Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008
(revised January 2009)

Members of Northeast States for Coordinated Air Use Management

Arthur Marin, Executive Director
Northeast States for Coordinated Air Use Management

Anne Gobin, Bureau Chief
Connecticut Department of Environmental Protection, Bureau of Air Management

James P. Brooks, Bureau Director
Maine Department of Environmental Protection, Bureau of Air Quality

Barbara Kwetz, Director
Massachusetts Department of Environmental Protection, Bureau of Waste Prevention

Robert Scott, Director
New Hampshire Department of Environmental Services, Air Resources Division

William O’Sullivan, Director
New Jersey Department of Environmental Protection, Office of Air Quality Management

David Shaw, Director
New York Department of Environmental Conservation, Division of Air Resources

Douglas L. McVay, Acting Chief
Rhode Island Department of Environmental Management, Office of Air Resources

Richard A. Valentinetti, Director
Vermont Department of Environmental Conservation, Air Pollution Control Division

UNITS, SPECIES, ACRONYMS

Acronyms

APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
BOOS – Burners Out of Service
CAA – Clean Air Act
CAAA – Clean Air Act Amendments (of 1990)
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – Electrostatic Precipitators
FBC – Fluidized Bed Combustion
FF – Fabric Filter (also known as baghouse)
FGD – Flue Gas Desulfurization (also known as SO_2 scrubber)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
FSI – Furnace Sorbent Injection
GR – Gas Reburn
HHV – Higher Heating Value
ICI – Industrial, Commercial, and Institutional (boilers)
LAER – Lowest Achievable Emission Rate
LNB – Low-NOx Burner
LSDI – Lime Slurry Duct Injection
LSFO – Limestone Forced Oxidation
LSC – Low-Sulfur Coal (also known as compliance coal)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic-Northeast Visibility Union
MC – Mechanical Collector
NAAQS – National Ambient Air Quality Standard
NCG – Non-Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standards
NSR – Normalized Stoichiometric Ratio
OFA – Overfire Air
PC – Pulverized Coal
PRB – Powder River Basin (coal)
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SCA – Specific Collection Area
SCR – Selective Catalytic Reduction

SD – Spray Dryer
SIP – State Implementation Plan
SNCR – Selective Non-Catalytic Reduction
TCR – Total Capital Requirement
TR – Transformer Rectifier
UBC – Unburned Carbon
US EIA – United States Energy Information Administration
US EPA – United States Environmental Protection Agency
ULNB – Ultra Low-NOx Burner
VOM – Variable Operating and Maintenance (costs)
WESP – Wet Electrostatic Precipitator
WFGD – Wet Flue Gas Desulfurization (also known as wet SO_2 scrubber)

Chemical Species
HCl – Hydrochloric Acid
HF – Hydrofluoric Acid
H_2SO_4 – Sulfuric Acid
NOx – Oxides of Nitrogen (NO_2 and NO)
NO – Nitric Oxide
NO_2 – Nitrogen Dioxide
NH_3 – Ammonia
$PM_{2.5}$ – Particulate Matter up to 2.5 µm diameter in size
PM_{10} – Particulate Matter up to 10 µm diameter in size
S – Sulfur
SO_2 – Sulfur Dioxide
SO_4 – Sulfate
VOC – Volatile Organic Compound

Units
Length
m – meter
µm – micrometer or micron (0.000001 m; 10^{-6} m)
km – kilometer (1000 m; 10^{3} m)
Mm – Megameter (1,000,000 m; 10^{6} m)

Flow Rate
acfm – actual cubic feet per minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
µg – micrograms (0.000001 g; 10^{-6} g)

kg – kilograms (1000 g; 10^3 g)

Force
psi – pounds per square inch

Power
W – watt (Joules/sec)
kW – kilowatt (1000 W; 10^3 W)
MW – megawatt (1,000,000 W; 10^6 W)

Energy
Btu – British thermal unit (= 1055 Joules)
MMBtu – million Btu
MWhr – megawatt-hour
kWhr – kilowatt-hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Northeast States for Coordinated Air Use Management (NESCAUM)

November 2008

(revised January 2009)

Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

Project Director

Praveen Amar, Ph.D., P.E., Director, Science and Policy, NESCAUM

Principal Contributors

Constance L. Senior, Ph.D., Reaction Engineering International
Rui Afonso, Energy and Environmental Strategies

Acknowledgments

NESCAUM gratefully acknowledges the funding support provided by the United States Environmental Protection Agency (Clean Air Markets Division (CAMD) and Office of Air Quality Planning and Standards (OAQPS)). Mr. Sikander Khan (CAMD) and Mr. Tim Smith (OAQPS) acted as the Project Managers and Mr. Gene Sun was the Grant Manager.

This report was managed and directed by NESCAUM (Dr. Praveen Amar). NESCAUM was very ably supported by its contractors, Reaction Engineering International (Dr. Constance L. Senior) and Energy and Environmental Strategies (Mr. Rui Afonso). Additionally, Mr. Addison Faler, a student intern at NESCAUM, did extensive data analysis of emission estimates from industrial, commercial, and institutional boilers in the Northeast and the US. Ms. Wendy Roy, Administrative Assistant, NESCAUM, was extremely helpful in final formatting of the report.

NESCAUM thanks the members of the NESCAUM Stationary Sources and Permitting Committee, who guided the design of this report in early stages and provided access to the operating permits data, included in this report. The following individuals provided strong technical support and comments on various draft versions of this report:

Andrew Bodnarik, New Hampshire Department of Environmental Services

Sunila Agrawal, New Jersey Department of Environmental Protection

NESCAUM is an association of the eight northeast state air pollution control programs and provides technical guidance and policy advice to its member states.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

ES-1 Objectives

The main objective of this study is to evaluate the viability of technologies for controlling emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM) from industrial, commercial, and institutional (ICI) boilers. These pollutants contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. This source sector is coming under increased scrutiny by air quality regulators needing emission reductions to meet Clean Air Act requirements.

This study also includes a literature review of emission control costs and develops methods for estimating the costs and cost effectiveness of air pollution controls for ICI boilers. The study concludes that ICI boilers are a significant source of emissions, are relatively uncontrolled compared to electricity-generating units (EGUs), and offer the potential to achieve cost effective reductions for all three pollutants. The results of this technical and economic evaluation are intended as a resource in assessing regulatory and compliance strategies for ICI boilers.

Most of the technologies considered in this report have been successfully applied to the larger EGU boilers. This study investigates both the feasibility of down-scaling such control technologies for ICI boiler applications and of certain technologies that have not been applied to EGUs, but show promise for the ICI boilers.

ES-2 Report Organization

Chapter One provides an overview of the ICI boiler fleet in terms of boiler size, applications, fuel type and associated emissions. Chapters Two, Three, and Four discuss control technology options for NOx, SO_2 and PM, respectively. Each chapter provides: (1) descriptions of available control technologies; (2) a discussion of the applicability of these technologies to ICI boilers; (3) published cost estimates; and (4) an assessment of the impact of control technologies on overall facility efficiency. Chapter Five summarizes information about air pollution control equipment costs for ICI boilers calculated with the Coal Utility Environmental Cost (CUECost) model.

ES-3 Differences between ICI and EGU Boilers

ICI and EGU boilers differ in size, application, design, and emissions. Most commercial and institutional boilers are relatively small, with an average capacity of 17 MMBtu/hour. Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. By contrast, the average size of a coal-fired EGU boiler in the U.S. is greater than 2,000 MMBtu/hr.

All coal-fired EGUs in the United States are equipped with PM control devices and many have SO_2 and NOx emission controls. ICI boilers are significantly less likely to have air pollution control devices.

As part of this study, NESCAUM conducted a preliminary survey of the use of emission controls on ICI boilers in the Northeast. Survey results revealed that more than half of the units surveyed in the region had no controls; about one-third had PM controls, while very few units had NOx controls. None of the surveyed units had SO_2 controls, although some have wet venturi scrubbers for PM control, which minimally reduce SO_2 emissions.

Technical, operational, economic and regulatory factors impose different opportunities and constraints on the applicability of air pollution control devices (APCDs) for EGU and ICI boilers. The following technical and operational characteristics must be evaluated in determining the potential applicability of emission controls for specific ICI boilers.

- Fuel type and quality – SO_2, PM, and NOx emissions from coal-fired boilers are typically higher than from those burning natural gas, oil, or wood waste. Some APCD technologies are not particularly sensitive to such variations. For example, an electrostatic precipitator (ESP) or a fabric filter (FF) can accommodate different PM concentrations, although the type and size of PM and gas temperatures will have an impact. Other controls that utilize reagents, such as SO_2 scrubbers and selective catalytic reduction or selective non-catalytic reduction (SCR/SNCR) technologies for NOx, are directly affected by fuel type and quality.
- Duty cycle – APCD controls must be capable of accommodating significant variation or cycling of boiler loads. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – The presence of equipment such as economizers or air preheaters has a direct impact on flue gas temperatures. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers, and SCR/SNCR that are widely used in EGUs may or may not be applicable to ICI boilers in certain cases.

ES-4 NOx Control Technologies

Emission control strategies for NOx can be divided into two basic categories: combustion modifications and post-combustion technologies. Control efficiency ranges and cost effectiveness ($/ton of NOx removed) for various technologies are provided in Table ES-1. Combustion modification technologies, which minimize the formation of NOx during the combustion process, include: combustion tuning; low-NOx burners and overfire air (LNBs and OFA); and gas, oil, or coal reburn.

LNBs have minimal effect on overall operating costs, but may introduce higher carbon monoxide and/or carbon levels in the fly ash, which reflect lower plant efficiency. In the case of gas reburn, operating costs are primarily a function of the fuel cost differential; for coal or oil reburn, fuel preparation costs (pulverization and atomization, respectively) represent the primary operating and maintenance costs. While gas reburn is easier to implement, the fuel differential costs are often prohibitive. The overall cost of low-NOx combustion technology installation depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity.

Post-combustion technologies reduce the amount of NOx exiting the stack that was formed during combustion. This group includes SNCR, SCR, and regenerative SCR (RSCR) technologies. Because the reaction occurs without the need for catalysts, SNCR systems have lower capital costs, but achieve lower NOx reduction. SCR, on the other hand, is capital-intensive, but offers the opportunity for significantly greater NOx reductions because a dedicated reactor and a reaction-promoting catalyst ensure a highly controlled, efficient reaction. RSCR combines a regenerative thermal oxidizer with SCR technology, making it suitable for facilities with lower gas temperatures, such as those found in some ICI boilers. RSCRs can also reduce carbon monoxide emissions by half.

ES-5 SO_2 Control Technologies

SO_2 emission control technologies are post-combustion devices that utilize a process involving SO_2 reacting in the exhaust gas with a reagent (usually calcium- or sodium-based) and removal of the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 control technologies are commonly referred to as flue gas desulfurization (FGD) and/or “scrubbers” and are usually characterized in terms of the process conditions (wet vs. dry), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable). Wet scrubbers provide much greater levels of SO_2 control. Conventional dry processes include spray dryers (SDs) and dry sorbent injection (DSI). The capital costs of wet scrubbers are higher than those of dry scrubbers, although the cost effectiveness values (in dollars per ton of SO_2 removed) of wet and dry processes are similar. DSI technology has a significantly lower capital cost than wet or dry scrubbers and should therefore be more attractive for ICI boilers than conventional scrubbers.

In the eight-state NESCAUM region, residual oil is a common fuel for ICI boilers. Switching to a lower sulfur residual oil (for example, from 3 percent to 1 percent sulfur residual oil) can provide cost-effective SO_2 reductions. The cost of switching to lower sulfur distillate oil is much higher than switching to low sulfur residual oil, because the cost of distillate oil has been about twice that of residual oil in recent years. The cost effectiveness (in dollars per ton of SO_2 removed) from switching from residual fuel oil to distillate fuel oil is not as attractive and falls in the range of the cost effectiveness of installing a FGD scrubber.

ES-6 PM Control Technologies

Combustion processes emit both primary and secondary particulate matter. Primary emissions consist mostly of fly ash (e.g., non-combustible inorganic matter and unburned solid carbon). Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter. PM control technologies include: fabric filters or “baghouses,” wet and dry ESPs, venturi scrubbers, cyclones, and core separators. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired ICI boilers.

ES-7 Impact of Control Technologies on Operational Efficiency and Carbon Dioxide Emissions

Air pollution control technologies and strategies (e.g., fuel switching) can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative depending on technology and fuel choices.

Carbon dioxide (CO_2) emissions are primarily a function of the carbon content of fuels. However, the application of conventional pollutant control technologies can affect CO_2 emissions. This impact can vary widely among technologies within the same pollutant (e.g., LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. scrubbers for SO_2).

Combustion modification technologies for NOx have essentially no impact on the CO_2 emissions of the host boilers – with the noted exception of reburn when displacing coal or oil with natural gas – because the technologies do not impose any significant parasitic energy consumption (auxiliary power) requirements. With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy demand on the host boiler. These impacts include pressure, compressor, vaporization, and steam losses, and can range from 1–2 kW/1000 actual cubic feet per minute (acfm) for SNCR and up to about 4 kW/1000 acfm for SCR.

The major components affecting energy consumption for SO_2 systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. The power consumption of the SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. SO_2 controls have a range of potential parasitic losses, from duct injection representing about 1–2 kW/1000 acfm to wet FGD at as high as 8 kW/1000 acfm.

PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can be up to 10 kW/1000 acfm or higher.

ES-8 Cost Analysis

Cost is an important factor in evaluating the viability of air pollution control technologies. Information on capital and operating costs is more readily available for EGU than ICI boilers. Operating costs may be different for ICI boilers than utility boilers because of their size and the fact that they are typically located on smaller sites. Operating costs also include waste disposal and reagent use. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs, as a percentage of total capital cost, than those for utility boilers.

Cost estimates for ICI boilers with capacities ranging from 100 to 250 MMBtu/hr were generated by the CUECost model. This model, created by Raytheon Engineers for US EPA, was originally developed for large coal-fired EGUs and calculates capital and operating costs for certain pre-defined air pollution control devices for NOx, SO_2, and PM. The CUECost model produces approximate estimates (±30 percent accuracy) of installed capital and annualized operating costs. The CUECost model was adapted in this study for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. This study represents the first attempt to utilize a comprehensive cost model specific to ICI boilers.

Chapter Two contains a detailed discussion of the literature values for NOx control costs for ICI boilers. The NOx control costs for ICI boilers computed with CUECost were largely consistent with values reported in the literature. In terms of NOx removal, reported values were in the range of \$1,000 to \$3,000 per ton for LNBs or SNCR, and \$2,000 to \$14,000 per ton for SCR. The SCR costs for coal-fired ICI boilers appear to be consistent with the literature, although the CUECost capital cost values for residual oil were higher than the literature values. The capital costs for SNCR calculated from the CUECost models were in good agreement with literature values, particularly their sensitivity to boiler capacity. The capital costs for LNBs calculated from CUECost for coal-fired boilers were consistent with the literature values, although the costs for residual oil-fired boilers were higher in CUECost than the literature values.

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs for ICI boilers. In terms of the cost per ton of SO_2 removed, reported values were in the range of $1,600 to $5,000 for spray dryers (SDs) and $1,900 to $5,200, for wet FGDs. The SO_2 capital costs computed with CUECost for SDs were in the range of the literature values at 250 MMBtu/hr. However, the capital costs computed by CUECost for wet FGDs were high compared to values reported in the literature.

Chapter Four contains a detailed discussion of the literature values for PM control costs. Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to industrial boilers. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM for coal and up to $15,000 per ton of PM for oil.

The dry-ESP control costs computed with CUECost were consistent with the literature values, although the CUECost predicted slightly higher values than reported by EPA for dry, wire-plate ESPs. The baghouse/fabric filter costs computed with CUECost were higher than the literature values for pulse-jet fabric filters.

This adaptation of CUECost model from EGUs to ICI boilers was intended to investigate the feasibility of estimating costs of controlling emissions of NOx, SO_2, and PM from ICI boilers. Further detailed work would be needed to validate this approach, but initial results included in this report are promising.

ES-9 Conclusion

ICI boilers are a significant source of NOx, SO_2, and PM emissions, which contribute to the formation of ozone, fine particles, and regional haze, and to ecosystem acidification. These boilers are relatively uncontrolled compared to EGUs and offer the potential to achieve cost-effective reductions for all three pollutants. A host of proven emission control technologies for EGUs can be scaled-down and deployed in industrial, commercial, and institutional settings to cost-effectively reduce emissions of concern. Other technologies that have not been applied to EGUs show promise for ICI boiler applications. Careful analysis will be needed to match the appropriate emission control technology for specific applications given: boiler size, fuel type/quality, duty-cycle, and design characteristics. Further, regulators will need to determine the level of emission reductions needed from this sector in order to inform the appropriate choice of controls.

Table ES-1. ICI Boiler Control Technologies

Pollutant	Technology	Control Efficiency	Cost Effectiveness $ per ton
NOx			
Combustion Modifications	Tuning	5-15%	current data not available
	LNB	25-55%	$750-$7,500
	Reburn	35-60%	current data not available
Post-Combustion	SNCR	30-70%	$1,300-$3,700
	SCR	70-90%	$2,200-$14,400
	RSCR	60-75%	$4,500
SO_2	Wet Scrubbers	95+%	$1,900-$5,200
	Spray Dryers	90-95%	$1,600-$5,200
	Dry Sorbent Injection	40-90%	current data not available
PM			
	Fabric Filters/Baghouses	99+%	$400-$1,000 – coal $6,900-$16,500- oil
	Wet/Dry ESPs	99+%	$160-$2,600 – coal $2,300 to $43,000 - oil
	Venturi Scrubbers	50-90%	current data not available
	Cyclones	70-90%	current data not available
	Core Separators	60-75%	current data not available

1 INTRODUCTION

1.1 Objectives

The main objective of this study is to evaluate various available control technologies and their cost effectiveness in reducing emissions of three pollutants: oxides of nitrogen (NOx), sulfur dioxide (SO_2), and primary fine particulate matter ($PM_{2.5}$) from industrial, commercial, and institutional (ICI) boilers. The study results should provide a strong technical and economic basis for developing cost-effective regulations and strategies to reduce emissions of these three major pollutants from ICI boilers.

1.2 Regulatory Drivers

Federal, state and local governments regulate all major criteria air pollutants under the authority of the Clean Air Act (CAA). The CAA mandates control of pollutants such as NOx, SO_2, and $PM_{2.5}$ to attain and maintain National Ambient Air Quality Standards (NAAQSs) for ozone and $PM_{2.5}$, reduce acidic deposition, and improve visibility under regional haze regulations. Emission standards for specific source categories, including ICI boilers, are also set by federal, state, and local governments to attain and maintain a NAAQS. Examples of these emission standards include New Source Performance Standards (NSPS), Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), Reasonably Available Control Technology (RACT), and Best Available Retrofit Technology (BART).

States must formulate State Implementation Plans (SIPs) that provide a framework for limiting air emissions from major sources as part of a strategy for demonstrating attainment and maintenance of NAAQS. Some individual SIPs (if allowed by the state law) may set more stringent limits on emissions of NOx, SO_2, and $PM_{2.5}$ than required by the federal rules. However, states cannot set less stringent limits than required by federal rules and regulations. Generally, federal, state, and local permitting authorities rely upon available information on the latest advanced technologies for emission control when setting emission limits. Where applicable, permitting authorities require BACT and RACT in order to reduce air emissions from stationary sources. In areas that have not achieved a NAAQS (i.e., non-attainment areas), the CAA requires air pollution limits established by LAER for new major stationary sources and major modifications to existing stationary sources. BACT and RACT analyses consider the cost of controls. LAER control technologies, applicable to new major sources located in non-attainment areas, must be installed, operated and maintained without consideration of costs.

1.3 Characterization of Combustion Sources

1.3.1 Description of Combustion Sources

Boilers utilize the combustion of fuel to produce steam. The hot steam is then employed for space and water heating purposes or for power generation via steam-powered turbines.

Boiler size is typically represented in four ways: fuel input in units of MMBtu/hr, output of steam in lb steam/hr at a specified temperature and pressure, boiler horsepower (1 boiler hp = 33,475 MMBtu/hr), or electrical output in MWhr or MW (if electricity is generated).

The three main types of boilers are described below:

- *Firetube boilers*. Hot gases produced by the combustion of fuel are used to heat water. The hot gases are contained within metal tubes that run through a water bath. Heat transfer through thermal conduction heats the water bath and produces steam. Typically, firetube boilers are small, with capacity below 100 MMBtu/hr.
- *Watertube boilers*. Hot gases produced by fuel combustion heat the metal tubes containing water. Typically, there are several tubes configured as a "wall." Watertube boilers vary in size from less than 10 MMBtu/hr to10,000 MMBtu/hr.
- *Fuel-firing*. Fuel is fed into a furnace and the high gas temperatures generated are used to heat water. Fuel-firing boilers include stoker, cyclone, pulverized coal, and fluidized beds. Stokers burn solid fuel and generate heat either as flame or as hot gas. Pulverized coal (PC) enters the burner as fine particles. The combustion in the furnace produces hot gases. The ash (the unburned fraction) exits in molten or solid form. Fluidized beds utilize an inert material to "suspend" the fuel. The suspension allows for better mixing of the fuel and subsequently better combustion and heat transfer to tubes.

Boilers are also classified by the fuel they use – chiefly coal, oil, natural gas, wood, and waste byproducts.

1.3.2 Emissions by Size, Fuel, and Industry Sector

In 2005, Energy & Environmental Analysis, Inc. [EEA, 2005] estimated that there were 162,805 industrial and commercial boilers in the U.S., which had a total fuel input capacity of 2.7 million MMBtu/hr as summarized in Figure 1-1 and Table 1-1. This estimate included 43,015 industrial boilers with a total capacity of 1.6 million MMBtu/hr and 119,790 commercial boilers with a total capacity of 1.1 million MMBtu/hr. In addition, EEA estimated that there were approximately 16,000 industrial boilers in the non-manufacturing sector with a total capacity of 260,000 MMBtu/hr, but details on size distribution of these boilers were not provided because these units were not well characterized.

The EEA report divided boilers into two major categories (industrial and commercial) instead of the more common characterization as industrial, commercial, and institutional boilers. One segment of the ICI boiler population, identified as non-manufacturing industrial boilers, is not included in the EEA analyses due to a lack of sufficient data. The non-manufacturing segment accounted for only 11 percent of energy consumption in the industrial boiler population. The manufacturing and non-manufacturing segment of the population appear (from EEA's description) to correspond to what would be called industrial boilers. The commercial segment of the population includes what are designated in this report as commercial and institutional boilers. For example, there are several large boilers located at major institutions such as universities (e.g., Notre Dame, Cornell, etc.) and also several large boilers located at major hospitals (e.g., Massachusetts General Hospital) that belong in the institutional category instead of the commercial sector. Thus, EEA's analysis appears to apply to most of the ICI boiler population, representing 89 percent of energy use by ICI boilers.

Industrial boilers were generally larger than commercial units. Sixty percent of the boilers in the manufacturing sector were greater than 100 MMBtu/hr in capacity, whereas 60 percent of the boilers in the commercial sector were in the range of 10 to 100 MMBtu/hr. The average capacity of the commercial boilers was 10 MMBtu/hr, with most less than 10 MMBtu/hr; the capacity of the average industrial boiler was 36 MMBtu/hr. Non-manufacturing boilers fell in between, at an average capacity of 16 MMBtu/hr. For industrial boilers, the average capacity factor was 47 percent (capacity factor is defined as the ratio of actual heat input in MMBtu to the maximum heat input based on nameplate capacity of the unit, calculated for a period of one year).

Table 1-1. Capacity of industrial boilers [EEA, 2005]

Unit Capacity	Manufacturing Boilers	Non-Mfg Boilers*	Commercial Boilers	Total
<10 MMBtu/hr	102,306	---	301,202	403,508
10-50 MMBtu/hr	277,810	---	463,685	741,495
50-100 MMBtu/hr	243,128	---	208,980	452,108
100-250 MMBtu/hr	327,327	---	140,110	467,437
>250 MMBtu/hr	616,209	---	33,639	649,848
Total Capacity, MMBtu/hr	1,566,780	260,000	1,147,617	2,714,397
Total Capacity >10 MMBtu/hr	1,464,474	---	846,415	2,310,889**
Total number of units	43,015	16,000	119,790	162,805
Average Capacity, MMBtu/hr	36	16	10	17

*No details provided on range of capacities

**Total does not include non-manufacturing boilers

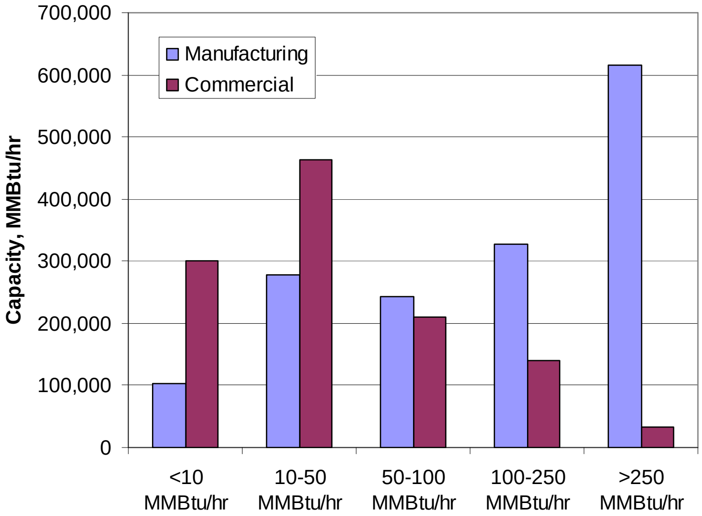


Figure 1-1. Total capacity of industrial boilers as a function of size [EEA, 2005]

Five major steam-intensive industries accounted for more than 70 percent of the boiler units and more than 80 percent of the boiler capacity of the manufacturing segment of industrial boilers: food, paper, chemicals, petroleum refining, and primary metals. The non-manufacturing segment of the industrial sector included agriculture, mining and construction. The largest categories in the commercial sector, by capacity, were schools, hospitals, lodgings, and office buildings.

Industrial boilers in the manufacturing sector are used to generate process steam and electricity. The fuels used in manufacturing boilers are related to the size of the boilers and, in some cases, the byproducts generated in the particular manufacturing process.

In the food production subsector, the average boiler capacity was 20 MMBtu/hr. The relatively small average capacity was reflected in the higher percentage (58 percent) of natural gas-fired boilers in the food industry than in any other major subsector, since very small boilers tend to burn natural gas.

The paper industry included some of the largest industrial boilers, with an average boiler size of 109 MMBtu/hr. The paper industry represented more than half (230,000 MMBtu/hr) of the total capacity of the manufacturing sector. More than 60 percent of the fuel used in paper industry boilers was wood (bark, wood chips, etc.) or black liquor, a waste product from the chemical pulping process.

The chemical industry employed both large and small boilers, with about seven percent of the units with capacities smaller than 10 MMBtu/hr, and a significant number (about 350 or 37 percent of total capacity) larger than 250 MMBtu/hr. The primary fuels for chemical industry boilers were natural gas (43 percent), process off-gas (39 percent), and coke (15 percent).

The refining industry had an average boiler size of 143 MMBtu/hr, the largest of any of the major industries, with over 200 boilers with capacities above 250 MMBtu/hr. By-product fuels (refinery gas or carbon monoxide) were the most common fuel source for boilers (58 percent), followed by natural gas (29 percent) and residual oil (11 percent).

About half of the total boiler capacity in the primary metals industry was from boilers larger than 100 MMBtu/hr. By-product fuels, like coke oven gas and blast furnace gas, provided the largest share (63 percent) of boiler fuel in the primary metals industry.

