Methods for Evaluating the Costs of Utility NO\textsubscript{x} Control Technologies

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For Presentation at:
89th Annual Meeting
Air & Waste Management Association
Nashville, TN

June 1996
INTRODUCTION

Titles I and IV of the 1990 Clean Air Act Amendments (CAA) are the driving forces behind the control of nitrogen oxides as precursor air pollutants. Title I addresses the control of nitrogen oxides (NOx) as a means of achieving the National Ambient Air Quality Standard (NAAQS) for ozone attainment. Title IV targets nitrogen oxides for the prevention of acid rain formation. In addition to these regulations, certain areas have adopted stricter regulations for the control of NOx. For example, the Northeast States Coordinated Air Use Management (NESCAUM) agency and the South Coast Air Basin (SCAB) in California have developed stricter NOx emission limits in order to meet local air quality standards.

A variety of technologies have been developed to reduce NOx emissions from fossil-fuel-fired utility boilers. Combustion controls for NOx include operating modifications, burners out of service (BOOS), flue gas recirculation (FGR), low-NOx burners (LNB), overfire air (OFA) and reburning. Combustion control technologies are generally adopted by utilities in which low to moderate reductions are needed. Of these combustion controls, LNB and LNB combined with OFA (LNB+OFA) are most commonly applied to coal-fired power plants with tangential and wall-fired boilers.

PULVERIZED-COAL-FIRING CONFIGURATIONS

The design of combustion-based NOx control technologies depends on the design of a furnace. Most of the installed coal-fired power plant capacity in the U.S. is comprised of pulverized coal-fired systems. The burners required to combust the pulverized coal can be arranged in two general configurations: horizontally on the furnace walls or in the corners of the furnace. The first configuration, referred to as “wall-fired,” includes burner arrangements on one or more walls of the furnace. In the wall-fired configuration, the burners are independent of each other and provide separate flame envelopes. The second configuration is referred to as tangential-fired. The tangential-fired configuration is such that one flame envelope is produced at the center of the furnace. The implications of these two furnace designs for NOx formation and control are discussed.

NOx Formation Mechanisms

Nitrogen oxides (NOx) production in combustion systems is primarily due to two mechanisms: fuel and thermal NOx. Fuel NOx is produced when chemically bound nitrogen compounds in the fuel are oxidized. Formation of fuel NOx is dependent on O2 availability and the concentration of nitrogen in the fuel. Fuel nitrogen conversion rates increase with increasing flame air-to-fuel ratio or fuel nitrogen content. Thermal NOx, on the other hand, is formed due to reactions of nitrogen and oxygen in the combustion air at high temperatures. At high temperatures N2 and O2 are dissociated into radicals that react to form NO. Fuel and thermal NOx formation in coal-fired combustion systems can be reduced or controlled by adjusting the air-to-fuel stoichiometry, the rate of air and fuel mixing and the temperatures at which combustion takes place. The technique most applied in coal-fired utilities for the control of NOx is operation of the bulk of the flame zone under fuel-rich conditions to reduce the availability of O2 at high temperatures, followed by a fuel lean zone to complete the burn-out of the fuel. This technique is commonly referred to as staged combustion. Combustion-based NOx control technologies, such as LNB and LNB+OFA, apply this technique for the control of NOx emissions in utility boilers.

Wall-Fired Boilers

Wall-fired boilers have several configurations. The burners can be arranged as single-wall or opposed-wall. Single-wall fired boilers have burners on one wall of the furnace. Opposed-wall boilers have burners on two opposing walls. Each wall with burners has several circular burners. Each burner has its own flame zone. Coal and primary air are fed via nozzles at the center of each burner. The inlet vanes in the furnace windbox assembly, from which secondary combustion air is drawn, can be adjusted to achieve better fuel and air mixing. Air swirl and high velocities combined with the contour of the burner throat results in a recirculation pattern across the furnace. The recirculation of flue gas back to the burner provides more thermal energy to the burner for more efficient combustion. Temperature and air circulation control in wall-fired boilers is achieved by adjusting the amount of excess air and the heat input.

The air swirling and circulation patterns can often lead to turbulence. The high level of turbulence results in poor mixing between the fuel and the secondary air creating two conditions in which NOx formation is
favored. First, under these conditions, the combustion gas temperatures are high. With high temperatures, thermal NO$_x$ is formed. Second, the turbulence reduces the residence time of the combustion process. With less residence time, the reducing reactions that would convert nitrogen species to diatomic nitrogen are not allowed to proceed to completion.

As an example to indicate both the range and average of emissions from wall-fired boilers, emissions testing of 18 dry-bottom, wall-fired boilers, has shown the range of NO$_x$ emissions to be 0.42-1.77 lb/10$^6$ BTU. The average of this range was 0.95 lb/10$^6$ BTU.

**Tangential-Fired Boilers**

In tangential-fired boilers, fuel and air are combined and combusted while being projected towards the center of the furnace. The flames produced evolve into a rotating “fireball” due to high turbulence and mixing. Four air zones are handled by the windbox: primary, fuel, overfire, and auxiliary. Primary air injected through the coal nozzle assembly dries and transports the coal. Fuel air or secondary air is supplied via secondary air nozzles. The overfire air portion is injected via ports either on top of or separate from the windbox. The auxiliary air is the portion of air needed for complete combustion besides the primary, secondary, and OFA portions. The auxiliary air is also introduced via the windbox.

The windbox assembly, which includes the fuel and air nozzles, is tilted uniformly during the combustion process. A tilting mechanism allows the fireball to travel up and down the furnace, enabling control of the flue gas and steam temperatures during changes in the boiler load. The position of the fireball along the furnace is adjusted based upon the accumulation of ash on the furnace walls. It begins at the bottom of the furnace and travels upward. With ash build-up, less heat is absorbed by the furnace walls, and less heat is transferred at the convective pass of the boiler. When this occurs, the fireball is moved upward by tilting the windbox assembly to compensate for the heat loss. The fireball will cycle back down once the ash deposits are removed, for example, after soot-blowing incidents.

In the burner assembly, the secondary air nozzles are located between the two coal nozzles. This arrangement allows the fuel and air to mix well and for efficient combustion to occur. Because of the more uniform fuel-to-air ratio created by the fireball-firing configuration, the uncontrolled NO$_x$ emissions from tangential-fired boilers tend to be lower than for wall-fired boilers. Emission testing of 19 units has shown the range of baseline uncontrolled NO$_x$ emissions to be 0.45-0.80 lb/10$^6$ Btu for tangential-fired boilers. The average of this range was 0.65 lb/10$^6$ BTU, 32 percent lower compared to the average baseline emission rate of wall-fired boilers.

**NO$_x$ COMBUSTION CONTROL TECHNOLOGIES**

OFA, LNB and LNB+OFA are the most commonly employed technologies for combustion based NO$_x$ control. These technologies are briefly reviewed here.

