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EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium

The Mega Symposium
Opening Plenary Session and NOx

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Sponsored by
Electric Power Research Institute
U.S. Department of Energy
U.S. Environmental Protection Agency

August 25-29, 1997
Washington Hilton & Towers Hotel
Washington, DC

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Prepared by
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REPORT SUMMARY

This "Mega" Symposium combined several conferences that had been held separately over the years to provide utilities and other interested parties with comprehensive information on air pollution control technologies at a single time and place. Emphasizing field experience, the conference showcased the state-of-the-art in the measurement and reduction of NO_x, SO_2, and particulate /air toxic emissions.

Background

This first-ever "Mega" Symposium combines the SO_2 Control Symposium, the Joint Symposium on Stationary Combustion NO_x Controls, the Particulate Control Symposium, and the control technology portions of the EPRI/DOE International Conference on Managing Hazardous and Particulate Pollutants. The Symposium also includes sessions on Continuous Emissions Monitors.

Objective

To provide information on the latest developments and operational experience with state-of-the-art methods for measuring and reducing NO_x, SO_2, and particulate/air toxics emissions from fossil-fueled boilers.

Approach

EPRI, the U.S. Department of Energy, and the U.S. Environmental Protection Agency cosponsored a "Mega" Symposium in Washington, DC on August 25-29, 1997. Over 120 papers were presented with sessions grouped by pollutant, topical area, boiler type, and/or process.

Key Points

The Symposium proceedings are published in three volumes: Volume I, NO_x controls; Volume II, SO_2 Controls and Continuous Emissions Monitors; and Volume III, Particulates and Air Toxics Controls. Topics covered during formal presentations and poster sessions include:

- Combustion tuning/optimization
- Low NO_x Systems for Coal- , Gas-, and Oil-Fired Boilers

- Selective Catalytic Reduction
- Selective Noncatalytic Reduction
- Cyclones - Combustion NO_x Controls
- Full-Scale Flue Gas Desulfurization (FGD) Experience
- FGD Conversions
- FGD Process Improvements
- Dry SO_2 Control Processes
- Advanced SO_2 Control Processes
- Continuous Emission Monitors
- New Technologies for Particulate Control
- Lab- and Pilot-Scale Research in Mercury Capture by Sorbents
- Mercury Capture by FGD
- High Gas-to-Cloth Ratio Baghouses
- Engineering Studies in Particulate Control
- Postcombustion NO_x/SO_2 Reduction

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Interest Categories
Air emissions control
Air toxics measurement and control
Emissions monitoring
Fossil steam plant performance optimization

Key Words
Nitrogen oxides
Flue gas desulfurization
SO_2 control
Air toxics control
Particulates
Continuous emission monitoring

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Monday, August 25; 8:00 a.m.
Opening Plenary Session

APPLY PRINCIPLES OF INDUSTRIAL ECOLOGY TO MANAGE EMISSIONS

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Abstract

Considering a powerplant as more than a fuel-to-electricity station can raise its economic value to its owner and the community at large and solve emissions and discharge problems more holistically. The emerging field of industrial ecology offers a set of organizing principles to do this. This paper reviews the basis for industrial ecology and specifically its relevance to solving problems in the removal of particulates, SO2, and NOx from powerplant flue gas. Highlights from one successful example of industrial ecology worldwide is provided, along with references to regulatory and technical developments.

Introduction

Chemists talk of atomic "bonds" between and among elements. Social scientists speak of social bonds among people, families, communities, and political entities. The financial and business community use bonds as a binding agreement for payment of taxes or money owed. Ecologists talk of bonds in nature, such as how the food chain bonds different species together.

Deregulation and competition is causing the traditional bonds within the power industry to break down. The reactions which are resulting are traumatic for some but opportunistic for many. With both directed (regulated) and non-directed (so-called free market) components, the industry is also at the same time being re-arranged.

Industrial ecology offers all professionals involved with emissions control, and non-professionals concerned about the environment, a new set of organizing principles to manage emissions control with competitive operation. Importantly, this set of principles, in my estimation, ultimately will help interest groups focused on environmental control—including

regulators, technology and equipment suppliers, scientists and the R&D community, economists, and the environmentalist advocacy groups—to approach problems within a framework that all can understand.

Most importantly, is that the concept of industrial ecology is fully compatible with the competitive direction of the industry, although it may not appear so. Some even broaden the phrase to the "business ecosystem," to describe how companies compete and cooperate—much like organisms and species do—on many different levels to achieve profitability. James Moore, in The Death of Competition: Leadership Strategies in the Age of Business Ecosystems, advocates such an view of the business world[9].

What is industrial ecology?

In its simplest form, industrial ecology, which some might construe as a contradiction in terms, is a set of design and operating principles patterned after what goes on in nature, where connections among organisms see to it that raw materials and waste materials are used efficiently. Similarly, industrial processes should not be considered in a vacuum but relative to other processes that can feed and support each other, especially in terms of recycling materials that otherwise "pollute" the surroundings in some way.

As a field of study, industrial ecology is emerging, evidenced by the new *Journal of Industrial Ecology*, which began publication this year[3]. The publication is a joint effort of Massachusetts Institute of Technology and Yale University. Many magazine articles have appeared recently, the nation's laboratories and academic institutions are initiating industrial ecology programs, and industry appears to be taking note.

But activities embodied by industrial ecology didn't just appear. Industrial ecology is found in other "paradigms," such as sustainable development, life-cycle economics, the "industrial park," holistics or holism, integrated environmental management, industrial symbiosis, and others. Many powerplant design and engineering concepts that are commercially applied today are components of industrial ecology. The phrase simply provides a more convenient, or perhaps more complete, means of not only pursuing ideas that balance economic progress and environmental impact, but to *communicate* these efforts as well.

The phrase has particular meaning with respect to the debate between "environmentalists" and industry. It pairs a form of the word industry, the "enemy" of environmentalists, with ecology, perceived by environmentalists to be the "victim" of industry. Pairing the two words connotes a greater sense of interaction, even harmony. For a long time, this industry has needed something like industrial ecology to properly describe its considerable efforts

in protecting the environment and recycle waste materials while still delivering the electricity everyone demands.

In a more subtle way, the phrase industrial ecology implies, as it should, that everything, whether "industrial" or "natural" begins and ends in the earth. It does away with the false notion that things "industrial" are somehow less than things natural or "ecological."

Just as so-called natural ecological systems are constantly adapting to changing conditions—higher than normal rainfall, disruptions to the size and number of species, nutrient levels, sunlight, etc—industrial ecology is a way to understand that industrial systems constantly adapt, too. And, perhaps most importantly of all, our surroundings have a keen ability to adapt to the changes wrought by industrial activity. Industrial ecology acknowledges the existence of this ability to adapt, though not the magnitude of this capability.

Analogies to other areas. Another way to understand the concept of industrial ecology is to relate it to the concept of quality. American manufacturing has been pursuing vigorously for at least a decade the ISO (international standards organization) 9000 certification process for product quality. This is also a set of organizing principles, a certain set of procedures a company or a site follows to ensure the quality of its products for its customers worldwide. ISO9000 doesn't specify that the product's quality actually will meet some specific value. Rather, it defines work and management processes, inspections and oversights, and quality control programs that certainly raise the chances that product quality specifications will be met. And it forces all firms to achieve a minimum level of quality performance—table stakes, if you will, to do business in the worldwide market.

In the same way, industrial ecology doesn't necessarily define the SO2, NOx, or flyash emissions standards that a site must meet or the technologies used to meet them. Rather, it can provide a framework for achieving a more practical site-specific, local, and/or regional balance among them.

The need for a new set of organizing principles is acute for other reasons. One, germane to the goals of flyash, NOx, and SO2 reduction, is that, as lower emissions levels are sought for specific pollutants, the impact on the others may grow. One perfect example of this is the application of low-NOx burners to NOx reduction. The impact of low-NOx burners on carbon levels in flyash is by now well-known. But the *economic and ecological impacts* from huge volumes of flyash unfit for recycle is only now being discovered. Another example is the huge volumes of scrubber byproducts that had to be managed as a result of tight restrictions on SO2 levels.

The recent regulatory emphasis on so-called air toxics alone signifies that environmental regulation and management must now govern smaller and smaller volumes of potential pollutants. As people become more informed and aware and society more advanced, less pollution of any form is tolerated. But a society can also advance in terms of understanding of the relative levels of different pollutants, their true, measurable impact on the environment, and so on.

History has shown that proscriptive, command and control, single-pollutant regulatory strategies and subsequent compliance efforts, have often simply transferred the problem elsewhere or created new environmental management problems. Often these residual problems were anticipated and solutions readied, but institutional barriers prevent these solutions from being implemented. In addition, the one-pollutant regulations are written such that competition among technologies is not fostered.

The fact that limestone-based flue-gas desulfurization (FGD) captures 90% of the domestic market—and appears to be capturing a similar share of the world market—suggests that competition among technologies is lacking, and incentives to apply potentially better technologies is non-existent. That switching to low-sulfur coal, which has significant impacts on other emissions and waste streams, as well as on powerplant efficiency, proved to be the compliance method of choice for phase I of the Clean Air Act is another indicator that more holistic approaches to emissions control should be encouraged.

If low environmental impact, low-cost electricity, and a generation sector that can attract private investment on a profit basis (not a regulated rate of return basis) are going to be simultaneously attained, new regulatory regimes are clearly necessary.

Another good reason for applying industrial ecology takes a business slant. I believe that the nation's largest coal-fired power stations will become more than electricity generators in a competitive marketplace. These facilities are economic anchors in their communities. Because they encompass vast tracts of land, have rail and other transportation access, and generally have the necessary industrial infrastructure, they will become centerpieces for new industrial concepts—perhaps industrial parks—that may best be governed by industrial ecology-based regulation.

Whatever regulations are passed at the federal level, states and regions will have to protect indigenous industries and their tax base. So, as one example, if states in New England do not want to build new power stations, then the Midwest with its own coal and access to western coal may become an electricity producing center for the nation. A fitting analogy here is the natural gas industry in based in Texas. Texas' gas is transported all over the

country. Midwest and other low-cost sources of coal-based electricity may experience a similar fate. And states and regions will encourage regulations that allow economic development to coalesce around these facilities. The principles of industrial ecology could help govern the new bonds that are likely to form between states dependent on coal for their economies, coal companies, and electricity generators.

Examples of Industrial Ecology

Industrial ecology is a broad framework. But specific acts of industrial ecology have been undertaken in the power industry for decades.

Flyash. Coal-fired plants have been recycling flyash into cement and concrete markets for decades. That's an example of industrial ecology—a "waste" material from one industrial process is recycled into another. For the most part, though, this has been a secondary, perhaps tertiary consideration and priority for most of these plants. When the principles of industrial ecology are applied, equal emphasis will likely be placed on this recycle stream.

When you consider that plants are searching for new revenue streams in a competitive business arena, you can quickly understand that the *incidental* production of flyash at a coal-fired station becomes the *deliberate* production of a raw material for the cement industry which requires that material within certain quality tolerances, seasonal volume ranges, and so on.

Now take this a step further and think about the "bonds" mentioned earlier in this paper. Perhaps the bond between generation and transmission weakens as plants operate as independent profit or business centers. But perhaps the bond between a large coal-fired plant owner/operator and a cement company grows. Or the bond between the "new" utility industry and the cement/concrete industry as a whole. In fact, I would argue that the bonds among cement producer, coal producer, and power generator are more logical than that between generator and transmitter. As one symbiotic idea, coal companies can backhaul flyash to cement producers which may extend the economic radius of flyash recycle.

For those involved in the design, selection, operation, and maintenance of electrostatic precipitators, fabric filters, and other devices for collecting flyash, industrial ecology suggests that you think of your product in terms of (1) helping your "customer" produce the highest-quality flyash possible and (2) providing a third-party service for your customer that solves both the collection and recycle problems. A few emissions control process suppliers are already using this "third-party" model. Although unsuccessful to date, the probabilities of success should be greater when the proper motivation and incentives are in place.

Water. Perhaps the most comprehensive application of industrial ecology principles at powerplants today involves water. New powerplants being built today source their water not from clean lakes, streams, and rivers, but from nearby industrial facilities or the municipal waste water treatment plant. Some plants report that they take water from polluted streams and outfalls and in the process of using it and cleaning it up to meet discharge requirements, return it far cleaner that it was originally. Granted, some of it may be returned as through a cooling tower vapor, but it is still returned to the water cycle.

Other examples. Examples abound in the industry of the partial application of industrial ecology:

- Recovery of powerplant flue gas CO_2 for food-grade applications. At least three powerplants in the US recover CO_2 from a small percentage of flue gas so treated.
- Use of a byproduct of nylon manufacture to enhance the absorption efficiency in SO_2 removal systems.
- Ammonia-based FGD systems which result in valuable fertilizer materials. This FGD process is now poised to compete with limestone/lime-based processes and several suppliers are eyeing the worldwide market.
- Use of FGD gypsum in wallboard manufacturing and/or stabilized FGD waste in road-building and other civil construction projects.
- Applying an integrated coal gasification combined cycle (IGCC) process and recycling the slag and sulfur and perhaps even producing methanol or other chemicals on the front end (what has been called the 'coal refinery').
- Raising energy crops (fast-growing trees) that can serve as biomass fuel to sequester carbon and regulate CO_2 buildup.
- Combining front-end recycling operations—ferrous, glass, and aluminum recovery—with a municipal-refuse waste-to-energy/electricity plant.

Each of these examples of industrial ecology at work has obvious business analogies that may help powerplants find new revenue streams and bond with new business partners in the competitive environment.

New regulatory structures needed

Industrial ecology suggests that regulators consider a more holistic approach to compliance with emissions limits. Is simply stipulating a limit at the powerplant good enough? How about some form of credit to those who properly recycle flyash into new products? Perhaps that credit could consist of a break on the limit specified in the permit for that plant. In other worlds, encourage a plant to recycle its flyash by being more lenient on the limit that plant has to meet, or by being lenient on a separate pollutant limit. Another alternative is to grant a credit of some form to those who use wastes productively.

One reason why so-called "integrated" or multi-pollutant control initiatives and technologies languish is because regulations are built up around single pollutants in specific industries. And, not to be neglected, bureaucracies within regulatory agencies, and product lines within environmental control companies, are constructed in the same way. Returning again to the concept of "bonds," it is clear that industrial ecology may help us break some bonds holding together antiquated ways of regulating industry and developing products and technologies to meet those regulations.

In recent years, EPA has attempted to pilot regulations based on a site-wide permit for several pollutants. It was tried in the pulp and paper industry and has been discussed for the power industry. These initiatives have often been viewed with suspicion by industry as guises for greater regulation. But they should be applied—and hopefully accepted—as prescriptions for more *balanced* regulation, not more regulation.

Combine with externalities. Today, less discussion seems to emanate from the industry about the so-called environmental externality—the idea of placing some monetary value on the damage or environmental impact of pollution and discharges. The economics for virtually any industrial process change if externalities are factored in. How that damage is assessed and valued is a separate complex subject that cannot be addressed here. But clearly the externality concept plays well with industrial ecology. Externalities would, for example, help government justify and reestablish taxes and subsidies to pursue environmental goals.

Externalities, combined with risk assessments, also help us understand the tradeoffs among different environmental control objectives. Rather than simply pursue the often destructive and unrealistic goal of "lower is better," regulators could in fact support new concepts that, for example, allow one pollutant to be discharged at a higher level in one location, in exchange for a lower limit in a region more severely impacted by that particular pollutant.

The idea, after all, is to protect the environment and public health. The goal of environmental regulation is <u>not</u> to see how low an industry can go with reducing emissions, or to add burdensome costs onto industry at a time when global competitiveness can be precarious and fleeting. I think most of us, at the end of the day, would agree that the protection of public health from a 9-ppm NOx limit on a gas turbine is vague at best, and probably not worth the capital costs and efficiency penalties at worst. This is perhaps the most egregious example of a regulatory limit promulgated solely on the basis that lower is better.

But without a truly integrated regulatory framework, the principles of industrial ecology will, in the worst case, never work, and in the best case, not live up to their true potential.

Fortunately, agencies are beginning to respond. Although details are not available, at least one report mentions the Interagency Environmental Technologies Office of the federal government and EPA's Design for the Environment Program[10], both of which seem to be pursuing regulatory objectives that could support industrial ecology. Also within the Clinton administration, the President's Council on Sustainable Development, formed in 1993, issued a report that addresses the concepts of industrial ecology and eco-industrial parks[11].The council now has a task force on eco-industrial parks.

EPA also has an initiative called Project XL which seeks to grant regulatory flexibility in exchange for an enforceable commitment by a regulated entity to achieve better environmental results than would have been attained through full compliance with current regulations. Project XL is part of the president's Reinventing Environmental Regulation initiative. Finally, EPA has launched the Clean Air Power Initiative (CAPI) which specifically addresses an approach to rationalize and streamline emissions reductions strategies at power generation facilities. Utilities, in commenting on CAPI, are seeking a "final" rule or at least some certainty over a specified time frame that regulations for NOx and SO2 will not change. Although these initiatives may or may not succeed, or may be viewed by industry as unprogressive, they do indicate that antiquated regulatory philosophies may be changing.

Putting it all together

An underlying feature of industrial ecology is "community." Apart from other challenges in using waste materials, the distance that they have to be transported has always been an economic barrier. Plus, long distance transport consumes more energy, results in more pollution, etc, so, in economic terms, the sense of community becomes identical to the practical economic need for closeness.

Suppose you combine a mine-mouth coal-fired powerplant equipped with an FGD system that produces gypsum with a wallboard manufacturing plant, a cement production plant, and plan for mine reclamation, acid-mine drainage, and so on using ash from the coal. Suppose you also supply other industrial and commercial facilities with steam and/or hot water, chilled water, potable water, and other services. If this industrial park anchored by the coal-fired plant supplies building products to the surrounding community, then transportation of materials is avoided as are potentially higher costs for "imported" raw materials or goods and services. Now you have a community supported by an industrial ecological system, along with the usual social and political support systems.

To some, this sounds like industrial utopia, not ecology. To others, it may be reminiscent of a page from a communist manifesto. But there is at least one real-world situation that approximates the description. That is at an eco-industrial park in Kalundborg, Denmark, which has been written about extensively in the literature[1, 2].

At what is perhaps the rallying point for industrial-ecology enthusiasts worldwide, a 1500-MW coal-fired district heating plant, the Asnaes station, anchors a web of industrial and social concerns. The Asnaes plant supplies steam to heat almost all of the surrounding town of Kalundborg's houses and commercial buildings, 40% of the heat needed by a nearby refinery's tank farm, and all the process heat required by a pharmaceutical manufacturing complex. Gypsum from the plant's FGD system meets two-thirds of the input needed by the local wallboard-maker. Flyash and clinker from Asnaes are sold for use in road-building and cement-making. Process gas once flared at the refinery is burned in the Asnaes boilers, displacing 30,000 tons of coal a year. The refinery sends the powerplant its cooling water, which is treated and used and boiler feedwater. Waste water from the refinery is also used to clean equipment at Asnaes. Other materials are recycled among various industrial facilities in the town.

Importantly, Kalundborg was not hatched as a grand, centrally planned experiment in industrial ecology. Rather, it evolved piecemeal over 25 years and arose from (1) the relative isolation of the town, (2) the social interaction among the employees and managers at the various facilities, (3) increasing pressure to sustain profits under greater environmental regulation, and (4) an atmosphere that apparently fosters constructive negotiation about regulations, not special interests lobbying their Congressional representatives at all hours. Danish regulatory processes seem to encourage the parties to focus on creative solutions rather than fight among each other.

Because of its evolutionary development and implementation, the experience at Kalundborg may not easily transfer to greenfield developments, according to some who have studied the situation[3]. And, of course, Denmark is relatively small, homogenous country and hardly resembles the US situation. Also of strategic interest, the manager of Asnaes has reported that existing economic incentives were sufficient to motivate most of the relationships between Asnaes and other industrial firms. In other words, no deliberate institutional mechanism was necessary to promote the exchanges.

Symbiotic initiatives. The United Nations University, Tokyo, Japan, has launched the zero emissions research initiative (ZERI), funded by the Ministry of International Trade and Industry. According to one source[4], it's objective is to achieve technological breakthroughs that facilitate manufacturing without any form of waste. To date, the efforts do not appear

to be focused on powerplants, but on process industries. In addition, Oak Ridge National Laboratories (ORNL), Oak Ridge (TN) is working with the City of Chattanooga (TN) to set up a zero emissions industrial park but again activities specific to electric production have not been reported to date.

Several years ago, at least one researcher under contract to ORNL, Dale Merrick of Parsons Engineering Science, Oak Ridge (TN), had proposed the R4C process to handle all types of municipal wastes, which includes a waste-to-electricity component. R4C certainly has industrial ecology concepts supporting it even if the phrase is not used within the description of the process[8]. At the Research Triangle Institute, Research Triangle Park (NC), researchers are involved producing a "field book" for developing an eco-industrial park in the US. EPRI has also recently announced initiatives to help its clients reshape generation markets with energy partnerships focused on concepts that certainly could fall under the industrial ecology umbrella. Lawrence Livermore Laboratories also has industrial ecology programs going on[14].

US Examples. Some of the examples of emerging industrial ecology in the US relevant to electricity production include the Great Plains Gasification Complex[5] and two of the integrated gasification combined cycle (IGCC) demonstrations taking place under the DOE Clean Coal Technology Demonstration Program—the IGCC project at Tampa Electric Co's Polk power station[6] and at Cinergy's Wabash River station[7] One plant is a greenfield site, one is a repowering of an older fossil unit. Although not a power station, but with directly transferrable experience, Eastman Chemical Co, Kingsport (TN) is producing industrial chemicals from a coal gasifier unit, and recently announced successful operation of an advanced process there.

Finally, it deserves mention that the National Academy of Engineering's National Research Council (NRC), Board on Energy and Environmental Systems is planning a two-day project planning meeting to define issues and develop the scope of a prospective NRC study or activity related to eco-industrial coal-fired powerplants. The National Academy also has published valuable reports on industrial ecology[12, 13].

International focus

An unfortunate paradox of industrial ecology is that the huge developing economies of India, Brazil, Indonesia, and China, facing enormous present or neat-term industrial growth can most benefit from industrial ecology because *everything* is growing—industry, infrastructure, population—and different processes to satisfy that growth could feed off each other more sustainably. At the same time, these countries are growing so fast that planners are unable to contain that growth within the boundaries of a more integrated approach.

Meanwhile growth has slowed in North America, Europe, and Japan, where the principles of industrial ecology are being aired.
Although some countries are striving for more integrated regulatory frameworks, most initiatives are young and require coordinated support from environmentalists and industrial concerns alike.

Challenges abound

Challenges are many in applying industrial ecology, although it is not my intent to focus on them here, but a few deserve mention. One is that a waste material often replaces a naturally occurring one. These natural materials often have extremely low value because of technical efficiencies built up over decades in a particular industry (gypsum is always cited as an example here), low labor costs, and other reasons. Existing industries must protect their own profits and turf. Economically, it may be impossible for recycled material to compete. Also, by their nature, "wastes" are more difficult to control in terms of quality and quantity. Such issues as product quality and inventory management have dogged supporters of industrial recycling for years. Alternate disposal methods are still necessary for when markets go sour. The plant, after all, has to continue making its main product, electricity.

Fluctuations in the prices and supply of recycled materials often make investors skittish. These effects have been amply demonstrated in recent years in the municipal-waste recycling markets—newspapers, plastics, ferrous, aluminum, and glass. Others have noted that industrial wastes are often poorly characterized, although recently several waste exchanges have sprung up to address this challenge.

Summary

Industrial ecology is a set of organizing principles, a new way of thinking, a common frame of reference for parties to the debate to gather around. It is not a solution to any emissions control problem. It is not, to use a well-worn word, a panacea. Nor should it be construed as a mandate for all-embracing centrally planned regulatory initiative. The principles of industrial ecology can, however, be used to help reconstruct environmental regulation in a more holistic fashion, develop new revenue streams and business units, and protect the environment and public health without sacrificing competitive electricity production economics.

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SO_2 AND NO_X COMPLIANCE OF NEW ENGLAND POWER CO'S COAL FIRED UNITS

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Abstract

New England Power Company (NEPCo) brought six coal units at two fossil generating stations into SO_2 and NO_X compliance in 1995 and has continued to maintain compliance and improve unit performance.

This paper focuses on the coal fired units and outlines regulations which required SO_2 and NO_X emission reductions, discusses the planning, strategic decisions and the multi-functional team approach, and reviews the operational results.

Coal fired units, environmental enhancements included Low NO_X Burners (LNB) with and without Overfire Air, Gas Co-Firing, Selective Non-Catalytic Reduction (SNCR) Controls, Flue Gas Conditioning Systems (both Conventional and EPRICON), Precipitator Improvements and Pulverizer Replacements.

Introduction

New England Power Co's Fossil Generating Stations have had the unique experience of requiring air quality environmental compliance in SO_2 and NO_X prior to most of the U.S. and most foreign countries. Therefore, New England Power Company (NEPCo), the wholesale electric generating company of New England Electric System (NEES) and New England Power Service Company (NEPSCo), a service company that provides engineering, construction and environmental services to the affiliated NEES subsidiaries, have gained considerable experience in strategic planning, technology evaluation and selection and project implementation, and are continuing to gain system operational experience in pollution control systems.

This compliance program involved both Brayton Point and Salem Harbor Stations. Each station has three coal fired units. The unit characteristics for these coal fired units are provided in Table 1.

Regulations

The regulations which resulted in these requirements included the Massachusetts Acid Rain Law and U.S. Federal Clean Air Act Amendments of 1990.

- Sulfur Dioxide (SO_2). The Massachusetts Acid Rain Law required environmental compliance with sulfur dioxide (SO_2) regulations starting in 1995. The law required that Brayton Point and Salem Harbor Station (Massachusetts) units have a compound annual average SO_2 emission rate of 1.2 Lbs/MMBTU or less. In effect, the Massachusetts regulations requires early compliance with year 2000 federal acid rain requirements.

- Nitrogen Oxides (NO_X). Title 1 of the Clean Air Act Amendments (CAAA) of 1990 required that areas out of compliance with National Ambient Air Quality Standards (such as ground level ozone) develop a strategy to obtain compliance. In general, much of the eastern United States and a large portion of New England is in non-compliance for ground level ozone, a primary cause of summer smog. The two precursors for ground level ozone are Volatile Organic Compound (VOC) and Nitrogen Oxides (NO_X) emissions. In Massachusetts, utilities contributed less than 1% of the VOC emissions but about 30% of the NO_X emissions. The Federal and State Regulatory Agencies determined that significant power generation sector NO_X reductions would be required to obtain ozone compliance with the National Ambient Air Quality Standards. One of the steps in the attainment process was that all fossil fired generating units in Massachusetts should meet Reasonably Available Control Technologies (RACT) standards for NO_X emissions by May 31, 1995.

Compliance Approach

The overall compliance effort occured in two phases. Planning for compliance with the Mass Acid Rain Regulations began first. The overall SO_2 Compliance Strategy was developed in the late 80's and the projects were installed in the early 90's. NO_X Reduction studies and evaluations were also ongoing during this time frame. In 1992 the Massachusetts RACT Regulations were starting to take shape and NEES began the focused effort of attaining NO_X Compliance by May 31, 1995.

These two compliance efforts were conducted in a similar manner, using the same overall philosophy directed by in house program teams. Both compliance programs involved four major areas which are outlined as follows:

- Planning - At the onset NEES' management made it clear that 100% compliance was the corporate objective. Multifnctional corporate teams were established to evaluate the alternatives, develop comprehensive plans, evaluate plans on base assumptions and possible scenarious and finally setting strategic direction.

- Approvals - The multi-function team set the strategic direction and the program team developed the detail implementation plans. NEES management approved the overall plan on a conceptual basis allowing the program team the flexibility to adapt to continuously changing challenges. Regulatory approval was enhanced by reviewing the overall program approach up front with our regulators.

- Project Implementation - Multi-department project program teams were established and met on a bi-monthly basis at the stations to coordinate the many ongoing projects. The program team had a program manager, a management advisory group and representatives from all the major functions. Each project was assigned to a project engineer/manager who reported on the project progress at the coordination meetings. Having all departments represented allowed issues to be addressed in a

comprehensive fashion. The meetings focused on major issues and assigned responsiblity to resolve details.

- Operations - Given that the overall objective of the program was successful compliance through project operation, therefore, there was considerable emphasis on testing, training and operation. For example, compliance coal testing started more than three years before SO_2 compliance was required.

SO_2 Compliance

The Massachusetts Acid Rain Law required that the SO_2 emissions from Massachusetts fossil fired units not exceed 1.2 Lbs per million BTU's starting January 1, 1995 (see Table 2). Strategic planning began at NEES in the late 80's leading to the most effective strategies to comply. Numerous scenarios were evaluated using various sensitivity factors to ensure a robust solution. The strategic decision was made to comply with Massachusetts Acid Rain Law through the use of compliance fuels. Plant improvements were required to insure success burning of the compliance coals. These improvements included pulverizer replacements, flue gas conditioning and precipitator enhancements.

- **Pulverizer Replacements.** The SO_2 compliance strategy recommended replacing the Brayton Point Units 1&2 pulverizers to allow burning lower cost, harder, compliance (low sulfur) coals. Brayton Point Unit 3 was already equipped with B&W MPS Mills (harder coal capable) which allowed Brayton Point Station to convert to the more agressive compliance coal specification. This decision was based on the Fuels Department analysis of extensive sources of the world wide coal market which determined that significant fuel savings could result due to domestic and international low sulfur coals. The Pulverizer Replacement Projects were completed in 1992. The existing CE 1960 vintage Bowl Mills were replaced with ABB/CE HPS Exhauster Mills. The pulverizer replacements opened up new fuel markets for Brayton Point Station which began testing compliance coals in 1992 and is currently burning a wide variety of compliance coals.

- **Fuel Characteristics.** Both Brayton Point and Salem Harbor receive coal by ocean going ships. The Fuel Department cost effectively purchases a wide variety of compliance coals. The sources of coal are from both domestic (West Virginia, Kentucky and Virginia) and international (Columbia and Venezuela) coal sources. These coals have a wide variety of properties. Table 3 provides the range of coal properties burned at these stations.

- **Precipitator Enhancements & Flue Gas Conditioning.** The low sulfur coals resulted in anticipated changes in fuel characteristics (resistivity) which can result in less efficient precipitator collection efficiency. To insure precipitator performance, the Brayton Point coal unit precipitators control systems were enhanced, the Unit 3 original precipitator was rebuilt, and NEPSCo evaluated Flue Gas Conditioning Systems. NEPCo evaluated Flue Gas Conditioning industry options and sulfur trioxides (SO_3) injection was selected as the system to insuring optimum precipitator performance. NEPCo worked with EPRI and installed a new process called EPRICON on Brayton Point Units 1&2. The EPRICON process uses a side stream of flue gas to produce the SO_3. The flue gas side stream is run through a catalyst which converts SO_2 to SO_3 and distributes the SO_3 back into the main flue gas flow. This was a first of a kind installation and has provided very effective control at Brayton Point Station. A conventional SO_3 conditioning system was installed on Brayton Point

Unit 3 to insure precipitator performance.

- **SO_2 Compliance Results.** Starting in 1995, the Massachusetts Acid Rain Law required the Brayton Point and Salem Harbor Units to achieve a compound annual average SO_2 emission rate of 1.2 lbs per MMBtu or less. Meeting this Massachusetts requirement will put NEPCo SO_2 emissions roughly in balance with the SO_2 allowances to be received from the EPA in the year 2000. Brayton Point and Salem Harbor Station significantly reduced their emissions of sulfur dioxide (SO_2) from historic levels. For both 1995 and 1996 the annual average SO_2 emission rate was less than 1.1 Lbs/MMBTU's for the coal fired units.

NO_X Compliance

Plans for NO_X controls of the fossil generating stations started in the late 80's and continue into the 90's. The 1995 NO_X compliance plans encompassed a number of different NO_X control strategies. The Massachusetts RACT Regulations allowed four different methods of compliance. NEES evaluated all four compliance methods in detail and elected to comply with the Generic Limits. This method provided the most stringent NO_X Limits but provided the most straight forward regulatory approval process. The Generic RACT Limits for coal fired units are .45 and .38 Lbs/MMBTU for wall fired and tangential fired boilers respectively. The NEES units with the RACT Limits and other more stringent Regulatory Limits are provided in Table 4.

NEES selected a variety of control strategies and manufacturers to suit the specific unit requirements. In general, there are three basic types of NO_X controls which include pre-combustion, combustion and post-combustion. NEPCo developed considerable expertise in all three methods of NO_X control in the compliance efforts.

- **NO_X Pre-Combustion Controls.** Pre-combustion NO_X control primarily consists of fuel changes. For the three major fuels, the uncontrolled emission rates vary by fuel with natural gas having less uncontrolled NO_X emissions than either coal or oil. NEPCo provided the three coal fired units at Brayton Point Station with natural gas co-firing to allow enhanced start-ups and operational flexibility which can be translated into both NO_X and SO_2 reductions. When cofiring natural gas which has negligible sulfur, the SO_2 emission reductions are directly related to the percent of natural gas fired. NO_X reductions on the other hand are an in-furnance emission reduction process which is more complex and, unit specific. To evaluate the potential for seasonal NO_X controls extensive gas cofiring was conducted on the Brayton Point coal units, and the results are reviewed later in this paper.

- **NO_X Combustion Controls.** Combustion controls included Low NO_X Burners with and without overfire air. NEPCo has installed Low NO_X burners in five of the six units using three different manufacturers (ABB CE, B&W, and Riley Stoker) with the sixth unit being retrofit with burner components to achieve partial NO_X reduction. The low NO_X burners combined with overfire air achieved greater than 50% reductions.

- **Post Combustion Controls.** NEPCo was first in the nation to use Selective Non-Cataytic Reduction (SNCR) controls on coal fired boilers. SNCR which consists of injecting chemicals

(Urea) into the upper portion of the furnace to react with and to reduce the NO_X in the flue gas. SNCR Systems were installed on the three coal fired units at Salem Harbor Station and when combined with low NO_X burners, they achieved approximately a 70% NO_X reduction from the 1990 baseline levels.

- **Gas Co-Firing.** A gas co-firing development project jointly sponsored by the Electric Power Research Institute (EPRI), The Gas Research Institute (GRI), New England Power Company and Energy System Associates (ESA) was conducted on the three Brayton Point Coal Fired Units. Brayton Point Units 1&2 are subcritical units with tangentially fired twin furnaces. The units were retrofitted with ABB CE Low NO_X concentric firing system (LNCFS) Level III with close coupled overfire air (CCOFA) and three elevations of separate overfire air (SOFA). The Low NO_X burner retrofit included gas ignitor and upper level gas burners. Ignitor co-firing testing provided a 12% reduction in NO_X emissions when firing 10% natural gas.(1) The upper furnance gas burner reburning of NO_X emissions was hampered by insufficient natural gas jet penetration into the furnace. Improvements in the gas penetration are in review and include gas burner modifications and the use of a gas carrier.

  Brayton Point Unit 3 is an opposed wall-fired Babcock & Wilcox (B&W) designed supercritical boiler. The unit was retrofit with B&W DRB-XCL Low NO_X Burners and separated overfire air. The Low NO_X retrofit included gas variable heat input ignitors at each burner capable of providing up to 10% of the units heat input. Brayton Point Unit 3 also had a CO limit of 200 ppm which limits the reduction in excess oxygen. The gas co-firing was found to have a significant positive benefit on CO emissions reductions. As little as 2.5% gas co-firing mitigated or eliminated the high CO peaks.(2) The improved CO emission characteristics allowed reduction in the oxygen levels, which resulted in NO_X reductions. Demonstrated reduction of NO_X were achieved in the 5 to 10% range using gas heat input at or above the 2.5% level. Seasonal NO_X reductions will be required in Massachusetts 1999 and gas co-firing is one of the control options that will be considered for additional NO_X reductions.

NO_X Results. Since May 31, 1995, the RACT Compliance date, there have been significant NO_X Reductions in all of NEPCo coal fired units. Some of the major improvements include:

- 100% compliance with NO_X Emission Limits (enforced on a 24 hour average) for the six coal fired units.

- Overall NO_X Reductions of greater than 65% from Brayton Point and Salem Harbor coal units 1990 Baseline NO_X Emission rates.

- Currently 70% NO_X Emission Rate Reductions from Brayton Point Unit 3, a supercritical unit.

- 70% NO_X Emission Rate Reductions from Salem Harbor Units 1, 2 & 3 using the combined NO_X reduction technologies of Low NO_X Burners and Selective Non-Catalytic Reduction.

- "No Visible Stack Emissions" at Brayton Point Station. The station has gone from visible plumes to no visible signs of the coal unit operations.

- No detectable waterwall wastage due to Low NO_X Burners after more than two years of service for all six units.

- Cost effective NO_X reductions at approximately $400/Ton of NO_X removed.

Summary

The SO_2 and NO_X Compliance effort has been and continues to be very successful due to the dedication and commitment of all at NEES to 100% environmental compliance. A summary list of the projects implemented in this program is provided in Table 4 and graphly displayed in Figure 1.

Acknowledgements

There were numerous NEES engineers, construction workers and managers, outside vendors, manufacturers and supporting firms which contributed to the successful SO_2 and NO_X compliance efforts at NEES' Brayton Point and Salem Harbor Stations.

Some of the many NEES departments involved in the Clean Air Projects include: Generation Operations, Power Engineering (Mechanical, Civil, Controls and Electrical Engineering and Design), R&D, Fuels, Generation Marketing, Load Forecasting, Environmental and Safety, Generation Services Construction (Mechanical, Electrical, Structural, Environmental Services and Construction Coordination), Purchasing, Legal and the Station's management, operations and maintenance personnel.

The final acknowledgement is to NEES' executive management which provided the solid commitment and resources to achieve and maintain compliance and to the Massachusetts Department of Environmental Protection (DEP) regulators who worked to insure timely implementation of this program.

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Table 1

Brayton Point (BP) & Salem Harbor (SH) Unit Characteristics

Station / Unit	Net Capacity (MW)	Primary Fuel	Boiler Manuf.	Type Firing	No. of Burners
BP 1	245	Coal	CE	Tangential	32
BP 2	245	Coal	CE	Tangential	32
BP 3	626	Coal	B&W	Opposed	40
SH 1	81	Coal	B&W	Wall	12
SH 2	78	Coal	B&W	Wall	12
SH 3	145	Coal	B&W	Wall	16

Table 2

SO_2 Compliance Requirements & Actual Emissions

Combined Brayton Point & Salem Harbor Coal Units			
1990 Baseline Limit		2.4	Lbs/MMBTU
1995 Regulatory Limit		1.2	Lbs/MMBTU
1995 Actual Emissions		1.09	Lbs/MMBTU
1996 Actual Emissions	-	1.07	Lbs/MMBTU

Table 3

Range of Coal Properties

Properties	Range
Moisture (%, As Received)	6 - 12
Fixed Carbon (%)	45 - 54
Ash (%)	8 - 12
Volatile Matter (T)	26 - 36
Nitrogen (%, Dry)	1.2 - 1.7
Sulfur (%)	.6 - .8
Heating Value (Btu/lb)	12,000 - 13,500
Grindability Index (HGI)	42 - 55

Table 4

NO_x Compliance Requirements and Actual Emissions

Station/ Unit	Primary Fuel	NO_x Emissions (Lbs/MMBTU)			Percent Reduced from Baseline
		1990 Base	Regulatory Limits(1)	1996 Annual Average	
BP 1	Coal	.7	.38	.30	57%
BP 2	Coal	.7	.38	.32	54%
BP 3	Coal	1.4	.45	.38	73%
SH 1	Coal	1.0	.33	.30	70%
SH 2	Coal	1.0	.33	.30	70%
SH 3	Coal	1.0	.33	.30	70%

Note:
1. Based on a regulatory agreement Salem Harbor Units 1, 2 & 3 had NO_x Emission Limits below the RACT Limits of .45 Lbs/MMBTU.

Table 5

SO_2 & NO_x Compliance Technologies for Brayton Point & Salem Harbor

	Primary	Fuel	Furnace Controls		SNCR	SO_3	Other
Unit	Fuel	Modifications	LNB	OFA	Control	Cond.	Controls
BP 1	Coal	LSC/GCF	X	X		X	
BP 2	Coal	LSC/GCF	X	X		X	
BP 3	Coal	LSC/GCF	X	X		X	(1)
SH 1	Coal	LSC	X		X		
SH 2	Coal	LSC			X		(2)
SH 3	Coal	LSC	X	X	X		

Key:

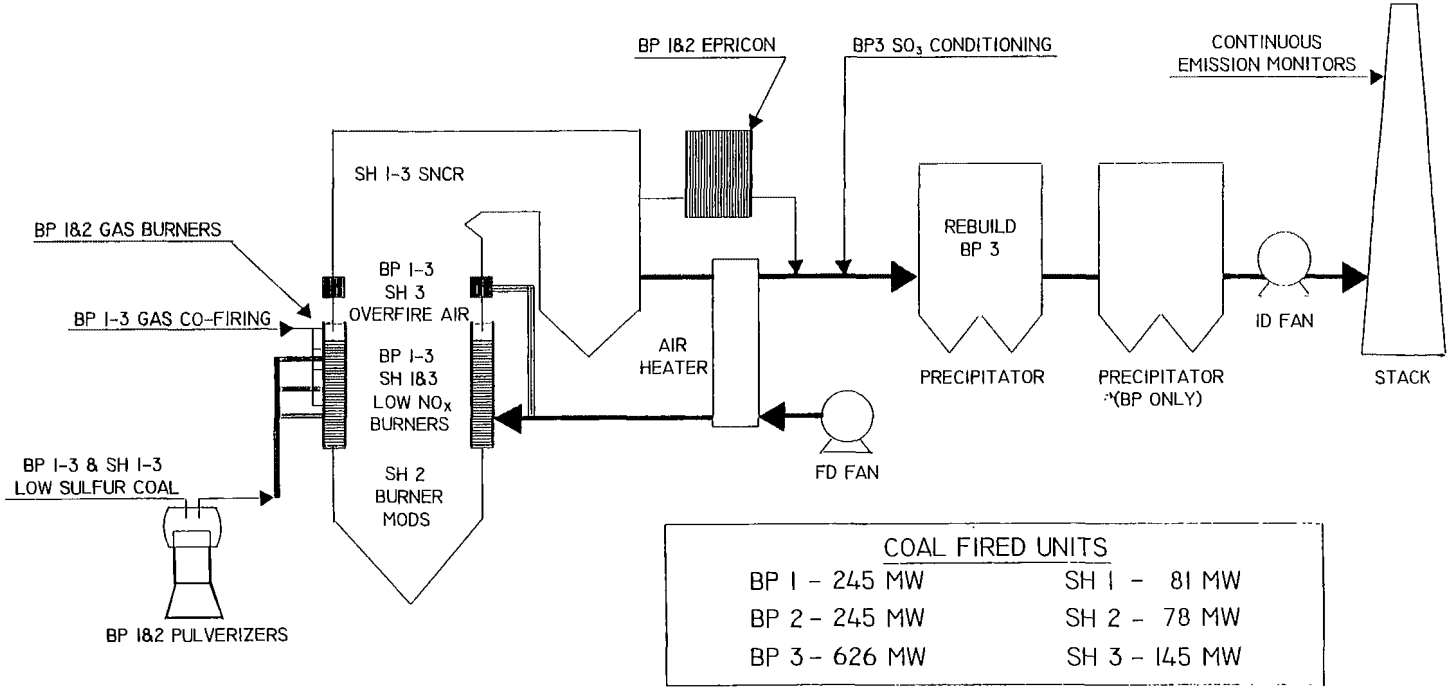
LSC	Low Sulfur (Compliance) Coal
GCF	Gas Co-Firing
LNB	Low NO_x Burners
OFA	Overfire Air (Separate)
SNCR	Selective Non-Catalytic Reduction
SO_3 Cond.	Flue Gas Conditioning with SO_3 System

Notes:

1. The original Unit 3 precipitator was rebuilt. The unit has an original precipitator in series with a new precipitator installed as part of a late 1970's coal conversion.
2. During normal maintenance the coal nozzles and coal spreaders were replaced with the updated Riley Low NO_x design.

FIGURE 1

BRAYTON POINT AND SALEM HARBOR STATIONS COAL FIRED UNITS "SO_2' AND "NO_X" CONTROLS



COAL FIRED UNITS	
BP 1 - 245 MW	SH 1 - 81 MW
BP 2 - 245 MW	SH 2 - 78 MW
BP 3 - 626 MW	SH 3 - 145 MW

Planning for NO_x Emission Regulations via EPRI's CAT Workstation

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As the EPA and the states struggle to address existing and proposed ambient air quality standards for ozone and particulates, electric utilities must prepare for a very uncertain future. Regulations could take many forms in the future, ranging from unit-specific emission limits to plant, non-attainment, state-wide or system-wide bubbles to emissions trading. Utilities are, therefore, faced with a myriad of choices ranging from the exact value of a system-wide NO_x emission limit to which control technology is appropriate for a particular unit.

To further compound utility planning problems, industry restructuring looms on the horizon. For some sites, a project which is economical from a system perspective could damage a particular unit's ability to compete in a restructured industry. For this reason, it is critical to evaluate the assumptions and scenarios that drive decisions.

Questions of whether units would be retired, what new generation facilities need to be built, and how current unit loading regimes will change in the future need to be addressed. The centerpiece of the evaluation is not only what is the lowest cost and most practical way to meet a new NO_x emission limitation, but also what are the key uncertainties and assumptions that drive decisions.

The issues of NO_x transport and its contribution to ozone formation and transport are complex. These issues have been and are now being addressed in other forums. Therefore, this paper does not touch on these issues, but does address the impacts of stricter NO_x emission standards.

In 1996, Entergy Services embarked on system-wide assessment of NO_x control technologies and their attendant costs. The goal of this initial assessment was to identify the major contributing units; establish reduction requirements associated with three potential system-wide emission rates; define cost impacts to meet the potential emission rates; and promote a framework to focus

resources in the future to refine control technology capabilities, impacts and cost estimates on an individual unit basis. In essence, this initial assessment would frame the issues and point a direction for future analysis.

In order to perform this initial assessment and recognizing the large number of units and control technology combinations, it was necessary to utilize a computer model which would meet assessment budgets and schedule constraints. To that end, we found EPRI's Air Emissions CAT Workstation™ to be a perfect fit for the assessment's needs.

Unit Characterization and Setup

The assessment began by characterizing each of the 54 fossil-fuel fired units in Entergy's system. This characterization involved identifying each unit's projected rate in generation over the next 12 years. Essentially, units were classified as either active or inactive. Although the assessment concentrated on the active units, the system-wide database developed included the inactive units. This inclusion of inactive units provided for future flexibility should generation planning evolve into a different base scenario. For each unit, projected annual capacity factors were established as well as bi-hourly loading regimes on a four season basis. The primary fuel for each unit was then designated and unit heat rate curves from 10 to 100 percent were developed. Next, unit NO_x emission rate (lb/MBtu) versus unit load curves were created from the Acid Rain CEMS data.

With the unit technical data developed, the next step involved identifying the economic parameters upon which the analyses would be conducted. These parameters were levelized fixed charge rate, pre-tax discount rate, general escalation rate, replacement capacity and energy charges, fuel cost and escalation, and the unit's remaining life. The technical and economic data was inputted to the CAT Workstation.

The CAT Workstation permitted establishing a NO_x reduction profile for each control technology or combination thereof specific to each unit. These reduction profiles were based on the uncontrolled NO_x emission rates over a 10 to 100 percent load range. The reduction profiles were based on generally accepted technology achievable reductions. Reduction rates were decreased as load was reduced, and eventually a minimum sustainable NO_x emission rate, i.e. outlet stopper, was used. The relationships between NO_x, load and control technology reduction levels add great complexity to the analysis. These complexities make NO_x compliance planning far more difficult than Title IV Acid Rain SO_2 compliance planning.

Essential to any assessment analysis is the financial impact of control technologies on a unit-specific basis. This was again established through the use of the CAT Workstation supplemented with recent implemented project costs. This technique gave assurance that economic decisions would be realistic. The Workstation's decision making revolved about making the least cost selection mix of technology and reduction level based on combining average reduction cost ($/ton removed) and annual fuel cost.

Analysis

With unit characterizations complete, technology reduction levels and costs identified, and the system-wide database developed, the analyses can then move forward. In doing so, the first task is to determine the current annual NO_x emissions on a unit-specific and system-wide basis. This is referred to as the "Do Nothing" scenario. This then provides a baseline to evaluate the impact of proposed limitations on NO_x emissions. For example, such proposed system-wide limitations could be:

Case I

- 0.25 lb NO_x/MBtu for coal-fired units
- 0.20 lb NO_x/MBtu for gas- and oil-fired units

Case II

- 0.20 lb NO_x/MBtu for all fossil-fired units

Case III

- 0.15 lb NO_x/MBtu for all fossil-fired units

These scenarios permit one to determine how the unit/control technology mix changes; establishes order of magnitude cost impacts; identifies a need to provide for safety factors so that annual emission limitations are not exceeded; and creates a basis to develop a future work plan that focuses resources in a most cost-effective manner.

With such an overall plan in place, we found that the CAT Workstation identified many critical issues which may not have been readily apparent. These issues can be summarized by the following:

- The NO_x versus load curves are developed through use of CEMS data. In using data over a year's period of time, there can be a significant amount of scatter with variations in the ±20

to 40 percent range from the mid-point curve. Some units may even have variations approaching 100 percent. This creates tremendous uncertainty in any assessment and can almost assure that either excessive emission controls would be applied or that emission limitations would be exceeded on a routine basis. Therefore, each unit should be fine tuned and operate with low excess air in order to minimize and stabilize NO_x emissions, thus reducing data scatter and decision uncertainty.

- For large units, annual capacity factors can change by up to 20 percentage points over a ten-year study period, whereas, small units tend to have consistent capacity factors. It should be noted that generally the more complex and capital-intensive control technologies are applied to large units since they generate more kilowatt-hours over which to spread the capital investment. However, significant reductions in capacity factors will increase the marginal production cost for these units; hence they may be placed lower on the generating dispatch order, further aggravating the situation. Therefore, wherever possible, large unit capacity factors should be maintained at a reasonably constant level.

- In evaluating the impact of proposed NO_x limitations, the time over which the emissions are averaged becomes critical. It was found that annual emission limitations are easier to achieve than seasonal limitations due to a wider variety of unit loading regimes. Typically, the "ozone season" extends from March through October. For many areas of the country, this is the peak generating season where large units have very high capacity factors and peaking units are brought on-line. All of this translates into high NO_x emission rates. When meeting annual emission limitations, one gains flexibility in achieving a specific limit if one can take advantage of relatively low NO_x emissions during the spring and fall.

- It is important to identify those units which most contribute to the system's overall NO_x emissions. One may find that 20 percent of a system's units contribute more than two-thirds of the annual NO_x emissions. These "heavy hitters" then need to be the focus of most of the assessment efforts and refined analysis. The CAT Workstation, therefore, helps to focus engineering resources on critical units.

- The actual NO_x reductions achievable at a unit will be highly dependent upon boiler configuration, design parameters and operating practices. Therefore, before committing to a specific control technology as a function of economic computer modeling, additional investigation and testing work must be performed to establish actual and reliable achievable NO_x reduction levels. Such testing is usually more easily accomplished for combustion-related technologies such as burners-out-of-service or biased firing.

- Although capital cost estimates are within reasonable limits, operating and maintenance costs must be closely examined. We found it most helpful to convert computer model generated values into a $/ton removed basis which provided a better way to adjust them to reflect actual project experiences.

- One must be mindful that there are practical limits to any analysis in terms of the number of unit/control technology combinations to be studied. These limitations can be computer program or time/cost driven. Hence, prescreening of unit/technology combinations should be performed. For example, small, low capacity factor units would not use capital-intensive technologies.

- One may wish to view the model results in terms of a NO_x reduction level and a cost but not necessarily reflecting a specific control technology. For example, if a 40 percent reduction was required, then further site-specific and detailed cost estimates would be developed via additional studies. The study would then focus on which technology (i.e., burners-out-of-service, biased firing, flue gas recirculation, or selective noncatalytic reduction) can meet or better the economic value upon which a decision was made in the initial assessment.

In conclusion, the CAT Workstation is a cost-effective method to performing initial screening of proposed emission limitation and provides focus to further evaluation activities to finalize a compliance plan.

THE COST OF COMPLYING WITH NO_x EMISSION REGULATIONS FOR EXISTING COAL FUELED BOILERS

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Abstract

Utilities are facing many difficult decisions regarding NO_x compliance. The challenge is how to meet these new NO_x emission regulations while simultaneously positioning plants for the competitive marketplace of a deregulated industry.

Complicating these decisions is the uncertainty regarding future NO_x regulations. Title IV NO_x emission limits have been finalized and a number of states in the Ozone Transport Region (OTR) are well along the way of implementing Memorandum of Understanding (MOU) agreements. However, EPA and state implementation of the Ozone Transport Assessment Group (OTAG) recommendations have not yet been finalized.

Although the cost of NO_x reduction alternatives can be well defined, the development of an effective strategy to hit the two moving targets of NO_x compliance and deregulation must be made at some risk. Accordingly, determining the optimum compliance strategy is an iterative process.

Black & Veatch has assisted numerous utilities by providing regulatory insight along with performance, cost, and plant impacts for all major types of NO_x reduction equipment on all major boiler types. This paper summarizes the capital and economic cost results of these coal fueled boilers investigations. To assist in compliance plan development, current and pending emission regulations are also summarized.

Compliance Planning

Developing the cost of compliance has two predominant components: strategy development and technology assessments. Activities associated with strategy development primarily consist of assessing current and likely future regulatory requirements and subsequent systemwide modeling of utility compliance costs. The result of strategy development is the establishment of a specific plan for compliance. Technology assessments consist of establishing the site specific performance and costs of implementing a range of compliance alternatives. The results of these assessments are used as inputs to strategy development activities. As such, a number of questions must by addressed during compliance planning.

Strategy Development:
- What known emission limits must be met?
- What level of future emission limits may have to be met?
- How will compliance costs impact competitiveness in a deregulated industry?
- What is the cost to implement various strategies?
- What is the most cost effective strategy that minimizes future risk?

Technology Assessment (Site Specific):
- What is the performance potential of each alternative?
- What are the impacts to plant operation?
- What is the cost to install and operate this technology?

Regulatory Environment

Federal, state, and regional environmental agencies and groups are in the process of establishing regulations to reduce NO_x emissions from existing power plants. The following is a brief discussion of some major regulatory factors presented to illustrate the present and potential requirements that impact utilities developing a NO_x compliance plan.

Federal Regulations: Title IV NO_x Reduction Program

In response to Title IV of the 1990 Clean Air Act Amendments, the final rules of 40 CFR 76 detailing NO_x emissions reduction requirements for coal fired boilers was promulgated in December 1996. This rule defines the Phase II NO_x emission limits for Group 1 and Group 2 boilers. These requirements are summarized in Table 1. As noted, the emission limits are dictated by the type of boiler. Each boiler type has a technology basis, which is the EPA-selected technology expected to achieve the required NO_x emissions, although use of these technologies to meet the emission limit is not specifically required.

The federal regulations allow multiple power plants to perform emissions averaging among all the units with the same designated representative. Emission averaging consists of comparing the average emission rate of all the units in the averaging plan to the emission rate those same units would average if each unit met the limits listed in Table 1. From this comparison, the plant owner can determine how much systemwide reduction is required and decide how best to achieve these reductions.

These regulations require all power plant owners to submit a NO_x Compliance Plan to the EPA by January 1, 1998, that discusses the proposed plan for complying with the regulatory requirements meeting the regulations. All plans must be implemented by January 1, 2000.

Ozone Transport Region (OTR)

Twelve northeastern states and the District of Columbia, which make up the OTR, signed an MOU in which they agreed to reduce NO_x emissions of utility sources from 1990 levels. The MOU requires that NO_x emissions be reduced by 65 percent for states in the Inner Zone and 55 percent for states in the Outer Zone by the year 1999.[1] Additional reductions of 75 percent in both the Inner and Outer Zones and 55 percent for the Northern Zone are required by the year 2003.[1]

The OTR will not be a uniform code because the MOU calls for the states to develop their own State Implementation Plan (SIP). These SIPs will define NO_x emission limits, trading programs, and emission seasons within that state. These seasons typically require further NO_x reduction during the hot weather months when the impact of NO_x emissions on ozone formation is highest.

Ozone Transport Assessment Group (OTAG)

OTAG is a group of state agency, industry, and environmental organizations from 37 states, including states in the Midwest, South and Northeast. OTAG is organized to evaluate the impact of pollution from upwind states on the air quality of downwind states.

On June 3, 1997, OTAG recommended that the EPA determine an emissions reduction program which would reduce NO_x emissions below that of federal Title IV requirements. While the OTAG recommendation does not specify an actual emission limit, their findings indicate that NO_x emissions from power generation facilities need to be reduced by 55 to 85 percent or to an emission limit of 0.15 lb/MBtu in order to minimize ozone transport. It was also recommended that 12 states, and portions of eight other states, be exempt from any rules developed as a result of the OTAG findings.[2]

By not providing quantitative reduction requirements, OTAG left the EPA with the primary responsibility of developing the emission limits regulations to reduce ozone transport. OTAG's final report will provide the EPA with the detailed emissions and modeling data developed during the OTAG evaluation.

Other Environmental Initiatives

Other environmental activities are also occurring which could result in additional reduction requirements. The Clean Air Power Initiative (CAPI), a program started by the EPA, encompasses the development of a regulatory strategy which would bring consistency to SO_2, NO_x, and mercury emissions for electric power generators. The results of this effort could further reduce NO_x emissions limits. Also, in July 1997 the EPA promulgated final Ambient Air Quality Standards (subject to congressional approval) which revise the standards for ozone and replace the standard for PM-10 with new standards for particulate matter less than 2.5 microns. These regulations have the potential to significantly affect the power industry, especially those facilities in areas with poor air quality.

Utility Deregulation

Along with the environmental activities, the federal government and state governments are implementing alternatives for utility system restructuring and deregulation. The goal of most of these restructuring plans is to reduce the cost of power to the consumer by providing a more competitive environment. Many states, such as Massachusetts and California, have already initiated programs to restructure the utility industry in their state. In addition, several bills which address this issue are currently before Congress. Although each proposal has unique features, they share the following common characteristics:

- Removing the link between generation of power and transmission of power.
- Allowing consumers to choose their power generation provider.

- Addressing how stranded costs incurred by the utilities will be handled in a deregulated market.
- Increasing the role of independent power producers.

Deregulation impacts the development of compliance strategies because utilities that develop cost effective compliance strategies will have an advantage over those utilities that do not optimize their compliance plans.

NO_x Reduction Alternatives

Several alternatives exist for reducing NO_x emissions from coal fueled boilers. The following is a brief overview of the alternatives that have been demonstrated in operation and are commercially available for coal fueled units. These alternatives are typically described as being either combustion or post-combustion control techniques.

Combustion Control

Combustion controls suppress NO_x formation during the combustion process, and include boiler tuning, low NO_x burners, and natural gas reburn.

Boiler Tuning. Boiler tuning consists of operational modifications utilizing the current boiler and boiler auxiliary equipment. Boiler tuning can be implemented on most types of existing boilers to achieve NO_x reductions up to 25 percent. Boiler tuning is attractive because capital investment is either minimal or not required. However, operating costs may increase as a result of more frequent boiler testing and a greater degree of operator and maintenance personnel attention.

Operational modifications may include coal flow balancing, air flow balancing, optimizing flue gas recirculation (if applicable), reduced air preheat, reduced excess air, biased optimizing, or burners out of service. Some tuning contractors attempt to reduce NO_x formation through the use of computational modeling and modification of control setpoints while others provide testing services in an effort to balance items such as coal and air flow. Many methods have proven successful, but tuning contractors do not typically guarantee NO_x reduction.

Low NO_x Burners (LNB). LNBs are available for wall and tangential fired boilers as well as cell fired boilers.

LNBs for wall and tangential fired boilers control the mixing of fuel and air in a pattern designed to minimize flame temperatures and quickly dissipate heat. These burners typically reduce the NO_x generated by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This minimizes the reaction time at oxygen-rich, high-temperature conditions. The construction time for an LNB retrofit is approximately 14 weeks with an outage time of about 8 weeks.

An LNB for a cell burner is somewhat different than those for wall or tangential fired boilers because the burners are too close to allow installation of the standard multi-register burners. Most retrofits involve shifting introduction of the coal from the over/under two burner cell to inject all the coal through the lower burner. The upper burner is then converted into an overfire air (OFA)

port. Another method to retrofit LNBs onto cell fired units is to increase the space between the close coupled cell burner and install a standard LNB. This alternative requires a relatively complex installation due to water wall and windbox modifications.

Operational impacts include additional primary air system resistance and the potential for an increase in unburned carbon. To minimize the increase in unburned carbon, manufacturers typically suggest coal fineness of 65 to 80 percent through 200-mesh and 98 to 99 percent through 50-mesh. Retrofit installation of LNBs may impact opacity and particulate emissions.

Natural Gas Reburn. Natural gas reburn is a common form of fuel staging. The natural gas reburning process employs three separate combustion zones to reduce NO_x emissions. The first zone consists of the normal combustion zone in the lower furnace in which 75 to 80 percent of the total fuel heat input is introduced with about 10 percent excess air (a 1.10 stoichiometric ratio). The second combustion zone, called the reburn zone, is created above the lower furnace by operating a row of natural gas burners at a stoichiometric ratio of about 0.80 to 0.95. The introduction of OFA to complete combustion of the unburned materials in the upper furnace comprises the third and final zone. The process results in an overall excess air for the boiler of 15 to 20 percent.