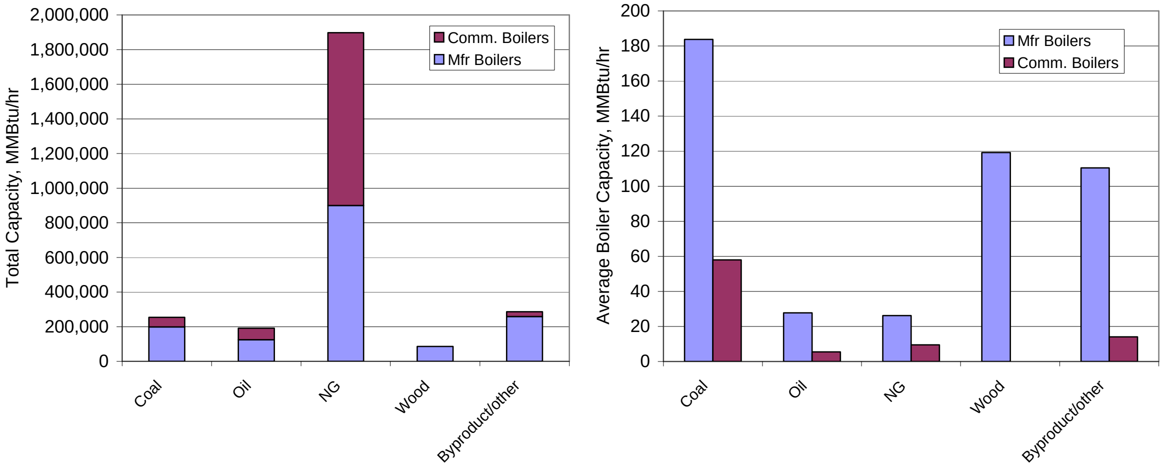
The remaining industries accounted for about 29 percent of manufacturing boilers (12,000 units) or about 18 percent of industrial boiler capacity. The average capacity for the rest of the manufacturing subsector was 23 MMBtu/hr. Approximately 100 boilers at other manufacturing facilities had capacities larger than 250 MMBtu/hr.

Unlike industrial boilers, which serve production processes, commercial boilers provide space heating and hot water for buildings. Natural gas fired the vast majority of commercial boilers, including 85 percent of commercial boiler units and 87 percent of the total commercial boiler capacity. About 10 percent of the commercial boilers were fired by oil. Coal was fired at about one percent of the commercial boilers, but represented five percent of the capacity, reflecting the larger size of commercial coal-fired boilers.

Figure 1-2 summarizes the total US boiler capacity in the manufacturing and commercial sectors as a function of fuel fired (left side of figure) and shows the average capacity per boiler (right side of figure) by fuel type. Coal-fired boilers were the largest in size on average. As discussed above, natural gas accounted for 70 percent of the total industrial boiler capacity in the

EEA survey. Coal and byproduct fuels accounted for about 10 percent each, with lesser capacity in oil- and wood-fired boilers.

In the manufacturing sector, the average coal-fired boiler capacity was about 180 MMBtu/hr, but the average capacity in both sectors combined was about 125 MMBtu/hr. Wood- and byproduct-fired boilers in the manufacturing sector were also large on average (120 and 110 MMBtu/hr, respectively). On the other hand, oil- and natural gas-fired boilers were small, on the order of 20 MMBtu/hr in the manufacturing sector and less than 10 MMBtu/hr in the commercial sector.



(a) Total capacity by fuel and sector

(b) Average capacity by fuel and sector

Figure 1-2. Total and average boiler capacity of U.S. industrial boilers as a function of fuel fired [EAA, 2005]

From EEA's 2005 study, the following general conclusions about boiler size for the entire U.S. ICI boiler population can be drawn:

- natural gas is the fuel fired at most ICI boilers;
- natural gas- and oil-fired boilers tend to be small, less than 20 MMBtu/hr in capacity;
- boilers fired with coal, wood, or process byproducts are larger in size, greater than 100 MMBtu/hr on average;
- although natural gas fired most of the ICI boilers in the U.S., coal, oil, and wood contribute substantially more to the emissions of SO_2 and PM; and
- all fuels are sources of NOx emissions.

One needs to be careful drawing conclusions for the eight-state NESCAUM region based on the national data in the EEA 2005 study because there are large region-to-region and state-to-state differences in boiler populations. For example, fuel oil is an important fuel in the Northeast, especially in rural areas where natural gas may not be available, while natural gas is predominant in other areas of the country.

A preliminary assessment of emissions from ICI boilers by pollutant in the U.S. and in the eight-state NESCAUM region was carried out using data from the AirData database via the EPA website (www.epa.gov/air/data). In this database, stationary sources, such as electric generating plants and factories, are identified individually by name and location. Figure 1-3 compares the annual emission of NOx, SO_2, and $PM_{2.5}$ in the U.S. with the eight-state NESCAUM region for 2002. Emissions in the NESCAUM region are about 5 percent of the US total emissions.

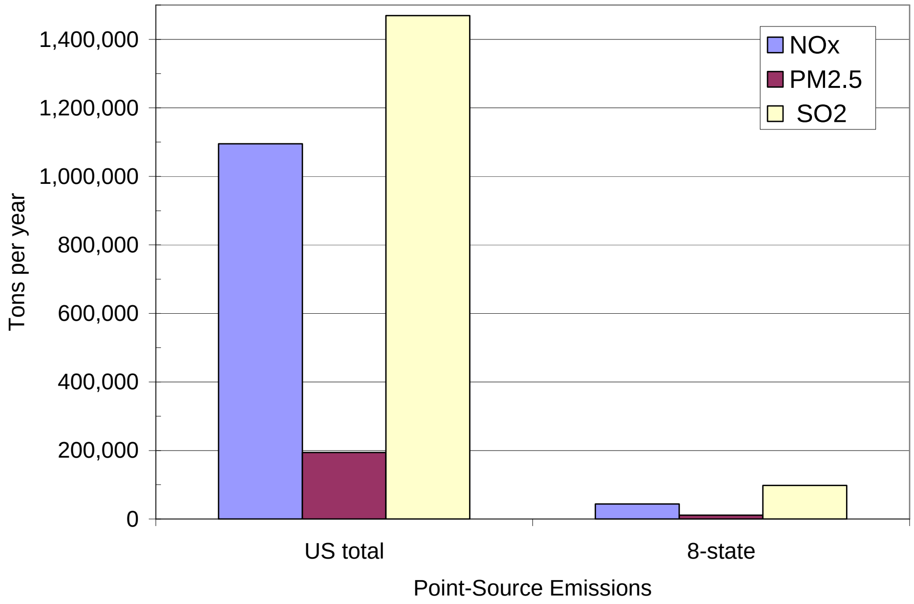


Figure 1-3 Total annual emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the U.S. and in the eight-state region from EPA AirData database

Another set of data from the eight-state region was extracted from the MANEVU 2002 non-road inventory (www.manevu.org). In this data set, oil-fired boilers were divided into distillate oil and residual oil-fired boilers (Figure 1-4).

NOx emissions in the eight-state NESCAUM region are mostly from oil- and gas-fired boilers. Because these are generally small boilers, combustion controls are good candidates for NOx control. For larger, coal- or wood-fired boilers, SNCR or SCR might also be applicable.

PM emissions are relatively low from coal-fired sources in the eight-state region, which suggests that most of the coal-fired sources already have particulate control devices. Oil- and wood-fired units have higher PM emissions, and PM emissions attributed to natural gas are quite small.

As might be expected, most of the SO_2 emissions from oil-fired boilers come from residual oil-fired boilers because of residual oil’s higher sulfur content.

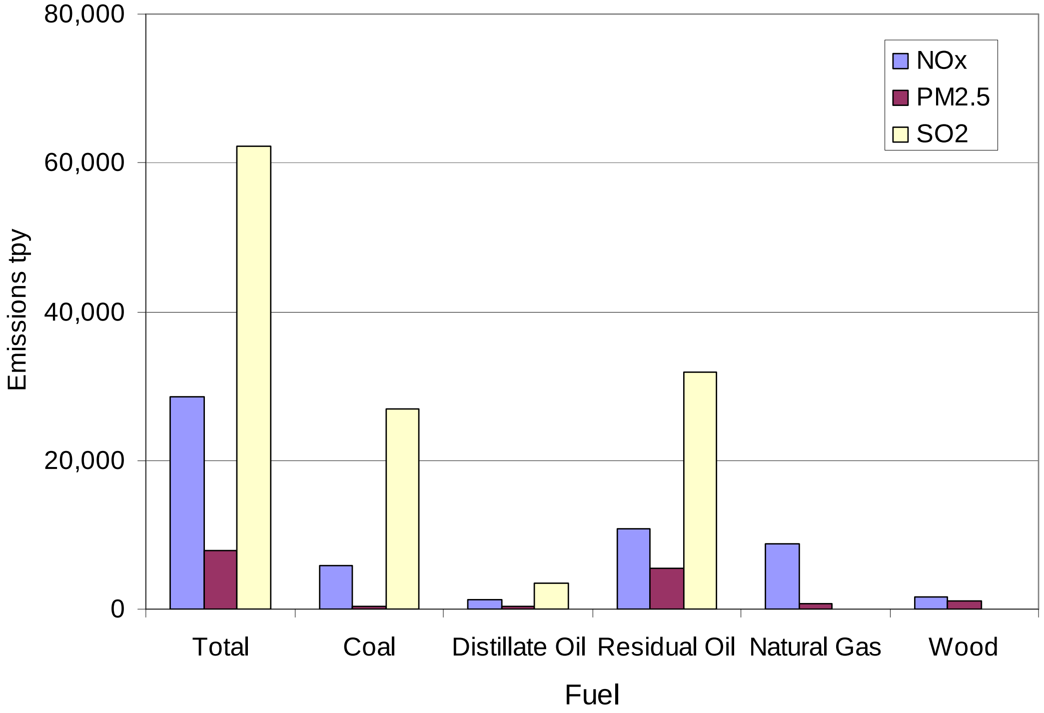


Figure 1-4. Emissions of NOx, SO_2, and $PM_{2.5}$ from ICI boilers in the NESCAUM region from MANEVU database as a function of fuel fired

1.3.3 Differences between EGU and ICI boilers

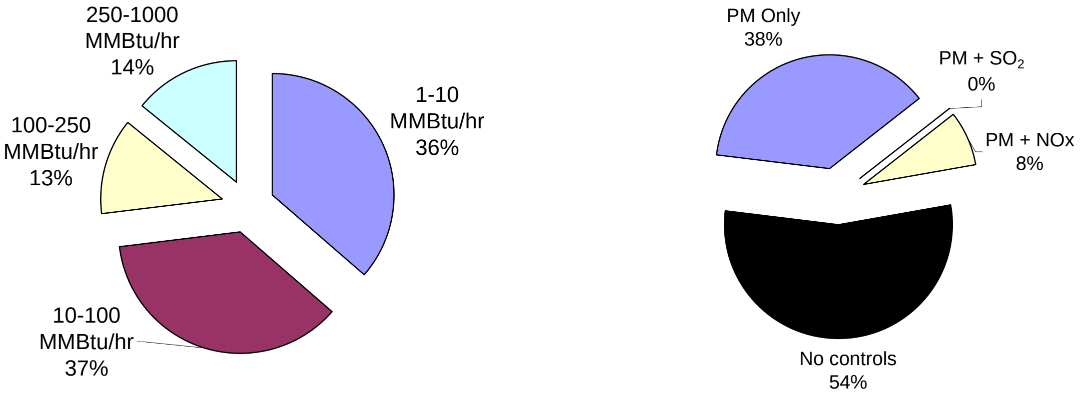
EGU boilers produce steam in order to generate power. While ICI boilers do in some cases generate steam for electricity production, ICI boilers differ from EGUs in size, steam application, design, and emissions. Most commercial and institutional boilers are small, with an average capacity of 17 MMBtu/hour (Table 1-1). Industrial boilers can be as large as 1,000 MMBtu/hr or as small as 0.5 MMBtu/hr. The average size of a coal-fired EGU boiler in the U.S. is over 200 MW or over 2,000 MMBtu/hr.

All coal-fired EGUs in the United States use control devices to reduce PM emissions. Additionally, many of the EGU boilers are required to use controls for SO_2 and NOx emissions, depending on site-specific factors such as the properties of the fuel burned, when the power plant was built, and the area where the power plant is located.

According to 1999 EPA Information Collection Request (ICR) responses from coal-fired EGUs, 77.4 percent of EGUs had PM post-combustion control only, 18.6 percent had both PM and SO_2 controls, 2.5 percent had PM and NOx controls, and 1.3 percent had all three post-combustion control devices [Kilgroe *et al.*, 2001]. Information from 2004 indicated that the fractions of total capacity of large coal-fired EGUs that have flue gas desulfurization (FGD) to control SO_2 and selective catalytic reduction (SCR) to reduce NOx controls were 38 percent and 37 percent, respectively [NESCAUM, 2005]. Since the 1999 ICR survey, additional NOx and SO_2 controls have been added at a rapid pace to coal-fired EGUs. It is presently not clear how the implementation of NOx and SO_2 control technologies for EGUs would evolve as a consequence of the recent vacatur of Clean Air Interstate Rule (CAIR) by the U.S. D.C. Circuit.

In contrast to EGUs, ICI boilers are substantially less likely to have air pollution control devices. A study of industrial boilers and process heaters [USEPA, 2004] that looked at 22,117 industrial boilers and process heaters, which burned natural gas, distillate oil, residual oil, and coal, found that 88 percent had no air pollution control equipment.

A preliminary survey was undertaken as part of this study to evaluate the extent to which various emission controls were currently being applied to ICI boilers in the Northeast. These data were acquired from State Title V permits for solid-fueled (coal and wood) boilers as well as additional information from state personnel. The survey collected data in four states: Massachusetts, Vermont, New Hampshire, and New York. The data set was composed of 64 boilers – 47 wood-fired and 17 coal-fired. *Figure 1-5* illustrates the distribution of boiler capacity (by size) and the air pollution control devices (APCDs) in this data set. The full data set is summarized in Appendix A. As can be seen in *Figure 1-5(b)*, more than half of the units had no controls, about one-third had controls only for PM, and very few units had controls for NOx. There were no units with SO_2 controls, although some of the PM controls were wet venturi scrubbers, which might have a limited impact on SO_2 emissions.



(a) Distribution of capacity

(b) Distribution of APCDs

Figure 1-5. Solid-fuel boiler information from four northeast states, based on Title V permit information

There are several factors that directly or indirectly affect the reasons for the discrepancy in APCD deployment between EGU and ICI boilers. Technical and operational as well as business, economic, and regulatory factors impose different constraints and provide different opportunities for the applicability of APCDs for these two categories of boilers. The following discussion summarizes some of the important technical and operational issues.

Large, base-loaded EGUs operate mainly near maximum capacity or steam production. Industrial boilers typically do not run at maximum capacity, although this varies from one industry to another [EEA, 2005]. EGUs produce steam for electricity generation, while ICIs may produce steam for a variety of applications. The type of manufacturing is often more important in determining boiler operation, or duty cycle (load vs. time) than manufacturing demand in general.

ICI boilers generate steam for processing operations for paper, chemical, refinery, and primary metals industries. Commercial boilers produce steam for a variety of processes, while institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities.

Another difference between EGU and ICI boilers is fuel diversity. EGU boilers are mostly single-fuel (coal, No. 6 oil, natural gas), while ICI boilers tend to be designed for and use a more diverse mix of fuels (e.g., fuel by-products, waste, wood) in addition to the three conventional fuels above.

These differences in operational and fuel usage not only affect a boiler's duty cycle, but its design, which is equally important from the perspective of APCD applicability. Examples that directly affect APCD choice and applicability include equipment such as economizers or air preheaters, which affect the temperature of the flue gas at the stack. The differentiation in fuel usage also leads to different design parameters for emissions controls. For example, the iron and steel industry generates blast furnace gas or coke-oven gas, which is used in boilers, resulting in sulfur emissions. Pulp and paper boilers may use wood waste as a fuel, resulting in high PM emissions. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category.

These factors relate directly to APCD equipment choices and applicability. The following examples should help explain some of these impacts.

- Fuel quality – different fuels have different emission characteristics. SO_2, PM, and NOx emissions from coal fired boilers are different from those burning natural gas, oil, or wood waste. Some APCD technologies are not very sensitive to fuel quality variations (e.g., an electrostatic precipitator (ESP) may accommodate different levels of PM concentration, although the type and size of particles and gas temperatures will have an impact). However, others can be directly affected by changes in fuel quality and the resulting changes in pollutant concentrations in the flue gas to be treated (e.g., SO_2 and NOx controls that utilize reagents such as scrubbers for SO_2 and SCR/SNCR for NOx).
- Duty cycle – significant variation or cycling of boiler load requires APCD controls capable of accommodating such variations. These variations affect flue gas flow rates and temperatures, which in turn may require different control capability. For example, an SCR or SNCR system must operate within a temperature window that may or may not exist across the load range for a particular ICI boiler.
- Design differences – the use of equipment such as economizers or air preheaters has direct impact on the resulting flue gas temperature. Temperature-sensitive technologies such as ESPs, SO_2 scrubbers (wet and dry), and SCR /SNCR that are widely used in EGUs may or may not be applicable for some ICI boilers in such cases.

1.3.4 Control Technology Overview

A variety of emission control technologies are employed to reduce emissions of NOx, SO_2, and primary PM emissions. Technical details of control technologies for NOx, SO_2, and PM are discussed in Chapters Two, Three, and Four, respectively. Pollutant emission controls are generally divided into three major types given in the following list.

- *Pre-combustion Controls*. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls*. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Data on costs of pollution control equipment taken from the literature are reviewed in the individual technology chapters. In Chapter Five, an existing model for the estimation of air pollution control equipment costs for coal-fired EGUs (CUECost) is applied to ICI boilers burning different fuels (coal, oil, wood) with appropriate caveats and assumptions to provide reasonable and approximate control costs for ICI boilers.

1.4 Chapter 1 References

Energy & Environmental Analysis, Inc. (EEA). *Characterization of the U.S. Industrial Commercial Boiler Population.* May 2005.

Kilgroe, J.D. *et al. Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report*, EPA-600/R-01-109, December 2001.

MACTEC. *Assessing Reasonable Progress for Regional Haze in the Mid-Atlantic North Eastern Class I Area - Revised Final Draft*; MACTEC Federal Programs: Research Triangle Park, NC, March 8, 2007.

NESCAUM. *Assessment of Control Technology Options for BART-Eligible Sources*; 2005.

Ozone Transport Commission (OTC). *Identification and Evaluation of Candidate Control Measures – Technical Support Document*. February 28, 2007.

Sabo, E.; Toothman, D. *Identification and Evaluation of Candidate Control Measures Final Technical Support Document*; MACTEC Federal Programs, Inc.: Herndon, VA, February 28, 2007.

Sliwinski, R. “ICI Boiler Control Recommendations,” Ozone Transport Commission Fall Meeting, November 15, 2006.

State and Territorial Air Pollution Program Administrators/Association of Local Air Pollution Control Officials (STAPPA/ALAPCO), now known as National Association of Clean Air

Agencies (NACAA). *Controlling Fine Particulate Matter under the Clean Air Act: A Menu of Options*, March 2006.

US EPA. *Alternative Control Techniques Document--NO Emissions from Industrial/Commercial/Institutional (ICI) Boilers*; EPA-453/R-94-022; 1994.

US EPA. *Regulatory Impact Analysis for the Industrial Boilers and Process Heaters NESHAP*, EPA EPA-452/R-04-002, February, 2004.

2 NOx CONTROL TECHNOLOGIES

2.1 Introduction

This brief introduction applies to chapters Two, Three, and Four, which discuss control technology options for ICI boilers for NOx, SO_2, and PM, respectively. However, these chapters are not intended to provide detailed descriptions of the many available technologies for each pollutant. Significant literature is available for that purpose; in the context of this report, these chapters are intended to provide the reader with a general understanding of concepts, performance, applicability, and costs of the main technologies available. Further, in recognition of the concern with climate change, a brief discussion of energy consumption (parasitic power) associated with major technologies is included.

Specifically with respect to the deployment and applicability of air pollution controls, comparisons between ICI boilers and EGUs are relevant because of the more widespread application of pollution control equipment in the EGU sector. This was discussed in some detail in Chapter One. In addition, a few considerations specific to certain technologies and strategies are discussed, as appropriate.

2.1.1 ICI versus EGU Boilers

In general, the greater proliferation of air pollution control technologies in the EGU sector, as opposed to the industrial sector, seems to be driven by three dominant, differentiating factors.

- Size difference and associated emissions between the two: Because EGUs are much larger than ICI boilers, they have been targeted for environmental regulatory controls more heavily over the years.
- Technology costs: While not universally true, ICI boilers often have constraints due to their smaller sizes, diversity of plant layouts, and urban settings, all of which can have a negative impact on the costs of applying some of the control technologies. Conversely, and equally important, opportunities for lower-cost applications to ICI boilers do exist as a result of the smaller sizes, such as in the ability to have systems pre-fabricated and ready to erect onsite, as opposed to on-site construction requirements often needed with larger systems for EGUs.
- Cost recovery: The two sectors are significantly different from a fundamental business view, with EGUs being regulated entities, as opposed to openly competitive markets that exist within the ICI boiler population. This is important in that it affects how business decisions are made in the two sectors, how capital equipment purchases are funded, and also how ICI plants are designed and operated.

2.1.2 Control Technologies' Impact on Efficiency and CO_2 Emissions

Air pollution control technologies and strategies can have varying impacts on the overall efficiency of the host plant. This impact can be either positive or negative and it is a function of the type of technology, as well as fuel choices.

An extreme example of this is the control of SO_2 from a coal-fired unit by two significantly different approaches: in one case, the use of an energy–intensive FGD "scrubber" penalizes the efficiency of such unit by up to 2 percent, resulting in a corresponding increase in CO_2 emissions; a very different and contrasting case, in which the unit chooses to reduce its SO_2 generation by switching from coal to natural gas, yields a corresponding and substantial decrease in its CO_2 emissions. Similarly, an efficient Low-NOx Burner (LNB) may replace an older burner and increase unit efficiency, while reducing NOx emissions, whereas a SNCR or SCR also reduces NOx, but will have some inherent parasitic power requirement that will have a negative impact on overall efficiency (and emissions of CO_2).

These chapters primarily address control technology options, as opposed to fuel switching strategies, except for SO_2. Switching from high-sulfur oil to low-sulfur oil is also discussed in Chapter 3. CO_2 impacts are well established as a function of the carbon content of fuels. The same applies in the case of renewable, carbon-based fuels (biomass). However, with control technologies, the impacts can vary widely among technologies for the same pollutant (e.g., LNB vs. SCR for NOx), as well as across different pollutants (e.g., fabric filter for PM vs. wet and dry scrubbers for SO_2).

In general, efficiency impacts from application of air pollution control technologies can be divided into two major general areas:

- Direct impact (positive or negative) on the combustion process itself (e.g., changes in concentrations of O_2 or CO and in the amount of unburned carbon (UBC) in ash)
- Parasitic power associated with the particular technology or its components (e.g., increased gas pressure loss, power requirements for pumps/fans)

This parasitic power is given here in terms of electric power (kW) per flue gas flow rate (acfm) or kW/1000 acfm. These units are appropriate for several reasons:

- Most ICI boilers do not produce electricity, hence, size is more universally characterized by a parameter other than electrical generation (e.g., flow rate);
- Most control technology suppliers rank their equipment size in terms of gas flow rate as this is the dominant parameter for gas handling equipment sizing;
- If the objective is to "correlate" this parasitic power loss to an equivalent CO_2 impact, it can be done simply by knowing the size (acfm) of the technology application and the CO_2 emission profile of the equivalent kW generation (or savings) to offset the parasitic power loss.

2.2 Discussion of NOx Control Technologies

2.2.1 NOx Formation

The formation of NOx is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form NOx. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NOx emissions.

2.2.2 NOx Reduction

As a result of complex interactions in the formation of NOx, a variety of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NOx emission control is to divide them into two major categories: (1) those that minimize the formation of NOx itself during the combustion process (e.g., smaller quantities of NOx are formed); and (2) those that reduce the amount of NOx after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach under the “umbrella” of combustion modifications whereas technologies in the second category are termed post-combustion controls. Within each of these two categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NOx control than the application of a stand-alone technology.

2.2.3 Other Benefits of NOx Control Technologies

Some NOx control technologies have shown the potential to promote the capture of mercury (Hg) from the flue gas. Examples include combustion modification technologies (e.g., Low-NOx Burners and Overfire Air – though potentially with higher levels of unburned carbon) and post-combustion technologies (SCR – through the oxidation of mercury, making it more soluble and amenable to capture in a downstream process such as a scrubber for SO_2). This suggests that strategic and economic analyses for NOx controls need to also consider the potential impacts on mercury removal.

2.3 Summary of NOx Control Technologies

2.3.1 Combustion Modifications

Combustion modifications can vary from simple “tuning” or optimization efforts to the deployment of dedicated technologies such as LNBs, Overfire Air (OFA) or reburn (most often done with natural gas and called Gas Reburn - GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to reductions in NOx emissions of 5 to 15 percent or even higher in cases where a unit was originally badly “de-tuned.” It is important to remember that optimization results are truly a function of the “pre-optimization” condition of the power plant or unit (just as the improvement in an automobile from a tune-up depends on how badly it was running prior to it), and as such have limited opportunity for substantial emission reductions.

Development of “intelligent controls” – software-based systems that “learn” to operate a unit and then maintain its performance during normal operation, can also go a long way towards keeping plants well tuned, as they gain acceptance and become common features in combustion control systems.

2.3.2 Low-NOx Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NOx during combustion. Simply, this is accomplished by controlling the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as “fuel or air staging”).

Figure 2-1. Low-NOx burner [TODD Dynaswirl-LN^{TM}]

Figure 2-1 shows a gas/oil Low-NOx burner. These technologies are prevalent in the electric power industry as well as in ICI boilers at present and increasingly used by ICIs, even at small sizes (less than 10 MMBtu/hr). Competing manufacturers have proprietary designs, geared towards application for different fuels and boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NOx reductions of 30 to 65 percent from uncontrolled baseline levels. Again, the type of boiler and the type of fuel will influence the actual emission reduction achieved.

Particularly for gas-fired applications, as in the majority of ICI boilers, advanced Low-NOx Burners, often referred to as ultra Low-NOx Burners (ULNBs), are commercially offered by several companies. Ultra Low-NOx Burners are capable of achieving NOx emission levels on the order of single digits in ppm. As with all technologies, “pushing the envelope” on emission levels requires increasingly more careful suitability analyses as well as a good understanding of operational constraints. Conversely, the advent of these very low-emission burners (less than 10 ppm NOx), allows units to achieve very low emission rates at costs well below post-combustion alternatives like SCR.

All combustion modification approaches face a common challenge of striking a balance between NOx reduction and decrease in fuel efficiency. The concern is exemplified by typically higher CO and/or carbon levels in the fly ash, which reflect lower efficiency and also the contamination of the fly ash itself, possibly making it unsuitable for reutilization such as in concrete manufacturing. This is a bigger concern for large EGUs than for ICI boilers due to the much larger quantities of ash produced and the associated costs of disposal.

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss). Low-NOx Burners are applicable to most ICI boiler types, excluding stoker types and Fluidized Bed Combustion units (FBCs).

2.3.3 Reburn

Reburn, while generically included in the “Combustion Modification” category, is different from the other technologies in this group (LNBs/OFA) in that it “destroys” (or chemically reduces) NOx shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, however, natural gas is the most common) into the boiler above the main burner region. A portion of the heat input from the primary fuel is replaced by the reburn fuel. Subsequently, this “fuel-rich” environment reacts with and destroys the NOx formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as popular as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. *Figure 2-2* shows a typical reburn system applied to a stoker boiler.

