, J.; Durham, M.; Lindsey, C.; Martin, C.; Schlager, R.; Donnelly, B.; Sjostrom, S.; Harrington, P.; Haythornthwaite, S.; Johnson, R.; Morris, E.; Chang, R.; Renninger, S., "Full-Scale Test of Mercury Control with Sorbent Injection and an ESP at Wisconsin Electric's Pleasant Prairie Power Plant," AWMA 95th Annual Conference and Exhibition, Baltimore, June 23-27, 2002.
29. DOE National Energy Technology Laboratory Mercury Field Evaluation – PG&E NEG Salem Harbor Station – Unit 1, Project No. 00-7002-76-10, Field Evaluation Summary Report, January 2003.
30. Memo from Michael Durham, ADA Environmental Solutions to Mary Jo Krolewski, U.S. Environmental Protection Agency.
31. Powerspan Corporation Web site, http://www.powerspan.com (Accessed October 2003).
32. Personal Communication, telephone conversation with Phil Boyle, Powerspan, March 14, 2003.
33. Personal Communication, e-mail and telephone conversation with Phil Boyle, Powerspan, March 6, 2003.
34. Boyle, P.; DoVale, A. "Commercial Readiness of Electro-Catalytic Oxidation (ECO™) Multipollutant Control Technology," paper available from Powerspan and Wheelabrator.

35. DePriest, W.; Pope, F., "Economic Evaluation of a Multi-Pollutant Control Approach for Ameren UE's Sioux Plant," International Power Generation Conference, Orlando, December 2002.
36. Personal Communication, e-mail from Will Goss, Beaumont Environmental, February 6, 2003.
37. F.L. Smidth Airtech Corporation web site, http://www.flsairtech.com (Accessed October 2003).
38. Personal Communication, telephone conversation with Will Goss, RJM-Beaumont, February 4, 2003.
39. Personal Communication, telephone conversation with Milas Ballard of Lurgi, February 20, 2003.
40. Graf, R., "High-Efficiency Circulating Fluidized Bed Scrubber," DOE-EPRI-U.S. EPA-A&WMA Power Plant Air Pollutant Control Mega Symposium, Chicago, IL, August 20-23, 2001.
41. Design for 250 MW and 500 MW plants provided by Beaumont Environmental Systems, February 4, 2003.
42. "Roanoke Valley Energy Facility Mercury Testing," report prepared by Arcadis Geraghty & Miller for Roanoke Valley Energy Facility, January 25, 2001.
43. RJM-Beaumont Next Generation Multi-Pollutant Technology, available at http://www.RJM.com (Accessed October 2003).
44. Lurgi Lentjes CFB Scrubber Reference List, March 7, 2003.
45. Personal Communication with Sam Kumar, F.L. Smidth AirTech, March 3, 2003.
46. "10 MW_e Demonstration of Gas Suspension Absorption," Clean Coal Technology Program: Program Update 2000, DOE/FE-0437, April 2001, pp 5-22 to 5-25.
47. Circulating Fluidized Bed – Flue Gas Desulfurization Technology, Prepared for Lurgi-Lentjes North America, March 2003.
48. Black & Veatch Corporation, "Effective Mercury Reduction Strategy for Western Coal – Report to EPA – K-Fuel Technology," Report to U.S. Environmental Protection Agency, March 2003.
49. Personal Communication with Ted Venners, KFx Corporation, May 8, 2003.
50. Black & Veatch Corporation, "K-Fuel Market Value and Market Potential Preliminary Evaluation," August 2002.
51. U.S. Patent No. 5,316,737, "Process for Removing NO_X and SO_X from Exhaust Gas," Arthur P. Skelley, et al; May 31, 1994.
52. Goss, W.L.; Lutwen, R.C.; Ferrell, R.; Suchak, N.; Hwang, S.C. "A Report of the Startup of a Multi-Pollutant Removal System for NO_X, SO_X, and Particulate Control Using a Low Temperature Oxidation System on a 25 MW Coal Fired Boiler," Power-Gen 2001, Las Vegas, NV, December 12, 2001.