Adequate residence time within the furnace for both the additional burning zone and the associated OFA burnout is required for optimum performance. If adequate residence times are not available, the effectiveness of the reburn system will be limited. For applications with adequate residence times, reburn technology has demonstrated reductions in NO_x of 40 to 65 percent.

Implementation of gas reburn often requires the installation of new gas supply lines, reburn burners, and an overfire air system. Integration of reburn systems in existing plants includes interfaces such as the air heater outlet, penetrations into the boiler for the reburn burners and OFA ports, and the control system upgrades. Due to the complexity of the reburn operation and the requirement for accurate control, a digital control system is required.

Natural gas reburn has been demonstrated on several domestic units. However, lack of long-term experience introduces some risk associated with applying gas reburn technology to utility sized units. The construction schedule for the installation of a gas reburn system is approximately 18 weeks including about 8 weeks of outage time.

Post-Combustion Control

Post-combustion controls are flue gas treatments that reduce NO_x after its formation. Alternatives consist of selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and hybrid (SNCR followed by catalyst) systems.

SNCR. SNCR systems can use either ammonia or urea as the reagent. These systems rely on appropriate reagent injection temperature and good reagent/gas mixing to achieve NO_x reduction. The optimum temperature range for injection of ammonia or urea is approximately 1,550 to 2,200°F. Therefore, the optimum temperature occurs in the backpass of the boiler. The location of this temperature window will change as a function of unit load so multiple injection levels are

usually installed. In addition, effective reagent injection becomes complex and difficult for boilers larger than 150 MW.

The performance of SNCR systems are a function of boiler arrangement and allowable ammonia slip. On a given boiler, the ammonia slip will increase as the NO_x reduction increases. The conventional philosophy for coal fueled boilers limits ammonia slip to 5 ppm or less, which leads to NO_x reduction of 20 to 35 percent. However, recent experience indicates that to ensure reliable air heater operation, ammonia slip values should be limited to 2 ppm or less[4].

Installation of SNCR systems is relatively simple. The reagent storage tanks, injection metering skids, and piping can be installed with the unit online. A short outage of 1 to 2 weeks is required to finish installation of the injection points on the boiler.

SCR. With an SCR system, ammonia is injected into the flue gas stream upstream of a catalyst bed. Ammonia in the presence of the catalyst reacts with both NO and NO_2 to form nitrogen and water vapor. SCR systems have been used on over 50,000 MW of coal fired boilers throughout Germany and Japan for many years and are now operating on six coal fired units totalling nearly 1,800 MW in the United States.

The ammonia (either aqueous or anhydrous) is received and stored as a liquid and is then vaporized, diluted with air, and injected into the flue gas. Injection of the ammonia must occur at catalyst temperatures between 600 and 800° F (site specific). Therefore, catalyst is typically located between the economizer outlet and the air heater inlet.

Specific plant characteristics will affect the ease by which SCR can be implemented in a retrofit situation. Boilers which have short duct runs between the economizer and the air heater may require a large amount of ductwork reconstruction to install SCR. Units with horizontal shaft air heaters generally present difficult retrofit scenarios resulting in additional costs. In these situations, the SCR can also be installed downstream of the particulate removal or flue gas desulfurization system where additional space is often available. However, this arrangement requires duct burners and a gas-gas reheater to raise the flue gas temperature to the minimum operating temperature of approximately 600°F.

SCR systems can be designed to keep the ammonia slip reliably below 2 ppm. At these levels, the problems associated with plugging of air heaters and ammonia deposition on the fly ash are minimized. The pressure drop resulting from an SCR system retrofit will be between 3 and 6 in w.g. This often results in ID fan modifications. In most cases, forced draft units must be converted to balanced draft operation. The outage required to tie-in the SCR reactor ductwork to the existing ductwork is about 3 to 5 weeks. Total construction time is approximately 18 months.

SNCR/Catalyst Hybrid Systems. Hybrid systems attempt to combine the features of SNCR and SCR. Reagent is injected in the boiler like a traditional SNCR system. However, rather than trying to minimize ammonia slip, NO_x reduction is maximized, and the resulting ammonia slip is used for further NO_x reduction in the catalyst bed. Typically, the catalyst is installed inside the ductwork to minimize cost. A variation of the hybrid concept is to install the catalyst material in the regenerative air heaters. The catalyst allows the SNCR to have the greatest amount of effectiveness while maintaining ammonia slip as low as 2 ppm.

Performance is based on SNCR effectiveness, catalyst volume, velocity through the catalyst, and distribution of the ammonia slip within the flue gas stream. Because the catalyst is typically installed inside the existing ductwork (or air heater), construction must be completed with the unit out of service, leading to construction outages of 10 to 20 weeks, with a total project construction time of 30 to 40 weeks.

Cost of NO_x Reduction Alternatives

Black & Veatch has performed compliance planning activities for more than 60 coal fueled units totalling in excess of 17,000 MW over the past 4 years. The cost information presented in this section summarizes a majority of the results from these investigations. Capital cost, busbar cost, and cost effectiveness values are provided for each NO_x control technology as a function of NO_x reduction. The NO_x reduction percentage was selected as the basis of comparison in order to illustrate and define the situations where each technology is most appropriate. Table 2 describes the wide range of boiler types and sizes used in developing the costs that are presented in this paper.

As always, costs are very site specific. The costs presented in this paper have been somewhat normalized to ensure a level of comparability. The results presented should not be used in lieu of more detailed compliance planning estimates. However, the results presented are representative of relative cost ranges.

Capital Cost Ranges

Figure 1 presents the capital cost of the most common NO_x control alternatives expressed in dollars per kilowatt ($/kW) on a single unit basis. These capital costs include contingency, owner indirects, interest, and escalation for a January 2000 startup.

This figure illustrates the differences in both performance and cost between these technologies. For LNB, gas reburn, SNCR, and hybrid (when based on an in-duct catalyst) the maximum attainable NO_x reduction is defined by the physical arrangement of the boiler. The maximum NO_x reduction of SCR is a design factor, with little impact from boiler characteristics. For example, the performance of a gas reburn system may be limited in a boiler that does not have the height required to achieve adequate residence time while the performance of an SCR system is based on the required NO_x removal.

Figure 1 illustrates that LNB and SNCR have a smaller range of capital costs than gas reburn, SCR, and hybrid systems. Those alternatives whose performance is dictated by boiler arrangement and baseline NO_x emission values have capital costs that are not highly influenced by boiler arrangement and baseline NO_x. The equipment and construction required for installation of an LNB, gas reburn, or SNCR system are largely independent of NO_x reduction percentage and retrofit difficulty. The apparently large range of capital cost for gas reburn results from including the pipeline required to supply natural gas to the coal boiler. Otherwise, the range of capital cost would be quite small.

Conversely, the capital cost of SCR, whose performance is not defined by boiler arrangement, is greatly influenced by boiler arrangement and associated retrofit factors. As illustrated on Figure 2, retrofit difficulty and baseline NO_x emissions have a significant impact on the capital cost of an SCR system. Table 3 lists the definitions of retrofit difficulty ranging from nominal to difficult.

Busbar Cost

Development of a NO_x compliance strategy must also evaluate the total ownership (annual O&M and capital) cost of each alternative. Busbar costs for each alternative technology are illustrated on Figure 3. This information is based on levelized annual costs (capital and operating costs for a 20-year life) and includes, as applicable, differential fuel, reagent (ammonia for SCR and urea for SNCR), differential power consumption (including fan energy due to increased pressure drop), catalyst replacement, O&M (material and labor), and fixed charges on capital. NO_x reduction system costs are based on 12-month operation. This information is useful in estimating the total annual expenditures to operate each technology independent of NO_x removal.

Cost Effectiveness

Figure 4 presents the cost effectiveness of the various technologies defined as levelized dollars (as defined in the previous section) per ton of NO_x removed. Essentially, cost effectiveness is the true measure of economic efficiency.

All control alternatives demonstrate a wide range of cost effectiveness due almost entirely to the combination of baseline NO_x emissions and removal efficiency. This information shows that focusing on high NO_x producing units within a system as part of an averaging strategy may have the greatest strategic value for minimizing systemwide compliance costs. This concept of averaging will be further illustrated in the following section of this paper.

Figure 5 illustrates the relationship between cost effectiveness and busbar costs for an SCR system (90 percent removal) installation on a 500 MW boiler with a nominal retrofit factor. As the cost effectiveness improves due to higher uncontrolled NO_x emissions (more tons of NO_x removal), the busbar cost increases because of higher requirements for ammonia and energy consumption. Although the cost effectiveness and busbar values would be different, this relationships is consistent with other NO_x reduction systems such as SNCR, hybrid, and gas reburn.

The Value of Systemwide Averaging

There are two options for incorporating NO_x control technologies into a compliance strategy. The determination of which option to use is based on comparing the systemwide emission limit target to the existing NO_x emissions. The outcome of this comparison will help decide which option to use.

- Option 1: Unit by unit compliance: install reduction alternatives as required to achieve compliance for each unit.
- Option 2: System averaged compliance: install high-reduction alternative on one or more units to offset the emissions of other units.

Option 1: Unit by Unit Compliance

This option is based on installing a NO_x control technology on all units requiring emission reductions to meet NO_x limits. For Group 1 boilers, this most likely includes installation of LNB. A large portion of Group 2 boilers do not have such a "plug-in" alternative available, so control alternatives such as boiler tuning and the EPA-defined technology basis can be implemented to achieve compliance with the emission limit. Developing the compliance cost of Option 1 consists of adding the capital and operating costs of those technologies selected to be installed at each unit.

Option 2: System Averaged Compliance

Title IV, known OTR SIPs, and draft OTAG requirements allow for some degree of systemwide averaging among units. While the details may vary or are not yet finalized, the option of averaging multiple units has the potential to cost substantially less than individual compliance as described in Option 1.

For those generating systems that have both Group 1 and Group 2 boilers, this option is based on the concept of leveraging by overscrubbing NO_x on one or more of the high baseline NO_x emitters to cover the reduction requirement boilers needing less NO_x reduction.

To illustrate this option, a fictitious utility (ABC) is presented as an example. ABC has two 500 MW cyclone units, each with a baseline NO_x emission of 1.3 lb/MBtu. The remaining units in the ABC system consist of lower emitting Group 1 and Group 2 boilers. ABC's objective is to meet Title IV NO_x emission limits. Figure 6 illustrates the number of megawatts of generation from the remaining units that can be offset if SCR systems designed to achieve a controlled emission limit of 0.13 lb/MBtu (90 percent removal) were installed on the two cyclone units.

In this example, the two SCR systems would produce 24,000 tons per year of NO_x reduction that could be used to offset other units within the system. As shown on Figure 6, the offset is great enough to cover 3,000 MW of wall-fired boilers with uncontrolled NO_x emissions of 0.70 lb/MBtu, 1,400 MW of cell-fired boilers with uncontrolled NO_x emissions of 1.2 lb/MBtu, 3,800 MW of tangential fired boilers with uncontrolled NO_x emissions of 0.6 lb/MBtu, or any other combination of boilers requiring 24,000 tons of NO_x emission offsets. Therefore, leveraging high-NO_x units to offset the need for numerous burner replacement retrofit projects can be very effective in developing the best compliance strategy.

An important consideration in developing a system averaged compliance strategy is ensuring that the emission limit can be met year-round under various generating system operating scenarios. While using the offsets from the installation of an SCR on a very high NO_x producing unit may be able to cover all other units in the system, this compliance concept will become jeopardized in the event the controlled plant is taken off line due to an unexpected long-term outage. Installation of a limited number of LNBs on selected units as part of the systemwide compliance plan would provide a buffer for this type of unexpected occurrences.

It is also prudent to design the SCR system for additional removal to allow for compensation of downtime, so if a long-term outage does occur on the high-reduction unit, the SCR can be operated for higher reduction for the remainder of the year.

Summary

Utility compliance plans for meeting Title IV NO_x emission limits must be submitted to the EPA on January 1, 1998. Every compliance plan will be different, but the components of strategy development and technology selection will be the key tools in the development of each plan. An appropriate strategy should be based on meeting emission limits, optimizing capital and operating expenditures, and positioning the plants to remain competitive in the deregulated market.

The cost of compliance is determined by the selected strategy to meet the NO_x emission limit and the technology selected to implement this strategy. In developing the strategy, site specific factors will predominate because no single technology provides a "one size fits all" solution. While numerous strategies can achieve the desired emission limit, thorough, comprehensive planning is required in the selection of a compliance plan that will provide performance, flexibility, cost effectiveness, and competitiveness during the upcoming deregulation of the industry.

References

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2. Utility Boiler Regulations Under the Title IV NOx Emission Reduction Program, presented at the AWWA 1996 Technical Conference, September 1996, by Stanley Rasmussen, Kevin Eisenbeis, Andy Byers, Black & Veatch
3. Environmental Reporter, June 6, 1997, Volume 28, No. 6, OTAG Suggests Broad Range of Controls for Utility Emissions, Exempts 12 States
4. "Seward Unit 5 An SNCR NO_x Control Experience," Daniel Kessler, GPU Genco, presented at the Pennsylvania Electric Association Meeting, Indiana, Pennsylvania, April 8, 1997.

Table 1
Title IV NO_x Emission Limits

Type of Boiler	Phase II Emissions Standard	Technology Basis
Group 1 Boilers		
Tangential	0.40 lb/MBtu	Low NO_x Burners
Dry Bottom Wall	0.46 lb/MBtu	Low NO_x Burners
Group 2 Boilers		
Cyclone (> 155 MW)	0.86 lb/MBtu	Gas Reburn or SCR
Wet Bottom (> 65 MW)	0.84 lb/MBtu	Gas Reburn or SCR
Cell Burners	0.68 lb/MBtu	Plug-In and Non Plug-in Combustion Controls
Vertical	0.80 lb/MBtu	Combustion Controls

Table 2
Boiler Types Investigated in NO_x Compliance Planning Studies

- Boiler Types.
  --Front and Rear Wall Fired PC.
  --Tangential PC.
  --Cell.
  --Cyclone.
  --Wet Bottom.
- Boiler Sizes Ranging from 80 to 1,300 MW.
- Uncontrolled NO_x Ranging from 0.35 to 2.5 lb/MBtu.
- Bituminous and Subituminous Fuels.
- Wide Range of Retrofit Difficulties.

Table 3
Definition of SCR Retrofit Difficulty Factors

- Nominal.
  --Clear Access for Construction.
  --Unimpeded Reactor and Ductwork Arrangement Possible.
  --Adequate ID Fan Capabilities.
  --No Electrical System Modifications.
  --No SCR Bypass Necessary.

- Moderate.
  --Clear Access for Construction.
  --Difficult Ductwork Transition.
  --ID Fan Motor Replacement Required.
  --Moderate Electrical System Modifications.
  --Includes SCR Bypass.

- Moderately Difficult.
  --Construction Access Implemented.
  --Some Relocations.
  --ID Fan Motor and Rotor Replacement.
  --Extensive Electrical Modifications.

- Difficult.
  --Construction Significantly Impeded.
  --Extensive Relocations.
  --Difficult Ductwork Transition.
  --Constrained Reactor Arrangement.
  --Complete ID Fan Replacement.
  --Extensive Electrical Modifications.

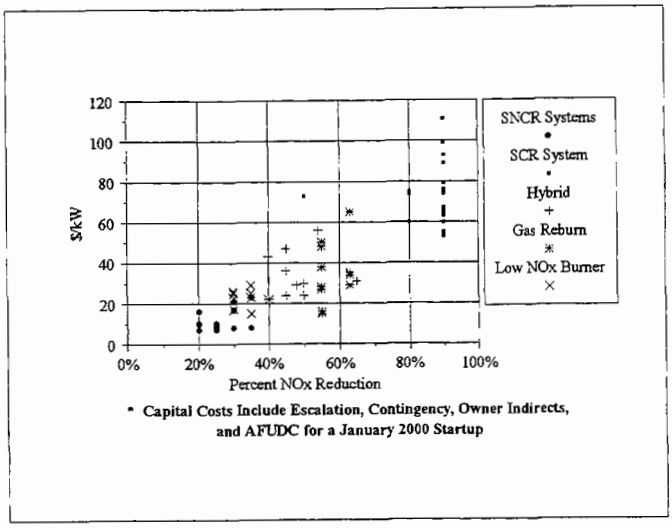

Figure 1
NO_x Compliance Planning Study All-In Capital Costs

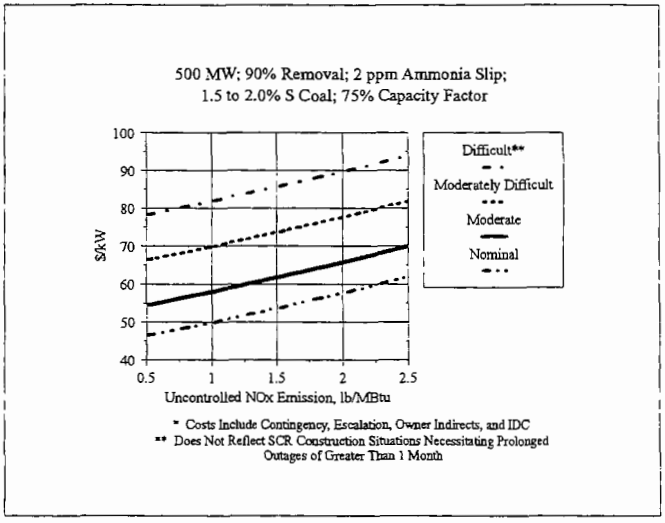

Figure 2
SCR (High Dust) Capital Cost

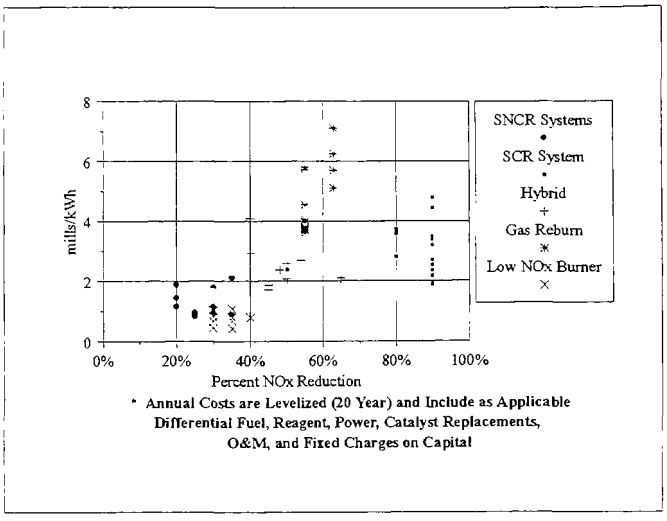

Figure 3
NO_x Compliance Planning Study All-In Busbar Costs

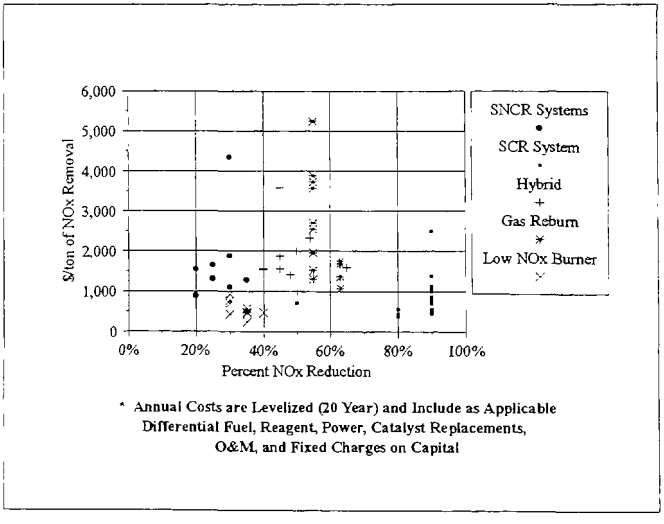

Figure 4
NO_x Compliance Planning Study All-In Cost Effectiveness

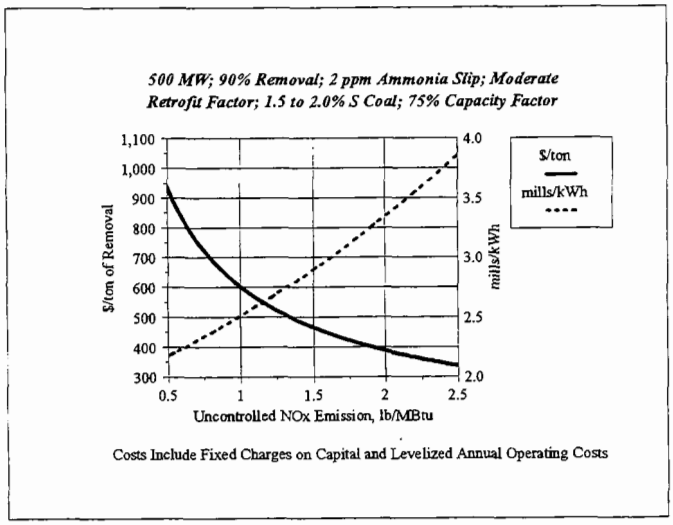

Figure 5
SCR Cost Effectiveness

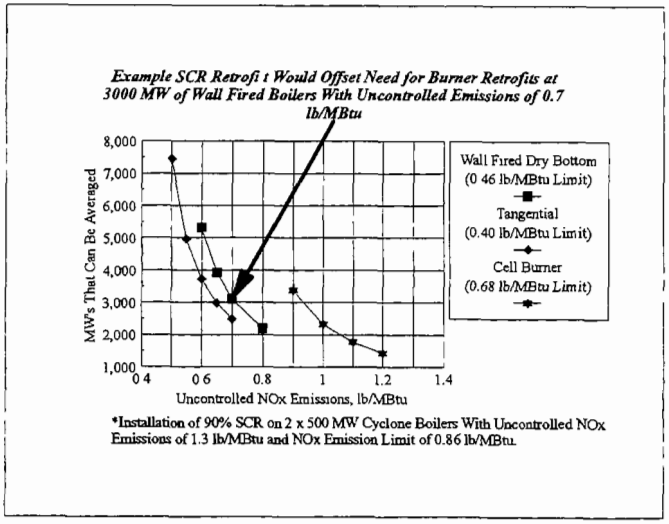

Figure 6
System Averaging Example

Monday, August 25; 10:00 a.m.; 1:00 p.m.
Plenary Session:
Combustion Tuning/Optimization (PC Units)

The Role of Combustion Diagnostics in Boiler Tuning

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Abstract

Boiler tuning to achieve low NO_x emissions, efficient operating O_2 levels and acceptable ash carbon content requires effective combustion diagnostics to quickly identify equipment and operating constraints. Many coal-fired utility boilers have nonuniform combustion as indicated by large O_2 and NO_x gradients at the economizer exit. Common causes of this nonuniformity or imbalance in O_2 and NO_x are uneven fuel distribution to the burners, malfunctioning or misadjusted air registers/dampers, restricted or plugged burner pipes, nonuniform air distribution to OFA ports, uneven or variable burner tilt position, furnace air inleakage, etc.

Failure to identify and correct the causes of nonuniform combustion can often result in slagging, fouling and high ash carbon levels in the low O_2 regions of the furnace and high NO_x, and reduced efficiency in the high O_2 regions. This paper discusses some common causes of nonuniform combustion, the use of cost-effective diagnostic techniques and experiences from recent field test programs. In particular, the paper addresses how to distinguish air inleakage from nonuniform combustion, the importance of proper placement of plant instrumentation, specific equipment related diagnostics, and issues related to performance guarantees for low NO_x firing systems. The equipment related diagnostic techniques discussed in this paper are an important complement to optimization software.

Introduction

The importance of combustion diagnostics in boiler tuning has grown significantly as more utilities install retrofit NO_x emission controls on pre-NSPS units and also convert to low sulfur coal (or coal blends). Although the installation of low NO_x burners and/or overfire air (OFA) systems may satisfy the Phase I requirements of the Clean Air Act Amendments (CAA), many utilities have realized that achieving reduced emissions *and* peak performance often requires optimization of the combustion process. Although periodic calibration/maintenance of O_2

analyzers and pulverizers may have been all that was needed in the past, more extensive boiler-tuning to establish and maintain uniform combustion is now required. Failure to achieve uniform fuel and air distribution to the burners can aggravate a natural tendency of low NO_x burners and OFA systems to operate at increased ash carbon levels. Local regions of low O_2 combustion are often the source of CO and high ash carbon levels, whereas local high O_2 regions produce above average NO_x emissions.

Another boiler tuning related issue concerns the conversion of a boiler originally designed for a high Btu Eastern bituminous coal to a low sulfur high moisture Western coal. This can result in a major change in boiler combustion characteristics and an increased sensitivity to equipment maintenance and operating conditions. Increased coal pipe loadings at high moisture, low mill outlet temperatures can lead to coal pipe plugging and nonuniform combustion. The tendency of high calcium content Western coals to deposit a reflective ash often results in high furnace exit gas temperatures and slagging/fouling. Local fuel rich regions caused by nonuniform combustion can trigger a slagging and fouling episode resulting in a unit derate or forced outage.

A more recent combustion related problem that is emerging at some Phase I units is accelerated furnace waterwall tube wastage.[1] High waterwall corrosion rates have been most noticeable on supercritical high heat release rate units burning high sulfur fuels. Corrosion occurs primarily as the result of reducing atmospheres along the waterwalls, particularly on units with large amounts of overfire air (OFA). Nonuniform combustion in the burner zone can cause flame impingement on the walls, fuel rich reducing atmospheres, and ash deposition that traps corrosive species. Supercritical units are more susceptible to waterwall wastage because of their inherently higher operating temperatures. Although some of these units previously experienced waterwall wastage before conversion to low NO_x firing, the wastage accelerated with the advent of low NO_x deeply staged combustion which increases the potential for fuel rich reducing atmospheres at the furnace wall.

As utilities gain experience with retrofit low NO_x firing systems and conversion to coals with combustion characteristics different from the design coal, the importance of combustion diagnostics and boiler-tuning during *baseline testing* has also grown. Baseline testing is typically conducted with the original equipment burners and the *normal* coal to establish a reference point of emissions and performance prior to conversion to low NO_x firing and/or an alternate coal. Some utilities previously relied on little more than plant continuous emissions monitor (CEM) and boiler panel board data from existing instrumentation during pre-retrofit baseline testing. Although large gradients in O_2 and NO_x emissions may have been present in the combustion zone (indicating potential coal and air flow distribution problems related to coal pipe or windbox air distribution), they went unnoticed. Thus, important indicators of potential future combustion related problems were ignored with the expectation that the new low NO_x equipment would accommodate any off-design operation inherent in the baseline boiler firing practice. However, utilities are now realizing, as Phase II baseline testing accelerates, that detailed combustion diagnostics data are essential in establishing a good baseline from which to compare post-retrofit warranty emissions and performance. Failure to carefully document pulverizer performance, burner settings, O_2 and NO_x gradients, furnace exit gas temperatures, furnace wall atmospheres, and LOI can lead to potential warranty disputes with equipment vendors concerning the cause of a possible change in unit performance. For example, if a large increase in LOI occurs following

the installation of an OFA system, is it due solely to the deep staging associated with low NO_x firing? Another possibility is that LOI increases are due to other changes (e.g., pulverizer fineness, mill bias, air register settings or increased furnace air inleakage) that occurred between the pre-retrofit baseline and post-retrofit warranty tests. Without detailed combustion diagnostic test data under comparable boiler operating conditions, it is often difficult to resolve these issues.

In summary, the role of combustion diagnostics in boiler tuning has grown to meet the following needs:

- Tuning of Phase I units to reduce LOI, optimize NO_x, increase efficiency/thermal performance and reduce waterwall tube wastage.

- Emissions and performance optimization of Phase I units that have failed to meet vendor warranty requirements and have petitioned for an Alternative Emission Limit (AEL).

- Baseline testing of Phase II units to carefully document existing combustion related emissions and performance constraints that could impact post-retrofit operation.

- Optimization of emissions and performance on Phase II units that qualified for the "early election" option for NO_x control under the CAA amendments.

- Reduction of slagging and fouling derates or forced outages on boilers having an inherent sensitivity to variations in coal quality and combustion characteristics.

- Trial test burns of varying blend ratios of low sulfur Western and Eastern bituminous coals to minimize SO_2 emissions and boiler performance impacts.

Combustion Diagnostics and Boiler Tuning

Combustion diagnostics play an important role in boiler tuning because utility boiler emissions and performance are directly dependent upon the quality and effectiveness of the combustion process. Achieving low NO_x emissions at efficient operating O_2 levels with acceptable ash carbon content requires effective combustion diagnostics to quickly identify equipment and operating constraints. Some of the most common combustion related problems concern:

- Operation at nonoptimum excess air levels
  - furnace air inleakage
  - O_2 instrumentation operation/placement problems

- Equipment malfunctions/maintenance issues
  - air heater partial pluggage or seal leakage
  - FD/ID fan capacity limitations or windbox pressure constraints
  - plugged burner pipes
  - worn coal pipe orifices
  - worn pulverizer grinding elements

broken air register linkages or motor drives
combustion controls performance problems

- Lack of combustion uniformity
  uneven coal flow distribution
  uneven air flow distribution
  uneven overfire air distribution

A very common problem with balanced draft coal-fired boilers is operation at a nonoptimum excess air level. In many cases the actual O_2 level in the burner zone is significantly less than that measured at the plant O_2 probes because of air inleakage between the furnace and economizer exit. High LOI or ash carbon content often results. A common source of this problem is leaks in the furnace roof, casing leaks and leaks at duct expansion joints. If the air inleakage is more prevalent on one side of the boiler than another, it is very difficult to maintain balanced combustion conditions because the instrument readings will not accurately reflect the actual O_2 in the burner zone. From a combustion diagnostics perspective, furnace air inleakage can be characterized by comparing measurements of the O_2 concentration profile at the furnace exit with those at the economizer exit.[2]

Combustion diagnostic testing to evaluate O_2 probe placement or equipment operation problems is strongly recommended. Even in cases where air infiltration is *not* an issue, the O_2 analyzer reading may not be representative of the duct average. This is a more common problem with tilting tangentially-fired units where a large O_2 gradient or "split" between furnace halves can develop for certain burner tilt positions. A large O_2 gradient can result not only in above average NO_x emissions from the high O_2 regions, but it can lead to operational problems if not rectified (e.g., high LOI, slagging and fouling in the low O_2 regions of the furnace). Many utilities are reevaluating the location of their O_2 probes or are installing multiple O_2 analyzers in each duct to obtain a more representative average. Combustion diagnostic testing at the furnace and economizer exit can aid in defining the best location for these new analyzers. However, recalibration of the existing plant O_2 analyzers is strongly recommended before conducting any combustion diagnostic testing.

Many combustion related emissions and performance problems are related to equipment malfunctions or maintenance related issues that may have been overlooked during periodic boiler inspections. Some examples include: (1) air heater partial pluggage or seal leakage; (2) FD/ID fan capacity limitations; (3) plugged burner pipes; (4) worn coal pipe orifices; (5) worn pulverizer internal or classifier settings; (6) broken air register linkages or motor drives; or (7) combustion controls problems (e.g., response time, dead band, etc.).

Nonuniform Combustion

Although many equipment and operational related issues can contribute to boiler emissions and performance problems, a very common source is nonuniform combustion in the burner zone. Nonuniform combustion makes efficient low O_2, low NO_x firing difficult because local fuel-rich zones can result in: (a) incomplete combustion, CO or elevated ash carbon content, and (b) a tendency toward increased ash deposition with coals that have a marginal slagging index. To

avoid this, the boiler overall operating O_2 level is often set at a higher than required average level resulting in unnecessarily high NO_x emissions and reduced boiler efficiency. For example, if one burner region or furnace corner is operating at a much lower O_2 level than the others, it will dictate the overall average O_2 at which the unit is operated, even if the majority of the burners are capable of operating at a much lower level. Thus, one of the primary goals of boiler tuning is to establish uniform combustion so that the overall O_2 level (and NO_x emissions) can be lowered.

Several of the more common causes of nonuniform combustion include:

- Uneven coal flow distribution
  - coal piping and orifices
  - riffle box configuration
  - biased pulverizer coal flow

- Uneven air flow distribution
  - air register/damper settings
  - windbox design
  - air register/actuator malfunction

- Uneven overfire air distribution

Achieving uniform combustion typically involves combustion diagnostics to improve both the fuel and air-side balance. The general approach to boiler combustion tuning is summarized below:

- Measure coal fineness, primary air and coal flow distribution
- Optimize mill performance
- Improve coal fineness
- Characterize air inleakage between furnace and economizer exit
- Balance coal flow to individual burners
- Balance air flow
- Adjust secondary air dampers to achieve uniform air/fuel ratio at each burner
- Reduce air infiltration
- Improve instrumentation/placement
- Bias mills between elevations -- O_2, NO_x and LOI optimization

Typically, the most significant improvements in combustion uniformity are achieved by performing combustion diagnostics on the fuel system to achieve uniform coal flow to all burners at target fineness levels. Balanced coal flow is typically achieved by measuring the "as found" primary air and coal flow distribution followed by modification of the individual burner line orifices to achieve balanced coal flow within ±10% of the mean.

Burner coal pipe diagnostic testing typically involves measurements of both the primary air and coal flow distribution plus pulverized coal fineness using a RotorProbe™ sampler. The RotorProbe™ is an approved ISO method of pulverized coal sampling. It has a rotating sample head that collects coal samples at sixteen radii of the coal pipe (which is very important if any

coal roping is present). A typical example of the improvement in coal flow balance achieved with coal pipe orifice adjustments is shown in Figure 1 for a 125 MW tangentially-fired unit equipped with four Raymond Bowl mills. Coal flow deviations of up to 12% were reduced to 5% or less. The corresponding emission benefits of balancing coal flows are summarized below:

- NO_x (corrected to 3% O_2) was reduced from 0.411 lb/MMBtu to 0.346 lb/MMBtu,
- CO was reduced from 91 to 50 ppm,
- LOI was reduced from 15.7% to 9.7%.

The improvement in combustion uniformity allowed the boiler to operate at reduced O_2 levels benefitting NO_x emissions without adversely impacting CO emissions. The LOI reduction was attributed to a combination of better combustion balance and improved coal fineness through 50 mesh.

Results of a similar combustion diagnostics test program to improve coal flow balance on a 135 MW tangentially-fired unit are shown in Figure 2. Deviations in coal flow of more than 10% were reduced to 3% or less. The corresponding emission benefits were:

- NO_x (corrected to 3% O_2) was reduced from 0.483 lb/MMBtu to 0.423 lb/MMBtu,
- LOI was reduced from 12.8% to 10.1%.

A 165 MW tangentially fired unit with 16 burners had large deviations in coal flow between burner pipes ranging from +28% to -22% as shown in Figure 3. Replacement coal pipe orifices improved the coal flow balance to ±10% for all but one pipe (12%). The associated improvement in combustion uniformity is illustrated in Figure 4, where the baseline O_2 and NO_c profiles at the economizer exit are shown in the top half of the figure. The profiles after coal flow balancing are shown in the lower portion, where NO_c = NO @ 3% O2. (All other test conditions were directly comparable, except the coal flow distribution.) Because of significant air inleakage at the ends of the duct, the improvement in combustion uniformity is not very obvious based on just O_2 measurements at the economizer exit, except in the duct region between 15 and 35 feet where the O_2 gradient from 2.4 to 3.2% was completely eliminated.

Since NO_c emissions are so strongly dependent upon local air/fuel ratio in the burner zone, the baseline and post orifice replacement NO_c emissions profiles in Figure 4 give a much clearer picture of the benefits of balanced coal flow in terms of combustion uniformity. A NO_c emissions gradient of 40 ppm (or 15%) was evident in the baseline NO_c profile but reduced to 20 ppm (or 7%) with new coal pipe orifices. Eliminating the low O_2 region (2.4%) in the baseline O_2 profile, normally would allow a further reduction in the average O_2 and NO_c emissions for comparable CO and LOI levels. However, these efforts are dependent upon additional pulverizer testing to improve coal fineness, which currently dictates the unit operating practice. Secondary air damper tuning to further minimize the NO_c gradients in Figure 4 could also be performed, but typically is not initiated until all pulverizer work has been completed.

Advanced Diagnostic Instrumentation

Fossil Energy Research Corp. has found that advanced combustion diagnostic instrumentation is essential to identifying and resolving combustion uniformity problems, particularly those associated with retrofit low-NO_x burner and OFA systems. Two instruments have proven to be particularly valuable:

- a real time multipoint NO, O_2, CO combustion diagnostics analyzer (12 channels),
- a portable HOT FOIL® LOI analyzer (for rapid ash LOI determinations).

In a typical installation at a large unit, a grid of 24 sample probes (12 per duct) is installed in the divided economizer exit duct as shown on the right side of Figure 5. Gas samples are drawn individually through each probe in the grid to define the gas composition at each location in the duct. A computer graphics program is used to generate the emissions contour plots previously shown in Figure 4 to evaluate combustion uniformity. Until recently, generating just one of the profiles for a 24-point sample grid would require up to a half-day of point-by-point sampling, data reduction and plotting. However, Fossil Energy Research Corp. has developed a *real time* multipoint sampling, data acquisition and graphical display system that continuously monitors and displays O_2, NO and CO profiles. The system, shown on the left side of Figure 5, allows up to 12 points in a duct to be sampled and analyzed simultaneously. The PC-based data acquisition and custom software updates the screen display at 10-second intervals, computes averages over user selectable time intervals and provides storage of the profiles to a hard disk for later recall. With the use of this custom instrumentation, the test engineer can make air register, mill bias or fan bias adjustments and immediately see the impact on the O_2/NO profiles and the boiler combustion uniformity. This instrumentation has been very effectively used to optimize NO_x emissions by means of combustion tuning. Fossil Energy Research has found that it can significantly reduce the time needed to tune a boiler by using two way radio communications between an equipment operator making air register adjustments on the burner deck and a test engineer in the truck who can observe the change in the emission profile(s). The test engineer can direct the burner adjustments until uniform O_2 and NO_x emissions have been achieved. Because the NO emissions data are corrected to 3% O_2 to compensate for air inleakage, the difference between the O_2 and the NO profiles can be used to distinguish air inleakage from nonuniform combustion.

The diagnostic approach outlined above was very effectively applied during a test program conducted on a 375 MW tangentially-fired unit that had very large variations in coal flow to individual burners. The burner pipe-to-pipe variation in primary air and coal flow, measured with a RotorProbe™, is summarized in Table 1 for each of the five pulverizers.

Normally, Fossil Energy Research recommends that initial diagnostic testing to improve combustion uniformity focus on balancing primary air and coal flow distribution to the burners before tuning the secondary air dampers/registers. However, in this case the real time multipoint NO, O_2, CO combustion diagnostic analyzer was used to adjust secondary air dampers/registers in a manner that offset the coal flow imbalance. Table 2 summarizes the results of these damper adjustments. A large O_2 and NO_c imbalance or "split" between the North and South furnaces

was evident during the full load baseline test with the A mill OOS (i.e., a 0.6% O_2 difference and 78 ppm (~30%) NO_c difference), as shown in Table 2 for Test # 7.

Table 1
Coal and Primary Air Flow Variation at a 375 MW Tangentially-Fired Unit

Pulverizer Number	Primary Air Flow Percent Deviation from the Mean	Coal Flow Percent Deviation from the Mean
3A	±22.6%	±30.0%
3B	±10.9%	±20.0%
3C	±33.3%	±27.2%
3D	±21.7%	±33.6%
3E	±13.1%	±22.8%

Table 2
Results of Damper Adjustments on a 375 MW Tangentially-Fired Unit

		North			South			Delta O_2	Delta NO_c	Test Description
Test No.	Mill OOS	O_2 %	NO_c ppm	CO ppm	O_2 %	NO_c ppm	CO ppm	(S-N) %	(S-N) ppm	
7	A	2.4	229	2	3	307	5	0.6	78	Baseline with A Mill OOS.
8	A	2.85	269	0	2.7	272	5	-0.15	3	Bias North and South Aux. Air dampers, and South Fuel dampers.

Secondary air damper adjustments (Test #8) reduced the O_2 "split" between furnaces from 0.6% to .15% and reduced the NO_c split from 78 ppm (30%) to 3 ppm (1%). In addition, combustion uniformity within each furnace was improved, particularly the South furnace, as shown in the "before" and "after" NO_c profiles in Figure 6. A South furnace NO_c gradient of 60 ppm (19%) was reduced to 20 ppm (6%) following a brief period of damper tuning using the multipoint combustion diagnostics analyzer for real time viewing of uniformity improvements. Similar full load tests were conducted with other mills out-of-service and the O_2 "split" was typically reduced from 65-85% and the NO_c split from 50 to 96%. Based on these preliminary combustion diagnostic and boiler tuning tests, it was estimated that an average O_2 reduction of 0.5% was feasible corresponding to a NO_c reduction of 20%. These predicted benefits are based solely on boiler tuning as opposed to hardware modifications.

Boiler secondary air tuning was conducted on a 350 MW tangentially-fired unit that also exhibited a large coal flow non uniformity.[2] NO_c emissions gradient from 380 to 550 ppm (i.e., 170 ppm or 37%) was reduced in one day to only 20 ppm or 5% with damper adjustments.

Following these adjustments, the composite O_2 level was briefly reduced to the boiler minimum air stop which prevented further O_2 reductions. Except for these controls limitations, it is anticipated the overall O_2 could have been reduced by 0.6 to 0.8% for a substantial gain in boiler efficiency.

Boiler combustion diagnostics and tuning are much more easy to perform on wall-fired units than on tangentially-fired units because of the plug flow nature of the flow field through the furnace compared to the cyclonic flow in a tangentially-fired unit. Baseline combustion diagnostic tests on a 130 MW wall-fired unit with four mills and 16 burners indicated a substantial full-load O_2 and NO_c gradient as shown in Figure 7. Although combustion uniformity was difficult to judge based on the O_2 contours because of air inleakage, a large gradient in NO_c (140 ppm or 26%) was evident in the NO_c profile. After only two sets of burner secondary air register adjustments, the NO_c gradient was reduced to less than 10 ppm or 2% as shown in Figure 8.

Overfire Air Combustion Diagnostics

It should be noted that the real time multipoint combustion diagnostics analyzer has also been used to effectively tune OFA systems (which are not inherently well balanced). A 250 MW twin furnace tangentially-fired boiler was initially emitting substantial CO emissions at high O_2 levels of 4% or greater.[3]

Using the multipoint combustion diagnostics analyzer to guide the OFA damper adjustments, it was necessary to open the separated overfire air (SOFA) dampers on the front of the boiler to three times the opening of the rear dampers in order to achieve uniform balanced combustion that was comparable to the pre-retrofit emission contours with the original equipment burners. At the conclusion of the OFA adjustments (conducted prior to the warranty tests), the composite O_2 was reduced by nominally 0.9% at comparable CO levels. The estimated annual fuel cost savings at an 80% capacity factor was approximately $110,000. Subsequent tests on a similar 250 MW twin furnace tangentially-fired unit confirmed that the unbalanced OFA flow was not an isolated incident. A similar OFA tuning test series was conducted to achieve uniform combustion at design OFA flow rates.

Conclusions

The role of combustion diagnostics in boiler tuning has grown significantly in response to a need to improve emissions and performance of: (1) Phase I units requiring optimization, (2) baseline testing on Phase II units, (3) early election and alternative emission limit units, and (4) units undergoing slagging and fouling episodes (or operating with blends of low sulfur western coals having substantially different properties than the design coal).

Non-uniform combustion can result in above average O_2 levels and NO_x emissions and/or local regions of low O_2 combustion with high CO and LOI levels. Common causes of non-uniform combustion include uneven coal flow distribution, uneven air flow distribution, or uneven overfire air distribution. The general approach to boiler combustion tuning includes the following actions:

- Measure coal fineness, primary air and coal flow distribution.
- Optimize mill performance.
- Improve coal fineness.
- Characterize air inleakage between furnace and economizer exit.
- Balance coal flow to individual burners.
- Balance air flow.
- Adjust secondary air dampers to achieve uniform air/fuel ratio at each burner.
- Reduce air infiltration.
- Improve instrumentation/placement.
- Bias mills - O_2, NO_x, and LOI optimization.

Measurement and balancing of coal flow to the individual burners are recommended as the first step in achieving combustion uniformity, although an effective balance can often be achieved with secondary air tuning, particularly if the coal flow imbalance is not large. The use of a *real time* combustion diagnostics analyzer allows boiler tuning to be performed very quickly and cost-effectively compared to older manual methods.

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2. Thompson, R.E., et al., *Boiler Tuning for NO_x Control as an Alternative to Low NO_x Burners*. ASME Int'l. Joint Power Generation Conf., Phoenix, Arizona, October 1994.

3. Thompson, R.E., et al., *Optimization of Low-NO_x Overfire Air Systems to Improve Boiler Performance"*, EPRI Heat Rate Improvement Conf., Dallas, Texas, May 1996.

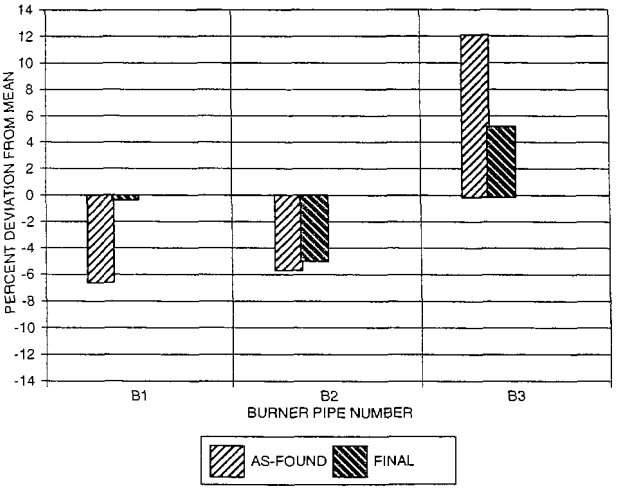


Figure 1. Improvement in Coal Flow Balance Due to Coal Pipe Orifice Modifications, 100 MW Wall-Fired Unit

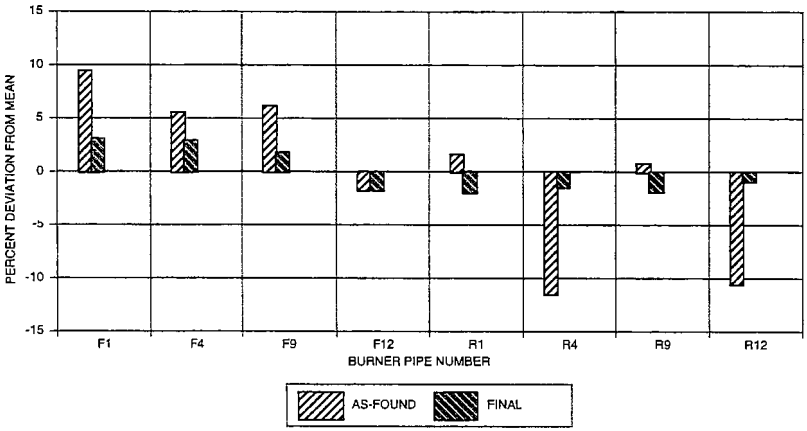


Figure 2. Improvement in Coal Flow Balance Due to Coal Pipe Orifice Modifications, 400 MW Turbo-Fired Unit

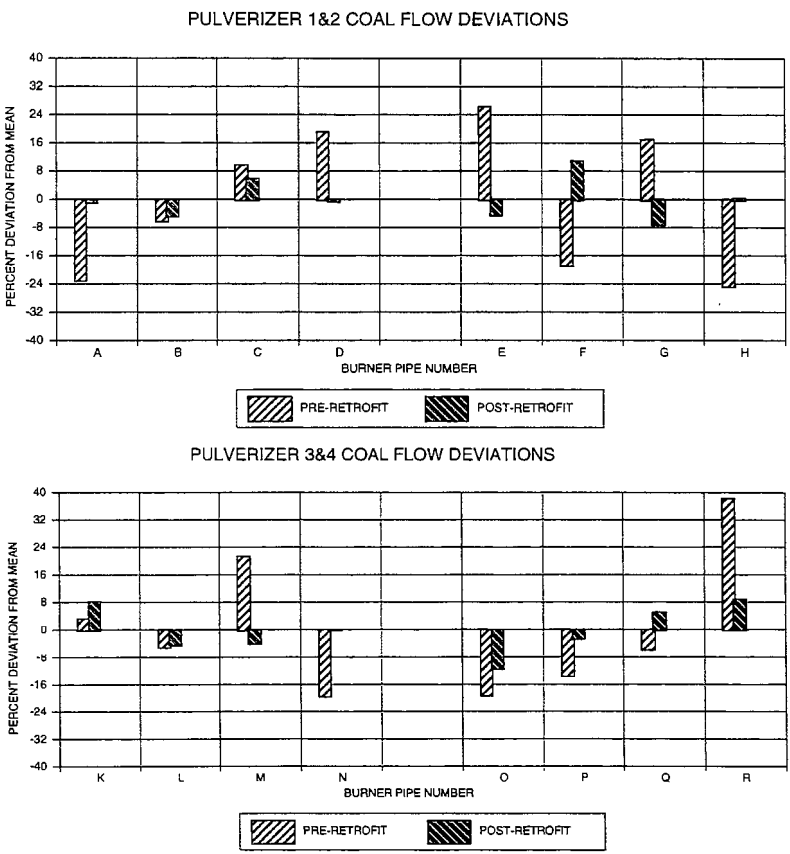
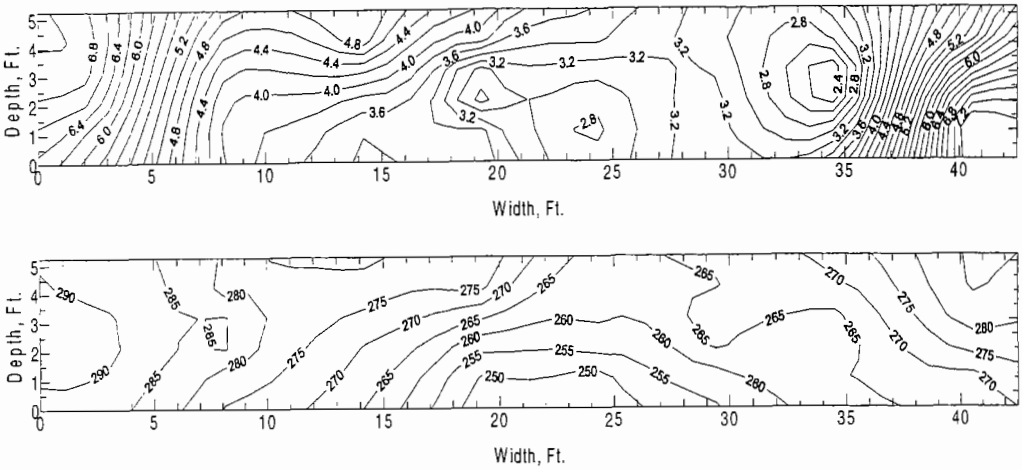


Figure 3. Improvement in Coal Flow Balance with Coal Pipe Orifice Modifications, 165 MW Tangentially-Fired Unit

Baseline O_2 (%) and NO_c (ppm @ 3% O_2) Profiles



Post Orifice Replacement O_2 (%) and NO_c (ppm @ 3% O_2) Profiles

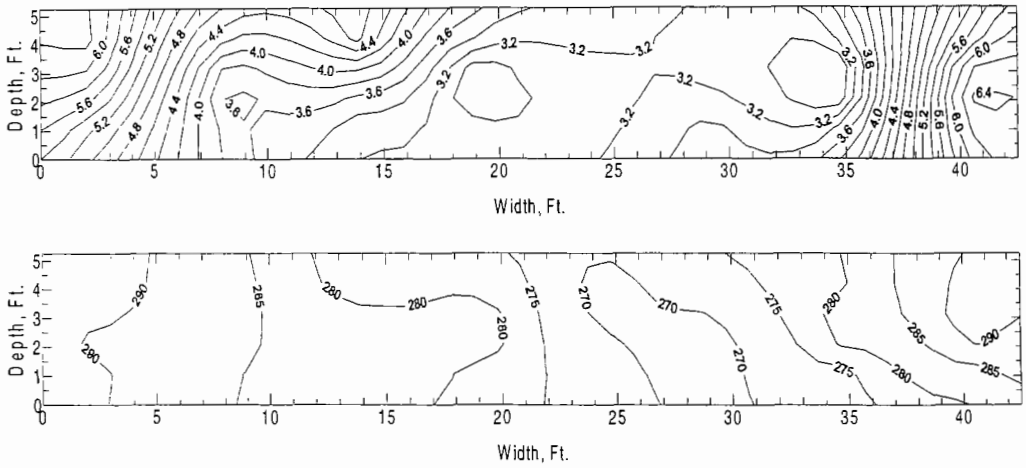


Figure 4. Improvement in Combustion Uniformity with Coal Flow Balancing, 165 MW Tangentially-Fired Unit

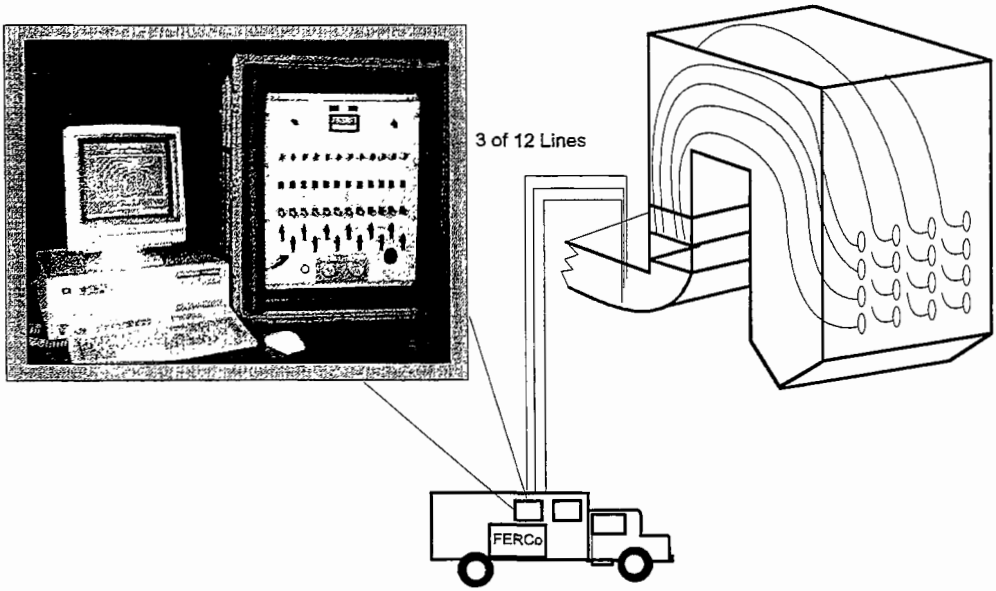
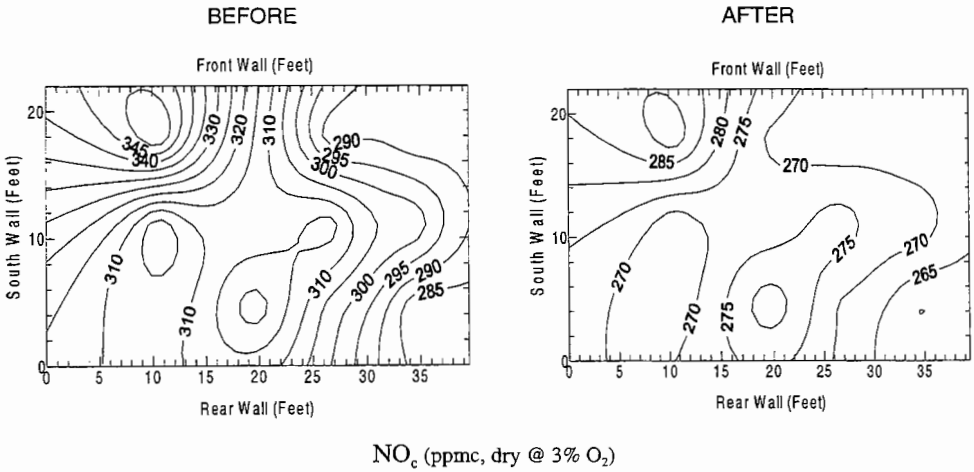
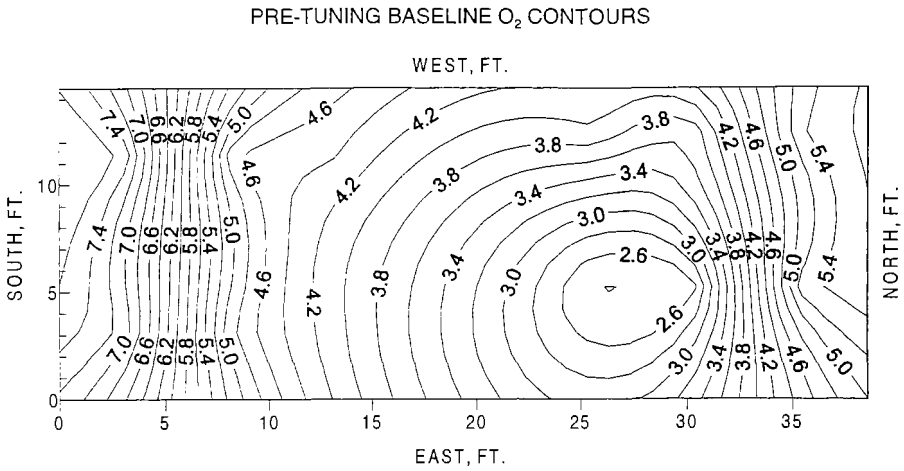


Figure 5. Typical Multipoint NO, O_2, CO Analyzer Installation



NO_c (ppmc, dry @ 3% O_2)

Figure 6. Improvement in Combustion Uniformity by Secondary Air Damper Tuning to Offset Coal Flow Imbalance, 375 MW Unit



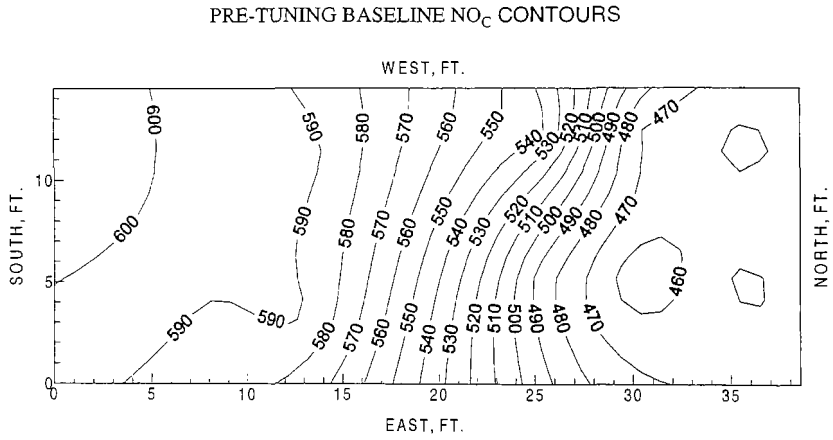
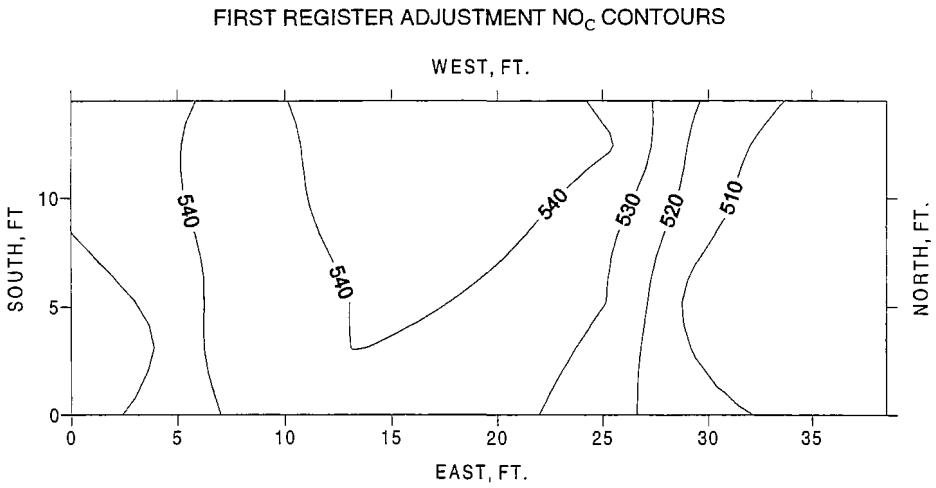


Figure 7. Baseline O_2 and NO_c (ppm @ 3% O_2) Economizer Exit Profiles, 130 MW Wall-Fired Unit



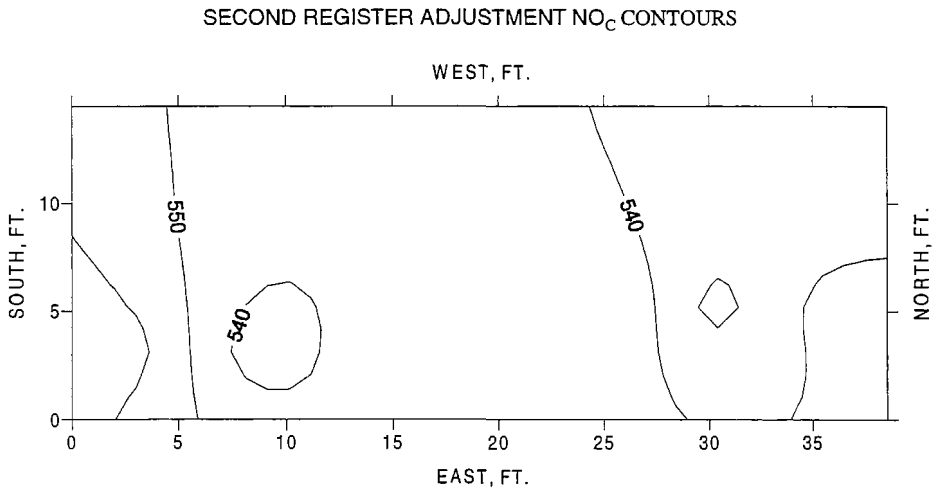


Figure 8. Uniform Combustion Achieved with Secondary Air Register Tuning, 130 MW Unit

POST LOW NO_x BURNER RETROFIT BOILER TUNING RESULTS FOR A FRONT WALL-FIRED BOILER

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Abstract

In June 1996, Union Electric Company completed a major retrofit of its Meramec Plant Unit #4 boiler. The Foster Wheeler front wall-fired boiler was originally commissioned in 1961. Among the major modifications, the boiler was retrofitted with Babcock & Wilcox DRB-XCL® low NO_x burners, furnace rear wall overfire air ports, furnace sidewall ports, extensive fuel delivery equipment modifications, and a Westinghouse WDPF burner management control system.