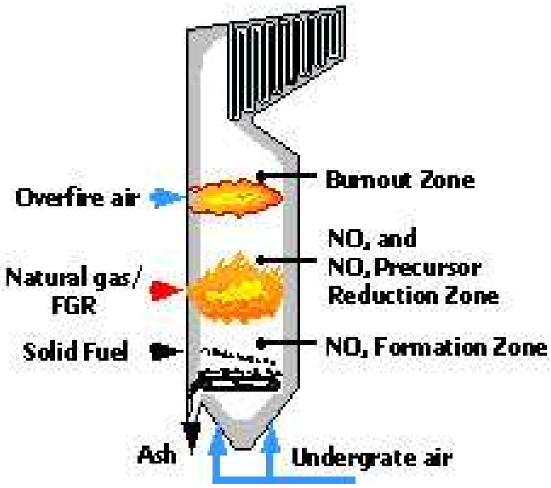


Figure 2-2. Gas reburn applied to a stoker boiler [www.gastechnology.org]

Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel, are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with a particular type of boiler – “Cyclone,” – for which the previously mentioned technologies are not particularly well suited. However, this technology has been used only in large EGUs and is not a typical option for ICI boilers. Cyclone boilers are inherently high NOx emitters and are not an attractive option for new or retrofit units with increasingly lower NOx emission limits requirements.

Reburn performance has been shown to range from 30 to 60 percent reduction in NOx emissions, depending on such factors as reburn fuel type and quantity, initial NOx levels, boiler design, etc. Similar to the other combustion modification options, reburn can affect efficiency and fly-ash quality. As such, it requires the same optimum balance between NOx reduction and avoidance of negative impacts. On the other hand, reburn can be thought of as a “dial-in” NOx technology in that NOx reductions are, to a degree, a function of the amount of reburn fuel.

Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Reburn using coal or oil as the reburn fuel does not seem like a very attractive option for ICI boilers for technical reasons (boiler size, residence times), as well as the wider availability of similar performance options simpler to implement, such as LNBs. Gas reburn, while easier to implement, often has a prohibitive operating cost if, for example, natural gas is partially substituted for a less expensive primary fuel. Reburn is therefore an option for larger watertube-type boilers, including stokers, but require appropriate technical and economic analyses to determine suitability. Gas reburn has an impact on CO_2 emissions that is proportional to the type and quantity of fuels displaced (gas vs. coal or oil).

2.3.4 Post-Combustion Controls

Conventional, commercial post-combustion NOx controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NOx produced in the boiler to convert the NOx to harmless nitrogen and water. SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NOx. As noted below, SCR technology is capable of achieving much larger reductions in NOx emissions, higher than 90 percent, compared to the 30 to 60 percent reductions achievable by SNCR. *Figure 2-3* and *Figure 2-4* depict views of these two systems.

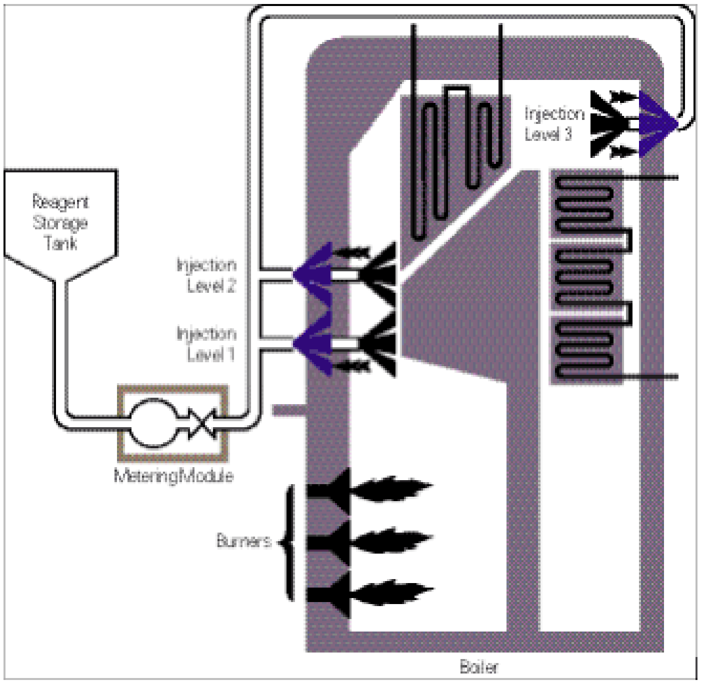


Figure 2-3. SNCR system schematic [FuelTech]

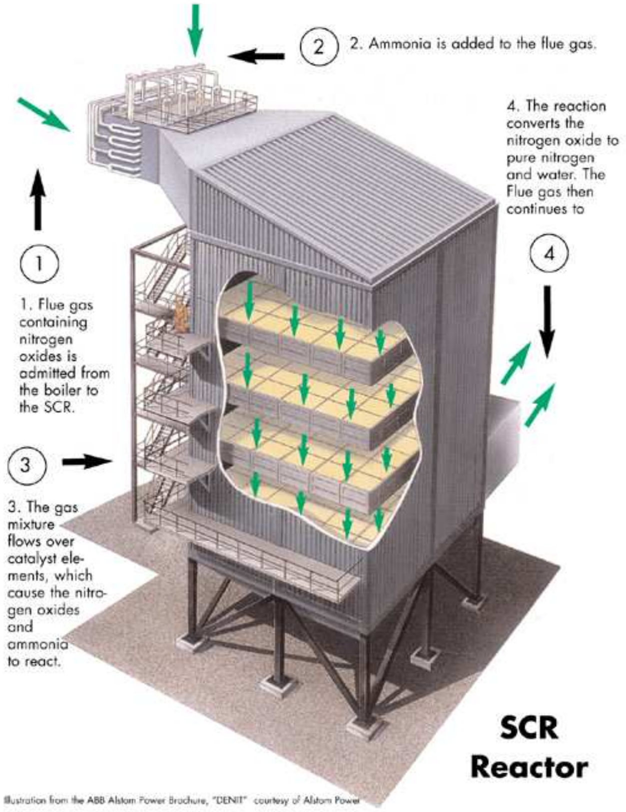


Illustration from the ABB Alstom Power Brochure, "DENIT" courtesy of Alstom Power

Figure 2-4. 3-D schematic of an SCR system [Alstom Power]

While the difference between the SNCR and SCR may seem minor, it yields significant differences in performance and costs. In the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the reaction vessel, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NOx); and finally, has lower NOx reduction capability (typically 30 to 50 percent, with some units achieving reductions in the 60 percent range). SCR, on the other hand, is capital intensive, but offers lower reagent costs and the opportunity for very high NOx reductions (90 percent or higher).

Costs are driven primarily by the consumption of the chemical reagent – usually (but not necessarily) urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NOx level and the desired percent reduction. It is also important to consider possible contamination of fly ash (in the case of coal firing) by ammonia making it potentially unable to be sold. This is, again, a bigger issue for larger EGU plants than for ICI boilers due to the size and quantities involved; as already stated, ICIs burning solid fuel do not typically sell their fly ash.

2.3.4.1 RSCR

Commonly, EGU boilers utilize SCR systems to reduce NOx emissions. However, a conventional SCR may not be cost-effective to retrofit into smaller units like ICI boilers because of the extensive modifications required to accommodate the unit. For some applications, the SCR may be located downstream of the particulate control equipment, where the flue gas temperature is much lower than the range of 650-750°F required for a conventional SCR (Toupin, 2007). These conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

If it is necessary to compensate for the reduction of flue gas temperatures, a regenerative selective catalytic reduction (RSCR^{TM}) system allows the efficient use of an SCR downstream of a particulate control device. The primary application of an RSCR system is the reduction of NOx emissions where the flue gas is typically at 300-400°F (Toupin, 2007). *Figure 2-5* illustrates the schematic and the actual RSCR system. *Figure 2-6* shows a block of ceramic heat exchanger.

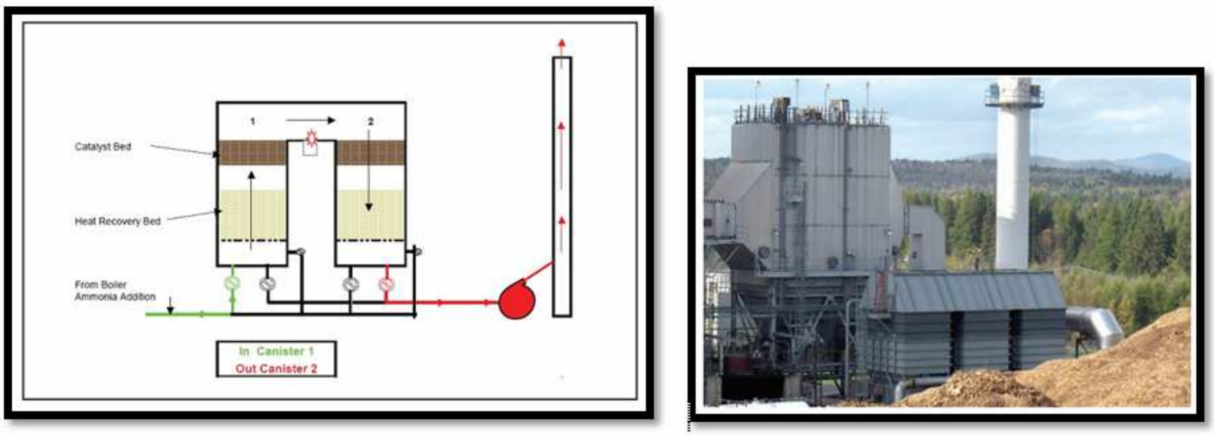


Figure 2-5. Schematic and actual RSCR [Toupin, 2007]

A direct-contact regenerative heater technology (i.e., burner), coupled with cycling beds of ceramic heat exchangers, is used to transfer heat to the flue gas. Additionally, some oxidation of CO to CO_2 in the flue gas occurs. The NOx reduction portion of the RSCR takes place on a conventional SCR catalyst. Either anhydrous or aqueous ammonia can be used.

Figure 2-5 (left side) shows the working principles of the RSCR. Essentially, the flue gas in the space between the two canisters (called the retention chamber) is heated by the burner to make up for heat loss through the walls of the canisters and inefficiency in the ceramic heat transfer modules. This raises the temperature in the retention chamber by about 10-15ºF. The gas flows into the second canister, through the catalyst, and passes through the second ceramic module, which absorbs heat from the hot flue gas. Once this cycle is completed, the flow reverses, so that the second canister (which was just heated) becomes the inlet canister and the first canister becomes the outlet canister. The cycling between canisters accomplishes a similar function to the continuously rotating heating elements of a conventional regenerative air/gas heater.

Other components of the RSCR include the ductwork, fans, and the ammonia delivery system. Ductwork must be adequately sized to provide sufficient distance for ammonia mixing and to minimize pressure drop. For the ceramic heat exchanger, factors that need to be taken into consideration during the design process are gas-side pressure drop, thermal efficiency, and cost. A large bed face area reduces the pressure drop and operating cost but increases capital cost. The ammonia delivery system consists of ammonia pumps, storage tanks, interconnecting piping, and a control system. The pump typically does not exceed one horsepower and often a redundant pump is provided to assure continuity in system operation [Toupin, 2007].

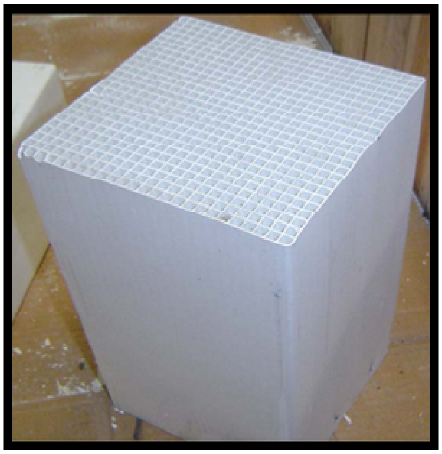


Figure 2-6. Block of monolith ceramic heat exchanger [Toupin, 2007]

The RSCR combines a regenerative thermal oxidizer (RTO) (e.g., retention chamber burner) with SCR technology. This ability to control flue gas temperatures allows for high NOx reduction under varying temperature conditions. *Table 2-1* shows the expected reduction in NOx and CO emissions [BPEI, 2006]. This study indicated that the RSCR is able to reduce NOx by 60 to 75 percent and CO by about 50 percent.

Table 2-1. CO and NOx reduction using RSCR [Source: BPEI 2006]

	Typical Stoker Design	**CO and NOx Reductions from Baseline**
Steam Flow lbs/hr x 10^3	100 – 500	
Steam Press, psi	600 – 900	
Steam Temp., °F	955 – 1000	
Unburned Combustibles Boiler Efficiency Loss (%)	1.0 – 1.5	
Furnace Retention sec.(1)	3.0	
Grate Heat Release Btu/hr-ft	850,000 maximum	
Emissions:		
CO lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.30 (122 – 370)	Base
CO **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.05 – 0.15 (61 – 185)	(-50%)
NOx lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.15 – 0.25 (112 – 186)	Base
NOx **w/SNCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.10 – 0.17 (75 – 130)	(-30 to 40%)
NOx **w/RSCR** lbs/10^6 Btu @ 3.0% O_2 (ppm)	0.06 – 0.075 (45 – 56)	(-60 to 75%)

Additionally, the heat exchanger part of the RSCR has a thermal efficiency of about 95 percent, which translates to fuel savings. Traditional technologies that utilize Ljungstrom or plate type heat exchangers for heat recovery and duct burners to reach the catalyst operating temperature are typically in the range of 70 to 75 percent thermal efficiency.

An analysis performed by BPEI on a typical 25 MW plant with a 75 percent reduction in NOx shows a cost effectiveness of $4,514 per ton of NOx removed. The cost breakdown is tabulated below in *Table 2-2*.

Table 2-2. RSCR cost efficiency [BPEI, 2008]

Plant Overview:	
Plant Gross MW	25
GROSS HEAT INPUT, MMBTU/HR	321
TYPICAL UNCONTROLLED NOx, LB/MMBTU	0.25
TYPICAL CONTROLLED NOx, LB/MMBTU	0.065
NOx REMOVED, TONS/YEAR	249.4
RSCR Cost:	
AMMONIA COST, $/TON NOx	$ 419
NATURAL GAS, $/ton NOx	$ 404
POWER COST, $/TON NOx	$ 589
CATALYST COST, $/TON	$ 555
CAPITAL COST, $/TON	$ 2,546
TOTAL COST PER TON NOx REMOVED	$ 4,514

Two RSCR installations (15 and 50MW) are currently in operation in the Northeast. The 15 MW plant uses whole tree chips as fuel; the 50 MW plant uses whole tree chips, waste wood, and construction and demolition wood as fuel for the boilers. The goal of the two installations was to qualify for the Massachusetts Renewable Energy Credits (RECs). The state requirement for qualifying for RECs imposed a NOx level of 0.075 lb/MMBtu or less on a quarterly average basis.

2.3.5 Technology Combinations

In theory, most of the technologies described above can be used together. However, NOx reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NOx levels entering the SCR/SNCR system. Another combination offered commercially is the hybrid SNCR/SCR concept, which uses the excess ammonia (ammonia “slip”) of the SNCR to promote additional NOx reduction in a downstream SCR catalyst.

2.4 Applicability to ICI Boilers

The NOx control technologies previously described are commercially available and are used extensively in EGUs, but most are also applicable to ICI boilers. Because conventional fuels (e.g., coal, oil, gas) as well as alternative fuels (e.g., wood, petroleum coke, process off-gases) emit NOx, these technologies are applicable to most boilers using various fuels. With the exception of FBC and Stoker boilers, LNBs are available and widely used for most combinations of boiler types and fuels. OFA and reburn as well as SNCR and SCR technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility. As already stated, these include available space, residence times and gas temperatures. Conversely, other than firetube type boilers, these technologies are potential candidates for the other boiler types including stokers and FBCs. Finally, the RSCR may offer advantages for applications where low flue gas temperatures are present and a conventional SCR may be more costly to implement.

2.5 Efficiency Impacts

The NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the noted exception for reburn when displacing coal or oil with natural gas. This is because combustion modification technologies do not impose any significant parasitic energy consumption (auxiliary power). Note that combustion modification technologies can affect the resulting combustion conditions in addition to the desired reduction in NOx emissions. These impacts are reflected in varying temperatures, oxygen levels, and CO/UBC, all of which affect combustion efficiency as discussed previously. However, we do not attempt to quantify these impacts. The overriding assumption is that these NOx control technologies, once deployed, are optimized such that the resulting NOx emissions are achieved without compromising the above parameters (or at least their combined effects).

With respect to the post-combustion technologies, both SNCR and SCR impose some degree of energy impact on the host boiler. The losses attributable to these technologies include the following:

- For SNCR
    - compressor power (air atomization/mixing)
    - steam (if steam atomization/mixing)
    - dry gas loss (air injection into furnace)
    - water evaporation loss
- For SCR
    - compressor
    - reactor pressure loss
    - steam (sootblowing)

Table 2-3 summarizes the key parameters for major NOx control technologies.

Table 2-3. Summary of NOx control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impacts (kW/1000 acfm)	Comments
LNB	All except Stokers, FBC	30 – 60 (<10ppm possible on gas)	NA	Assumed not to have negative impact on $CO/UBC/O_2$
OFA	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
Reburn	All except firetube/FBC	30 - 60	NA	Assumed not to have negative impact on $CO/UBC/O_2$
SNCR	All except firetube (Must have adequate temperature window)	30 - 70	1 - 2	Compressor/vaporization losses
SCR	All (Most likely for larger coal units where LNBs cannot reach very low NOx levels)	60 - 90	0.5 – 1 (gas) 2 - 4 (oil/coal)	Pressure loss/steam

2.6 NOx Control Costs

The following tables summarize published NOx control costs for ICI boilers reported in the literature [US EPA, 1996; NESCAUM, 2000; Khan, 2003; US EPA, 2003; MACTEC, 2005; Whiteman, 2006]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars per ton of NOx removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some operating costs. Costs of reagents and fuels (e.g., ammonia, natural gas) and consumables (e.g., SCR catalyst) change with time, but not always at the general rate of inflation. Some of these costs have increased at rates higher than the general rate of inflation. Thus, cost effectiveness values (or operating costs) from before 2005 have not been reported.

Table 2-4 summarizes the published NOx control costs for combustion modification technologies. The cost of the installation of low-NOx combustion technology depends on the firing system, and this is reflected in the lack of a clear relationship between capital cost and boiler capacity (*Figure 2-7*). Smaller boilers (10 to 50 MMBtu/hr) are often firetube or packaged watertube, whereas larger oil and gas boilers are more likely to be field-erected watertube boilers. Coal-fired boilers can be stokers, pulverized coal (PC), or cyclones. Combustion modification technologies therefore need to be evaluated on a case-by-case basis, taking into account both the fuel and the design of the combustion system. For the substantial majority of the estimates for ICI boilers, capital costs are in the range of $1,000 to $6,000 per MMBtu/hr. Cost effectiveness values, where available, are generally in the range of $1,000 to $7,000 per ton of NOx removed.

Table 2-4. NOx control costs for combustion modifications applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
Overfire Air	15-30	Coal	500	$2,682	1996		1
Fuel-Lean GR	35%	Coal	350	$1,302	1999		2
Gas Reburn	55%	Coal	500	$2,604	1999		2
LNB	25%	Coal	350	$6,378	1999		2
LNB	36.0%	Coal	350	$6,378	1999		2
LNB	50%	Coal	500	$8,464	1996		1
LNB	51%	Coal	100	$9,287	1999		6
LNB	51%	Coal	250	$7,055	1999		6
LNB	51%	Coal	1000	$4,654	1999		6
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,383	3
LNB	42.6%	Coal (Tangent.)	250	$5,088	2005	$3,988	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$2,636	3
LNB	49%	Coal (Wall)	250	$5,088	2005	$3,101	3
LNB	40%	Pulv. Coal	250	$346-$3,610	2005	$749-$3,393	3
LNB	45.0%	Resid. Oil	250-FT	$5,088	2005	$6,361-$7,483	3
LNB	50%	Resid. Oil	250-WT	$5,088	2005	$4,691-$5,519	3
LNB	40%	Resid. Oil	250	$346-$5,088	2005?	$1,505-$6,813	3
LNB	45%	Resid. Oil	10	$7,617	1996		1
LNB	45%	Resid. Oil	50	$3,021	1996		1
LNB	45%	Resid. Oil	150	$1,563	1996		1
LNB	45%	Dist. Oil	10	$7,617	1996		1
LNB	45%	Dist. Oil	50	$3,021	1996		1
LNB	45%	Dist. Oil	150	$1,563	1996		1
LNB	25%	Gas	350	$6,378	1999		2
LNB	40%-55%	Gas	10	$7,617	1996		1
LNB	40%-55%	Gas	50	$3,021	1996		1
LNB	40%-55%	Gas	150	$1,563	1996		1
LNB+FGR	50%	Pulv. Coal	250	$930-6,629	2005	$1,482-$3,582	3
LNB+FGR	72%	Pulv. Coal	250	$930-6,629	2005	$1,029-$2,488	3
LNB+FGR	50%	Resid. Oil	250	$930-6,629	2005	$2,977-$7,197	3
LNB+FGR	72%	Resid. Oil	250	$930-6,629	2005	$2,068-$4,998	3
LNB+OFA	51%-65%	Coal	100	$9,287	1999		6
LNB+OFA	51%-65%	Coal	250	$7,055	1999		6
LNB+OFA	51%-65%	Coal	1000	$4,654	1999		6
LNB+OFA	30%-50%	Oil	100	$3,258	1999		6
LNB+OFA	30%-50%	Oil	250	$2,474	1999		6
LNB+OFA	30%-60%	Oil	1000	$1,633	1999		6
LNB+OFA	60%	Gas	100	$3,258	1999		6
LNB+OFA	60%	Gas	250	$2,474	1999		6
LNB+OFA	60%	Gas	1000	$1,633	1999		6

Table 2-4 [continued]

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref
ULNB	46%	Pulv. Coal	250	$1,364	2005	$1,876	3
ULNB	63%	Pulv. Coal	250	$1,364	2005	$933	3
ULNB	72%	Pulv. Coal	250	$1,364	2005	$619	3
ULNB	75%	Pulv. Coal	250	$1,364	2005	$784	3
ULNB	85%	Pulv. Coal	250	$1,364	2005	$692	3
ULNB	75%	Resid. Oil	250	$1,364	2005	1575	3
ULNB	85%	Resid. Oil	250	$1,364	2005	1390	3
ULNB	80%	Dist. Oil	24.5	$8,619	2005	17954	3
ULNB	80%	Dist. Oil	70	$2,280	2005	5756	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4751	3
ULNB	94%	Dist. Oil	68	$1,987	2005	4564	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, “Selective Non-Catalytic Reduction Technology Costs for Industrial Sources,” memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

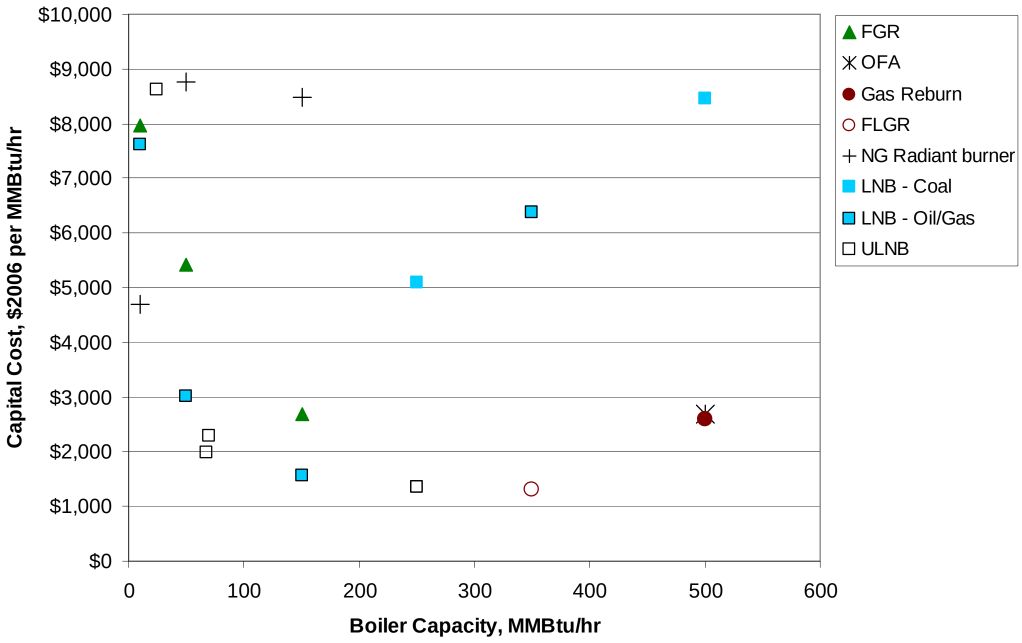


Figure 2-7. Capital cost for NOx control for combustion modification applied to ICI boilers as a function of boiler capacity

Table 2-5. NOx control costs for SNCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SNCR	30%-70%	Coal	500	$2,044	1996		1
SNCR	40%	Coal	100	$6,717	1999		6
SNCR	40%	Coal	250	$5,102	1999		6
SNCR	40%	Coal	1000	$3,366	1999		6
SNCR	30%-70%	Resid. Oil	50	$4,297	1996		1
SNCR	30%-70%	Resid. Oil	150	$4,297	1996		1
SNCR	35%		350	$2,862	1999		2
SNCR			21	$17,101	2006	$3,718	4
SNCR			120	$6,377	2006	$2,231	4
SNCR			240	$4,493	2006	$1,821	4
SNCR			387	$2,899	2006	$1,564	4
SNCR			543	$2,319	2006	$1,538	4
SNCR			844	$1,449	2006	$1,346	4
SNCR	40%	Oil	100	$5,205	1999		6
SNCR	40%	Oil	250	$3,954	1999		6
SNCR	40%	Oil	1000	$2,608	1999		6
SNCR	30%-70%	Dist. Oil	50	$4,297	1996		1
SNCR	30%-60%	Natural Gas	50	$4,297	1996		1
SNCR	40%	Gas	100	$5,372	1999		6
SNCR	40%	Gas	250	$4,082	1999		6
SNCR	40%	Gas	1000	$2,693	1999		6
LNB+SNCR	50%-89%	Pulv. Coal	250	$2,064-6,829	2005	$1,409-$4,473	3
LNB+SNCR	50%-89%	Resid. Oil	250	$2,064-6,829	2005	$2,229-$7,909	3

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

Table 2-5 summarizes the published NOx control costs for SNCR applied to ICI boilers. As with combustion modifications, the capital cost of SNCR systems is sensitive to the type of combustion system. As long as the boiler has sufficient space for installation of injection lances and mixing of reagent and flue gas (at the appropriate temperature), the capital costs should not depend on the fuel burned. The relationship between capital cost and boiler capacity is shown in *Figure 2-8*. Except for the 1996 EPA estimates for gas and oil boilers, there is a pronounced effect of boiler capacity on capital cost. The graph shows that fuel type is probably secondary to boiler capacity, although there will be an indirect effect of fuel, because fuel type influences the design of the combustion system. The cost effectiveness for SNCR was given by ICAC [Whiteman, 2006] without regard to fuel type and by MACTEC [2005] for coal and residual oil.