**OFA Technology**

In a conventional boiler, all of the air required for combustion is introduced into the furnace through the burners. Over-fire air (OFA) is an application of two-staged combustion in which a portion of the combustion air is diverted to injection ports above the top row of burners or between the burner rows in the furnace. The existing windbox is extended or duct systems are installed to supply secondary air to the OFA ports. When OFA is employed, the primary air flow to the burners is reduced to promote fuel rich combustion in the flame zone. The secondary air promotes the burnout of products of incomplete combustion from the primary flame zone. This control technique reduces NO$_x$ emissions by two mechanisms. First, the combustion process is delayed due to the staging, resulting in a lower flame temperature which suppresses thermal NO$_x$ formation. The second mechanism involves the inhibition of fuel NO$_x$ formation due to low O$_2$ levels in the combustion zone.

For wall-fired systems, OFA has been applied as a “stand-alone” NO$_x$ combustion control technology and in combination with other control technologies such as LNB. OFA systems for wall-fired boilers can be described as either conventional OFA or advanced OFA (AOFA). In the traditional systems, there is one OFA port above each burner column, and 20 percent of the total air flow is diverted equally to these OFA ports. In the AOFA systems, the OFA ports are installed on walls other than the burner walls of the
furnace, and the diverted flow is typically 45 percent of the total air flow. Existing traditional OFA systems can be modified by adding additional OFA ports and adjusting the air flow. The process of adjusting air flows through multiple OFA ports is referred to as biasing. Some AOFA systems include not only OFA ports on the walls of the furnace but also ports in the corners of the furnace and between the burner levels. These wing and auxiliary OFA ports allow air to be introduced in areas normally starved of air in conventional OFA systems.7

For tangential-fired boilers, the OFA systems can include either close-coupled OFA (CCOFA) or separated OFA (SOFA). CCOFA is analogous to the conventional system of wall-fired boilers while SOFA is similar to the AOFA. In the SOFA system, a separate windbox and duct system supply the OFA.5 These OFA systems were used in tangential-fired boilers for the control of NOx in pre- and NSPS boilers.

**LNB Technology for Wall-fired Boilers**

LNB utilizes staging for the reduction of NOx formation. Through the application of LNBs, thermal NOx is reduced by the reduction of flame temperature and reduced residence time at peak temperature; while fuel NOx is reduced by sub-stoichiometric oxygen levels in the primary flame zone.9 Because the design and performance of the LNB technology differ for wall-fired and tangential-fired boilers, the technology for the tangential-fired boilers will be discussed separately.

Two general categories of LNBs are delayed combustion and internal staged. In delayed combustion burners, the fuel is combusted slowly with long, low-intensity flames. This burner design is different from conventional burner designs. Combustion in conventional burners is achieved rapidly in turbulent, high-intensity flames. Internal-staged LNBs inhibit NOx formation by creating fuel-rich and fuel-lean conditions near the burner zone. In the fuel-rich regions, fuel nitrogen is converted to N2 instead of NO due to oxygen-deficient conditions. In the fuel-lean regions, thermal NOx formation is inhibited by lower-temperature conditions.

Tests of retrofitted LNBs have shown NOx reduction efficiencies ranging from 40 to 60 percent.1 Data in the open literature indicate that the NOx reduction efficiencies for wall-fired boilers range from 30 to 60 percent.3,4,5 The extent to which NOx is reduced depends upon the LNB system and the specific unit performance characteristics such as fuel properties and combustion temperatures.3

**LNB Technology for Tangential-fired Boilers**

The LNB technology configurations for tangential-fired boilers differ from those of wall-fired boilers, even though the theory behind the LNB controls is similar. Some wall-fired LNB technologies are currently being tested and applied to tangential-fired boilers, but the most accepted technologies are those designed specifically for tangential-fired boilers. An example is the Low NOx Concentric Firing System (LNCFS). This system is common in U.S. coal-fired boilers. LNCFS retrofit requires replacement of all fuel and air nozzles and some changes in the boiler structure, windbox, and waterwall.

The basic NOx control strategy behind the development of the LNCFS is directing the fuel and a fraction of the secondary combustion air towards the center of the furnace while directing the rest of the secondary air horizontally and parallel to the furnace walls. Redistributing the secondary air in the combustion zone creates separation between fuel and air. This separation creates fuel-rich conditions at the center of the furnace. With low O2 availability, NOx formation is inhibited. This firing configuration also creates a blanket of air along the walls of the furnace. This layer of air reduces the slagging and corrosion potential under fuel-rich or reducing conditions of the low NOx firing configuration.

Four different types of air are handled by the windbox: primary, secondary, auxiliary, and fuel. The LNCFS is designed to inhibit NOx emissions by controlling the mixing of the fuel and the combustion air. Instead of directing the auxiliary air directly towards the fireball as done in conventional tangential-fired boilers, the air is directed towards a bigger imaginary circle surrounding the fireball. As a result, the fireball area of the furnace becomes fuel-rich.

LNCFS systems come in three configurations, Levels I, II, and III. In all three designs, combustion staging is achieved along with some protection against waterwall corrosion by diverting the combustion air towards the walls of the furnace.3 Level I (LNCFS I) is the level at which the LNB is operated with close-
coupled over-fire air (CCOFA). The CCOFA is integrated directly into the windbox by exchanging the highest coal nozzle with the air nozzle immediately below it. This level is considered as the representative LNB technology applied to tangential-fired boilers.

The NO$_x$ reduction efficiencies for this technology range from 25 to 35 percent.$^3$ Even though this range is lower than the range for LNB technologies in wall-fired boilers, the efficiency can be sufficient to meet the applicable NO$_x$ standards. This is because uncontrolled tangential-fired boilers typically emit less NO$_x$ on a lb/10$^6$ BTU basis than uncontrolled wall-fired boilers.

**LNB+OFA Technology**

For further control of NO$_x$ emissions, the LNB technology may be combined with OFA technology. For wall-fired boilers, the “stand-alone” OFA and LNB technologies are operated simultaneously to achieve NO$_x$ reductions ranging from 40 to 60 percent. LNB+OFA systems in tangential-fired boilers include the LNCFS, Levels II and III (LNCFS II and LNCFS III). LNCFS II operates using the LNCFS with SOFA while LNCFS III incorporates both CCOFA and SOFA. These systems can achieve NO$_x$ reduction efficiencies ranging from 30 to 50.$^3$ These technologies allow more efficient use of staging and as a result, further control of thermal and fuel NO$_x$ formation.