Post retrofit performance objectives included reducing NO_x emissions below 0.45 lb/MMBtu at full load (a 58% reduction), CO emissions not to exceed 175 ppm at full load, and unburned carbon (UBC) objectives based on a matrix of parameters for two contract coals.

Tuning of the boiler is still in progress. Preliminary tuning results indicate that predicted NO_x performance will be met. However, problems attaining a satisfactory balance between boiler excess O_2 and CO production remain. Due to higher than desired boiler excess O_2 levels, current UBC results are inconclusive.

Background

Union Electric Company's Meramec Plant is located at the confluence of the Meramec and Mississippi Rivers just south of St. Louis, Missouri. Unit #4 was placed on line in 1961 as a base loaded 360 MW unit. Figure #1 shows a current cross-section arrangement of the boiler and pulverized fuel system. The boiler, originally supplied by Foster Wheeler, is a pulverized coal-fired subcritical drum boiler with a full load steam flow capacity of 2,310,000 pounds per hour at 2200 psig and 1010 °F. Furnace depth is a relatively narrow 28'-6" Three double ended ball tube mills provide pulverized coal to 18 burners located on the furnace front wall. The burners are arranged with six burners in each of three horizontal rows. Each mill provides coal to one level of burners. A rotating table-type feeder (2 per mill) feeds coal to each end of the mills. Coal is conveyed from a classifier on each end of the mills by an exhauster (2 per mill) and transported through a ceramic-lined three-way distributor and coal piping to a trio of burners.

Reasons For Retrofit

Compliance with the Clean Air Act Amendments of 1990 was the primary stimulus for retrofit of the original Unit #4 Foster Wheeler Intervane burners. Prior to the combustion system retrofit, NO_x emissions were on the order of 1.02 lb/MMBtu. Being a dry-bottom, wall-fired, pulverized coal unit, Meramec Unit #4 was required to comply with a Phase I NO_x emission limit of 0.50 lb/MMBtu. Additional impetus to replace the burners was provided by the general condition of the boiler furnace. As a result of Union Electric adding more efficient coal-fired units and a nuclear unit, Meramec Unit #4 has been relegated to cycling duty since the early 1970's. Having been designed for base load operation, cycling duty had extracted a heavy toll on Unit #4's steam-cooled Downflow Upflow Radiant Superheater furnace front wall, boiler tieback and buckstay system, boiler insulation and casing system, and windbox structural integrity. By 1990, studies to redesign and replace the boiler furnace were already well underway. Accordingly, the furnace retrofit provided an opportune time to replace the original burners with a low NO_x emitting combustion system.

Low NO_x Combustion System Retrofit

After evaluation of separate bids, Babcock & Wilcox (B&W) was ultimately selected to supply both the furnace retrofit and low NO_x combustion system supply scope. The low NOx combustion system consists of eighteen DRB-XCL® low NO_x burners, six overfire air ports, and two sidewall air ports.

The DRB-XCL® burners are a dual zone burner design that operates on the principle of delayed combustion.[1] The burner diverts air away from the core of the flame, which increases coal devolatization and subsequently reduces initial NO_x formation. The burners are located on the new furnace front wall in the same general location as the previous burners with six burners in each of three horizontal rows. The upper and lower elevation burners were supplied with conical diffusers and notched end rings for flame stability. The middle elevation of burners were supplied with distribution cones and conical impellers to minimize flame length and CO production.

A NO_x port is located on the right and left furnace sidewall at the lower burner elevation. These ports were designed to provide secondary air to not only reduce NO_x emissions from the lower elevation burners but also intercept their flames before they reach the furnace rear wall. Six overfire air ports are located on the furnace rear wall directly opposed to the six upper elevation burners. These ports were designed to provide secondary air for sufficient mixing to complete combustion in the upper furnace and help prevent flame impingement at the upper burner elevation.

Associated Equipment Retrofits

In conjunction with the furnace and burner retrofit, the pulverized fuel delivery system was redesigned and upgraded. The coal piping from the mill exhausters to the burners was replaced and rerouted. Ceramic-lined distribution bottles and adjustable orifices were installed to balance the coal flow equally to each burner. Union Electric Company undertook the responsibility for completely overhauling the three ball tube mills and replacing the six mill exhausters with larger capacity exhausters. The controls for Meramec Unit #4 were also upgraded during the boiler retrofit. A Westinghouse WDPF control system, including a burner management system compliant with NFPA standards, was installed.

Retrofit work was completed in late June, 1996.

Design Challenges

From the onset of the burner retrofit project, there were several design challenges that required particular attention. Among the concerns were installation of burners that would produce extended flame lengths in our relatively shallow depth furnace (28'-6") and the ability of the mills to produce the required coal fineness. Additionally and of utmost concern was the ability to achieve proper fuel distribution to the low NO_x burners given our double-ended ball tube mill arrangement. Substantial fuel output variations can occur from mill end-to-mill end with these types of pulverizers. The basic problem lies in the coal feed rate to the mills. Coal feed is not a mill output control parameter, but is used instead to control the level of coal in the mill. Consequently, there is no direct provision to balance coal flow output from each end of the mill. Accordingly, Union Electric Company assumed responsibility for proper distribution of fuel into and out of the mills.

Performance Objectives

Union Electric and B&W negotiated performance objectives for the low NO_x combustion system that dovetailed with the performance objectives secured for the boiler retrofit contract. Combustion system objectives for simultaneous achievement of NO_x, carbon monoxide (CO), excess oxygen (O_2), and unburned carbon (UBC) levels were obtained as shown and discussed below. Objectives were developed for firing either of two similar Illinois bituminous coals or a representative blend. The contract coals are from the Kerr McGee #5 and Rend Lake mines. Table #1 in the Appendix lists proximate and ultimate analysis parameters for these two fuels.

MERAMEC #4 BOILER & COMBUSTION SYSTEM PERFORMANCE OBJECTIVES

	BOILER PERFORMANCE		COMBUSTION SYSTEM PERFORMANCE			
OBJECTIVE	MAIN STEAM FLOW (lb/hr)	(%)	NOx (lb/MMBtu)	CO (PPM)	O_2 (+/- .25%) (Wet Basis)	UBC (%)
#1	2,650,000	100%	< 0.45	175/120	<3.3%	See Figure #2
#2	1,520,000	57%	< 0.45	175/120	<4.85%	
#3	662,500 - 2,650,000		< 0.50	-		

NOTES:
1. Steam flows are allowed to vary +20,000 to -80,000 lb/hr.
2. CO performance objectives are based on a pipe-to-pipe coal flow balance of +/- 10% or +/- 5%.
3. Performance objective #3 is based on any combination of mills and exhausters in service.
4. UBC performance objectives depend on coal fired, coal pipe balance, and mill fineness.

NO_x Performance Objectives

In general, the combustion system was supplied to reduce NO_x (as measured by EPA Reference Method 7E) below 0.45 #/MMBtu at 100% boiler main steam flow production. This performance objective is based on all 18 burners being in-service. Additionally, with any combination of mill exhausters and burners in-service, NO_x is predicted not to exceed 0.50 #/MMBtu from 25% to 100% rated main steam flow production.

Carbon Monoxide (CO) Performance Objectives

CO objectives are contingent upon coal pipe-to-pipe balance. With a coal pipe-to-pipe balance of +/- 10%, CO production (as measured by EPA Reference Method 10) is predicted not to exceed 175 ppm on a dry volume basis corrected to 3% O_2. With a pipe-to-pipe balance of +/- 5%, CO production is predicted not to exceed 120 ppm on a dry volume basis corrected to 3% O_2.

Excess Oxygen (O_2) Performance Objectives

Excess O_2 concentration in the flue gas at the economizer outlet (as measured by EPA Reference Method 3A) is predicted to range between 3.3% to 4.85% (+/- .25%) on a wet volume basis at the 100% to 57% main steam flow conditions, respectively. Additionally, minimum excess O_2 is predicted to be greater than or equal to 3% on a wet volume basis at all conditions.

Unburned Carbon (UBC) Performance Objectives

Recognizing that average UBC content in the fly ash could vary with mill fineness, ash content of the contract coals, and coal pipe-to-pipe balance, a set of curves was developed to correlate UBC objectives with these variables. UBC predictions range from 3.7% to 22.3%, depending upon the set of variables that apply. Figure #3 exhibits the UBC performance objectives curves that were developed for the combustion system contract.

Boiler and Combustion System Tuning

Boiler and combustion system tuning commenced in late August, 1996. Initial tuning efforts have been interrupted and extended in part due to malfunctions of non-B&W supplied equipment, unit dispatch obligations, a six week test burn of non-contract coal, and additional needed equipment modifications uncovered during initial tuning activities. Tuning work continues with concentration on producing a satisfactory balance between boiler O_2 and CO production. Specific initial tuning results and problems that have been encountered are as follows:

NO_x Tuning Results

NO_x emissions from the low NO_x combustion system have been well within the performance targets. As indicated in Figure #3 in the Appendix, emissions during testing have ranged from as low as 0.27 #/MMBtu to a value generally less than 0.40 #/MMBtu. These values have been achieved despite operating with economizer exit O_2 values much higher than desired or predicted as discussed below. Therefore, we are optimistic about maintaining NO_x emission performance, when the CO and O_2 targets are eventually achieved.

CO and O_2 Tuning Results

Attaining a satisfactory balance between CO production and boiler excess O_2 has been a challenge ever since the modified boiler and low NO_x combustion system went into service. Several fuel delivery system components appear to be contributors to this problem. Specifics of the problems encountered are as follows:

Initial recorded CO levels exceeded 500 ppm (the calibration range of the CO monitor) unless the boiler O_2 was raised to > 5%. Additionally, the CO levels changed erratically from side-to-side in the furnace and from day-to-day without any apparent reason. Initial efforts concentrated on verifying the accuracy of the O_2 probes and the CO monitor and inspecting the boiler for sources of air in-leakage. Some minor instrument problems were corrected but no significant air in-leakage was found. CO levels remained unacceptably high. Adjustments were made to burner inner and outer secondary air vanes, but no positive effect on the CO levels was apparent. The possibility that one or two individual burners might need some fine tuning was then investigated. However, restaging the secondary air about the furnace from burner-to-burner, level-to-level, etc. also had little positive effect. Eventually, through trending of various operating parameters on the

distributed control system, it was discovered that CO spikes occurred in unison with the two speed mill feeders changing speeds. As stated earlier, the end-to-end balance of coal through the ball mills had been an initial system design concern. However its sensitivity to mill feeder speed changes and its effect on CO production was not readily apparent until tuning efforts commenced. Through the ingenuity of the Westinghouse DCS service engineer, we were able to program the operation of the two speed feeders to simulate variable speed-like operation in an attempt to level out the feed of coal to the mills. Substantial improvements in the CO levels were obtained. Concern over feeder motor longevity led us to eventually embark on a program to retrofit the mill feeders with variable speed drives and new motors.

Although the mill feeder modifications resulted in substantial CO emission improvements, the levels still either regularly exceed the 175 ppm target or the boiler O_2 has to be raised to 5+%. Figure #4 in the Appendix displays recent test data relating CO production and excess O_2. Qualitatively, the data suggests that substantial amounts of CO are being generated from all burner levels. However, the middle level of burners (the ones with impellers) and to a lesser extent, the lower level burners appear to contribute substantially more to high CO production levels.

High CO production from the middle level of burners (ones with impellers) exemplifies the complexity thus far trying to tune the combustion system. B&W generally supplies impellers to reduce CO production at some expense of producing NO_x. Accordingly, high CO production from the middle level of burners was contrary to everyone's expectations and B&W's previous experience. The impellers were initially set during unit start-up at a position 4 inches retracted from the edge of the burner nozzle. During recent tuning efforts, the position of the impellers was varied to determine its effect on CO and NO_x production. The results as shown on Figure #5 in the Appendix indicates that CO production dramatically increased when the impellers were either retracted further into the burner nozzles or when pushed flush with the end of the burner nozzles. Accordingly, the initial setting appears to be the optimal position for minimizing CO production with these particular impellers for our application. Therefore, other factors, such as primary air-to-fuel ratio and burner level-to-burner level coal flow imbalances, may warrant additional investigation.

Field observations during the tuning effort have indicated that the mill serving the bottom row of burners is supplying substantially more fuel to the burners than the other two mills. Measures to reduce the output from this mill in an effort to improve the burner level-to-burner level imbalance would reduce unit load capability since the exhausters on the other two mills are at capacity at full unit load. Thus far, to compensate for these fuel imbalances we have increased the distribution of excess air to the bottom row of burners.

The primary result of operating the boiler with excess O_2 at 5+% in order to minimize CO emissions to tolerable levels, is an undesirable boiler heat rate penalty. In addition, there is a genuine concern that the unit will have insufficient forced draft capacity to achieve rated load during the summer months at this O_2 level.

Unburned Carbon

Limited UBC data has been obtained thus far during the tuning effort due to having to operate the unit with high boiler excess O_2. However, the most recent fly ash samples that have been analyzed indicate that UBC levels are running at 7% to 9% on essentially Kerr McGee coal. Mill fineness data corresponding to these UBC levels are averaging 98.72% through the 50 mesh sieve and 73.7% through the 200 mesh sieve. Accordingly, the mills are very close to demonstrating the minimum fineness necessary to support UBC performance objectives. Additional UBC data will be collected once excess O_2 and CO has been reduced to acceptable levels.

Boiler/Unit Output

Another initial fuel delivery related incident encountered was that the unit was unable to attain more than about 90% of rated output. Field observations of mill amperage led us to suspect that the mills were under performing. It quickly became apparent that more attention would have to be paid than in the past to maintaining proper mill coal level and ball charge if the unit was to obtain rated capacity as well as optimum emission performance. Accordingly, we embarked on a program to optimize the performance of the newly refurbished mills. After some mill optimization adjustments, the unit was able to achieve full load without any support fuel.

Future Tuning Activities

B&W has been cooperative and actively involved with us trying to tune the low NO_x combustion system to meet the project objectives. Future tuning activities will likely be directed at replacing the impellers on the middle row of burners with a different design and possibly retrofitting impellers to the burners on one or more additional elevations. Other fuel delivery system related factors for which Union Electric has primary responsibility, such as primary air-to-fuel ratio and end-to-end ball tube mill output, may also warrant additional investigation and corrective action.

Acknowledgments

The author gratefully acknowledges Mr. Kevin Kersting (Power Plant Maintenance & Engineering), the Meramec Plant operating staff, and Mr. Bill Mariner (B&W Service) for their cooperation and determined efforts in pursuing the Meramec Unit #4 combustion system tuning objectives.

REFERENCES

S.A. Bryk, E.G. Lansing, M.P. Meyer, J.C. Morgan, and D.A. Sampson, "Total Furnace Upgrade of Aging Boiler Significantly Increases Reliability, Reduces NO_x Emissions, and Improves Cycling Operation," Technical Paper BR-1628, presented at the Power-Gen International '96 Conference, Orlando, Florida (December 1996).

Table 1

ULTIMATE ANALYSIS OF CONTRACT COALS

Constituent	KERR McGEE	REND LAKE
Moisture	12.19	12.0
Carbon	67.07	62.7
Hydrogen	4.37	4.2
Nitrogen	1.36	1.4
Chlorine	0.34	0.4
Sulfur	1.27	1.25
Ash	6.3	12.0
Oxygen	7.1	6.3

PARTIAL PROXIMATE ANALYSIS

Fixed Carbon	49.58	45
Volatiles	31.93	31

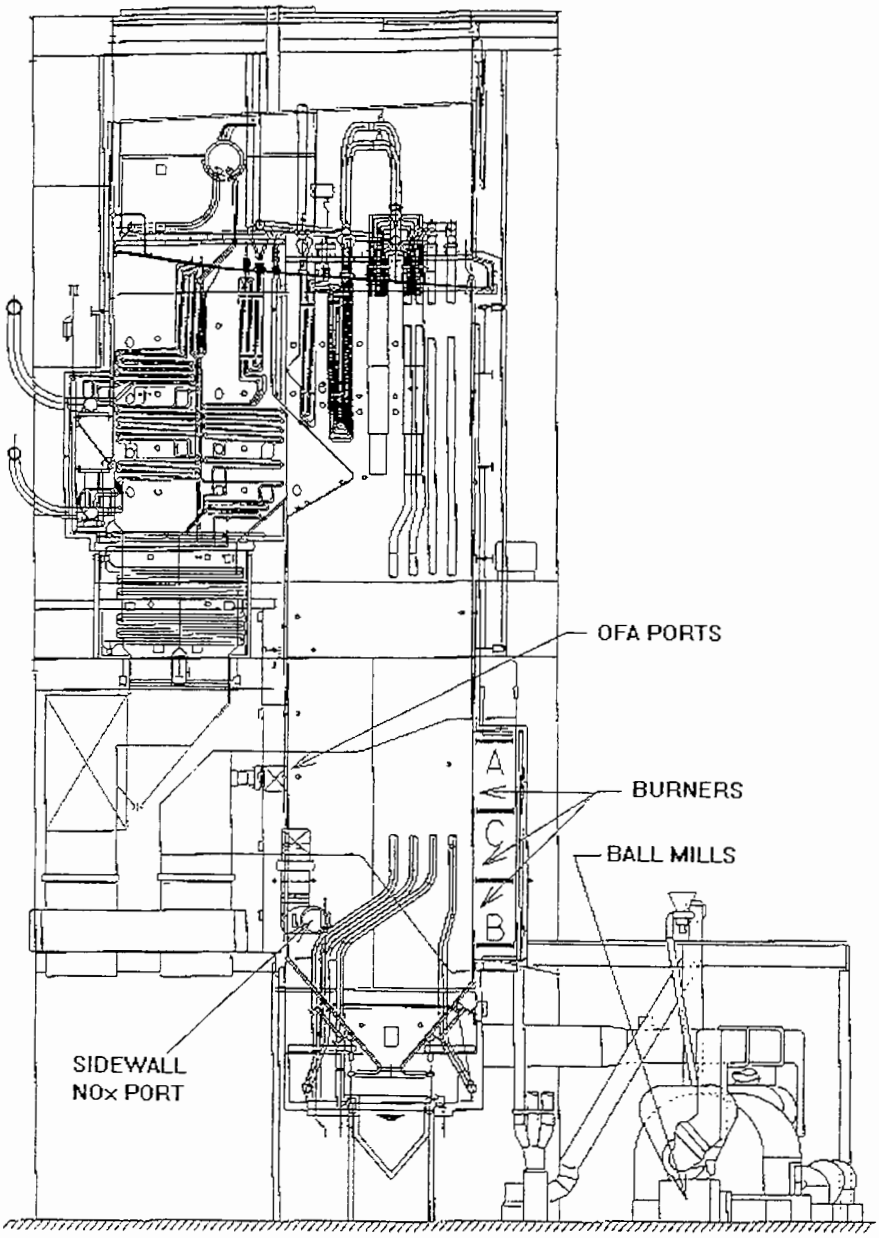

Figure 1
Meramec Unit #4 Boiler Cross-Section

COAL FIRED	MILL FINENESS (%)	UBC PERFORMANCE OBJECTIVES PIPE-TO-PIPE FUEL BALANCE	
		+/- 5%	+/- 10%
0% Kerr McGee	70/99.0	10.6	12
100% Kerr McGee	70/99.0	18.8	22.3
0% Kerr McGee	80/99.9	3.7	5.0
100% Kerr McGee	80/99.9	6.8	9.3
100% Rend Lake	70/99.0	10.6	12
0% Rend Lake	70/99.0	18.8	22.3
100% Rend Lake	80/99.9	3.7	5.0
0% Rend Lake	80/99.9	6.8	9.3

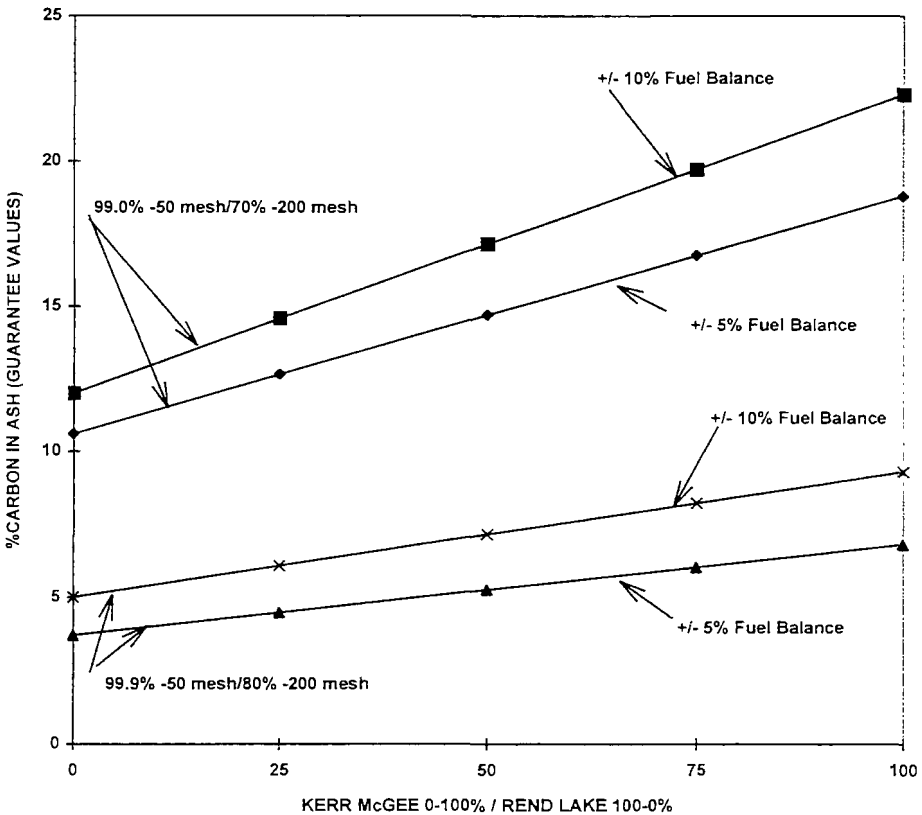

Figure 2
Meramec Unit #4
B&W Carbon In Ash Performance Objectives

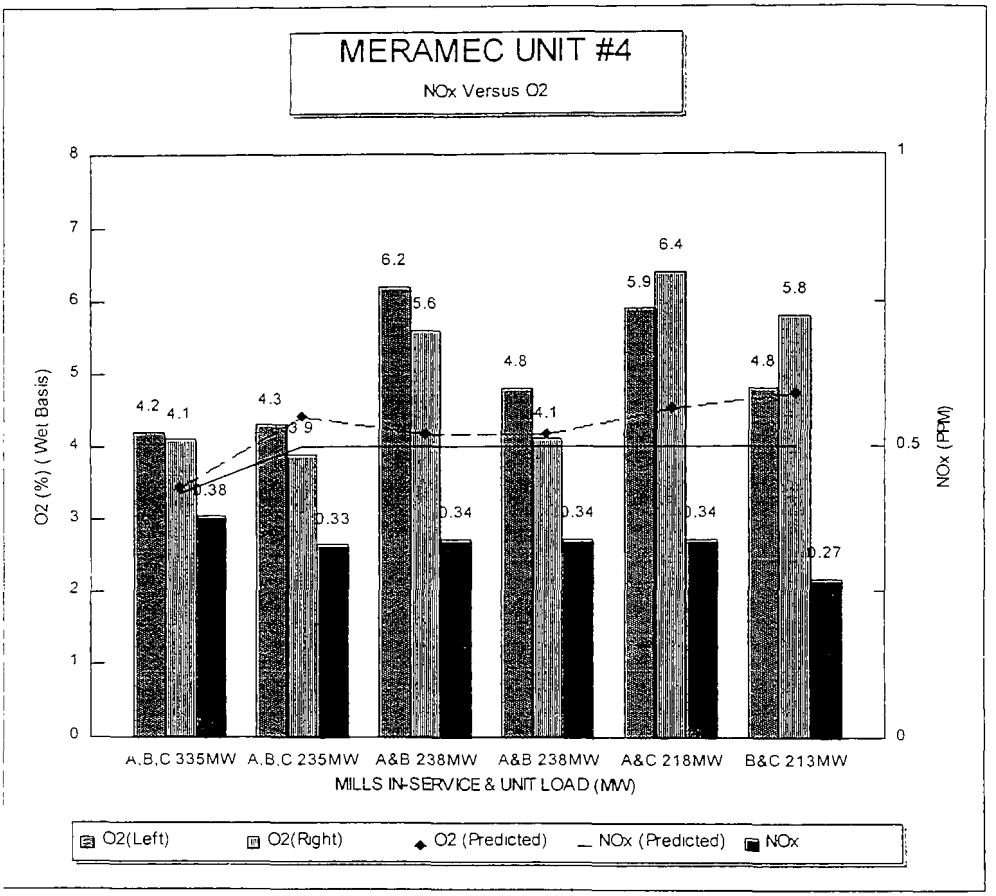

Figure #3
NO_x Versus O_2 Tuning Results

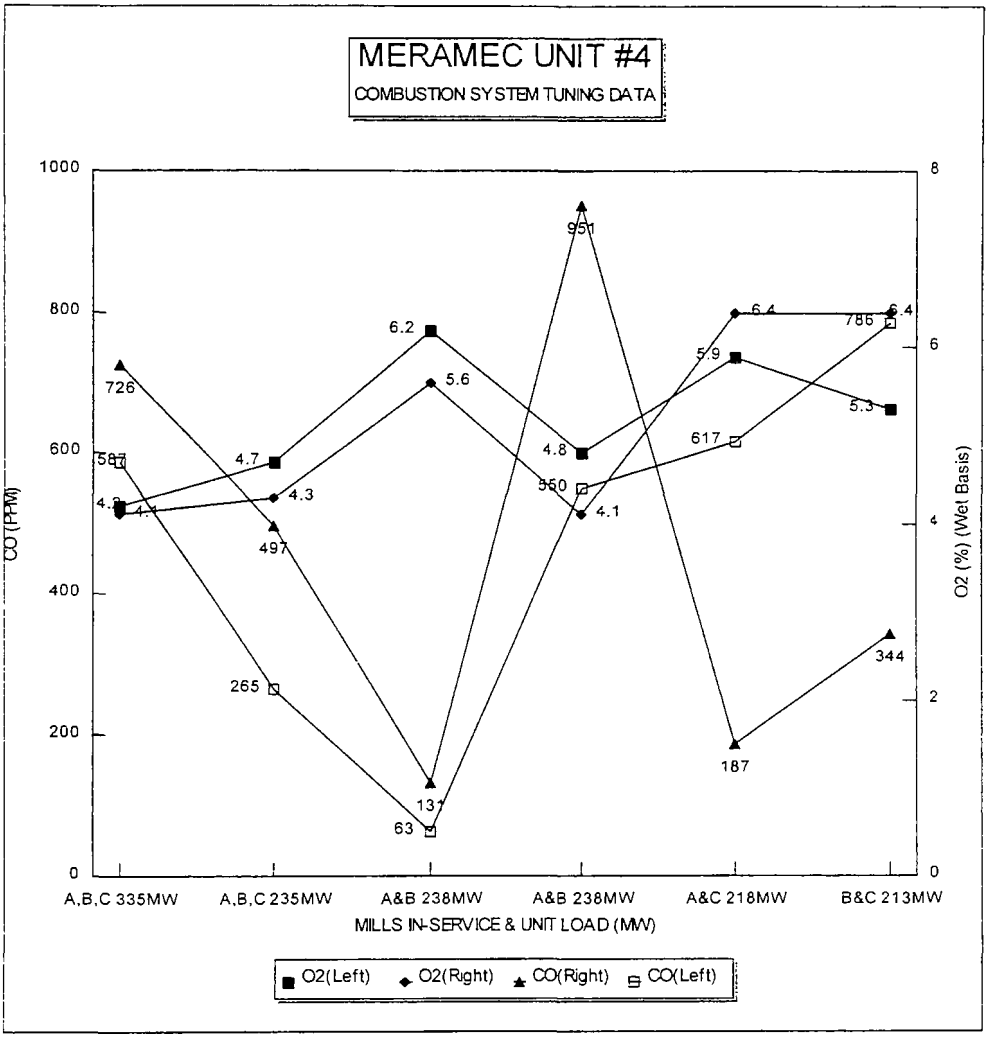

Figure #4
CO Versus O_2 Tuning Results

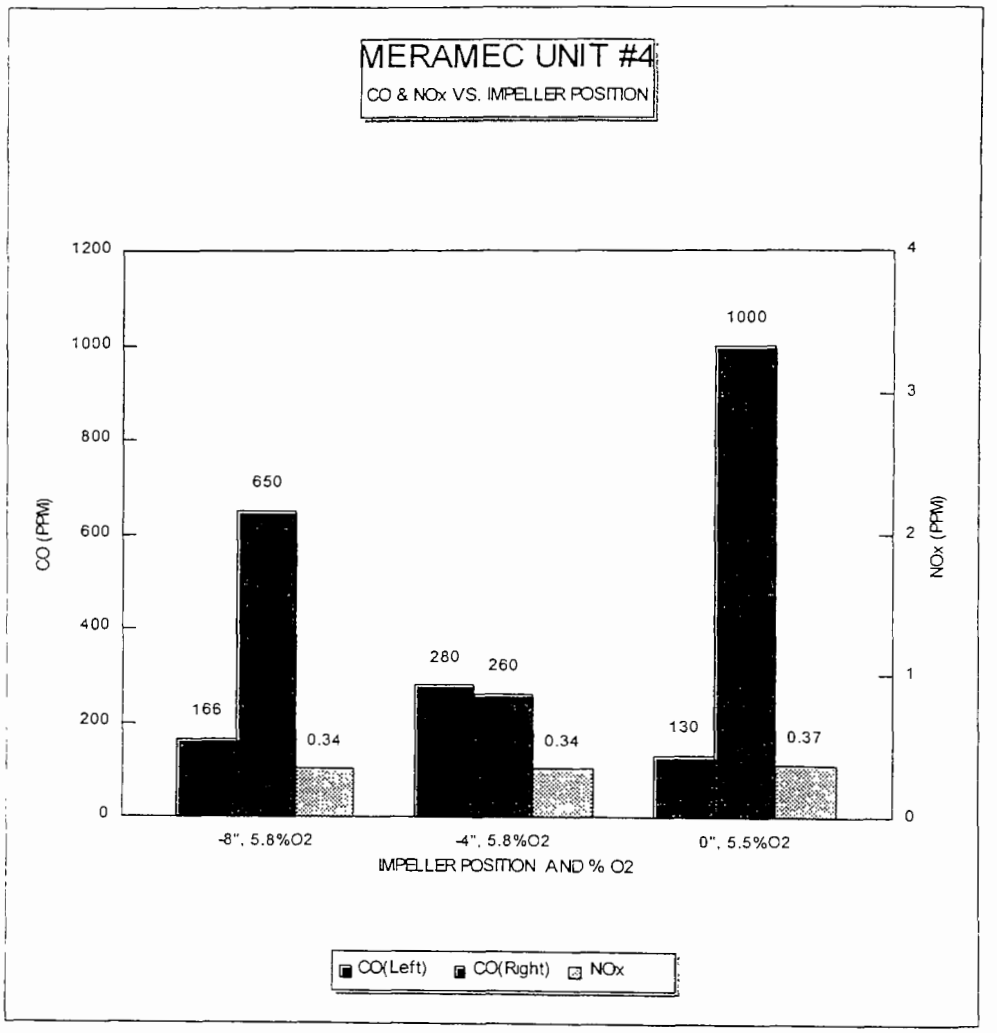

Figure #5
CO & NO_x Versus Impeller Position

FUEL SYSTEM MODIFICATIONS AND BOILER TUNING TO ACHIEVE EARLY ELECTION NO_x COMPLIANCE ON A 372-MWe COAL-FIRED TANGENTIAL BOILER

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Abstract

Minnesota Power's (MP) coal-fired generation system is comprised of Title IV-Phase II boilers. Although Phase II boilers are not required to meet emission limits until January 1, 2000, the standards will be more stringent than Phase I NO_x limits. MP investigated the merits of foregoing system averaging under a Phase II rule, and pursued an early election option with current Phase I NO_x limits.

Carnot conducted combustion performance and NO_x emissions characterization for MP's Boswell Unit 3. This engineering diagnostic program included pre- and post-retrofit fuel system performance testing.

This paper presents the results of applying commercially available fuel system modifications to successfully achieve NO_x compliance on a 372-MWe, coal-fired tangential utility boiler. The design focused on modifications to the fuel delivery system so that boiler tuning and optimization could be implemented to achieve compliance with EPA's Phase 1 Early Election NO_x emission standard of 0.45 lb/MMBtu. Compliance was achieved without installing new low-NO_x burners or overfire air. This retrofit included an evaluation of pulverizer modifications, fuel balancing options, and boiler instrumentation and control (I&C) modifications. Specific pre-retrofit and post-retrofit performance data for the boiler in terms of NO_x emissions, slagging impacts, and efficiency are presented. Pre- and post-retrofit data are also included for pulverizer

performance as a result of installing high-efficiency exhauster wheels and other pulverizer improvements.

Introduction

Carnot was contracted by Minnesota Power Corporation (MP) to assist in the development of a cost-efficient strategy to ensure compliance with the NO_x emissions limits mandated by Title IV of the 1990 Clean Air Act Amendments (CAAA). The first step in the development of a NO_x Compliance Strategy is to perform baseline evaluations of current boiler performance and NO_x emissions. This paper describes the results of the field evaluations of MP Boswell Unit 3. The primary test objectives to evaluate existing boiler operations were as follows:

- Quantify and verify the baseline NO_x emissions for each boiler.
- Determine the achievable NO_x reductions available with existing plant equipment, with a focus on operating modes which were previously not tested.
- Identify existing hardware which limits further NO_x reductions, and identify what the limiting factors of this equipment are. In particular, focus on mill performance and fuel/air distribution.

In order to accomplish these objectives, solutions were sought which minimized not only the capital costs, but also the Operating and Maintenance (O&M) costs. Moreover, combustion retrofit options were considered which could provide incremental improvements in efficiency or reduce other O&M costs to offset the cost of compliance.

Development of this low cost NO_x reduction compliance strategy began in 1994 and was completed with the post-retrofit performance evaluation in 1996.

Boswell Unit 3

Boswell Unit 3 is a Combustion Engineering tangential boiler which currently fires sub-bituminous coal (nominally 1% sulfur). This unit began operation in 1973. Full load rating is 2,472,000 lb/hr steam evaporation and 365 gross MW generation. Design superheat outlet steam is 2,619 psi/1005°F and reheat outlet steam is 548 psi/1005°F. The furnace cross sectional dimensions are 45'-4" wide by 40'-5" deep corresponding to a current full load NHI/PA of 1.9 x 10^6 Btu/hr-ft^2.

Steam temperatures are controlled primarily with burner tilt. The unit is balanced draft and equipped with a back end scrubber for particulate control.

This unit is equipped with five CE-Raymond bowl mills model 863 RS with mill A as the uppermost and mill E as the lowermost elevation. The boiler burns a PRB coal that averages 10% ash, 25% moisture, 30% volatiles, and HHV of 8,650 Btu/lbM.

Test Variables

Baseline (as-found operation) testing was conducted from approximately 45% load to full load in order to determine the operating adjustments and equipment modifications necessary to reduce NO_x emissions. All tests were conducted at steady state operating conditions. The goal of the program was to identify the effects of the variables on reducing NO_x emissions, such as load, excess O_2, BOOS firing, and mill performance. Another of the underlying project objectives was to test some different operating modes previously untested specifically for reduced NO_x, such as fuel and air biasing.

Specific items that were of concern during the testing and that were closely monitored by Carnot included steam temperatures, flame characteristics, combustibles, slagging and fouling, and boiler efficiency.

Data Collection

On site, Carnot was responsible for selecting operating conditions, within limits acceptable to the Control Operator, and reviewing data from previous tests to determine subsequent test conditions. The data collection process is described below.

Operating Data. Operation was closely observed and documented during the test program.

Gaseous Emissions Data. A gaseous emissions sampling matrix was installed by Carnot in the air preheater inlet ducts. This matrix consisted of stainless steel probes fitted with in-duct sintered metal filters. A 16 probe matrix was installed on Unit 3. The CEMS was used to monitor NO_x, O_2, CO_2 and CO levels during all tests.

Loss-on-Ignition. Carnot collected flyash samples from the inlet breaching to the scrubber for each unit.

Primary Air Velocities. Carnot measured the primary air velocities in the coal pipes using a "dirty air" pitot probe.

Coal Fineness. MP personnel collected coal samples for coal fineness determinations during the same test conditions that Carnot was measuring primary air velocities.

Raw Coal Sampling and Analyses. Daily raw coal samples were taken from the inlets to the feeders of the mills that were on-line. The samples were sent to Commercial Testing & Engineering located in Lombard, Illinois for the following analyses:

- proximate analysis (total moisture, volatile matter, fixed carbon, ash)
- ultimate analysis (sulfur, carbon, hydrogen, nitrogen, oxygen)
- higher heating value
- hardgrove grindability index (HGI)

Additionally, one sample from Unit 3 was analyzed further for ash fusion and mineral content. These data were used to evaluate slagging and fouling potential.

Baseline NO_x Emissions

Baseline NO_x emissions are plotted in Figure 1 for Unit 3. Baseline NO_x emissions were measured across the full range gross loads of 184-366 MW on Unit 3.

NO_x emissions were nearly constant from minimum to 90% loads at 0.48 lb/MMBtu on Unit 3. Full load peak NO_x emissions were 0.56 lb/MMBtu.

Excess Air Effect on NO_x

The effect of varying boiler excess O_2 was tested on Unit 3 as graphed in Figure 2. Three different O_2 levels were tested at full load resulting in an emissions sensitivity of 0.04 lb/MMBtu NO_x per 1% O_2 variation. At 90% load and under staged combustion conditions, the sensitivity was shown to be 0.09 lb/MMBtu per 1% O_2. These results were applied to other test staged combustion test results in order to normalize emissions to a constant excess O_2 for purpose of comparison. In instances where CO levels were above acceptable limits, the NO_x/O_2 sensitivity curve was also used to normalize NO_x emissions to a higher O_2 where CO emissions could be anticipated to be within acceptable limits.

The tendency for reduced steam temperatures with lower excess air could be countered with minor tilt adjustments.

Staged Combustion NO_x Reduction

Bulk staging of combustion for reduced NO_x operation included the following:

- Burners Out of Service
- Fuel Biasing
- Air Biasing

Burners Out of Service (BOOS). The effectiveness of BOOS was tested on Unit 3 by opening the A fuel air and/or the AA auxiliary air dampers with the A mill removed from service. Table 1 summarizes the test results.

Reductions in NO_x emissions ranged from 15% to 30% due to the effect of BOOS. These comparison tests were selected as having similar operating conditions with the exception of the staged combustion operation. The emissions sensitivity to excess O_2 was used to correct measured emissions to a different O_2 level than tested. This was done for Test 3 because measured CO was 425 ppm, thus an O_2 correction of 0.5% was added and the adjusted NO_x of 0.33 lb/MMBtu was used to estimate the achievable reduction.

Fuel Biasing. The impact of biased fuel flow on NO_x was tested, consistent with the program objective of investigating previously untested operating modes. Fuel biasing was implemented

by adjusting the feeder speed hand/auto controller bias. A summary of fuel biasing tests is contained in Table 2.

Fuel biasing tests on Unit 3 resulted in 11% NO_x reduction by itself, and 28% reduction with the addition of full OFA. With these tests the lower furnace was more fuel rich than the upper; however, there were no significant changes on boiler operation including steam temperatures.

Burner Tilt Effect on NO_x

The effect of burner tilt on NO_x emissions was tested on Unit 3 as shown in Table 3. Tests 5 at +13° and 6 at -24° tilts were conducted sequentially on November 4, while Test 11 at 0° tilt was conducted November 5. All tests, when normalized to a constant excess O_2, showed approximately the same NO_x emissions of 0.52 lb/MMBtu.

Combustion Air Distribution

Unit 3 exhibited O_2 maldistribution, with the south side frequently having a 1-2% higher O_2 level. Figures 3 and 4 show a typical O_2 and NO_x contour plots for Unit 3. This maldistribution was consistent throughout the Unit 3 load range under both baseline and low NO_x operating conditions. The plant probes also indicated the O_2 imbalance.

Flyash LOI

All flyash loss-on-ignition (LOI) tests on Boiler 3 resulted in less than 0.4% weight loss after burn-off of the samples. This was true even for tests with combustion imbalances such the low O_2 with A level BOOS which had average CO levels of 2,950 ppm and only 0.37% LOI.

Slagging and Fouling Properties of Ash

The slagging and fouling properties of the ash are summarized in Table 4. The ash type for all coals is lignitic with an iron oxide to calcium and magnesium oxide ratio of less than one.

The coal samples from Unit 3 show low slagging potential and tend toward weak slag adherence to tube metal.

Fouling potential is indicated by the percentage of NaO_2 ash content for lignitic coal ash. As shown in Table 4, the coal sampled from Unit 3 indicate very low potential with 0.4% or less NaO_2.

Impacts on Boiler Efficiency

Impacts on boiler efficiency are quantified by various parameters which most affect performance as shown in Table 5. Included are steam temperatures, attemperation flows, CO emissions, and air preheater exit temperature. Baseline tests are compared with the minimum NO_x emission tests for each load.

Unit 3 Pulverizer Performance. The coal pulverizer performance for Unit 3 mills C and D are illustrated in Figures 5 and 6 using Rosin and Rammler plots. All tests were conducted with a classifier vane setting of 2.5-3.5 and air inlet temperature of approximately 700°F. There were two conditions which could be limiting the mill capacity:

1. The average as-received coal moisture content of 25% requires either higher air temperature or increased air flow to maintain output above the dew point temperature.

2. The nameplate mill capacity of 106,000 lb/hr is for 70% through 200 mesh with 55 HGI coal. Actual conditions were 70-75% through 200 mesh and 48-51 HGI.

Tests were performed over the range of 42,000-96,000 lb/hr (39-91% of nameplate capacity). The design air flow for these mills is 159,000 lb/hr (2650 lb/min from curve) from 50%-100% mill capacity, compared to 152,000-158,000 lb/hr primary air measured on the high mill loading tests.

Test 19 on mill D had a relatively low mill loading with coal flow at 42,000 lb/hr. The measured primary air flow was 183,000 lb/hr, indicating an increase from the high mill loading operation. By design, the primary airflow control should begin ramping down at 50% mill capacity. Figure 6 shows the coal fineness improved substantially on this test as a result of the higher air/coal ratio and low loading on the grinding elements.

Figures 7 and 8 show bar graphs of the pipe-by-pipe air flows measured for mills C and D. A convenient measure of air and/or fuel distribution is the standard deviation divided by the mean flow (also known as "coefficient of variation"). This value ranged from 2.3% to 9.8% for each mill for the various tests. A coefficient of variation of 5% is generally achievable. Note that coal flow per pipe was not measured, and even if air flows are balanced the air/coal ratio could still vary significantly. The intent of this testing was to get a "first level" indication of the performance of two representative mills.

Pre-Retrofit Fuel System Performance Tests

The first task of the NO_x implementation program for Minnesota Power's Boswell Unit 3 was to perform pre-retrofit mill characterization tests.

The test objectives included the following:

- Evaluate the coal fineness from each mill (A, B, C, D, E);
- Measure the coal flow distribution through each coal pipe;
- Measure the velocities through each coal pipe to assess primary air flow distribution; and
- Quantify mill power requirements.

These tests involved primary air velocity measurements in the coal pipes and pulverized coal sampling for fineness analysis. The coal sampling for the mill characterization tests utilized a

RotorProbe system that collects coal samples at an isokinetic rate to ensure that a representative coal sample is collected.

The results of the fuel system performance tests are summarized in Table 6 for each mill. The key results derived from the pulverizer tests are:

- **Coal Grinding Capacity Limitations.** Based upon the design capacity of the RS 863 mill, the low coal grindability (HGI) measured, and the spillage observed, it is concluded that the pulverizers are limited in capacity due to reduced coal grindability. The original design of the RS 863 pulverizer was to pulverize 106,000 lb/hr of 55 HGI coal as shown in Figure 9. For reference, the required coal flows for full load operation with four and five mills are shown on the figure. Actual HGI measurements ranged from 45 to 54. (Per the contract coal specifications, HGI could be as low as 42). Independent of any air flow limitations, the mill capacity would be de-rated to 91.7 klb/hr with 45 HGI coal.

- **Primary Air Flow Capacity Limitations.** Based upon the high fuel moisture content and the inability to consistently maintain outlet temperatures over 130°F, it is concluded that the pulverizers are limited in capacity due to inadequate air supply to dry the coal. Other measures to increase exhauster fan head capability or reduce backpressure on the exhauster will be required. ABB-CE's high efficiency exhauster wheel (HEEW) should be consisted.

- **Coal Fineness.** Acceptable coal fineness for these mills is 70% through 200 mesh, 90% through 100 mesh, and less than 1% on 50 mesh. Mills A, C, D, And E demonstrated acceptable coal fineness. Mill B fineness was slightly short of these guidelines.

- **Primary Air Flow Balance.** With the existing equipment features, the primary air flow balance should have a variance coefficient of 5% or less. Only Mills A and E demonstrated acceptable primary air balance near 5% variation. Mills B, C, and D have less than satisfactory balance ranging from 12% to 31% variation.

- **Coal Flow Balance.** With the existing equipment features, the coal flow balance should have a variance coefficient of 10% or less. All mills have less than satisfactory coal balance, with measured variation coefficients of 12% to 32%.

Post-Retrofit Fuel System Performance Test

Performance tests of mills C and D on Boswell Unit 3 were conducted after each of these mills were retrofit with ABB-CE's high efficiency exhauster wheel (HEEW).

The tests performed on 3C and 3D mills were conducted under good operating conditions. The coal grindability met or exceeded the specification requirements of 48 HGI. The coal total moisture content was above the design specification value of 25%. Both mills had been overhauled within the previous weeks, and the 3C hot air damper was repaired. Hot primary air (air preheater exit) temperatures ranged from 616-681°F, compared to 650°F design.

The test results for 3C mill at 71% load are as follows:

- coal properties: 49 HGI and 26.4% total moisture
- feeder speed: 71%
- coal flow: 89,713-98,636 lb/hr (see Discussion of Results below)
- % on 50 mesh fineness: 2.6
- % through 100 mesh fineness: 84.0
- % through 200 mesh fineness: 57.7
- fuel balance standard deviation/mean: 26%
- primary air balance standard deviation/mean: 12%
- mill outlet temperature: 138°F
- mill motor amps: 104

The test results for 3D mill at 75% load are as follows:

- coal properties: 48 HGI and 25.9% total moisture
- feeder speed: 75%
- coal flow: 94,767-104,193 lb/hr
- % on 50 mesh fineness: 1.3
- % through 100 mesh fineness: 92.3
- % through 200 mesh fineness: 76.7
- fuel balance standard deviation/mean: 12%
- primary air balance standard deviation/mean: 2%
- mill outlet temperature: 140°F
- mill motor amps: 114

The test results for 3D mill at 80% are as follows:

- coal properties: 49 HGI and 27.3% total moisture
- feeder speed: 80%
- coal flow: 101,085-111,139 lb/hr (see Discussion of Results below)
- % on 50 mesh fineness: 4.6
- % through 100 mesh fineness: 84.9
- % through 200 mesh fineness: 65.5
- fuel balance standard deviation/mean: 17%
- primary air balance standard deviation/mean: 2%
- mill outlet temperature: 142°F
- mill motor amps: 114

Discussion of Results

The primary purpose of the HEEW retrofit was to increase the capacity of the mills. In order to evaluate capacity, the feeder calibration needs to be known. With the DCS upgrade on Unit 3, the feeder calibration was changed from 0-1,567 RPM (as specified by Stock originally) to 0-1,800 RPM. This means that the current feeder speed readings cannot be directly compared to

the pre-DCS feeder speed readings. Since the feeders were calibrated per Stock procedures, it is reasonable to apply the Stock data sheet calibration factor of 70.198 lb/hr of coal per RPM. However, the baseline test data showed a calibration factor of 77.18 lb/hr of coal per RPM. The range of coal flows reported above reflects these two methods. It should be noted that the indicated lb/hr and TPH of coal flow currently in the DCS underestimate the coal flow relative to either of these calibration factors.

Fuel and primary air balance exceeded the project targets of 10% and 5%, respectively. However, these parameters were not guaranteed with the HEEW installation since the HEEW does not inherently provide any means of controlling fuel line balance.

Coal fineness did not achieve the guaranteed performance of 1% on 50 mesh for any of the tests.

Conclusions

Unit 3 NO_x Characteristics

- Baseline NO_x emissions for Unit 3 were 0.56 lb/MMBtu at full load, and 0.48 lb/MMBtu from minimum load to 90% load.
- Burners out of service (BOOS) reduced NO_x emissions 16-30% at 90% load. BOOS is not possible at full load due to pulverizer capacity limitations. With adequate mill capacity similar reductions could be expected.
- The sensitivity of Unit 3 to boiler excess air ranges from 0.04-0.09 lb/MMBtu per 1% change in O_2.
- Biasing more fuel to the lower elevations was effective in reducing NO_x emissions by 11-28% at minimum load. Air biasing and burner tilts did not reduce NO_x emissions under the conditions tested.
- The coal fired in Unit 3 has a low potential for slagging and fouling, and future operations with staged combustion (reducing environments) should not significantly increase this potential.
- Fly ash loss on ignition (LOI) levels were less than 0.4% under all test conditions, including heavy staging of fuel and air. Flyash LOI should not be a critical limiting factor to implementing combustion NO_x controls with the characteristics of the coal being utilized on Unit 3.

Unit 3 Fuel/Air Distribution and Pulverizer Performance

- Primary air flow coefficient of variation (standard deviation divided by mean) on mills C and D ranged from 2.3-9.8% from pipe to pipe. A coefficient of variation of 5% or less is generally achievable.

- Combustion imbalance was consistently prevalent in the boiler indicated by significant differences in O_2 and NO_x emissions in the south and north boiler exit ducts.

- Pulverizer C and D are performing well relative to design. The coal being utilized has higher moisture and lower grindability than the design properties necessary to achieve 106,000 lb/hr nameplate capacity.

- The retrofit of the HEEW clearly made a substantial improvement in mill capacity, particularly in the drying capability of the mills. Drying capability was the critical limiting factor prior to the modification because of high fuel moisture content relative to original fuel specifications. Mill outlet temperature was maintained at approximately 135-140°F without fully opening the hot air damper.

- Mill 3C is not achieving its guaranteed capacity or 50 mesh fineness by any estimates.

- Mill 3D appears to be achieving its guaranteed capacity.

- Mill 3D is not achieving its guaranteed coal fineness.

- The mills are not achieving the required fuel line balance.

- Based upon the increased capacity achieved, it is expected that Boswell 3 will be able to reliably achieve full load on four mills once all mills are retrofit with the HEEW.

References

1. Coal Fouling and Slagging Parameters, Winegartner, E.C., ed., ASME, 1974. Steam, Babcock & Wilcox, 40th Edition, 1992.

2. Title IV-Phase II NO_x Compliance Strategy for Minnesota Power, Himes, R. and Scharnott, M., Power-Gen '95, Anaheim, California.

Table 1
NO_x Reduction Effectiveness of BOOS
MP Boswell Unit 3

	Test No.	Gross Load MW	APH In O_2 % dry	Measured NO_x lb/MMBtu	Excess O_2 Normalized NO_x lb/MMBtu	NO_x Change
Comparison: Baseline, AMIS	1	325	4.31	0.473		
A-BOOS, AA dampers open	3	326	4.84	0.298	0.33	- 30%
Comparison: A-MOOS	8	337	4.75	0.467	–	–
A-BOOS, AB & A dampers open	9	335	4.83	0.392	n/a	- 16%
Comparison: A,E-MOOS	17	241	3.51	0.297	–	–
A-BOOS, AA dampers open	18	239	3.46	0.251	n/a	- 15%

Notes:
(1) "AMIS" means all mills in service.
(2) Test 3 was normalized to an O_2 of 5.3% to offset excessive CO measured at 425 ppm.
(3) Neither Test 9 nor Test 18 required normalizing to a different O_2 due to acceptable CO levels.

Table 2
NO_x Reduction Effectiveness of Fuel Biasing
MP Boswell Unit 3

	Test No.	Gross Load MW	APH In O_2 % dry	Measured NO_x lb/MMBtu	Excess O_2 Normalized NO_x lb/MMBtu	NO_x Change
Comparison: D (lower) bias low	19	184	5.82	0.476	–	–
B (upper mill) biased low	20	188	5.69	0.422	n/a	- 11%
Comparison: D (lower) bias low	19	184	5.82	0.476	–	–
B bias low + open AA dmprs (BOOS)	21	184	6.39	0.366	0.342	- 28%

Notes: (1) Unit 3 low load Tests 19, 20, and 21 had mills A and E removed from service.

Table 3
NO_x Reduction Effectiveness of Burner Tilt
MP Boswell Unit 3

	Test No.	Gross Load MW	Outlet Temps. SH/RH °F	Attemp. Sprays SH/RH Klb/hr	APH In O_2 % dry	Excess O_2 Measured NO_x lb/MMBtu	Normalized NO_x lb/MMBtu	NO_x Change
Comparison: 0° Tilt	11	365	1002/1008	18/30	3.32	0.526	–	–
Up Tilt @ +13°	5	366	997/1015	4/0	4.21	0.557	0.520	0%
Comparison: 0° Tilt	11	365	1002/1008	18/30	3.32	0.526	–	
Down Tilt @ -24°	6	364	967/991	4/0	2.97	0.510	0.524	0%

Table 4
Ash Slagging and Fouling Potential
MPL Boswell Unit 3

Unit		3
Sample Date		5-Nov
Sample ID/Carnot Test #		3B
Mill Feeder Inlet		all
<u>Ash Type Determination</u>		
Normalized % Acidic		77.1%
Normalized % Basic		22.9%
Base to Acid Ratio		0.30
Fe203/(CaO+MgO)		0.20
Ash Type		lignitic
<u>Slagging Potential Indicators</u>		
T-250	°F	2,557
Slagging Potential		low
Rfs = (max HT+4*min IT)/5	°F	2,273
Slagging Potential		med
FT-IT Temp Diff	Reducing °F	150
	Oxidizing °F	160

If <100°F tends toward thin slag buildup and tight slag adherence (undesirable).
If >200°F tends toward thick slag buildup and weak slag adherence (control with sootblowing).

<u>Fouling Potential</u>		
Index (NaO_2 content)		0.40
Type	(low/med if Index <3)	low
	(high if Index >3)	

Table 5
Efficiency Impact Summary
MP Boswell Unit 3

Test No.	Gross Load MW	Mill Out of Service	Description	NO_x lb/mmBtu	Boiler O_2 dry	Average Main Steam °F	Average Reheat Steam °F	SH Spray Klb/hr	RH Spray Klb/hr	CO ppm	APH Exit Temp °F
5	366.3	none	Baseline	0.557	4.21	997	1,015	4	0	0	258
6	363.9	none	Minimum NO_x	0.510	2.97	967	991	4	0	0	264
			Change	-8%	-1.24	-30	-24	0	0	0	6
1	324.7	none	Baseline	0.473	4.31	965	947	26	3	3	252
3	326.3	A	Minimum NO_x	0.298	4.84	988	982	25	0	425	238
			Change	-37%	0.53	23	35	0	-3	422	-14
15	238.5	E	Baseline	0.481	4.61	1,009	969	39	3	0	n/a
18	239.4	A,E	Minimum NO_x	0.251	3.46	995	971	28	0	60	n/a
			Change	-48%	-1.15	-14	2	-11	-3	60	n/a
19	183.6	A,E	Baseline	0.476	5.82	1,004	956	23	0	0	226
21	183.3	A,E	Minimum NO_x	0.366	6.39	1,012	952	18	0	0	224
			Change	-23%	0.57	8	-4	-5	0	0	-2

Table 6
Fuel System Performance Results Summary
MP Boswell Unit 3

Mill	Test	Raw Coal Feed lb/hr	Primary Air Flow, Wet lb/hr	Primary Air Flow, Dry lb/hr	Air/Fuel Ratio*	% thru 200 Sieve	% thru 100 Sieve	% on 50 Sieve
A	3	81,000	140,175	130,691	1.61	73.1	92.6	0.7
	5	90,000	155,690	142,949	1.56	71.7	91.4	1.3
	AVE	85,500	147,933	136,820	1.60	72.4	92.0	1.0
B	1	88,800	132,635	122,862	1.38	69.6	90.1	1.5
	2	90,000	114,929	104,565	1.16	67.5	89.0	1.6
	3	90,000	118,788	108,424	1.20	69.5	90.5	1.4
	4	97,500	115,889	102,088	1.05	67.2	89.2	1.5
	AVE	91,575	120,560	109,485	1.20	68.5	89.7	1.5
C	1	85,200	137,777	128,402	1.51	73.0	92.6	0.8
	2	87,600	127,586	117,054	1.34	70.0	88.5	0.8
	4	91,500	126,364	112,197	1.23	76.2	93.8	0.6
	AVE	89,550	130,576	119,218	1.36	73.1	91.6	0.7
D	1	75,600	143,657	135,336	1.79	70.6	91.2	1.0
	2	81,600	137,374	127,886	1.57	78.0	94.1	0.4
	4	85,500	128,456	115,003	1.35	76.4	93.5	0.6
	AVE	83,550	136,496	126,075	1.57	75.0	92.9	0.7
E	1	76,800	147,296	138,980	1.81	70.9	91.4	1.1
	2	85,200	130,708	120,655	1.42	71.3	91.6	0.9
	4	85,500	137,512	124,787	1.46	73.0	91.9	0.9
	AVE	85,350	138,505	128,141	1.56	71.7	91.6	1.0

*Based on dry air flow, which was calculated.