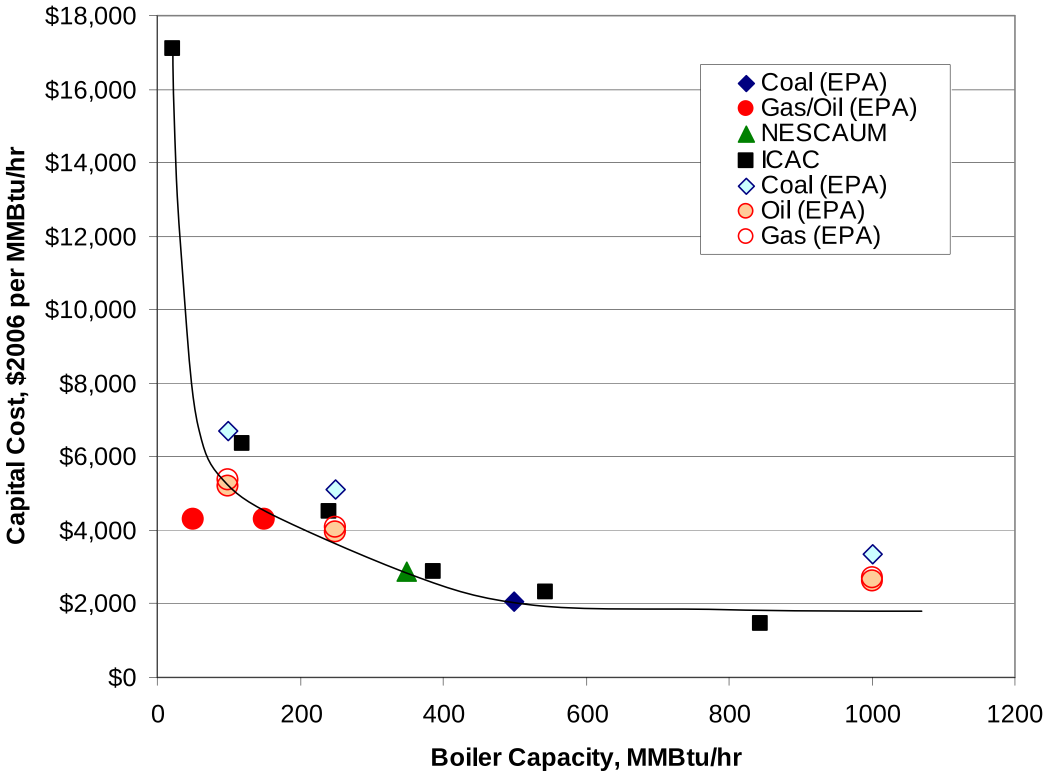


Figure 2-8. Capital cost for NOx control for SNCR applied to ICI boilers as a function of boiler capacity

Table 2-6 summarizes the published NOx control costs for SCR. The relationship between capital cost and boiler capacity is shown in *Figure 2-9*. The capital cost of SCR systems is sensitive to the type of fuel and to the level of NOx reduction desired, but not to the combustion system. The volume of catalyst required for an SCR installation depends on the level of desired NOx reduction and on the fuel. Coal-fired power plant applications are the most expensive, since the flue gas entering the SCR contains fly ash, which affects the design of the catalyst. The capital cost for a given fuel and boiler size can vary (see, for example, the variation in capital costs reported for coal application). When an SCR must be retrofit, the cost of the installation depends on the configuration of the specific system. Because the amount of ductwork required, significant variation in installed capital cost can occur for a given boiler size. Upgrades like rebuilding the air preheater also affect the installed capital cost. MACTEC [2005] gave the cost effectiveness (in dollars per ton of NOx removed) for SCR for coal and residual oil; these costs showed a wide range, because of the wide range in assumed capital costs.

Table 2-6. NOx control costs for SCR applied to ICI boilers

Technology	NOx Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs @2006$ ($/MMBtu/hr)	Base yr. for or Ref. yr	Cost ($/ton NOx @ base year)	Ref.
SCR	80%	Coal	*350*	$12,755-19,133	1999		2
SCR	80%-90%	Coal	500	$15,365-16,145	1996		1
SCR	70%-90%	Pulv. Coal	250	$1,666-13,881	2005	$2,233-$7,280	3
SCR	80%	Coal	100	$18,574	1999		6
SCR	80%	Coal	250	$14,110	1999		6
SCR	80%	Coal	1000	$9,309	1999		6
SCR	80%	Oil	100	$14,116	1999		6
SCR	80%	Oil	250	$10,723	1999		6
SCR	80%	Oil	1000	$7,075	1999		6
SCR	--	Oil	--	$5,102-7,653	1999		5
SCR	70%-90%	Resid. Oil	250	$1,666-13,881	2005	$4,363-$14,431	3
SCR	80%-90%	Resid. Oil	50	$8,359	1996		1
SCR	80%-90%	Resid. Oil	150	$4,909	1996		1
SCR	80%-90%	Dist.	50	$8,359	1996		1
SCR	80%-90%	Dist.	150	$4,909	1996		1
SCR	80%	Gas	100	$10,216	1999		6
SCR	80%	Gas	250	$7,760	1999		6
SCR	80%	Gas	1000	$5,120	1999		6
SCR	80%	Gas	100	$9,566	1999		2
SCR	80%	Gas	350	$7,015	1999		2
SCR	80%-90%	Natural Gas	50	$8,359	1996		1
SCR	80%-90%	Natural Gas	150	$4,909	1996		1
SCR	80%	Wood	350	$6,378-7,653	1999		2
SCR	74%	Wood	321	$1,978	2006	$4,514	7

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, “Selective Non-Catalytic Reduction Technology Costs for Industrial Sources,” memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.
7. BPEI. (2008, February). RSCR Cost Effective Analysis.

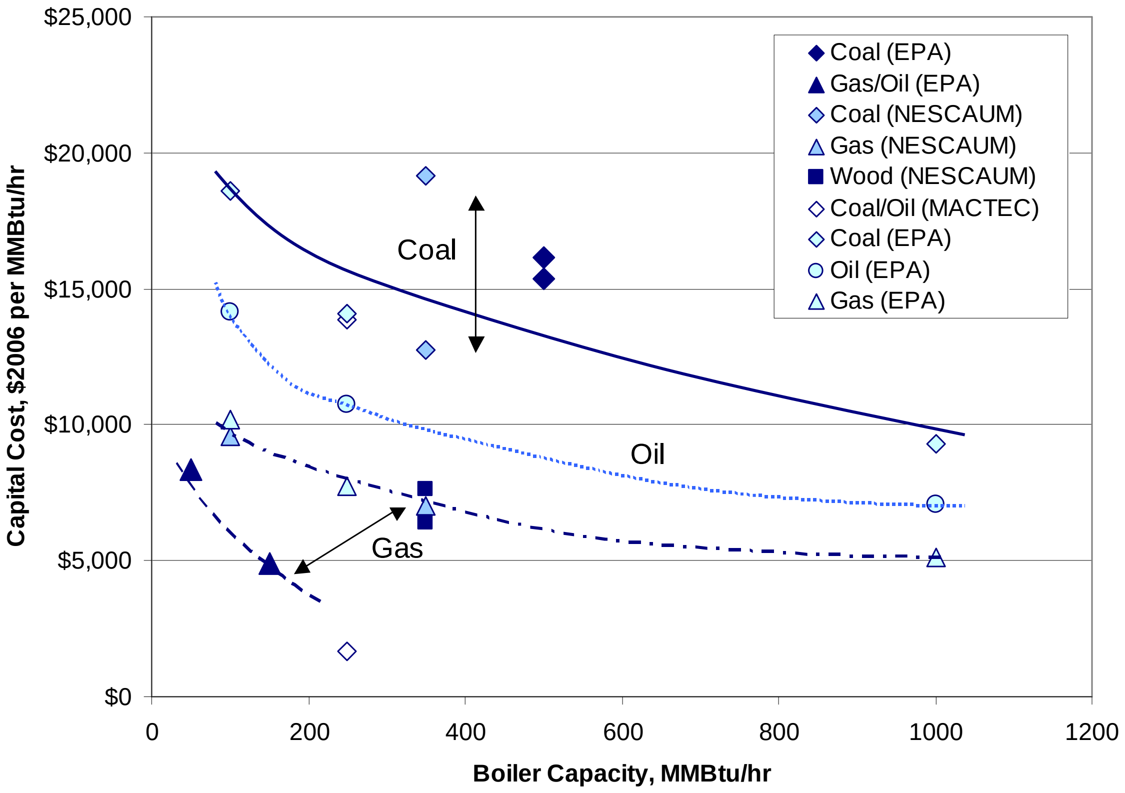


Figure 2-9. Capital cost for NOx control for SCR applied to ICI boilers as a function of boiler capacity

2.7 Chapter 2 References

Albanese, Vince (2006). "Applications, Issues, & Answer for SNCR." NACAA Fall Meeting in San Antonio, TX.

Babcock Power Environmental Inc. (2006). Regenerative SCR. Worcester: Babcock Power Environmental Inc.

Bodnarik, Andrew M. New Hampshire Department of Environmental Services, "ICI Boiler NOx Control Cost Estimates from the OTC Methodology," presented at the OTC Control Strategy/SAS Committee Meeting, November 2, 2006.

Babcock Power Environmental Inc. (2008). RSCR Cost Effective Analysis.

Khan, Sikander. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

MACTEC. Boiler Best Available Retrofit Technology (BART) Engineering Analysis; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.

NESCAUM. Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness, (Praveen Amar, Project Director), December 2000.

STAPPA/ALAPCO (2006). “Controlling Fine Particulate Matter under the Clean Air Act: A Menu of Options.”

Toupin, R. F. (2007). Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today’s Marketplace. Worcester: Babcock Power Environmental Inc.

US EPA. Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf.

US EPA. OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/.

Whiteman, C. ICAC, “Selective Non-Catalytic Reduction Technology Costs for Industrial Sources,” memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.

3 SO_2 CONTROL TECHNOLOGIES

3.1 SO_2 Formation

SO_2 is an undesirable byproduct of the combustion of sulfur-containing fossil fuels. SO_2, like NOx, is a precursor to ambient fine particles: Thirty to 50 percent of ambient fine PM mass in the eastern U.S. is attributable to sulfate derived from SO_2. SO_2 is a significant contributor to wet and dry acid deposition on various ecosystems (lakes, streams, soils, and forests). Various coals in the U.S. can have 1 to 3 percent (by mass) sulfur; residual oil (No. 6 oil) can have sulfur contents of 2 percent and higher. Distillate oils are generally lower in sulfur content (less than 0.5 percent by mass). Natural gas has essentially zero sulfur content. However, unlike nitrogen in coal or oil, essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics). This means that the relationship between sulfur content in the fuel and SO_2 emissions is much more direct and linear than that between fuel nitrogen and NOx emissions, and as such, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal or from higher-sulfur oils to lower-sulfur oils) are directly proportional to the difference in sulfur contents of fuels.

Another important difference is that this relationship is, for all practical purposes, independent of the type of boiler technology. Two exceptions to this include the high–alkaline nature of ash in some sub bituminous coals, which causes a portion of the sulfur in the coal to react and form various sulfate salts (mostly calcium sulfate); another is the combustion of coal in fluidized bed combustion (FBC) boilers where the lower temperatures of combustion and the use of alkaline material (e.g., limestone) in the "bed" promote the reaction of SO_2 with calcium to form sulfate, thereby reducing the net emissions of SO_2. In practical terms, this means that most solid- and liquid-fuel-fired systems produce SO_2 emissions proportional to their sulfur content, whereas natural gas combustion produces essentially no SO_2.

Additionally, despite the much smaller quantities of SO_3 formed in comparison to SO_2, as noted above, SO_3 presents both operational and environmental challenges. Operationally, SO_3 is a concern because if the temperature of the back-end flue gas handling equipment (e.g., ducts, particulate control devices, scrubbers) falls below the acid dew point, corrosion and material deterioration can result. From an environmental perspective, nucleation and condensation of ultra-fine sulfuric acid particles formed from the SO_3 present in the flue gas can contribute to the primary emissions of fine PM from the stack into the atmosphere.

3.2 SO_2 Reduction

As a result of the relationship between fuel sulfur content and SO_2, SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. This is accomplished by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers" and are usually described in terms of the process conditions (wet vs. dry), methods for gas-sorbent contact (e.g., absorber vessel vs. duct for dry sorbent injection), byproduct utilization (throwaway vs. saleable), and reagent utilization (once-through vs. regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction, and the use of enhancing additives. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability to ICI boilers, and data on performance and cost. For a more detailed description of FGD technologies, see Srivastava [2000].

As noted earlier, SO_2 control strategies can also include fuel switching (from high-sulfur coal to low-sulfur coal or from high-sulfur oil to low-sulfur oil/natural gas). While not considered a "technology," switching from a higher-sulfur fuel to a lower-sulfur one requires considerable cost and operational analysis. Major issues include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

3.3 Other FGD Benefits

Significant attention has been given recently to the issue of mercury emissions from EGUs and ICI boilers. It is relevant to note that some FGD technologies have been shown to capture mercury from the flue gas [Jones and Feeley, 2008] by absorbing the water-soluble oxidized forms of mercury from the flue gas. Both wet and dry SO_2 control processes have been and are being tested to determine their mercury capture potential. This suggests that strategic and economic analyses for SO_2 control technologies need to consider the potential side-benefit of mercury removal as well.

3.4 Summary of FGD Technologies

A brief overview of FGD technologies is provided here to give the reader a broad perspective on SO_2 controls.

3.4.1 Wet Processes

Wet FGD (WFGD) or "wet scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s [NESCAUM 2000]. They represent the predominant SO_2 control technology in use today with over 80 percent of the controlled EGUs capacity in the world and the U.S. [EPA 2000].

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield >90 percent SO_2 capture. Currently, advanced scrubber designs for EGUs have eliminated not only many of the early operational problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with the technology being capable of well over 95 percent SO_2 control [Dene *et al.*, 2008]. *Figure 3-1* provides a schematic view of a wet scrubber.

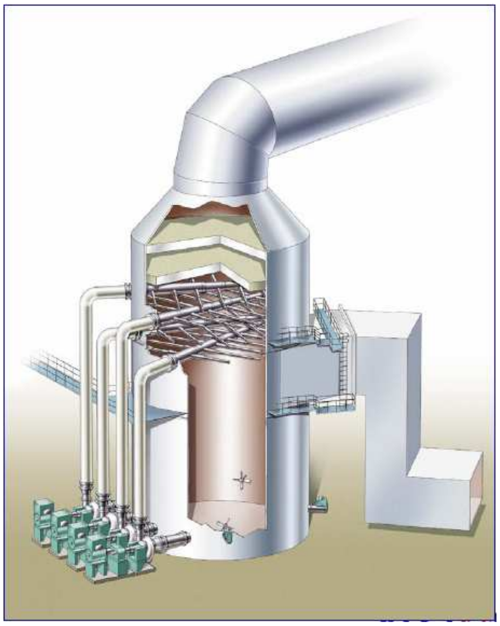


Figure 3-1. Schematic of a WFGD scrubber [Bozzuto, 2007]

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate, ammonia, and even seawater-based processes are all commercially available. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, and efficiency targets.

Technology costs have changed over time, as expected, reflecting changes in market conditions, labor and raw material costs, local, state, regional, and federal regulatory drivers, and site-specific considerations. Recently, capital costs have trended upward after a downward trend in the mid-late 1990s. These fluctuations have in large part, been driven by labor and material costs, the global nature of technology markets, and regulatory changes within the electric power sector [Sharp, 2007; Cichanowicz, 2007].

3.4.2 Dry Processes

Conventional dry processes include spray dryers (SDs) or "dry scrubbers" and Dry Sorbent Injection (DSI) technologies, and are shown in *Figure 3-2* and *Figure 3-3*, respectively. The technologies are referred to as "dry" because the SO_2 sorbent, while it may be injected as a slurry or a dry powder, is finally dried and collected in a conventional particulate control device, a fabric filter, or an ESP.

SD refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber vessel. DSI technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the "reactor," and several configurations are possible based on the temperature window desired. This can occur at the furnace (1800-2200ºF), economizer (800-900ºF), or in a low-temperature duct (250-300ºF). In addition, another common feature of dry scrubbing systems is the need for the particulate control equipment downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (although, depending on the application, ESPs may be used) that are not only efficient collectors of fine particulates, but can also provide some additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the bags. Dry processes are more compatible with low- to medium-sulfur coals because of the need to limit solid concentrations in the slurry below a threshold for adequate atomization and the need to limit the amount of solids collected in an existing particulate control device. This requirement precludes higher sulfur fuel applications where the required amount of reagent would be above that threshold. Therefore, high-sulfur applications are more typically associated with wet FGDs.

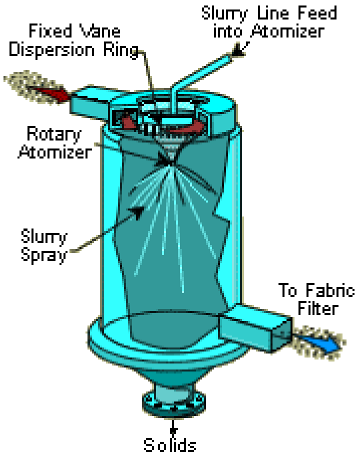


Figure 3-2. Schematic of a spray dryer [http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

It is relevant to note that DSI technology did not gain any meaningful market penetration as part of the EGU compliance options to meet the requirements of the 1990 CAAA (Title IV) “acid rain” legislation for reducing emissions of SO_2. The large number of wet FGD installations in response to the Clean Air Act of 1970, and creation of “emission allowances,” combined with the trend to switch fuels (mostly to low-sulfur Powder River Basin or PRB coal) in response to the 1990 CAAA, help explain this situation. However, more recently, interest in DSI technology applications for ICI boilers has been renewed and companies are “revamping” the knowledge base for DSI.

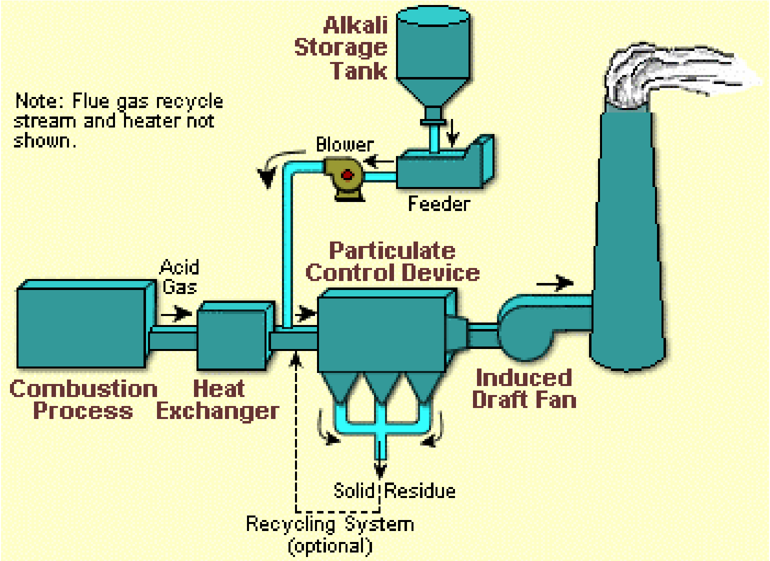


Figure 3-3. Dry Sorbent Injection (DSI) system diagram [http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm]

DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector. Companies such as O'Brien and Gere [Day, 2006; Day, 2007] and Siemens Environmental [Siemens, 2007] are marketing and deploying duct injection systems, and Nalco Mobotec [Haddad *et al.*, 2003] offers furnace sorbent injection (FSI) systems for ICI boilers. O'Brien and Gere, for example, have conducted over 5,000 hours of demonstrations at 15 different boilers since January 2005 to evaluate the viability, performance, and economics of DSI [Day, 2007]. These processes require relatively little new equipment and are thus suitable candidates for ICI boiler retrofit applications, where site constraints (e.g., space) are often critical.

Two examples of DSI systems are Furnace Sorbent Injection (FSI) in which hydrated lime is injected into the upper furnace of the boiler, and Lime Slurry Duct injection (LSDI) where atomized lime slurry is sprayed into the gas stream in the duct. FSI systems were first demonstrated in the 1980s on EGU boilers and are currently operating at ICI boilers [Dickerman, 2006].

FSI systems are capable of removing between 20 to 60 percent of the SO_2 and have shown removal percentages of as high as 90 to 99 percent for HCl and SO_3 [Haddad *et al.*, 2003]. The FSI systems also offer a low capital cost option and the attractiveness of quick cost recovery for ICI boiler sector [Dickerman, 2006].

The LSDI utilizes an atomized spray of lime slurry. The particles are subsequently captured in the downstream particulate collector. Sorbent particle size distribution is important for maximizing SO_2 capture while minimizing operational problems such as duct fallout and deposition.

LSDI systems have been utilized to mitigate plume generation from cement plants, and are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent [Dickerman, 2006].

In either case, both dry sorbent injection technologies offer an economical method for reducing emissions of SO_2. *Table 3-1* compares the FSI and LSDI systems for a 100 MW boiler, burning coal with one percent sulfur.

Table 3-1. Comparison of price for FSI and LSDI systems for a 100 MW coal-fired boiler [Dickerman, 2006]

Parameter	***FSI (Hydrated Lime)***	***LSDI***
SO_2 Removal	35%	50%
Reagent Cost ($\$10^3$/yr)	$1,400	$370
Parasitic Power ($\$10^3$/yr)	$182	$182
Disposal Cost ($\$10^3$/yr)	$168	$93
Subtotal ($\$10^3$/yr)	$1,750	$645
Capital Cost ($/kW)	$1,000,000 (10 $/kW)	$2,500,000 (25 $/kW)
Annual Capital Charge ($\$10^3$/yr)	$100	$250
Total Operating Cost ($\$10^3$/yr)	$1,850	$895
$/ton SO_2 Removed	$1,070	$311

Trona (sodium sesquicarbonate) is another reagent that has shown potential to reduce SO_2 emissions. A typical flow diagram is shown in *Figure 3-4* for injection of trona into a duct.

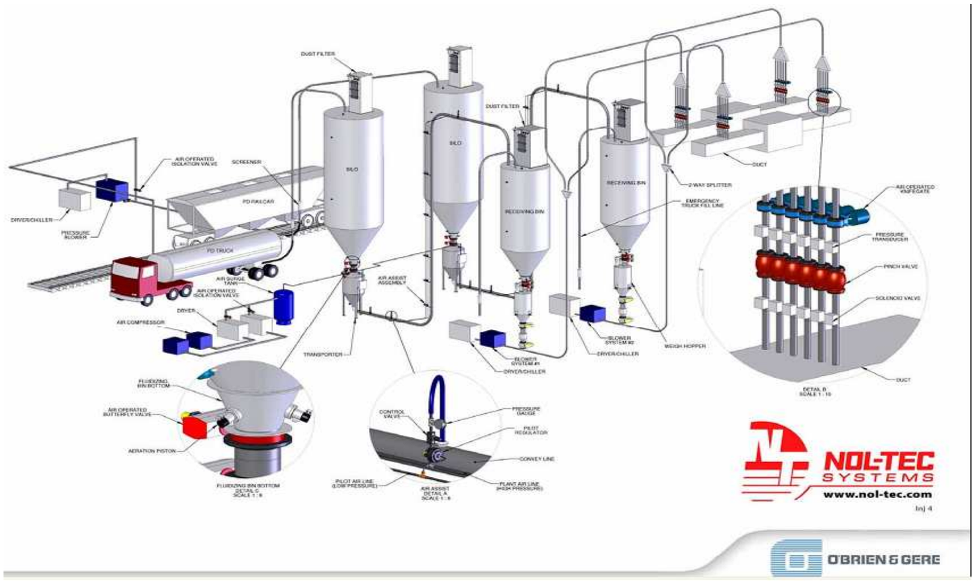


Figure 3-4. Flow diagram for trona DSI system [Day, 2006]

Trona's higher reactivity compared to lime helps it to offset the reaction stoichiometry advantage of lime. More importantly, due to the ability of trona to capture SO_2 when injected at higher temperatures [Cremer *et al.*, 2008], it is potentially applicable to many ICI boilers where flue gas temperatures may be higher that the desired ~300°F required for lime. *Figure 3-5* gives some test data showing percent SO_2 reduction, [Day, 2006], averaged over several applications for units with ESPs.

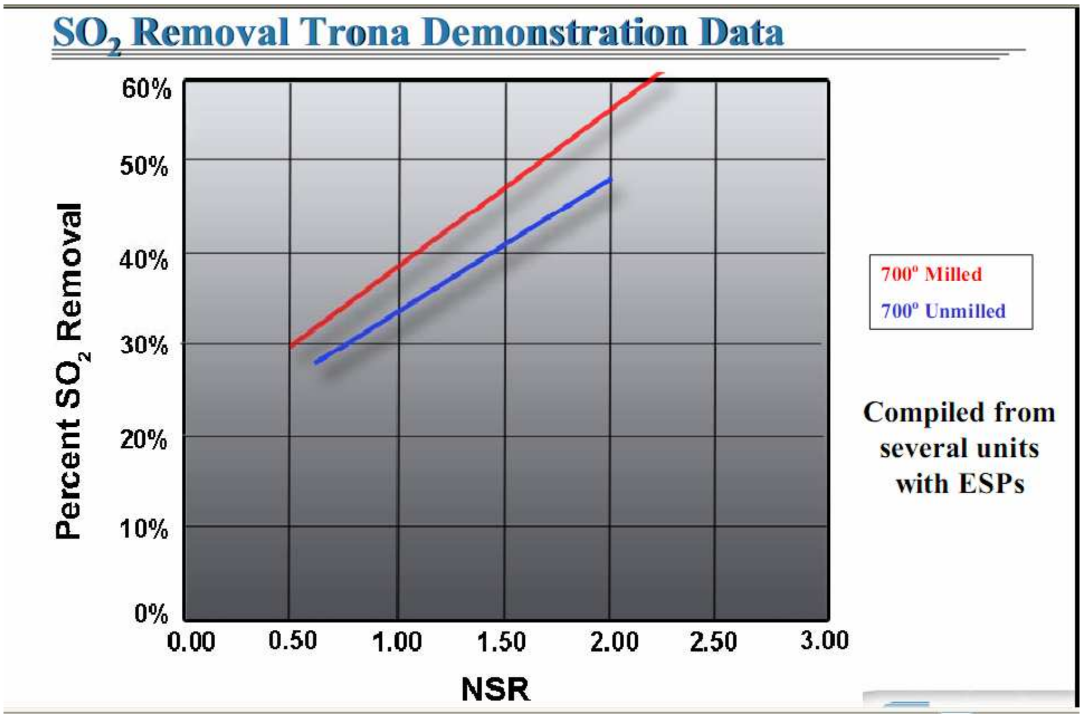


Figure 3-5. SO_2 removal test data [Day, 2007]

Figure 3-5 presents results for SO_2 reduction as a function of normalized stoichiometric ratio (NSR), which is the ratio of the reagent (trona in this case) to SO_2 in the flue gas. The two lines depict SO_2 reduction potential for two different sizes of trona at the same flue gas temperature of 700°F. Larger particles (unmilled) result in lower SO_2 reductions, as expected, relative to the milled condition (smaller particle size).

3.4.3 Other SO_2 Scrubbing Technologies

A number of other scrubber technologies have been developed for control of SO_2, but have not to date received significant market share. Among them are sodium- and ammonia-based wet scrubbing technologies. Some of these technologies, like the activated coke process [Dene, 2008], are regenerable (meaning the reagent can be regenerated and used repeatedly) and may produce useful byproducts, such as sulfuric acid, elemental sulfur, and ammonium sulfate. *Table 3-2* and *Table 3-3* present a comparison of the key performance characteristics and attributes for several alternative scrubbing technologies compared with conventional wet and dry scrubbers [Bozzuto, 2007].

Table 3-2. Comparison of alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Features	• High Efficiency • Low cost reagent • Byproduct flexibility	• Low investment cost • Dry byproduct • Small footprint • No liquid waste	• High value byproduct • Economics improved at high sulfur levels • Low operating cost	• Low investment cost • Operational simplicity
Pros	• Small flue gas flow • Operational simplicity required • Acute capital cost • Short evaluation period	• Low/medium sulfur fuel • Smaller flue gas flow • Short evaluation period	• High sulfur fuel • Larger flue gas flow • Gypsum market •Medium cost evaluation period	• High sulfur fuel • Larger flue gas flow • Fertilizer market
Cons	• Effluent discharge issue	• Limited landfill area • High lime/limestone cost ratio	• Acute capital cost sensitivity • Ultra-low PM emission requirements	• Acute capital cost sensitivity
Reagent	Limestone	Lime	Ammonia	Caustic, soda ash
Byproduct	Marketable gypsum or landfill	Landfill	Fertilizer	Sodium sulfate
SO_2 inlet	High	Low/medium	High	High
Removal Efficiency	>98%	90 – 95%	>98%	>98%

Table 3-3. Cost estimates for alternative FGD technologies [Bozzuto, 2007]

	Limestone WFGD	Spray Dryer	Ammonia WFGD	Sodium WFGD
Capital Cost ($/acfm)	25 – 45	15- 25	35 – 60	10 – 20
Power Consumption (kW/acfm)	3-6	2	3-6	2-3
Reagent Cost ($/ton SO_2 removed.)	$15 – 25/ton	$60 – 75/ton	$80 – 105/ton	$100-130/ton
Byproduct Cost ($/ton SO_2 removed.)	$12 – 20/ton – disposal ($15/ton) – sale	$12 – 20/ton	$150 – 250/ton	??