**SYSTEM IMPACTS**

The LNB and LNB+OFA technologies are successful at controlling NO$_x$ emissions from coal-fired, tangential- and wall-fired boilers, but their impact on the base plant performance can be significant. These adverse impacts include increased unburned carbon levels and carbon monoxide (CO) emissions. The increase in total unburned carbon can result in a decrease in the boiler efficiency. In addition, high levels of unburned carbon in the flyash can lead to costs associated with the potential inability to sell the flyash as a byproduct.

In general, there is an upper limit to the amount of combustion air which can be diverted from the primary air supplied with the coal. If the primary air flow is too low, then incomplete combustion will occur in the flame zone. Therefore, the extent of staging for OFA systems is limited by operational problems caused by incomplete combustion conditions due to low primary air flow$^6$ or due to poor mixing of the secondary air with the combustion products.$^7$

Operation of LNBs in tangential-fired and wall-fired boilers have shown negligible to significant increases in unburned carbon (UBC). Unburned carbon includes uncombusted carbon residue contained in both the bottom ash and fly ash. Loss on ignition (LOI) refers specifically to UBC in the flyash only. Both UBC and LOI are indicators of reduced combustion efficiency. For example, significant increases in UBC were observed at Edgewater Unit 4,$^9$ Hammond Unit 4,$^4$ Stuart Unit 4,$^5$ and Gaston Unit 2, whereas little to no increase in UBC was observed at Pleasants Unit 2$^9$ and Four Corners Unit 4.$^{10}$

Another impact, aside from reduced plant efficiency, that results from increases in the LOI is the impact on the flyash saleability. Several utilities indicated that the LOI increases may prevent sale of the flyash as a byproduct. The byproduct specifications are such that only a certain level of unburned carbon are allowed in the flyash. Once this level is exceeded, the flyash is no longer suitable for byproduct sales. The inability to sell the flyash can result in substantial costs associated with the disposal of the unsaleable flyash.

**COSTS OF NO$_x$ COMBUSTION CONTROL TECHNOLOGIES**

This section contains a brief review of published cost data for retrofit LNB and LNB+OFA technologies.

**LNB Technology**

Retrofit of LNBs in wall-fired boilers normally involves small modifications to the waterwall, but major modifications to the windbox for improved air distribution may also be required in some cases. The economic analysis study of low-NO$_x$ combustion systems by Lisauskas et al estimated the total capital cost, including indirect costs, of the LNB technology to be $1.4/kW to $2.8/kW for a modification of existing burners and $4.6/kW to $8.7/kW for a total burner replacement in 1987 dollars.$^7$ Vatsky reports
the retrofit material cost, not including indirect costs, for the LNB technology to range from $4.0/kW to $9.3 /kW in 1990 dollars.\textsuperscript{3} For boilers surveyed by the Acid Rain Division of the U.S. Environmental Protection Agency, the reported total capital costs ranged from $9.32/kW to 36.05 $/kW.\textsuperscript{4} The design basis underlying these cost data are often not completely reported.

The LNCFS I retrofits require replacement of all air and fuel nozzles. Installed capital costs typically include the costs associated with the new burner system and modifications to the existing equipment. Few cost data are publicly available for LNCFS I retrofits. The capital cost reported for Gallatin Unit 4’s LNCFS I retrofit was $21/kW in 1992 dollars.\textsuperscript{3}

\textbf{LNB+OFA Technology}

The capital cost of retrofitting LNB+OFA technologies differs for wall-fired and tangential-fired units due to differences in the modifications required. Cost estimates for wall-fired units in the open literature range from $6/kW to $40/kW.\textsuperscript{3,12} Lower cost estimates have been reported for wall-fired applications such as those for Schiller Stations 4, 5, and 6. The installed costs for the LNB+OFA technologies at the Schiller Stations 4, 5, and 6 were $6.81/kW, $6.25/kW, and $7.62/kW, respectively. These costs included direct and indirect expenses, exempt and non-exempt labor, materials, and outside purchases.\textsuperscript{12} Several studies have shown LNB+OFA costs to be higher in wall-fired boilers than tangential-fired boilers.\textsuperscript{3,4} Retrofit costs of LNB+OFA in tangential-fired boilers have been reported to range from $20/kW to $33$/kW.\textsuperscript{3} These cost ranges are expressed in early 1990s dollars. Escalation to 1994 dollars shows that the cost estimates would be approximately six percent higher.\textsuperscript{11} It is difficult to compare the costs of LNB+OFA to the costs of LNB or OFA only if the comparisons are for different power plants. This is because of variability in the modifications required and often unreported differences in the design basis.

\textbf{EXISTING NO\textsubscript{X} CONTROL COST MODELS}

Several performance and cost studies have been conducted to address the performance and cost implications of NO\textsubscript{x} combustion technologies as applied to coal-fired power plants.\textsuperscript{3,4,5} In addition to these studies, several cost and performance models are available. These include, for example, the NO\textsubscript{x} PERT\textsuperscript{TM} CODE\textsuperscript{13}, IAPCS\textsuperscript{14}, IECM\textsuperscript{15}, and the CAT Workstation.\textsuperscript{13} The NO\textsubscript{x} PERT\textsuperscript{TM} CODE and the CAT Workstation models are proprietary packages with substantial licensing fees. Therefore, they are not readily accessible to the public. The IAPCS was developed under contract to the U.S. EPA and focuses on both combustion and post-combustion NO\textsubscript{x} control technologies. The IECM was developed at Carnegie Mellon University for the U.S. Department of Energy and incorporates post-combustion technologies for the control of NO\textsubscript{X} emissions. In addition to these models, several cost algorithms have been derived from actual retrofit and estimated cost data.\textsuperscript{3,4,5} A study of the NESCAUM region produced cost algorithms for NO\textsubscript{x} combustion control technologies for several different types of fossil-fuel fired boilers.\textsuperscript{3} Recently, a similar study was conducted for fossil-fuel fired boilers in the U.S. by the Emission Standards Division (ESD) of the U.S. EPA.\textsuperscript{5} The U.S. EPA Acid Rain Division (ARD) is currently publishing a report on a cost-effectiveness study of LNB technology for the wall- and tangential-fired boilers already retrofitted as required by Title IV of the CAA.\textsuperscript{4}

The latter three cost studies focused on the capital costs and the cost effectiveness associated with the combustion control technologies, but the manner in which the operating and maintenance costs were estimated differed. In the NESCAUM\textsuperscript{3} and ESD\textsuperscript{5} studies, the plant performance impacts imposed by these technologies were reflected in a decrease in the boiler efficiency. In order to maintain the plant electrical output, the reduction in boiler efficiency was compensated for by an increase in the fuel consumption, and the costs associated with the increase in fuel usage were reflected in the operating and maintenance cost. However, for some technologies, operating and maintenance cost components were not included in the cost estimates due to either lack of data or insignificant impacts on the boiler performance.\textsuperscript{5} The impact on the boiler efficiency due to either lack of data or insignificant impacts on the boiler performance. These inputs were estimates obtained from either data available in the open literature,\textsuperscript{3,5} data obtained from actual retrofits,\textsuperscript{3,5} or estimates given by vendors.\textsuperscript{3,5}

Many capital cost estimates for NO\textsubscript{x} combustion control technologies in the open literature include cost components such as coal pulverizer mill upgrades, electrostatic precipitator upgrades, or other unit upgrades which may not be directly related to the NO\textsubscript{x} technology to be installed. In some cases, upgrades...
are necessitated by the effect of retrofit NO\textsubscript{x} technologies on power plant performance, but in other cases the upgrades may have been done for other reasons. Including the costs of upgrades may result in overestimating the costs associated with the NO\textsubscript{x} control technology. Because most capital cost data reported in the open literature are not clearly defined, it is difficult to assess how precise the data are pertaining to the control technologies being studied.