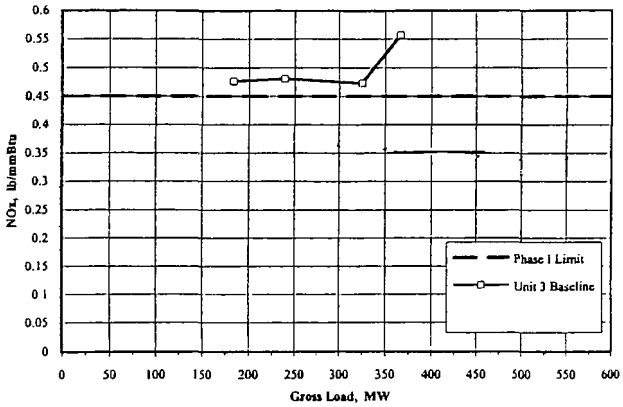

Figure 1
Baseline NO_x vs. Load, MP Boswell Unit 3

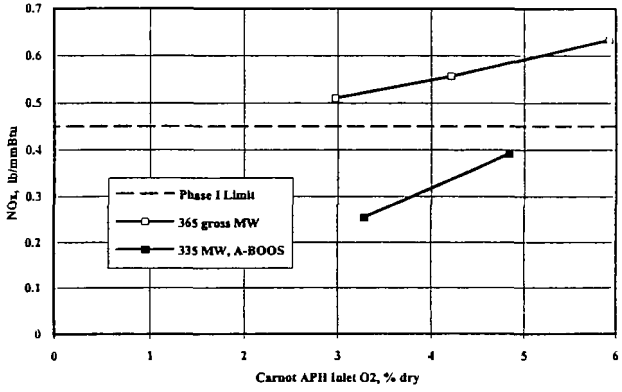

Figure 2
NO_x vs. Excess O_2, MP Boswell Unit 3

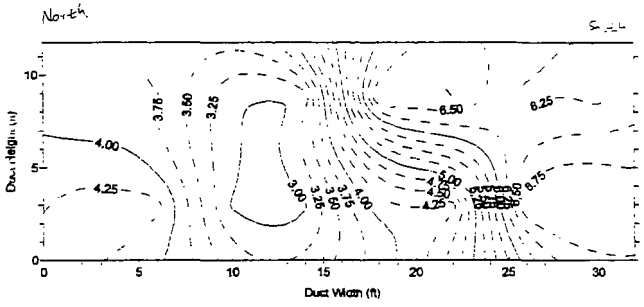

Figure 3
Economizer Exit - Excess Oxygen Contours, MP Boswell Unit 3

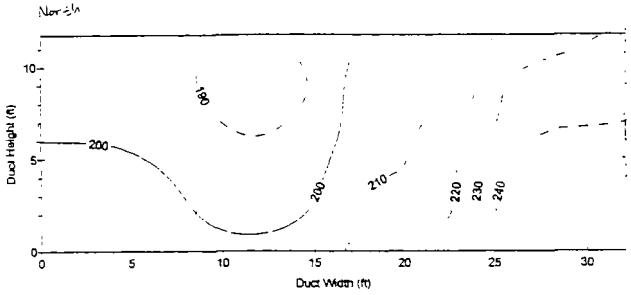

Figure 4
Economizer Exit - NO Contours, MP Boswell Unit 3

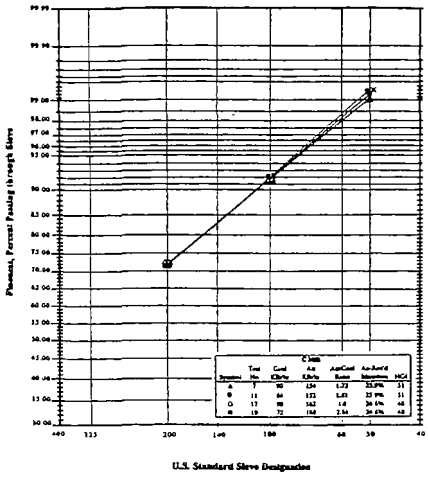

Figure 5
C Pulverizer Performance, MP Boswell Unit 3

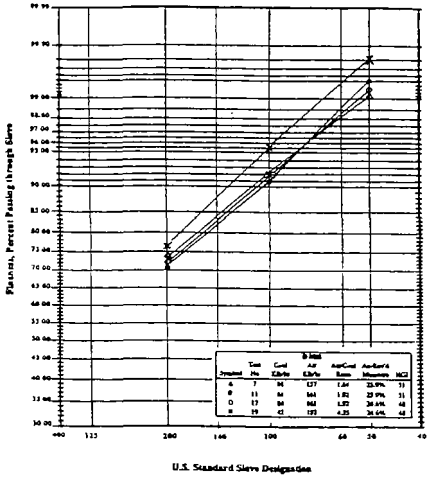

Figure 6
D Pulverizer Performance, MP Boswell Unit 3

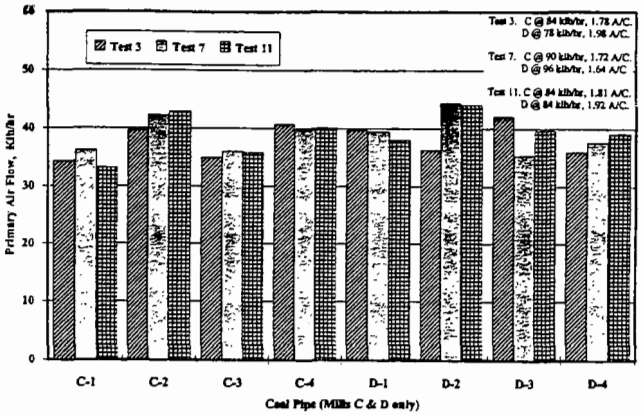

Figure 7
Primary Air Flow Distribution, MP Boswell Unit 3

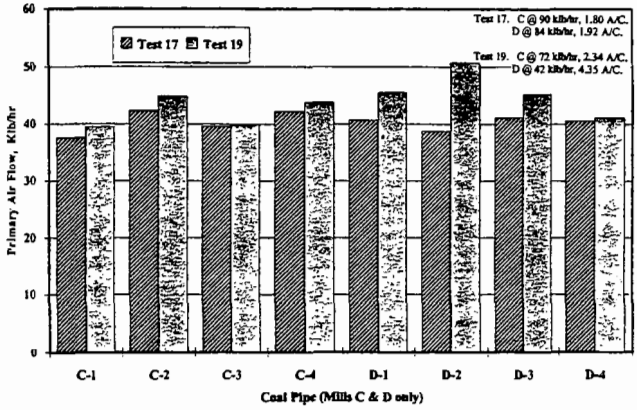

Figure 8
Primary Air Flow Distribution, MP Boswell Unit 3

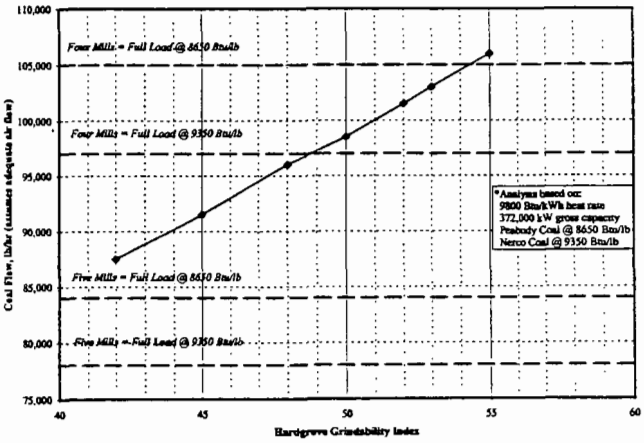

Figure 9
RS863 Pulverizer Capcity vs. HGI, MP Boswell Unit 3

Experience with Combustion Tuning and Fuel System Modifications to InexpensivelyReduce NO_X Emissions from Eleven Coal-Fired Tangential Boilers

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Abstract

This paper presents commercially-available, low-cost options for achieving NO_X compliance on pulverized coal-fired tangential boilers which require approximately 5% to 50% reductions. Often reduced NO_X and economic benefits (e.g. increased efficiency, reduced maintenance) can be achieved simultaneously. Actual performance data are presented based upon direct experience applying combustion tuning and fuel system modifications on eleven coal-fired, dry-bottom tangential boilers in the U.S. Several low-cost options are presented, some of which are generally unknown to electric utility engineers. Frequently combustion tuning efforts fall short of required NO_X reduction goals because it is not known how to inexpensively overcome common limiting factors (e.g. unburnt carbon, slagging). Important limiting factors are described, including low-cost methods to overcome these factors.

Introduction

This technical paper focuses on low-cost combustion tuning and fuel system modifications to reduce NO_X emissions and improve performance on dry-bottom, pulverized coal-fired tangential boilers. This technical results focus on four low-cost NO_X reduction techniques which can be applied to the majority of tangential boilers:

1. Fuel biasing
2. Air Biasing
3. Reduced O_2
4. Burners out of service (BOOS)

Although these methods are not ostensibly new and unique, they are often overlooked in favor of higher cost techniques because common limiting factors are encountered but not addressed. One purpose of this paper is to highlight these limiting factors and to present options to overcome them.

Higher cost techniques such as overfire air, low NO_X burners, reburn, or post-combustion controls are not discussed. Furthermore, tuning methods with large efficiency penalties or potentially high fuel costs are also not included such as air preheat control (e.g. hot air recirculation or air preheater bypass) or gas co-firing.

Minimizing the primary air-to-coal ratio is a proven technique for reducing NO_X emissions[1] by 5-10%, although no data is presented in this paper because most units did not have adequate control over pulverizer fuel and air flow. Nonetheless it is recommended that minimized primary air-to-coal ratio be considered a viable, low-cost NO_X reduction technique for those units which have adequate controls and which have an available margin to reduce coal pipe velocity while maintaining coal particle transport. Reduced pulverizer air flow can also provide other benefits[2] such as improved fineness and coal balance, reduced wear, reduced proclivity to pulverizer fires, and increased boiler efficiency. It is emphasized that tangential units often require higher coal pipe velocities (typically 4,000 fpm or higher) than wall-fired units because of longer pipe runs. Lastly, it is cautioned that when reduced primary air flow is assessed, individual pipe-to-pipe balance needs to be verified and maintained, not just average coal pipe velocity for each pulverizer.

Burner tilt control is frequently touted as a method for reducing NO_X emissions on tangential units as it has been well established that horizontal tilts result in lower NO_X. than upward or downward tilts. Although this has been verified in the experience of the authors, it is recommended that flexibility to adjust burner tilts be retained in most cases in order to maintain proper steam temperatures and boiler efficiency. It has been found in general that overall lower NO_X emissions and optimum efficiency can be simultaneously achieved by tuning with the key methods described above. For example one of the impacts of BOOS operation is to increase or decrease steam temperatures, depending on unit-specific factors and load, and design steam temperatures can frequently be maintained by adjusting burner tilts. All factors being equal, tangential boiler operators should attempt to maintain horizontal burner tilts for minimum NO_X.

Sootblowing and boiler cleanliness is yet another factor which can aid in reducing NO_X emissions. Although this has also been verified in the experience of the authors, it is recommended in most cases not to constrain sootblowing procedures solely to reduce NO_X emissions. Similar to burner tilt control, flexibility to adjust sootblowing pattern and frequency is best maintained to respond to changes in fuel properties, unit loading demands, or to offset performance impacts induced by staged combustion (e.g. to control furnace slagging or to maintain steam temperatures).

Results of Low-NO_X Combustion Tuning on Eleven Boilers

A description of critical characteristics for each of the boilers is shown in Table 1. All eleven units were dry-bottom, tangential boilers firing a low-sulfur coal (less than 1.4% S).

Table 1
Dry-Bottom, Coal-Fired Tangential Unit Characteristics

Unit Designation	Coal Rank and Characteristics	Rating MW_e	Comments
A	Bituminous (low S)	75	4-corner unit
B	Bituminous (low S)	75	4-corner unit
C	High Volatile Bituminous (low S)	75	4-corner unit Baseline operation with biased fuel & air and low O_2
D	Bituminous (low S)	100	4-corner unit
E	High Volatile Bituminous (low S)	115	4-corner unit Baseline has biased fuel & air and low O_2
F	Bituminous (low S)	125	8-corner unit
G	Bituminous (low S)	125	8-corner unit
H	Bituminous (low S)	140	8-corner unit Equipped with OFA
I	Bituminous (low S)	230	4-corner unit Equipped with OFA
J	Subbituminous (low S)	370	4-corner unit
K	Subbituminous (low S)	550	4-corner unit Equipped with OFA

A summary of the tuning results is included in Table 2. Although many techniques were tested, only the four principal low-NO_X techniques previously introduced are summarized in this table. As the intent is to provide a results-oriented technical paper, the theory underlying each technique will not be discussed in detail. Each of the four techniques presented employ stoichiometry control to reduce NO_X formation. Each technique will be discussed individually highlighting NO_X reductions achieved, practical considerations to implement, and typical limiting factors. Following this discussion, the most common limiting factors will be addressed.

Fuel Biasing

As shown in Table 2, fuel biasing resulted in NO_X reductions up to 23% and was successfully applied across the load range. Besides reducing NO_X emissions, five of the eleven boilers tested showed that stack opacity was actually reduced by fuel biasing. This was possibly due to increased residence time in the furnace and a favorable change in particle size conducive to improved ESP performance. Fuel biasing is accomplished by adjusting raw coal feeder speed, usually by biasing down the uppermost pulverizer and allowing other pulverizers to pick up automatically to maintain load. Typical limiting factors to implementing fuel biasing include control capability (i.e. feeder controls), pulverizer capacity, burner tip flame attachment, and small increases in flyash loss on ignition (LOI) or CO emissions.

Table 2
Summary of Low-NO_X Combustion Tuning

Unit Designation	Load	Baseline NO_X Emissions lb/MMBtu	Reduced NO_X lb/MMBtu (% reduction)	Principal Low-NO_X Technique(s) Applied	Limiting Factor(s) to Maintain Low-NO_X or Further Reduce NO_X	Target NO_X lb/MMBtu (averaging period)*
A	100%	0.68	0.58 (15%)	fuel bias + reduced O_2	pulverizer capacity	0.45 (annual)
	70%	0.78	0.43 (44%)	BOOS + reduced O_2		
	50%	0.79	0.66 (16%)	fuel bias	low windbox pressure	
B	100%	0.72	0.59 (18%)	fuel bias + reduced O_2	pulverizer capacity	0.45 (annual)
	70%	0.86	0.37 (57%)	BOOS + reduced O_2		
	50%	0.64	0.45 (30%)	FA/AA Bias + reduced O_2	low windbox pressure	
C	100%	0.42 (air bias + reduced O_2)	0.42 (0%)	FA/AA Bias + increased O_2	boiler efficiency & flyash LOI	0.45 (annual)
D	100%	0.53	0.45 (15%)	reduced O_2	pulverizer capacity	0.45 (annual)
	80%	0.56	0.36 (36%)	BOOS + reduced O_2		
	60%	0.83	0.42 (49%)	BOOS + reduced O_2		
E	100%	0.42 (air bias + reduced O_2)	0.40 (5%)	fuel and FA/AA Bias	boiler efficiency & flyash LOI	0.45 (annual)
F	100%	0.48	0.41 (15%)	reduced O_2	opacity	0.45 (annual)
	70%	0.54	0.40 (26%)	BOOS + reduced O_2		
	50%	0.54	0.48 (15%)	FA/AA bias + reduced O_2	low windbox pressure	
G	100%	0.59	0.51 (14%)	fuel bias + reduced O_2	pulverizer capacity	0.45 (annual)
	70%	0.55	0.43 (22%)	BOOS + reduced O_2		
	50%	0.53	0.47 (11%)	fuel bias + reduced O_2	low windbox pressure	
H	100%	0.55	0.36 (35%)	BOOS + full OFA	flyash LOI	0.42 (24-hour)
	70%	0.44	0.39 (11%)	BOOS + full OFA	low windbox pressure	
I	100%	0.60	0.51 (18%)	BOOS+ full OFA	pulverizer capacity & flyash LOI	0.42 (24-hour)
J	100%	0.56	0.53 (5%)	FA/AA bias + reduced O_2	pulverizer capacity & slagging	0.45 (annual)
	90%	0.47	0.30 (36%)	BOOS + increased O_2		
	50%	0.48	0.37 (23%)	fuel bias	steam temperatures	
K	100%	0.33	0.30 (9%)	fuel bias (unit has OFA)		0.45 (annual)

* Individual unit compliance emission rate shown; all units could possibly be included in a system average NO_X compliance strategy.

Air Biasing

Air Biasing refers to biasing secondary air to the upper burner elevations by manipulating the auxiliary air (AA) and fuel air (FA) dampers. As shown in Table 2, air biasing ("FA/AA bias") achieved NO_X reductions of 5-30% depending on unit characteristics and load. To implement air biasing, a boiler would ideally have individual control of each elevation of AA and FA dampers so that lower elevations are biased towards the closed position and upper elevations are biased more open. The largest NO_X reduction effect results from biasing AA dampers because of the relatively large compartment size, but biasing FA dampers can provide additional NO_X reductions. If the control system has the capability to control dampers by elevation, which is frequently the case when control systems are upgraded, then air biasing is easily accomplished. For units without individual elevation AA controls, partial air biasing can be accomplished by failing open upper level(s) of AA dampers with the upper elevation burners in service. However, failing open dampers is recommended only for testing purposes and not for ongoing operation.

Typical limiting factors to implementing air biasing include control system limitations, and small increases in flyash LOI or CO emissions. Windbox pressure (or windbox-to-furnace differential) needs to be carefully observed, however it was generally found not to be a serious limiting factor.

Reduced O_2

Reduced O_2 is clearly not an original technique for reducing NO_X as it has been well established. However, in some cases surprisingly low O_2 levels can be operated in tangential boilers firing pulverized coal. Boiler O_2 as low as 1% (dry, volumetric basis) can be operated on a long-term basis on some units. In general, reduced boiler O_2 was found to reduce NO_X emissions by 0.05 to 0.10 lb/MMBtu per 1% O_2 reduced for the eleven tangential boilers. Usually reduced O_2 is applied in combination with other methods (e.g. fuel bias plus reduced O_2). Typical limiting factors include poor fuel properties such as high sulfur, high burner zone heat release density, inadequate boiler O_2 metering, inadequate combustion air control, and poor fuel and air balance.

Burners Out Of Service (BOOS)

BOOS is accomplished by removing upper burners from service (one pulverizer) and opening upper level AA (and possible FA) dampers. Dampers can be failed open for testing purposes, but controls should be automated for ongoing operation. BOOS was shown to achieve NO_X reductions up to 57%, which is the same order of NO_X reduction achievable with higher cost retrofits such as overfire air and low-NO_X burners (LNB). There are two common limiting factors to implementing BOOS: pulverizer capacity at full load, and low windbox pressure at reduced loads. Other limiting factors may include those common to all staged combustion NO_X controls such as flyash LOI, CO, opacity, slagging, or fouling. Given the large potential NO_X reduction through BOOS, it is particularly worthwhile evaluate the modifications needed to offset operational impacts.

Applying Combustion Tuning for NO_X Compliance

In order to apply combustion tuning for NO_X compliance there typically are three steps involved: conduct baseline tuning, assess NO_X strategy, and implement modifications required to maintain compliance.

1. *Conduct Baseline Tuning*. The objectives of baseline tuning are to assess NO_X reductions achievable with existing equipment, and to assess limiting factors to achieving further NO_X reductions. Baseline tuning involves detailed testing incuding many of the following elements:

    - measure O_2 at economizer outlet by multiple-point sample grid or traverse
    - measure O_2 at furnace outlet (for balanced draft units only)
    - measure NO_X and CO with a multiple-point sample grid at economizer outlet or using stack CEMS
    - measurement of flyash LOI at the air preheater or particulate control device
    - measure boiler efficiency and air preheater leakage
    - measure furnace exist gas temperature (FEGT)
    - detailed recording of control settings and boiler instrumentation readings
    - visual inspection of windbox damper and other critical field device positions
    - visual observation flame characteristics
    - analysis of raw coal samples collected from a moving stream at the feeders
    - isokinetic sampling of coal flow balance and fineness, and dirty air velocity in coal pipes
    - measurement of pulverizer inlet air flow
    - measurement of secondary air balance (especially for 8-corner units)

    The exact scope of the initial tuning effort is determined based upon the project objectives, quality of existing plant instrumentation, and availability of previous test data. Note that not all parameters need to be measured for all tests or at all loads. With improved tools currently available and experienced personnel, such tuning efforts can often be completed in 5 days or less for one boiler. Steady load and load ramping tests may be conducted, depending on the operating profile of the unit. For base-loaded units, typically only full load tests need to be conducted.

2. *Assess NO_X Strategy*. Assessing NO_X strategy may involve a detailed and complex analysis of technical and non-technical factors, which is too lengthy to be properly addressed in this paper. For a given unit, this process ultimately results in establishing a target NO_X emission rate across the operating load range and a budget. Key factors include predicted future operating load profile, predicted generation (i.e. annual MWH), application of system averaging, regulatory NO_X emission rate, and time averaging requirement ranging from an instantaneous limit to an annual heat input-weighted average. As a general rule, longer time averaging limits make combustion tuning more plausible. For example, suppose a unit is tuned to achieve full load NO_X emissions of 0.50 lb/MMBtu but has a regulatory limit of 0.45 lb/MMBtu. It may be able to comply on an annual average basis considering that NO_X reductions can be

achieved across the load range. This was the case for several of the eleven boilers described in this paper where the compliant NO_X emission rate could not be achieved at full load, but NO_X could be over-controlled at reduced loads for NO_X compliance calculated on a heat-input weighted basis.

3. *Implement Modifications.* This is a critical step required to maintaining long-term compliance. To implement combustion tuning typically involves operating procedure changes and low-cost modifications designed to overcome critical limiting factors. A unit-specific package of modifications must be developed to overcome all critical limiting factors.

   The package of modifications necessary to implement combustion tuning will be different for every unit, and can best be illustrated by example. Suppose a unit can achieve NO_X compliance by operating with air biasing at full load, BOOS at reduced loads, and reduced O_2 at all loads. However testing showed inadequate windbox damper controls to safely bias secondary air, low windbox pressure at reduced load when testing with BOOS, and high flyash LOI as a result of reduced O_2. In such a case, a package of modifications may include: modifying the AA damper controls to enable control adjustment by elevation, modifying windbox dampers to increase backpressure at low loads, balancing coal pipes to balance fuel and primary air to the burners, and installing four new boiler O_2 probes at the economizer outlet. Typically these types of modifications would cost less than LNB and, in fact, retrofit of LNB could require the same set of modifications in addition to the cost of the burners.

Common Limiting Factors and Methods to Overcome

This section includes a description of the most common limiting factors to implementing combustion tuning for NO_X compliance, and descriptions of how to overcome them.

Pulverizer Capacity Limitations

Often the only major obstacle to implementing BOOS at full load is pulverizer capacity. Pulverizers perform three basic functions: dry, grind, and classify. Capacity may be limited because of any one of these three interrelated processes.

Pulverizers limited by drying capability will exhibit low discharge temperatures. The options available to improving capacity can be grouped into three categories as shown below. This discussion is specific to Raymond Bowl pulverizers, but mostly applies to other pulverizer designs as well.

1. **Optimize Existing Hardware**. This involves minimizing backpressure (ΔP) imposed by problems such as plugged pipes, plugged riffles, or tight gaps in the pulverizer throat. Suction pulverizers can have significant amounts of in-leakage which cools the coal/air stream and overloads the exhauster fan, and in-leakage paths should be repaired. Proper maintenance and tuning of the air flow controls is also important; this involves the exhauster inlet damper,

barometric damper, and hot air damper on suction pulverizers and the hot and cold air flow dampers on pressurized pulverizers.

2. **Upgrades to Increase Air-Flow Capacity**. The most effective option to increase air flow capacity is to install high efficiency exhauster wheels on suction pulverizers or increased capacity primary air fans on pressurized. One installation of high efficiency exhauster wheels was made on RS 863 pulverizers which were temperature limited due to a high moisture coal of 25% as-fired. Demonstrated increased coal flow capacity was approximately 15% from 91,000 lb/hr to 105,000 lb/hr. Improved air flow controls on suction pulverizers will also help maximize drying capacity by controlling the relative amounts of hot and tempering air. Less effective upgrades in terms of air flow capacity include reducing backpressure with course-cut riffles, improved coal pipe orifices, improved static classifiers, retrofit of dynamic classifiers, or improved vane wheels.

3. **Upgrades to Increase Hot Air Temperature**. As an alternate to increasing air flow by increased fan capacity or reduced backpressure, it is technically viable to increase the temperature of hot air supplied to the pulverizer up to 850 F depending on coal properties. There are two available methods for achieving this: primary air duct burners and flue gas recirculation to the primary air. These options can incur higher costs relative to fan or exhauster wheel upgrades, however added benefits can result due to reduced flow through the pulverizer as described earlier. Flue gas to primary air would also provide added NO_X reduction due to lower oxygen content in the fuel stream. There are at least two successful installations of primary air duct burners on Raymond Bowl mills known to the authors.

Pulverizers which are limited by grinding and/or classification also have three categories of options to increase capacity:

1. **Optimize Existing Hardware**. This involves inspections and repairs of the pulverizer which should be conducted prior to investing in upgrades. Plant O&M staff are generally well familiar with requirements for maintaining mechanical tolerance such as replacing worn components, proper setting or springs or hydraulics, ring to bowl clearances, inner cone to inverted cone position, etc.

2. **Upgrades to Increase Grinding Power**. For pulverizers which are limited by motor power, the solution is relatively simple which is to rewind or replace the electric motors. Grinding element upgrades are also available such as increased roll diameters, ribbed rollers, or bowl extension ring height modifications.

3. **Upgrades to Increase Classification Efficiency**. Standard equipment Raymond Bowl pulverizers are reported to have a classification efficiency on the order of 20-30%, which means that 70-80% of properly sized particles are returned to the grinding zone. Improving the particle separation efficiency effectively increases the grinding power of the pulverizer. Improved static classifier designs are available to make relatively small, but inexpensive, improvements in fineness or capacity. Improved vane wheels, in addition to reducing backpressure on the exhauster or fan, also are intended to reduce internal recirculation of coal particles.

   For large improvements in classification and capacity, dynamic classifiers are the best available technology; various designs are reported to have a classification efficiency of

50-70%. One such retrofit on an RPS 703 pulverizer increased capacity by at least 15% while maintaining 200 mesh fineness, improving 100 mesh fineness, and eliminating the 50 mesh fraction. It should be noted that unlike all other hardware or control upgrades described in this paper, dynamic classifiers should not be considered to be "low cost" as their costs ranges in $100,000's for each pulverizer, depending on size of the unit and design features.

Low Windbox Pressure at Reduced Loads

BOOS is a viable low-NO_X operating mode for nearly every tangential boiler which operates a portion of the time at reduced loads. Often the limiting factor is low windbox pressure due to reduced restriction in the combustion air path by opening upper level AA and FA dampers.

One unique solution was applied successfully on an 8-corner coal-fired unit and is generally applicable to any 4- or 8-corner unit. Typically each windbox damper compartments has 2 or more damper blades linked together, with one driven blade and one or more "slave" blades. The modification involved removing the linkage to the slave blade, and then all slave blades from the AA compartments on each corner were linked together and tied to a new manual positioner. The same was done for each FA compartment on each corner. This provided a tunable system to establish proper control sensitivity for the secondary air and windbox pressure, and hence it enabled BOOS operation across the load range. An additional benefit was realized because this 8-corner unit exhibited secondary air imbalances (as is often the case for 8-corner units), and the new manual positioners were tuned to alleviate this imbalance.

Other solutions to this problem are available such as installing perforated plate in the windbox or replacing nozzle tips with those having smaller flow area. These options should be evaluated, however one drawback of both is there would be no flexibility for on-line adjustment once installed. Perforated plate installations on tangential boilers has also been shown in some cases to result in increased NO_X emissions, possibly due to increased air through the FA compartment. It is important to note that the damper modification described above allows for tuning of the relative amounts of AA and FA.

Steam Temperatures

In response to BOOS, fuel biasing, air biasing, or reduced O_2 there is usually a change in the steam temperatures which must be addressed. Fortunately design steam temperatures can often be maintained on tangential units with only operational changes such as adjusting burner tilt, changing sootblowing pattern and frequency, or burner pattern selection. Some coal-fired units also have flue gas recirculation to the furnace bottom which provides an excellent means of controlling steam temperatures as it was designed to do. Although generally not preferred due to efficiency impacts, total excess air can be used as a variable to control steam temperatures by changing the mass flow through the boiler. One example where this can be applied successfully is operation with BOOS at

low load, where steam temperatures tend to drop below baseline levels. Usually the amount of excess air can be increased from baseline levels to improve steam temperatures, while still providing a large decrease in NO_X emissions (i.e. the staged combustion NO_X reductions more than offset the effect of increased O_2).

Incomplete Combustion

Nearly every low-NO_X installation results in undesirable effects due to products of incomplete combustion. This includes the low-cost tuning methods as well as higher cost retrofits such as overfire air or LNB. Improved combustion balance is an important element to offset all of these undesirable effects, and this topic is discussed in the next section below. The most common effects observed and methods of overcoming them are:

- **Flyash LOI**, which is the most common measure of unburnt carbon in the flyash, must be maintained for reasons of efficiency and/or flyash sales. The best solution to maintaining flyash LOI within acceptable levels is to improve fuel and air balance, which is discussed in the next section below.
- **Slagging and fouling** problems can arise and must be addressed. Assuming fuel properties remain constant, the best approach to controlling slagging and fouling in the boiler is to improve fuel and air balance, alter sootblowing procedures, and maintain adequate levels of total excess air. Some units are also constrained in capacity due to intentional load reductions designed to "de-slag" the boiler.
- **CO emissions** typically are targeted to be kept below 100 ppm on coal-fired units. It is important that testing be conducted to measure CO emissions under low-NO_X conditions and to ascertain the need for CO monitors. Although CO is often a useful parameter to monitor, the need can vary drastically on different units depending on coal properties and combustion conditions. For example, one of the eleven units tested exhibited CO emissions over 3000 ppm with no measurable increase in flyash LOI, which indicated that CO monitors would be useful as an operator tool. By comparison, another unit tested at less than 1% O_2 in the upper furnace at full load still showed less than 25 ppm CO while the flyash LOI levels increased by an order of magnitude; in this case, CO monitors clearly would not be a useful parameter to monitor. To offset high CO emissions, is necessary to improve fuel and air balance, which is discussed in the next section below.
- **Stack opacity** problems often occur on units with electrostatic precipitators (ESPs) and may be caused by a number of factors, some of which can be related to low-NO_X techniques described herein. ESP performance can also be adversely affected by several "non-ideal" effects: rapping, gas flow distribution problems, sneakage (a portion of the flue gas bypassing the electrified sections through the hopper and high-voltage feedthroughs), and reentrainment of collected ash into the gas stream. If low-NO_X operation results in increased opacity, it can often be more than offset by minimizing these "non-ideal" effects on ESP performance by modifying the rapping schedule, improving gas distribution, or reducing the flue gas flow or temperature. It is also important to note that reducing flyash LOI can improve ESP performance by altering the flyash resistivity.

Improving Combustion Balance for Coal-Fired Tangential Units

Improving combustion balance will provide simultaneously reduced NO_X emissions and improved efficiency. For tangential boilers combustion balance can be grouped into three categories: (1) balanced fuel and air from elevation to elevation, (2) balanced fuel and primary air from pipe-to-pipe (corner-to-corner), and (3) distribution within the coal pipe commonly called "coal roping." Additional critical factors discussed below are boiler O_2 metering, and procedures to measure and maintain pulverizer performance.

Balanced Fuel and Air by Elevation

Balanced fuel and air by elevation can be accomplished by having properly calibrated coal feeders and good control over the air-to-fuel ratio for each pulverizer. Typically gravimetric feeders are preferred over volumetric, and with either design fuel balance can be improved via upgraded variable speed drive (VSD) controls. Pulverizer total air flow control is achieved by metering the inlet air flow to the pulverizer and having good damper control over the hot and tempering air. Pressurized pulverizers frequently were designed with these elements and only need to be calibrated and tuned. Suction pulverizers typically have barometric tempering dampers and no air flow meters; the barometric damper can be upgraded with a common louver blade design and inlet air flow meters are available from several manufacturers (pitot, hot wire anemometer, venturi, etc.).

Balanced secondary air from elevation to elevation is important as well. On both 4- and 8-corner tangential units, the first task necessary to accomplish this is to ensure AA and FA dampers and drives are well calibrated and maintained. Moreover, it is also highly recommended that position feedback be installed to provide the operator with an indication of actual damper positions, or at least to alarm based on position error. Testing on a large number of tangential units has proven that controller output is insufficient to assure proper AA and FA damper position, and if position feedback is not available then each damper drive must be visually inspected on a regular basis.

It should be noted that if coal flow and inlet air flow are metered, then average coal pipe velocity and dew point temperature can be calculated for on-line indication. These are two important parameters which would provide useful information to boiler operators.

Coal Pipe and Corner-to-Corner Combustion Balance

Balanced combustion from corner-to-corner is a matter of balancing the secondary air fed through the windbox, and also balancing the coal pipes (fuel and primary air). Acceptably balanced secondary air from corner-to-corner can usually be achieved with calibrated AA and FA dampers and drives as described above, with the exception of 8-corner units. The secondary air delivery system on 8-corner units is usually designed asymmetrically so that balanced flow from corner to corner is not assured. On these units, it may be additionally necessary to measure and/or model air flow and install turning vanes in the ductwork or windbox. The windbox damper modification described earlier as a method of enabling reduced load BOOS will also provide corner-to-corner balance control. It is also possible,

albeit expensive, to install on-line flow meters in each AA and FA damper compartment on tangential units, but if these are installed there needs to be some accompanying method of controlling the distribution, not just measuring it.

Coal pipe balance is a topic of high interest in the utility industry and there are many devices available such as adjustable orifices, improved fixed orifices, venturi distributors, coal balancing valves, and adjustable riffles. Before investing in coal pipe balancing devices, it is recommended to first ensure that temperature and fineness can be maintained. Pulverizers which operate at or below the dew point or have inconsistent fineness or course particles will invariably lead to pipe plugging and malfunction of any devices installed. Consideration should also be given to the ability to control primary air balance and coal flow balance separately so that air-to-coal ratio can be maintained in each pipe.

Coal Pipe Distribution (Roping)

Coal roping refers to maldistribution of coal particles over the cross section of individual coal pipes. It results from having bends in the pipes, however coal pipe bends are an inevitable condition due to practical design requirements. Roping is exacerbated by poor coal fineness and operating with wet coal in the pipes (i.e. below the dew point temperature). Before expending effort to measure and control roping in the coal pipes directly, it is first recommended to address elevation-to-elevation balance, pipe-to-pipe balance, fineness, and temperature. Once these parameters are optimized and further improvements are sought, then coal roping can be measured with SMG-10 or other advanced tools; however it is recommended that roping be measured after the last pipe bend (i.e. downstream of the burner elbow). To remedy roping there are devices available from at least 3 vendors to control roping, but practical considerations need to be addressed such as piping fit up and available space.

Boiler O2 Monitoring

Accurate boiler O_2 indication should be considered as an essential parameter provided to boiler operators for reasons of NO_X control, energy efficiency, and operating safety. It is generally advisable that a multiple number of probes be installed at an appropriate location in the boiler to provide a reliable, representative indication of average O_2. A multiple number of probes will also provide the operator with on-line data to indicate combustion imbalances (e.g. from side to side). On forced draft units, the economizer exit is often the best location since air in-leakage is not a problem and the gas temperature is relatively low. On balanced draft units, air in-leakage needs to be measured (i.e. conduct O_2 traverses at the furnace exit and economizer exit as a minimum) and carefully considered in the selection of the number and location of O_2 probes. Generally the nearest practical location to the furnace exit will provide the most accurate indication, although the higher temperatures may inevitably lead to higher failure rates for the O_2 monitoring system.

Measuring and Maintaining Pulverizer Performance

Because coal pulverizer performance is integral with maintaining NO_X emissions and because they are inherently subject to high rates of wear and performance degradation, some degree of ongoing performance measurement is required. A general guideline of minimum requirements for ongoing performance measurement is shown in Table 3.

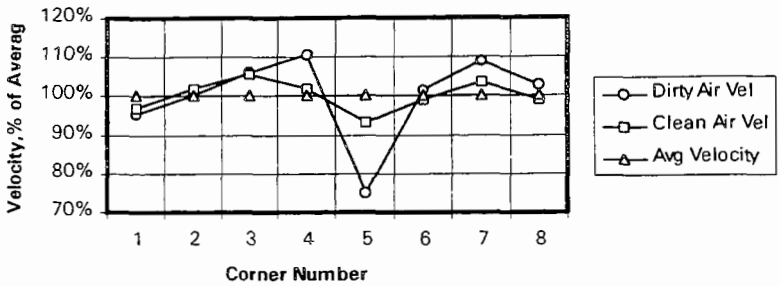
Table 3
Guideline for Fuel System Measurement Methods and Frequency

Parameter	Minimum Frequency	Method(s)	Goal	Comments
Fineness	every 3 months	ASME sampler from Coal Pipes is acceptable if coal pipe isokinetic sampling is not conducted.	> 70% 200 mesh > 99% 50 mesh	Isokinetic sampling not required if only interested in fineness. NOT recommend sample @ riffles. Adjust classifier vanes considering capacity versus fineness tradeoff.
Clean Air Coal Pipe Velocities	every year	pitot tube	+/- 5% balance pipe to pipe for each pulverizer	Re-size fixed orifices to achieve balance. Caution: excessive ΔP may limit air flow.
Dirty Air Coal Pipe Velocities	every year or when problem indicated	Dirty air pitot	+/- 5%	Dirty air velocity balance is final basis for sizing orifices, not clean air.
Coal Flow	every year	Isokinetic	+/- 10%	If fineness and temperature are within design limits, coal flow balance achieved by riffles or pulverizer maintenance & repair
Raw Coal	every quarter	ASTM	ultimate, proximate, HGI	Changes in HGI and moisture important for pulverizer O&M.
Raw Coal	every year	ASTM & other	coal erosiveness mineral analyses slagging/fouling properties[3]	Erosiveness important if high degree of wear/erosion is experienced.

As shown in the table, fineness is recommended to be measured a minimum of once every quarter as determined from composite samples collected from the coal pipes. Fineness samples collected at or near the riffles on suction pulverizers have yielded erroneous results. Degradation in coal fineness is one good indication of problems and should signal an off-line inspection and assessment of the pulverizer. It should be noted that if there is a high percentage of particles retained on 50 mesh sieve (e.g. over 1%), then consideration should be given to sieving for 30 mesh fineness.

Recommendations for clean air velocity, dirty air velocity, and coal flow sampling shown in Table 3 represent general guidelines. The requirement for more frequent sampling or tighter criteria for balanced fuel and air may be reasonable for many boilers considering unit-specific conditions. For example, a boiler with a propensity for slagging problems and/or a high market value for flyash sales would justify more frequent testing requirements and investment in higher cost equipment upgrades. One important recommendation is that coal pipes be balanced based on dirty air velocities which represent the as-fired operation, and not to over emphasize clean air balance. Balancing coal pipes to +/-5% on a clean air basis will generally correlate to good balance in the as-fired condition. However, this is not always the case since imbalances tend to be exacerbated by the presence of the entrained coal as shown in the example plotted in Figure 1.

Figure 1
Example of Pulverizer Clean Air vs. Dirty Air Velocities
(8-Corner Tangential Unit)



Summary, Conclusions, and Costs

A summary of low-cost NO_X reduction techniques and range of costs is shown in Table 4. BOOS, fuel biasing, air biasing, and reduced O_2 have all demonstrated NO_X reduction potential on the eleven boilers as shown in Table 2, as well as a multitude of other units throughout the U.S. As described in the introduction, tuning of primary air-to-coal ratio is a viable method. One additional method available, shown at the bottom of Table 4, is to convert the upper-most AA compartment to larger nozzle tips. This concept is designed to maximize the use of this upper compartment in order to provide a partial overfire air effect. Based on experience on two units, an increase in nozzle area of 30 to 50% may be achieved with a resulting NO_X reduction of 5% or more. There are some mechanical design issues with burner tilt control which must be addressed, however these obstacles can be overcome in most cases. Moreover, if nozzle tips are replaced on a regular basis then this modification could be done for little or no incremental cost.

A range of cost for each option is shown in the second column of Table 4 expressed as dollars per kilowatt. Generally all of the modifications described in this paper can be implemented in this range of costs shown, with the exception of dynamic classifiers. Many

units already have the necessary controls in place to implement some of the methods described, and so costs would only be incurred to conduct field tuning and possibly operator training. Older units, especially those built prior to 1980, tend to require more of the low-cost upgrades in order to safely and reliably implement these NO_X reduction techniques. However, it is important to note that many of these upgrades would be required with higher cost upgrades such as overfire air or LNB were to be installed. One last important point is that many of the improvements described herein result simultaneously in NO_X reductions, performance improvements, and reduced maintenance.

Table 4
Summary of Low-Cost NO_X Reduction Techniques

Technique	Range of Cost, $ per kW	Typical NO_X Reduction, %	Usual Limiting Factor(s)	Approach to Overcome Limitation(s)
BOOS	$0-$3	25-50%	Low WB pressure at reduced loads. Pulverizer capacity at full load.	WB damper modifications (for reduced loads). Pulverizer or exhauster upgrades to increase capacity.
Reduced O_2	$0-$2	5-15%	Slagging/fouling, opacity, CO, and flyash LOI.	Improve boiler O_2 metering and minimize boiler in-leakage. Fuel system balance. Secondary air balance.
FA/AA Bias	$0-$2	5-15%	Inadequate controls or lack of feedback signal.	Modify controls. Add FA/AA damper feedback.
Fuel Bias	$0-$2	5-10%	Inadequate feeder controls.	Increase frequency of feeder calibration. Feeder VSD upgrade.
Optimize PA-to-coal ratio	$0-$3	5-10%	Inadequate feeder or inlet air flow controls. Baseline pipe velocity already at a minimum. Low coal pipe temperatures.	Upgraded feeder controls. Install pulverizer air flow meters. Increase hot air supply temperature.
Convert upper AA to larger nozzle tips	$0-$1	5%	Nozzle tilt mechanical interference.	Disconnect from tilt and install fixed nozzles with upward tilt.

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APPLICATION OF AN EXPERT SYSTEM AND NEURAL NETWORKS FOR OPTIMIZING COMBUSTION

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Abstract

Lehigh University's Energy Research Center and the Potomac Electric Power Company have been developing software for use by plant personnel in tuning a pulverized coal-fired boiler to reduce NO_x and minimize heat rate. The software is based on the interactions of an expert system, neural networks, and a mathematical optimization algorithm. It uses the expert system to guide the plant engineer through a series of parametric boiler tests and gather a data base which characterizes boiler operation over a wide range of conditions. The neural network portion develops non-linear mapping functions between the outputs of NO_x, heat rate, LOI, opacity, and the controllable boiler input parameters. These mapping functions are then analyzed by the mathematical optimization algorithm and the optimal boiler operating conditions are identified. This paper describes the application of the software to a wall-fired boiler. In addition, a technique is described for using results from the software to develop continuous, on-line closed-loop combustion control.

Introduction

Over the last several years, the U.S. electric utility industry has become sensitive to the benefits associated with optimizing boiler operation. The utility might wish to adjust the control settings of the boiler to minimize NO_x or heat rate, or perhaps find the boiler operating conditions which give the best heat rate subject to meeting a target level of NO_x. Additional constraints which must be satisfied include limits on steam temperatures, restrictions on fly ash unburned carbon, and limitations on stack opacity. Numerous papers have been written which show the extent to which NO_x, steam temperatures, heat rate, and LOI can be varied through changes in boiler operating conditions. Typical controllable parameters include air register settings, furnace O_2 levels, mill loading patterns, and burner swirl settings [see for example, 1 to 4].

In recent years, quite a few boiler optimization software packages have been made commercially available for use by utilities and industrial boiler operators. Most rely on either one of two techniques: the use of neural networks for on-line data acquisition or the use of sequential optimization to determine the optimal settings [5 to 9].

Under a collaborative arrangement with the Potomac Electric Power Company, Lehigh University's Energy Research Center has recently developed software for combustion optimization which relies on an expert system, neural networks, and mathematical optimization algorithm. Referred to as Boiler OP, the software is used to guide the plant engineer through a series of parametric boiler tests. This results in development of a database which characterizes boiler operations over a wide range of conditions. The software then analyzes the data and identifies the optimal boiler control settings.

The first versions of Boiler OP were developed for use with tangentially-fired boilers. Results of the applications of the software to optimization of units at PEPCO's Morgantown and Potomac River Stations were described in previous papers [10, 11]. A wall-fired version of the software is now available. This version can be used for both front-wall and opposed-wall fired boilers using burners with either single or dual registers. This paper describes some of the results obtained by using the software to analyze parametric test data obtained from a wall-fired boiler. In addition, an application of the software is described for helping the plant engineer use the DCS to establish closed-loop combustion control to maintain NO_x emissions within a narrow range over the long term.

Software Description

Figure 1 illustrates how the expert system, neural networks and optimization algorithm are linked together within Boiler OP. The expert system portion of the code is used to guide the plant engineer safely through the parametric boiler tests. To accomplish this, the engineer configures the software to reflect the boiler and burner design, testing objectives, and operating constraints. The expert system then recommends control settings for the test points. The boiler controls are adjusted by the boiler operator and the test data are collected by the plant's data acquisition system. The test data, which are stored in a database for later use, are utilized by the expert

system to determine each successive point in the testing sequence. After the testing is complete, the database exports the data to the neural network for modeling. The optimization algorithm then determines the best combination of control settings which meets the test objectives. The code can be used to determine the boiler settings which produce minimum NO_x emissions or to determine those settings which produce a minimum heat rate subject to a target NO_x level.

The comprehensive database generated during the parametric testing makes it possible to carry out a variety of analyses which can be used to assist the plant in fine-tuning boiler operations over the long term. These calculation tools make it possible for the operators to review the status of boiler operations as they affect NO_x and unit performance, examine the consequences of improper control settings, explore alternative control settings and reoptimize the boiler settings subject to new operating constraints. Once the initial parametric testing is complete, no additional testing is needed to carry out these calculations. The neural networks and optimization algorithm within the software use the original database to obtain the desired answers (see Figure 2).

Analysis of Wall-Fired Boiler Data

Parametric tests were carried out at full-load conditions at a unit with a wall-fired boiler having low NO_x burners with overfire air registers. During these tests, the overfire air, economizer O_2, burner secondary air and swirl settings and the primary air velocities were varied. The data were then analyzed by the neural networks in the newly developed version of Boiler OP. These tests were concerned primarily with determining the relative effects of the different control parameters on NO_x and thus, the trends shown here are limited to impacts on NO_x.

Figure 3 shows the effects of both economizer O_2 level and overfire air setting on NO_x. The effects of overfire air and burner secondary air setting are shown in Figure 4. The impacts of the burner swirl, primary air bias and overfire air are shown in Figure 5 and, finally, the variation of NO_x with primary air bias for different swirls and overfire air settings is shown in Figure 6. The primary air bias is an indication of the deviation of the primary air flow from its normal setting. The positive bias shown here reflects an increase in primary air velocity.

These results show that NO_x responded most strongly to overfire air settings and economizer O_2 level, while the burner swirl setting and primary air bias have smaller, but significant, effects on NO_x. In this case, NO_x was relatively insensitive to secondary air setting.

Using these data, the optimization feature of the software was used to find the boiler control settings which produce the minimum NO_x level at full-load conditions. The results of this analysis are shown in Table 1.

Table 1

Predicted Full-Load Boiler Control Settings for Minimum NO_x

Parameter	
O_2 Level [%]	3.21
OFA Damper Position	92.4
Secondary Air Position	50.9
Secondary Air Bias	0.2626
Swirl Register Setting	36.1
Mill Bias	-0.0156
PA Bias	9.62
NO_x, [lb/MBtu]	0.492

Application To On-Line Closed Loop Control

Boiler OP was developed as off-line advisory software, providing advice to plant engineers and operators and helping them identify the best boiler control settings. However, recent results have been obtained at PEPCO's Morgantown and Potomac River Stations which show how the software can also be used to provide closed loop on-line combustion control.

There are two 600 MW tangentially-fired boilers at Morgantown station, both of which have low NO_x burners with both separated and close coupled overfire air. Following the low NO_x burner conversions, in 1994 and 1995, parametric tests were conducted, to determine the optimal boiler control settings. These tests were carried out over the load range and provided the data needed to specify key parameters such as overfire air damper setting, economizer O_2 level and burner tilt angle as functions of load. The control systems (DCS) were than programmed to permit automatic operation at these optimized settings. Despite the fact the boilers meet the station's NO_x and heat rate objectives most of the time, it was found there are periods during which NO_x deviates from the target level. These deviations occur because of fluctuations in coal quality and variations in furnace cleanliness, which in some cases cause the NO_x to be higher than desired, and in other cases to be lower.

Data published in the literature show NO_x depends on coal composition, varying with volatile content, amount of fixed carbon and the nitrogen content of the coal. Analysis of coal quality data from PEPCO suppliers showed the expected variations in coal composition are large enough to cause significant variations in NO_x.

Furnace cleanliness also affects NO_x emissions. As slag accumulates on the waterwalls, the flame temperature increases and this results in increased NO_x. Sootblowing tests carried out at Morgantown Unit 2 showed changes in NO_x emissions ranged up to 0.06 lb/MBtu as the waterwalls were cleaned [12].

Both Morgantown units are subject to opacity excursions related to combustion conditions. These units use cold-side electrostatic precipitators for opacity control, and the performance of these devices is sensitive to the electrical resistivity of the fly ash. Variations in coal composition and furnace O_2 level lead to variations in the amount of fly ash unburned carbon, which affects fly ash resistivity, which, in turn, impacts opacity.

Using a control logic which they developed from results obtained by analyzing Boiler OP test data, PEPCO engineers configured the boiler controls to maintain NO_x at the target level and prevent opacity from exceeding the regulatory limit (Figure 7). The control logic depends on access to NO_x and opacity signals from the CEM. It also uses relationships between NO_x, heat rate and the boiler control settings provided by the software.

Figures 8 and 9, which are for full-load conditions, illustrate the types of results which are generated by the software using its "reoptimize" capability. The individual points are the results of calculations performed by the software to indicate the combinations of O_2 and SOFA settings which result in the best heat rates as NO_x is increased or decreased around a target value. For this boiler at these conditions, the software recommended the other boiler control parameters be maintained at fixed positions. The solid curves, which are curve fits of the predictions, are then used as input to the DCS to maintain NO_x at a fixed level.

A similar strategy was found to work well at Potomac River Station. Each of these units has a tangentially-fired boiler with conventional burners and a capacity in the range of 100 MW. NO_x was reduced from baseline levels in the 0.65 lb/MBtu range to 0.45 lb/MBtu at Potomac River through combustion optimization. To maintain closer control over NO_x and prevent the fluctuations which were found to arise due to variations in coal quality and furnace cleanliness, results obtained from Boiler OP were used to configure the boiler controls to maintain NO_x at the 0.45 lb/MBtu target.

Summary

Relationships between parameters such as NO_x, opacity, heat rate and the boiler control settings are complex, making it difficult to optimize combustion without assistance from a computer code. Through application of an expert system to guide the testing and neural networks and an optimization algorithm to analyze the data, Boiler OP can be used to determine the optimal control settings for a wide a variety of boiler types. The code has been applied to tangentially-fired boilers, with conventional and low NO_x firing systems. A new version of the software was recently developed for use with wall-fired boilers.

The database generated using this approach can be used by the plant to maintain the boiler in an optimized state, provided there are no major changes in the maintenance condition of the equipment or in the coal supply. Recent work at PEPCO has shown how results from the software can be used by the plant engineer to configure the DCS to provide continuous closed-loop combustion control to maintain NO_x emissions within a narrow range over the long term.

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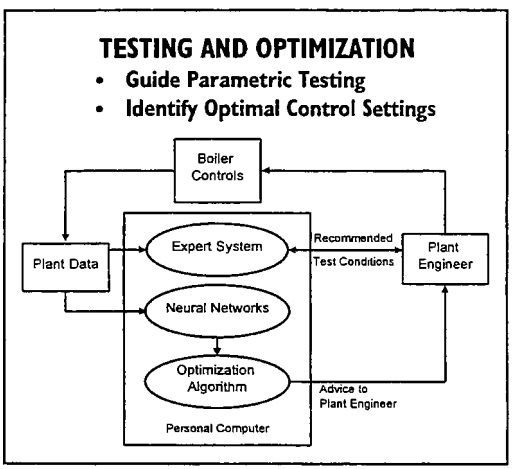

Figure 1: This diagram shows how Boiler OP is used to assist a plant engineer in testing the boiler and determining the best combination of control settings.

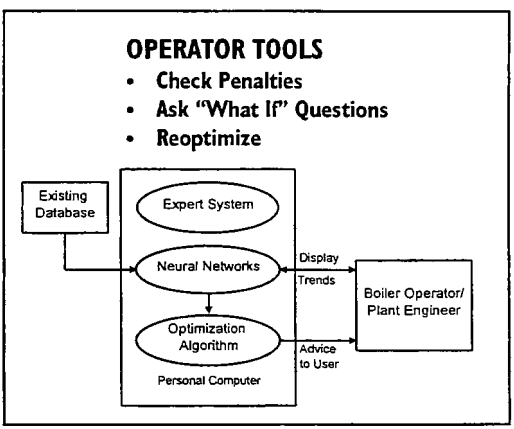

Figure 2: Boiler OP also provides the boiler operators with assistance in maintaining the unit in a well-optimized condition.

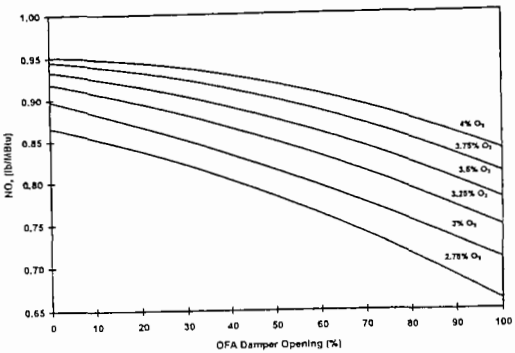

Figure 3: Effects of OFA Damper Opening and Economizer O_2 Level on NO_x.

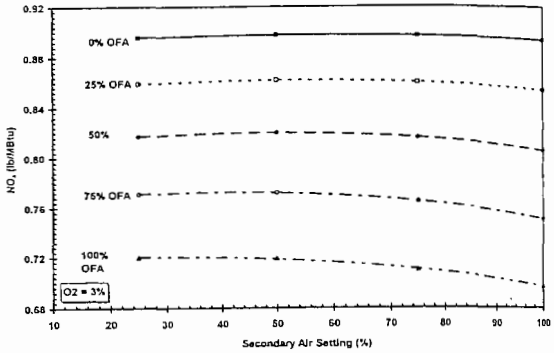

Figure 4: Variation of NO_x with OFA and Secondary Air Settings.

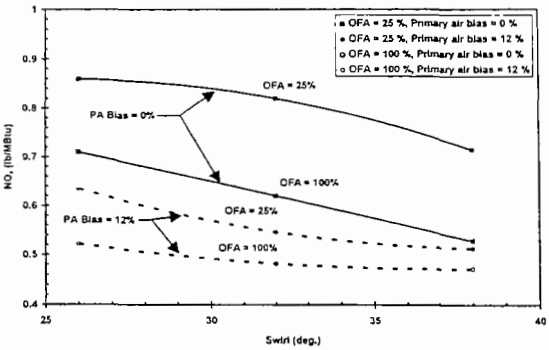

Figure 5: Effects of Burner Swirl, OFA and Primary Air Bias on NO_x.

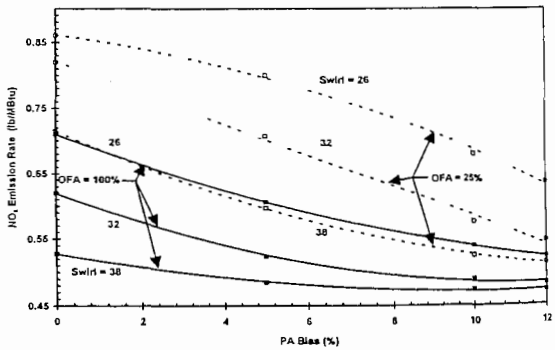

Figure 6: Effects of PA Bias, Burner Swirl and OFA Setting on NO_x.

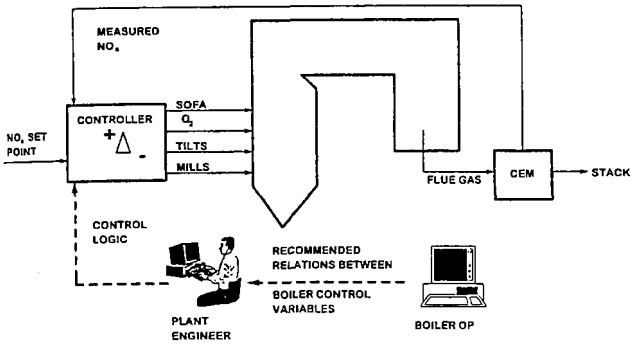

Figure 7: Illustration of how Boiler OP can be used to develop closed-loop combustion control for limiting variations in NO_x.

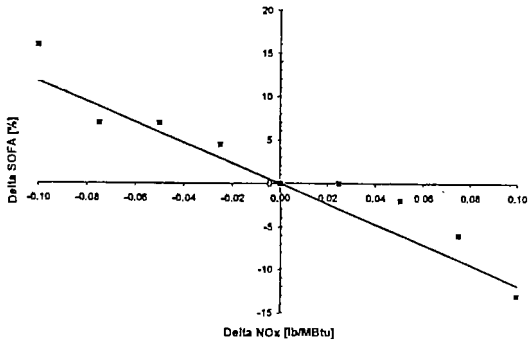

Figure 8: Predicted change in NO_x with change in SOFA setting required to eliminate NO_x variations while maintaining minimum heat rate. Figure 9 shows corresponding change in economizer O_2.

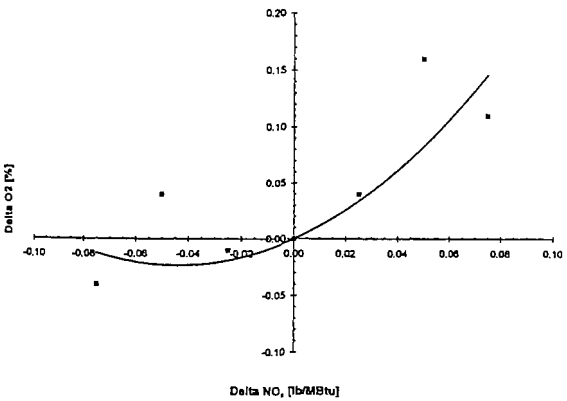

Figure 9: (See caption for Figure 8).

The Emissions, Operational, and Performance Issues of Neural Network Control Applications for Coal-Fired Electric Utility Boilers

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Abstract

NO_x and unit heat rate are sensitive to the combustion process occurring in a boiler. Boiler combustion profiles change continuously due to coal quality, boiler loading, changes in slag/soot deposits, ambient conditions, and the condition of plant equipment. This paper presents the benefits of applying an on-line, real-time neural network to several bituminous coal fired utility boilers. The system dynamically adjusts combustion setpoints to reduce NO_x emissions and improve heat rate. The neural network can dynamically track and optimize operations for a large number of input variables. Neural network technology augments but does not replace performance monitors or engineering diagnosis. It is a tool that has been proven to improve boiler operation through dynamic adjustments that results in reduced power plant emissions and improved boiler performance.

The NeuSIGHT neural network based system has been applied to units with tangential-, cell-, single wall-, and opposed wall-burner arrangements that have ranged in capacity from 146 to 800 MW in an advisory mode. Several sites have employed the neural network system for supervisory (i.e., closed loop) boiler control.

The neural network is applied to the boiler by first modeling the multi-dimensional and non-linear problem of NO_x formation and performance improvement in the furnace. This is done by operating the boiler in prescribed modes that are designed to encompass a wider range of parameter variations than will occur in daily operation. This is done to provide the neural network a large experience base. Once modeled, the neural network continually retrains itself using current boiler information and performs many 'what if' simulations to optimize setpoints for the current operating and equipment status conditions. The neural network periodically updates the model, learning from most recent data, to keep up with changes in operating conditions. Through on-line retraining, the neural network system optimizes the boiler operation by accommodating equipment changes due to wear and maintenance outages and adjusting to changes in fuel quality to widen compliance margins and improve operating flexibility and performance.

The system helped reduce NO_x emissions up to 60%, meeting compliance and providing significant operational benefits. The NeuSIGHT system has also helped to optimize sootblowing and slag deposition relationships, superheat and reheat temperature control, pulverizer operation and maintenance, and has improved operational procedures at low load. The system also improved heat rate up to 2% overall (5% at low load) and reduced LOI as much as 30% while meeting NO_x emission compliance through combustion optimization alone.

Combustion Optimization

The basis for boiler combustion optimization lies in identifying the relationship of important fuel/air parameters. Values for these parameters are computed and input to the boiler control system as modified setpoints that will provide improvements for heat rate, NO_x and combustibles (CO and LOI).

Maintaining reduced NO_x can be difficult as operating personnel, fuel, and/or equipment condition change over time. Long term emission gains require a methodology that can satisfactorily model the various non-linear interactions and accommodate changing equipment and coal conditions. An accurate and dynamic plant model requires dozens to hundreds of process values as inputs in order to keep up with the changing plant conditions. The key features of the neural network are its ability to empirically model non-linear data, the ability to continually learn in an on-line mode and modify setpoints and bias adjustments to keep the unit tuned to the desired emission and performance levels.

Neural Network Model Development

Depending on the size and complexity of each unit, as many as 350 boiler operational parameters are collected at prescribed intervals and averaged over a short time period (typically 30 seconds and 10 minutes, respectively) during a two to four week test period. The objective of these tests is to vary one operational parameter per test to develop a history of unit operating data that can be used to train a neural network model for use on the subject unit. It is desirable to exercise most parameters to values beyond those encountered in normal operation. This provides the neural network model a wide data range upon which to train.

Following these tests, the logged data is modeled by Pegasus' NeuSIGHT neural network program using NO_x, heat rate, or other boiler performance measures as model targets. Many combinations of node arrangement and functional link enhancement terms are tested. For modeling heat rate, up to 35 hidden nodes are used. The ideal number varies with the particular input list used. For NO_x, it is usually necessary to have at least one layer of FE (sin/cos type nodes) terms. Without at least one FE layer, the NO_x model accuracy is typically only +/- 20% and misses many peaks and valleys. Additional testing is performed on the boiler at various loads and operating modes to ensure the model will be accurate over an extended time period.

Programs are utilized to condition the input data to and from the neural network, compensating for inherently noisy data. The objective is to tune the system to respond gradually to changes (slag and ash buildup, pulverizer degradation, instrumentation drift, etc.), but not be so sensitive that the system may "hunt" between optimum setpoints.

Some of the issues affecting the system's sensitivity include: process/equipment dynamics, instrumentation response times and time lags between input data. Additional programs are incorporated to provide gradual transitions for the setpoint and bias adjustments as the system responds to changes in operating conditions or equipment performance. Limits, in addition to those imposed by the DCS, are established to ensure safe and stable operation. Examples include using low CO to bound the O_2 loop and high motor current to limit the pulverizer bias adjustments.