3.5 Use of Fuel Oils with Lower Sulfur Content

Distillate fuel (No. 2 oil) is used in combustion systems in which an atomizer sprays droplets of oil into a combustion chamber and the droplets burn in suspension. Residual fuel oil (No. 6 oil) is also atomized and burned in ICI boilers. No. 6 oil is more viscous and has a higher boiling point range than distillate oil. Preheating is required for metering and atomization of No. 6 oil in industrial combustion systems. A wide range of sulfur contents are available, from less than 0.3 wt% to greater than 3 wt%.

For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2. There is also an additional and important benefit of reduced emissions of $PM_{2.5.}$ There are generally costs associated with switching to lower-sulfur fuels, which will undoubtedly vary from region to region.

Table 3-4 shows an example of the stocks of the fuel oils available on the East Coast and in the U.S. in 2006, taken from the Energy Information Administration (EIA) Petroleum Supply Annual [US EIA, 2006]. Substantial stocks of low-sulfur No. 6 fuel oil (less than 0.3 percent sulfur) and of ultra-low-sulfur No. 2 fuel oil (less than 0.0015 percent sulfur) were available both in the U.S. and on the East Coast.

Table 3-4. Distillate and residual oil stocks in 2006 (x1000 barrels) [US EIA, 2006]

	East Coast		**U. S. Total**	
Distillate Fuel Oil	**4,174**		**31,318**	
0.0015% sulfur and under	1,856	(44%)	16,531	(53%)
Greater than 0.0015% to 0.05% sulfur	560	(13%)	6,223	(20%)
Greater than 0.05% sulfur	1,758	(42%)	8,564	(27%)
Residual Fuel Oil	**2,486**		**11,936**	
Less than 0.31% sulfur	869	(35%)	1,291	(11%)
0.31 to 1% sulfur	975	(39%)	2,544	(21%)
Greater than 1% sulfur	642	(26%)	8,101	(68%)

Figure 3-6 shows the prices for residual oil and distillate oil from 1983 through 2007. The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been narrowing in recent years. The price of distillate oil in recent years, however, has been at times twice as much as the price of residual oil. The EIA prices for residual oil do not include a breakdown for very low sulfur residual oil (less than 0.31 percent sulfur). However, the prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm S), low-sulfur (15-500 ppm S), and high-sulfur (>500 ppm S). These prices, shown in *Figure 3-7*, do not show much difference in price as a function of sulfur content of No. 2 oil.

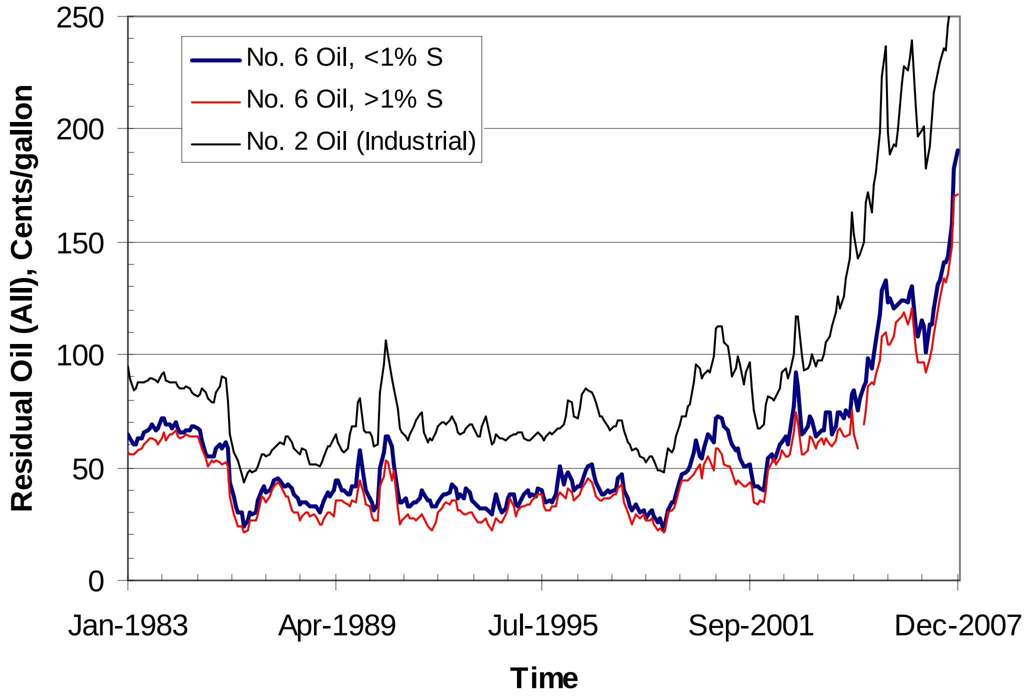


Figure 3-6. Industrial energy prices for No. 6 oil greater than 1 percent S, No. 6 oil less than 1 percent S, and No. 2 oil [Source: US EIA, 2008]

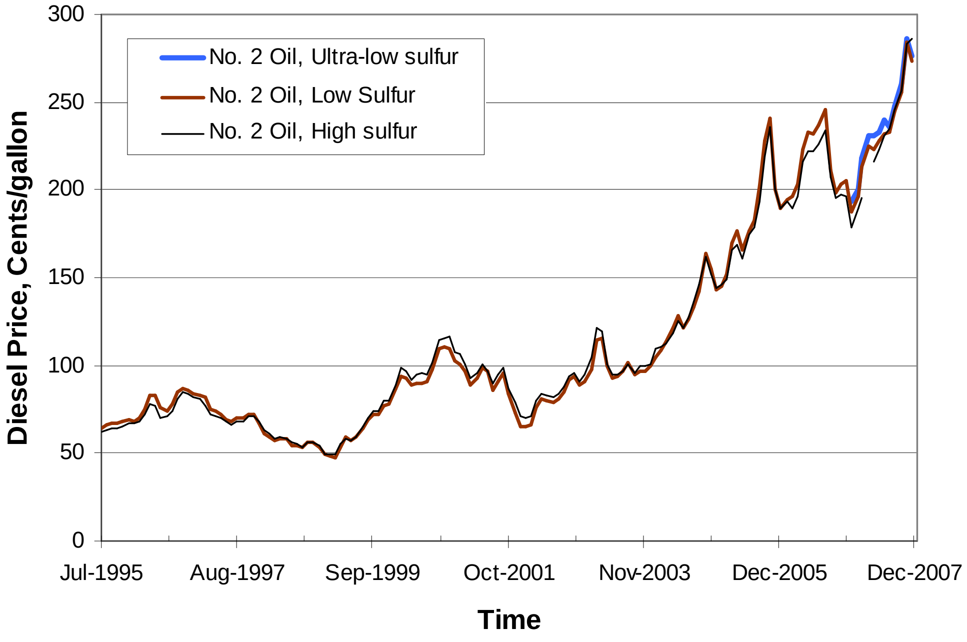


Figure 3-7. Industrial energy prices for No. 2 (distillate) oil [Source: US EIA, 2008]

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example, in which December 2007 fuel prices are used. If the high-sulfur residual oil is assumed to be 3 percent S, the low-sulfur residual oil is assumed to be 1 percent S, and the distillate oil is assumed to be 0.2 percent S, then the cost for fuel switching is shown in *Table 3-5*. These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in *Table 3-5* suggest that switching from a 3 percent sulfur residual fuel oil to a low-sulfur residual oil (1 percent S) would provide a cost-effective sulfur removal strategy at about $771 per ton of SO_2 removed. The cost of switching to distillate oil is estimated to be much higher than switching to low-sulfur residual oil, because the cost of distillate oil has been as much as twice that of residual oil in recent years. The cost effectiveness of a wet FGD for 90 to 99 percent SO_2 removal is in the range of $2,000 to $5,200/ton SO_2 (see Section 3.8). Thus, a switch to lower-sulfur fuel represents a cost-effective sulfur-compliance strategy for residual oil-fired boilers. The cost effectiveness (in dollars per ton of SO_2 removed) of switching from residual fuel oil to distillate fuel oil is not as attractive and is in the range of the cost effectiveness of installing a FGD or scrubber.

Table 3-5. Example of costs of switching to low-sulfur fuel oil [Fuel Prices from US EIA, 2008]

Fuel Switch	**SO_2 reduction**	**\$/ton SO_2 removed (2007\$)**
From 3% S to 1% Residual Oil*	66.7%	$771
From 3% S Residual to 0.2% Distillate**	93.6%	$5,335

*Assuming December 2007 prices for <1%S and >1%S residual oil
**Assuming December 2007 prices for >1%S and distillate oil

3.6 Applicability of SO_2 Control Technologies to ICI Boilers

The technologies described above are commercially available and are used extensively throughout the electric utility industry for coal-firing applications. The EGUs have deployed SO_2 controls (mostly wet and dry scrubbers) since the 1970s. ICI boilers firing coal are good candidates for the application of SO_2 control technologies. At least one oil-fired installation of a wet FGD has been noted in the literature [Caine and Shah, 2008]. Economics, however, will dictate preferred options on a case-by-case basis. It is likely that the higher capital-cost intensive technologies (e.g., wet and dry scrubbers) will be most attractive to larger ICI boilers, whereas the injection technologies (such as DSI) would likely be favored at smaller ICI boilers. The annualized cost of a wet FGD scrubber using wet sodium or alkaline waste can be lower relative to lime and limestone FGD, especially if low-cost waste disposal is available and the amount of SO_2 to be removed is small [Emmel, 2006]. This would suggest that smaller ICI boilers may not be good candidates for high capital-cost FGD systems. However, they should be good candidates for application of lower capital cost technologies such as DSI.

In terms of applicability, it is also important to recognize the impact of sulfur content of coal. Dry scrubbing has been typically restricted to low and medium sulfur coals (less than 2 wt% S) due to economic and technical considerations, including constraints associated with sorbent slurry concentration and adequate atomization performance. Lastly, while theoretically feasible, fluidized bed combustion (FBC) boilers are low emitters of SO_2 due to their inherent combustion process (bed temperature and composition), and are not likely candidates for SO_2 scrubber systems.

3.7 Efficiency Impacts

From the brief descriptions above, it should be clear that the common thread among the major SO_2 control technologies involves the reaction of SO_2 in the flue gas with a sorbent or reagent. The chemical reaction occurs either in a dedicated vessel (scrubber), or in the existing flue gas duct system. The major components affecting energy consumption for these systems include electrical power associated with material preparation (e.g., grinding) and handling (pumps/blowers), flue gas pressure loss across the scrubber vessel, and steam requirements. As expected, the energy penalties associated with a highly efficient (99 percent SO_2 reduction) wet scrubber are higher than for a less energy-intensive technology such as DSI.

The power consumption of SO_2 control technologies is further affected by the SO_2 control efficiency of the technology itself. In other words, SO_2 control performance is related to reagent utilization, commonly referred to as liquid-to-gas (L/G) ratio for wet systems and normalized stoichiometric ratio or reagent (Ca or Na) to-sulfur ratio for dry technologies. This can be explained based on the fact that for a given SO_2 reduction level, lower quantities of reagent not only translate to lower reagent costs, but also to lower energy costs.

Table 3-6 summarizes performance and energy efficiency impacts for the three general SO_2 technologies discussed. It is important to note the values shown in the table, specifically in the "Energy Impact" column, represent nominal ranges based on generic combustion calculations and parasitic energy consumption for each technology. They are not site- or fuel-specific calculations, which are generally dependent on many variables, such as fuel composition, combustion and steam efficiencies, and operating conditions (e.g., excess air). However, these values represent broad, industry-wide averages for impacts of SO_2 control technologies on efficiency.

Table 3-6. Summary of energy impacts for SO_2 control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)
WFGD	Larger coal units, high sulfur coals, excluding FBC	90 - 95+	4 – 8+
Dry Scrubbers (SDs)	Larger units w/ low/medium sulfur coals, excluding FBC	70 – 90+	2 - 4
Duct Injection	Larger units w/ low/medium sulfur coals (FBC applications possible for additional "SO_2 trim")	30 – 60+	1 - 2

3.8 SO_2 Control Costs

Table 3-7 summarizes published SO_2 control costs for ICI boilers, as reported in the literature [Khan, 2003; US EPA, 2003; Whiteman, 2003; MACTEC, 2005]. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars/ton of SO_2 removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs, and reagents or consumables can make up a large portion of some of the operating costs. Costs of reagents and fuels (e.g., limestone, trona) change with time, but not always at the general rate of inflation. Thus, cost effectiveness values (or operating costs) from years before 2005 are not shown in the table. *Table 3-7* summarizes the published SO_2 control costs for a number of SO_2 control technologies.

A range of capital costs has been reported for sorbent injection technologies. *Figure 3-8* shows costs for dry duct injection (e.g., trona injection), wet duct injection (e.g., LSDI), and furnace sorbent injection (FSI). There was a large range of capital costs reported for dry sorbent injection. Wet sorbent injection (e.g., injection of hydrated lime slurry) was reported to have a significantly lower capital cost than dry sorbent injection. FSI capital costs were between dry and wet duct injection. The cost effectiveness (cost in dollars per ton of SO_2 removed) depends on the specific sorbent used and the stoichiometric ratio of sorbent to SO_2.

Table 3-7. SO_2 control costs applied to ICI boilers

Technology	SO_2 Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
In-Duct Dry Sorbent Inj.	40%	High-S Coal	100	$34,228	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	250	$24,028	1999		1
In-Duct Dry Sorbent Inj.	40%	High-S Coal	1000	$15,954	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	100	$22,953	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	250	$16,565	1999		1
In-Duct Dry Sorbent Inj.	40%	Low-S Coal	1000	$11,031	1999		1
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	100	$17,327	2003		3
In-Duct Dry Sorbent Inj.	50 - 90%	Coal	250	$12,624	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	100	$8,663	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	250	$4,703	2003		3
In-Duct Wet Sorbent Inj.	50 - 70%	Coal	1000	$4,641	2003		3
Furnace Sorbent Inj.	70%	Coal	100	$26,609	2003		3
Furnace Sorbent Inj.	70%	Coal	250	$14,851	2003		3
Furnace Sorbent Inj.	70%	Coal	1000	$7,054	2003		3
Spray Dryer	90%	Coal	100	$69,744	1999		1
Spray Dryer	90%	Coal	250	$46,209	1999		1
Spray Dryer	90%	Coal	1000	$25,861	1999		1
Spray Dryer	90%	Coal	250	$13,300-188,820	2005	$1,712-3,578	4
Spray Dryer	95%	Coal	250	$13,300-188,820	2005	$1,622-3,390	4
Spray Dryer	90%	Oil	250	$13,300-188,820	2005	$1,944-5,219	4
Spray Dryer	95%	Oil	250	$13,300-188,820	2005	$1,841-4,945	4

Table 3-7 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet FGD	90%	High-S Coal	100	$81,939	1999		1
Wet FGD	90%	High-S Coal	250	$62,318	1999		1
Wet FGD	90%	High-S Coal	1000	$41,216	1999		1
Wet FGD	90%	Low-S Coal	100	$76,018	1999		1
Wet FGD	90%	Low-S Coal	250	$57,759	1999		1
Wet FGD	90%	Low-S Coal	1000	$38,122	1999		1
Wet FGD	90%	Coal	250	$11,507-172,672	2005	$2,089-3,822	4
Wet FGD	99%	Coal	250	$11,507-172,672	2005	$1,881-3,440	4
Wet FGD	90%	Oil	100	$69,848	1999		1
Wet FGD	90%	Oil	250	$53,066	1999		1
Wet FGD	90%	Oil	1000	$35,019	1999		1
Wet FGD	90%	Oil	250	$11,507-172,672	2005	$2,173-5,215	4
Wet FGD	99%	Oil	250	$11,507-172,672	2005	$1,956-4,694	4

References

1. Khan, S. Methodology, *Assumptions, and References Preliminary SO_2 Controls Cost Estimates for Industrial Boilers*; US EPA: 2003.
2. US EPA, *Air Pollution Control Technology Fact Sheet: Flue Gas Desulfurization (FGD - Wet, Spray Dry, and Dry Scrubbers*; EPA-452/F-03-034, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf
3. Whiteman, C., ICAC, “SO_2 Control Technology Cost Estimates for Industrial Boilers” memo to John Robbins, US EPA, December 12, 2003.
4. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.

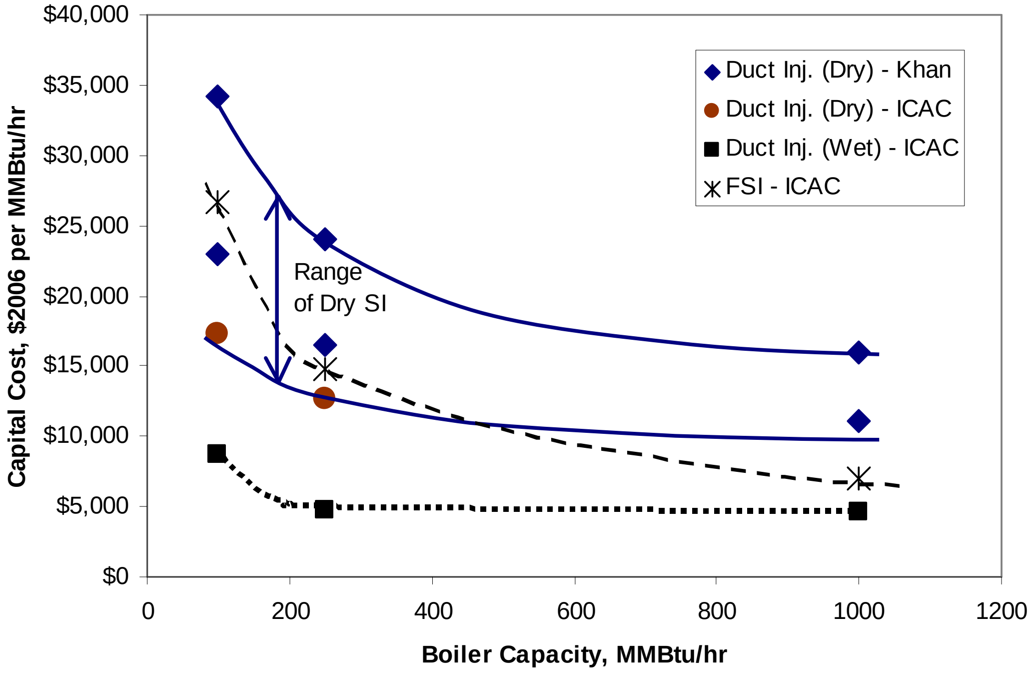


Figure 3-8. Capital cost for SO_2 control for dry sorbent injection applied to ICI boilers as a function of boiler capacity

Spray dryer (SD) technology has been widely applied to coal-fired EGUs. Estimates in the literature for SD technology for ICI boilers give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005]. *Figure 3-9* summarizes these capital costs for ICI boilers. Note that the MACTEC estimates at 250 MMBtu/hr boiler size assumed high and low equipment cost, but a detailed cost breakdown was not given.

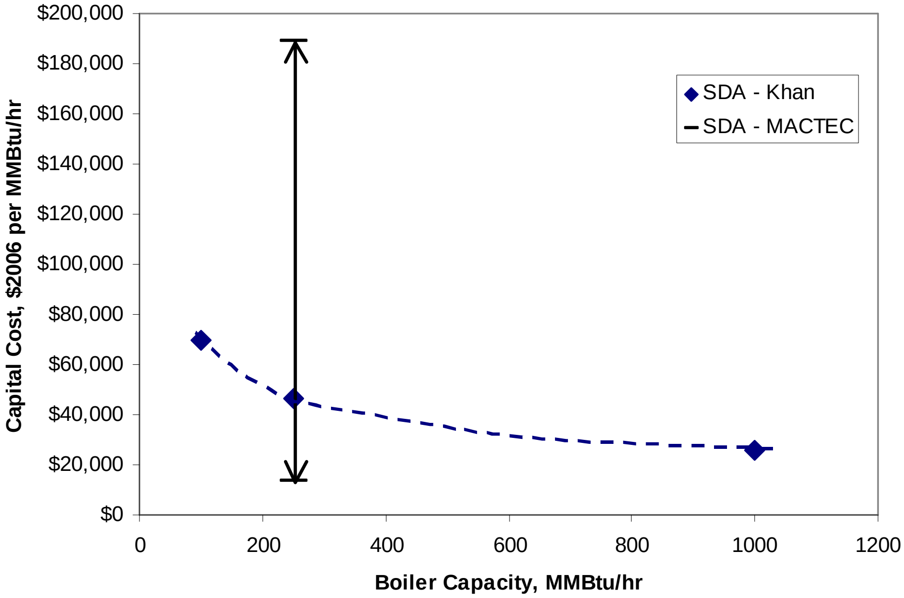


Figure 3-9. Capital cost for SO_2 control for Spray Dryer Absorber applied to ICI boilers as a function of boiler capacity

Wet FGD technology has been widely applied to coal-fired EGU boilers but rarely to ICI boilers, although at least one oil-fired installation has been noted in the literature [Caine and Shah, 2008]. The relationship between FGD capital cost and boiler capacity is shown in *Figure 3-10*. Estimates in the literature give the same capital costs for coal- and oil-fired boilers [ICAC, 2003; MACTEC, 2005], although these estimates are not always based on actual field installation data because installations of wet FGD technology on ICI boilers are few at present.

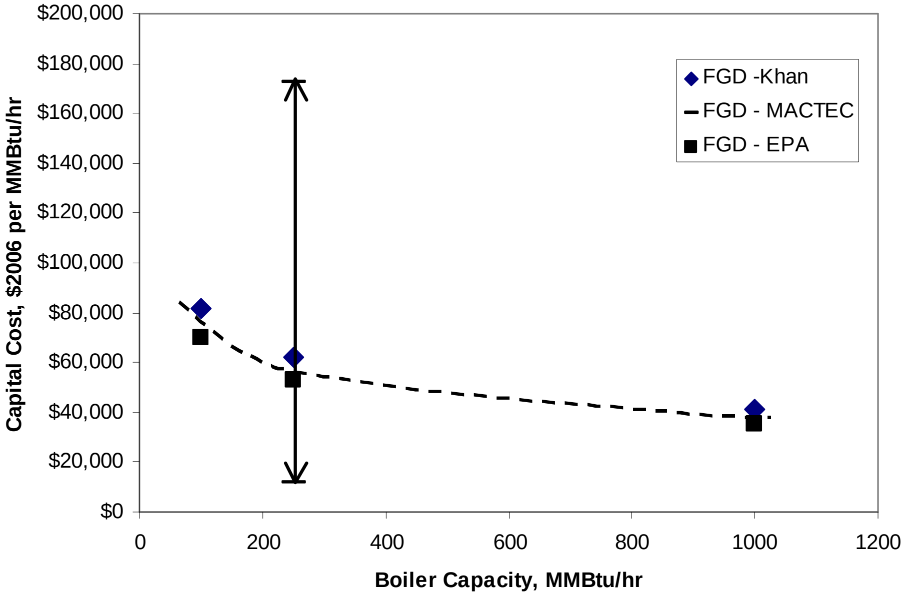


Figure 3-10. Capital cost for SO_2 control for wet FGD applied to ICI boilers as a function of boiler capacity

3.9 Chapter 3 References

Bozzuto, C. "SO_2 Scrubber Systems," CIBO Industrial Emissions Conference, Portland, ME 2007.

Caine, John, Shah, Hardik. "Next Generation Wet Electrostatic Precipitators," presented at 101st Air & Waste Management Association Annual Meeting, Portland, OR, June 24-26, 2008.

Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emission Control Systems," prepared for UARG, 2007.

Cremer, Marc, Wang, David H., Senior, Connie L. "Testing and Model Based Optimization of SO_2 Removal with Trona in Coal Fired Utility Boilers," presented at the DOE-EPRI-US EPA-A&WMA Combined Power Plant Air Pollutant Control Symposium - The Mega Symposium, Baltimore, MD, August 28-31, 2008.

Day, Keith. "Use of Dry Sorbent Injection Systems for Controlling Hg, HCL, SO_2/SO_3, NOx," CIBO 2007.

Day, Keith. *Duct Injection for Controlling SO_2, SO_3, Hg, and HCl;* O'Brien and Gere: Jan. 3, 2006.

Dene, Chuck, Baker, Lesley A., Keeth, Robert J. "FGD Performance Capability," presented at the DOE-EPRI-US EPA-A&WMA Combined Power Plant Air Pollutant Control Symposium - The Mega Symposium, Baltimore, MD, August 28-31, 2008.

Dene, Chuck. "ReACT Process Demonstration at Valmy Generating Station," presented at the DOE-EPRI-US EPA-A&WMA Combined Power Plant Air Pollutant Control Symposium - The Mega Symposium, Baltimore, MD, August 28-31, 2008.

Dickerman, Jim (2006). “SO_2 Emission Controls for Older and Smaller Boilers,” presented at the DOE-EPRI-US EPA-A&WMA Combined Power Plant Air Pollutant Control Symposium - The Mega Symposium, Baltimore, MD, August 25-28, 2006.

Emmel, T. “Use of CUECost Model for Developing Cost Estimates for Industrial Size Boilers,” memorandum to CIBO, March 2006.

Haddad, E., Ralston, J., Freen, G., Castagnero, S. “Full-Scale Evaluation of a Multi-Pollutant Reduction Technology: SO_2, Hg, and NOx,” presented at the DOE-EPRI-US EPA-A&WMA Combined Power Plant Air Pollutant Control Symposium - The Mega Symposium, Washington, DC, May 19-22, 2003.

Jones, Andrew P., Feeley, Thomas J. (2008) *Preliminary Economic Analysis of Wet FGD Co-Benefit Enhancement Technologies.* National Energy Technology Laboratory, Pittsburgh, PA, May 2008, http://www.netl.doe.gov/energy-analyses/pubs/Enhanced FGD Hg Capture Economics FINAL May2008.pdf.

Khan, Sikander. *Methodology, Assumptions, and References Preliminary SO_2 Controls Cost Estimates for Industrial Boilers*; US EPA: 2003.

MACTEC. *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.

NESCAUM. *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers* (Praveen Amar, Project Director), September 2000.

NJ DEP. Workgroup Recommendations and Other Potential Control Measures, Stationary Combustion Sources Workgroup, SCS003 – ICI Boilers, May 2, 2006. www.nj.gov/dep/airworkgroups/docs/wps/scs003_fin.pdf.

Nichols, B. “Air Pollution Control Systems at Virginia Tech’s Power Plant,” CIBO 2007.

Siemens Environmental Systems and Services. “Dry Scrubbing for Industrial Facilities,” CIBO2007.

Sharp, G. *Power Magazine*, 2007.

Srivistava, R. “Controlling SO_2 Emissions – A Review of Technologies,” EPA/600/R-00/093, November 2000.

US EIA. *Petroleum Price Data and Analysis*, accessed March 20, 2008. http://tonto.eia.doe.gov/dnav/pet/pet_pri_top.asp.

US EIA. *Petroleum Supply Annual 2006*, Volume 1, 2006. http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html.

US EPA. *Integrated Planning Model*, Documentation for EPA Base Case 2006 (v3.0), Section 8, Fuel Assumptions. http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/Section-8.pdf.

US EPA. *Integrated Planning Model*, Documentations for EPA Base Case 2006 (v3.0), Attachment O. http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/attachment-o.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Flue Gas Desulfurization (FGD - Wet, Spray Dry, and Dry Scrubbers*; EPA-452/F-03-034, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf.

Whiteman, C. ICAC, “SO_2 Control Technology Cost Estimates for Industrial Boilers,” memo to John Robbins, US EPA, December 12, 2003.