**OBJECTIVES FOR DEVELOPMENT OF A NEW NO\textsubscript{x} CONTROL PERFORMANCE AND COST MODEL**

Combustion-based NO\textsubscript{x} controls affect the base plant performance and impose capital and operating costs. Performance and cost models of the different technologies are needed to aid decision-making regarding which technologies will achieve performance and emissions goals with acceptable costs. The capability of predicting the performance and cost impacts associated with each control technology or system allows a utility or plant manager to determine the best control technology for their plant. A performance and cost model for combustion control technologies can also be useful for air quality planning. Such models can be used to explore alternative emission reduction strategies for multiple sources and to more accurately evaluate the costs of compliance.

Performance and cost of both the base plant and the control technologies are analyzed. In this report, efforts to develop a new series of performance and cost models of combustion-based NO\textsubscript{x} control technologies are described. The necessary foundation for such a model is accurate performance and cost data from actual retrofits or installations of these combustion control technologies. Such data have been compiled directly from several utilities. These new data are used as a basis for the development of model input assumptions. The model is comprised of two main modules: (1) performance and cost of the base plant and the LNB; and (2) LNB+OFA technologies for a coal-fired boiler.

**METHODOLOGY**

The application of different NO\textsubscript{x} combustion technologies can have significant impacts on the performance and cost of wall-fired and tangential-fired boilers. In an attempt to assess and predict these impacts, a cost and performance model has been developed for LNB and LNB+OFA technologies for wall-fired and tangential-fired boilers. The following is a discussion of the modeling approach and the basis for each performance and cost parameter being considered for each technology and the base plant.

**Data Collection**

Cost and performance data for LNB and LNB+OFA technologies were obtained from several utilities. Data were available for 29 boilers, of which 21 were tangential-fired and eight were wall-fired boilers. For proprietary reasons, the units and plants are identified using letter notation. These data have not been provided or included in previous reports referenced in this paper. The data are organized as follows:

- Table 1. Includes performance data for seven tangential-fired units retrofitted with LNB technology.
- Table 2. Retrofit LNB+OFA performance data were available for eight wall-fired units and two tangential-fired units.
- Table 3. Includes statistical analyses results for data presented in Tables 1 and 2.
- Table 4. This table includes the input assumptions for the performance module.
- Table 5. Capital cost data were available for retrofit LNB technology for four tangential-fired units.
- Table 6. Capital cost assumptions were available for retrofit LNB+OFA for eight wall-fired units and two tangential-fired units.

**Performance Data.** The baseline emissions for Sites A through Z provided in Tables 1 and 2 were data obtained from emissions testing. The controlled emission rates for Sites K to Z, as reported in Table 1, were obtained after retrofit of the control device. The controlled emission rates given for Sites A to J, as reported in Table 2, are estimates of controlled emission rates guaranteed by control technology vendors.
**Cost Data.** All cost data were provided as either total capital cost of the technology (Sites K, L, R, X) or as direct installed costs (Sites A through J). For the data provided as installed direct costs, the indirect costs were assumed to be 35 percent of the total cost of the equipment, based on 10 percent project contingency, 10 percent process contingency, 10 percent engineering and office fees, and five percent general facilities. The total capital cost data are provided in Tables 5 and 6. The estimated cost data for Sites A to J depend on the following modification requirements: (1) replacement or modification of existing burners; (2) installation of control and management systems for the LNB+OFA technology; (3) fan and primary flow elements modifications; and (4) replacement of ignitors and scanners.

**Performance Models**

In this section, performance models for both the base plant and NOₓ control technologies are described.

**Base Plant Performance Module.** The base plant performance model was adopted from the (IECM) which is implemented in a modeling environment called Demos. However, the new models developed here were implemented in FORTRAN, to allow for integration with air quality modeling decision support systems. Process parameters adopted from the IECM model include those associated with the flue gas and solid streams. These parameters account for the quantity of different gases and solids which originate at the combustion zone and are transported through the pollution control system to the stack exit. Detailed equations and explanations to this model can be found in the IECM report developed by Rubin et al.

The changes in the composition and flow rate of the flue gas and solids streams due to these control technologies produce changes in the base plant operating parameters. The extent of carbon, sulfur and nitrogen combustion determines the products of combustion. Carbon in the fuel can oxidize to CO or CO₂ or it can remain unoxidized as unburned carbon. Sulfur in the coal can oxidize to SO₂ or SO₃ or it can be retained in the ash. The nitrogen in the coal can oxidize to either NO₂ or NO or be emitted as N₂. The amount of NOₓ formed by both fuel and thermal mechanisms is represented by the NOₓ emission factor. The fraction of NOₓ as NO is an input parameter. For coal, the NOₓ emission factor is based upon the coal type and boiler type. From these input parameters, the combustion products are determined by a mass balance.

The boiler efficiency is the ratio of energy absorbed by the steam cycle to the energy in the fuel. Energy not absorbed by the steam cycle is considered lost energy. The loss of energy is defined in five categories: (1) sensible heat loss of the dry flue gas; (2) sensible and latent heat loss from water vapor in the flue gas; (3) unburned carbon and carbon monoxide, which are indicative of incomplete combustion; (4) radiative heat transfer from the boiler to the surroundings; and (5) unaccounted losses.

Combustion-based NOₓ control technologies may decrease the boiler efficiency due to unburned carbon increases. Energy loss due to carbon losses is associated with the formation of CO and unburned carbon. The energy loss associated with each pound of unburned carbon is 14,100 BTU. The energy loss associated with each pound of CO formed instead of CO₂ is 9,755 BTU.

**NOₓ Control Technologies’ Effect on Base Plant Performance.** Application of the NOₓ control technologies can fall under two categories: retrofit at an existing facility or installation at a new plant. This distinction is important when considering performance and cost implications of the control technology to the base plant. The plant performance parameters effected by the application of these technologies are briefly discussed.

**NOₓ Emissions.** The control efficiency of each technology is an input into the performance model. Using the control efficiency, the uncontrolled NOₓ emission rate is modified to determine a new emission factor.