Finally, supervisory control can be implemented. Initially, the loops are put into service one at a time under the supervision of an engineer. After the desired operating characteristics are gained, the loop is released to the operators, who are provided three control options: manual, DCS, or supervisory (closed loop).

The original model is periodically retrained to reflect current operating conditions. A major concern is to ensure the model is trained on valid data. Algorithms are designed to monitor the "breadth" of data and to sort incoming data into groups representative of different modes of plant operation; thereby ensuring a "robust" data set for the neural network throughout the plant's operating range. Individual inputs are monitored through pattern matching checks. Bad values are replaced with estimations, based on the patterns of associated input parameters. If too many inputs are bad or too little data exists for the current conditions, the neural network reverts to the original digital control system setpoints until the system has sufficient data to make valid recommendations.

Results From Four Neural Network Applications

The following discussion summarizes the results from four electric utility boilers that represent a wide range of furnace and burner types.

Unit "A"

Unit "A" is a 1963 vintage Babcock & Wilcox wall fired boiler with gross generation capacity of 146 MW. Baseline NO_x was 1.0 lb/MMBtu. Linear parametric testing, by plant personnel and others, reduced NO_x to 0.78 lbs/MMBtu at full load under normal operating conditions. The project goal was to further reduce NO_x at least 20% while maintaining or improving heat rate and flyash loss on ignition (LOI). Since the plant operating permit includes an annual NO_x tonnage limit on each unit, reducing NO_x emissions would improve the capacity factor resulting in increased operating flexibility of this unit.

The control system interfaced a SUN Unix workstation to a Bailey Controls Net90 digital control system (DCS) through a Bailey Controls Computer Interface Unit (CIU). The neural network and data collection/processing system resided on the workstation. New

setpoint values were determined by the neural network periodically within defined constraints to insure safe operation.

Initial model results identified nine on-line parameters that could be used to reduce NO_x an estimated 15% below current levels. These parameters are:

- O_2 setpoint bias (1);
- Mill bias (4), and;
- Pulverizer primary air outlet temperature (4).

Secondary air register positions also affected NO_x emissions, but testing was limited since these are manually adjusted .

NO_x Emissions. Two major changes were implemented during an outage, based on recommendations by the NeuSIGHT system and plant maintenance guidelines. These were to reposition the secondary air registers and replace the balls and tighten down the heads of the two lower mills (A and D). These changes reduced NO_x by 10% before the neural network supervisory control was implemented.

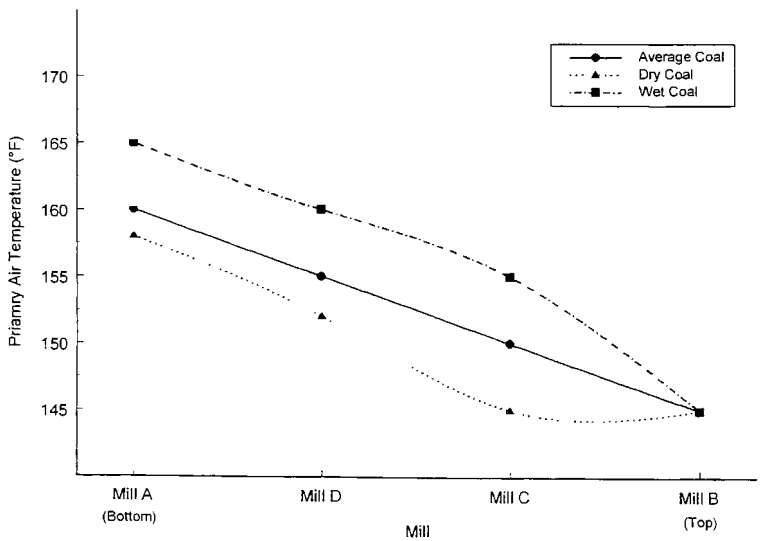

Figure 1
Pulverizer Primary Air Temperature Operating Range

The baseline pulverizer primary air outlet temperatures were maintained at 150 °F. Currently, the optimum settings vary day to day based on coal quality. Figure 1 illustrates the primary air temperature range that each mill operates at and the effect of coal moisture on these temperatures.

These setpoints are constrained between 145 °F and 165 °F under neural network supervisory control. They are also affected by the excess air setpoint and pulverizer bias settings.

Implementing supervisory control on excess oxygen, pulverizer primary air outlet temperatures, and mill biases has maintained the NO_x emissions between 0.56 to 0.70 lbs/MMBtu at high loads. This represents a NO_x reduction as high as 28%. Figure 2 shows the impact of specific primary air temperature settings on NO_x during a ten hour operating period.

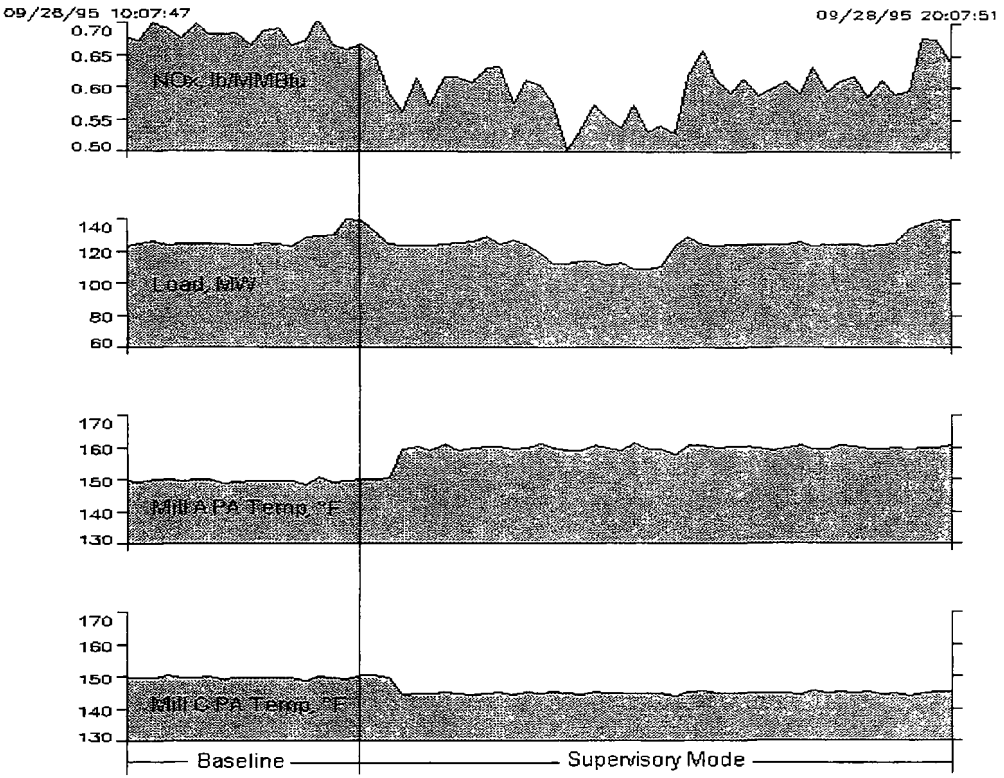

Figure 2
Impact of Primary Air Temperature with Supervisory Control of NO_x

Figure 3 shows the change in NO_x that was achieved throughout the normal unit load range.

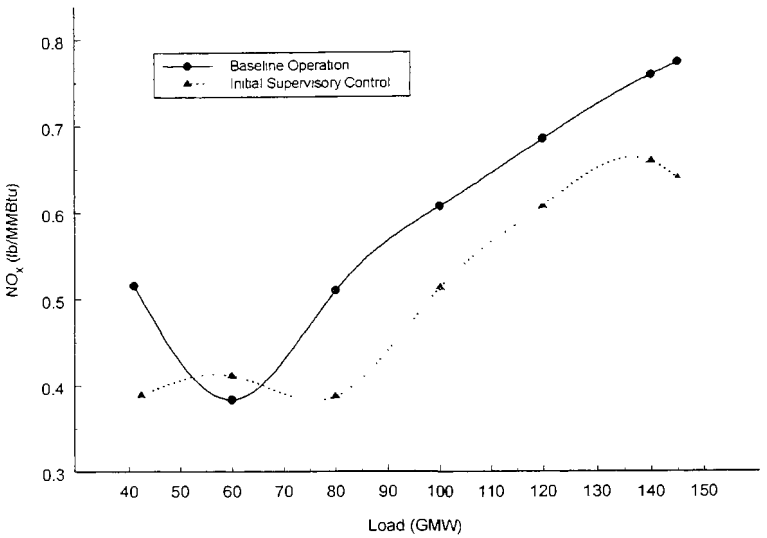

Figure 3
Effect of Supervisory Control on NO_x Emissions

Adding supervisory control of mill biasing provided additional gains. The results from 80MW to 120MW indicate larger NO_x reductions are feasible due to greater mill biasing flexibility.

Heat Rate and Loss of Ignition (LOI). Neither heat rate nor loss of ignition (LOI) values were available on-line. However, they were manually tracked during the project.

Comparing heat rate values for a 30-day baseline period prior to a similar period of supervisory operation showed that, after correcting for circulating water inlet temperatures, the average for the test period was 1.2% below the baseline value. This data is summarized in Table 1. Also included is a 15-day period of supervisory control with mill bias that resulted in a 4.4% heat rate improvement.

Table 1

Unit "A" Heat Rate

Operating Mode	Uncorrected Heat Rate	Corrected Heat Rate	% Improvement
Baseline	13,049	12,794	
Supervisory Mode	12,633	12,644	1.2%
Supervisory w/mill bias	12,206	12,233	4.4%

Limited LOI data suggests a significant reduction in the amount of unburned carbon in the ash. Table 2 presents typical values recorded prior to this project, followed by the values taken during the 30-day availability run, which indicates a reduction of 30% to 60%.

Table 2

Unit "A" Ash Analysis

Operating Mode	LOI (%)
Baseline	9.7
Baseline	10.4
Supervisory	3.1
Supervisory	3.4
Supervisory	2.8
Supervisory	6.1

More values are required to statistically verify this dramatic improvement.

Unit "B"

Unit "B" is a 500 MW tangential unit with five levels of burners in a single furnace. The objective of this program was to determine the feasibility of unit "B" to meet a 0.45 lb/MMBtu NO_x compliance emission limit utilizing a neural network advisory control system. Three weeks of on-site tests were performed during which the following parameters were adjusted on an individual basis to provide data for the neural network model:

- Primary air temperature of each coal mill;
- Coal loading from each mill;
- Excess O_2;
- Burner tilt;
- Warm-up oil air damper opening;
- Auxiliary air damper opening, and;
- Active coal air damper opening.

These tests were followed by a brief (two day) period of multi-variable tests to assure the system's ability to meet the NO_x compliance limit.

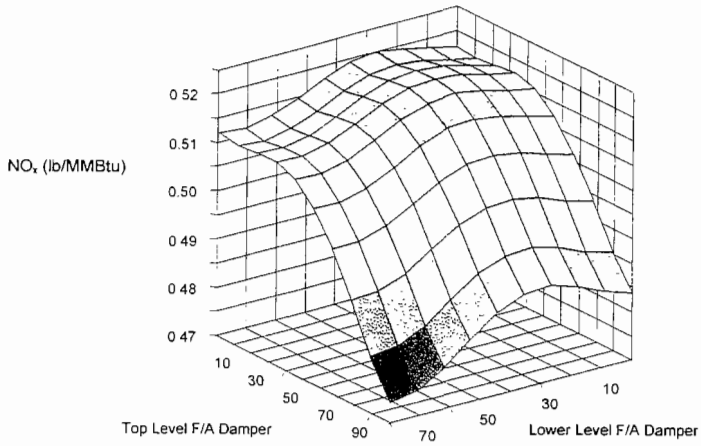

Figure 4
Effect of Fuel/Air Damper Position on NO_x

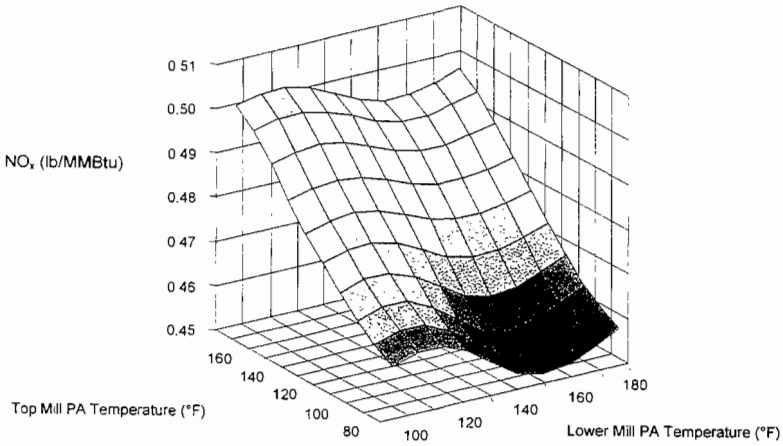

Figure 5
Effect of Mill Primary Air Temperature on NO_x

Figures 4 and 5 illustrate the sensitivity of NO_x to the top and lower burner secondary airflow and primary air temperature, respectively.

CO and LOI. Full load tests utilizing a multi-point emissions sample grid showed that the combustion uniformity (represented by point-to-point NO_x emissions) was relatively unchanged from the baseline. During these tests the average CO increased from 9 to 207 ppm when the optimum low NO_x firing mode was employed. However, unburned carbon in the flyash decreased from 10.9 (baseline) to 7.3 % during low NO_x firing.

NO_x Emissions. The preliminary recommendations for low NO_x operation after the conclusion of neural network modeling included:

- Reduce the top elevation mill coal flow whenever feasible;
- Remove the top elevation mill from service whenever load can be sustained with four or less coal mills in service;
- Open coal air dampers 100% on active burner levels;
- Close manually operated warm-up oil air dampers; and;
- Open the top two levels of auxiliary air dampers 100%.

The third recommendation, above, is counter-intuitive to usual NO_x reduction practice for tangential boilers. However, testing confirmed that this recommendation was valid.

Figure 6 represents the minimum NO_x emissions that were achieved for one week of operation after the preliminary recommendations were given to the boiler operators. The neural network modeling indicated that NO_x compliance could be achieved throughout the normal operating load range on this unit.

Although NO_x emissions from a tangentially fired boiler are usually highest at minimum load, NO_x was reduced 55% from the baseline average at minimum load after NeuSIGHT's recommendations were implemented.

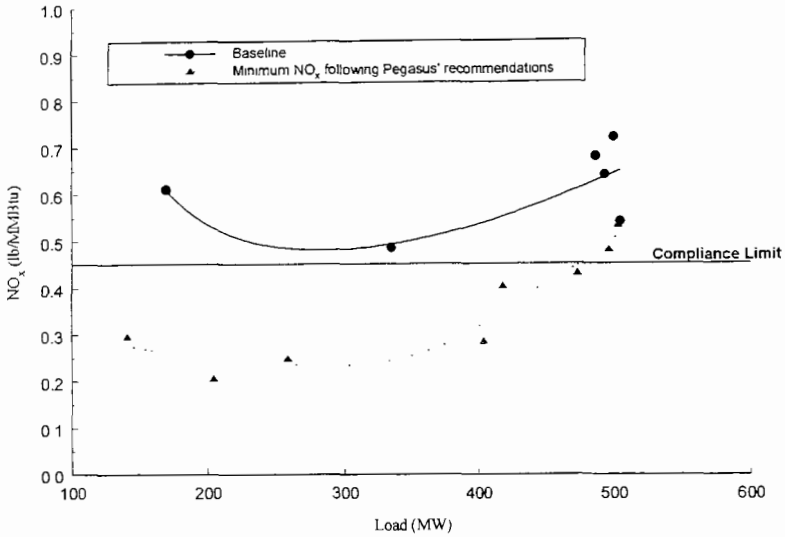

Figure 6
NO_x Emissions After System Optimization

A NeuSight based advisory or closed loop system would enable this unit to be operated with an acceptable margin for compliance at all loads. However, in light of the NO_x reduction that was achieved, the utility opted to implement these operating recommendations but delay the installation of an advisory system until the time when increased NO_x compliance margin is required or until heat rate and LOI considerations become more important.

Unit "C"

Unit "C" is an 800 MW boiler with opposed wall burners. The unit is equipped with low NO_x burners and overfire air (OFA). A RS-232 data link connects a SPARCstation 10 based NeuSIGHT process optimization to a Honeywell TDC 3000. The linking software transmits and receives over 350 points, analog and digital, per minute although the number of points processed by the system could be increased to more than 2000 points per minute.

The insights derived from the neural network modeling indicated that:

- The O_2 setpoint should be increased from 3.2 to 4.0%;
- NO_x varies directly with excess O_2;
- Opening the overfire ports 5 - 10% can actually lower heat rate and NO_x simultaneously (above 10%, the heat rate increased);
- Varying the overfire air port openings reduced NO_x by 30%;
- Balancing secondary air flow (i.e. O_2 probes +/- 0.5% of average) shifted the NO_x curve from 0.45 - 0.65 lb/MMBtu to 0.30 - 0.45 lb/MMBtu, and;
- Balancing air flow reduced the O_2 setpoint and improved combustion conditions virtually eliminating furnace slagging.

Although the initial model recommendations included increasing the excess O_2 to 4.0%, a subsequent calibration of the O_2 probes revealed that these probes had been reading low (approximately 0.8%). After the probes were calibrated the neural network reduced its O_2 recommendations, as it retrained, to 3.2%.

Load cycling affects O_2 and heat rate:

- When load decreases the control system lags air behind fuel causing high O_2;
- At the same time the heat rate will improve as the latent heat in the boiler requires less fuel to maintain the desired load, and:
- When the unit reaches steady state (even for a few minutes) the O_2 will continue to decrease (due to the lag) and the heat rate will degrade.

Methods to correct this problem included time averaging of the data and the introduction of lead/lag terms.

Other parameters that the optimization system identified as needing adjustment include:

- Superheat attemperation flow;
- Feedwater inlet temperature;
- Furnace exit temperatures;
- Furnace pressures, and;
- Secondary airflow balance.

The superheat attemperation flow and the furnace exit temperatures appear to have high penalties: as much as 20 - 50 btu/kwhr. This is likely due to changing furnace and convective pass cleanliness since the penalty increases over time. A means of incorporating a soot blowing model that will help minimize these penalties is being explored.

NO_x Emissions. The NeuSight system on this unit has been operating for 18 months. During this period NO_x levels have remained consistently within compliance and boiler performance has been improved. As part of ongoing modifications to this system, the

logic has been adjusted to provide compliance with NO_x for the adjusted regulatory limits (0.7 for 3 hour average and 0.5 for 30 day average) instead of instantaneous NO_x values. Analysis of the year long database from Unit "C" show some significant and interesting observations. The new NO_x requirements will have a very positive effect of improving heat rate nearly 1.5% while still maintaining a good compliance margin. New logic that modifies target values to avoid achieving a future average value has been developed and incorporated into this system.

Figure 7 shows NO_x values predicted for various excess oxygen levels and OFA settings at four different load points.

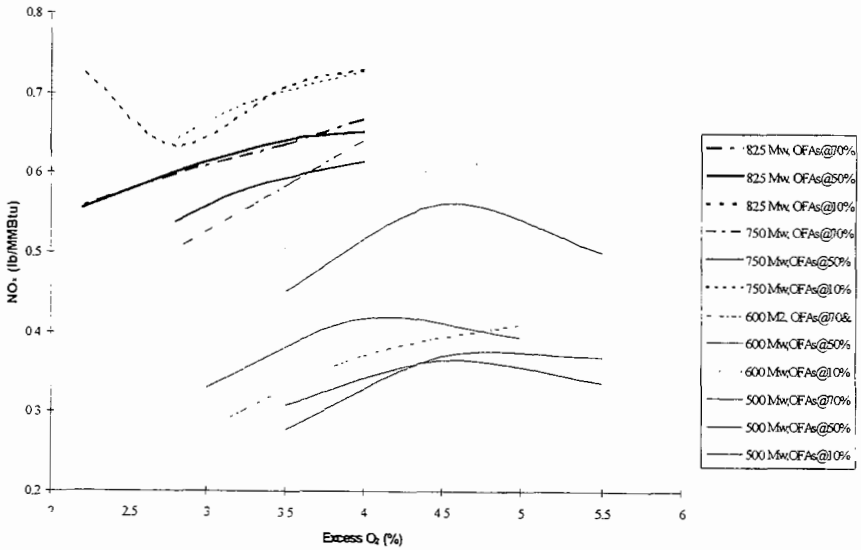

Figure 7
Effect of Over Fire Air and Excess O_2 on NO_x

Heat Rate. Figure 8 shows heat rate values predicted using the final trained data set developed from the year long database for the same operational parameters.
This indicates that closing the OFA dampers will improve the unit heat rate. Closing the OFA dampers will nominally shorten the combustion zone which for this boiler improves heat rate.

The heat rate data also show that O_2 control is not always the major heat rate improvement factor. For this boiler increasing O_2 decreased heat rate at most conditions.

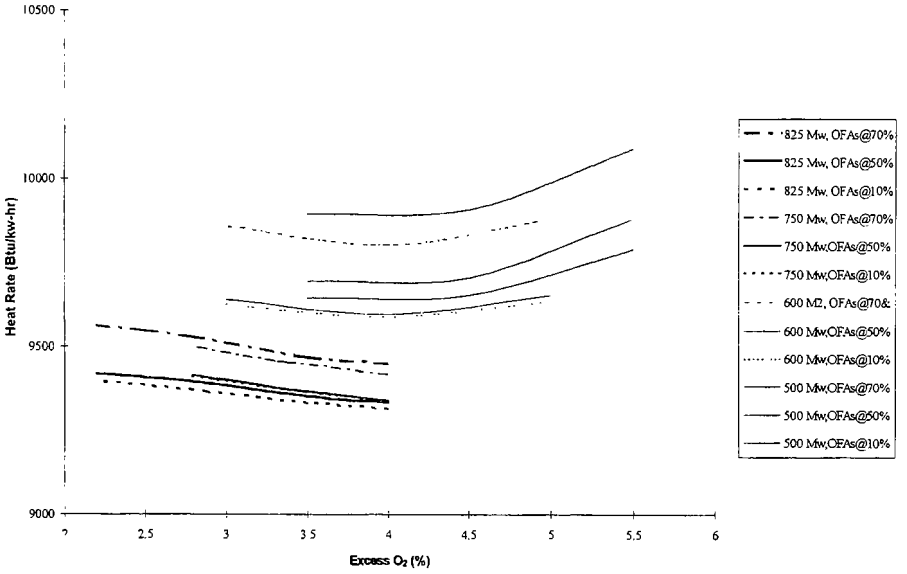

Figure 8
Effect of Over Fire Air and Excess O_2 on Heat Rate

Unit "D"

Unit "D" is a B&W boiler that is nominally rated at 650 MW. It has an opposed wall burner configuration supplied by seven pulverizers. This unit was commissioned in 1983 and was designed to meet a NO_x guarantee of 0.65 lb/MMBtu. The objective of the neural network program was to reduce NO_x to 0.50 lb/MMBtu or less.

The initial evaluation was performed for normal full load conditions (i.e. 620+ GMW) where minimizing NO_x was most critical. The model results showed that:

- The loading of the top mill (D) has the greatest impact on NO_x;
- Based on the model, the middle mills B, C, and E should be biased up to reduce the loading on top mills D and G;
- The optimized settings for the secondary dampers vary over time, in response to heat transfer surface cleanliness and mill operation;
- Primary air flow and pressure have weak model correspondence to heat rate and NO_x;
- Reduced NO_x emission can be obtained by lowering the primary air temperatures in the upper mills, particularly mill D;
- The superheat spray flow shows a strong sensitivity for both NO_x and heat rate, reflecting the influence of furnace cleanliness on these parameters.

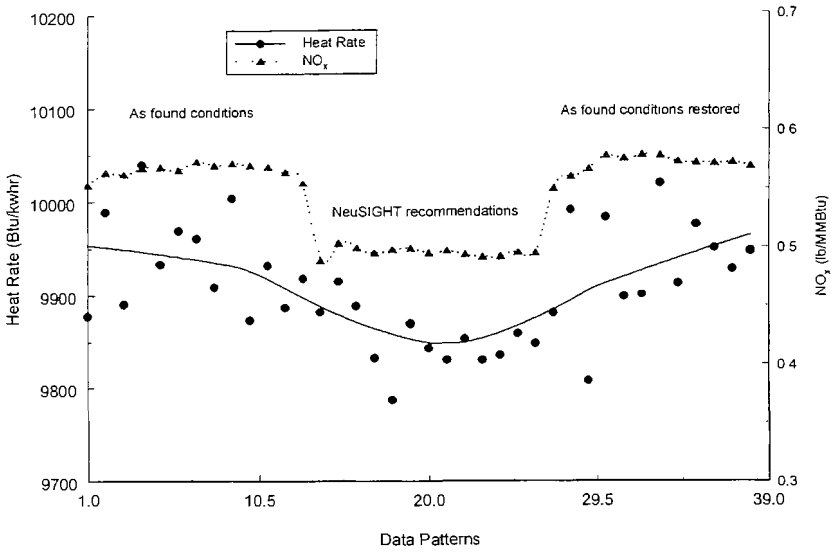

Figure 9
Effect of NeuSIGHT Recommendations on NO_x and Heat Rate

NO_x Emissions. Testing showed that NO_x was reduced 15% at full load. Although this was somewhat less than the initial model analysis had indicated, it reflects the fact that reality is often more constrained than a model.

Heat Rate. Although the model predicted that heat rate could be decreased approximately 5%, actual testing determined that a 0.75 - 1.25% heat rate improvement could be achieved. In fact, reduced NO_x operation was accompanied by a nominal 1% heat rate improvement. This is illustrated in figure 9, above.

Setpoints for supervisory control include mill feeder speed, primary and secondary airflow, primary air temperature, superheat and reheat spray flow, and excess O_2.

Conclusions

NO_x reduction and heat rate improvements are not contradictory goals under all circumstances. Heat rate **and** NO_x reductions are possible by optimizing the boiler combustion process. An additional benefit of improving heat rate is the direct reduction of SO_2 and CO_2 emissions. NO_x emission levels can be reduced, in some cases, to levels comparable to low NO_x burner retrofits without an LOI penalty for a fraction of the cost. In all cases, improved combustion can only lead to better performance and increased operating flexibility.

One advantage of using NeuSIGHT in supervisory control is that the system learns from the best operators and automatically captures and uses that knowledge through periodic model retraining. Thus, their experience with the boiler is incorporated directly into boiler operation for all shifts.

Observing data from various plants shows that sootblowing frequency and location has an immediate effect on both NO_x emissions and heat rate. Utilizing a neural network to provide guidance in activating the sootblowing sequence can provide NO_x and heat rate benefits while minimizing the costs of sootblowing. This system could, in addition, quickly learn to modify sootblowing operations to accommodate changing coal conditions rather than learning by costly changes in performance and/or emissions.

Pulverizer performance has a direct effect on NO_x emissions, unit heat rate and LOI. A neural network-based supervisory control system reacts to the performance of a pulverizer. If a pulverizer performs poorly, it is biased down automatically by the neural network to minimize it's impact on performance. A subsystem of the neural network is under development that will associate "bad" areas of operation with maintenance activities enabling plant personnel to plan maintenance activities proficiently. This will help increase the unit availability and capacity factors by reducing unplanned pulverizer outages.

Neural network technology has been shown to provide significant reductions in NO_x emissions and significant increase in unit performance. Future applications of this technology will provide users of the technology with improved availability, reliability, and operability, with reduced maintenance expense.

EMISSION SOLUTIONS THROUGH OPTIMIZATION

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Abstract

Electric utility companies face the challenge of remaining competitive while developing environmental strategies that address regulatory compliance issues within economic restraints. Air emission compliance standards have had a significant financial impact throughout the industry. "Best Available Control Technology" (BACT) solutions are expensive, implementation is often complicated, and results vary. Alternative solutions could prove to be more cost effective. This paper documents efforts made by The Lower Colorado River Authority to use neural net optimization software as a pollution prevention tool to reduce emissions from a large utility boiler. This project was funded in part through the EPA Pollution Prevention Incentive for States (PPIS) 1995 Grant Program. The paper details development of models built to predict NO_x and CO_2. These models identify and rank variables that affect the pollutants in order of influence. Control models were developed for use in determining the optimal set point for each control variable needed to attain the emission reductions. This report summarizes data gathering methods, test plans, modeling scenarios, recommendations, and implementation results; and analyzes the resulting economical benefits. It is the intent of this paper to identify a cost-effective alternative solution for emissions reduction.

Introduction

In many instances, environmental requirements can be impediments for profitable business. Industry's concern for the financial impacts of new regulations is perceived by the public as being insensitive towards the environment. The cost of compliance continues to increase, while managers are forced to operate with flat or reduced budgets. It is imperative that we search for solutions that allow us to meet our regulatory obligations with the least economic impact. Some of the answers may be discovered through the use of advanced software tools that learn the dynamics of complex processes. An increased understanding of the relationship

between the boiler process and the formation of pollutants could reveal opportunities for emission reductions. The initial investment required for this is minimal compared to "Best Available Control Technology " options.

This project was conducted at The Lower Colorado River Authority's, Thomas C. Ferguson Power Plant located in Horseshoe Bay, Texas. The facility is a 430 MW, natural-gas fired Combustion Engineering boiler rated at 2,900,000 lbs/hr steam flow. The objective of the project was to use an advanced modeling tool to decrease the greenhouse gas emissions from the boiler. To achieve reductions in carbon dioxide (CO_2) emissions, the strategy was to reduce the unit heat rate. A secondary objective of the modeling was to reduce emissions of oxides of nitrogen (NO_x).

Approach

The method used to achieve the project objectives can be divided into three tasks. These are data collection, modeling and implementation. Data collection includes planning which tests should be conducted, how the data will be collected, and an evaluation of the data quality prior to the beginning of the modeling task. Pavilion Technologies' *Process Insights*™ was chosen as the software tool for the modeling. Prediction and control models were developed to identify which input variables were most important to controlling the process. Once the models were completed, the recommendations were implemented, and the results were documented.

Data Collection

The quality of data collected will affect every aspect of a project, so it is important that close attention be given to this task. The data sets need to contain all the process and continuous emissions monitoring system (CEMS) data in a common format. Data were acquired by coupling the plant's Honeywell 4000 with a Levi Lamb, Inc. EX4000 interface. The *EX4000* software runs in a DOS windows environment, and interfaces with the Honeywell through a custom designed communications board installed in the Honeywell. The software allows the user to choose any or all tags and log their values in any time range from one second to one day. The data values are written in an ASCII format to a series of user defined "roll" files. The user defines the data interval and number of intervals each roll file is to contain.

The ability to retrieve plant data in sufficient quantity and format is critical. Data were collected at one minute intervals for 200 tags from the Honeywell and five tags from the CEMS. The data sets were created by merging ASCII data from the DCS and CEMS in an Excel spreadsheet. *Process Insights* readily imports the data sets, and combines the individual data sets to form one complete data set.

Once the data collection issues were addressed, a test plan was developed. The plan required the plant to operate through different scenarios at specified load ranges. To build an accurate model, the data must reflect the complete range of operation for each of the process

variables. The test plan consisted of forty tests, in seven load bins, with a duration of one hour per test.

There are additional issues concerning implementation of the test plan. There are costs associated with taking a unit off dispatch control during testing. The load profile may also require the testing to be conducted at night after peak. This can increase the cost and complicate the coordination of consultants, engineers, and plant personnel . It can rapidly turn into a major logistical problem and delay the project.

After the data are collected, they must be reviewed prior to the start of the modeling task. It is important that the data be an accurate reflection of the process to be modeled. Outliers like CEMS calibrations, erroneous readings from plant instrumentation, and downtime data are removed. This will prevent the software from focusing on data that are not consistent with the normal operation of the boiler.

Modeling

Once the data are collected and reviewed, the model development phase begins. Models are developed in two stages. In the first, prediction models are prepared to help identify which variables are most important for predicting the process. In the second stage, control models are developed in which the process control variables are manipulated to achieve the optimum conditions. The optimization software selected for this project was a neural net based software, *Process Insights*™ from Pavilion Technologies' Inc. This software is designed to evaluate the data and determine patterns in the process.

Prediction Models. In a prediction model, process variables are used to predict the desired output variables. The output variables are those parameters that will be optimized as part of the control model. In addition, any parameters which may require special constraints may be included as outputs. The objective of the prediction modeling task is to develop a model that combines the highest accuracy with the minimum number of inputs.

The initial process of determining which inputs to keep, requires personnel with knowledge of the combustion process and the overall operation of the facility. During this phase, the number of inputs in the training data set was reduced from 200 variables to 60 variables. The next step was the training and development of the prediction models. The NO_x and CO_2 values were identified as outputs, along with the boiler fuel flow rate, net heat rate, and windbox-to-furnace differential pressure. The other 55 variables were included as inputs.

The software learns the behavior of the process and predicts the outputs. The result of the predicted values of the outputs are then compared to the actual values. The software ranks the sensitivity of the outputs to each of the input variables, and a few of the less important variables are removed to create each succeeding model. This process is repeated until the inputs are reduced to approximately 10 to 20 variables. The final prediction model used for this project contained 13 inputs. The sensitivity ranking reports for NO_x and CO_2 are indicated

in Tables 1 and 2, respectively. This final model was verified with a separate validation data set to confirm the models' ability to accurately predict the outputs.

Table 1

Sensitivity Analysis for CO_2 Prediction Model

Rank#	Input Name
1	Net Generation
2	Main Steam/ Hot Reheat Differential Temperature
3	Degrees to Saturation
4	C Level Burner Status
5	Flue Gas Combustibles
6	Burner Tilt Position
7	Excess Oxygen
8	B Level Burner Status
9	A Level Burner Status
10	Main Steam Temperature
11	E Level Burner Status
12	D Level Burner Status
13	Throttle Pressure

Table 2

Sensitivity Analysis for NO_x Prediction Model

Rank#	Input Name
1	Net Generation
2	Degrees to Saturation
3	Excess Oxygen
4	Main Steam/ Hot Reheat Differential Temp. Flue Gas Combustibles
6	Burner Tilt Position
7	A Level Burners
8	Main Steam Temperature
9	E Level Burners
10	B Level Burners
11	C Level Burners
12	D Level Burners
13	Throttle Pressure

Control Models. The control model is developed using the same input and output variables that were contained in the final prediction model. In the control model, variables that require optimization or special constraints are designated as outputs. The inputs are divided into independent and dependent variables. Independent variables consist of those inputs that are manipulated to control the process, and inputs that are completely external to the process. Dependent variables consist of inputs whose value changes as a result of a change in an independent variable, but that cannot be manipulated to significantly affect the process.

In the case of a utility boiler, outputs may consist of pollutant emission rates, fuel flow rates and net heat rate. Independent variables include unit load, level of excess oxygen and burners in service. Dependent variables may be steam temperatures and pressures, or flue gas temperatures. It should be noted that the classification of a variable as an independent or a dependent variable may change during the model development process, because the relationship between the two sets of variables may significantly affect the accuracy of the control model's recommendations.

The control model accuracy is evaluated differently than that of a prediction model. In developing a prediction model, the accuracy of each succeeding model may be determined by loading a validation data set and comparing the predicted and actual values. However, in a control model, the input variables are being adjusted so that the outputs will achieve their optimum values. As a result, it is not possible to take an existing data set and run it through the model to determine accuracy.

The only way to truly evaluate the control model's effectiveness is to implement the recommendations on the actual process, but it is not practical to do this with each succeeding control model produced during model development. Thus, it is necessary to use engineering judgement to determine if the set point changes recommended by the control model are consistent with boiler optimization practices, and make practical sense. For instance, if the model suggests that a small change in the level of excess oxygen will produce a ten percent heat rate improvement, it is obvious that the model is not correct. However, if the model shows that a decrease in the level of excess oxygen will produce a small reduction in both heat rate and NO_x emissions, it is more accurate because the recommendation is consistent with boiler optimization experience.

There are a number of ways to affect and improve the model accuracy. Input variables may be removed or replaced, or reclassified from independent to dependent, or vice versa. New variables can be developed using data transforms, which may allow the software to get a different "look" at the data, and possibly identify a pattern that was previously missed. Finally, the constraints that are placed on the independent variables, and the optimization scheme for the output variables may be adjusted to yield better results.

The initial control model for the Ferguson station had a total of thirteen inputs and four outputs. These included net heat rate, NO_x emission rate, CO_2 mass emission rate and the windbox-to-furnace differential pressure. Only one of the inputs was classified as a

dependent variable and the rest were independent. From experience, this was not a good balance, and during model development, a number of the inputs were changed from independent variables to dependent variables. It also became apparent that it would be necessary to include the fuel flow rate as an output so that it could be minimized as part of the overall optimization.

The final control model included these same five outputs. It also had twelve inputs, of which seven were independent variables and five were dependent. Both burner tilts and throttle pressure were included as dependent variables, even though they may be used to control the process. This was because the burner tilt settings were driven by steam temperature, and the throttle pressure was a function of the load. The model inputs and outputs are summarized below:

Table 3

List of Control Model Variables

Independent Variables	Dependent Variables	Output Variables
Excess Oxygen	Main Steam Temperature	Net Heat Rate
Net Generation	Burner Tilts Position	Fuel Gas Flow Rate
A Level Burner Status	Main Steam/Reheat Steam Differential Temperature	Windbox/Furnace Differential Pressure
B Level Burner Status	Degrees to Saturation	NO_x, lb/hr
C Level Burner Status	Throttle Pressure	CO_2, lb/hr
D Level Burner Status		
E Level Burner Status		

Implementation And Results

The control system at Ferguson is not capable of supporting a closed-loop control model. It is not possible to track and manipulate the control variables that are necessary for the models that were developed. For example, the burner control system is separate from the Honeywell system, and burners must be taken in and out of service manually. As a result, it is not possible to install the control model and document the resulting improvements in performance. In this case, the model's recommendations had to be implemented by changing the way in which the operators configure the boiler at different loads. The following sections describe how the model's recommendations were implemented by plant personnel, and the resulting changes in emissions and heat rate.

Implementation

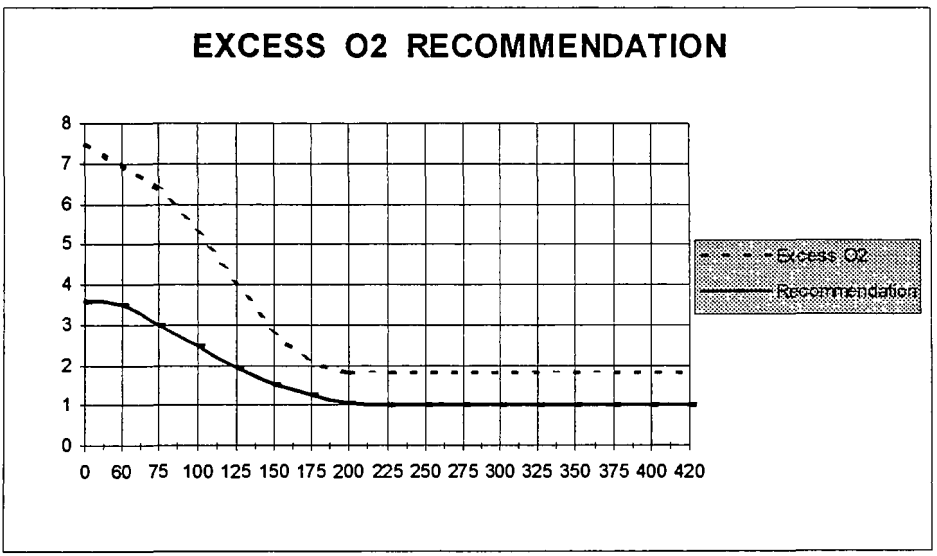
As described previously, it was not possible to install a closed-loop control model on the Ferguson boiler. Therefore, the operational changes recommended by the model were put in place through a series of modifications to the control system logic for excess oxygen set points and burner tilt position, combined with changes in the order that the operators took burners in and out of service.

The Ferguson Plant is a load control unit routinely operating throughout the entire load range. To follow the recommended change for excess O_2 curve, it was necessary to make the following changes to the control system logic:

1. The low air flow alarm was moved from 27.5 % to 26 %.
2. The excess O_2 flow alarm was moved from 1.0 % to 0.5 %
3. The excess O_2 controller logic was modified (Figure 1).

As seen in the figure, the model's recommendations called for a reduction in the excess oxygen set point. This was especially true at the low loads, where a change in the burner firing configuration allowed the boiler to operate with much less excess air flow.

Figure 1



A new sequence for taking burners in and out of service was also recommended as part of the boiler optimization. The effect of the recommendations was to push the fireball further up into the furnace, which allow the boiler to operate with lower levels of excess air at lower loads. The recommendations for the new burner configurations are detailed in Table 4.

Table 4

Recommendation for Burner Operation Starting at Minimum Load

Burners in Service: All D level and ½ of C level

As load increases:

- Add other ½ of C level
- Add B level
- Add A level
- Add E level

As Load decreases:

- Remove E level
- Remove A level
- Remove B level
- Remove ½ of C level

Since the recommended changes to the burner firing configuration caused the flame to be pushed higher into the firebox, it was necessary to make some modifications to the burner tilt positions to maintain steam temperature at acceptable levels. The changes to the burner tilts were programmed into the control system logic so that it would be possible to run the boiler in automatic control. The changes that were made to the burner tilt control logic at various loads are listed in Table 5.

Table 5

Burner Tilt Curve Recommendation

MEGAWATTS	TILT POSITION IN DEGREES
70	-15
80	-10
90	-5
100	0
110	5
120-160	10
180-210	5
240	0
260	-5
300	-10
320-400	-12

Results

Once the recommended changes to the boiler operation were implemented, it was possible to determine their effect on boiler emissions performance. The predicted emissions for CO_2 and NO_x were compared to the values from the existing CEMS to determine their accuracy. Improvements in the boiler heat rate were calculated by comparing the optimized operation with the baseline heat rate.

The results from the comparison of the emissions predictions showed that the software was able to accurately predict emissions through the entire load range. Figure 2 presents a plot of the actual CO_2 emissions compared to those predicted by the model. As seen in the figure, it is difficult to differentiate between the two curves. Figure 3 shows the results of the predicted NO_x emissions versus the actual NO_x emissions measured by the plant CEMS. Again, the two curves agree quite well.

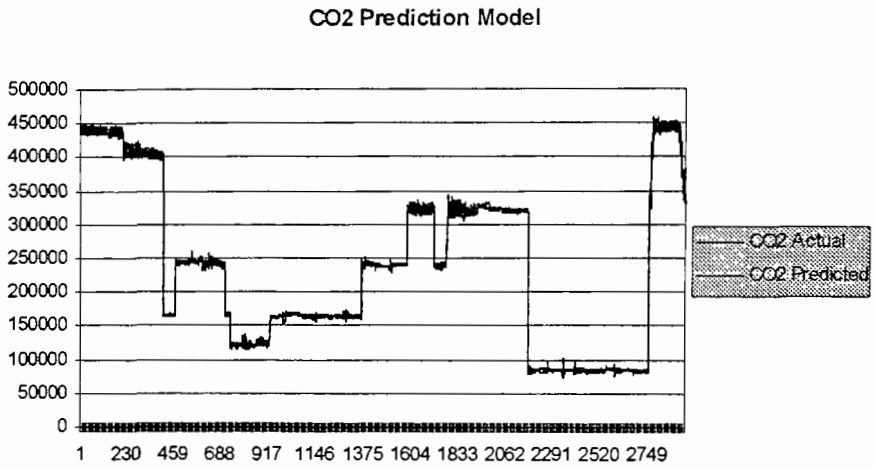


Figure 2

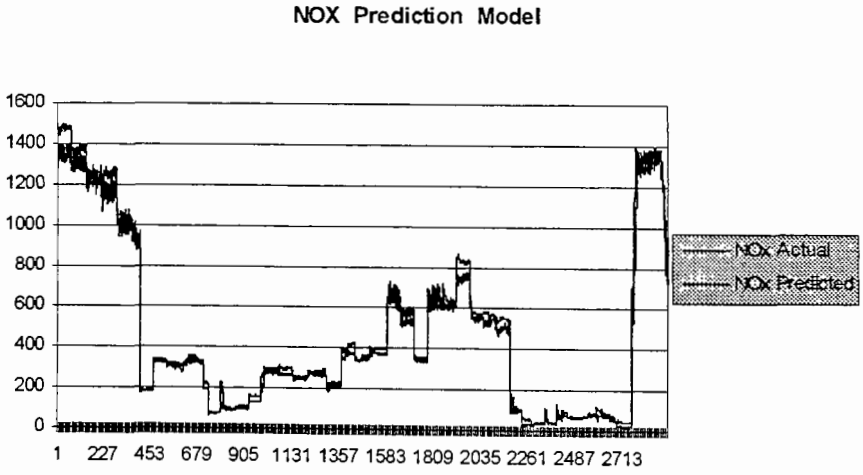


Figure 3

A series of tests were conducted at seven load bins to determine the effect of the recommended operating set points on the boiler heat rate. In these tests, the boiler was first operated for a time at the baseline condition. The recommendations were then implemented to show the optimum performance, and the change in the amount of fuel required to produce a MWh was documented. The reductions in emissions and fuel costs as a result of implementation are detailed in Table 6. These numbers are based on a 1996 load profile with an estimated gas price as an example .

Table 6

Table of Results from Model Validation Testing

Load Bin	1996 Hours in Load Bin	Fuel Reduction MMBtu*	Fuel Savings (@$2.37)	NO_x Reduction lb/hr	CO_2 Reduction lb/hr
60-70	1428	7100	$16,800	12852	3194436
71-120	1173	7900	$18,700	-63342	-1414638**
121-180	1047	10600	$25,100	14658	1376805
181-270	1940	17800	$42,200	153260	1879860
270-330	1794	29600	$70,100	157872	2868606
331-391+	518	3000	$ 7,100	81844	254338
Total	7900	76000	$180,000	357144	8159407

*Fuel Reduction was calculated by taking the fuel flow in MCFH, assuming 1020 Btu/CF to get MMBtu/hr, and then multiplied by hours to give MMBtu in each load bin.
**Apparent negative value for CO_2 is due to slight load increase from baseline test to optimized test condition. Therefore, overall CO_2 increased, although the amount of CO_2 per MWh actually decreased (as seen in the reduction in MMBtu).

As seen in the table, the optimized condition resulted in a significant decrease in overall emissions and fuel costs. Even the negative numbers shown in the second load bin are an anomaly, because the boiler load drifted up slightly between the baseline and the optimized tests. Therefore, although the total emissions increased, they actually decreased on a per MWh basis.

The evaluation of the model's recommendations showed that overall, the CO_2 emissions (and unit heat rate) were decreased by 0.5 percent. The decrease in overall NO_x emissions were determined to be 15 percent. These results clearly show the potential benefits of using advanced software tools for optimizing boiler operations.

Future Work

The results of the greenhouse gas reduction project at the Ferguson station have demonstrated the usefulness of neural net models for optimizing the combustion process in a utility boiler. However, there is a significant amount of unrealized potential for further improving both the emissions rates and the unit heat rate, which are currently being evaluated. These future possibilities for optimization include closed-loop control models, improved air damper controls, and feedwater heater optimization. Implementation of these improvements are dependent upon an upgrade to the existing distributive control system.

Foxboro I/A

The potential of the neural network models at Ferguson has not been fully realized due to the lack of a state-of-the-art distributive control system. LCRA is currently upgrading all of its units to a Foxboro I/A control system, and is planning for implementation at Ferguson no later than 2001. Once installed, the plant will be able to access and to manipulate all of the instrumentation that will be required to perform the additional optimization tasks described in the following paragraphs.

Closed Loop Modeling

The current DCS at Ferguson does not allow the facility to receive the full benefit of the optimization models. Implementation of the control model's recommendations has been accomplished at the lowest possible level of technology. That is, the optimum operation of the boiler, as identified by the model, has been divided into load bins, and used to make changes to the excess oxygen set points and burner configurations used by the operator. A higher level of technology would be an open-loop, or advisory, control model, in which the model would provide real-time recommended set points to the operator's screen. The operator could then implement those changes as often as possible, which would improve performance in two ways. The first is due to the fact that the safety margin has to be greater when the recommendations are not real-time. The second is because it is not necessary to determine an average optimum condition across the load bin, thus improving performance within a load bin, and producing a higher degree of optimization.

The highest level of implementation would be to install a closed-loop control system. In this mode, the optimization model would evaluate the current requirements and operating constraints for the boiler, and would automatically adjust the control set points to maintain the optimum performance at every operating condition. Since it is not practical for the operator to make changes to a number of control set points on a minute-by-minute basis, the closed-loop control system would allow for full implementation of the recommendations, and full realization of the potential of the boiler combustion optimization model.

Air Damper Controls

The stoichiometry of the combustion process affects both the boiler emissions, and the boiler heat rate. Installation of automated air damper controls would balance the airflows within the boiler, and alter the shape of the fireball to produce the optimum heat release within the furnace. Automated air damper controls could also be utilized to adjust the combustion stoichiometry on smaller scales, and produce localized regions of fuel-rich flames, followed by lean burnout. By staging the combustion in this manner, the boiler NO_x emissions could be minimized. In addition, the Ferguson unit is limited at the low end of the operating range by the fixed amount of air that passes through the windbox below a certain load. Automated controls would allow the airflow to be decreased and possibly decrease the minimum load rating for the boiler, thereby producing significant savings during off-peak operation.

Feedwater Heaters

Feedwater heating is another area in which a series of units expend a significant amount of energy to achieve the desired temperature. At Ferguson, there are seven feedwater heaters in all, including two high-pressure heaters and five low-pressure heaters. Heat rate improvements may be realized by optimizing the level control of individual heaters. Additional gains may be achieved by optimizing the overall feedwater heating system.

Summary

Deregulation of the utility industry will redefine how electricity is generated for the foreseeable future. The trend for emissions of criteria pollutants is towards tighter control and more stringent requirements. The combination of the need to produce electricity more economically and with reduced emissions is a serious challenge. To meet this challenge and to be environmentally responsible we must pursue the practical, workable and affordable solutions.

Advanced control systems coupled with advanced software will be important tools in the future. The results of this project have demonstrated that neural network modeling, combined with an understanding of the boiler process, may be used to lower the cost of producing electricity, while at the same time reducing emissions of greenhouse gases and criteria pollutants.

Acknowledgments

The authors would like to acknowledge the support of the EPA for co-funding the project. We would also like to express our thanks to the LCRA project manager, Randy Tobey, who was instrumental in the success of the project. In addition, we would like to express our appreciation to Mark Johnson, Ray Treadway, Ferguson Operations, and the LCRA management. Finally, thanks to Mark Hebets and Trish Tarbell of Radian International for their help in setting up the computer platform for the modeling, and for their assistance in the modeling efforts.

GNOCIS
A PERFORMANCE UPDATE ON THE GENERIC NO_X CONTROL INTELLIGENT SYSTEM

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Abstract

The Generic NO_x Control Intelligent System (GNOCIS) is an on-line enhancement to existing digital control systems or plant information systems that is targeted at improving unit performance while meeting or improving other operational constraints such as NOx emissions and fly ash carbon content. The GNOCIS methodology utilizes a model of the combustion characteristics of the boiler that includes NO_x emissions and boiler performance. The software applies an optimizing procedure to identify the best setpoints for the plant, which are implemented automatically without operator intervention (closed-loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open-loop). GNOCIS development was funded by a consortium consisting of the Electric Power Research Institute, PowerGen, Radian International, Southern Company, UK Department of Trade and Industry, and US Department of Energy. After a brief review of the GNOCIS technology, a summary of several ongoing GNOCIS projects will be presented.

Introduction

Deregulation of the industry has forced electric utilities to improve operating efficiencies of their units in an effort to reduce overall operating cost and become more competitive. Also, passage of the 1990 Clean Air Act Amendments has challenged US electric utilities to reduce nitrogen oxide (NO_x) emissions and to maintain these low emission rates during day-to-day operation. Boiler efficiency, fly ash carbon-in-ash (CIA or LOI), and NO_x emissions are strongly influenced by a number of controllable and non-controllable operating parameters. Due to the combustion complexity and high coupling of a number of important process parameters associated with boiler

combustion -- especially for pulverized-coal-fired units -- it is difficult to obtain an optimum or even acceptable operating point (EPRI, 1993). When one operating parameter is improved, another is usually adversely affected. Therefore, continuous delicate balancing is needed to maintain the optimum over a wide operating range and for extended periods. The difficulty in optimization is compounded on units with low NO_x combustion technologies installed.

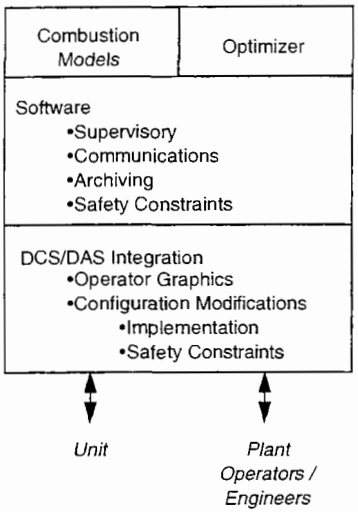

Figure 1
Major Elements of GNOCIS

Description of GNOCIS

GNOCIS™ (Generic NOx Control Intelligent System) is an enhancement to digital control systems (DCS) targeted at improving utility boiler efficiency and reducing emissions. GNOCIS is designed to operate on units burning gas, oil, or coal and is available for all combustion firing geometries. The major elements of GNOCIS are shown in Figure 1. The basic elements of GNOCIS are described below.

Combustion Models. Modeling of the furnace is a critical element of GNOCIS. Since all optimization techniques make use of models (either local or global) of the process in developing recommendations, the veracity of the process model is highly important for the success of the optimization. GNOCIS utilizes neural networks for the combustion model (Beale, 1990) (NeuralWare, 1993).

The combustion models are usually developed in two steps. The first step is the development of predictive models of the combustion process. Given the combustion process, predictive models are created using a subset of the measurable inputs and outputs of the process. The inputs may consist of both controllable parameters (such as valve positions) and non-controllable parameters (such as ambient temperature or fuel quality).

Although predictive models are useful tools, what is required in GNOCIS are control models. A predictive model is designed to predict outputs given a set of inputs, but a control model must be designed to work in reverse—to predict inputs given a set of desired outputs. To predict the inputs effectively, a more complex structure is more appropriate. This structure is necessary since not all important inputs to the combustion model are controllable, and if controllable, they may not be independent. A critical element of the control model design is the selection and assignment of the various inputs to the controllable (or manipulated), non-controllable, and dependent

classes. In many cases the partitioning is non-intuitive. Also, consideration must be given to the accessibility of the parameter within the DCS in a closed-loop installation or the ability of the operator to manipulate the control variables in an open-loop installation.

The flexibility of the modeling approach utilized in GNOCIS permits rapid development and modification of the combustion models. Although process variables utilized are very boiler dependent, variables that have been modeled include NOx, CO, opacity, LOI, boiler efficiency, heat rate, and furnace temperatures.

Optimizer. Optimization is the process by which a performance index is minimized (or equivalently, maximized) by the manipulation of one or more independent variables for which the performance index is a function (Dixon, 1972) (Press, 1988). GNOCIS utilizes a general, non-linear constrained optimizer with capabilities to handle disjoint feasible regions. The latter feature enables GNOCIS to make recommendations concerning operating conditions such as whether a mill should be removed or placed into service. Several factors were considered in this selection:

- GNOCIS is designed to be part of a supervisory control structure, and therefore dynamic optimization was not a consideration.
- The combustion process is generally highly non-linear.
- Constraints are needed for inputs, outputs, and derived functions.

A "typical" optimization scenario that can be readily configured in GNOCIS may be stated as shown in the box to the right. Further constraints could also be placed on the control variables such that only certain mills are to be considered in the optimization. Also, plant staff can easily change the goals through the operator screens.

Typical Optimization Scenario
Maximize boiler efficiency While {Maintaining NOx below 0.45 lb/Mbtu Maintaining LOI below 5 percent } Using {Mill biasing Excess oxygen Overfire airflow }

Digital Control System / Data Acquisition System Integration. GNOCIS is designed to be either integrated with a DCS, providing closed-loop optimization, or as an open-loop advisory system interfaced with a DCS or DAS. Plant data is collected via a DCS or DAS and passed on to the GNOCIS host platform. Recommendations are then conveyed to the operator either through recommendation screens on the DCS/DAS or screens built in the GNOCIS host platform. The operator can then implement the recommendations, either manually or through the DCS. A closed-loop implementation

is shown in Figure 2. In this configuration, GNOCIS gathers unit operating data via the DCS, and calculates the optimum setpoints. The optimum setpoints can be implemented by the operator or automatically by the DCS.

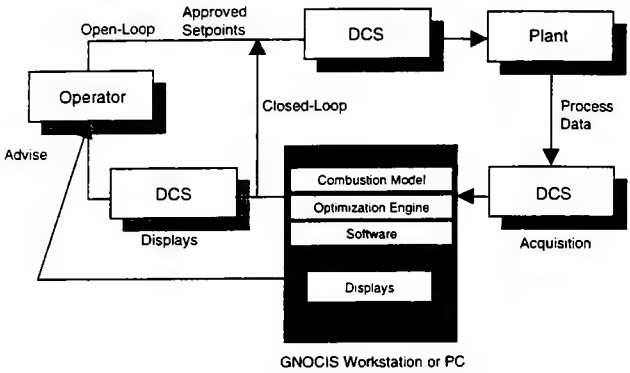

Figure 2
GNOCIS Implementation Structure

The recommendations provided by GNOCIS, whether open- or closed-loop, are supervisory in nature and are ideally implemented via the DCS. Therefore, many facets of a GNOCIS implementation are involved with the modification and upgrade of the DCS to implement the recommendations.

Operator Graphics. The operator displays are the principal interface to GNOCIS. These displays (1) convey to the operator the recommendations and predicted benefits and (2) allow the operator flexibility in setting constraints. An example of a GNOCIS operator screen is shown in Figure 3. As shown, the operator is presented with the current operating conditions and two sets of recommendations and predictions. One set corresponds to the current mills-in-service operating condition. If accepted, the operator can either implement the recommendations by individually setting the manipulated parameters to the targets or have the DCS automatically implement the recommendations (*Implement Recommendations*).

When *clamped*, the independent parameter is assumed to be unavailable for optimization purposes and is set to the current operating condition. The optimization is then performed with the remaining parameters. The operator can remove or add parameters from the optimization by using this screen (*Clamped / Free*).

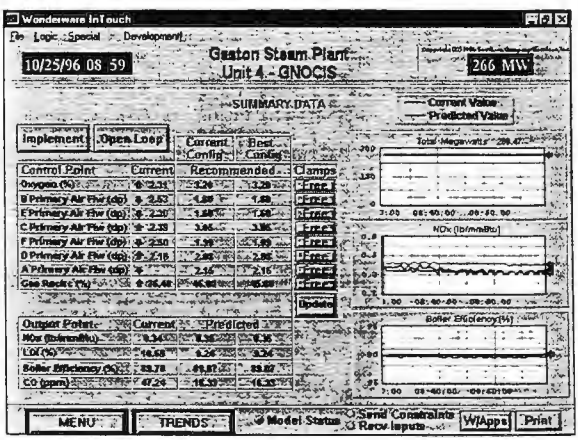

Figure 3
Example of GNOCIS Summary Screen

Since in many instances the mill selection can affect performance and emissions, it is important to provide recommendations concerning the mills in service. However, due to many externalities unmeasurable by the DCS or best judged by the operator, the mill configuration should not be automatically implemented. As a compromise, another set of recommendations is provided as to the optimum mills in service and the performance/emissions benefits. Given the predicted improvement and the current state of the plant, the operator can decide whether it is of overall advantage to change the mills in service. Closed-loop mode, if implemented, can be toggled with *Open Loop* by selecting the *Close Loop / Open Loop* button from this screen.

As discussed previously, the constraints and objective function implementation in GNOCIS is very flexible. A subset of this functionality is accessible via an operator graphic. High and low limits can be placed on both the controllable parameters (manipulated variables) and outputs. Hard constraints (cannot be violated) are used for the former, whereas soft constraints (can be violated but with a penalty applied to the objective function) are used for the latter.

Configuration Modifications. In order to obtain the full benefits of GNOCIS, modifications must usually be made to the DCS configuration, particularly for closed-loop implementations. However, whether open- or closed-loop, GNOCIS recommendations are considered supervisory in nature, and in most cases, setpoints or deviations from design curves are recommended. The level of complexity of the modifications is dependent on the desired integration of GNOCIS into the DCS and falls into three broad categories: addition of I/O blocks, implementation of GNOCIS recommendations, and validity checking (Table 1).

Table 1
Summary of DCS Configuration Modifications

	Open-Loop		
	Operator Implemented	DCS Implemented	Closed-Loop
Addition of I/O Blocks	✓	✓	✓
Implementation of GNOCIS Recommendations	n/a	✓	✓
Validity Checking	n/a	n/a	✓

GNOCIS Projects

GNOCIS projects and demonstrations are underway at a number of sites (Table 2). Initial trials of GNOCIS were conducted at PowerGen's Kingsnorth Unit 1 in 1994 and Alabama Power's Gaston 4 in 1995. Since that time, several other projects have been initiated. As shown, the projects span most of the major firing geometries, fuel, and digital control system types. Several of these projects are discussed in the following paragraphs.