4 PM CONTROL TECHNOLOGIES

4.1 PM Formation in Combustion Systems

PM emissions from combustion processes include primary and secondary emissions. Primary emissions consist mostly of fly ash. Secondary emissions are the result of condensable particles such as nitrates and sulfates that typically make up the smaller fraction of the particulate matter (PM_{10} and $PM_{2.5}$). Fly ash refers to the mineral matter of the fuel, which typically includes some level of unburned carbon. ICI boilers burn a variety of fuels that contain ash and, as such, have PM emissions. Therefore, ICI boilers are candidates for PM controls.

Coal and oil contain non-combustible ash material. Other liquid or solid fuels (e.g., petroleum coke, wood) also contain ash. The quantity of ash in the flue gas depends on many factors, such as fuel properties, boiler design, and operating conditions. In dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash, and the remaining ash is collected as bottom ash. However, in wet-bottom, pulverized-coal-fired boilers, about 50 percent of the total ash exits the boiler as fly ash. In cyclone boilers (common in the EGU sector but not in the ICI population), most of the ash is retained as liquid slag, and the fly ash is only about 20 percent of the total ash. Fluidized-bed combustors (FBC) emit high levels of fly ash because the coal is fired in suspension and the ash is present in dry form. Stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers because combustion takes place in a relatively quiescent fuel bed.

In addition to the nitrates and sulfates mentioned as secondary PM, NOx control technologies that inject ammonia or amine-based reagents (SNCR and SCR) yield a certain amount of ammonia "slip," which can also form fine particulate (ammonium sulfate) as the flue gas temperatures decrease towards the stack.

This section presents a brief description of the major primary PM technologies.

4.2 PM Control Technologies

PM control technologies have been commercially available and widely used in ICI and EGU boilers for many years. *Table 4-1* summarizes the main types of commercially available technologies.

Table 4-1. Available PM control options for ICI boilers

Technology	Description	Applicability	Performance
Fabric filters (Baghouse)	“Baghouses” made of close-knit fabrics remove particulates through filtration.	Primarily used in coal/wood fired industrial/utility boilers. Not used with oil boilers due to clogging.	>99% total and $PM_{2.5}$ removal
ESPs (Dry/Wet)	Charged particles attracted to oppositely charged plates. Collection method either wet/dry.	Widely used in coal applications. Suitable for oil, pet coke and waste solid fuels. Wet ESPs suitable for saturated flue gas.	Effectiveness depends on resistivity of particulates. Low sulfur can reduce performance of dry ESP. >99% reduction of total PM (dry/wet) and sulfuric acid mist and $PM_{2.5}$ (wet)
Venturi Scrubbers	Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste.	High pressure required for significant removal. Applicable to a wide range of fuels.	50% removal for fine particulates, 99% removal for large (>5 micron) particulates
Cyclones	Cyclones use aerodynamic forces to separate particles from the gas stream.	Widely applicable to all fuels.	70%-90% total PM potential

4.3 Description of Control Technologies

4.3.1 Fabric Filters

Fabric filters (also called baghouses) are essentially giant vacuum cleaners and very effective devices for collecting dry PM from flue gas. They are used in ICI and EGU applications, although less widely than ESPs. Separation occurs when the ash-laden flue gas passes through a porous layer of filter material. As the individual particles accumulate on the surface of the filter, they gradually form a layer of ash known as the “dust cake.” Once formed, the dust cake provides most of the filtration. However, they are not particularly well suited for wet gas applications due to the negative impact of wet gas on the bag filters. *Figure 4-1* shows a photograph of the internal components of a fabric filter compartment with several individual bags and mounting mechanisms.

Figure 4-1. Photograph of fabric filter compartment with filter bags [Source: www.hamon-researchcottrell.com]

As shown in *Figure 4-1*, multiple bags are assembled in compartments to provide a large surface area for filtration. The large surface area is required to maintain acceptable pressure loss across the fabric. Groups of bags are placed in compartments, which can be isolated from one another to allow cleaning of the bags (see below), or to allow replacement of some of the bags without shutting down the entire baghouse.

Baghouse size is typically defined in terms of "air-to-cloth" ratio, expressed in the units of velocity in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The size of the baghouse depends on the particulate loading and characteristics, and the cleaning method used.

The type of bag cleaning method employed characterizes baghouses. Cleaning intensity and frequency are important because the dust cake provides a significant fraction of the fine particulate removal capability of a fabric. Hence, too frequent or too intense a cleaning method may lower the removal efficiency. Conversely, if removal of this dust cake happens infrequently or inefficiently, the pressure drop will increase to unacceptable levels. The major cleaning methods are as follows.

- Reverse-air baghouse – In this case, the flue gas flows upward through the vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the baghouse is taken off-line, and the gas flow in this compartment reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers.
- Pulse-jet baghouse – In this case, the dust is collected on the outside of the bags, which are mounted on cages to keep them from collapsing. Dust is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, allowing it to be done on-line. Because pulse-jet cleaning is more intensive than in reverse-air baghouses, the bags in a pulse-jet baghouse remain relatively clean, resulting in the ability to use a higher air-to-cloth ratio or a smaller baghouse compared to the reverse-air type.

Additionally, fabric filters can also be used in applications where fly-ash resistivity makes it difficult for collection with ESPs. Further, baghouses are capable of 99.9 percent removal efficiencies, as well as being able to remove the smaller size PM fraction ($PM_{2.5}$) more efficiently.

4.3.2 Electrostatic Precipitators

ESP's operate on the principle of electrophoresis by imparting a charge to the particulates and collecting them on opposed charged surfaces. Dry vs. wet ESPs refer to whether the gas is water-cooled and saturated prior to entering the charged collection area or is dry. *Figure 4-2* and *Figure 4-3* show schematic views of dry and wet ESPs, respectively. Older ESPs are often of the wire-pipe design, in which the collecting surface consists of one or more tubes (operated wet or dry). The wire-plate design is the other commonly used ESP design, as illustrated in the schematic in *Figure 4-2*.

In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 µm on a mass basis with wet ESPs being capable of such reductions well into the sub-micron level (0.01 µm) [Altman, 2001].

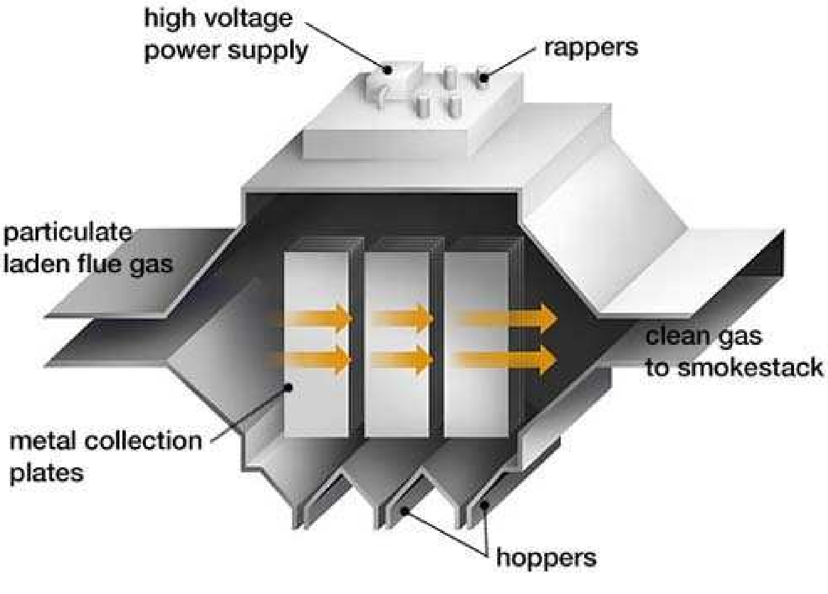


Figure 4-2. Side view of dry ESP schematic diagram [Source: Powerspan]

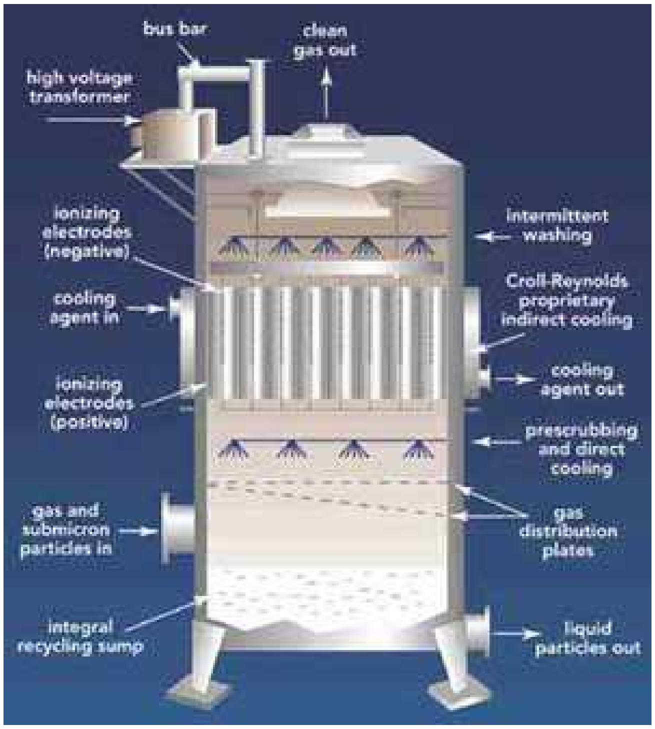


Figure 4-3. Wet ESP [Croll Reynolds]

Compared to fabric filters, ESPs affect the flue gas flow minimally, resulting in much lower pressure drops then an equivalent baghouse (typically less than two inches H_2O vs. greater than six inches H_2O for the fabric filter).

An electric field between high-voltage discharge electrodes and grounded collecting electrodes produces a corona discharge from the discharge electrodes, which ionizes the gas passing through the precipitator, and gas ions subsequently ionize fly ash (or other) particles. The negatively charged particles are attracted to the collecting electrodes. To remove the collected fly ash, the collecting electrodes are rapped mechanically, causing the fly ash to fall into hoppers for removal.

A balance generally needs to be struck between higher voltages for higher particulate removal efficiency and excessive sparking which will have the opposite effect. Larger ESPs are sectionalized (see *Figure 4-2*) such that higher voltages can be used in the first sections of the precipitator, where there is more particulate to be removed. Lower voltages are then used in the last, cleaner precipitator sections to avoid excessive sparking between the discharge and collecting electrodes. This has the added advantage that particles re-entrained in the flue gas stream by rapping (striking the electrode to dislodge the dust) may be collected in the downstream sections of the ESP.

Precipitator size is a major variable affecting overall performance or collection efficiency. Size determines residence time (the time a particle spends in the precipitator). Precipitator size also is typically defined in terms of the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher SCA leads to higher removal efficiencies. Collection areas can range from as low as 200 to as high as 800 ft^2/1000 acfm. In order to achieve collection efficiencies of 99.5 percent, SCA of 350-400 ft²/1000 acfm is typically used. The overall (mass) collection efficiencies of ESPs can exceed 99.9 percent, and efficiencies in excess of 99.5 percent are common. Precipitators with high overall collection efficiencies can achieve high efficiencies across a range of particle sizes so that good control of PM_{10} and $PM_{2.5}$ is possible with well designed and operated electrostatic precipitators.

Unlike dry ESPs, which use rapping to remove particulates from the collecting electrodes, wet ESPs use a water spray to remove the particulates. By continually wetting the collection surface, the collecting walls never build up a layer of particulate matter. This means that there is little or no deterioration of the electrical field due to resistivity, and power levels within a wet ESP can therefore be higher than in a dry ESP. The ability to inject greater electrical power within the wet ESP and elimination of secondary re-entrainment are the main reasons a wet ESP can collect sub-micron particulate more efficiently.

Overall, ESPs have historically been the collection device of choice for many applications in the ICI boiler and EGU boiler sectors. High removal efficiencies are possible and the units are rugged and relatively insensitive to operating upsets. Wet ESPs offer performance characteristics for capturing $PM_{2.5}$ similar to fabric filters and are well suited for applications such as oil firing, for which fabric filters are less attractive, because the sticky ash particles produced from oil combustion can blind the bags.

4.3.3 Venturi Scrubbers

Venturi scrubbers for PM control operate on the principle of rapid mixing and impingement of PM with liquid droplets and subsequent removal with the liquid waste. For particulate controls, the venturi scrubber is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressure drops are required. High-energy scrubbers operate at pressure losses of 50 to 70 inches of water. Higher pressure drop translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis. However, venturi scrubbers are seldom used as the primary PM collection device because of excessive pressure drop and associated energy penalties. *Figure 4-4* depicts a venturi scrubber.

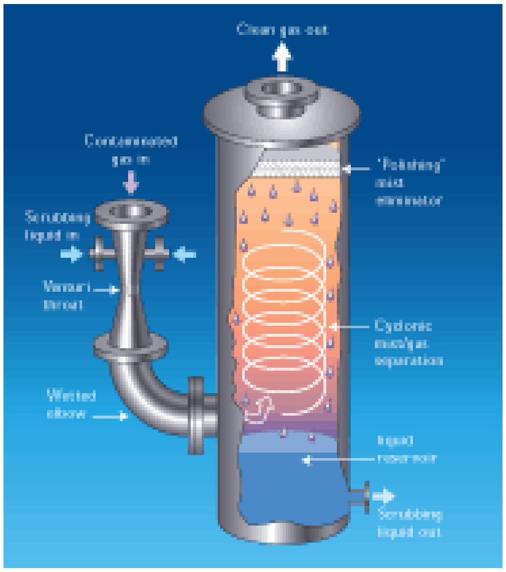


Figure 4-4. Venturi scrubber [Croll Reynolds]

4.3.4 Cyclones

Cyclones are devices that separate particulates from the gas stream through inertial forces. As ash-laden gas enters the cyclone near the top, a high-velocity vortex is created inside the device. Heavy particles move outward due to centrifugal force and begin accumulating on the wall of the cyclone. Gravity continuously forces these particles to move downward where they collect in the lower, hopper region of the cyclone. The collected particles eventually discharge through an opening in the bottom of the hopper into a system that transports the particles to a storage area. Smaller and lighter particles that remain suspended in the flue gas move toward the center of the vortex before being discharged through the clean-gas outlet located near the top of the cyclone (see *Figure 4-5*).

Cyclones are comparatively simple devices in design and construction, with no moving parts. Cyclones can operate over a wide range of temperatures, which makes them attractive for smaller ICI boilers that do not have economizers and/or air preheaters (and thus higher stack temperatures than in EGU boilers). Pressure drops across cyclones are typically in the range of 2 to 8 inches of water for a single cyclone. Cyclones can be arranged in arrays (multi-cyclones) and have overall mass removal efficiencies of 70 to 90 percent with the corresponding increase in pressure drop. However, cyclone collection efficiencies are very sensitive to particle size, and control efficiency for fine particulate ($PM_{2.5}$) is poor [Licht, 1988].

Cyclones are most effective at high boiler loads, where flue gas flow rates are highest. From an operational perspective, cyclones have no moving parts, are not sensitive to fuel quality or gas temperature, and require only regular cleaning to avoid plugging. These characteristics have made them good options in the past, particularly in the absence of regulatory $PM_{2.5}$ requirements.

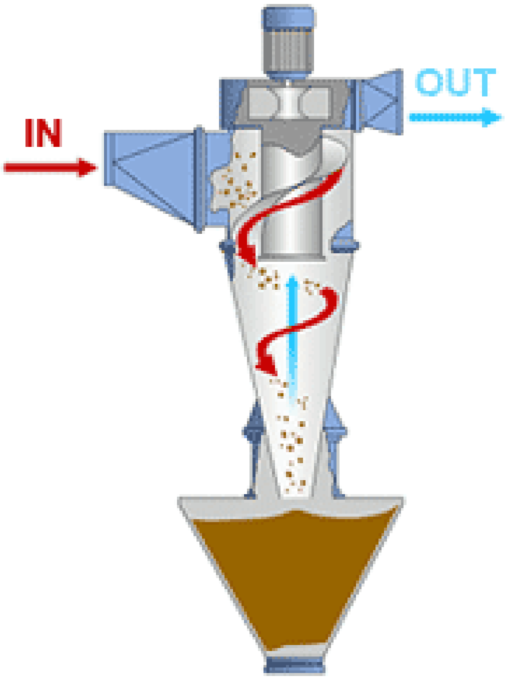


Figure 4-5. Schematic of a cyclone collector [www.dustcollectorexperts.com/cyclone]

Due to the limited potential for $PM_{2.5}$ capture, use of cyclones in new combustion applications is primarily limited to fluidized-bed boilers where they are used to re-circulate the bed material – and not as primary PM control devices.

4.3.5 Core Separator

The core separator is a mechanical device that operates based on aerodynamic separation (like cyclones), but also utilizes a "core separator." The separator portion of the device consists of multiple cylindrical tubes with one inlet and two outlets. One outlet allows for a clean gas stream to exit, while the other outlet is used for recirculating the concentrated stream. This recirculation stream then passes through the cyclone unit (see *Figure 4-6* [Resource Systems Group, 2001]), where it is further cleaned and returned to the separator. This sequential process enhances its overall control efficiency as compared to single or multiple cyclones.

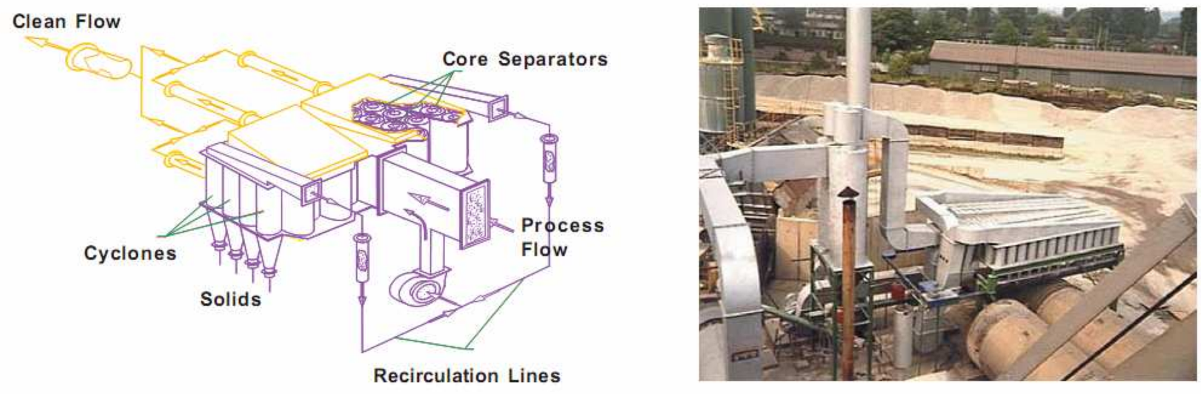


Figure 4-6. Schematic (left) and actual (right) core separator system [EPA, 2003]

The core separator capability for PM removal falls between that of an ESP and a cyclone. Several systems are currently installed on coal- and wood-fired boilers. The core separator unit is capable of overall PM reductions of up to the 90 percent range. Its collection efficiency, however, diminishes to about 50 percent for $PM_{2.5}$. *Table 4-2* displays inlet and outlet PM concentrations and removal efficiency of a core separator at two different plants. *Table 4-3* presents estimated costs for the core separator for two different sizes and gas flow conditions.

Table 4-2. Core separator collection efficiency [USEPA, 2008; Resource Systems Group, 2001]

Core Separator Inlet Loading (lb/million Btu)	Core Separator Outlet Loading (lb/million Btu)	Removal Efficiency	Boiler Type
0.17	0.07	59%	Wood Fired
0.846	0.214	75%	Stoker – Coal

Table 4-3. Core separator cost analysis [B. H. Eason to P. Amar, 2008]

Boiler Size	MMBtu/hr	8	10
	Estimated gas temperature (°F)	500	500
	Estimated gas flow rate (acfm)	4979	5996
Core Separator Size and Estimated Price (uninstalled)	Gas Flow per 12” module	660	660
	Number of 12” Modules	7	9
	Estimated price	$110,000	$130,000
	Gas Flow per 24” Module	2640	2640
	Number of 24” Modules	1	2
	Estimated Price	$55,000	$83,000

4.4 Applicability of PM Control Technologies to ICI Boilers

The PM control technologies described in this section are widely available and are used in both ICI and EGU applications. Because all these PM controls are based on the collection of particulates from the flue gas, they are applicable to a variety of boiler types and ash-containing fuels, including coal, oil, wood, petroleum coke, and other waste fuels. Determining the most attractive option for individual applications is a case-by-case decision that needs to account for technical, economic, and regulatory considerations. One exception, as mentioned, is that fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash.

4.5 Efficiency Impacts

PM control technologies do result in some parasitic energy loss as can be deduced from the brief descriptions of technologies above (see *Table 4-1*). The inherent energy losses associated with each technology are given below and summarized in *Table 4-4*.

- For Fabric Filters
  - compressor (bag cleaning)
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For ESPs
  - transformer-rectifier (TR) power
  - flue gas pressure loss
  - electric power (heaters, ash handling)
- For Venturi Scrubber and Cyclone
  - flue gas pressure loss

Table 4-4. Summary of energy impacts for control technologies

Technology	Applicability	Performance (% Reduction)	Energy Impact (kW/1000 acfm)	Comments
Fabric Filter	Coal, Wood	99+	1 – 2	Pressure loss / compressor / ash handling
Dry ESP	Coal, Oil, Wood	99	0.5 – 1.5	Pressure loss / TR power / ash handling
Wet ESP	Coal, Oil, Wood	99+	3 - 6	Pressure loss / TR power / ash handling
Venturi Scrubber	Coal, Oil, Wood	70-90 (Not efficient for $PM_{2.5}$)	5 - 11	Pressure loss
Cyclone	Coal, Wood	70-90 (Not efficient for $PM_{2.5}$)	0.5 – 1.5	Pressure loss

4.6 PM Control Costs

The following tables summarize published PM control costs for ICI boilers reported in the literature [US EPA, 2003a; US EPA, 2003b; US EPA, 2003c; US EPA, 2003d; US EPA, 2003e; US EPA, 2003f; MACTEC, 2005]. Literature values of capital cost have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using the Chemical Engineering Plant Cost Index values. Cost effectiveness in dollars per ton of PM removed is only quoted for the literature references from 2005 or 2006 (and in those year's dollars). Cost effectiveness depends on the operating costs. Reagents or consumables can make up a large portion of some of the operating costs, but these items do not always increase with the rate of inflation for chemical plant equipment. Thus, cost effectiveness values (or operating costs) from years before 2005 have not been reported.

Table 4-5 summarizes the published PM control costs for several different PM control technologies. In the EPA references, the capital costs were given in terms of dollars/scfm (2002 dollars). These costs were converted to dollars per MMBtu/hr using the flow rates given in Chapter Five and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values.

The MACTEC capital costs [MACTEC, 2005] span a large range, because high and low estimates for capital equipment were used in the calculation. The EPA capital costs are much higher for the wire-pipe ESP (also known as a tubular ESP) than the wire-plate ESP. Note that a size was not given in the EPA cost estimate, so a range is shown. The capital cost comparison is similar for wet ESPs although the capital costs themselves (in dollars/MMBtu/hr) are higher for wet ESPs as compared to dry ESPs.

For fabric filters, pulse-jet and reverse-air fabric filters were considered. These types of equipment have similar collection efficiencies, but the capital costs and effectiveness of pulse-jet fabric filters are lower than that of reverse-air fabric filters.

Table 4-5. PM control costs applied to ICI boilers

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu /hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Dry ESP	90%	Coal	250	$12,365-$160,754	2005	$171-$1,300	7
Dry ESP	99%	Coal	250	$12,365-$160,754	2005	$156-$1,172	7
Dry ESP	90%	Oil	250	$6,713-$87,275	2005	$2,584-$21,009	7
Dry ESP	99%	Oil	250	$6,713-$87,275	2005	$2,328-$18,912	7
Dry ESP (Wire-Pipe)		Coal	--	$6,571-$41,070	2002		1
Dry ESP (Wire-Plate)	90%-99%	Coal	--	$3,286-$10,843	2002		2
Dry ESP (Wire-Pipe)		Resid.Oil	--	$5,198-$32,486	2002		1
Dry ESP (Wire-Plate)	90%-99%	Resid.Oil	--	$2,599-$8,576	2002		2
Dry ESP (Wire-Pipe)		Dist.Oil	--	$5,117-$31,983	2002		1
Dry ESP (Wire-Plate)	90%-99%	Dist.Oil	--	$2,559-$8,443	2002		2
Dry ESP (Wire-Pipe)		Wood	--	$7,560-$47,249	2002		1
Dry ESP (Wire-Plate)	90%-99%	Wood	--	$3,780-$12,474	2002		2
ESP	99.50%	Wood	Small	--	2005	$594	8
ESP	99.50%	Wood	Medium	--	2005	$203-$292	8
ESP	99.50%	Wood	Large	--	2005	$114-130	8
Fabric Filter	90%	Coal	250	$7,453-$93,158	2005	$444-$1,006	7
Fabric Filter	99%	Coal	250	$7,453-$93,158	2005	$423-$957	7
Pulse-Jet Fabric Filter	95%-99.9%	Coal	--	$1,971-$8,543	2002		5
Reverse-Air FF	95%-99.9%	Coal	--	$3,286-$28,585	2002		6
Fabric Filter	90%	Oil	250	$4,046-$50,577	2005	$7,277-$16,464	7
Fabric Filter	99%	Oil	250	$4,046-$50,577	2005	$6,915-$15,643	7
Pulse-Jet Fabric Filter	95%-99.9%	Resid.Oil	--	$1,559-$6,757	2002		5
Reverse-Air FF	95%-99.9%	Resid.Oil	--	$2,559-$22,260	2002		6
Pulse-Jet Fabric Filter	95%-99.9%	Dist.Oil	--	$1,535-$6,652	2002		5
Reverse-Air FF	95%-99.9%	Dist.Oil	--	$2,599-$22,610	2002		6
Fabric Filter	99.50%	Wood	Small	--	2005	$958	8
Fabric Filter	99.50%	Wood	Medium	--	2005	$147-249	8
Fabric Filter	99.50%	Wood	Large	--	2005	$91-$107	8
Pulse-Jet Fabric Filter	95%-99.9%	Wood	--	$2,268-$9,829	2002		5
Reverse-Air FF	95%-99.9%	Wood	--	$3,780-$32,886	2002		6

Table 4-5 [continued]

Technology	Reduction Range	Fuel Type	Size of Boiler (MMBtu/hr)	Capital Costs, $2006 per MMBTU/hr	Base year for Costs	Cost Effectiveness ($/ton @Base Yr)	Ref
Wet ESP	90%	Coal	250	$25,968-$252,260	2005	$906-$2,627	7
Wet ESP	99.9%	Coal	250	$25,968-$252,260	2005	$815-2,365	7
Wet ESP (Wire-Pipe)	90%-99.9%	Coal	--	$13,142-$65,712	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Coal	--	$6,571-$13,142	2002		4
Wet ESP	90%	Oil	250	$14,098-$136,955	2005	$14,938-$43,036	7
Wet ESP	99.9%	Oil	250	$14,098-$136,955	2005	$13,446-$38,736	7
Wet ESP (Wire-Pipe)	90%-99.9%	Resid.Oil	--	$10,395-$51,977	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Resid.Oil	--	$5,198-$10,395	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Dist.Oil	--	$10,235-$51,172	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Dist.Oil	--	$5,117-$10,234	2002		4
Wet ESP (Wire-Pipe)	90%-99.9%	Wood	--	$15,120-$75,599	2002		3
Wet ESP (Wire-Plate)	90%-99.9%	Wood	--	$7,560-$15,120	2002		4

References

1. US EPA, *Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire-Pipe Type*; EPA-452/F-03-027, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fdespwpi.pdf
2. US EPA, *Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire-Plate Type*; EPA-452/F-03-028, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf
3. US EPA, *Air Pollution Control Technology Fact Sheet: Wet Electrostatic Precipitator (ESP) - Wire-Pipe Type*; EPA-452/F-03-029, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fwespwpi.pdf
4. US EPA, *Air Pollution Control Technology Fact Sheet: Wet Electrostatic Precipitator (ESP) - Wire-Plate Type*; EPA-452/F-03-030, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fwespwpl.pdf
5. US EPA, *Air Pollution Control Technology Fact Sheet: Fabric Filter - Pulse-Jet Cleaned Type*; EPA-452/F-03-025, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf
6. US EPA, *Air Pollution Control Technology Fact Sheet: Fabric Filter - Reverse-Air Cleaned Type*; EPA-452/F-03-026, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/ff-revar.pdf
7. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
8. STAPPA. *Controlling PM2.5 Under the Clean Air Act: A Menu of Options*; STAPPA/ALAPCO: March 2006.