**Unburned Carbon.** Changes in the total unburned carbon in the base plant can include changes in the unburned carbon content of the flyash and bottom ash, both expressed as mass percent. Increases in any of these parameters as a result of NOₓ combustion controls are given as inputs to the performance model. The total amount of unburned carbon (lb C/lb fuel) in the ash is the sum of the unburned carbon content in the flyash and the bottom ash.
CO Emissions. Operation of NO\textsubscript{x} combustion control technologies can result in higher concentrations of CO emissions. The percentage increase in CO emissions is an input to the model. The model calculates the CO\textsubscript{2} content in the flue gas based on a mass balance that includes carbon in the fuel, unburned carbon in the bottom ash and flyash, and carbon emitted as CO. As a result, the flue gas composition will change with any increases in the CO emissions.

Boiler Efficiency. Increases in the ash carbon content and the CO concentration will result in an increase in carbon losses and a decrease in boiler efficiency. The boiler efficiency algorithm contained in the performance model calculates the effect of user-specified levels of unburned carbon, using the same method as in the IECM.\textsuperscript{14}

Fuel Consumption. With a decrease in boiler efficiency, the plant manager can choose to accept the decrease in electricity output or increase the fuel consumption to compensate for the decrease in boiler performance. With a decrease in boiler efficiency, the plant heat rate increases. The increase in heat rate may be met by increasing the fuel flow rate into the furnace to maintain a constant plant output, or by accepting a derate on plant output for a given fuel flow rate.

Flyash Saleability. The impacts associated with the inability to sale flyash as a byproduct due to the unburned carbon increases in the flyash are reflected in an increase in the disposal cost.

NO\textsubscript{x} Combustion Control Technologies Performance Models. The following is a discussion of how the decrease in boiler efficiency is addressed for each control technology. This discussion applies to both wall- and tangential-fired boilers. Also specified are the differences associated with retrofit at an existing plant versus installation of the control device at a new plant.

Low NO\textsubscript{x} Burners. LNB retrofits can cause a decrease in the electricity output of the unit. This decrease results from more carbon loss due to increases in the flyash and bottom ash unburned carbon levels and CO emissions. The decrease in boiler efficiency is reflected in an increase in the net heat rate. With a higher net heat rate and a constant fuel flow rate, the electricity output is decreased. Alternatively, if the plant has sufficient excess capacity to increase the amount of gross megawatts of electricity generated, it may be possible to increase fuel flow and maintain the net electrical output at the same value as before the retrofit. However, in some cases additional capital costs may be required for pulverizer mill or other upgrades to accommodate the latter approach.

For the performance of the LNB technology at a new unit, the loss in electricity output due to the carbon losses will be addressed by increasing the gross capacity of the boiler. As a result, the fuel consumption will also be increased to meet the expected electricity output.

Low-NO\textsubscript{x} Burners + Overfire Air. The LNB+OFA application’s adverse effects to the base plant performance are similar those discussed for the individual LNB and OFA technologies. The performance algorithm described for the LNB technology can also be applied to the performance of this technology.

Cost Models
In this section, cost models for both the base plant and NO\textsubscript{x} control technologies are presented.

Base Plant Cost Module. The algorithm for the base plant economics was adopted from the IECM. In the IECM, the power plant and the pollution control equipment are considered separate entities. Any power consumed by the control equipment is bought from the base plant. For the base plant, electricity or steam is required to run pulverizers, steam cycle pumps, flue gas fans, cooling system and miscellaneous other equipment. The internal utility consumption or auxiliary power requirement reduces the amount of electricity that the power plant can sell and increases the net plant heat rate.

For the base plant, operating and maintenance costs are associated with fuel use or non-fuel expenses. The fuel cost depends on the fuel consumption. The non-fuel cost typically depends on the size of the plant and the amount of nonfuel consumables required. Non-fuel costs are costs associated with labor, maintenance, overhead, and taxes. The total revenue requirement is obtained by annualizing the total capital cost andlevelizing the total operating and maintenance costs.
**NOₓ Control Technology Cost Module.** The following is a discussion of the cost algorithm for the
cost estimation of the NOₓ combustion control technologies. The cost algorithm addresses costs
associated with adverse effects on the base plant performance as a result of operating the NOₓ combustion
control technologies. The total installed capital cost for each technology is an input to the cost model.
Therefore, the cost model calculates: (1) total capital cost on a $/kW basis; (2) the operating and
maintenance costs associated with each technology; and (3) annualized total revenue requirements.

For the O&M costs, the model assumes that no significant costs are associated with material and labor,
because such data are not publicly available or have been cited as insignificant. Specifically, it is
anticipated that there is no significant increase in the operating and maintenance requirement for LNB or
LNB+OFA than there would be for a conventional burner. Therefore, the O&M costs associated with
each control technology are due primarily to the fuel or utility cost, and to the impact on flyash saleability.
These O&M cost components will depend on the type of control technology being applied and whether the
technology is applied at an existing facility or at a new plant. The methodology in determining the O&M
costs for each technology can be applied to both wall- and tangential-fired boilers. This methodology is
applied here to both LNB and LNB+OFA technologies.

In the retrofit case, in which the decrease in boiler efficiency is reflected in a decrease in the electricity
output, the control device is charged a utility expense. The reduction in net electricity output is treated as a
lost source of revenue that is charged to the control device. Therefore, the cost of the not meeting the
original plant net output is absorbed by the control technology as a utility expense (MS$/yr).

In the new plant case, in which the plant size is adjusted to accommodate the boiler efficiency effects of the
NOₓ control technologies, the costs for the increase in plant size are reflected in the NOₓ control capital
costs. The O&M costs associated with the increase in fuel consumption are absorbed by the control
technology.

**MODEL APPLICATIONS**

The new performance and cost models of combustion-based NOₓ controls were applied in a series of case
studies to illustrate key factors that should be addressed in evaluating the system impacts of such controls.
The case studies developed here utilize recent data on performance and cost obtained from selected electric
utilities.

**Model Inputs**

The following is a discussion on the model inputs.

**Baseline Emissions.** Analyses of the performance data given in Table 2 show that the baseline
emissions for the wall-fired plants range from 0.55 to 1.43 lb/10⁶ BTU, with an average emission rate of
0.99 lb/10⁶ BTU (Table 3). The range and average are comparable to the NESCAUM data previously
discussed.

The baseline emissions for the tangential-fired units given in Tables 1 and 2 range from 0.53 to 0.73 lb/10⁶
BTU, with a corresponding average of 0.62 lb/10⁶ BTU (Table 3). The range and average are comparable
to the NESCAUM data previously discussed. Thus, the baseline emissions for tangential-fired boilers in
both the utility and publicly reported data sets have lower average and narrower ranges than the wall-fired
boilers. The wall-fired units’ average emission rate is approximately 37 percent higher than the tangential-
-fired units in the utility survey. This is consistent with findings in previous studies.