Table 2
GNOCIS Sites / Projects Underway

Unit	Company	Date YY QQ	Inst. Type	Boiler Type	Fuel	DCS Type	Size MW
Kingsnorth 1	PowerGen	94 Q4	OL	T	C,O	Cutlass	500
Gaston 4	Alabama Power	95 Q2	CL	W	C	L&N Max 1000	270
Kingsnorth 3	PowerGen	94 Q4	OL	T	C,O	Cutlass	500
Hammond 4	Georgia Power	96 Q2	CL	W	C	Foxboro I/A	500
Nelson 4	Entergy	97 Q3	CL	W	G	L&N Max 1000	540
Cheswick 1	Duquesne	97 Q3	CL	T	C,G	West.WDPF	570
Wansley 1	Georgia Power	97 Q3	CL	T	C	Foxboro I/A	865
Branch 3	Georgia Power	97 Q3	CL	W	C	Foxboro I/A	480
Gaston 3	Alabama Power	97 Q3	CL	W	C	L&N Max 1000	270
Kingston 9	TVA	97 Q4	CL	T	C	Foxboro I/A	200
Watson 4	Mississippi Power	97 Q4	MS→CL	W	C	Bailey Infi 90	250
Watson 5	Mississippi Power	97 Q4	MS→CL	W	C	Bailey Infi 90	500
Wansley 2	Georgia Power	97 Q4	MS→CL	T	C	Foxboro I/A	865
							6310

Inst. Type
OL - Open-loop
CL – Closed-loop
MS – Model study

Boiler type
T - Tangential-fired
W - Wall-fired
C - Cyclone

Fuel
C – Coal
G – Natural gas
Date - Initial testing date

Kingsnorth Units 1 and 3. Kingsnorth Power Station, owned and operated by PowerGen plc, is on a coastal site on the Medway estuary in Kent, UK. It has four 500 MW tangential-fired units which were commissioned between 1970 and 1973. It is supplied with coal by sea from a range of domestic and international sources. It was selected for the trials because (1) it had the worst carbon-in-ash problem of PowerGen's five 2000 MW stations, (2) it had a suitably modern DCS to which GNOCIS can be interfaced, and (3) the very wide range of coals it uses makes it a particularly challenging implementation. GNOCIS was initially installed on Unit 1 as part of the original developmental program. Due to unavailability of Unit 1, GNOCIS was later added to Unit 3 to continue the test program.

The boilers were constructed by NEI International Combustion to be capable of meeting full load on either pulverized coal or residual fuel oil. Each unit is fitted with only five mills, all of which are required to achieve full load on most (but not all) of the coals supplied to the station. Each furnace is fitted with a low NO_X concentric firing system with separated overfire air. The coal mill control system uses mill feeder speeds as the prime control variables. In fully automatic mode, the goal of the control system is to match the feeder speeds of all mills in service, while maintaining the required load. One or more mills may be put on manual control where the feeder speed is fixed at a constant value and the remaining feeder speeds are again varied to meet the required load. The station has a NOx emission limit of 390 ppm at 6 percent O_2, set in agreement with Her Majesty's Inspectorate of Pollution. These emissions are not, however, subject to statutory continuous monitoring.

GNOCIS was used to optimize NOx emissions and carbon-in-ash. Controllable parameters used for the optimization include feeder speeds (5), excess oxygen, and burner tilts (Figure 4). The actual objective function that GNOCIS sought to minimize varied in the trials. However, the constraints that the optimizer had to obey were common. Specifically, advised values for controllable inputs should not be outside their operational limits, load must not decrease, and mill speeds should be between 800 and 2000 rpm or they should be zero (that is, the mills each have a dead-band). The recommended control settings that GNOCIS produces are passed back to the DCS, where they pass to the operator via a display on the unit control panel (Figure 4). The panel shows current values for the variables, their upper and lower constraints, and the GNOCIS recommendations.

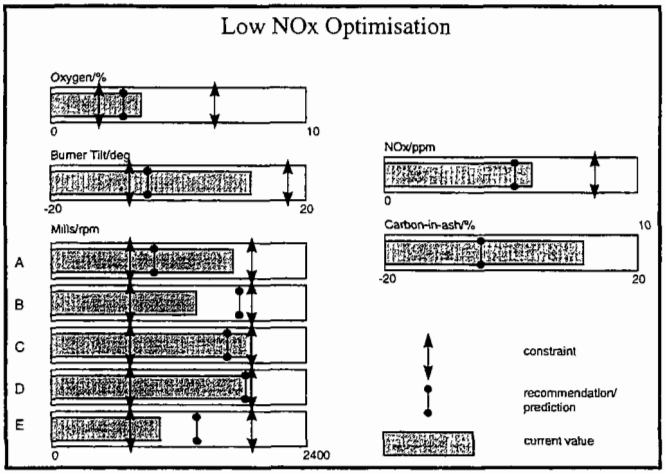

Figure 4
Operator Interface at Kingsnorth

Numerous tests were conducted during the course of the trials at this site which lasted from December 1994 through December 1996. For example, for several tests, GNOCIS was instructed to produce the best set of inputs which would keep NO_X below its statutory limit and minimize carbon-in-ash. Figure 5 shows the result of one such trial, where a 4 percentage point reduction in carbon-in-ash was obtained at the small cost of a 10 ppm rise in NO_X (but still well below the statutory limit of 390 ppm at 6 percent oxygen).

To demonstrate GNOCIS's flexibility and to show that it could cope with other objective functions, a further test was undertaken. In this, the optimizer attempted to reduce NO_X while containing any increase in carbon-in-ash. Figure 5 shows the success of this test: NO_X fell from 350 ppm to 325 ppm with barely any change in the carbon-in-ash, which stayed at 12 percent.

GNOCIS is currently available to the operators on both Unit 1 and 3 and is used as needed to provide operational recommendations.

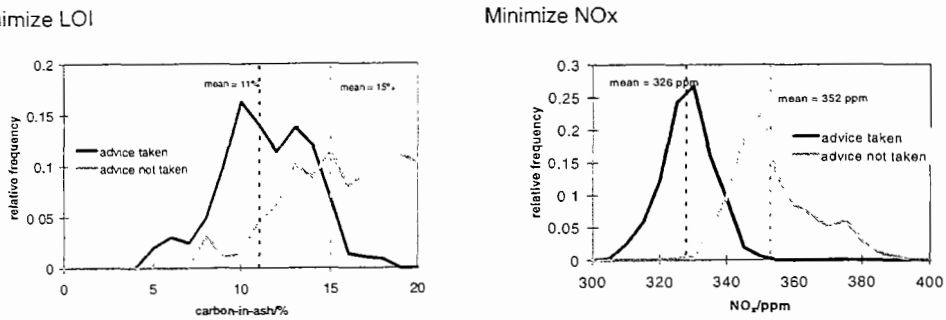

Figure 5
Example Results from Kingsnorth

Gaston Unit 4. Alabama Power's Gaston Unit 4, along with Kingsnorth Unit 1, was a development site for GNOCIS. Gaston Unit 4 is a 270 MW pulverized-coal unit. The Babcock and Wilcox (B&W) opposed-wall-fired boiler is arranged with nine burners (3W x 3H) on two opposing walls such that no burner has another burner directly across from it. Combustion air is supplied to the burners via common wind boxes on each side of the boiler. The unit is equipped with B&W XCL low NO_x burners and six B&W EL-76 ball and race mills. Fuel is delivered to the mills by two-speed table feeders. The unit has two forced-draft fans, six primary air fans, and two flue gas recirculation fans. Combustion air is heated with Ljungstrom air preheaters. The boiler control system for Gaston Unit 4 is a Leeds and Northrup MAX 1000 distributed digital control system.

The original objective at Gaston was to implement an open-loop, advisory system with no immediate plans to migrate to closed-loop operation. However, during the course of the project, it was determined that there were significant benefits, both in performance and ease of use of the system, if upgrades were made to GNOCIS to enable closed-loop operation. These enhancements also give the operator an easier way to implement open-loop recommendations.

The informational flow for the GNOCIS implementation at Gaston is similar to that shown in Figure 2. All process data is collected through the DCS and passed on to the GNOCIS host for calculation of the recommendations. These recommendations are then conveyed to the operator via the DCS operator displays, similar to those shown before, except residing on the MAX operator stations. If acceptable, the operator can then implement these changes through the DCS operator displays. Also, the operator has the option of running GNOCIS closed-loop with recommendations automatically implemented.

Testing of GNOCIS was conducted during second quarter 1995 and was completed third quarter 1996. Open-loop tests conducted as part of the developmental program indicated that GNOCIS was able to improve boiler efficiency by approximately 0.5 percentage points and reduce LOI by approximately 3 percentage points when this was the objective. When used to minimize NO_x, reductions of nearly 15 percent were obtained (Figure 6). Following completion of the formal test developmental program, the site conducted some intermediate load tests during December 1996, the results of which are shown in Figure 7. GNOCIS is currently operating in closed-loop mode at this site.

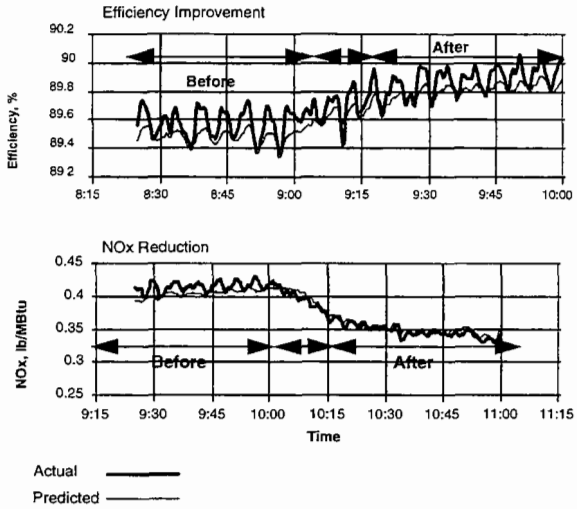

Figure 6
Open-Loop Testing at Gaston 4

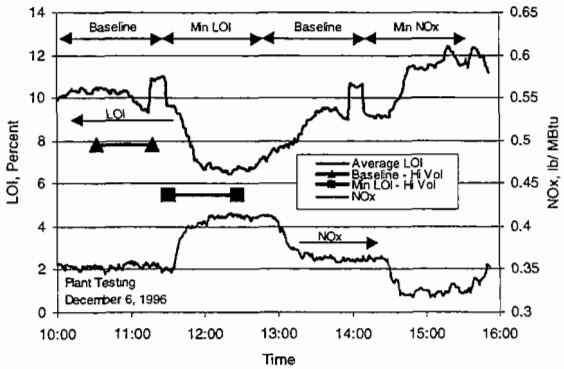

Figure 7
Closed-Loop Testing at Gaston 4

Hammond Unit 4. The GNOCIS project at Georgia Power's Plant Hammond was undertaken as part of a US Department of Energy Innovative Clean Coal Technology program being conducted at this site. The overall project provides a stepwise evaluation of the following NO_x reduction technologies: Advanced overfire air (AOFA), Low NO_x burners (LNB), LNB with AOFA, and advanced digital controls and optimization strategies. GNOCIS is being demonstrated as the advanced control/optimization technology.

Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW. The balanced draft unit is equipped with a coldside ESP and utilizes two regenerative secondary air preheaters and two regenerative primary air heaters. Six Babcock & Wilcox MPS 75 mills supply pulverized eastern bituminous coal to twenty-four FWEC Controlled Flow/Split Flame (CF/SF) low NO_x burners. The unit is also equipped with a FWEC designed Advanced Overfire Air (AOFA) system.

The boiler control system for Hammond 4 is a Foxboro I/A distributed digital control system.

From project inception, the goal of the GNOCIS installation at Hammond has been to implement a closed-loop, supervisory system. The Foxboro DCS, installed in 1994, included configuration enhancements that facilitated incorporation of GNOCIS into the overall control strategy. As at Gaston, all operator interactions with GNOCIS are through the DCS operator displays. The GNOCIS host platform at this site is a Windows NT workstation networked to the DCS.

Testing of GNOCIS at Hammond 4 began during February 1996 and continues to date. The test program has been hampered by general unavailability of the unit; however, tests to date have been encouraging. Test 158 is a representative example (Figure 8). This test was conducted with the unit off economic dispatch and at 480 MW. The purpose of the test was to evaluate the performance of GNOCIS in regards to boiler efficiency improvements as GNOCIS was made sequentially less constrained. As shown, nominal boiler efficiency was near 87.5 percent at the beginning of the testing and with sequential application of the GNOCIS recommendations, an efficiency of approximately 88.3 percent was attained. As can be seen in the figure, recommendations for excess oxygen, AOFA damper, and mill loading were implemented at approximately 11:15, 12:10, and 12:45, respectively. Although not shown, the recommended AOFA damper position is dependent on whether the mills are included in the optimization mix which is indicative of a non-linear process.

GNOCIS is currently operating in closed-loop mode at the site. Completion of the test program is expected during third quarter 1997.

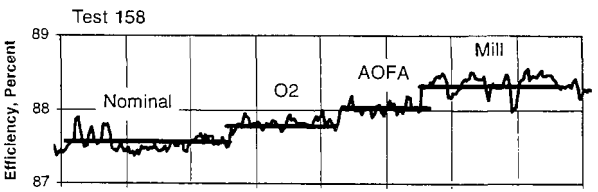

Figure 8
Hammond / Results of Test 158

Cheswick Unit 1. Duquense Light's Cheswick Station is a 570 MW coal-fired generating station located in Cheswick, Pennsylvania. The unit also has the capability to co-fire natural gas at up to about 20 percent of heat input. The unit is equipped with overfire air and low NOx burners. The unit has installed a LOI monitor and CO monitors in the boiler exit ducts. Cheswick fires a blend of coals (blend based on coal sulfur content) and is equipped with an on-line coal analyzer in the coal yard.

The GNOCIS demonstration at Cheswick, which is an EPRI funded tailored collaboration project, has two objectives. These include NOx reduction and heat rate improvement. In addition, opacity reduction is being investigated. Two optimization scenarios are being investigated:

- Find the optimum operating conditions (best heat rate) while maintaining NOx and opacity in compliance with the current operating permit.

- Find the operating conditions that result in the lowest possible NOx emissions with acceptable penalties on opacity, heat rate, carbon loss, and furnace conditions.

The important control variables that have been identified through both modeling efforts and actual testing at the plant include excess oxygen, mill biasing, SOFA damper positions, and gas co-firing level.

The GNOCIS models' outputs are NOx, heat rate, LOI, CO, and opacity. Sensor validation models have also been developed for all of the model inputs. These were deemed necessary to ensure reliable model operation at this facility. Frequent sensor problems are encountered at the plant with oxygen probes (there are six, located at various positions across the ductwork) and some temperature sensors. The sensor validation models also estimate NOx concentrations when the NOx monitor is going through a calibration cycle. This ensures continuous system optimization. The GNOCIS models run on a Westinghouse WDPF workstation with operator screens integrated into the DCS. The initial installation is open-loop, with closed-loop operation scheduled for late summer 1997. The open-loop installation allows "one-button" implementation of the GNOCIS setpoint recommendations at the operator's discretion. Model predictions and initial testing indicate NOx reductions of at least 15 percent at full load and heat rate improvements of 0.5 percentage points.

Future enhancements under consideration for the system at Cheswick are to include additional inputs from the ESP so that opacity predictions and control can be improved. GNOCIS will eventually receive data from ESPert, an expert system developed by EPRI for diagnosing precipitator problems (EPRI, 1994).

Nelson Unit 4. Unit 4 at Entergy's Plant Nelson is a 540 MW gas-fired generating unit located in Lake Charles, Louisiana. It is a B&W wall-fired unit, with 16 two-burner cells in an opposed-firing arrangement. The unit is equipped with flue gas recirculation. There are "NOxports" for overfire air, but they are apparently too small and have minimal impact on NOx.

The EPRI funded GNOCIS demonstration at Nelson will investigate two optimization scenarios:

- Find the optimum operating conditions (best heat rate) while maintaining NOx in compliance with the current operating permit.

- Find the operating conditions that result in the lowest possible NOx emissions with acceptable penalties on heat rate and furnace conditions.

The important control variables that have been identified through both modeling efforts and actual testing at the plant include excess oxygen, FGR fan damper position, burners out of service, and FGR bias between the windbox and the hopper. The GNOCIS models' outputs are NOx, fuel consumption, CO, and furnace draft.

The GNOCIS models run on a PC running Windows NT. The PC is networked to an application processor in the unit's L&N MAX 1000 DCS. Operator screens are integrated in the DCS. The initial installation is open-loop, with closed-loop operation scheduled for late summer 1997. The open-loop installation allows "one-button" implementation of the GNOCIS setpoint recommendations at the operator's discretion. NOx reductions of at least 15 percent at full load and heat rate improvements of 0.3 percent are indicated by model predictions and initial testing. Testing of GNOCIS is now underway at this site.

Wansley Unit 1. Georgia Power's Plant Wansley, located near Roopville, Georgia, is the site of two 865 MW pulverized-coal units. Unit 1 and Unit 2 are sister units and are in most respects identical. The Unit 1 Combustion Engineering (CE) tangential-fired boiler has seven elevations of burners with eight corners (split-furnace) each supplied by CE 983 RP roller type pulverizers. The balanced-draft unit has two forced-draft fans and four induced-draft fans. The unit has been retrofit with an ABB CE LNCFS Level 2 separated overfire air (SOFA) low NOx combustion system installed in 1992. The boiler control system for the unit utilizes a Foxboro I/A system and a data acquisition system is used for process data collection and storage.

Kickoff for the EPRI funded GNOCIS project at Wansley was in late January 1997. The project has the primary objective of further verifying the NOx and performance improvement potential of GNOCIS. The site is also interested in applying GNOCIS to control fly ash LOI level. Operating parameters to be considered in the optimization mix include boiler efficiency, LOI, NOx emissions, and opacity. Control variables are expected to be excess oxygen, mill coal flows (7), and overfire air flow. Major activities in the project include: (1) GNOCIS host platform installation, (2) pre-installation testing, (3) installation of a Mark and Wedell on-line carbon-in-ash analyzer, (4) DCS configuration changes, (5) model development, and (6) post-retrofit testing. GNOCIS is

being installed to be operable in either open- or closed-loop modes.

A Windows NT workstation hosting the GNOCIS software was installed during March 1997. Prior to this installation, process data used to train the combustion models resided on the plant information servers and was transmitted to SCS by site personnel who subsequently transmitted the data to Radian. With installation of the workstation, the pertinent process parameters (approximately 100 points) are archived on the workstation thus streamlining the transmittal of data to Radian. Based on prior GNOCIS and combustion experience, a pre-installation test plan was developed to provide reasonable coverage of the potential unit operating envelope and provide process information in regions where the unit did not normally operate. Unit operators conducted the actual testing while the unit was in economic dispatch.

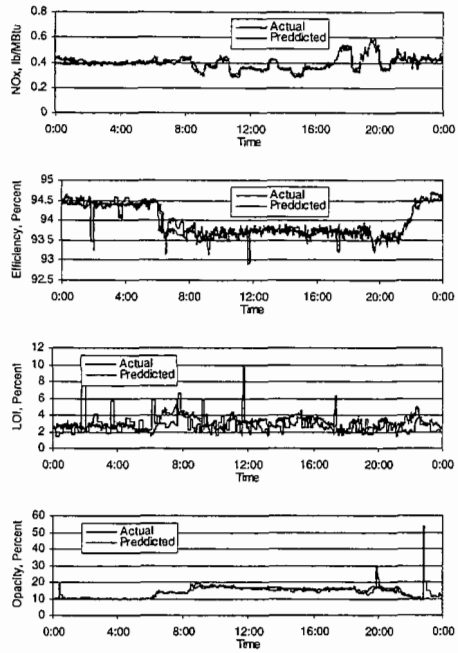

Figure 9
Wansley / Predicted vs. Actual

Since the site was concerned about LOI levels, a Mark and Wedell on-line carbon-in-ash analyzer has been installed on the unit. The system samples from two ports, located on the "A" and "B" sides of the furnace. The system began initial operation during the spring; however, to date it is not considered completely operational, and the vendor continues to refine the installation. After a review of potential control variables with the site, marked up DCS functional drawings were submitted to the site for configuration into the DCS by site I&C personnel with assistance from Southern Company Services. The control strategies and implementation specifics were guided by the installations at the earlier GNOCIS sites but customized to reflect the specifics of the boiler and DCS.

Combustion models, both predictive and control, have been created. An example of the predictive qualities of one model is shown in Figure 9. The data shown represent one day out of several weeks of data. As shown, the predictive qualities were quite good for all variables. The models are now being revised to reflect recent refinements in the control strategy.

Open-loop testing is scheduled to begin in July 1997, with closed-loop testing following in August 1997.

Branch Unit 3. Georgia Power's Plant Branch, located near Milledgeville, Georgia is the site of four pulverized-coal units with a total generation capacity of 1750 MW. Unit 3 is a 480 MW Babcock and Wilcox (B&W) unit equipped with cell burners (double). Ten B&W EL76 pulverizers supply eastern bituminous coal to the furnace. The balanced-draft unit has two forced-draft fans and two induced-draft fans. The boiler control system for the unit utilizes a Foxboro I/A system, and a data acquisition system is used for process data collection and storage.

The EPRI funded GNOCIS project at Branch began in January 1997. The project has the primary objective of further verifying the NOx and performance improvement potential of GNOCIS. Specific operating parameters to be optimized include NOx, boiler efficiency, LOI, and opacity. Control variables to be used in the optimization include excess O_2 and mill biasing -- a total of 11 parameters. GNOCIS is to be open- and closed-loop capable on this unit. The major activities to date include (1) installation of the GNOCIS host platform and archival of process data and (2) DCS configuration modifications. A CAMRAC on-line carbon-in-ash monitor is being installed on the unit to support the test program and is scheduled to be operational during July 1997. Pending unit availability, GNOCIS is scheduled to be operational in open-loop mode in August with closed-loop capability provided in September.

Gaston Unit 3. Gaston Unit 3 is a sister unit to Gaston 4, having the same boiler and DCS configuration. This project, funded by EPRI and Southern Company, was initiated during December 1996. A primary goal of this project is to determine potential cost savings from installation of GNOCIS on a sister unit. Also, since Unit 3 and 4 share a common stack CEM, enhancements to the predictive qualities of the combustion model for each unit will be possible by utilizing process data from each unit. The DCS configuration changes associated with the GNOCIS installation have been completed and archiving of plant data is in progress. It is expected that the GNOCIS installation and testing will be completed by third quarter 1997.

Kingston Unit 9. TVA's Kingston Unit 9 is a 200 MW tangential-fired pulverized-coal unit retrofitted with a Foxboro I/A digital control system. This site, located near Kingston, Tennessee, is host to the EPRI I&C Center. The split furnace has four levels of auxiliary air and is supplied fuel from six pulverizers. Potential control variables include excess oxygen, mill biasing, auxiliary air damper position, and burner tilts. The GNOCIS installation for this site is now being defined with startup by fourth quarter 1997.

Summary

A summary of the project and the results to date are as follows:

- GNOCIS has been successfully deployed in both open-loop advisory and close-loop supervisory modes.
- GNOCIS has been able to provide advice which reduced carbon-in-ash and improved boiler efficiency.
- GNOCIS provided advice which reduced NO_x emissions.
- The advice GNOCIS makes is consistent with good engineering judgment.
- Several projects are underway which will further quantify the benefits and costs associated with GNOCIS.

Acknowledgments

The authors wish to gratefully acknowledge the following for their guidance, support, and efforts related to the development and demonstration of GNOCIS: Gary Fotheringham, Rob Holmes, and Ian Mayes, PowerGen; Jim Noblett and Mark Hebets, Radian International; Bob Kelly, Kerry Kline, and Mike Slatsky, Southern Company. Also, the support from Rabindra Chakraborty, ETSU, Dave Crockford, DTI, Scott Smouse, DOE, and Tom Brown, DOE is greatly appreciated. We would like to thank our respective organizations for permission to publish this paper. Lastly, we would like to thank the staff at each of the host sites for their gracious toleration of our frequent requests and for allowing their units to be host sites for GNOCIS.

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Monday, August 25; 3:30 p.m.
Parallel Session A:
Low-NOx Systems for Coal-Fired Boilers (Wall and Tangential)

BURNER MODIFICATIONS FOR COST EFFECTIVE NO_X CONTROL

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Abstract

The development of commercial Low NO_x Burners has provided Energy and Environmental Research Corporation (EER) with the expertise to modify existing burner equipment to provide the controlled fuel/air mixing conditions required for low NO_x combustion. This approach represents a viable alternative to a full burner retrofit for many applications. EER has modified burners to lower NO_x emissions at Louisville Gas & Electric's (LG&E) Cane Run Station and at Jamestown Board of Public Utilities (JBPU). This paper will discuss the method and results of these burner modifications.

Introduction

With deregulation of the Utility Industry approaching, many utilities are looking for lower cost alternatives to satisfy NO_x regulations. Justifying new low NO_x burners on a boiler that is 30-40 years old and has limited remaining life is also difficult. Performing modifications to the existing burners provides the utility an option. Modifications are usually 2 to 4 times less expensive than new low NO_x burners.

Units which are the best candidates for burner modifications include:

- Older units where the expense of new burners is difficult to justify over the remaining boiler life.
- Units operating under a system-wide NO_x averaging strategy, where compliance on all boilers is not essential, and where burner modification offers an economical option for smaller units.

- Units requiring greater than 55% NO_x reduction, where burner modification can provide an economical NO_x reduction and then coupled with Reburn, SNCR, SCR, or other technologies to provide the overall NO_x reduction.

- Units with first generation low NO_x burners, where only moderate NO_x reduction is required.

- Units with conventional burners, firing sub-bituminous or other highly reactive coals.

The modifications to be performed on each project vary widely according to the type of burner, the NO_x reduction required, and site specific information such as coal, burner area heat release rate, etc. To perform an initial evaluation, EER requests specific site information. After completing preliminary calculations the next step is usually a windbox inspection of the existing burners. Some projects then require a reduced scale isothermal modelling study of the existing burner in order to determine the exact detailed modifications. Other projects that are similar to previous jobs or only require a small NO_x reduction do not require modelling. The goal of modelling is to determine the specific modifications required to simulate the burner mixing rates and exit aerodynamics of EER's commercial Low NO_x Burner. The hardware modifications are usually configured so that the existing burner does not have to be removed from the windbox which is a major advantage when old boilers contain asbestos.

Low NO_x Burner Technology

In 1987, EER participated in a joint development program between Elkraft Power, a Danish utility, and Burmeister & Wain Energi (BWE), a Danish boiler and combustion system manufacturer, to develop a reliable, high quality, high performance low NO_x burner capable of meeting mandated 50% emissions reduction goals. The burner developed is shown in Figure 1. The burners have been installed in both Europe and North America. The burner has some similar components and NO_x performance results when compared to other commercial low NO_x burners. However, the mechanical construction of the burner is unique and has several advantages compared to other burners. The key functional features of the design include:

- Variable combustion air supply through separate secondary and tertiary passages
- Variable swirl on both the tertiary and secondary air
- Flameholder attached to the coal nozzle

Mechanically, the burner has been designed to minimize the number of moving parts. Those parts which do move, slide axially, eliminating complex linkages and gears. The secondary and tertiary swirl control vanes, called turbolators, move back and forth within conical passages of the burner. As the turbolators are moved toward the narrow end of the cone more air passes through the vanes increasing the amount of swirl. As the turbolator is moved in the opposite direction, the air follows the path of least resistance and by-passes the vanes, resulting in less swirl. The amount of combustion air entering each burner is controlled by a sliding ring damper. Similarly, the split between secondary and tertiary (outer zone) air is controlled by a second ring

damper. The parts of the burner which are subjected to a high heat flux are fabricated from a high strength, heat resistant alloy.

The air distribution between the secondary and tertiary zones and moderating the tertiary air swirl to lengthen the flame across the available firing depth represents the main variables for control of NO_x emissions. The low primary air/coal velocity and flameholder are designed to provide good flame stability and acceptable flame characteristics for a wide range of operating conditions and fuel characteristics. The flameholder establishes local recirculation zones and promotes local mixing between the coal and the secondary air. This leads to a rapid devolitalization of the coal and liberation of fuel nitrogen in a low excess air environment resulting in reduced NO_x formation.

Modelling

EER constructed a six tenths scale model of the "RO" type burner for LG&E. The majority of the burner was constructed of light weight carbon steel, and modelers clay was utilized to create several different flameholder configurations. Particular attention was directed at specific components (coal inlet scroll, coal nozzle rifling, air register) to assure that a baseline flow was established. LG&E personnel observed some of the flow study as it occurred at EER's Combustion Test Facilities in El Toro, California.

A combination of flow visualization, velocity mapping, and engineering judgement was used to examine near field aerodynamics of the current "RO" burner design. The burner was then modified to create the same flow fields as EER's commercial low NO_x burner. The study was interactive as each of the burner modifications was tested independently and then assembled to assure that the proper flow fields were being created as the air and fuel exited the burner.

Louisville Gas & Electric

Unit #4. Cane Run Station Boiler #4 is a 170 MWe front wall fired CE boiler that went on line in 1962. The boiler steam flow is 1,200 Klb/hr. The boiler width is 40'-5" and the depth is 26'-3.5". The boiler has four CE 683 Raymond bowl mills, each of which supplies pulverized coal to four (4) CE type "RO" burners. The sixteen burners are rated at 100 MMBtu/hr each. The burner throats are 38 inches. New refractory was installed but new pressure parts were not required. The burners are configured in four elevations of four burners per row. The horizontal and vertical spacing of the burners is 8 to 10 feet. New Forney gas igniters, scanners, and a Burner Management System were installed during the 10-week late winter 1996 outage. A Honeywell DCS system was also installed to complete the system. The baseline NO_x emissions were 1.2 lb/MMBtu and the current NO_x requirements are 0.5 lb/MMBtu. EER guaranteed 0.48 lb/MMBtu NO_x emissions with the burner modifications. Installation was completed by LG&E. The modified burner is shown in Figure 2.

The burners were started up in April 1996. The flames are very stable and a NO_x reduction of greater than 50% has been achieved across the operating range as shown on Figure 3. The boiler normally operates with an oxygen content of 4.0% or greater at full load to maintain steam

temperature. The data shown in Figure 3 is for an O_2 of 4.5-5.0% at full load. The full load NO_x emissions at 4.0% O_2 are 0.45 lb/MMBtu. The typical coal analysis is shown in Table 1. The pulverizers and exhaustors were rebuilt during the outage and the riffle boxes replaced. During start-up the full load LOI was 6% which is the same as baseline. However, EER recently tested three of the four mills with our Rotorprobe™ System to check on fineness and fuel distribution. Both the fineness and fuel balance were below requirements and that has resulted in progressively higher LOI since start-up. During May 1997 the pulverizers averaged 2.5% retained on 50 mesh, 85.7% through 100 mesh, and 64.5% through 200 mesh. EER has provided an adjustable orifice device (FlowmastEER) shown in Figure 4 to balance the coal flows to each of the top eight burners. EER will balance the coal flows in August after the FlowmastEERs are installed.

Unit #5. Cane Run Station Boiler #5 is a 180 MWe front wall fired Riley Stoker boiler that went on line in 1966. The boiler steam flow is 1,360 Klb/hr. The boiler width is 47'-3" and the depth is 27'-0". The boiler has three Foster Wheeler ball mills, each of which supplies pulverized coal to four burners. The twelve burners are rated at 155 MMBtu/hr each. The original burner throats were 38 inches. The burners are configured in three elevations of four burners per row. The horizontal and vertical spacing of the burners is 10 to 11 feet. New Phoenix low NO_x burners were installed in 1994. New Forney gas igniters, scanners, a Burner Management System, and a Honeywell DCS system were installed during that outage. The baseline NO_x emissions were 0.9 lb/MMBtu with the old FW Intervane burners. The low NO_x burners were operating at 0.8 lb/MMBtu but the current NO_x requirements are 0.5 lb/MMBtu.

EER modified the existing burner as shown in Figure 5. The existing coal inlet scroll and air register were utilized to minimize costs. The modifications consisted of a new coal nozzle with flame stabilizer, a secondary air sleeve, a core air pipe, waterwall panels forming new burner throats, and a tertiary air sleeve to attach the existing register to the new burner throat. Installation was completed by LG&E. The burners were started up in November 1996 and the most recent 30-day average on NO_x emissions was 0.50 lb/MMBtu. EER also provided an adjustable orifice device (FlowmastEER) to balance the coal flows to each burner. The precipitator performance was marginal before the low NO_x retrofit. After the coal flows were balanced to 10 of the 12 burners, the operators noticed a reduction in the number of opacity excursions above 20%. To minimize opacity concerns and assist in maintaining steam temperature the boiler is operated at full load with an oxygen content of 4.5-5.0% and this results in LOI less than 4%. Some recent CEMS NO_x data is shown on Figure 6.

Jamestown Board of Public Utilities

The Jamestown Board of Public Utilities (JBPU) operates a 50 MWe coal fired electric generating station. The plant has four pulverized coal fired boilers supplying steam at 850 PSIG and 900°F to two 25 MWe turbines. The boilers are rated from 150 to 230 Klb/hr steam flow.

Boiler #12. The boiler was installed by Erie City Iron Works (Zurn Industries) in 1967. It is rated at 230,000 lb/hr. The furnace width is 17'-0" and the depth is 19'-3" The horizontal and vertical burner spacing is approximately 6 feet square. The unit has two (2) CE 473 Raymond

bowl mills each of which supplies pulverized coal to two (2) CE type "R" burners. The burner throat is 31.5 inches and the burners are rated at 62.5 MMBtu/hr. The throat refractory was patched during the outage. Peabody oil lighters and the Burner Management System are interconnected to a Westinghouse WDPF Control System. Baseline NO_x Emissions are 0.9 lb/MMBtu and flyash unburned carbon was 4 to 7%. The current New York State DEC regulation is .45 lb/MMBtu. To satisfy these requirements, EER installed burner modifications and may utilize gas reburning to meet future requirements. The burner modifications occurred during the July/August 1996 outage when the superheater was also replaced. EER provided a turnkey project for this boiler.

The burner modifications were very similar to LG&E. EER also installed a FlowmastEER adjustable orifice device shown in Figure 4 to balance the coal flows to each burner and the coal fineness is 75% through 200 mesh. At full load the NO_x emissions are maintained below .45 lb/MMBtu with an oxygen content of 3% as shown on Figure 7. Burner flame shaping can be accomplished by adjusting the air register. The typical coal analysis is shown in Table 2. The flyash unburned carbon from ESP hopper grab samples during the first week of operation averaged 7 to 10%.

Boiler #11. After the successful start-up of Boiler #12, JBPU awarded EER a similar project for Boiler #11. The boiler is rated at 165,000 lb/hr steam flow and is very similar to boilers 9 & 10 described below. EER provided the same burner modifications and the start up was April 1997. The current New York State DEC NO_x regulations for this boiler is 0.5 lb/MMBtu. The boiler is able to satisfy these regulations while operating at 5% O_2 levels. The NO_x emissions verses steam flow is shown on Figure 8.

Boiler #9 & 10. The boilers were installed by CE and then retubed with membrane walls in 1990 by CE. Openings for ten (10) overfire air ports on the side walls were installed, but have not been utilized. The furnace width is 16'-3.5" and the depth is 17'-8". The horizontal and vertical burner spacing is approximately 5.5 feet. It is rated at 165,000 lb/hr. The unit has two (2) CE 453 Raymond bowl mills, each of which supplies pulverized coal to two (2) ABB type "RO-II" burners. The burner throat is 28 inches and the burners are rated at 50 MMBtu/hr. Peabody oil lighters and the Burner Management System are interconnected to a Westinghouse WDPF Control System. Baseline NO_x Emissions are 0.6 lb/MMBtu. The current New York State DEC regulations for these boilers is 0.5 lb/MMBtu. To satisfy these requirements, EER has installed burner modifications.

Based on the LG&E flow modelling, EER fabricated hardware to modify two of the burners on Boiler #10. The hardware consisted of a modified secondary air sleeve and coal nozzle tip/flameholder. JBPU fabricated a device to straighten the pulverized coal flow. JBPU installed the equipment in December of 1995. By utilizing the existing burner register, the on-line burner adjustments are limited to only varying the flow distribution between the secondary and tertiary air zones. There is no adjustment of air swirl. The results were promising so EER fabricated the remaining hardware for the other six burners which were installed in March 1996.

During the first start up one of the coal nozzles was plugged when operating with minimum primary air flow. No serious damage occurred and the problem has not recurred since the minimum exhaustor discharge pressure has been raised. With the same boiler air flow curve, the modified burners were operating at 0.4 lb/MMBtu. To reduce the unburned carbon, the plant has increased the boiler air flow such that they operate at approximately 0.48 lb/MMBtu. Increasing the secondary air and decreasing the tertiary air has also helped reduce the unburned carbon, as has modifying the sootblower schedule in the lower furnace. The burner flames are very stable and JBPU has been able to operate below 0.5 lb/MMBtu. The baseline unburned carbon was 24 to 30%. The modifications have reduced the unburned carbon to 18-24% while reducing the NO_x emissions. The unburned carbon values were quite responsive on Boiler #12 when adjusting the air swirl and it is speculated that the current swirl level is not optimized.

Future Work

EER will perform burner modifications for Dayton Power & Light on Unit #3 at their Stuart Station in the Fall of 1997. Unit #3 is a 605 MWe B&W universal pressure opposed wall fired boiler. The unit is equipped with 24 two-nozzle cell burners. The furnace depth is 39 feet. Cell burners were developed in the 1950s as high heat input, high efficiency burners. Each cell is composed of two closely spaced circular burners acting as a single unit. Cell burners generate very high levels of NO_x, ranging from 1.1 to 1.8 lb/MMBtu. EER has modeled the circular burner for DP&L and determined the burner modifications required to reduce the NO_x emissions.

Conclusion

Modifying existing burners is a viable alternative to new Low NO_x Burners as shown by these examples. EER has modified two different burner designs and is currently modifying two additional burner designs. The modifications have also been scaled over a large range of heat inputs from a 330 MMBtu/hr burner on a 913 MWe unit to the 50 MMBtu/hr burners at Jamestown. Modifying existing burners to satisfy NO_x regulations does provide a lower cost option that should be considered.

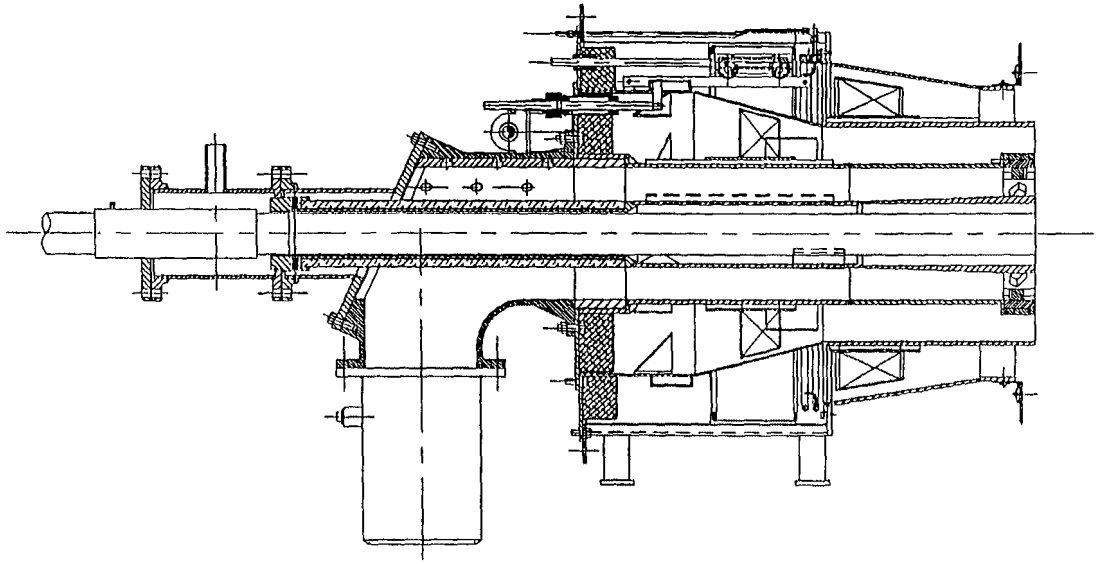


Figure 1. FlamemastEER™ Burner

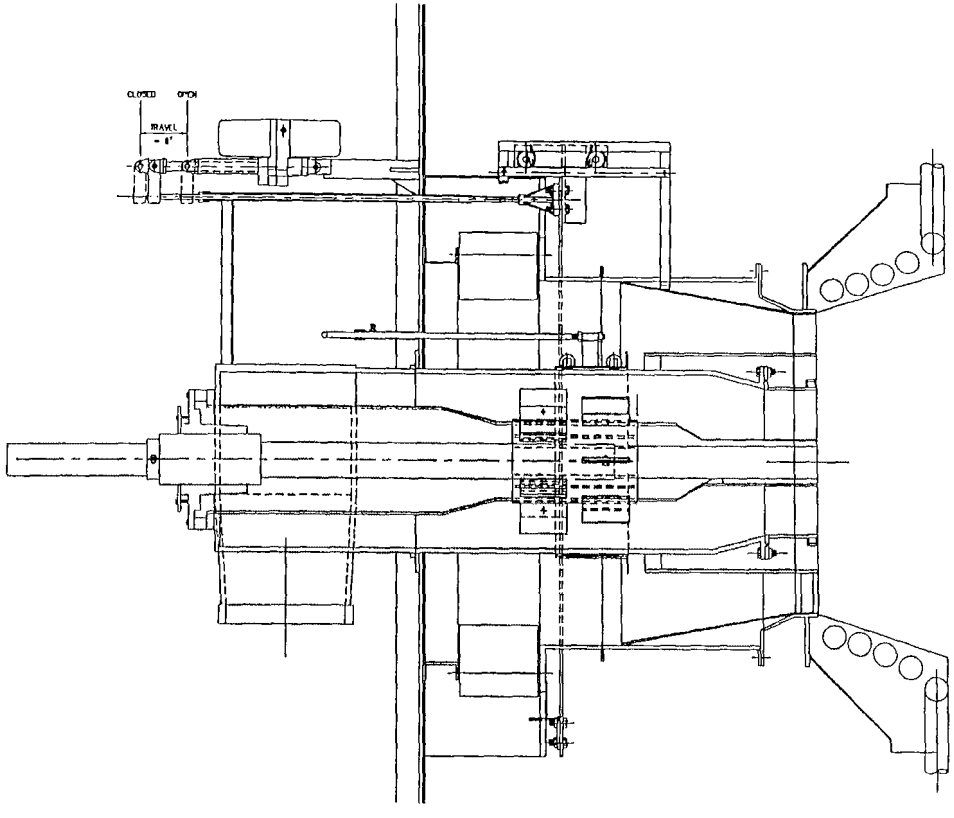


Figure 2. Louisville Gas & Electric Cane Run 4 Burner Modifications

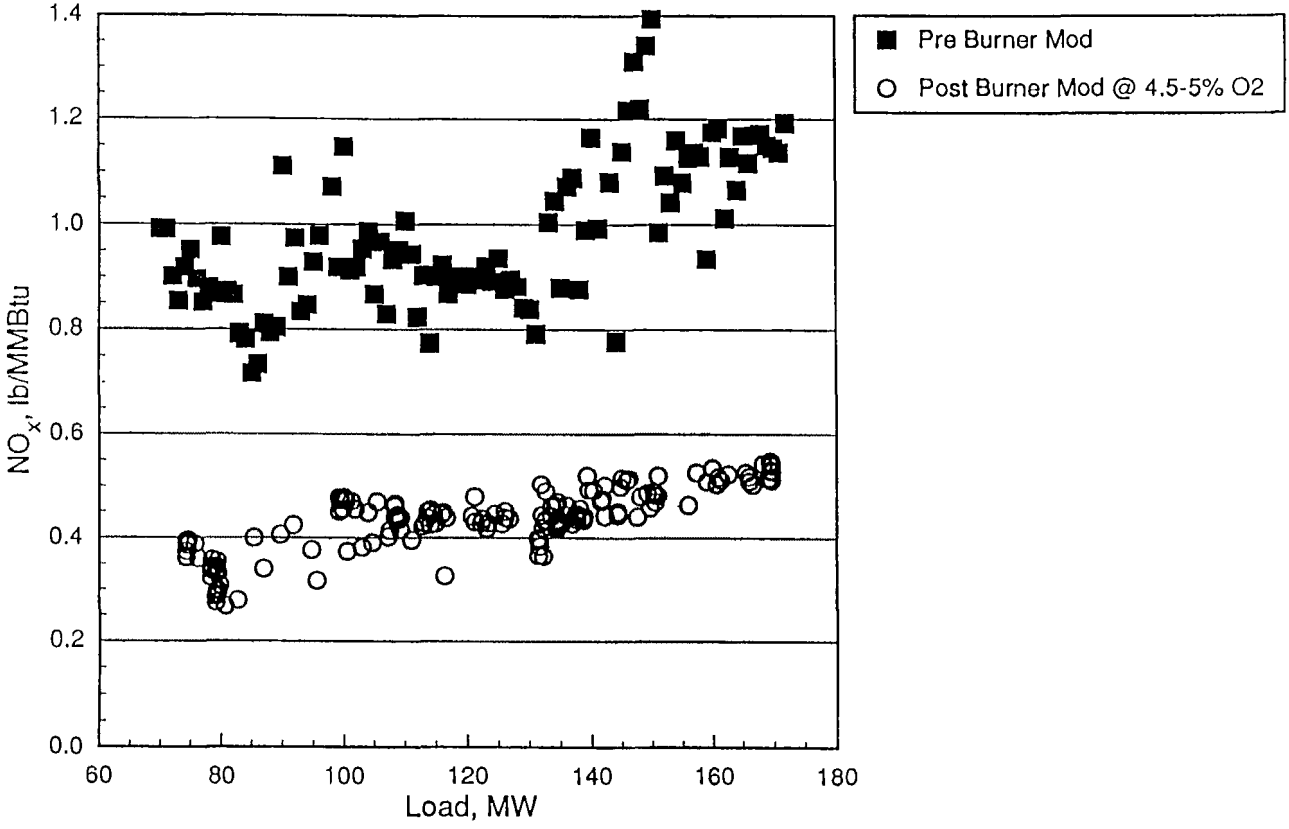
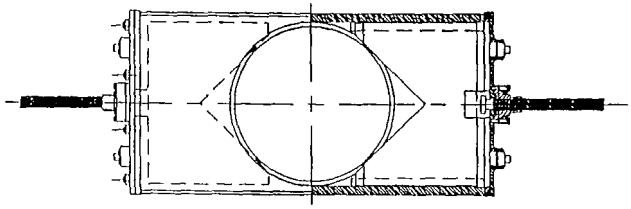
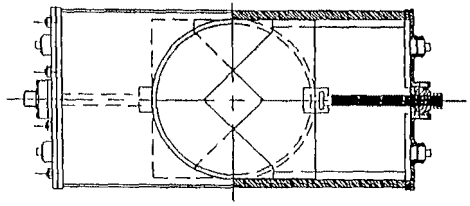


Figure 3. Cane Run Unit 4 Pre and Post Low NOx Burner Modification NOx vs. Load



Fully Open
100% Flow Area-No Restriction



Fully Closed
40% Flow Area-Maximum Control

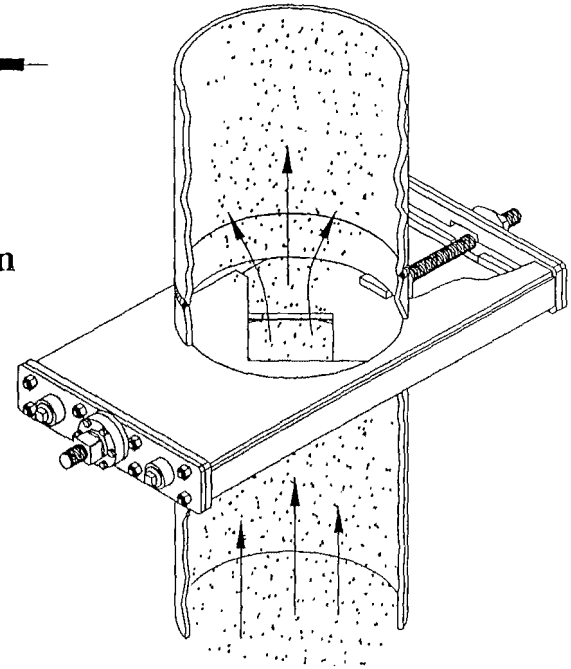


Figure 4. PC FlowmastEER™

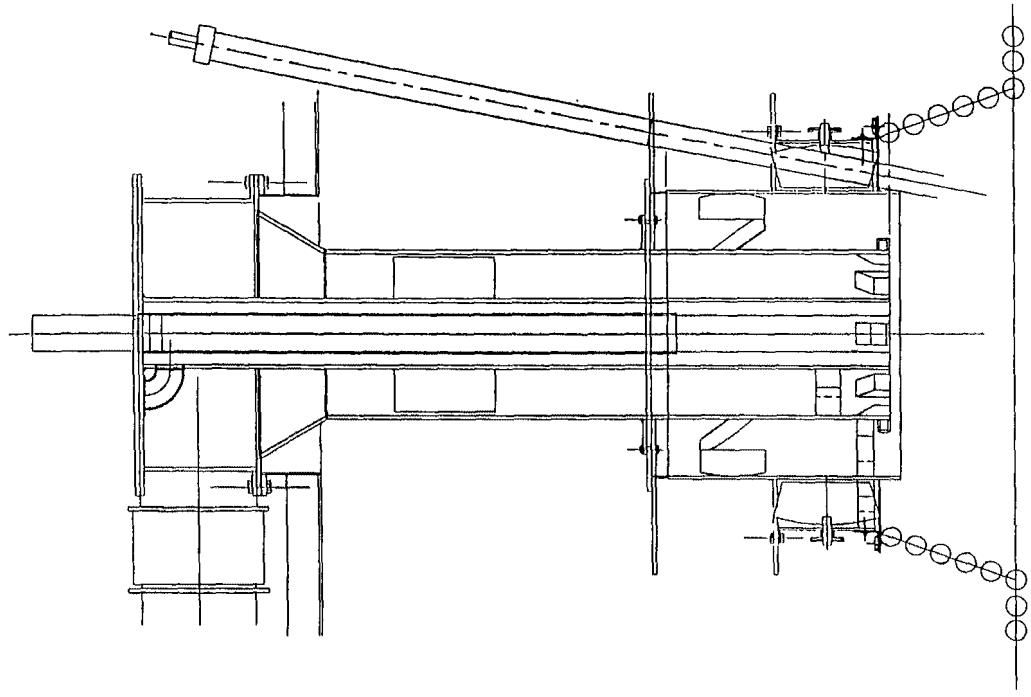


Figure 5. Louisville Gas & Electric Cane Run 5 Burner Modifications

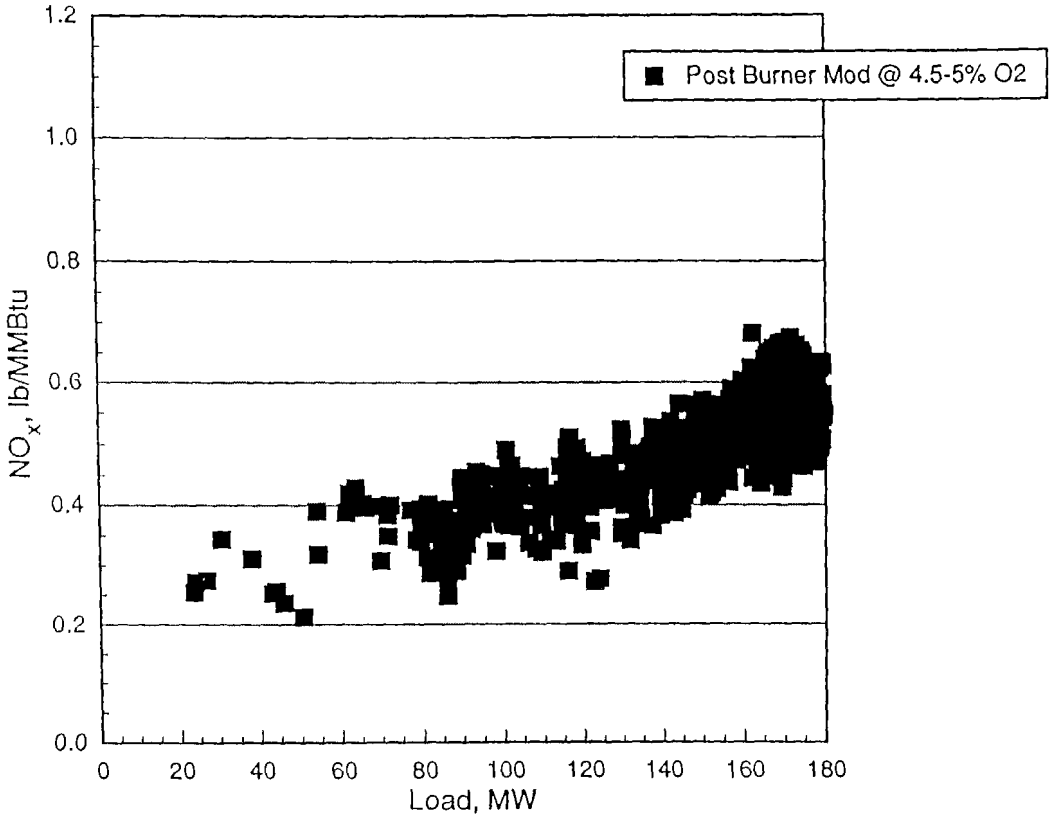


Figure 6. Cane Run Unit 5 Post Low NOx Burner Modification NOx vs. Load

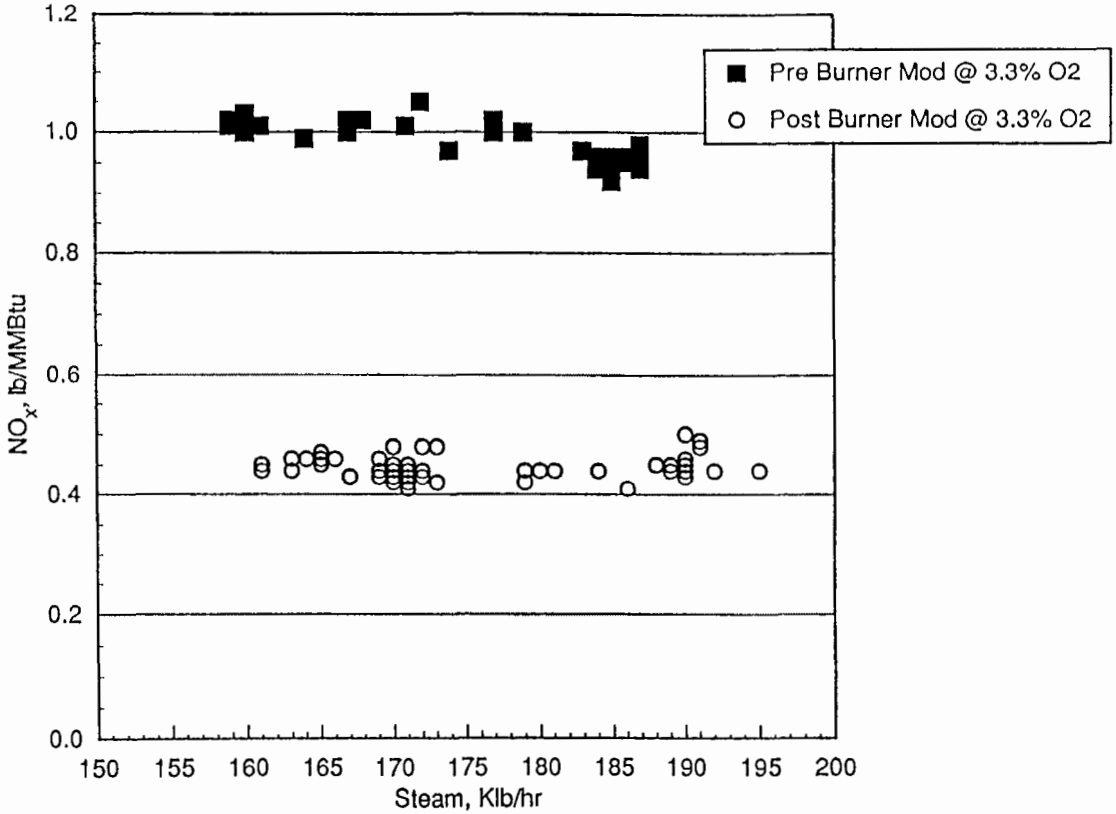


Figure 7. Jamestown Board of Public Utilities Unit 12 Pre and Post Burner Modification NOx vs. Load

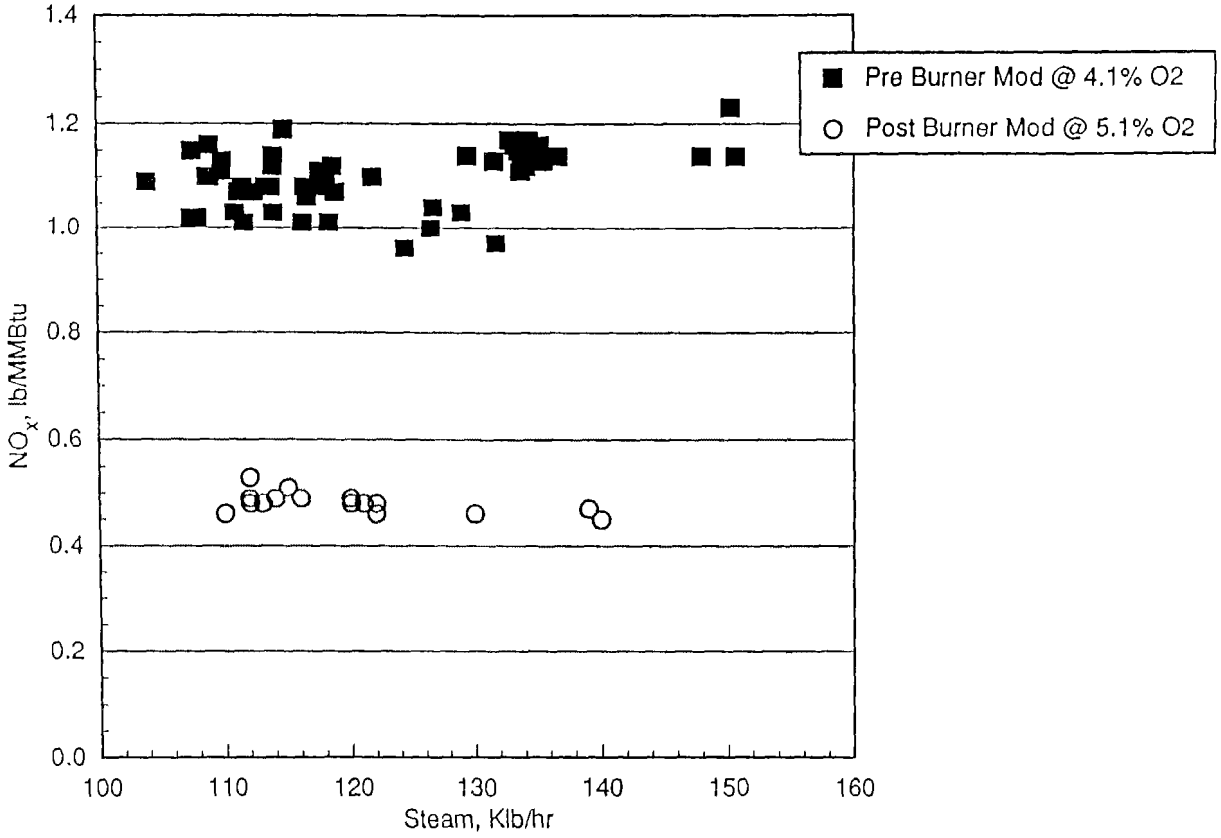


Figure 8. Jamestown Board of Public Utilities Unit 11 Pre and Post Burner Modification NOx vs. Load

TABLE I

Louisville Gas & Electric Coal Analysis

Ultimate (%)	**Typical**
Moisture (% by weight)	10.48
Carbon (% by weight)	64.06
Hydrogen (% by weight)	4.58
Nitrogen (% by weight)	1.32
Chlorine (% by weight)	0.04
Sulfur (% by weight)	2.91
Ash (% by weight)	9.43
Oxygen (by difference)	7.23
Proximate (%)	
Volatile Matter (% by weight)	36.09
Fixed Carbon (% by weight)	44.00
Higher Heating Value (Btu/lb)	11,600

Table II

Jamestown Coal Analysis

PROXIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	7.44	xxxxx
% Ash	9.14	9.87
% Volatile	32.30	34.90
% Fixed Carbon	51.12	55.23
	100.00	100.00
Btu/lb	12,433	13,432
MAF Btu/lb		14,903

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	7.44	xxxxx
% Carbon	70.65	76.33
% Hydrogen	4.42	4.77
% Nitrogen	1.39	1.50
% Sulfur	1.76	1.90
% Ash	9.14	9.87
% Oxygen (diff)	5.20	5.63
	100.00	100.00

NO_X SUBSYSTEM EVALUATION OF B&W'S ADVANCED COAL-FIRED LOW EMISSION BOILER SYSTEM AT 100 MILLION BTU/HR

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Alliance, OH

and

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Barberton, OH

Abstract

As part of a U.S. Department of Energy-sponsored Combustion 2000 program titled "Engineering Development of Advanced Coal-Fired Low Emission Boiler System", Babcock and Wilcox (B&W) has designed and evaluated a NO_X control system. At the heart of the NO_X control system is an advanced low-NO_X DRB-4Z™ pulverized coal (PC) burner design. The burner has undergone comprehensive combustion and emissions performance evaluation. Firing the unstaged burner with a high volatile bituminous Illinois No. 6 coal at 100 million Btu/hr and 17% excess air (1.17 burner stoichiometry) has achieved the program's minimum environmental performance requirement of 0.2 lb $NO_X/10^6$ Btu. Coal type variation tests have shown that NO_X formation increases mainly with decreasing fuel volatile matter (increasing rank). Air staging the burner at 0.86 stoichiometry with all other conditions being the same reduced the NO_X levels to 0.12 lb/10^6 Btu.