53. Ferrell, R.; Suchak, N.; Hwang, S.C.; Tseng, J.; Kelton, R.; Goss, W.; Lutwen, R. "A Report on the Application of Low Temperature Oxidation for Control of NO_X Emissions," presented at ICAC Forum 02, Houston, TX, February 13, 2002.
54. Jarvis, J.B.; Day, A.T.; Suchak, N.J. "LoTOxTM Process Flexibility and Multi-pollutant Control Capability," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
55. Altman, R.; Buckley, W.; Ray, I. "Multi-Pollutant Control with Dry-Wet Hybrid ESP Technology," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
56. Montgomery, J.L.; Battelson, D.M., Whitworth, C.G., Ray, I., Buckley, W., Reynolds, J., and Altman, R. "Plasma-Enhanced Electrostatic Precipitation Technology for Control of Elemental Mercury," International Power Generation Conference, Orlando, December 2002.
57. Montgomery, J.L., Battelson, D.M.; Whitworth, C.G.; Ray, I.; Buckley, W.; Reynolds, J.; Altman, R. "Latest Developments of the Plasma-Enhanced Electrostatic Precipitator for Mercury Removal in Off-gas," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
58. Blythe, G.M.; Richardson, M.F.; Lani, B.W.; Rhudy, R.G. "Pilot Testing of Oxidation Catalysts for Enhanced Mercury Control by Wet FGD," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
59. Butz, J.; Lovell, J.; Broderick, T.; Sidwell, R.; Turchi, C.; Kuhn, A., "Evaluation of Amended Silicates™ Sorbent for Mercury Control," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
60. Sjostrom, S.; Chang R., Apparatus and Method of the Removal of Contaminants in Gases, U.S. Patent 5,948,143, 1999 and U.S. Patent 6,136,072, 2000.
61. Sjostrom, S.; Chang, R.; Strohfus, M.; Johnson, D.; Hagley, T.; Ebner, T.; Richardson, C.; Belba, V., "Development and Demonstration of Mercury Control by Adsorption Processes (MerCAPTM)," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
62. "Coal Plant Achieves 99% NO_X and SO_X Removal with Multi-pollutant Technology," Power Engineering Magazine, May 2002.
63. Enviroscrub brochure: "Pahlman™ Process Overview"
64. Haddad, E.; Ralston, J.; Green, G.; Castagnero, S. "Full-Scale Evaluation of a Multi-Pollutant Reduction Technology: SO_2, Hg, and NO_X," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
65. Gebert, R.; Rinschler, C.; Davis, D.; Leibacher, U.; Studer, P.; Eckert, W.; Swanson, W.; Endrizzi, J.; Hrdlicka, T.; Miller, S. J.; Jones, M. L.; Zhuang, Y.; Collings, M. "Commercializa-

tion of the Advanced Hybrid™ Filter Technology," Air Quality III Conference, Arlington, VA, September 2002, Session B3.

66. Durante, V.A.; Stark, S.; Gebert, R.; Xu, Z.; Bucher, R.; Keeney R.; Ghorishi, B. "A Novel Technology to Immobilize Mercury from Flue Gases," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
67. Gostomczyk, M.A.; Jozewicz, W. "Simultaneous Control of SO_2, NO_X, and Mercury Emissions from Coal-fired Boilers," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
68. Electric Power Development Corp. "Isogo Thermal Power Station/Outline of Facilities," company brochure describing the Isogo power station, 2000.
69. Mitsui Mining Co., Ltd. "Dry Type Desulfurization and Denitrification Technology for Coal-fired Power Plants," company brochure, May 2000.
70. Olson, D.G.; Tsuji, K.; Shiraishi, I. "The Reduction of Gas Phase Air Toxics from Combustion and Incineration Sources Using the MET-Mitsui-BF Activated Coke Process," 1999 International Ash Utilization Symposium, Lexington, KY, October 18-20, 1999.
71. Keith, R.; Blag, R.; Burklin, B.; Kosmicki, B.; Rhodes, D.; Waddell, T. "Coal Utility environmental Cost (CUECost) workbook User's Manual, Version 1.0," EPA-600/R-99-056 (NTIS PB99-151938), June 1999.
72. Srivastava, R.K. "Current and Emerging Mercury Control Technologies," Western Mercury Workshop, April 21-23, 2003, Denver, CO.
73. Standard Specification for Coal Fly Ash and Raw or Calcined Natural Pozzolan for Use as a Mineral Admixture in Concrete, ASTM Standard C618-03.
74. Dombrowski, K.D.; Machalek, T.; Richardson, C.; Chang, R.; Rostam-Abadi, M. "Recent Developments in EPRI's Novel Mercury Sorbent Development Program," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.
75. Biermann, J.; Voogt, N.; Sorooshian, A.; Wendt, J.; Merritt, R.; Gale, T. "In-Flight Capture of Elemental and Oxidized Mercury in Coal Combustion Flue Gases by a Novel Mineral Sorbent Between 320 and 1540 °F (160-840 °C)," Combined Power Plant Air Pollutant Control Mega Symposium, Washington DC, May 19-22, 2003.