**Retrofit LNB Technology Controlled Emissions.** For the LNB technology, retrofit performance
data were available for the tangential-fired units. No performance data were available for LNB retrofit in
wall-fired boilers. The performance data for tangential-fired units included data for the LNCFS I
technology. Of the 17 tangential-fired units, retrofit LNCFS I data were available for seven. The
controlled emission rates ranged from 0.40 to 0.45 lb/10⁶ BTU, with an average of 0.43 lb/10⁶ BTU
corresponding to a reduction efficiency of 31 percent. The controlled emission rate average is consistent
with long-term test results of several tangential-fired units’ emission rates of 0.41 lb/10^6 BTU after retrofit of the LNCFS I technology as reported in previous studies. 4

**Retrofit LNB+OFA Technology Controlled Emissions.** Performance data given in Table 2 for the LNB+OFA technology were available for eight wall-fired units and two tangential-fired units. The controlled emission rates for the wall-fired units ranged from 0.32 to 0.51 lb/10^6 BTU, with an average controlled emission rate of 0.39 lb/10^6 BTU. Compared to the average baseline emission rate, the reduction efficiency is approximately 61 percent. This value is consistent with the efficiency ranges reported in the Alternative Control Study 2 of 60 to 70 percent, and the NESCAUM study of 40 to 60 percent. 3 These data are comprised of guaranteed data and not actual test data. Once these units are retrofitted and testing is conducted, the data set will be revisited and reanalyzed.

For the two tangential-fired units retrofitted with the LNB+OFA technology (LNCFS II), the reduction in NOx is guaranteed to be 64 percent for Site I and 30 percent for Site J. The significant difference in the LNB+OFA technology for the two units is due to the difference in plant size and performance characteristics. In addition, these efficiencies are guaranteed reductions provided by the vendor and not obtained from actual testing. The data will be re-evaluated once data are obtained from actual testing of the retrofits.

**Retrofit LNB Costs.** A summary of the performance and cost model outputs are provided in Tables 5 and 6. Cost data for the LNB retrofit were available for four wall-fired units.

**Retrofit LNB+OFA Costs.** Capital cost data for the retrofit LNB+OFA technology were available for eight wall-fired units and two tangential-fired units. Table 6 summarizes the capital cost data used as the model inputs.

**Unburned Carbon Levels.** For all the tangential-fired units at which LNCFS I was applied, given in Table 1, unburned carbon levels in the flyash increased by four percentage points or greater. Two of the wall-fired units, Site A and Site F, had increases in the flyash unburned carbon level of 7.4 and 2.6 percentage points, respectively. The rest of the wall-fired units retrofitted with the LNB+OFA technology had guarantees which included no increases in the unburned carbon level in the flyash.

**Other Model Inputs.** The coal used for all the model runs in this study was provided by a power utility. The higher heating value is 12,500 BTU/lb. The ultimate analysis on a dry basis is given below in weight percent.

<table>
<thead>
<tr>
<th>Component</th>
<th>Weight Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ash</td>
<td>10.70</td>
</tr>
<tr>
<td>Sulfur</td>
<td>1.07</td>
</tr>
<tr>
<td>Carbon</td>
<td>74.91</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>4.92</td>
</tr>
<tr>
<td>Oxygen</td>
<td>7.00</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>1.40</td>
</tr>
<tr>
<td>Moisture</td>
<td>6.50</td>
</tr>
</tbody>
</table>

Model applications were conducted for Sites K, L, R, and X using the input assumptions summarized in Table 4. For Sites A through J, for which no performance data other than plant size were available, a set of assumed performance inputs were applied. These inputs are also summarized in Table 4 in the row labeled “generic”. For the cost module, the total capital cost in millions of dollars for the control technology was an input. These values are summarized in Tables 5 and 6, which also report model output results.

Cost estimates were obtained in 1995 dollars with a levelization factor of 1.00 and a capital recovery factor of 10 percent. The opportunity cost of lost electrical power sales was assumed to be 64 mills/kWh and the fuel cost was $34/ton.
Model Outputs

Performance cost model results for retrofit LNB and LNB+OFA are reported here.

Retrofit LNB Costs. The model results for estimated capital cost including direct and indirect costs ranged from $2.3/kW to $10.3/kW. The average value of the estimated costs for these plants is $6.2/kW. This range of cost values for these LNB retrofits is low compared to values presented in previous studies, which varied from $15.1/kW to $29.0/kW when adjusted to 1995 dollars. The difference in the modeled costs estimate compared to the values from the previous studies may be due to the fact that the retrofits at these modeled units did not require major modifications. Most of the burners were modified rather than replaced.

An increase of four percentage points in UBC was assumed for each unit, because the unburned carbon data were provided as either increasing by four percentage points or by greater than four percentage points, without specifications as to how much greater. The utility cost for the increase in fuel consumption was then combined with the annualized capital cost to determine the total revenue requirement (TRR) in mills/kWh. The average TRR for these LNB retrofitted tangential-fired boilers was 0.35 mills/kWh. The average TRR for the utility cost is 0.16 mills/kWh. Thus, the loss of plant output due unburned carbon increases is shown in this case to be a substantial contributor to the total costs of the NOX control.

The Acid Rain Division study assumed O&M costs of 0.04 mills/kWh associated with the increase in unburned carbon levels in LNB retrofitted units. This O&M cost is much lower than the estimated utility cost. This is due to the fact that: (1) a lower boiler efficiency loss of 0.27 percentage points was assumed for all units in the ARD study; and (2) ARD evaluated the effects of an increase in fuel consumption, whereas here we are evaluating the effect of a loss of electrical revenues. An increase in UBC of four percentage points results in a boiler efficiency loss of 0.36 percentage points, which is 25 percent higher than the loss assumed in the ARD study. The costs calculated for loss of electrical output at constant fuel flow assume that the plant would be dispatched at full load. At partial loads, there would be no loss in revenues, but there would be an increase in fuel cost. Thus, our estimate is an upper bound. The ARD estimate may be representative of a lower bound.

Retrofit LNB+OFA Costs. The range of capital cost results for the wall-fired units is $15.2/kW to $28.3/kW with an average of $19.3/kW. These values are low compared to the ranges given in previous studies, which are $21/kW to $42/kW in 1995 dollars. For the tangential-fired units, the cost for Site I is $15.8/kW while the cost for Site J is $35.1/kW. The cost estimate for Site J is higher than capital cost data reported in previous studies, which range from $12/kW to $24.2/kW when adjusted to 1995 dollars.