4.7 Chapter 4 References

Caine, John, Shah, Hardik. "Next Generation Wet Electrostatic Precipitators," presented at 101st Air & Waste Management Association Annual Meeting, Portland, OR, June 24-26, 2008.

Licht, William (1988). *Air Pollution Control Engineering*, 2nd Edition. New York: Marcel Dekker.

Eason, B. "Core Separator Field Performance Data Summary 080118," personal communication to P. Amar, NESCAUM, September 2008.

MACTEC. Boiler Best Available Retrofit Technology (BART) Engineering Analysis; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.

Resource Systems Group (2001). "An Evaluation of Air Pollution Control Technologies for Small Wood-Fired Boilers." Prepared for Vermont Department of Public Service, Vermont Department of Environmental Conservation (Air Pollution Control Division), New Hampshire Governor's Office of Energy Resources and Community Services, and Massachusetts Division of Energy Resources.

STAPPA. Controlling PM2.5 under the Clean Air Act: A Menu of Options; STAPPA/ALAPCO: March 2006.

US EPA. *Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) – Wire-Pipe Type; EPA-452/F-03-027*, July 15, 2003a. http://www.epa.gov/ttn/catc/dir1/fdespwpi.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) – Wire-Plate Type*; EPA-452/F-03-028, July 15, 2003b. http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Wet Electrostatic Precipitator (ESP) – Wire-Pipe Type*; EPA-452/F-03-029, July 15, 2003c. http://www.epa.gov/ttn/catc/dir1/fwespwpi.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Wet Electrostatic Precipitator (ESP) – Wire-Plate Type*; EPA-452/F-03-030, July 15, 2003d. http://www.epa.gov/ttn/catc/dir1/fwespwpl.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Fabric Filter - Pulse-Jet Cleaned Type*; EPA-452/F-03-025, July 15, 2003e. http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Fabric Filter – Reverse-Air Cleaned Type*; EPA-452/F-03-026, July 15, 2003f. http://www.epa.gov/ttn/catc/dir1/ff-revar.pdf.

US EPA. *LSR Success Stories*; Acton, MA, December 16, 2003. http://es.epa.gov/ncer/sbir/success/pdf/lsr_success.pdf.

5 APPLICATION OF A COST MODEL TO ICI BOILERS

When evaluating the applicability of pollution control equipment to a specific ICI boiler, cost and performance capability need to be considered. A number of cost estimation models have been created for estimation of capital and operating costs of retrofit technology for air pollutants. However, most of the cost models have been developed for and applied to EGUs burning coal. Much less work has been carried out on cost estimation models for ICI boilers. In this Chapter, a cost modeling approach currently used for estimating control costs for coal-burning EGUs is modified and then investigated for its applicability to ICI boilers burning coal as well as other fuels. The purpose of this Chapter is to present this modified cost model (CUECost-ICI) and resulting cost calculations. The strengths and weaknesses of this approach are also discussed. However, the purpose of this effort is not to carry out an exhaustive calculation of costs, but to generate a set of reasonable cost estimates for ICI boilers burning different fuels and compare them with published cost information.

5.1 Cost Model Inputs and Assumptions

The Coal Utility Environmental Cost (CUECost) model was developed by Raytheon Engineers for EPA; version 3, and is available on EPA's website at http://www.epa.gov/ttn/catc/products.html. The model calculates capital and operating costs for certain predefined air pollution control devices for control of NOx, SO_2, and PM as applied to coal-fired power plants. The CUECost model produces approximate cost estimates (±30 percent accuracy) of the installed capital and annualized operating costs. The CUECost model was originally designed for and is intended for use on coal-fired boilers greater in size than 100 MW (about 1,000 MMBtu/hr heat input).

Table 5-1 gives the general plant inputs that are needed to set up the model; more inputs are needed for specific air pollution control devices (see Appendix B).

Table 5-1. CUECost general plant inputs

Input Parameter	***Comment***
Location - State	
MW Equivalent of Flue Gas to Control System	*This was designed for EGUs, but can be scaled to generate the appropriate gas flow for ICIs*
Net Plant Heat Rate	*Function of the efficiency of the plant*
Plant Capacity Factor	*Use averages from EEA study, parametric variations*
Percent Excess Air in Boiler	*Assume 3% O_2 for NG and oil, 7% O_2 for coal, wood*
Air Heater In-leakage	*Determines the flow rate for downstream devices such as scrubbers and particulate control devices*
Air Heater Outlet Gas Temperature	
Inlet Air Temperature	
Ambient Absolute Pressure	
Pressure After Air Heater	
Moisture in Air	
Ash Split:	*Depends on firing system*
Fly Ash	
Bottom Ash	
Seismic Zone	
Retrofit Factor	*Moderate effect on total capital requirement (TCR)*
(1.0 = new, 1.3 = medium, 1.6 = difficult)	
Select Fuel	*User can define "coal" with respect to HHV, %S, %ash*

The EPA version of CUECost contains the following modules for specific air pollution control devices:

- Limestone forced-oxidation, wet FGD scrubber
- Lime spray dryer
- FF
- ESP
- SCR
- SNCR
- LNB
- Natural Gas Reburn

CUECost bases the costs of equipment and operation on the generating capacity (in MW of electricity generated) of a given boiler. Industrial boilers are usually rated by the heat input (in MMBtu/hr); the boiler heat rate is used to convert from heat input to the equivalent size in MW. In order to use CUECost in its present form for ICI boilers, an equivalent size in MW needs to be estimated, although this could be modified in a dedicated ICI boiler version of CUECost (which was not developed in this effort).

Industrial boilers are operated differently from utility boilers, and the inputs for CUECost-ICI must be adjusted accordingly, including:

- Heat rate
- Excess air level

- Flue gas temperatures
- Capacity factor

The default values in the current version of CUECost for EGUs generally do not describe ICI boilers well. Fuel compositions vary widely for ICI boilers, while the EGU version of CUECost includes coal as the only fuel option (with different compositions). However, the user can define other fuels, as described below.

An important factor in determining total installed capital cost is the choice of appropriate retrofit factor, which expresses the difficulty of installing a control technology in an existing plant. In CUECost a retrofit factor of 1.0 denotes a new plant (corresponding to the lowest capital cost), and retrofit factors of 1.3 and 1.6 denote medium and difficult retrofits, respectively. Emmel [2006] noted that this range of retrofit factors significantly understated the cost of retrofit for FGD and SCR technologies when applied to EGUs less than 100 MW. Emmel also noted that on average a retrofit factor of 1.45 was more reasonable and that the factor should be even higher when CUECost is applied to ICI boilers.

The technology options in CUECost are also fixed, and the user cannot create a new technology option without supplying formulae for calculating the capital equipment cost. The technology options for SO_2 control in CUECost, in particular, have been noted to be more appropriate for larger utility boilers than for ICI boilers. Wet FGD and spray dryer technology – the SO_2 scrubbing options in CUECost – are based on lime or limestone reagents and have high capital and operating costs compared to alkaline scrubbers or duct injection. The latter scrubbing options might be more attractive for ICI boilers, but would have to be added to the current version of CUECost.

Finally, Emmel [2006] notes that most ICI boiler sites will have higher contingency, general facility, engineering, and maintenance costs (on a percentage of capital cost basis) than those identified for EGUs in CUECost in order to take into account necessary upgrades or demolition of existing facilities that are less likely to be needed at sites.

In this effort, the CUECost model was adapted for ICI boilers burning a variety of fuels by changing the fuel composition and heating value to simulate different fuels. Capital and operating costs in the model were based on correlations derived from coal-fired power plant experience since no reliable field data were available for the ICI boilers. It is not clear how robust the correlations for capital equipment are for small (≤ 25 MW equivalent) boilers.

The CUECost model is based on the electrical generating capacity. A combustion calculation was used to relate heat input rate to equivalent MW for five different fuels.

Table 5-2 gives the properties of these fuels. Boiler efficiency was specified, and heat rate was calculated from boiler efficiency. The uncontrolled or baseline emissions were based on fuel composition (in the case of SO_2 and PM) or on industry operating experience (in the case of NOx).

Table 5-3 shows the results (in terms of calculated flue gas flow rates) of the combustion calculations for a fixed heat input rate of 250 MMBtu/hr or 100 MMBtu/hr. Flue gas flow rate is an important parameter or input to the cost model, because the size of capital equipment is often related to the flue gas flow rate.

Table 5-2. Fuel characteristics and assumptions for CUECost calculation of heat rate and flue gas flow rates

	Bituminous	**Wood**	**No.2 Oil**	**No.6 Oil**	**Gas**
C, wt%	76.2	27.6	86.4	85.8	75
S, wt%	2.5	0.04	0.6	2.5	0
H, wt%	4.6	3.3	12.7	10.6	25
Moisture, wt%	1.4	45	0.02	0.02	0
N, wt%	1.4	0.3	0.1	0.5	0
O, wt%	7	22.86	0.1	0.5	0
Ash, wt%	6.9	0.9	0.08	0.08	0
Fuel heating value, BTU/lb	13,630	4,633	19,563	18,273	20,800
Unburned carbon, wt% in ash	5	1	75	75	0
Boiler efficiency*	34%	30%	39%	39%	45%
Stack O_2, vol% dry	7%	7%	3%	3%	3%
Boiler heat rate, Btu/kWh	10,000	11,370	8,750	8,750	7,600
Uncontrolled or Baseline emissions NOx, lb NO_2/MMBtu	0.60	0.26	0.20	0.40	0.40
SO_2, lb/MMBtu	3.67	0.17	0.61	2.74	0.00
PM, lb/MMBtu	5.06	1.94	0.04	0.04	0.00

*****Fuel to MW

Table 5-3. Equivalent heat input rate and flue gas flow rates for 250 and 100 MMBtu/hr heat input rates

	MW	MMBtu/hr	Flue gas, scfm
Bituminous coal (34% efficiency, 7% O_2)	25.0	250	65,305
Wood (30% efficiency, 7% O_2)	22.0	250	81,184
No.2 oil (39% efficiency, 3% O_2)	28.6	250	50,622
No.6 oil (39% efficiency, 3% O_2)	28.6	250	51,117
Natural gas (45% efficiency, 3% O_2)	32.9	250	59,336
Bituminous coal (34% efficiency, 7% O_2)	10.0	100	26,122
Wood (30% efficiency, 7% O_2)	8.8	100	32,474
No.2 oil (39% efficiency, 3% O_2)	11.4	100	20,178
No.6 oil (39% efficiency, 3% O_2)	11.4	100	20,375
Natural gas (45% efficiency, 3% O_2)	13.2	100	23,806

5.2 Comparison of the Cost Model Results with Literature

A comparison was made of the CUECost-ICI model with other published information for a selection of fuels and air pollution control devices applied to ICI boilers. Where possible, the inputs for the model were set to be the same as information cited in the literature.

Using the appropriate fuel composition and boiler heat rates, the modified ICI version of the original CUECost (CUECost-ICI) model was run for a number of ICI boiler cases. *Table 5-4*, *Table 5-5*, and *Table 5-6* show the installed capital costs, first-year annual operating costs, and cost per ton of pollutant removed for NOx, SO_2, and PM, respectively. Capital and operating costs were calculated on 2006 dollars basis in the CUECost-ICI model. A complete list of inputs to CUECost-ICI is included in Appendix B. For the NOx and SO_2 control technologies, percentage reduction of the pollutant was used as an input, so that the CUECost-ICI results could be easily compared to published literature results. For PM controls, a specific emission limit (in lb/MMBtu) was used as an input and the percentage PM reduction was calculated from the fuel ash content.

Table 5-4. Capital and operating costs for NOx control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost/ton
250	80.0%	Coal	SCR	Ammonia	$4.394	$1.253	$4,763
100	80.0%	Coal	SCR	Ammonia	$2.585	$0.702	$6,668
250	80.0%	No.6 Oil	SCR	Ammonia	$2.923	$0.790	$3,972
100	80.0%	No.6 Oil	SCR	Ammonia	$1.760	$0.460	$5,805
250	80.0%	Nat.Gas	SCR	Ammonia	$3.005	$0.811	$4,673
100	80.0%	Nat.Gas	SCR	Ammonia	$1.805	$0.472	$6,777
250	50.0%	Coal	SNCR	Ammonia	$1.142	$0.398	$2,422
100	50.0%	Coal	SNCR	Ammonia	$0.969	$0.317	$4,817
250	50.0%	No.6 Oil	SNCR	Ammonia	$0.724	$0.338	$2,722
100	50.0%	No.6 Oil	SNCR	Ammonia	$0.407	$0.196	$3,961
250	50.0%	Nat.Gas	SNCR	Ammonia	$0.785	$0.362	$3,335
100	50.0%	Nat.Gas	SNCR	Ammonia	$0.443	$0.209	$4,798
250	40.0%	Coal	LNB	--	$1.227	$0.301	$2,290
100	40.0%	Coal	LNB	--	$0.677	$0.166	$3,155
250	40.0%	No.6 Oil	LNB	--	$1.339	$0.329	$3,305
100	40.0%	No.6 Oil	LNB	--	$0.737	$0.181	$4,559
250	40.0%	Nat.Gas	LNB	--	$1.467	$0.360	$4,151
100	40.0%	Nat.Gas	LNB	--	$0.810	$0.199	$5,715

Table 5-5. Capital and operating costs for SO_2 control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	95%	Coal	wFGD	Limestone	$38.096	$11.137	$4,427
100	95%	Coal	wFGD	Limestone	$33.680	$9.608	$9,547
250	95%	No.6 Oil	wFGD	Limestone	$36.642	$10.733	$5,713
100	95%	No.6 Oil	wFGD	Limestone	$32.805	$9.368	$12,510
250	90%	Coal	SD	Lime	$29.598	$8.806	$3,694
100	90%	Coal	SD	Lime	$26.263	$7.540	$7,909
250	90%	No.6 Oil	SD	Lime	$28.463	$8.371	$4,704
100	90%	No.6 Oil	SD	Lime	$25.723	$7.344	$10,352

Table 5-6. Capital and operating costs for PM control technologies (assuming 7.5 percent interest and 15-year project life)

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	PM Emission, lb/MMBtu	Installed Capital Cost, $M	Capital cost, $/scfm	Capital cost, $/acfm	Annual Cost, $M	Cost Effectiveness (dollars per ton)
250	99.3%	Coal	ESP	0.03	$4.05	$62.00	$43.00	$1.11	$342
100	99.3%	Coal	ESP	0.03	$2.31	$88.50	$61.50	$0.63	$485
250	99.3%	Coal	FF	0.03	$4.77	$73.00	$50.70	$1.32	$406
100	99.3%	Coal	FF	0.03	$2.88	$110.20	$76.60	$0.78	$592
250	95.8%	No.6 Oil	ESP	0.01	$3.40	$66.60	$46.30	$0.93	$5,689
100	95.8%	No.6 Oil	ESP	0.01	$2.02	$99.00	$68.80	$0.55	$8,410
250	95.8%	No.6 Oil	FF	0.01	$4.09	$80.00	$55.60	$1.14	$6,940
100	95.8%	No.6 Oil	FF	0.01	$2.50	$122.80	$85.30	$0.68	$10,354

For comparison, the American Forest & Paper Association (AF&PA) calculated SNCR control costs in 2006 for wood-fired boilers ranging in size from 88 to 265 MMBtu/hr [Hunt, 2006]. *Table 5-7* below compares the AF&PA costs with the CUECost-ICI costs for wood-fired boilers. The installed capital cost values agree well between CUECost-ICI and the AF&PA estimates, although the CUECost-ICI values for cost effectiveness (dollars per ton of NOx removed) are 20 to 25 percent lower than the AF&PA estimates.

Table 5-7. Capital and operating costs for SNCR on wood-fired boilers, comparison of cost calculations from AF&PA and CUECost

MMBtu/hr	Pollutant removal efficiency	Fuel	Technology	Reagent	Installed Capital Cost, $M	Annual Cost, $M	Cost, $/ton
AF&PA							
88.5	70.0%	Wood	SNCR	Urea	$0.924	$0.250	$11,283
176.9	70.0%	Wood	SNCR	Urea	$1.400	$0.384	$8,574
285.4	70.0%	Wood	SNCR	Urea	$1.786	$0.502	$7,480
CUECost							
88.5	70.0%	Wood	SNCR	Urea	$0.923	$0.289	$9,239
176.9	70.0%	Wood	SNCR	Urea	$1.025	$0.324	$5,174
285.4	70.0%	Wood	SNCR	Urea	$1.130	$0.361	$5,011

Finally, the CUECost-ICI model results for capital cost were compared with some of the values reported in the literature [US EPA, 1996; NESCAUM, 2000; US EPA, 2003a; US EPA, 2003b; Whiteman, 2006], where available. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2006 using Chemical Engineering Plant Cost Index values.

The NOx capital costs computed with CUECost-ICI were largely consistent with the literature values. (Chapter Two contains a detailed discussion of the literature values for NOx control costs.)

Figure 5-1 compares capital costs for SCR for boilers burning coal, residual (No. 6) oil, and natural gas. The SCR costs appear to be consistent with the literature values. The literature value for SCR as reported by the Ozone Transport Assessment Group (OTAG) [US EPA, 1996] did not describe its basis in any detail, so it is difficult to determine if the OTAG cost estimates assumed a significantly different space velocity or different equipment than assumed in the CUECost-ICI model.

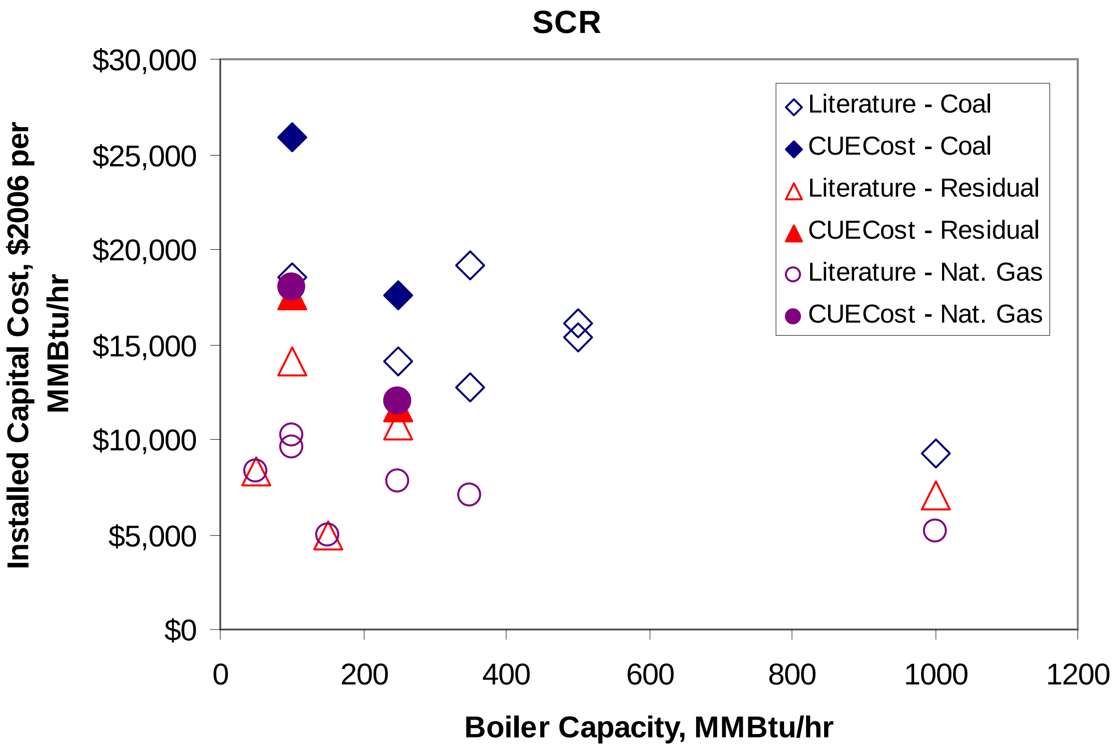


Figure 5-1. Comparison of CUECost-ICI model and reported literature values for capital cost of SCR for NOx control

The capital costs for SNCR (*Figure 5-2*) calculated from the CUECost-ICI model are in good agreement with literature values, particularly the sensitivity of capital cost to boiler capacity, which was also noted by ICAC [Whiteman, 2006].

The capital costs for LNB (*Figure 5-3*) calculated from the CUECost-ICI model for coal-fired boilers were consistent with the literature values, although the capital costs for residual oil-fired boilers were higher in the CUECost-ICI model than the literature values. Again, no details were provided in the literature references.

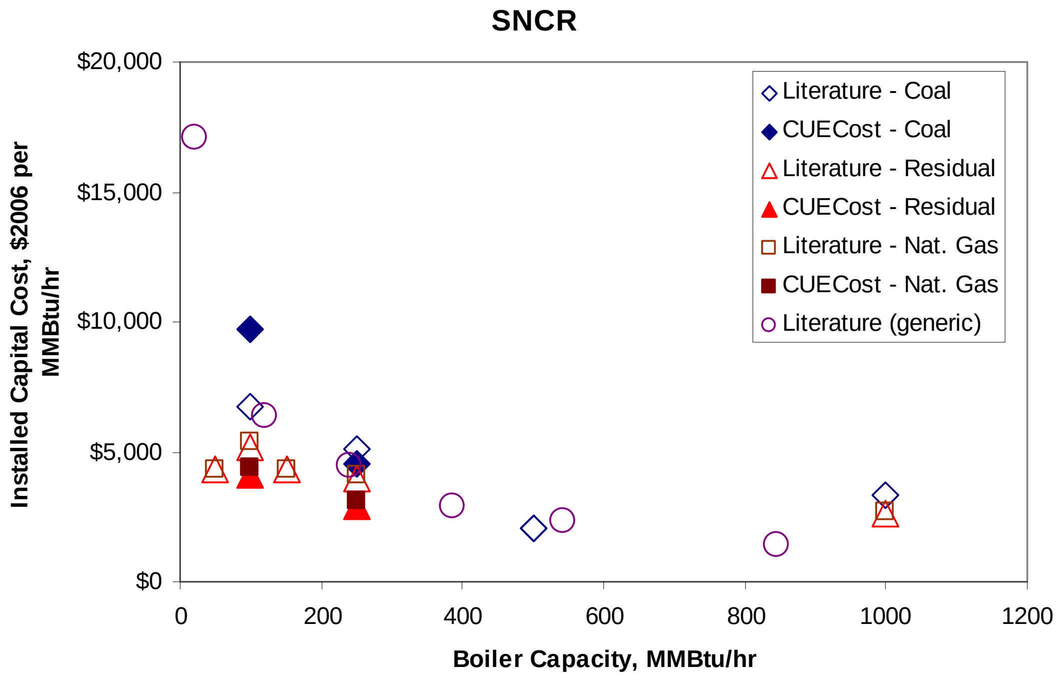


Figure 5-2. Comparison of CUECost-ICI model and reported literature values for capital cost of SNCR for NOx control

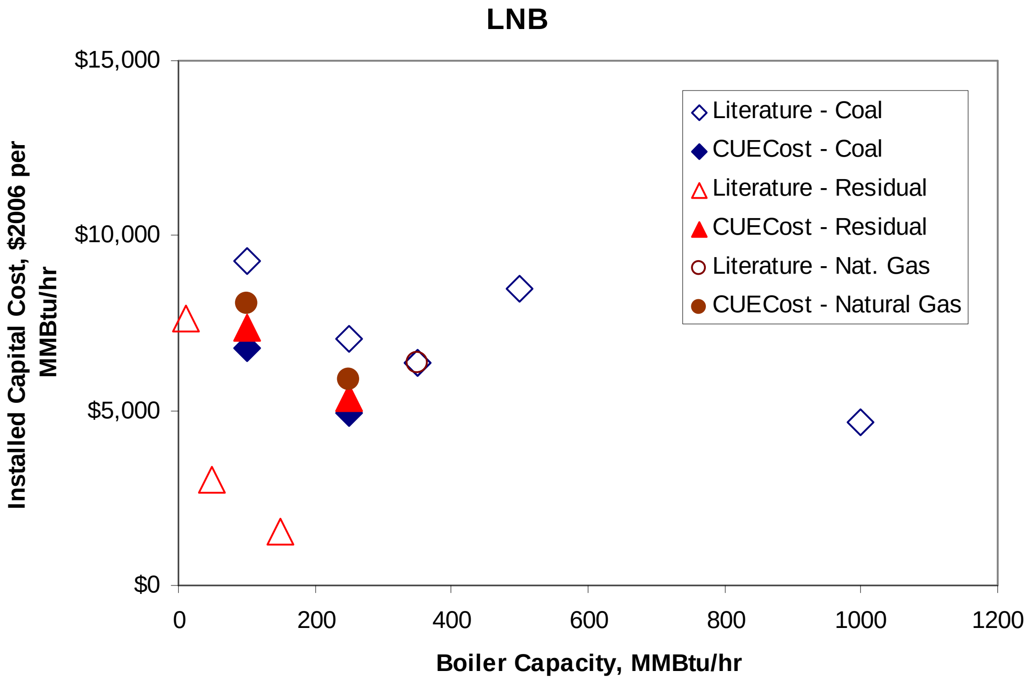


Figure 5-3. Comparison of CUECost-ICI model and reported literature values for capital cost of LNB for NOx control

Chapter Three contains a detailed discussion of the literature values for SO_2 control costs. The SO_2 capital costs computed with CUECost-ICI for spray dryers (SDs) were in the range of the literature values at boiler size of 250 MMBtu/hr (*Figure 5-4*). No literature data were available for residual oil-fired boilers and spray dryers. However, the capital costs calculated by CUECost –ICI for wet FGDs (*Figure 5-5*) were high when compared to the literature values.