Introduction

Under the sponsorship of the U.S. Department of Energy, Babcock and Wilcox is developing an advanced coal-fired Low Emission Boiler System (LEBS) for commercial application by the year 2000. NO_X control is one of the LEBS subsystems. At the heart of the NO_X control system is an advanced low-NO_X DRB-4Z™ pulverized coal burner design. Computer modeling and pilot-scale testing at 5 million Btu/hr (MBtu/hr) were used extensively to refine the burner design for scale-up. Following the scale-up, the DRB-4Z™ low-NO_X PC burner has undergone further refinements and performance evaluations [1-4] at 100 MBtu/hr. This paper discusses the latest burner performance results and more specifically the effects of coal rank, PC fineness, and air staging on NO_X, CO, and carbon burnout.

Test Facility

Babcock & Wilcox conducts the large-scale prototype burner tests in its Clean Environment Development Facility (CEDF) in Alliance, Ohio. Figure 1 shows a schematic of the CEDF furnace and convective pass section. The CEDF accommodates a single 100 MBtu/hr burner for firing natural gas, fuel oil, or coal. The inside surface of the furnace is refractory lined to replicate the thermal environment and flow characteristics of a typical utility boiler [5] Water-cooled tubes are spaced across the convective pass duct to closely simulate the tube metal and flue gas time-temperature profile of commercial utility boilers. Deposits on the tubes and the walls are removed by sootblowers. Raw coal is pulverized by a B&W EL-56 pulverizer equipped with a dynamically staged, variable speed (DSVS™) classifier to control PC fineness. Preheated air carries the pulverized coal to a small filterhouse that vents the air and drops the PC into a storage bin. Pulverized coal flow from the bottom of the storage bin is controlled by a weigh feeder. The coal is then transported to the burner by heated primary air at the desired air-to-fuel ratio. Typical primary air temperatures are around 150°F at the burner inlet. Secondary air is preheated by the flue gas and a gas-fired heater to 600°F.

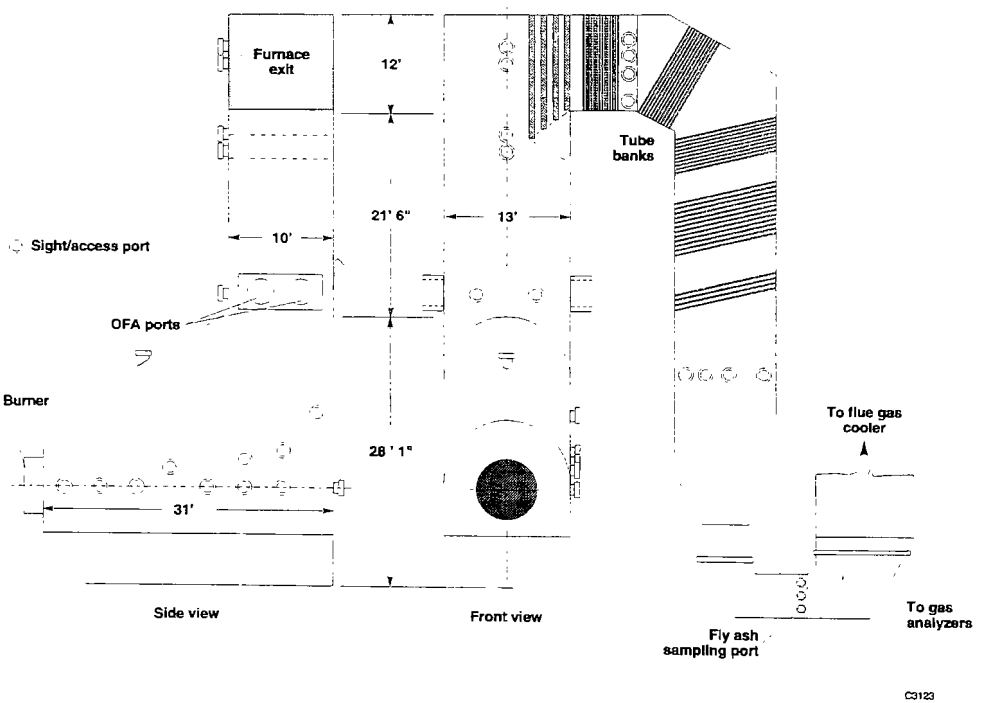

Figure 1
Furnace and Convective Pass Section Schematic of the Test Facility.

For staged combustion, part of the secondary air is directed to two opposed overfire air (OFA) windboxes located just above the furnace tunnel section. Each windbox houses two OFA registers equipped with outer spin vanes and a central core air damper control. Damper control and pressure drop indications across the in-duct orifice plates are used to balance the OFA flow equally to each side of the furnace.

Gaseous species are sampled continuously from the convective pass section outlet through a heated sample line. After filtering and drying, CO, CO_2, O_2, and NO_X concentrations are measured by calibrated analyzers. Fly ash is sampled across the duct via a multi-point probe with equally-spaced holes and analyzed for loss on ignition (LOI). Previous work [4] has shown that LOI measurements closely approximate the fly ash unburned carbon levels. Flue gas and fly ash sampling locations are shown in Figure 1. Computerized data acquisition is used to record species concentrations, flow rates, temperatures, pressures, and other relevant information for subsequent analysis.

DRB-4Z™ Low-NO_X PC Burner

An unstaged, 100 MBtu/hr, DRB-4Z™ low-NO_X PC burner was used for testing. This burner operates on the principle of controlled mixing of air and fuel to minimize NO_X emissions. What sets the DRB-4Z™ burner apart from other commercial designs is the implementation of special proprietary features [6] for greater NO_X reduction.

Coal Analyses

Four different coals including a subbituminous Powder River Basin Decker, a high volatile bituminous Illinois No. 6, a high volatile bituminous Ohio Mahoning, and a medium volatile bituminous Pennsylvania Middle Kittanning were chosen for testing with the DRB-4Z™ burner. Table 1 lists the proximate, ultimate, and heating value analyses of the as-received coals. Fixed carbon-to-volatile matter ratios (FC/VM) for these coals ranged from 1.16 to 2.81. Illinois No. 6 was the reference high volatile bituminous coal selected for this program.

Unstaged Combustion Results

Fuel Type and Excess Air Effects

Coal rank and excess air effects on the DRB-4Z™ burner performance were carried out at a nominal standard PC fineness of 75% through a 200 mesh screen. Table 2 lists the 16 to 200 sieve (1190 to 74 μm) cut sizes of actual coal samples extracted from the PC-laden stream after the mill and before the filterhouse.

Table 1 Coal Analysis				
Proximate	Montana Decker Subbituminous	Illinois No. 6 High Volatile Bituminous	Ohio Mahoning 7A Seam High Volatile Bituminous	Pennsylvania Middle Kittanning Medium Volatile
Fixed Carbon (%)	37.06	44.37	54.32	63.90
Volatile Matter (%)	31.93	33.53	34.49	22.74
Moisture (%)	26.36	13.92	3.90	3.26
Ash (%)	4.65	8.18	7.29	10.10
Fixed Carbon/Volatile Matter	1.16	1.32	1.57	2.81
Ultimate				
Carbon (%)	53.64	61.96	74.10	76.61
Hydrogen (%)	3.73	4.44	5.21	4.54
Nitrogen (%)	0.88	1.17	1.30	1.34
Sulfur (%)	0.51	3.02	1.22	0.81
Oxygen (%)	10.23	7.31	6.98	3.34
Heating Value (Btu/lb)	9237	11122	13292	13476
Hardgrove Grindability Index	47	54	50	86

Table 2 Standard Grind PC Size Distributions for Four Different Coals				
Mesh Designation and Size	Subbituminous Decker	High Volatile Illinois No. 6	High Volatile Mahoning 7A	Medium Volatile Middle Kittanning
Screen # (μm)	Percent Smaller			
16 (1190)	100.00	100.00	100.00	100.00
30 (595)	100.00	99.98	99.98	99.90
50 (297)	99.60	99.80	99.70	99.30
70 (210)	98.90	99.10	99.20	97.60
100 (149)	97.60	95.50	96.20	91.90
140 (105)	87.00	89.00	90.10	84.30
200 (74)	73.20	73.70	74.20	71.60

Figure 2 shows the NO_X and LOI results for each coal at optimum burner settings. In all cases, raising the excess air converted more fuel-N to NO_X, and decreased CO formation and LOI. As expected, NO_X levels increased with increasing fuel-N and decreasing volatile matter contents. But NO_X formation is a stronger function of the fuel factor (FC/VM) than the fuel-N content. For instance, the medium volatile Middle Kittanning coal forms more NO_X than the high volatile Mahoning coal despite having a similar fuel-N content. LOI levels were higher for the lower volatile and less reactive Middle Kittanning coal.

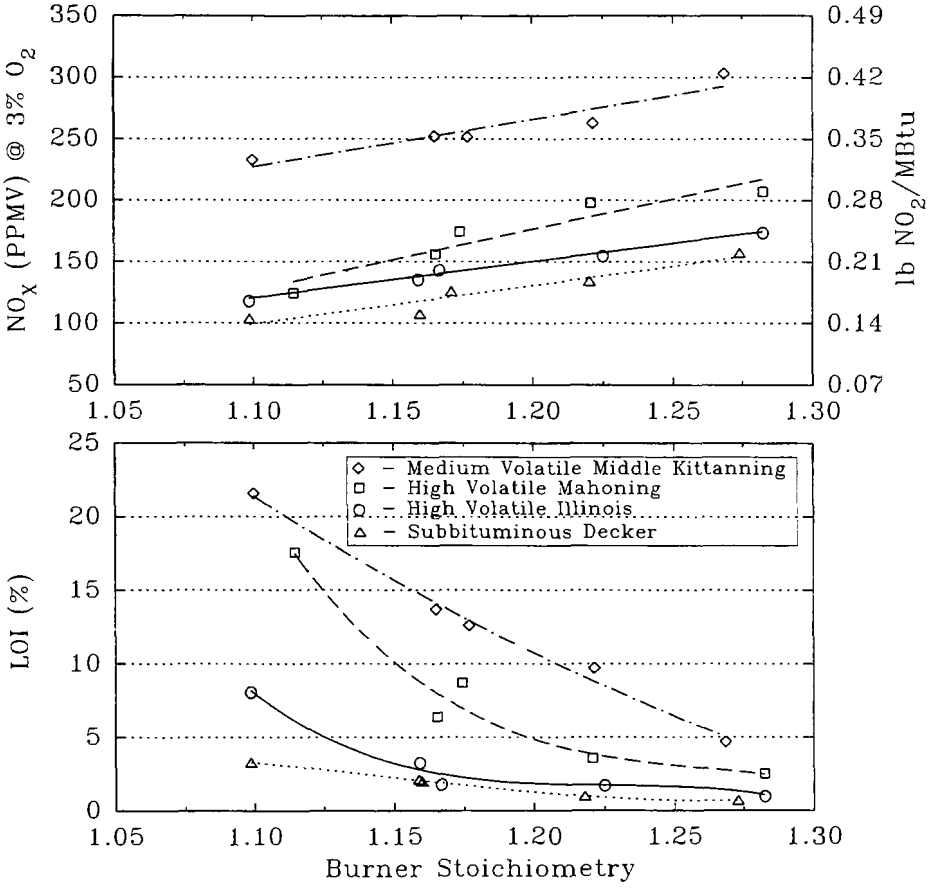

Figure 2
Coal Type and Excess Air Effects on NO_X and LOI for the DRB-4Z™ PC Burner. Nominal Conditions: 100 MBtu/hr and 75% through 200 Mesh Screen PC Fineness.

All flames were stable and attached at the burner throat. CO emissions from the two high volatile bituminous coals were higher than the subbituminous and medium volatile bituminous coals. Relative to full load conditions, part load operation at a fixed burner stoichiometry generated lower NO_X and higher LOI due to the reduced mixing and cooler furnace environment. Coal effects on unburned carbon loss (UBCL), and CO and NO_X emissions for 100 MBtu/hr and 17% excess air operation are illustrated in Figure 3. Where available, reproducibility of the results is shown by error bars, representing one standard deviation. UBCL is calculated from the LOI measurements and fuel analysis as a measure of the unutilized fuel and combustion efficiency.

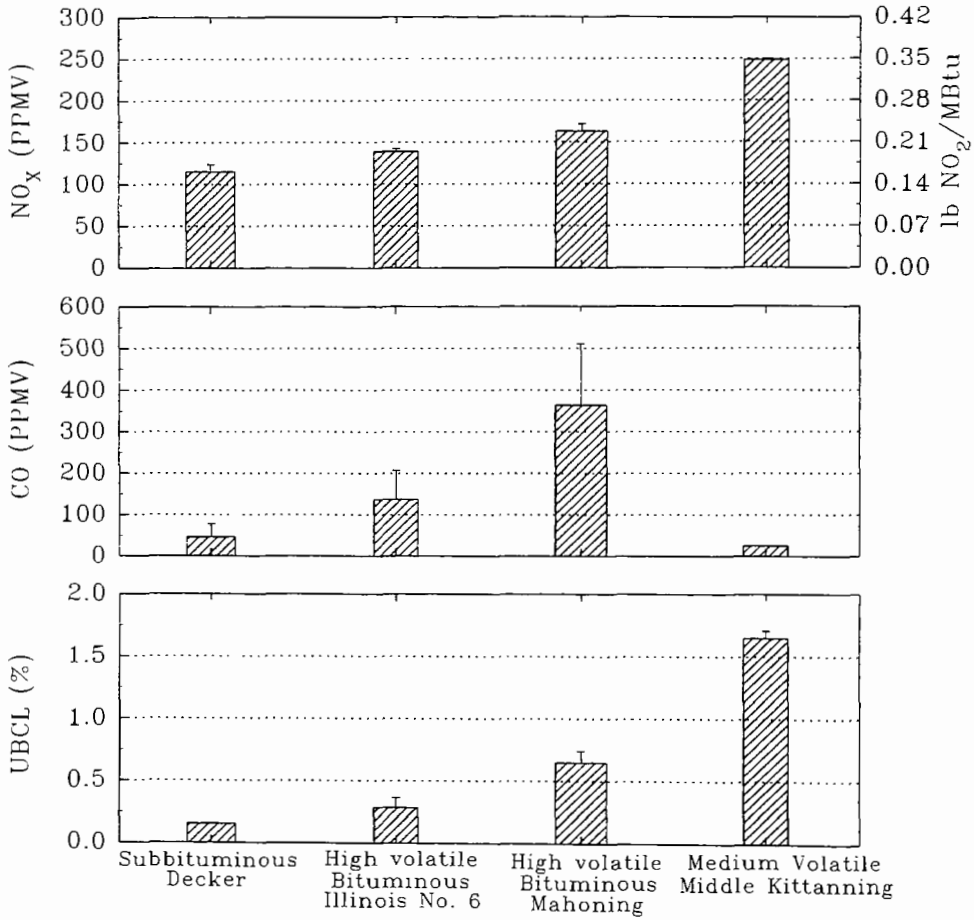

Figure 3
Coal Type Effects on NO_X, CO, and UBCL for the DRB-4Z™ PC Burner. Nominal Conditions : 100 MBtu/hr, 17% Excess Air, and 75% through 200 Mesh Screen PC Fineness.

Coal Fineness Effects

Pulverized coal particle size was also varied from 60 to 90% through a 200 mesh screen for the Illinois No. 6 coal. Representative size distributions are tabulated in Table 3.

Table 3 Representative PC Fineness Variations for the High Volatile Illinois No. 6				
Mesh Designation and Size	Coarse	Standard	Fine	Very Fine
Screen # (μm)	Percent Smaller			
16 (1190)	100.00	100.00	100.00	100.00
30 (595)	99.90	99.98	99.98	100.00
50 (297)	99.20	99.70	99.80	99.98
70 (210)	97.30	99.20	99.40	99.90
100 (149)	89.70	96.20	98.00	99.70
140 (105)	79.10	90.10	94.00	98.00
200 (74)	60.60	74.20	84.30	90.50

Figure 4 compares the full load NO_X and LOI data from burning various grind sizes of Illinois No. 6 coal in the DRB-4Z™ burners at 17% excess air level. Increasing the coal fineness generally improved the fuel oxidation and decreased the CO and LOI levels without an appreciable change in NO_X emissions. In the CEDF, the DRB-4Z™ burner generated about 35% less NO_X than other commercially available low-NO_X burners when firing the Illinois No. 6 coal. And although the LOI levels from burning coarse and standard fineness PC in the DRB-4Z™ burner were higher than the values of other commercially available low-NO_X burners, the difference is reduced significantly for the fine grind size (85% through 200 mesh). Average NO_X, CO, and LOI values for the DRB-4Z™ burner from firing the 85% through 200 mesh PC at 17% excess combustion air were 141 PPMV (0.20 lb NO_2/MBtu), 58 PPMV, and 1.71%, respectively. Because of these favorable results, the proof-of-concept demonstration phase of this program will also utilize the 85% through 200 mesh screen coal fineness.

Staged Combustion Results

Air staging tests were carried out by firing the standard fineness Illinois No. 6 coal at a fixed overall excess air level of 17% (3.2% stack O_2) in the same burner used for unstaged combustion. Both, the burner and OFA register settings were re-optimized at a nominal burner stoichiometry of 0.90. Burner stoichiometry was then varied from 0.86 to 1.17 by splitting the total secondary air flow between the burner and the OFA ports. Figure 5 shows the effect of burner stoichiometry on NO_X and LOI at three levels of staging for the DRB-4Z™ burner. NO_X concentrations from operating the DRB-4Z™ burners at 0.86 stoichiometry was 90 PPMV (0.12 lb NO_2/MBtu). Raising the burner stoichiometry from 0.86 to 1.17 increased the NO_X emissions by only 54%. LOI levels decreased as the burner stoichiometry was increased. Increasing the coal fineness to 85% through 200 mesh is also expected to reduce the LOI levels significantly when staging.

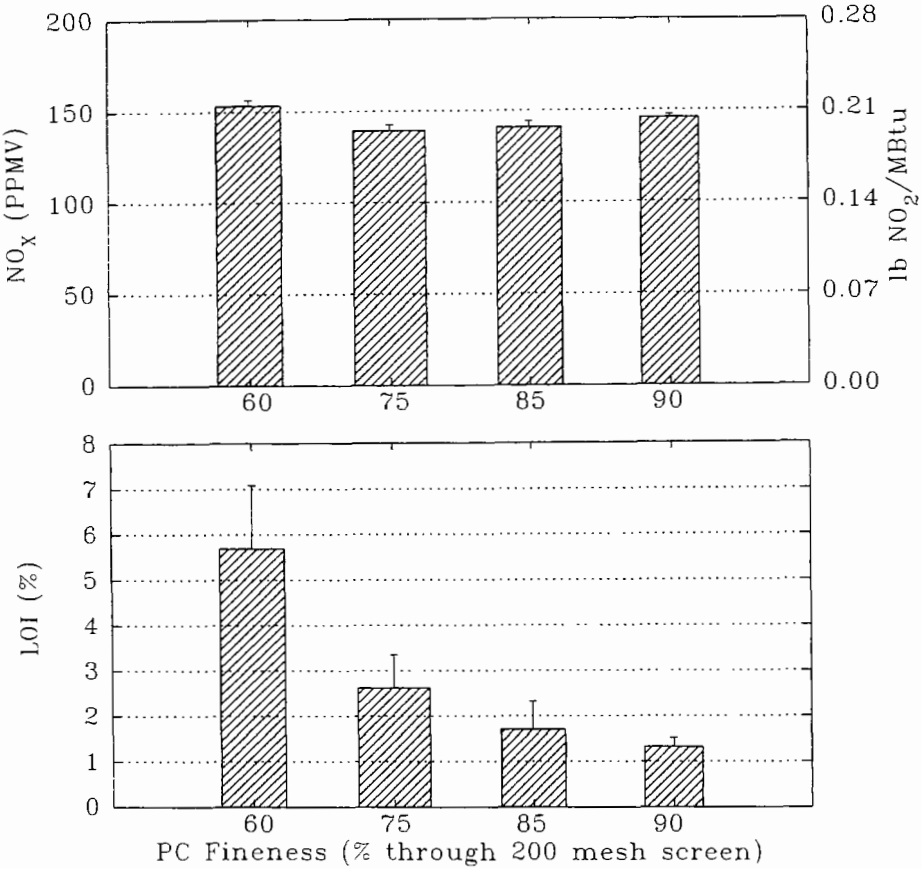

Figure 4
Coal Fineness Effects on NO_X and LOI for the DRB-4Z™ PC Burner. Nominal Conditions : 17% Excess Air and Firing Illinois No. 6 Coal at 100 MBtu/hr.

Although the burner was not sized for staging, it maintained the necessary aerodynamics for minimizing NO_X emissions at all stoichiometries. Staged burners are usually designed with smaller throats to maintain the proper aerodynamics and mixing patterns for minimizing NO_X and LOI levels. Thus, a DRB-4Z™ burner designed for 0.75 stoichiometry is expected to achieve the program developmental NO_X target of 0.1 lb/MBtu in the test facility without resorting to post-combustion NO_X control techniques. Figure 6 shows the changes in NO_X emissions with burner stoichiometry for the DRB-4Z™ burner.

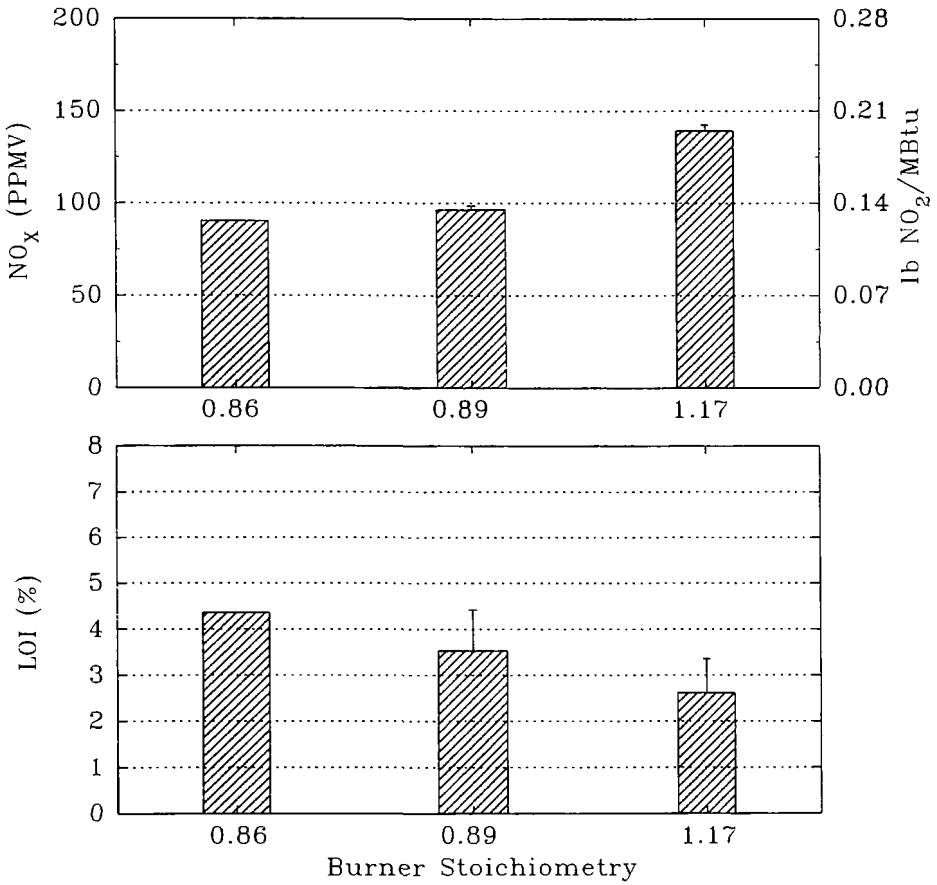

Figure 5
Air Staging Effects on NO_x and LOI for the DRB-4Z™ PC Burner. Nominal Conditions : 17% Overall Excess Air and Firing 75% through 200 Mesh Screen Illinois No. 6 Coal at 100 MBtu/hr.

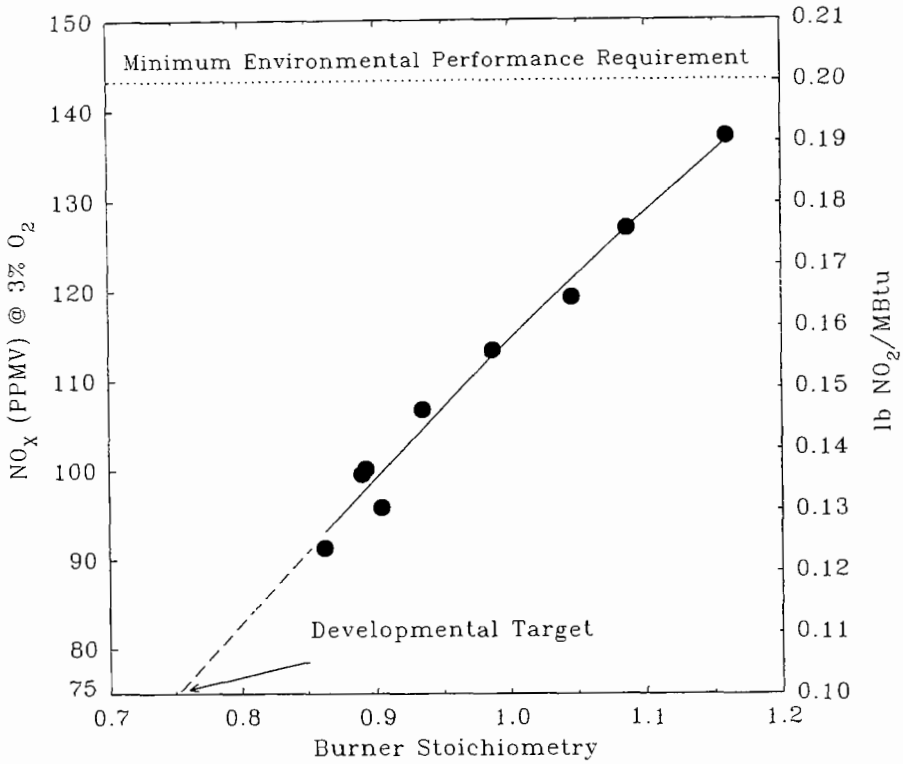

Figure 6
Burner Stoichiometry Effects on NO_X for the DRB-4Z™ PC Burner. Nominal Conditions : 17% Overall Excess Air and Firing 75% through 200 Mesh Screen Illinois No. 6 Coal at 100 MBtu/hr.

Conclusions

A NO_X control system was developed and tested for implementation in the proof-of-concept demonstration phase of the Combustion 2000 program. The DRB-4Z™ low-NO_X PC burner is the centerpiece of the NO_X control system. Operating the unstaged burner at 100 MBtu/hr and 17% excess air achieved the program's minimum environmental performance requirement of 0.2 lb NO_X/MBtu with the reference Illinois No. 6 coal. Air staging the burner at 0.86 stoichiometry with all other conditions being the same lowered the NO_X levels to 0.12 lb/MBtu. Coal type variation tests proved that the DRB-4Z™ burner generates consistently less NO_X than other commercially available burners.

Acknowledgments

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Field Demonstration of ABB C-E Services' RSFC™ Wall Burner for Coal Retrofit Applications

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Abstract

This paper outlines the first commercial application of ABB C-E Services' coal-fired RSFC™ Radially Stratified Flame Core burner for retrofit in wall-fired boilers. The successful evolution of the burner from the laboratory prototypes and oil and gas applications to a commercial coal-fired burner is discussed.

Fundamental design and operating features of the RSFC™ burner are examined, which allow the six burners currently installed in Richmond (Indiana) Power & Light, Whitewater Valley Station Unit 1 to surpass all emissions guarantees while firing a midwestern bituminous coal. NOx reduction performance was accomplished without the use of additional technology such as flue gas recirculation and/or a separated overfire air system. The burners have been in service full time since the retrofit installation during October 1996. Operational and mechanical performance of the burners has been exceptional with installation and commissioning being completed within a three-week time frame.

Introduction

Richmond Power & Light (RP&L), Whitewater Valley Station provides electricity to the city of Richmond, Indiana. In 1996 ABB C-E Services entered into a contract with RP&L

to retrofit six coal-fired RSFC™ low NOx burners in place of the original burners into their Whitewater Valley Unit 1. Whitewater Valley Station Units 1 and 2 share a common stack equipped with continuous emission monitoring (CEM) equipment. Under the 1990 Clean Air Act Amendments (CAAA) Title IV, both units at the station are under Phase II compliance regulations. RP&L decided to pursue the option of early compliance for both the front wall fired Unit 1, and the tangentially fired Unit 2. As a result, the combined NOx emissions limit for the two units, as measured by the stack mounted CEM is 0.45 lb/MBtu. After examining various alternatives, replacement of the original burners with ABB C-E Services RSFC™ low NOx burners was pursued as the most attractive means of entering compliance without having to perform any pressure part changes to the boiler. Figure 1 shows the post retrofit NOx emissions compared to the RP&L permit limitations.

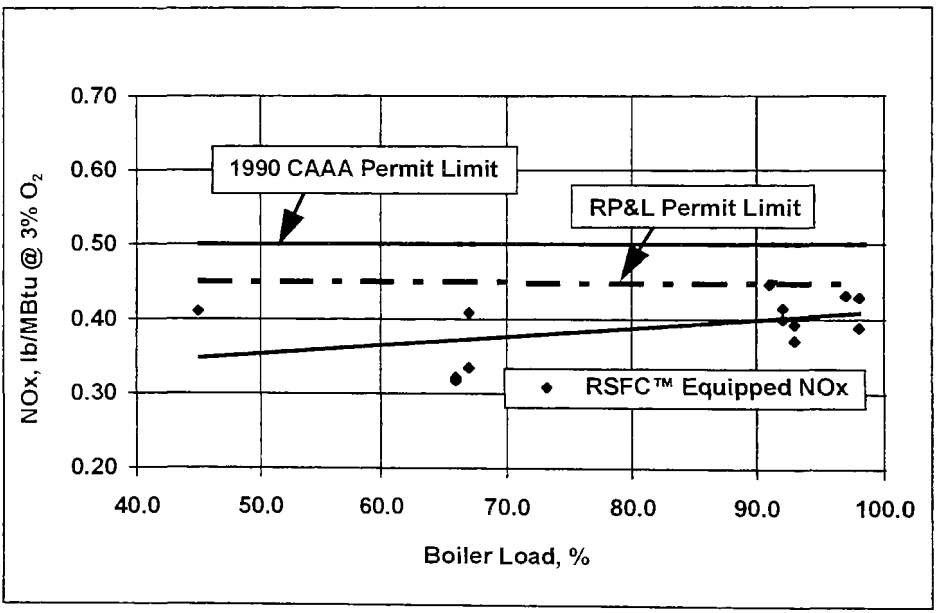

Figure 1
RP&L Whitewater Valley Operating Limits

Unit Description

Whitewater Valley Station Unit 1 is a 1950s vintage DB Riley Corporation front wall-fired, balanced draft, natural circulation steam generator with a superheated steam flow of

325,000 lbs/hr at 900°F and 900 psig. The six burners are arranged in two elevations of three burners each, and are supplied pulverized coal by a total of three DB Riley Atrita #550 pulverizers. Initial coal ignition is accomplished by the use of the original No. 2 oil mechanical atomized oil guns. A single Ljungstrom® air preheater is used to heat the secondary air from ambient conditions to a windbox temperature of 620°F at full load. Nominally rated at 33 MWe, the unit is equipped with an electrostatic precipitator that was added after the initial start up. As a result of the installation of the precipitator, Unit 1 is operationally constrained by induced fan draft limitations at full load.

Whitewater Valley Unit 1 fires a midwestern bituminous coal from sources in Indiana and Kentucky. The coal composition is relatively uniform as summarized in Table 1. All of the parameters reported in Table 1 (FC/VM and O/N ratios and ash and fuel nitrogen loadings) fall within the ranges encountered for midwestern bituminous coals. These values are indicative of a good utility coal, although it must be noted that this coal has a moderately high sulfur content, characteristic of midwestern bituminous coals; as such, it has a high SO_2 emission potential.

Table 1

Typical RP&L Coal Analyses

	Minimum Volatile Matter			Median Volatile Matter			Maximum Volatile Matter		
Quantity	As Rec'd	Dry	DAF*	As Rec'd	Dry	DAF*	As Rec'd	Dry	DAF*
Prox. & Ult. Analy., Wt.%									
Moisture	14.1	—	—	14.4	—	—	13.9	—	—
Ash	9.5	11.1	—	9.6	11.2	—	9.8	11.3	—
Volatile Matter	31.2	36.4	40.9	31.8	37.1	41.8	32.8	38.1	43.0
Fixed Carbon (Diff.)	45.1	52.6	59.1	44.2	51.6	58.2	43.6	50.6	57.0
Hydrogen	4.2	4.9	5.5	4.1	4.8	5.4	4.3	5.0	5.6
Carbon	62.7	73.0	82.1	62.3	72.7	82.0	61.7	71.6	80.8
Sulfur	2.5	2.9	3.2	2.5	2.9	3.2	2.6	3.0	3.4
Nitrogen	1.3	1.5	1.7	1.2	1.4	1.6	1.2	1.3	1.5
Oxygen (Diff.)	5.7	6.6	7.4	5.9	6.9	7.8	6.6	7.7	8.7
HHV, Btu/lb	11,330	13,193	14,838	11,187	13,061	14,714	11,112	12,907	14,556
Ash Loading, lb/MBtu	8.40	—	—	8.60	—	—	8.77	—	—
N Loading, lb/MBtu	1.16	—	—	1.06	—	—	1.03	—	—
FC/VM	1.45	—	—	1.39	—	—	1.33	—	—
O/N	4.34	—	—	4.99	—	—	5.75	—	—

*DAF = Dry-Ash-Free

RSFC™ Burner Description

The RSFC™ burner has three air register zones to supply three different air annuli at the burner exit, depicted in Figure 2. The combustion flow field is controlled by means of mass flow splits between, and swirl number for, each individual air annuli. The swirl in the

primary and tertiary air streams are generated through the use of moveable vane swirlers. An axial fixed vane swirler in the secondary air annulus provides a consistent swirl and pressure drop over the conditions tested.

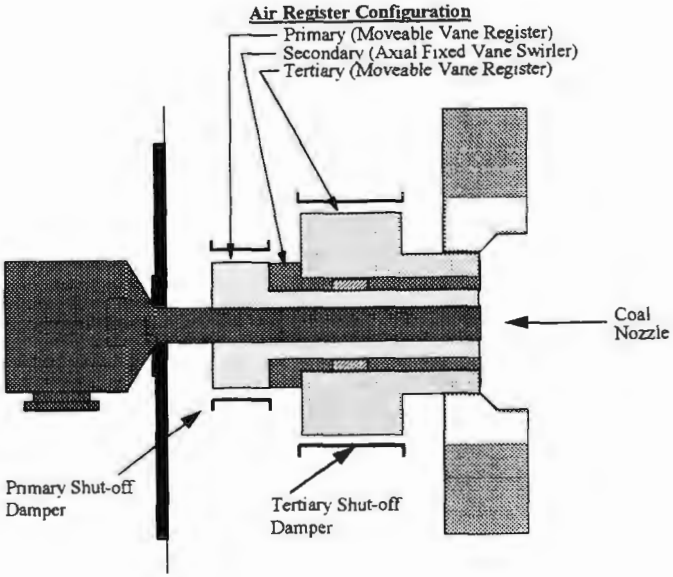

Figure 2
Diagrammatic Representation of the RSFC™ Burner

The workings of the moveable vane damper are hidden from radiant heat that could cause any part of the air registers or swirl adjustment linkages to overheat. Air flow through the burner when the shut off damper is closed is designed to be a nominal 10% to 15%. Most of this flow occurs through the secondary air zone where it cools both the primary and secondary air throats.

The modular construction of the swirl block makes the RSFC™ burner very strong and rigid. Each of the blocks used in the construction of the burner stiffens the entire swirler geometry. In addition, many of the parts in the RSFC™ burner have been constructed out of stainless steel in order to insure that the burner will be functional over the long term. The use of stainless steel protects the burner from heat, corrosion and rust on the critical moving parts, resulting in a more reliable design with minimal risk of binding during normal operation.

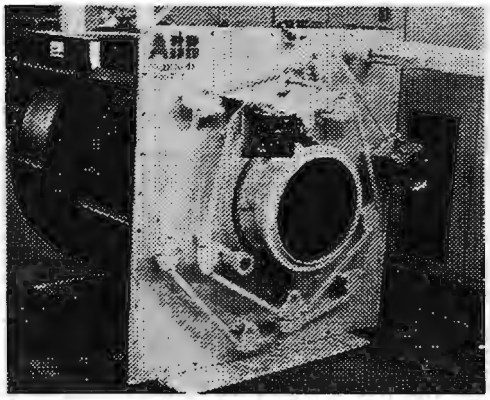

Photo 1
RSFC™ Coal Burner

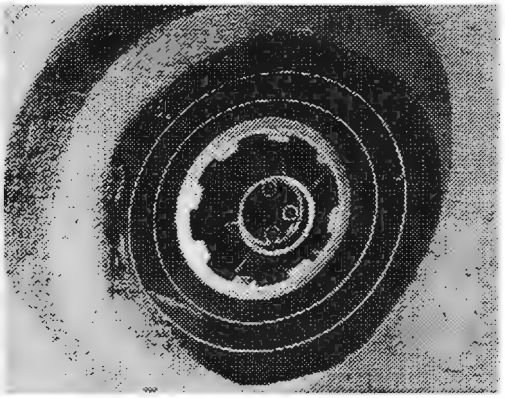

Photo 2
Furnace View of the RSFC™ Coal Burner and Refractory Throat

As shown in Photos 1 and 2, in order to maximize operational flexibility, the air flow and swirl through the primary and tertiary zones are independently controlled by externally mounted drive systems. Movement of the Richmond swirl vanes is accomplished through manual gearbox-driven linkage mechanisms. Although the swirl vane mechanisms can be easily automated, RP&L decided that the manual arrangement was preferable so boiler operators could maintain visual contact with the boiler and auxiliary equipment. Mounting the drive hardware external to the windbox eliminates the potential for bearing contamination and mechanical binding. If there were ever a problem with a damper linkage assembly, the burner would not need to be removed to complete the repairs.

The RSFC™ coal nozzle assembly incorporates standard ABB C-E Services design features to promote flame stability when firing both oil and coal. Concentric to the centerline of the coal nozzle is a coal spreader and guidepipe. The Richmond burner configuration has an ABB C-E Services high energy arc ignitor and the original mechanically atomized oil gun located inside the coal spreader guidepipe. A moveable coal spreader was developed to help minimize the unburned carbon, while maintaining the low NOx characteristics of the RSFC™ burner. The moveable links for the coal spreader are located inside the center guidepipe to protect them from erosion and impacting on the pulverized coal stream.

Another unique feature of the RSFC™ burner is the throat configuration. This design allows for the optimization of low NOx flame shaping without flame impingement or attachment to the front wall. The potential for wall slagging and overheating of the burner components is greatly reduced as a result of the unique design.

NOx Emissions Mechanisms

The formation of nitric oxides (NOx) during coal combustion is a complicated process involving three principal mechanisms, namely: fuel NOx; thermal NOx; and prompt NOx.

The combination of prompt NOx and thermal NOx mechanisms typically contribute a combined maximum in the range of 30% to 50% to the total NOx formation. Thermal NOx, described through the "Zeldovich mechanism," results from the oxygen fixation by atmospheric nitrogen (Zeldovich, 1947). This NOx contribution increases exponentially with temperature and with the square root of oxygen concentration in the reactant gas stream. Hence, judicious control of the flame temperature and oxygen concentration throughout the combustion process constitutes a powerful measure for controlling the formation of thermal NOx.

The fuel NOx, which results from the oxidation of the fuel nitrogen-bound intermediates, is the major source of total NOx emissions. Its contribution typically falls in the 50% to 70% range, although in some coal-fired units this contribution can range up to 90% (Pershing and Wendt, 1979; Levy, et al., 1978). Therefore, the major objective in staged combustion systems, such as the RSCF™ burner, is to mitigate the formation of fuel NOx. One of the ways to achieve this is to burn the fuel in such a manner that the fuel nitrogen-bound intermediates (HCN, NH_i, NO, etc.) are preferentially converted to molecular nitrogen (N_2). Here, the volatile matter is allowed to burn in an oxygen-lean environment (i.e., with a stoichiometry of less than one) near the burner zone. The nitrogen-bound intermediates released with the volatile matter must compete with carbon and hydrogen compounds for the limited supply of oxygen. Because the volatile hydrocarbons are comparatively more reactive, the nitrogen-bound intermediates are left to react with each other, leading auspiciously to the formation of molecular nitrogen. To be effective, the slow, heterogeneous char oxidation reaction must occur in an oxygen-rich environment. Hence, the nitrogen-bound intermediates formed via this route are preferentially oxidized to NOx; this implies that only a small portion of these nitrogen-bound intermediates can be converted to molecular nitrogen.

Figure 3 traces the fate of fuel nitrogen during the coal combustion process. It can be stated, based on the description given above, that the ultimate goal in staged combustion systems is to maximize the yields of both the volatile matter and fuel nitrogen-bound intermediates, under a sub-stoichiometric environment, and to convert these intermediates to molecular nitrogen. One of the reasons the RSFC™ burner is so effective in reducing NOx emissions is because it optimally applies the principle of combustion staging, as described in the next section. Another benefit of the RSFC™ burner is that it produces low NOx through the use of lower stoichiometry in a confined burner or flame region, rather than in the furnace as a whole. For this reason, waterwall corrosion is not a concern.

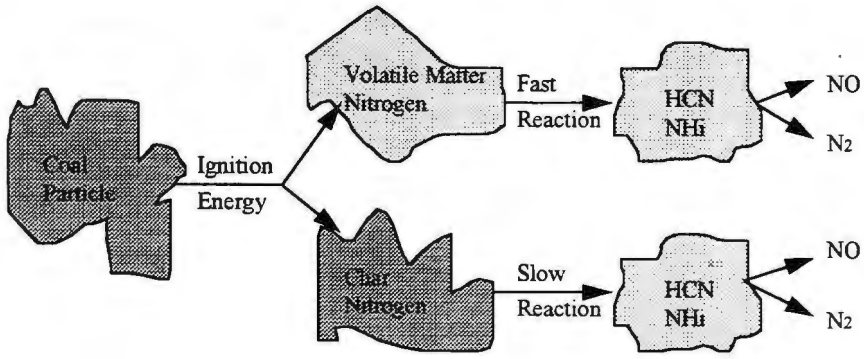

Figure 3
Fate of Fuel Nitrogen During The Coal Combustion Process

RSFC™ Technology

Radially Stratified Flame Core describes the unique flame structure that is at the heart of the RSFC™ burner design. Many wall-fired burners employ swirling flows to enhance mixing in the near-burner flow region. The RSFC™ burner is different in that swirling flow is used to create the opposite effect, namely the delay of mixing in the near-burner zone. It is this combination of a near-burner, high temperature, fuel-rich core followed by a downstream, fuel-lean combustion zone that creates the low NOx combustion conditions generated by the RSFC™ burner.

The delay of mixing is achieved through stratification between the pulverized coal and the surrounding, swirling combustion air. Stratification depends on density differences between the gases in the flame core and the surrounding, relatively cooler combustion air and turbulent mixing dampening at the flame/air interface. The fuel enters along the center line of the burner and is surrounded by strongly swirling air from three separate annuli as shown in Figure 4. The fuel jet penetrates into the central fuel-rich zone where the centrifugal forces of the surrounding air eventually cause the fuel jet to stagnate and recirculate back toward the root of the flame. The first flame region, the high temperature fuel-rich core, allows a large portion of the fuel nitrogen to be released in a low stoichiometric zone where it is easily converted to molecular nitrogen. The internal recirculation zone also helps stabilize the flame by providing adequate energy to the root of the flame. This higher temperature (lower density) fuel rich zone along the center line of the burner, surrounded by the cooler (higher density), swirling combustion air, creates the stratification that is characteristic of the RSFC™ burner flame structure. After passing through this initial stratified, low stoichiometric, combustion zone, the remaining combustibles then mix with the remainder of the combustion air to complete the combustion process.

The typical low NOx RSFC™ burner flow field is depicted in Figure 4. The concept of radial stratification originated with the work of Rayleigh (Beer and Chigier, 1970), and was brought to practical application by Beer, et al. (1972). This phenomena which was extensively studied during more than six years of fundamental study at M.I.T.'s Combustion Research Laboratory, was then further developed for commercial applications by ABB's Power Plant Laboratories. This extensive amount of research and development has now been incorporated into ABB C-E Services' RSFC™ burner.

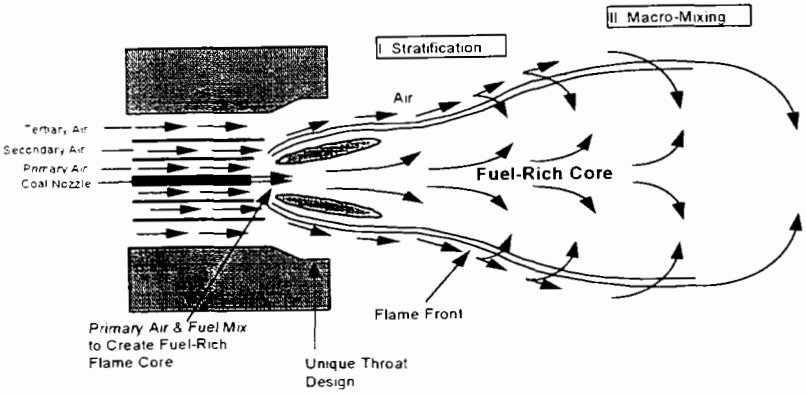

Figure 4

Typical Low NOx RSFC™ Burner Flow Field

Installation of the Coal RSFC™ Burners

The six coal RSFC™ burners, high energy arc (HEA) ignitors, flame scanner system, oil guns, actuators and new refractory throats were installed at the Whitewater Valley Station in ten days, working a single eight-hour shift per day. In addition to the burner installation, the work scope also included changes to the No. 2 fuel oil system piping, and the addition of air aspirated coal sample ports to the existing coal piping. The outage work went very smoothly since the RSFC™ burners were designed as a direct retrofit and no boiler pressure part replacements or coal piping modifications were required.

Initial Start Up Activities

Upon completion of the boiler outage, the new refractory was cured using the oil guns in a predetermined firing sequence. Refractory curing was accomplished in an eight-hour process. It is worth noting that the ignition of the oil guns by the HEA ignitors was always accomplished on the first attempt. Initial coal firing commenced immediately after

the refractory curing process was completed. The boiler was continuously in operation from the end of the October 1996 outage until the boiler's scheduled maintenance outage at the end of May 1997. An inspection during the May 1997 outage confirmed that the burners were in excellent condition with no visible signs of erosion or deformation.

Boiler Emissions Performance With The Coal RSFC™ Burner

Pre-retrofit and post-retrofit emissions tests were conducted to evaluate the performance of the coal RSFC™ burner. The primary objective of these test programs was to quantify the impact of the new burners over the full operating range of the boiler. The boiler emissions performance was measured through a series of parametric tests during which operational parameters were varied in order to quantify the results.

NOx Emissions

All NOx measurements in this paper were determined through the implementation of EPA Method 7E, using a chemiluminescent NOx analyzer sampling from the airheater gas inlet duct, and are reported in units of lbs NOx per 10^6 Btu. With the RSFC™ burner, NOx emissions range between 0.31 and 0.45 lb/MBtu, with the every day operating level averaging approximately 0.39 lb/MBtu. Figure 5 shows the relatively flat relationship of the measured NOx emissions to the furnace outlet oxygen level for the RSFC™ equipped Unit 1. The RSFC™ burner is able to maintain this flat relationship since the burner optimizes and lengthens the residence time of the fuel in the fuel rich primary zone. This is accomplished by stopping axial flow of the fuel and recirculating it back towards the burner front where it is mixed with the remainder of the combustion air.

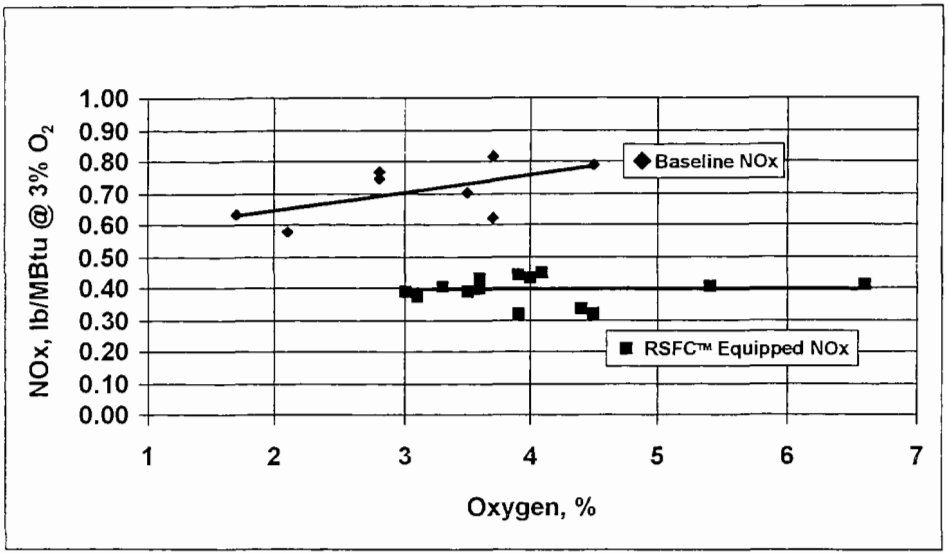

Figure 5
NOx Performance Comparison vs. Furnace O_2

In this zone, the fuel is allowed to burn as hot as possible because there is very little air and oxygen to drive the thermal NO_x formation. Any fuel nitrogen is also released in an oxygen lean environment where the nitrogen radicals are forced to combine with other nitrogen radicals to form elemental nitrogen (N_2) rather than a nitrogen oxide. It is this same effect that allows the burner to produce a flat curve of NOx emissions versus boiler steam load as shown in Figure 6.

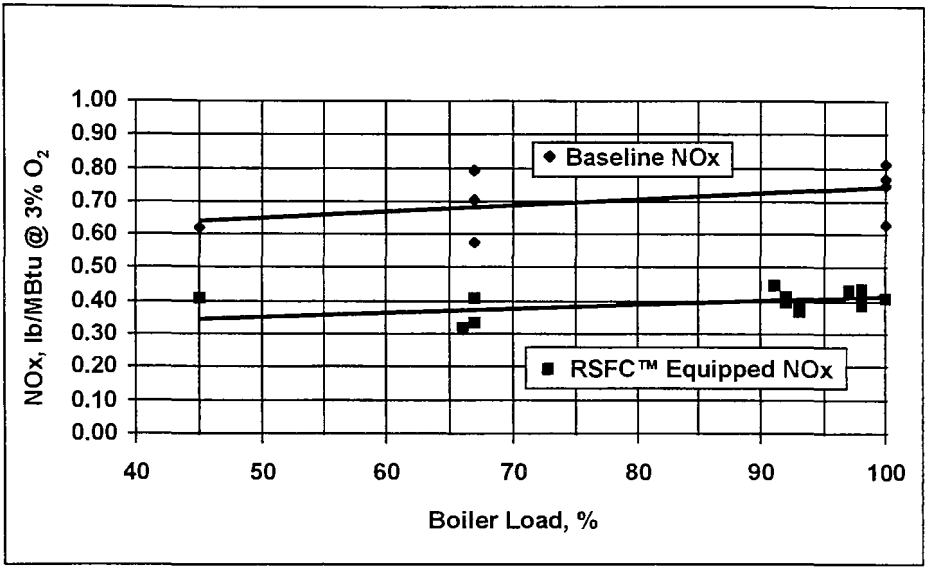

Figure 6
Comparison of NOx Emissions vs. Boiler Load

Carbon Monoxide Emissions

All carbon monoxide (CO) measurements reported in this paper are provided in units of parts per million (ppm) of gas and are corrected to 3% oxygen in the flue gas. All measurements were obtained through the use of non-dispersive infrared analyzers sampling from the airheater gas inlet duct. The test protocols used are in accordance with EPA Method 10. Pre-retrofit CO emissions averaged 48 ppm at MCR steam load. Post-retrofit testing CO averaged 47 ppm from minimum load to MCR boiler load throughout normal operating conditions.

Atrita Pulverizer Performance

It is important to understand that pulverized coal fineness plays a major role in determining the overall carbon burnout during pulverized coal combustion. The distribution of sizes of particles in a pulverized coal sample is commonly expressed as a plot of the fractions of the weight of the sample contributed by all particles larger (or smaller) than a succession of sizes. The Rosin-Rammler relationship (Field, et al., 1967), which is one of the techniques commonly used to characterize pulverized materials, was applied to the screen analysis data given in Table 2.

The characterized post-outage pulverized coal samples of the three mills all had a coarser consistency than the pre-outage pulverized coal samples. The post-outage coal fineness was 62-64 weight % through 200 mesh, with 1.2-2.4 weight % retained on a 50-mesh screen. Comparatively, the desired coal fineness in low NOx firing applications typically falls in the 75-85% through 200 mesh, with zero or only a fractional amount of material retained on a 50-mesh sieve. Hence, the coarse grinds obtained at RP&L Whitewater Valley Unit 1 compare unfavorably to those desired in a typical low NOx firing application.

Table 2

Particle Size Distributions of Pulverized Coal Samples

Mill #	Pre-Outage Fineness			Post-Outage Fineness		
	-200 Mesh	-100 Mesh	+50 Mesh	-200 Mesh	-100 Mesh	+50 Mesh
1	64.7	87.0	2.0	61.6	84.8	2.4
2	73.8	92.8	1.0	64.8	89.4	1.2
3	80.0	95.6	0.4	64.0	88.2	1.4
Composite	72.8	91.8	1.1	63.5	87.5	1.7

Another typical impact on low NOx firing is the pulverizer air/fuel ratio. Typically, an air to fuel ratio of approximately 1.5:1 is desirable to keep the pulverized coal particles in suspension, without providing an excess of transport air that will impact flame stability or NOx generation. The Unit 1 Atrita mills operate at an air to fuel ratio of 2.1:1 at high load, with lower load ratios on the order of 3.8:1. While this level of transport air flow typically tends to hinder low NOx operation, the post-outage testing shows that high air/fuel ratios had no effect on RSFC™ burner NOx reduction capability.

Unburned Carbon in the Fly Ash

Fly ash samples were obtained using EPA Method 17 isokinetic sampling techniques from the airheater gas inlet duct. Each fly ash sample was then analyzed for carbon content. Pre-outage baseline testing for unburned carbon content during normal operation throughout the load range averaged 15.29 % with an average mill fineness of 72.8 % through a 200 mesh sieve, with an average of 1.1 % left on a 50 mesh sieve. Post retrofit testing of unburned carbon content during normal operation throughout the load range averaged 16.9 % with an the average mill fineness 9.3% coarser through 200 mesh, and an average of 1.7 % left on a 50 mesh sieve. As discussed above, the negative change in pulverizer performance from pre- to post-retrofit most likely has more impact on the change in

unburned carbon than does the RSFC™ burner. After seven months of operation, Richmond reports that Unit 1 unburned carbon is within 0.5 to 1% of pre-retrofit unburned carbon levels. The strong recirculation zone created by the RSFC™ burner greatly enhances coal particle burn out and minimizes the typical low NOx increase in the unburned carbon content of the fly ash.

Boiler Operational Performance With The Coal RSFC™ Burner

During post-retrofit testing on the Whitewater Valley Unit 1 boiler, multiple aspects of boiler operation were examined to determine the impact of the RSFC™ burners on boiler operation. The operational performance issues discussed in this paper have been confirmed during the nine months of boiler operation since the burners were installed.

Ash and Slag Deposition Patterns

Since the installation of the RSFC™ low NOx coal burners, a long term change in the ash and slag deposition during operation has been observed. Prior to the burner retrofit, the original burner combustion resulted in moderate to heavy slag buildup around the burner throats which RP&L personnel had to manually rod out between two and three times a week. Since the installation of the RSFC™ burners, there has been no appreciable slagging in or around the refractory throats. In general, with the new burners, there has been minimal slag buildup on the furnace walls or convective sections of the boiler.

Furnace Oxygen and Coal Imbalances

During the tuning phase of the post0outage start-up activities a noticeable coal and O_2 imbalance was measured across the width of the furnace. Rather than perform the tedious task of balancing the coal flow to each burner, the decision was made to use the multiple operational tuning parameters available within the RSFC™ burners to "tune the burner to the fuel flow" Through the use of the burner biasing/shut off dampers and the primary and tertiary swirl vanes, each burner was optimized to the fuel flow through the respective coal nozzle. As a result of this tuning, the O_2 as measured across the width of the airheater gas inlet duct was balanced to within 0.3% side to side.

Steam Temperature Control

Post-retrofit testing and long term operation has confirmed that the installation of the coal RSFC™ burners has improved the control of steam temperature for this boiler. Prior to the retrofit, boiler operators had to perform operational burner adjustments in order to maintain design steam temperature. With the RSFC™ burners, no operational changes to the burners are required to maintain design steam temperature.

Acknowledgments

The authors would like to acknowledge the significant contribution of the following key individuals to the success of this project.

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Monday, August 25; 3:30 p.m.
Parallel Session B:
Low-NOx Systems for Coal-Fired Boilers - Group 2 Units

NOx Reduction without Low NOx Burners for a Riley Dry Bottom Turbo Furnace

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Abstract

Coronado Generating Station is a coal fired facility consisting of two Riley dry bottom turbo furnaces. When evaluating technologies for upcoming NOx reduction requirements, traditional reduction strategies were carefully considered. However, specification, procurement, and installation of low NOx burners appeared to require extensive engineering, and would be quite expensive. Instead, SRP teamed up with Burns & McDonnell to design and implement relatively simple burner secondary air flow controls. By partitioning the existing burner windbox, separate control was provided for burner secondary air and for overfire air. Proper sizing and placement of the partition helped both to better control overfire air flow, and to bring secondary air velocities closer to accepted norms. The entire project from kick-off, initial engineering, procurement and installation was conducted in just over two months. Minor tuning and adjustment of the new control equipment was conducted by SRP personnel after installation. NOx reduction ranged from 15% at high load to 20% at low loads. Notable improvements were also seen in flame shape and stability. Combustion was more stable and controllable, with less dark areas than before the modifications. The associated increase in LOI was minimal.

Introduction

Coronado generating station is a Salt River Project (SRP) facility located in eastern Arizona. The station consists of two coal fired Riley Turbo-style furnaces each rated for approximately 2,747 kpph steam flow. The units fall under Phase II of the 1990 Clean Air Act Amendment for NO_x. The requirements for NO_x reduction presented a particular challenge to the unique style of the turbo furnace with its downward-opposed square burners. Specification, procurement, and installation of new burners appeared to be complex and expensive, especially considering the units' marginal NO_x levels of around 0.55 lb/MMBTU. Instead, SRP retained Burns &

McDonnell to apply a relatively simple technique which B&McD used previously to reduce NO_x on other turbo furnaces.

Design/Specification

Each furnace consists of 24 opposed burners and overfire air fed by a compartmented windbox. The secondary air opening around each burner includes 12 directional vanes and two velocity dampers. The overfire air port includes a 1/3 and 2/3 damper to control air flow out of the port. Each compartment in the windbox is dedicated to a burner and overfire air port, and has a single shut-off damper. This common shut-off damper was the key to the NO_x reduction technique. B&McD proposed to partition each compartment in order to separate burner secondary air flow from overfire air flow. The partition consisted of a steel plate wall about 2/3 back from the furnace. The shut-off damper would be trimmed to only control air to the burner. The addition of modulating controls to the two-position cylinder actuator allowed the damper to be throttled back to control air flow at each burner. Throttling this new secondary air damper at each burner would increase windbox pressure upstream of the damper and increase overfire air flow. Used properly, this would reduce burner zone stoichiometry resulting in cooler flames and lower NO_x levels.

Partition Design

One key to successful design lies in the proper trimming of the secondary air damper and proper air velocities into the furnace. The damper was intended to control air **flow** to each burner, not air velocity. Velocity was controlled by the secondary air openings into the furnace. Therefore, the secondary air damper was sized 25% greater than the secondary air openings into the furnace.