For the retrofit LNB+OFA technology in wall-fired boilers, only two estimates of the increase in unburned carbon in the flyash were given. These estimates were provided for Sites A and F as guarantees from the LNB+OFA technology vendors. The percentage point increases of 2.6 and 7.4 are consistent with increases reported in the open literature. Table 6 includes the utility cost associated with those unburned carbon level increases. The average contributor to the TRR due to the unburned carbon from these two units is 0.22 mills/kWh.

Alternative Methods for Cost Implications of Unburned Carbon. To evaluate the sensitivity of NOX controls to assumptions regarding how the boiler efficiency impacts of changes in unburned carbon might be handled at various plants, we considered an alternative case study. Instead of penalizing a plant for a derate at a specified fuel flow rate, a case was considered in which fuel flow was increased to maintain plant output at its pre-retrofit level. This analysis assumed that no major modifications were required to accommodate an increase in the gross plant output. Site A was selected since it had the largest impact from unburned carbon. If the fuel consumption is increased to meet the required electricity output, the additional O&M cost for fuel would be 0.10 mills/kWh. This is almost one-third of the utility cost estimated for this unit using the default cost procedure. Therefore, the levelized costs associated with the decrease in boiler efficiency can vary significantly depending upon the method by which these costs are estimated. In extreme cases, these costs are a significant fraction of the total annualized costs for the combustion NOX control retrofits.
Flyash Saleability. Substantial increased levels of unburned carbon in the flyash can lead to the inability to sell the flyash as a byproduct. Many power plants are able to sell a portion of their flyash and hence avoid some disposal costs. Flyash containing unburned carbon levels higher than the levels specified by users of byproduct flyash, such as four percent, can no longer be sold and must be disposed. To study the cost impacts associated with the disposal of the flyash, as opposed to selling it as a byproduct, plant performance data for 15 plants from the model outputs were used to estimate the O&M costs associated with this issue. The data include the hourly flyash production, annual electricity output and operating hours. The value of the flyash as a byproduct was set at a revenue of $5/ton, while the cost to dispose of the flyash is assumed to be $15/ton. The potential inability to sell flyash as a byproduct was assessed by calculating loss in the byproduct revenues for varying percentages of the total flyash stream that would have otherwise been sold.

This flyash saleability analysis was conducted for 17 units assuming that 25 percent of the total ash is flyash and 40 percent of the total flyash is sold as byproduct. The analysis shows that the average cost of disposing the flyash without selling any of the flyash is 0.17 mills/kWh compared to 0.10 mills/kWh when 40 percent of the flyash is sold, a difference of 0.07 mills/kWh. Figure 1 depicts the loss revenue associated with the inability to sell the flyash due to the unburned carbon levels for Site K. For example, if the unit is typically able to sell 40 percent of its flyash as a byproduct, then not selling the flyash would result in a loss of 0.09 mills/kWh. Therefore, the cost impacts associated with the inability to sell flyash due to excessive increases in UBC can be significant compared to costs of NOx control. Increase in the disposal cost due to the unsaleability of the flyash may result in high O&M costs. Such costs should be charged to the NOx control technology. The sensitivity analysis here indicates that the loss of flyash revenues can range from 15 to 55 percent of the TRR for the NOx control equipment itself. Therefore, the costing methodologies should consider the flyash saleability issue when trying to determine the operating and maintenance costs associated with the operation of the technology.

FUTURE WORK

Once more performance and cost data are collected, the following work will be conducted to enhance the performance and cost models:

1. Further develop performance and cost algorithms for LNB and LNB+OFA technologies for different levels of retrofit at wall- and tangential-fired boilers including analysis of data sets to determine whether it is feasible to develop a regression model of capital cost versus plant size.

2. Apply the cost and performance algorithms to new case studies to evaluate the performance, emissions, and cost of NOx controls.

3. Characterize variability and uncertainty in the model predictions.

CONCLUSIONS

Retrofit of LNB and LNB+OFA technologies at wall- and tangential-fired boilers can result in significant impacts to the base plant performance. These performance impacts are in the form of increased unburned carbon levels in the flyash. This leads to potentially two significant impacts: (1) decrease in plant efficiency; and (2) a potential loss of flyash byproduct revenues.

The variation in capital cost for the control technologies shows that the capital cost depends upon the extent of modifications and the type of boiler being retrofitted.

Alternative approaches to quantifying the effect of unburned carbon on plant operating costs provide bounding estimates for NOx control costs. These alternatives include derating plant output versus increasing fuel flow. Flyash saleability is also an important issue to consider when attempting to estimate the costs associated with the application of NOx combustion control technologies. The inability to sell the flyash as a byproduct can lead to substantial disposal costs.
ACKNOWLEDGMENTS

We would like to thank the utilities who allowed us access to their performance and cost data and their expert opinions. This work was partially supported by MCNC-North Carolina Supercomputing Center and the U.S. Department of Energy. The authors are solely responsible for the content of this paper.

REFERENCES


### Table 1. Retrofit LNB Performance Data for Tangential-fired Boilers

<table>
<thead>
<tr>
<th>Plant/Unit</th>
<th>Boiler Size (MW)</th>
<th>Baseline Emissions (lb/10^6 BTU)</th>
<th>Controlled Emissions (lb/10^6 BTU)</th>
<th>NO\textsubscript{x} Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site K</td>
<td>165</td>
<td>0.73</td>
<td>0.45</td>
<td>38</td>
</tr>
<tr>
<td>Site L</td>
<td>270</td>
<td>0.67</td>
<td>0.45</td>
<td>33</td>
</tr>
<tr>
<td>Site R</td>
<td>562</td>
<td>0.60</td>
<td>0.41</td>
<td>32</td>
</tr>
<tr>
<td>Site W</td>
<td>385</td>
<td>0.57</td>
<td>0.45</td>
<td>21</td>
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<tr>
<td>Site X</td>
<td>660</td>
<td>0.59</td>
<td>0.45</td>
<td>24</td>
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<tr>
<td>Site Y</td>
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<td>0.65</td>
<td>0.40</td>
<td>38</td>
</tr>
<tr>
<td>Site Z</td>
<td>133</td>
<td>0.65</td>
<td>0.40</td>
<td>38</td>
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</table>