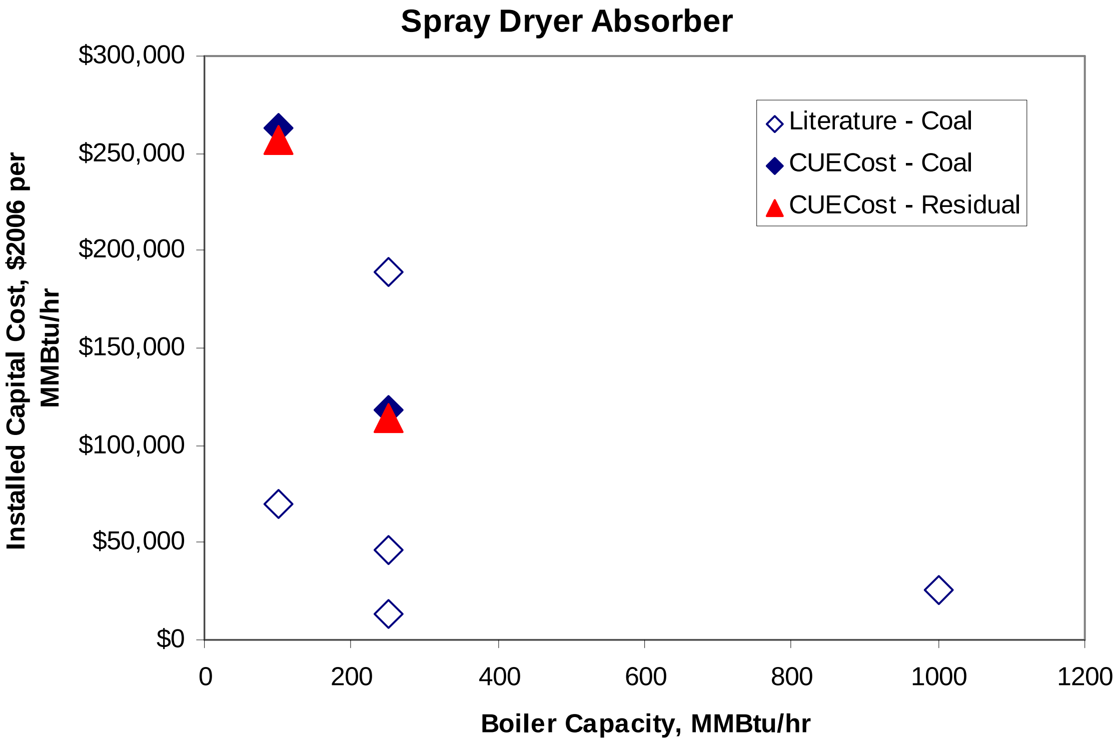


Figure 5-4. Comparison of CUECost-ICI model and reported literature values for capital cost of Spray Dryer for SO_2 control

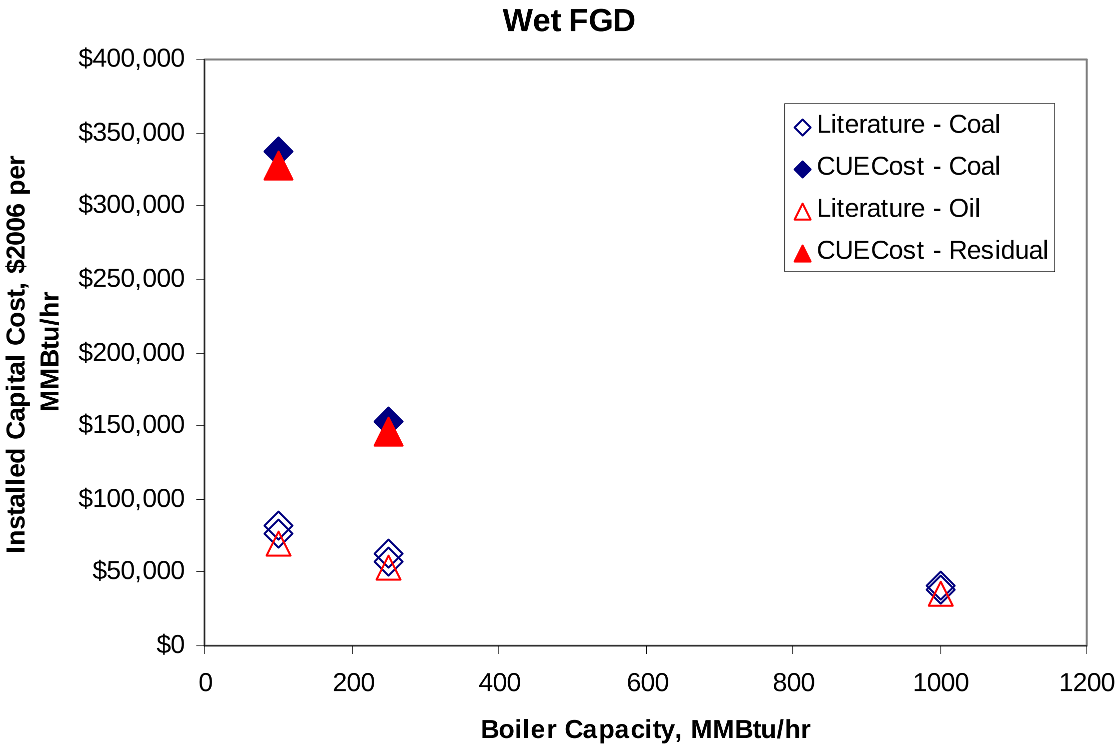


Figure 5-5. Comparison of CUECost-ICI model and reported literature values for capital cost of wet FGD for SO_2 control

Literature values for capital costs for PM control were evaluated from EPA reports on PM controls applied to ICI boilers [US EPA, 2003a; US EPA, 2003b]. In these references, the capital costs were given in terms of dollars/scfm (2002$). These costs were converted to dollars per MMBtu/hr using the flow rates in *Table 5-3* and then converted to 2006 dollars, using the Chemical Engineering Plant Cost Index values. Chapter Four contains a detailed discussion of the literature values for PM control costs.

The dry ESP control costs computed with CUECost-ICI were consistent with the literature values, although the CUECost-ICI predicted slightly higher values than reported by EPA for dry, wire-plate ESPs [US EPA, 2003a]. Note that a size was not given in the EPA cost-estimate. The FF costs computed with CUECost-ICI were higher than the literature values for pulse-jet fabric filters [US EPA 2003b].

5.3 Summary

An existing EPA model for estimating costs of selected control technology for NOx, SO_2, and PM for coal-fired EGU boilers greater than 1,000 MMBtu/hr was adapted for ICI boilers. Inputs were modified to allow a wider variety of fuels and to express boiler capacity in MMBtu/hr instead of MW. Modification of the correlations used for the coal-fired EGU model to calculate capital and operating costs for ICI boilers was outside the scope of this work. The new model, CUECost-ICI provided good agreement with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers. The resulting model provided a quick and flexible means to estimate capital and operating costs of specific control technologies as applied to ICI boilers. Further detailed and extensive work will be needed to validate and refine the model's calculation framework for ICI boilers, and to add other APCD technologies to the model.

5.4 Chapter 5 References

Emmel, Thomas. RTP Environmental Associates, "Use of CUECost Model for Developing Cost Estimates for Industrial Size Boilers," memorandum to Pat Dennis, Archer Daniels Midland Company, Robert Bessett, Council of Industrial Boiler Owners, March 22, 2006.

Hunt, T. American Forest & Paper Association, "AF&PA Comments on Draft NOx Model Rule and Related 6.7.06 OTC Resolution," letter to Christopher Recchia, Executive Director, Ozone Transport Commission, November 1, 2006.

MACTEC. *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.

NESCAUM. *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness* (Praveen Amar, Project Director), December 2000.

US EPA. *Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire-Plate Type*; EPA-452/F-03-028, July 15, 2003a. http://www.epa.gov/ttn/catc/dir1/fdespwpl.pdf.

US EPA. *Air Pollution Control Technology Fact Sheet: Fabric Filter - Pulse-Jet Cleaned Type*; EPA-452/F-03-025, July 15, 2003b. http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf.

US EPA. *OTAG Technical Supporting Document*, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/.

US EPA. *Air Pollution Control Technology Fact Sheet: Fabric Filter - Pulse-Jet Cleaned Type*; EPA-452/F-03-025, July 15, 2003b. http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf.

Whiteman, C. ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.

6 SUMMARY

ICI boilers are a significant source of NO_x, SO_2, and PM emissions, and are relatively uncontrolled, compared to EGUs. More than half of the surveyed ICI boilers in the Northeast have no controls, approximately one-third have PM controls, very few units have NOx controls, and no units have SO_2 controls.

There are a range of technology options for cost-effectively reducing emissions of NOx, SO_2, and PM emissions from ICI boilers in the U.S. Operating costs may differ for ICI boilers than utility boilers, primarily because of their size and location. ICI boiler sites typically have higher contingency, general facility, engineering, and maintenance costs as a percentage of total capital cost than do utility boilers. While ICI boilers often have cost constraints due to their sizes and diversity of plant layout and settings, these factors also provide opportunities for low-cost applications. It is critical to conduct site-specific suitability analyses to assess performance potential or retrofit feasibility, and match the appropriate emission control technology for specific applications given boiler size, fuel type/quality, duty-cycle, and design characteristics.

This study adapted the CUECost model -- initially developed by EPA to estimate costs of selected control technology for NOx, SO_2, and PM for large coal-fired EGU boilers -- to assess ICI boiler control costs. The modeling results were consistent with published values of capital cost of APCD equipment for small boiler sizes for coal-, oil- and natural gas-fueled boilers.

6.1 NOx Controls

Most of the commercially available NOx control technologies used extensively in EGUs may also apply to ICI boilers. Some technologies have potential to capture mercury from the flue gas. Employing a combination of technologies can be more effective in reducing emissions than a stand-alone technology. While most of these technologies can be used together, some combinations may be more cost-effective. This should be assessed on a site- and strategy-specific basis. Options include:

- *Boiler Tuning or Optimization*, which can yield reductions of five to 15 percent or more;
- *Low-NOx Burner (LNB) and Overfire Air (OFA)*, which can be used separately or as a system, and can reduce NOx emissions by 40 to 60 percent. LNBs are applicable to most ICI boiler types, and are being increasingly used at ICI boilers less than 10 MMBtu/hr. These technologies require site-specific suitability analyses, as several important parameters can have substantial impact on their performance or even retrofit feasibility.
- *Ultra Low-NOx Burners (ULNB)*, which can achieve NOx emission levels on the order of single digits in ppm.
- *Reburn*, which has been used only in large EGU applications, but is an option for larger watertube-type boilers, including stokers. It requires appropriate technical and economic analyses to determine suitability. Reburn may yield 35 to 60 percent reductions in NOx emissions.
- *Selective Catalytic Reduction (SCR)*, which can achieve reductions higher than 90 percent.

- *Selective Non-Catalytic Reduction* (*SNCR),* which can achieve between a 30 to 60 percent reduction in NOx.
- *Regenerative Selective Catalytic Reduction (RSCR^{TM}),* which is able to reduce NOx by 60 to 75 percent and CO by about 50 percent. These systems allow efficient use of an SCR downstream of a particulate control device, where the flue gas typically has a lower temperature than what is required for a conventional SCR. Such conditions are encountered in some ICI boilers firing a variety of fuels, including biomass.

NOx control technologies involving combustion modification have essentially no impact on the CO_2 emissions of the host boilers, with the exception of reburn. SNCR and SCR impose some degree of energy demand on the host boiler, including pressure, compressor, vaporization, and steam losses.

Most estimates for ICI boilers indicate capital costs in the range of $1,000 to $6,000 per MMBtu/hr and $1,000 to $7,000 per ton of NOx removed. LNBs and SNCR costs range from $1,000 to $3,000 per ton. For SCR, costs are between $2,000 and $14,000 per ton. SCR and SNCR costs are driven primarily by the consumption of the chemical reagent.

6.2 SO_2 Controls

ICI boilers firing coal are good candidates for employing SO_2 control technologies. Options include:

- *Flue Gas Desulfurization (FGD) or Scrubbers.* These technologies are commercially available, and have been used extensively on EGUs since the 1970s. *Wet scrubbers* (Wet FGD) are the predominant SO_2 control technology currently in use for EGUs, and are typically associated with high-sulfur applications. *Dry scrubbers* include Spray Dryers (SD) and Dry Sorbent Injection (DSI) technologies, and are more compatible with low- to medium-sulfur coals. Some dry scrubber systems can remove 20 to 60 percent of the SO_2, and in some cases up to 90 to 99 percent for HCl and SO_3. DSI technologies are currently being demonstrated on ICI boilers. Furnace Sorbent Injection systems used on cement plants are capable of SO_2 reductions of up to 90 percent for industrial applications and ICI boilers, as well as HCl and HF reductions of greater than 95 percent. For SDs, cost per ton of SO_2 removed was in the range of $1,600 to $5,000. Costs were between $1,900 and $3,800 per ton of SO_2 for wet FGDs. While the SO_2 capital costs computed with CUECost for SDs were consistent with the literature at 250 MMBtu/hr, the capital costs computed for wet FGDs were high compared to values reported in the literature.
- *Fuel switching*. While not a control technology *per se*, the emission reduction benefits of fuel switching are directly proportional to the difference in sulfur contents of the fuels. Fuel switching requires considerable cost and operational analyses. In the NESCAUM region, residual oil is commonly used in ICI boilers. Switching from a 3 to a 1 percent sulfur residual oil can provide cost-effective SO_2 reductions at about $771 per ton of SO_2 removed. For oil-fired ICI boilers, switching to lower-sulfur oil can provide significant reductions in emissions of SO_2, as well as in $PM_{2.5}$. The cost of switching to distillate oil is estimated to be much higher than for residual oil, because the higher cost of distillate oil.

6.3 PM Controls

ICI boilers burn a variety of fuels that contain fly ash and thus emit PM. PM control technologies have been commercially available and widely used in EGU boilers for many years. While PM controls are not currently widely used on ICI boilers, there are no technical reasons why PM controls cannot be applied to solid-fueled and oil-fired boilers. They are very effective in removing total PM and $PM_{2.5}$, with most options removing greater than 99 percent. The options include: (1) *fabric filters or baghouses*; (2) *wet and dry electrostatic precipitators (ESPs)*; (3) *venturi scrubbers*; (4) *cyclones*; and (5) *core separators*. Control technology decisions should be made on a case-by-case basis that accounts for technical, economic, and regulatory considerations. Fabric filters are not suitable for fuel oil applications due to the "stickiness" and composition of the ash. The cost effectiveness of baghouses was in the range of $50 to $1,000 per ton of PM removed for coal and up to $15,000 per ton of PM removed for oil. The cost effectiveness of ESPs was in the range of $50 to $500 per ton of PM for coal, and up to $20,000 per ton of PM for oil. PM control technologies will result in some parasitic energy loss due to pressure loss, power consumption, and ash handling. Dry ESPs and fabric filters have the lowest associated parasitic power consumption (<2 kW/1000 acfm), while high-energy venturi scrubbers can have a larger parasitic consumption – up to 10 kW/1000 acfm or higher.

APPENDIX A: Survey of Title V Permits in NESCAUM Region

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO$_2$		NOx		
Facility	**State**	**Year/ Manuf.**	**Heat Input (MMBtu/hr)**	**primary fuel**	**secondary fuel**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**Comments**
Solutia Incorporated	MA	Foster Wheeler	249	Coal (Bit. 0.7%S)	-	0.027	baghouse (Carborundum Environmental Systems)	1.2	-	0.525	OFA (Foster wheeler)	-
St. Gobain Abrasives	MA	Riley	230	Coal (Subbit. 0.63%S)	-	0.1	Dust Collector	1.1	-	0.45	LNB	-
UMASS Amherst	MA	Union Iron Works	80	Coal	-	0.12	baghouse	1.1	-	0.43	-	Convert to CHP No. 2 (9/07)
Cooley Dickinson Hospital	MA	Early 1980s	-	Wood	-	-	-	0.008	-	0.16	-	-
Cooley Dickinson Hospital	MA	2006/ AFS Energy Systems	29.88	Wood	-	0.01	Cyclone, Baghouse	0.025	-	0.15	FGR	-
Seaman Paper	MA	2006/ Hurst Boiler	29.88	Wood	-	0.01	Baghouse	0.025	-	0.15	FGR	-

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	**State**	**Year/ Manuf.**	**Heat Input (MMBtu/hr)**	**primary fuel**	**secondary fuel**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**Comments**
Cornell University	NY	-	248	Coal	-	0.3	Fabric Filter	Coal 1% S by weight	-	0.4	-	
Cornell University	NY	-	117	Coal	-	0.35	Fabric Filter	Coal 1% S by weight	-	0.4	-	-
Commonwealth Plywood	NY	-	16	Wood	-	-	Multi-Cyclone w/o Fly ash injection	-	-	-	-	-
Crawford Furniture	NY	-	6	Wood	-	-	Single Cyclone	-	-	-	-	-
Deferiet Paper Company	NY	1945/ Combustion Engineering	190	Coal	-	0.46	Multi-Cyclone w/o Fly ash injection, and wet Venturi scrubber	2.5	-	0.5	-	-
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 13

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Eastman Kodak	NY	-	265	Coal (Bit.)	-	0.26	ESP	2.5 (coal)	-	0.53	-	Boiler # 14
Eastman Kodak	NY	-	478	Coal (Bit.)	#2 Oil	0.26	ESP	-	-	-	-	Boiler # 15
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 41
Eastman Kodak	NY	-	500	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 42
Eastman Kodak	NY	-	640	Coal (Bit.)	#2 Oil	-	ESP	-	-	0.6	-	Boiler # 43
Eastman Kodak	NY	-	705	Coal (Bit.)	#2 Oil	0.035	ESP	.6 (coal)	-	0.42	-	Boiler # 44

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	**State**	**Year/ Manuf.**	**Heat Input (MMBtu/hr)**	**primary fuel**	**secondary fuel**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**Comments**
Gunlocke Co.	NY	E. Keeler	18	Wood	Oil #2	0.53	Fly Ash Cyclone	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	14.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	41.54	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Harden Furniture	NY	Industrial Boiler Co.	27.6	Wood	-	-	Multi-Cyclone w/ Fly ash injection	-	-	-	-	
Lyonsdale Biomass	NY	Zurn	290	Wood	-	0.1	-	-	-	0.2	-	
Morton International	NY	-	138	Coal	-	0.34	Fabric Filter, ESP	1.7	-	0.5	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	**State**	**Year/ Manuf.**	**Heat Input (MMBtu/hr)**	**primary fuel**	**secondary fuel**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**Comments**
SUNY at Binghamton	NY	International Boiler Works	100	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	X3
SUNY at Binghamton	NY	International Boiler Works	50	Coal	Coal/Wood Mix	0.6	Multi-Cyclone w/o Fly ash injection	1.7	-	-	-	
US Salt - Watkins Glen Refinery	NY	2000?	160	Coal and/or Wood	NG and/or Coal, Wood	0.051	Fabric Filter	1.2	-	0.18	SNCR	
Dirigo Paper	VT	1977	180	Wood	-	0.20 gr/dscf	multiclone	-	-	0.3	none	-
Ethan Allen	VT	1950	59.5	Wood	-	0.45 gr/dscf	multiclone	-	-	1.94lb/ton wet wood 7.45lb/ton dry wood	none	-
Fraser	NH	1981, Zurn	324	Wood/Bark/Paper	# 6 Oil	0.1	Multi-cyclone + Venturi scrubber	0.8	-	0.25	-	

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Tillotson Rubber	NH	1978	41	Wood	-	0.43	Multi-cyclone	-	-	-	-	
Allen Rogers Limited	NH		5	Wood								
Allen Rogers Limited	NH		5	Wood								
Forest Products Processing Center	NH		47	Wood								
Madison Lumber Mill	NH		13	Wood								
Chick Packaging	NH		10	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Ossipee Mountain Land Company	NH		4	Wood								
Ossipee Mountain Land Company	NH		4	Wood								
Tommila Brothers	NH		11	Wood								
Monadnock Forest Products	NH		30	Wood								
Whitney Brothers Company	NH		2	Wood								
HG Wood Industries	NH		9	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Design Contempo	NH		19	Wood								
Design Contempo	NH		13	Wood								
Solon Manufacturing	NH		9	Wood								
Rochester Shoe Tree/Ashland	NH		4	Wood								
Precision Lumber	NH		9	Wood								
King Forest Industries - Wentworth	NH		29	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Peterboro Basket Company	NH		3	Wood								
Souhegan Wood Products	NH		8	Wood								
Souhegan Wood Products	NH		1	Wood								
Souhegan Wood Products	NH		1	Wood								
Concord Steam Corporation	NH		40	Wood								
Concord Steam Corporation	NH		40	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	State	Year/ Manuf.	Heat Input (MMBtu/hr)	primary fuel	secondary fuel	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	limit (lb/MMBtu)	control device	Comments
Boyce Highlands	NH		4	Wood								
Herrick Millwork	NH		5	Wood								
Northland Forest Products	NH		5	Wood								
Anthony Galluzzo Corporation	NH		4	Wood								
Cousineau Wood Products	NH		14	Wood								
Newport Mills Inc	NH		6	Wood								

ICI Coal and Wood Fired in NESCAUM Region (CT,MA,ME,NH,NJ,NY,RI,VT)						PM		SO_2		NOx		
Facility	**State**	**Year/ Manuf.**	**Heat Input (MMBtu/hr)**	**primary fuel**	**secondary fuel**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**limit (lb/MMBtu)**	**control device**	**Comments**
Newport Mills Inc	NH		6	Wood								
Catamount Pellet Corporation	NH		40	Wood								
Durgin & Crowell Lumber Company	NH		10	Wood								
GH Evarts & Company	NH		7	Wood								

References: State Title V Permits, Coal SO_2 Database, ICI Coal Database, MA ICI 100-250 Boiler Database, VT ICI Boiler Database

APPENDIX B: CUECost-ICI Inputs

INPUTS

Description	Units	Input 1	Input 2	Input 3	Input 4	Input 5
General Plant Technical Inputs						
Location - State	Abbrev.	PA	PA	PA	PA	PA
Combustion Configuration	Abbrev.	PC	PC	PC	PC	PC
MW Equivalent of Flue Gas to Control System	MW	25	25.1	28.6	28.6	32.9
Net Plant Heat Rate	Btu/kWhr	10,000	11,370	8,750	8,750	7,600
Plant Capacity Factor	%	66%	66%	66%	66%	66%
Total Air Downstream of Economizer	%	154%	169%	118%	118%	119%
Air Heater Leakage	%	12%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	350	350	350	350	350
Inlet Air Temperature	°F	80	80	80	80	80
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013	0.013
Ash Split:						
Fly Ash	%	85%	85%	85%	85%	85%
Bottom Ash	%	15%	15%	15%	15%	15%
Seismic Zone	Integer	1.0	1.0	1.0	1.0	1.0
Retrofit Factor	Integer	1.0	1.0	1.0	1.0	1.0
(1.0 = new, 1.3 = medium, 1.6 = difficult)						
Select Coal	Integer	2	3	4	5	6
Is Selected Coal a Powder River Basin Coal?	Yes / No	No	No	No	No	No
Economic Inputs						
Cost Basis -Year Dollars	Year	2006	2006	2006	2006	2006
Service Life (levelization period)	Years	15	15	15	15	15
Inflation Rate	%	3%	3%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	8%	8%	8%	8%	8%
AFDC Rate (current $'s)	%	8%	8%	8%	8%	8%
First-year Carrying Charge (current $'s)	%	22%	22%	22%	22%	22%
Levelized Carrying Charge (current $'s)	%	17%	17%	17%	17%	17%
First-year Carrying Charge (constant $'s)	%	16%	16%	16%	16%	16%
Levelized Carrying Charge (constant $'s)	%	12%	12%	12%	12%	12%
Sales Tax	%	6%	6%	6%	6%	6%
Escalation Rates:						
Consumables (O&M)	%	3%	3%	3%	3%	3%
Capital Costs:						
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index.	Integer	478.7	478.7	478.7	478.7	478.7
If "No" input escalation rate.	%	3%	3%	3%	3%	3%
Construction Labor Rate	$/hr	$35	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%	3%

Operating Labor Rate	$/hr	$25	$25	$25	$25	$25
Power Cost	Mills/kWh	47	47	47	47	47
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5	3.5

<u>Limestone Forced Oxidation (LSFO) Inputs</u>

SO_2 Removal Required	%	95%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125	125
Design Scrubber with Dibasic Acid Addition? (1 = yes, 2 = no)	Integer	2	2	2	2	2
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Reagent Feed Ratio (Mole CaCO3 / Mole SO_2 removed)	Factor	1.05	1.05	1.05	1.05	1.05
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%	15%
Stacking, Landfill, Wallboard (1 = stacking, 2 = landfill, 3 = wallboard)	Integer	1	1	1	1	1
Number of Absorbers (Max. Capacity = 700 MW per absorber)	Integer	1	1	1	1	1
Absorber Material (1 = alloy, 2 = RLCS)	Integer	1	1	1	1	1
Absorber Pressure Drop	in. H2O	6	6	6	6	6
Reheat Required ? (1 = yes, 2 = no)	Integer	1	1	1	1	1
Amount of Reheat	°F	25	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$15	$15	$15	$15	$15
Landfill Disposal Cost	$/ton	$25	$25	$25	$25	$25
Stacking Disposal Cost	$/ton	$6	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$2	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%

Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Lime Spray Dryer (LSD) Inputs

SO_2 Removal Required	%	90%	90%	90%	90%	90%
Adiabatic Saturation Temperature	°F	127	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147	147
Reagent Feed Ratio (Mole CaO / Mole Inlet SO_2)	Factor	0.90	0.90	0.90	0.90	0.90
Recycle Rate (lb recycle / lb lime feed)	Factor	30	30	30	30	30
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%	35%
Number of Absorbers (Max. Capacity = 300 MW per spray dryer)	Integer	2	2	2	2	2
Absorber Material (1 = alloy, 2 = RLCS)	Integer	1	1	1	1	1
Spray Dryer Pressure Drop	in. H2O	5	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60	60
Reagent Cost (delivered)	$/ton	$60	$60	$60	$60	$60
Dry Waste Disposal Cost	$/ton	$25	$25	$25	$25	$25
Maintenance Factors by Area (% of Installed Cost)						
Reagent Feed	%	5%	5%	5%	5%	5%
SO_2 Removal	%	5%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)						
Reagent Feed	%	20%	20%	20%	20%	20%
SO_2 Removal	%	20%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)						
Reagent Feed	%	10%	10%	10%	10%	10%
SO_2 Removal	%	10%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%	10%

Particulate Control Inputs

Outlet Particulate Emission Limit	lbs/MMBtu	0.03	0.03	0.01	0.01	0
Fabric Filter:						
Pressure Drop	in. H2O	6	6	6	6	6
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	2	2	2	2	2
Gas-to-Cloth Ratio	acfm/ft^2	5.5	5.5	5.5	5.5	5.5
Bag Material (RGFF fiberglass only) (1 = Fiberglass, 2 = Nomex, 3 = Ryton)	Integer	1	1	1	1	1
Bag Diameter	inches	6	6	6	6	6
Bag Length	feet	20	20	20	20	20
Bag Reach		3	3	3	3	3
Compartments Out of Service	%	10%	10%	10%	10%	10%
Bag Life	Years	2	2	2	2	2
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
ESP:						
Strength of the electric field in the ESP = *E*	kV/cm	10.0	10.0	10.0	10.0	10.0
Plate Spacing	in.	12	12	12	12	12
Plate Height	ft.	36	36	36	36	36
Pressure Drop	in. H2O	3	3	3	3	3
Maintenance (% of installed cost)	%	5%	5%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

NOx Control Inputs

Selective Catalytic Reduction (SCR) Inputs

NH3/NOx Stoichiometric Ratio	NH3/NOx	0.9	0.9	0.9	0.9	0.9
NOx Reduction Efficiency	Fraction	0.70	0.70	0.70	0.70	0.70
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.4
Space Velocity (Calculated if zero)	1/hr	3000	3000	11800	11800	16800
Overall Catalyst Life	years	4	4	4	4	4
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Catalyst Cost	$/ft3	356.34	356.34	356.34	356.34	356.34
Solid Waste Disposal Cost	$/ton	25.38	25.38	25.38	25.38	25.38
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%
Number of Reactors	integer	1	1	1	1	1
Number of Air Preheaters	integer	1	1	1	1	1

Selective NonCatalytic Reduction (SNCR) Inputs

Reagent	1:Urea 2:Ammonia	1	1	1	1	1
Number of Injector Levels	integer	3	3	3	3	3
Number of Injectors	integer	18	18	18	18	18
Number of Lance Levels	integer	0	0	0	0	0
Number of Lances	integer	0	0	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	1	1	1
NOx Reduction Efficiency	Fraction	0.50	0.50	0.50	0.50	0.50
Inlet NOx	lbs/MMBtu	0.6	0.26	0.2	0.4	0.2
NH3/NOx Stoichiometric Ratio	NH3/NOx	1.2	1.2	1.2	1.2	1.2
Urea/NOx Stoichiometric Ratio	Urea/NOx	1.2	1.2	1.2	1.2	1.2
Urea Cost	$/ton	200	200	200	200	200
Ammonia Cost	$/ton	411.17	411.17	411.17	411.17	411.17
Water Cost	$/1,000 gal	0.22	0.22	0.22	0.22	0.22
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%

Low-NOx Burner Technology Inputs

NOx Reduction Efficiency	fraction	0.40	0.40	0.40	0.40	0.40
Boiler Type	T:T-fired, W:Wall	W	W	W	W	W
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%	1.2%	1.2%

Natural Gas Reburning Inputs

NOx Reduction Efficiency	fraction	0.61	0.61	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	4.24	4.24	4.24	4.24	4.24
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%	10%	10%