### Table 2. Retrofit LNB+OFA Performance Data

<table>
<thead>
<tr>
<th>Plant/Unit</th>
<th>Boiler Size (MW)</th>
<th>Boiler Type</th>
<th>Baseline Emissions (lb/10^6 BTU)</th>
<th>Controlled Emissions (lb/10^6 BTU)</th>
<th>NO\textsubscript{x} Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site A</td>
<td>390</td>
<td>W</td>
<td>1.32</td>
<td>0.38</td>
<td>71</td>
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<tr>
<td>Site B</td>
<td>750</td>
<td>W</td>
<td>0.62</td>
<td>0.32</td>
<td>48</td>
</tr>
<tr>
<td>Site C</td>
<td>200</td>
<td>W</td>
<td>1.03</td>
<td>0.41</td>
<td>60</td>
</tr>
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<td>W</td>
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<td>64</td>
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<td>Site E</td>
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<td>W</td>
<td>0.89</td>
<td>0.36</td>
<td>60</td>
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<tr>
<td>Site F</td>
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<td>69</td>
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<tr>
<td>Site I</td>
<td>390</td>
<td>T</td>
<td>1.32</td>
<td>0.38</td>
<td>71</td>
</tr>
<tr>
<td>Site J</td>
<td>715</td>
<td>T</td>
<td>1.43</td>
<td>0.44</td>
<td>69</td>
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</tbody>
</table>

### Table 3. Statistical Summary of NO\textsubscript{x} Control Effectiveness for Wall- and Tangential-Fired Boilers

<table>
<thead>
<tr>
<th>Statistical Data</th>
<th>Wall Baseline Emissions (lb/10^6 BTU)</th>
<th>Wall LNB+OFA Controlled Emissions (lb/10^6 BTU)</th>
<th>Wall LNB+OFA Reduction Efficiency (%)</th>
<th>Tangential Baseline Emissions (lb/10^6 BTU)</th>
<th>Tangential LNB Controlled Emissions (lb/10^6 BTU)</th>
<th>Tangential LNB Reduction Efficiency (%)</th>
</tr>
</thead>
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<tr>
<td>Mean</td>
<td>0.99</td>
<td>0.39</td>
<td>59</td>
<td>0.62</td>
<td>0.43</td>
<td>32</td>
</tr>
<tr>
<td>Standard Deviation</td>
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<td>10</td>
<td>0.06</td>
<td>0.03</td>
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<tr>
<td>Minimum</td>
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<td>40</td>
<td>0.53</td>
<td>0.40</td>
<td>21</td>
</tr>
<tr>
<td>Maximum</td>
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<td>0.51</td>
<td>71</td>
<td>0.73</td>
<td>0.45</td>
<td>38</td>
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<tr>
<td>Count</td>
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<td>8</td>
<td>8</td>
<td>17</td>
<td>7</td>
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</tr>
</tbody>
</table>

*Summary for wall-fired boilers is based upon data in Table 1. Summary for tangential-fired boilers is based upon data in Table 2 combined with additional utility-reported data for baseline emission.

### Table 4. Performance Model Inputs

<table>
<thead>
<tr>
<th>Unit (a)</th>
<th>Gross Capacity (MW)</th>
<th>Net Capacity (MW)</th>
<th>Capacity Factor (%)</th>
<th>Net Heat Rate (BTU/kWh)</th>
<th>Excess Air (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site K</td>
<td>165</td>
<td>158</td>
<td>30</td>
<td>10,337</td>
<td>14.3</td>
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<tr>
<td>Site L</td>
<td>270</td>
<td>259</td>
<td>35</td>
<td>9,946</td>
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<td>Site R</td>
<td>562</td>
<td>540</td>
<td>40</td>
<td>9,870</td>
<td>14.3</td>
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<td>Site X</td>
<td>660</td>
<td>635</td>
<td>70</td>
<td>8,970</td>
<td>14.3</td>
</tr>
<tr>
<td>Generic unit gross capacity</td>
<td>75</td>
<td>9,400</td>
<td>14.3</td>
<td></td>
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</tr>
</tbody>
</table>

*Generic assumptions were applied to case studies of units A through J due to the absence of site-specific data.*
Table 5. Selected Performance and Cost Model Inputs and Outputs for Retrofit LNB Technology

<table>
<thead>
<tr>
<th>Unit</th>
<th>Boiler Type</th>
<th>TCC (MW)</th>
<th>Heat Rate Change (BTU/kWh)</th>
<th>TCC ($/kW)</th>
<th>Utility (mills/kWh)</th>
<th>TRR (mills/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site K</td>
<td>T</td>
<td>1.25</td>
<td>44</td>
<td>8.1</td>
<td>0.19</td>
<td>0.39</td>
</tr>
<tr>
<td>Site L</td>
<td>T</td>
<td>2.50</td>
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<td>10.3</td>
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<tr>
<td>Site R</td>
<td>T</td>
<td>2.20</td>
<td>41</td>
<td>4.2</td>
<td>0.19</td>
<td>0.31</td>
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<tr>
<td>Site X</td>
<td>T</td>
<td>1.30</td>
<td>37</td>
<td>2.3</td>
<td>0.13</td>
<td>0.17</td>
</tr>
</tbody>
</table>

*a MW = Plant capacity in megawatts; Boiler Type: T=tangential-fired, W=wall-fired; TCC=total capital cost including indirect costs.  
b TCC=total capital cost; Utility=cost for loss in electricity output due to unburned carbon losses; TRR=total revenue requirement for NOx control.*

Table 6. Selected Performance and Cost Model Inputs and Outputs for Retrofit LNB+OFA Technology

<table>
<thead>
<tr>
<th>Unit</th>
<th>Boiler Type</th>
<th>TCC (MW)</th>
<th>Heat Rate Change (BTU/kWh)</th>
<th>TCC ($/kW)</th>
<th>Utility (mills/kWh)</th>
<th>TRR (mills/kWh)</th>
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</thead>
<tbody>
<tr>
<td>Site A</td>
<td>W</td>
<td>5.69</td>
<td>70</td>
<td>15.6</td>
<td>0.35</td>
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<tr>
<td>Site B</td>
<td>W</td>
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<td>0</td>
<td>15.8</td>
<td>0</td>
<td>0.15</td>
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<tr>
<td>Site C</td>
<td>W</td>
<td>4.43</td>
<td>0</td>
<td>23.5</td>
<td>0</td>
<td>0.37</td>
</tr>
<tr>
<td>Site D</td>
<td>W</td>
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<td>0</td>
<td>28.3</td>
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<td>0.45</td>
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<td>W</td>
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<td>0</td>
<td>22.9</td>
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<td>Site F</td>
<td>W</td>
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<td>23</td>
<td>16.6</td>
<td>0.08</td>
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<td>T</td>
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<td>0</td>
<td>15.8</td>
<td>0</td>
<td>0.25</td>
</tr>
<tr>
<td>Site J</td>
<td>T</td>
<td>5.78</td>
<td>0</td>
<td>35.1</td>
<td>0</td>
<td>0.55</td>
</tr>
</tbody>
</table>

*a MW = Plant capacity in megawatts; Boiler Type: T=tangential-fired, W=wall-fired; TCC=total capital cost including indirect costs.  
b TCC=total capital cost; Utility=cost for loss in electricity output due to unburned carbon losses; TRR=total revenue requirement for NOx control.*

Figure 1. Sensitivity Analysis of Revenue Loss Associated with Inability to Sell Flyash.