Air velocity is a significant consideration in burner design. Merely sizing the new secondary air damper without evaluating the openings into the furnace could result in poor fuel and air mixing, and defeat any emissions reduction capability produced by the additional overfire air flow. B&McD's experience indicated that secondary air velocities should run between 120 and 140 fps, and primary air velocities should run between 70 and 90 fps. The as-found configuration of both Coronado furnaces produced much higher velocities than preferred. This was confirmed by observations of poor flame conditions in the furnace. Therefore, as part of the program, the waterwall penetrations were enlarged by the removal of refractory. (The design of the turbo furnace did not normally require burner throat refractory)

These reduced air velocities from the refractory removal were closer to the targets, and were carefully evaluated in determining sizing for each secondary air damper. Also evaluated were target burner zone stoichiometry, current fuel analysis, and excess oxygen levels. A burner zone stoichiometry of 0.9 was chosen to maximize flame temperature reduction without severe waterwall corrosion.
The evaluation resulted in a 75% reduction in area of each secondary air damper.

The windbox partition was constructed of 1/4" steel plate and angle irons. It included bolt-on panels to provide access to the interior of the burner compartment. An outside contractor completed the work on Unit 1 during the fall outage in about 3 weeks. Plant personnel added electro-pneumatic positioners on each burner air damper and wired them back to the control system. Provisions in the DCS system were added for burner management permissives, cooling settings, as well as modulation of each burner secondary air damper, should it become necessary.

Windbox Baffles

Pre-outage flow testing showed a significant front-to-rear air flow imbalance. Physical inspection during the outage indicated that baffles inside the windbox might help with balancing. The unit had existing balancing dampers for the rear of the windbox only. However, the testing revealed that even with the dampers wide open, airflow was much higher on the front side of the windbox than on the rear. Therefore, during the outage, 15" baffles were installed in the windbox to help balance the secondary air flow from front to rear burners.

Tuning and Results

Tuning was conducted over a period of about 2 weeks, and included measurement of air flows at each burner and overfire air port after each adjustment was made. Windbox front-to-rear air flow balance was tuned first. The new baffles forced enough air to the rear of the windbox to make the existing dampers much more effective. This allowed the balancing dampers to be throttled between 30 and 50% to balance front and rear air flow.

Next, adjustments were made to each burner secondary air damper. Several combinations of damper positions were evaluated while simultaneously monitoring combustion conditions and unit emissions. Air flow traverses at each burner windbox compartment were made after each new setting. Working with the new secondary air dampers allowed much more control over combustion conditions. Adjustment of the burner secondary air dampers and primary air flow provided much better control of flame shape and attachment than before the outage. Low load flame stability was also much better. The upper furnace area was much clearer, with no sparklers.

The final setting was determined after about two weeks of testing. For light-off, the dampers were placed at 80% open. As load is increased, the inboard burners are modulated from 80% to 60% open. The remaining burner secondary air dampers were left at 80% open. Overfire air was left wide open throughout the load range. The final results showed a 15% reduction in NO_x levels at high load, and a 20% reduction at low loads. Windbox pressure increased from 4.5 inwc to 5.5 inwc. Unburned carbon increased minimally. Flame shape was better defined and more controllable. Dark areas of the furnace decreased significantly, as did sparklers in the pendants.

Conclusions

The entire project, from initial design to final tuning, was conducted in about 3 months. Of this time, 6 weeks was taken up by the outage and tuning. Emissions reductions were enough to comply with upcoming regulations, but were not so drastic as to cause significant increases in unburned carbon or furnace waterwall corrosion rate. Further emissions reduction may be possible with further throttling of the burner secondary air dampers, but was not necessary for the Coronado units. The entire cost of the project was approximately 20% of the cost of designing and installing new burners.

Success of the modification requires a careful evaluation of combustion conditions, fuels, stoichiometry and existing burner configuration. It also requires a good tuning procedure. This technique is a good alternative to new burners for Turbo-style furnaces with marginal emissions. Turbo furnaces with higher emissions could also be candidates for this modification, depending on the combustion conditions and the physical geometry of the furnace.

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NO_x REDUCTION ON A RILEY STOKER DRY BOTTOM TURBO FURNACE
THE MEGA SYMPOSIUM

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Abstract

Gainesville Regional Utilities of Gainesville, Florida retained the services of Burns & McDonnell of Kansas City, Missouri to conduct a NO_x reduction program. The NO_x target was 0.5 lbs/mmbtu. The unit was at 0.7 lbs/mmbtu at the start of the program.

The approach taken by Burns & McDonnell was to first get the combustion in order. This was done by balancing primary air and fuel to the burners through mill testing, improving the quality of fineness of the fuel, and making adjustments to burner directional vanes. These items alone reduced the NO_x to 0.56 lbs/mmbtu.

An outage was used to partition the windbox and add secondary air shutoff damper control to allow individual control of the secondary air to the burner front and force additional air to the overfire air ports. This was the major modification done regarding the NO_x reduction effort. However other work contributed including classifier modifications, mill reject valve upgrade, mill ball charge changes, and reducing secondary air velocities at the burner front.

When the physical modifications were completed and the unit brought back on line, boiler tuning took place to continue with the NO_x reduction and combustion improvement. The NO_x was reduced to 0.47 lbs/mmbtu at full load.

Initial Observations

Initial unit walkdowns were performed to determine existing combustion conditions. The lower furnace, burner level and upper furnace were all observed. The lower furnace was observed for areas of unburned fuel, uniformity of the fire, and flame conditions at the burners. The six observation doors at this level provide an excellent view of all eighteen burners. The level just above the burners provides some view of the overfire air ports and a limited view of the burners.

These doors were used extensively during the actual boiler tuning process, which took place after modifications were completed. Any incomplete combustion in the corners and along the furnace walls can be readily seen through the observation doors at this level. The upper furnace doors were used to observe any fire and/or sparklers present at the pendant level.

Early on, the furnace observations that were made showed a tremendous difference from the front to the rear burners. The rear burner fires had incomplete combustion at the burners while all of the front burners had good combustion. The front burners were very uniform in appearance, with consistent upswept fires. The rear burner fires were erratic with some burners having raw coal streams extending out considerable distances from the burner throats. Fire and clouds of unburned fuel were swirling in the lower furnace. Along with this erratic burn, the rear burners did not show any consistency from burner to burner.

Observations made through upper doors showed some incomplete combustion above the burner area while the upper furnace had fire present.

Primary Air and Fuel

Based on these furnace observations, the first items addressed were the fuel and primary air delivery to the burners. Isokinetic coal testing was performed on the three Riley ball tube mills. This testing revealed good primary air flow distribution, however there was pipe-to-pipe coal flow imbalance. The coal fineness of the three mills at full mill load was also less than the desired fineness of 70 percent passing a 200 mesh sieve and 98 percent passing a 50 mesh sieve.

The furnace observations combined with the mill test results dictated the need to review the mill ball charges. Discussions between B&McD and GRU personnel resulted in the decision to change out the mill ball charges during the upcoming Spring 1995 outage.

Prior to the outage, the primary air system hot and tempering air dampers were characterized to allow for proper mill temperature control without influencing flow control. All of the hot and tempering air dampers were restroked. The mill rating and bypass dampers were stroked to determine linearity between the rating damper and coal flow. This relationship was satisfactory and no changes were required. The turndown capability of the mills was also evaluated. Each mills rating damper was set to maintain a minimum classifier-to-furnace differential. Mill output was then reduced by opening the mill bypass dampers. A very good turndown of six to one was achieved while maintaining the minimum classifier-to-furnace differential.

Initial Modifications

Due to time restraints, not all of the recommended modifications for reducing NO_x and improving combustion could take place during the spring 1995 outage. However, some of the modifications were made, along with some routine maintenance work . For some recommendations, temporary modifications were substituted until the permanent modifications could be made during the spring 1996 unit outage.

The full modifications or changes that took place in 1995 included refurbishing the mill crusher/dryers, removing a portion of the perforated plate from above and below the burner igniters to reduce secondary air flow velocities, installing primary air flow measuring probes in each of the primary air ducts, adding mechanical stops to each burner shutoff damper to provide cooling air to out of service burners, and changing out the ball charge in each mill.

One of the temporary modifications included setting the upper and lower directional vanes at fixed downward angles relative to the front and rear furnace walls. Because the vanes had a tendency to stick in other positions when being adjusted, once the vanes were set they were welded in place. The permanent modification is to make the directional vanes adjustable and stable.

Another temporary modification was to place the burner velocity dampers in the fully open position. The permanent modification is to remove the velocity dampers completely. Because of the distance these dampers are from the burner front, any effect they have on the secondary air velocity is virtually lost by the time the air reaches the burner front.

Making the mill reject valves functional was another temporary modification. The permanent modification is to redesign the valve for better reliability and external indication of performance.

Observations Following Initial Modifications

After the spring 1995 outage when Unit 2 was brought back on line, unit walkdowns were repeated to observe combustion changes. The fire was definitely lower in the furnace. There was still some inconsistent burning at the rear burners but the fires were brighter. Swirling coal and fire were still present in the lower furnace. The NO_x level however had dropped to 0.537 lbs/mmbtu at full unit load.

A shipment of coal received shortly after Unit 2 was brought back on line had a Hardgrove Grindability Index (HGI) lower than the value that the mills were designed to. Full unit capacity could not be maintained on this harder to grind coal. Fuel gas had to be used to supplement the coal to achieve full unit load. After the harder quality coal was no longer being burned, mill capacity returned.

However, even with the return to a coal that had an HGI within the specified range of these mills, the coal inventory of the mills had to be increased to obtain full mill capacity. This additional coal inventory reduced the mill performance (fineness) considerably. The ball charge weight was increased slightly to bring all three mills closer to the design charge weight. This improved capacity some but the increased mill inventory was still required. The mill ball charge distribution needed further evaluation.

The mills use power and sound to control coal levels. The power levels indicated that the new balls charges were lighter than the old charges. Additional balls were added to two of three mills and full unit load was achieved without supplemental fuel gas. However the mills were still operating with a higher than desired mill inventory. The 50 mesh fineness was at desired values but the 200 mesh fineness was still quite low. During an October 1995 forced unit outage, the

mills were internally inspected for ball charge level and found to be low. Additional balls were added to all three mills.

No additional modifications would be made until the next unit outage scheduled for the spring of 1996. The unit continued to operate and maintain full load without the need for supplemental fuel gas.

Final Modifications

Specifications were prepared by Burns & McDonnell for the work to be done during the spring 1996 outage relating to the NO_x reduction program. These specifications were included in the GRU bid package covering additional plant outage work. The following NO_x related outage items included:

- Partition each burner compartment to separate the secondary air flow to the burner from the overfire air flow.
- Reduce the entry area to each burner compartment to improve secondary air damper controllability
- Convert the secondary air shutoff dampers from an open/close operation to modulating operation by installing positioners on each damper.
- Remove the secondary air velocity damper from each burner compartment. These dampers have no lasting impact on secondary air velocity due to their location back from the burner front.
- Replace the upper and lower directional vane operating rods to provide improved reliability. The existing rods have bends near the vanes to clear the velocity dampers which cause binding. New straight rods will eliminate the binding and provide easier adjustment of the vanes.
- Install a dual lift wing in each of the coal nozzles to maintain a homogenous distribution of the coal flow until it reaches the burner opening.
- Extend the classifier inner shroud below the classifier inlet vanes. This deters coal from short circuiting directly to the coal pipes, and improves both fineness and distribution.
- Install directional bars on the classifier inlet vanes to direct the larger coal particles downward and improve classification, therefore improving fineness.
- Redesign the mill reject valves to improve reliability and provide external indication of the valve operation. The new valves include a counterweight for positive shutoff and are shaft mounted. The external indication will allow for immediate identification of any valve problems.

- Change out the mill ball charge in the west mill to a charge which includes a higher percentage of small balls. This charge will provide a 10 percent greater surface area for the same ball weight.

All of the above tasks were completed during the spring 1996 outage.

Boiler Tuning and Observations Following Final Modifications

Boiler tuning for NO_x reduction was performed during a three week period in April 1996. The first task was to observe furnace conditions at full unit load prior to making any operating changes. The excess O_2 was approximately 4.0 percent and the overfire air dampers were 100 percent open. The NO_x was at .632 lbs/mmbtu. The fire at the rear burners was still inconsistent, with unburned coal extending out and down in the lower furnace area. The rear fires were also very erratic. The front burners showed good combustion with flames attached to the burner throats. Furnace temperatures were taken through six observation doors above the burner levels on both sides of the boiler at the front, center, and rear of the furnace.

The $^1/_3$ overfire air dampers were then closed and the $^2/_3$ overfire air dampers were left open. All other conditions remained the same. The NO_x climbed to .657 lbs/mmbtu. No major visual change was evident.

The $^1/_3$ overfire air dampers were then opened and the $^2/_3$ overfire air dampers were closed. Again all other conditions remained the same. The NO_x climbed again to .737 lbs/mmbtu. The fire appeared to be higher in the furnace.

With conditions still the same, all of the $^1/_3$ and $^2/_3$ overfire air dampers were then closed and the NO_x rose to .798 lbs/mmbtu. Although no carryover was occurring in the upper furnace, fire was observed between the radiant superheater tubes.

The overfire air dampers were then returned to their full open positions.

The next task was to increase the air to the rear burners to improve the combustion at the rear burners. All of the previous observations of coal streams out from the burners, swirling clouds of coal, and erratic fires indicated the need for additional air to the rear of the furnace. Also the overall fire in the lower furnace was not centered but more towards the rear of the furnace.

The new controllers installed during the outage were used to slowly close down on the front burner secondary air shutoff dampers. The control of the dampers was set up on a per classifier basis, therefore three burners are operated together during each adjustment. All nine rear dampers were closed down in 5 percent increments and furnace observations were made after each change. No noticeable change took place until the dampers were at 80 percent open. At this point the rear fires began to clear up. The furnace in this area became brighter. The lengths of the raw coal streams decreased as the additional air being forced to the rear burners was improving the combustion. The appearance of the fire continued to improve as the dampers were taken to 70 percent open. The location of the fire had shifted away from the rear wall and was

now centered in the lower furnace. The swirls of unburned coal and fire climbing the rear walls had ceased. Furnace temperatures were taken above the burner level through the same six observation doors. The furnace temperatures increased an average of 65^0 F.

Closing down on the front burner secondary air shutoff dampers did not have any adverse effects on the front burners. They continued to show good combustion.

All rear burner secondary air shutoff dampers were then closed down until a change could be observed above the burner level. These dampers were taken to 75 percent open. The front and rear secondary air shutoff dampers were then closed down simultaneously at 2 percent increments. Observations were made at each change in damper position. When the front dampers reached 56 percent open and the rear dampers reached 61 percent open, furnace observations were again made. The unit was still at full load and the excess O_2 was approximately 3.7 percent. The NO_x was now at .502 lbs/mmbtu. The furnace temperatures measured through the same observation doors above the burners remained nearly the same. The temperatures did however level out more from front to rear. This was apparent in the furnace observations. The fire is more centered and filling the furnace below the burners. The point where the front and rear fires converge was very close to the mid furnace area.

The next task was to reduce the coal inventory in the mills to improve coal fineness to the burners. New peak kW levels were determined for each mill. Operating KW levels were then selected that were closer to peak values than previously used. This allowed for smaller coal inventories in each mill.

The mills were tested to determine performance with the new coal inventory levels and the new ball charge in the west mill. The coal fineness was greatly improved on all mills with the west mill being the best performer. There was however a front to rear classifier coal flow imbalance on two of the mills. Results of this could be seen in the individual front and rear pipe fineness values. Front classifier vanes on both of these mills were opened up to balance these flows.

The excess O_2 set point was lowered to 3.0 percent at full load. At full unit load the NO_x was now running at .47 lbs/mmbtu. This NO_x value was able to be maintained as long as the furnace was kept relatively clean. As the furnace became dirty and the heat absorption decreased, thus allowing the overall furnace temperature to increase, the NO_x also increased. Cleaning furnace wall surfaces would bring the NO_x back in line. However, because of retractable soot blowers in the upper furnace and the gas recirculating system being out of service, furnace wall cleaning would decay steam temperatures. Placing these retractable blowers and the gas recirculating system back in service allowed steam temperatures and NO_x to be maintained.

The excess O_2 set point was further lowered to 2.8 percent. This was to allow for an additional margin of NO_x control during unit transient conditions. However, to effectively control NO_x at full load, the furnace cleanliness had to be maintained, no matter what the O_2 set point.

Comparisons of burner to burner air flows for burner air and overfire air were made using a hot wire anemometer. Having to adjust three dampers together on the same classifier was not always the preferred method to balancing air flows. Without individual control of each damper,

complete balancing was not attainable. Some in field modifications were made to allow control of some individual dampers. However, after further air flow readings were taken, the need for individual damper control on all 18 dampers became apparent. It was decided to stop further temporary modifications and order the material required to permanently install individual damper control.

The improved combustion at the burners allowed for any mill to be taken out of service during reduced load operation. In the past, only the east mill, which included the four end burners, could be taken out of service. Removing either the west or center mill caused burners that were adjacent to west or center mill burners to trip.

Changing the ball charge in the west mill improved its performance. The west mill will handle a higher coal capacity than the other two mills while maintaining proper fineness. The new charge provided approximately a 10 percent increase in surface grinding area for the same total ball charge weight. The ball charge in the center and east mills were changed to match the more proficient charge in the west mill.

NO_x REDUCTION IN ARCH-FIRED BOILERS BY PARAMETRIC TUNING OF OPERATING CONDITIONS

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Abstract

This paper presents the results of a research project whose objectives are to investigate the parametric sensitivity of boiler operation in relation with NO_x generation and heat rate, and to fine tune operating conditions to minimize NO_x emissions. The project is included in the European Coal an Steel Community Research Programme and was performed in arch-fired boilers burning low-volatile coals. Research was mainly composed of sets of in-field tests designed following the factor analysis methodology. Testing procedure included a complete survey of the experimental units operation with measurement of coal flow and size distribution to burners, furnace temperatures, in-flame gas composition profiles, and on-line boiler efficiency and unit heat rate monitoring, amongst others.

Results revealed a strong sensitivity of NO_x to operational parameters and deep differences between boilers of similar technology. NO_x emission reductions greater than 30% have been documented, exploring non-conventional boiler settings without penalizing or even increasing unit efficiency.

1. Introduction

A large proportion of the coal produced in the mining regions of the North of Spain are anthracites and other low-volatile coals. More than 3,500,000 tons/year of this coal (Volatile matter: 7.2%; N: 1.0%; Ash content: 33.5%) is burnt in the five arch-fired units of Compostilla Power Station (ENDESA).

Arch-fired furnaces (Figure 1) are designed for the industrial firing of low-volatile coals, as they provide a solution to problems arising due to the low ignitability and combustibility of these fuels. The characteristic high temperature levels and residence times of these combustion systems, as well as the higher char/volatile ratio of low-volatile coals, produce higher levels of NO_x emissions than bituminous coal firing. NO_x emissions values in the range of 1800-2000 mg/Nm^3 (d.b., 6% O_2) have been reported for different Spanish arch-fired boilers, such as Compostilla Units 4 & 5.

Although there is no current restriction for NO_x emissions in existing installations of this type, a limit of 1300 mg/Nm^3 (d.b., 6% O_2) is thought to be applied in the future. Commercial solutions for this oncoming problem with NO_x emissions, such as flue gas treatment using catalytic reduction systems by ammonia injection, are expensive alternatives. These techniques should therefore only be used after exhausting the possibilities of reducing NO_x emissions through the optimisation of the coal combustion process. Such primary measures should also be evaluated in terms of their possible effect on the thermal performance of boilers.

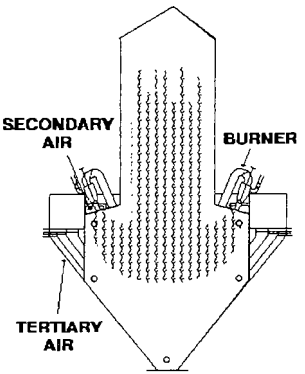

Figure 1. Arch-fired boiler.

Due to the above factors, a broad-based research project on the reduction of NO_x emissions, by the use of combustion fine tuning, has been undertaken in the arch-fired Units 3, 4 & 5 of Compostilla Power Station. This project, known by the initials RNA, is included in the European Coal and Steel Community Research Programme.

2. Objectives

The main objective of the RNA Project was to determine the feasibility of approaching, or even reaching, the 1300 mg/Nm^3 NO_x limit of possible future application in Compostilla Units 4 & 5, using only combustion adjustments.

Additionally, as NO_x emissions in Compostilla Unit 3 were as low as 1100–1200 mg/Nm^3, a comparative study has been conducted in order to determine the design and performance parameters that give rise to the different NO_x formation behaviour of Compostilla Unit 3, with respect to that of the twin Units 4 & 5.

3. Tests programme

An extensive programme of in-field combustion tests, at full load and using coal of practically constant properties, has been conducted during 3 years in two different phases:

- Phase I: Trials at the "high NO_x emissions" Units 4 & 5.
- Phase II: Trials at the "lower NO_x emissions" Unit 3. Comparison with Units 4 & 5.

The methodology adopted for these trials was based on the parametric sensitivity approach, and the following schedule was drawn up for each unit:

a) Boiler instrument checking.
b) Operational modifications testing (parametric sensitivity matrix).
c) Trend confirmation testing.
d) Maximum improvement testing.

In each test, a broad characterisation of boiler performance was made, by measuring or monitoring the following items, amongst others:

a) Temperature distribution within the furnace (60 measurement points).
b) Gas composition (NO, NO_x, O_2, CO) above the burner arch (24 measurement points).
c) Gas composition (NO, NO_x, O_2, CO) and temperature at the outlet of the economizer (using a grid of 32 measurement points).
d) Emission levels of NO, NO_x, O_2 and CO.
e) Coal fineness and flowrate to burners.
f) Fuel-oil support.
g) Excess oxygen.
h) Air damper positions.
i) Fly ash carbon content.
j) Coal analysis.
k) Desuperheating spray flows.
l) Boiler efficiency and unit heat rate.

Besides this, modelling of the windboxes of Units 4 & 3 has been performed, in order to establish the relationships between air dampers openings and actual air flowrates through them.

4. Discussion of experimental findings

4.1 Scope

The operating modifications tested during commercial operation of the boilers consisted of variations to several different parameters. These included excess air, secondary and tertiary air dampers openings, fuel-oil support, distribution of active burners, positioning of straightening vanes, and combustion air temperature. Other factors such as the degree of boiler slagging were also taken into consideration.

Although results obtained within this Project reveal significant effects of most of the above mentioned operating modifications[1], this paper will only focus on the relevant trends determined for excess air, secondary and tertiary air dampers openings and fuel-oil support at Compostilla Units 3, 4 & 5.

4.2 Phase I: Trials at Units 4 & 5

4.2.1 NO_x Emissions. The main findings obtained in Units 4 and 5 of Compostilla P.S. are shown below, in relation to the operating conditions that brought about a significant fall in NO_x emissions. More specifically, the distribution of air fed into the boiler, which determines the type of flame obtained, and the excess air are especially important factors in the generation of NO_x. Likewise, the influence of eventual fuel-oil support has been established.

Figure 2 details the results for Compostilla Unit 4 of the most important cases in terms of NO_x emissions. The percentages of change in comparison with reference data are shown in parentheses. This figure illustrates the possibility of achieving the limit of 1300 mg/Nm^3 NO_x, using only primary measures. Results produced in the identically designed Unit 5 are very similar.

It must be underlined that the general tendencies shown by the figures recording overall emission of NO_x in the different trials, were fully confirmed by local measurements made directly above the burners, using probes especially designed for this purpose.

Type of flame (excess air). One of the most important results of the studies undertaken in Units 4 and 5 of Compostilla P.S. was that two types of flame were identified (short and long). These were caused by differing relative proportions of secondary and tertiary air fed into the boiler (Figure 1). The qualitative difference between these types of flame arises due to the finding of a substantial modification in the causal relationship between the formation of NO_x and the operational oxygen level (Figure 3).

In fact, when the ratio between secondary air (S.A.) and tertiary air (T.A.) is low, as occurs with the air settings used in the past in the above-mentioned boilers (the base condition), an inverse dependence between concentrations of NO_x and O_2 is observed, i.e., less NO_x is formed when oxygen levels are higher.

This condition is associated with raising of the flame due to a greater flow of tertiary air. This gives rise to shorter and more intense flames (short flame), where combustion occurs with a less stratified supply of oxygen, i.e., with a greater initial mix of air and coal. The generation of NO_x is thereby controlled by temperature. This means that when an increase of excess air occurs, the flame cooling effect prevails over those deriving from higher local concentrations of oxygen, which brings about a net reduction in the formation of nitrogen oxides.

In this sense, correlations between the average temperature within the furnace and excess air have therefore been established. Variation coefficients of 40° C for each 1% change in excess oxygen are obtained. The cooling effect deriving from an increase of 1% in operational oxygen excess may be evaluated according to the ratios calculated between variations in NO_x and the average temperature in the furnace. A reduction of around 300 mg/Nm^3 in NO_x is produced, clearly demonstrating the importance of this factor in the formation of nitrogen oxides in this boiler type.

On the other hand, when the S.A./T.A. ratio is higher, the flame tends to occupy the lower part of the furnace, and therefore becomes longer, making the combustion process less intense, and with an increasingly stratified supply of oxygen. NO_x generation comes to be controlled by the influence of local concentrations of oxygen, i.e., by the stoichiometry of the oxidisation/reduction reactions involved in the formation of nitrogen oxides, to the detriment of the thermal control associated with variations in excess air.

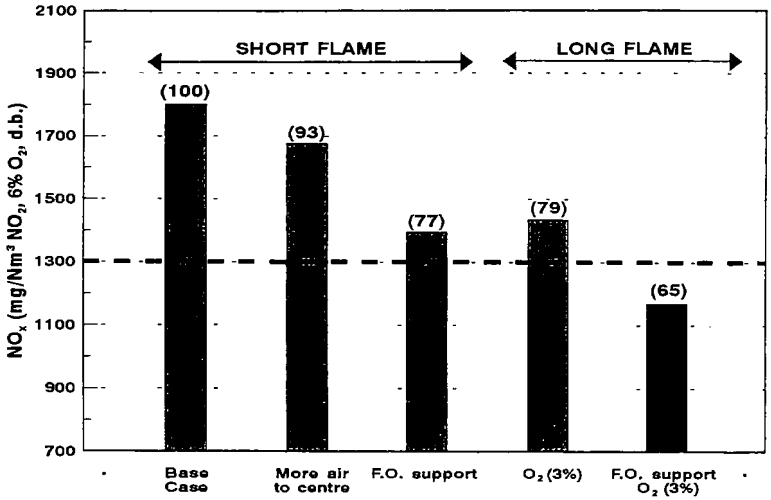

Figure 2: NO_x emission results in outstanding cases (the limit of 1300 mg/Nm³ NO_x of possible future application is represented) (Unit 4)

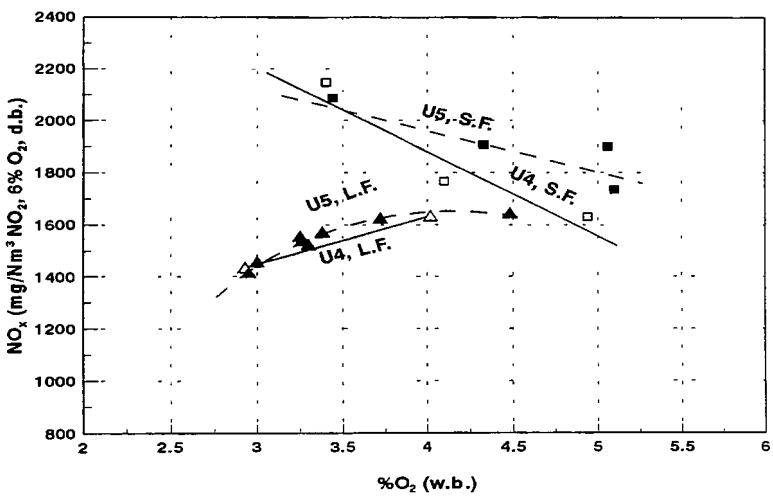

Figure 3: NO_x/O_2 general relationships for short and long flames (Units 4 & 5)

Thus, in this case (long flame), an increase in excess air gives rise to an increase in the generation of nitrogen oxides. This is the opposite of the situation when a short flame is formed. The overall tendencies in the NO_x/O_2 ratios shown in Figure 3 are supported by the measurements made at the level of the arch of burners, as shown in Figure 4.

These two flame types, which may be identified at a macroscopic level by the structure of the temperature profiles measured in the furnace, therefore present a form of behaviour that is contrary to the basic operating parameter of total feed air. As it is stated below, this fact is related to the influence of NO_x reduction, in each case, over unit heat rate.

Additionally, it was found that the conditions leading to the lowest NO_x generation corresponded to long flame type situations, attaining values of approximately 1400 mg/Nm^3 (d.b., 6% O_2). This is equivalent to a reduction in these emissions of 20% in comparison with the initial basis (1800 mg/Nm^3) (Figure 2).

On the contrary, reducing the generation of NO_x without changing the flame from the short type, using increases in the excess of overall operational oxygen or the airflow supplied to the boiler centre, only gives rise to improvements of approximately 7%.

Fuel–oil support. Important reductions in NO_x emissions were found in the two experimental boilers when fuel–oil support at central burners was employed in long flame type situations (Figure 5). Minor fuel–oil support (7 tons/h) together with a reduction in the excess of oxygen, implicated a fall of NO_x emissions to around 1200 mg/Nm^3 (Figure 2). This is equivalent to a 35% net reduction of this parameter.

These facts may be explained on the basis of the following factors:

- An increase in the temperature of the initial zone of the flame, which produces a greater devolatilisation. The literature on this subject states that the fraction of volatile nitrogen has a lower degree of conversion to NO_x under stratified combustion conditions, such as those existing in arch boilers.

- Fuel–oil combustion consumes the available oxygen in the first zone of the flame, creating an area rich in reducing substances in which the coal nitrogen and thermal NO tends to produce molecular nitrogen.

- A decrease in the average nitrogen content of the fuel (coal + fuel–oil) due to the lower content of the fuel–oil (approximately 0.3 – 0.5%), which is markedly lower than that of the coal used in Compostilla P.S. (1.4 – 1.6%).

Fuel–oil support was found to be most effective in these units when it took place in the central area of the boiler. This is explicable due to the greater formation of NO_x in this region, because of its higher temperature levels, which make reduction more probable.

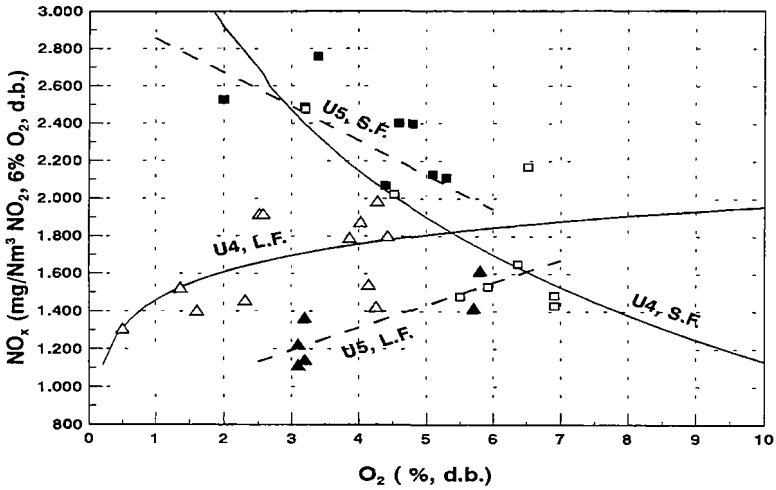

Figure 4: NO_x/O_2 burners arch relationships for short and long flames (Units 4 & 5)

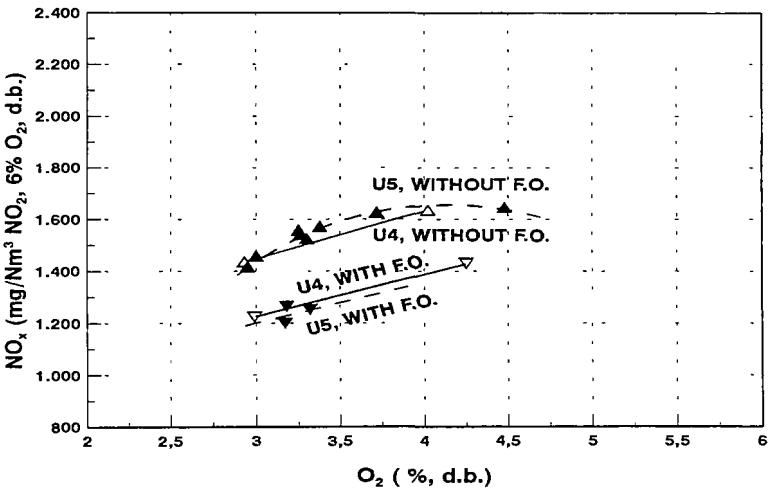

Figure 5: NO_x/O_2 general relationships for cases with and without F.O. support (Units 4 & 5, long flame)

Figures 6 and 7 show the correlations obtained at the level of the arch of burners in Unit 4 both with and without fuel–oil support, depending on type of flame. Thus when fuel–oil support is being used, the NO_x/O_2 ratio is found to be direct for both types of flame, i.e., the lowest concentrations of NO_x are attained for the lowest levels of excess oxygen.

This fact could be explained by the creation of more strongly reducing zones in the initial areas of the flame, thereby increasing the relative importance of local stoichiometry in relation with NO_x production. Another possible explanation of this phenomenon could be increased devolatilisation of fuel nitrogen, this fraction being very sensitive to local levels of oxygen respecting its conversion into molecular nitrogen.

NO_x emissions are found to be lower for short flames as the flow of supporting fuel–oil is increased. It may be observed that the degree of reduction decreases progressively towards an asymptotic value (Figure 6).

4.2.2 Collateral effects of reductions in NO_x. The measurement of NO_x emissions must be accompanied by checking of the effects of modifications on flyash carbon content and, with greater exactitude, on boiler efficiency and unit heat rate.

In general, the hypothesis that any action aimed at reducing the production of NO_x would produce a fall in boiler efficiency was widely accepted, this being due to an increase in the amount of ash unburnt. Although this hypothesis was supported by observations made during different experimental programs, it was found to be incorrect for Units 4 and 5 of Compostilla P.S., in the light of the results obtained.

In fact, the change from the usual boiler conditions (as the base case) to the final condition (with or without fuel–oil support) does not only bring about a significant reduction in NO_x emissions (from 20 to 35%), but is also accompanied by improvements in unit heat rate, in spite of a slight increase in ash carbon content.

These facts are shown in Table 1, where the most relevant results of trials with a short flame are presented (when NO_x production is optimised by supplying more air to the centre of the boiler) and final results using long flame with and without fuel–oil support.

Thus, although the levels of unburnt carbon increased about 0.8% under final conditions with a long flame, in net terms there was a 0.3% increase in boiler efficiency. This improvement in boiler performance is basically caused by a decrease in the volume of fluegas, due to the lesser excess air used in the final conditions (as was pointed out above, NO_x levels are decreased on reducing the supply of combustion air for a long flame type).

The use of a lower excess of air also gives rise to a reduction in auxiliary power consumption, which also has a positive effect on unit heat rate.

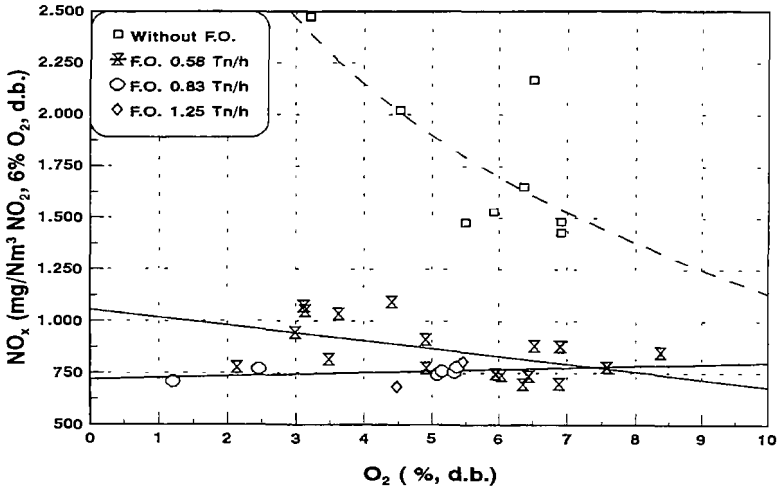

Figure 6: NO_x/O_2 burners arch relationships for different F.O. support flowrates (Unit 4, short flame)

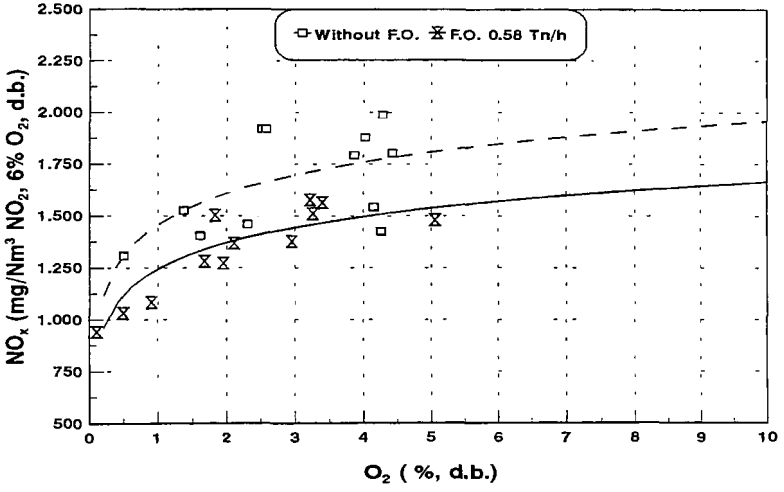

Figure 7: NO_x/O_2 burners arch relationships for cases with and without F.O. support (Unit 4, long flame)

In this context, making a greater use of heat transfer in the water walls, for long flame types, brings about a drastic reduction in desuperheating spray flowrates, which in turn leads to an improvement in turbine performance and the supply of higher quality steam to the latter.

Table 1: General data from the most important tests in Unit 4

Case	Short flame (air to centre)	Long flame (final condition, without F.O.)	Long flame (final condition, with F.O.)
% O_2 (v/v, w.b.)	4.28	2.93	2.99
% NO_x (mg/Nm^3, 6% O_2, d.b.)	1675*	1435	1223
% ash unburnt	3.22	4.07	4.02
Boiler efficiency (%)	**87.67**	**87.97**	**87.90**
Water walls efficiency (%)	59.09	67.24	66.34
Desuperheating spray flowrate (lb/h)	101,700	19,300	22,600
Unit heat rate (kcal/kWh)	**2429.48**	**2408.34**	**2411.05**

* 1800 mg/Nm^3 in the case of a non-optimised short flame (base case)

This therefore constitutes a clear demonstration of the possibility of attaining reductions in the emissions of NO_x from anthracite burning boilers by around 30%, while also offering substantial improvements to the economic balance of unit performance (approx. 20 kcal/kWh). The said results are obtained by abandoning the operational solution traditionally adopted, which involves combustion conditions that are optimised respecting the production of unburnt.

4.3 Phase II: Trials at Unit 3

4.3.1 Design and operating differences. Compostilla Unit 3 has performed very differently, with respect to Units 4 & 5, in terms of NO_x emissions over time. In this sense, an extensive study of the design and operating differences of Units 3 & 4 have been performed with the following main results (Figure 8):

Unit 3 (330 MW) presents a proportionally larger distance between front and rear walls than Unit 4 (350 MW). This determines a greater specific furnace volume for that boiler.

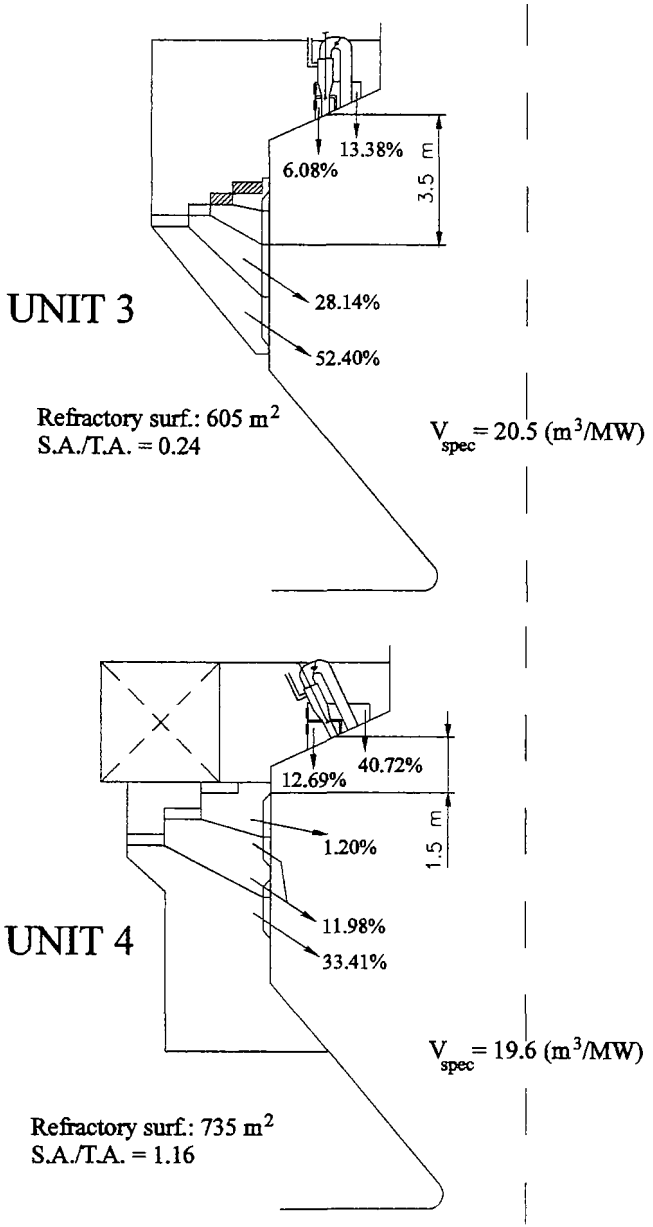

Figure 8: Furnace design and air distribution patterns for base cases (Units 3 & 4)

Refractory lining surfaces have a lower extent in Unit 3.

Unit 3 typical coal fineness is 95% through 200 mesh, due to the new classifiers installed in this plant, whilst Unit 4 coal size is around 88% through 200 mesh.

In Unit 3 only 2 adjustable vertical levels of tertiary air are used, whereas Unit 4 has 3 levels of tertiary air. Vertical distance from burners tips to the upper T.A. level is 3.5 m in Unit 3, and only 1.5 m in Unit 4.

Tertiary and secondary air distribution is substantially different in these units. As it can be noted in Figure 8, the S.A./T.A. ratio, obtained from windbox modelling, is much lower in Unit 3 for the base case. Additionally, Unit 4 presents a larger proportion of S.A. supplied through the vents.

4.3.2 Effects of modifications in air distribution. Tests campaign udertaken in Unit 3 has produced very important results in order to characterize NO_x formation and heat rate fine tuning in this boiler. Nevertheless, this paper will only emphasize those results which allow a comparison with the combustion patterns of Unit 4 (similar to those of Unit 5).

In this sense, the most relevant effect determined in Unit 3 is that produced through the modification of the S.A./T.A. ratio. Table 2 and Figures 9 and 10 show comparisons of Units 4 & 3 performance when varying this ratio.

Table 2: Comparison of performance data from most significant tests with variation of the S.A./T.A ratio (Units 4 & 3)

Case[1]	S.A./T.A.[2]	NO_x (mg/Nm^3, 6% O_2)	Desuperheating [3] spray flow	Ash unburnt (%)	Boiler effic. (%)	Heat rate (kcal/kWh)
U4. Base Case	1.16	1767	101700	3.2	87.67	2429.48
U4. Long flame	3.21	1635	29500	3.8	87.35	2423.56
U3. Base Case	0.24	1198	38.90	8.3	85.60	2498.42
U3. S.A./T.A.↑	0.41	1441	14.50	5.9	86.61	2463.05
U3. S.A./T.A.↓	0.21	1014	42.60	9.2	85.07	2526.29

1 Oxygen excess: U4: 4,1% ; U3: 4,6%
2 Flowrate ratio from windbox modelling
3 U4 (lb/h) ; U3 (%)

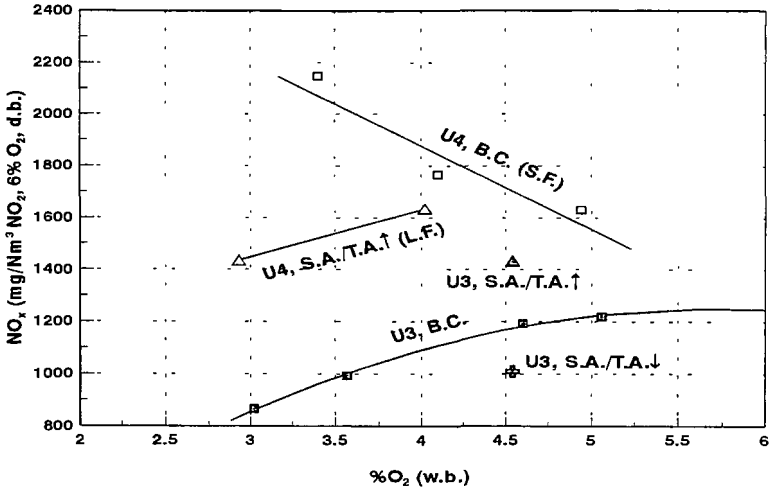

Figure 9: NO_x/O_2 general relationships for Units 3 & 4 when modifying the S.A./T.A. ratio (B.C.: base case; S.F.: short flame; L.F.: long flame)

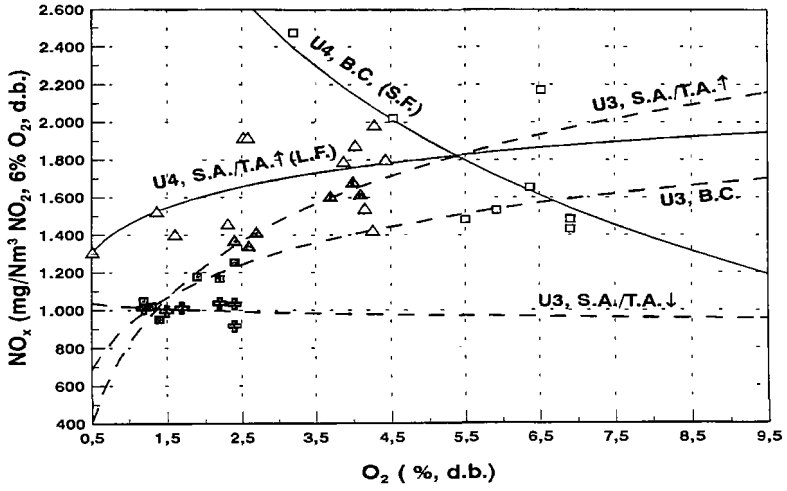

Figure 10: NO_x/O_2 burners arch relationships for Units 3 & 4 when modifying the S.A./T.A. ratio (B.C.: base case; S.F.: short flame; L.F.: long flame)

The following features could be established from the analysis of these data:

NO_x emissions are around 1700 mg/Nm^3 for Unit 4 (at 4,1% O_2), whereas these values are significantly lower for Unit 3 (1000–1400 mg/Nm^3) for an oxygen excess of 4,6%.

S.A./T.A. ratios are much lower in Unit 3, although substantial variations in air dampers openings are applied. The combined effect of this factor and the longer distance for T.A. supply in this unit seems to produce a higher degree of combustion stratification, as it can be concluded from the lower NO_x emissions and higher ash unburnt levels for Unit 3. In this sense, refractory extension and specific furnace volume seem not be the key parameters to explain Units 3 & 4 differences, as furnace average temperatures are similar (lower variations than those determined by the slagging influence). Significant effect of other factors like coal fineness or oxygen excess might also be discarded as they would determine a contrary trend of NO_x and unburnt results.

Increasing the S.A./T.A. ratio in both units produces a reduction in desuperheating spray flows, which positively affects to turbine efficiency and, therefore, to unit heat rate. This reduction is due to the higher heat exchange in the lower furnace.

Increasing the S.A./T.A. ratio seems to determine a less stratified combustion process in Unit 3, as NO_x emissions are higher and ash unburnt is lower in these conditions. These relationships are the opposite for Unit 4, most likely due to the very different air supply patterns of this unit, with T.A. addition much nearer the burners tips. This fact produces short, intense, and temperature controlled flames when the T.A. flow is high (base case), whilst, for lower T.A. supplies, flames tend to ocuppy the lower furnace, with an increasingly stratified supply of oxygen.

Increasing the S.A./T.A. ratio has a positive effect on heat rate for both units, although this influence is much lower in Unit 4, where the higher unburnt levels in this condition give rise to a penalization in boiler efficiency.

5. Economic implications

The economic implications of the results obtained in Phase I (Units 4 & 5) are very important.

The current costs of reducing NO_x levels (taking into account operating costs as well as investment write–off) to a level similar to that attained in these units (by around 30%) are approximately $400 per ton of NO_x eliminated. This cost corresponds to using primary measures according to the most recent evaluations published around the world.

If it were necessary to use secondary measures, this cost would be increased by about $2,000 per ton of NO_x eliminated.

Nevertheless, the expectations arising from the RNA Project indicate that it is possible to attain the above–mentioned reduction in NO_x emissions in anthracite – burning boilers without the need to make any additional investments, and even with a reduction in operating costs, that for Compostilla Units 4 & 5 might be evaluated in 200 $/Tn NO_x eliminated (1,400,000 $/year).

On the other hand, results obtained in Phase II (Unit 3) show the importance of air distribution design for NO_x emissions control in arch-fired furnaces. Additionally, the significant variability of NO_x emissions and unit heat rate, depending on air supply configuration, permits to operate this boiler according to different criteria: minimisation of heat rate, minimisation of heat rate for NO_x emissions below 1300 mg/Nm^3, minimisation of NO_x emissions, etc. These strategies might be decided on the base of the economic implications, in each case, of heat rate optimisation and NO_x control.

6. Conclusions

The fundamental conclusions arising from the results of the RNA Project are:

- They demonstrate the possibility of reducing NO_x emissions in arch-boilers consuming anthracites by approximately 20 - 35%, using only primary measures. This would represent for Compostilla Units 4 & 5 the possibility of achieving the 1300 mg/Nm^3 NO_x limit, without applying secondary measures.

- They demonstrate the compatibility, in some cases, of this said reduction in emissions with the attainment of noticeable improvements in units heat rate. These improvements are obtained by moving away from standard operating criteria aimed at reducing ash carbon contents to a minimum, and using long flame types of combustion and lower excess air, thereby improving the net performance of boilers and turbines.

- They also demonstrate the importance of air distribution design for NO_x control and heat rate improvement, with regard to the operating modifications to be implemented for these aims.

7. Acknowledgements

The authors gratefully acknowledge the financial support of OCIDE, OCICARBON and ECSC. They would also like to thank ENDESA for granting permission to publish this paper.

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Monday, August 25; 3:30 p.m.
Parallel Session C:
Low-NOx Systems for Gas/Oil-Fired Boilers

DEVELOPMENT, TEST AND INDUSTRIAL APPLICATION OF ADVANCED LOW NOx BURNERS

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Abstract

Over the last decade Ansaldo Energia and ENEL have worked closely to implement power plant NOx Control Technologies which have subsequently been applied both in Italy and abroad in over 20,000 MWe. Among the different technologies, which include air and fuel staging, a major role is played by the use of Low NOx burners. Ansaldo Energia and ENEL have developed and patented an oil/gas LNB, named TEA (Three-stream ENEL-Ansaldo) which has shown excellent performance and reliability in over 3,000 MWe. Further improvements have led to the development, testing and qualification of a new product, named TEA 2, characterized by lower pressure drop, higher NOx reduction, simplified mechanical design.
This burner is now the reference product for all ENEL and Ansaldo Low NOx retrofits.
A coal/oil version of this burner, named TEA C, has also been developed and has shown outstanding NOx reduction capability, in the order of 50÷55% with respect to the original circular burners emission with simultaneous good control of unburned carbon in fly ash.
The paper outlines the design philosophy of these burners, the qualification tests and the industrial applications.

Introduction

The use of LNB's as a NOx control option is well established and, in the USA, has been specified in the legislation. LNB's can be used as the sole NOx control method or as part of more sophisticated combustion modifications which range from OFA to Reburning.
ENEL and Ansaldo have long been involved in a cooperation program to develop both LNB's and combustion systems capable of satisfying the strict Italian legislation limits that, for plants rated more than 500 MW_{th}, are NO_x<200 mg/Nm^3 corrected at 3%O_2 for oil and gas and at 6% O_2 for coal.

The first LNB model named TEA 1, suitable for firing oil and gas, was developed by Ansaldo and ENEL in 1990. Details of the development program can be found in Ref. (1).
Extensive plant experience (see Table 1) confirmed a NOx reduction greater than 50% in comparison with the pre-retrofit values without significant increase in CO and particulate emissions, but also showed the possibility of introducing further improvements among which:

- reduction of pressure drop between windbox and furnace to obtain a product requiring lower ID fan head, and therefore smaller size of the pressure parts openings (compatible with the pre-retrofit ones);
- simplification of mechanical design, reducing the moveable parts, and also reducing manufacturing costs;
- additional NOx reduction;
- inherent possibility of adjusting air balancing among the different burners.

An improved version of TEA, meeting the above goals, named TEA MK2, has been developed and has replaced TEA 1 as the reference product of ENEL for all environmental retrofits of its plants. Details of the development program and of the burner design are reported after.
At the same time a new burner for coal and oil, named TEA C, was also developed to meet the upcoming needs of ENEL for Low NOx retrofits of its coal fired plants. This burner has taken advantage of the optimization of the aerodynamic structure of TEA MK 2 for oil and gas, so that secondary and tertiary air registers are common, in their basic design, for both versions.
Extra effort has been devoted to the design of a coal nozzle capable of providing not only NOx reduction but also the unburned carbon control. The development and qualification of this burner is also described.

T.E.A. MK2 - An Improved Version of T.E.A. Low-NOx Burner

General

In improving the design of the oil/ gas burner TEA, the same kind of approach already employed for the development of the MK1 version was followed. The flame's aerodynamic structure was improved, with the aim of further staging combustion, obtaining at the same time a mechanical simplification in order to reduce the construction costs.
The new burner configuration was defined by a theoretical and experimental approach based on the use of mathematical modeling, fluid-dynamic characterization of isothermal models and the use of various experimental furnaces to optimize the combustion behavior.
The most modern software and hardware tools were employed for theoretical studies while, for the experimental tests, the ENEL plants of Livorno and S. Gilla (CA) and the Ansaldo pilot plant of Gioia del Colle (BA) were utilized.

Base studies - Near Field Aerodynamics and Mathematical Modeling

Based on plant experience some assumptions have been made that suitable near field aerodynamics would have allowed improvement of the combustion efficiency, increase burner turn-down and possibly reduce NO_x. In the mean time a significant reduction of pressure losses could be obtained using fixed high efficiency swirlers in lieu of the spin vanes. The conversion of the tertiary air entrance from radial to axial could allow the use of a single barrel to regulate the entire flow of combustion air to each burner.

Preliminary full scale (35 MW_{th}) single burner tests on a TEA MK1 model, run in S. Gilla ENEL test plant, showed that modification of the burner front could achieve substantial improvement in terms of residual oxygen and even NOx reduction.
A comprehensive program was therefore started to examine the behavior of different burner exit plane geometries, versus calculated (FLUENT code) and measured (laser velocimetry) flow field. A good correlation was found between the data obtained with these techniques. Fig. 1 provides an example of the measured velocities for a given geometry.
The measurements have been performed on the ENEL CAUX-F cold flow test rig (2).

Base studies - Atomization

A significant amount of work has been devoted to atomization studies aimed to select the best atomizer for burner performance.
Tests have been run on the ENEL test rigs named ISA and ATOMO 1 in Livorno (3). Specific atomizer designs have been developed among which a "twin hole" atomizer capable of producing in-flame fuel staging.
A set of atomizers is available for use on the MK 2 for specific application i.e. maximizing unburned particulate control.

Tests at S. Gilla on a modified TEA MK 1

A modified TEA 1 burner, incorporating modification of burner front, the change of secondary and tertiary spin vanes to high efficiency swirlers, and the use of innovative atomizers, has been extensively tested at S. Gilla Large Burner Test Facility (4) (fig. 2), allowing the following conclusions to be drawn:

- atomizing quality was a parameter of paramount importance for both NOx reduction and residual O_2 control;
- the expected burner pressure reduction was achievable with the use of high efficiency swirlers;
- further NO_x reduction under oil firing, in respect to TEA 1, could be obtained acting on the primary air impeller.

These conclusions were the guidelines for the TEA MK 2 design.

TEA MK 2 Prototypical Design

A prototypical design of TEA MK 2 burner has been prepared following these guidelines:

- flow areas and exit geometry for primary, secondary and tertiary air have been maintained as per model TEA 1 to preserve the same near field aerodynamic profile;
- registers and swirlers have been changed to get the goals of lower pressure drop, manufacturing simplification and increase of the setting capability of the burner.

In detail, the following changes have been made (see fig. 3):

- use of a single barrel register controlling the entire air flow supplied to the burner;
- change of tertiary air inlet from radial to axial with compound profile and in fixed position;
- modification of secondary air swirlers in fixed compound profile with a second moveable part to allow some modification of the swirl with a reliable mechanical drive;
- design of a special primary air swirler as defined in previous cold tests on the CAUX-F test rig.

This prototype has been tested at S. Gilla firing oil and, after some further optimization, was frozen in design and finally tested at Gioia del Colle firing both oil and gas.

S. Gilla full scale combustion tests

The first prototype of the TEA MK 2 full scale burner has been tested in S. Gilla beginning in December 1994. The tests have been carried out, mainly firing oil, leaving the conduction of gas firing tests to Gioia del Colle.

The tests allowed the optimization of burner geometry with particular reference to:

- angle of deflector located between secondary and tertiary air;
- geometry of secondary and tertiary swirlers;
- geometry of primary air impeller.

Fig. 4 shows the comparison of the results obtained at S. Gilla with TEA 1, TEA MK 2, and a barrel burner having the same thermal capacity.

It can be noted that the capability of NOx reduction obtained with the TEA 1 (about 50% in respect to barrel burner) has been further improved in the MARK 2 version.

CO emissions of the two versions are similar, even though they are higher for the latter, confirming that the price to pay for a significant reduction of NOx corresponds to a slight increase of final O_2.

It should be pointed out that the S. Gilla test rig is characterized by a furnace temperature notably lower than that encountered in power plants, because the tests are performed at a burner load of about 50 MWth, that is at 50% of the boiler load. For the same reason, the residence time is also higher.

Measured values of air flow rate vs. burner pressure losses show that, in respect to the version MK 1, the TEA MK 2 burner is characterized by pressure losses at least 30% lower.

Gioia del Colle combustion tests

The combustion tests were performed at Gioia del Colle utilizing a 48 MWth furnace, designed to have the same residence time, and partially refractory lined in order to have the same exit gas temperature of industrial power plants.

These tests aimed to replicate oil firing tests and also to investigate the gas firing conditions.

Oil firing Combustion Tests. During the tests, some differences have been encountered between the results obtained at S. Gilla, making a further optimization of the burner geometry necessary. The best results, reported in fig. 5, have been obtained with an atomizing angle of 80° and 90°

Comparing these data with those obtained in S. Gilla, one can find the same trend, with a substantial equality in terms of NOx emissions, that appear slightly improved in the MK 2 version.

Gas Firing Combustion Tests. The results obtained in gas firing combustion tests are synthesized in fig. 6. The various curves correspond to different orientations (clockwise, counterclockwise) of the gas spuds.

The best results in terms of NOx vs. smoke point have been obtained with gas spuds oriented radially with respect to the burner axis.

The influence of flue gas recirculation (gas mixing) on emissions is shown in fig. 7; one can see that the decrease of oxygen concentration at the windbox (that is an increase of flue gas recirculation) leads to a dramatic reduction of NOx emissions, without significant increase of smoke point.

Orimulsion Combustion Tests. The results obtained during the combustion tests with Orimulsion are summarized in fig. 8. These tests have demonstrated the full ability of the burner to operate with this particular kind of fuel with limited NOx emissions (utilizing EPT V-

Jet atomizers, Ref. 5), or with higher emissions, but much lower oxygen concentration, utilizing PG F-Jet atomizers (Ref. 6).
The burner is therefore qualified and available on the market for this kind of fuel.

Pressure Drops. As a result of further modifications to the burner, the resulting pressure drops measured at Gioia del Colle were even lower than those encountered at S. Gilla, with a reduction of 37% in respect to TEA MK 1.
This fact is extremely important because, under the same nominal burner rate, it allows the reduction of the quarl diameter, allowing in most cases the burner retrofit in the existing openings without any modification to the pressure parts.

Development of TEA C

General

Low NOx burners currently on the market are valid products, although far from having exploited all NOx reduction potential included in their concept. NOx values that can be obtained are in the order of 600-800 mg/Nm^3 @ 6% O_2 in conditions of boiler operability, i.e. without impairing other essential values like CO and UBC. These values in Europe are over the admissible limits whereas in other countries like USA, limits are under revision in view of attaining significantly lower values than those accepted today, thus requiring the use of retrofits with more sophisticated technologies like air or fuel staging.
Further development of LNB's is therefore needed in the power industry especially for coal LNB's which represent the most difficult exercise. To properly address the problem it must be remembered that the aerodynamic flow conditions needed in a Low NOx coal burner should be such as to obtain maximum volatile release in flame zones with low oxygen partial pressure, also to obtain release of organic nitrogen. This lack of oxygen in the primary combustion zone endangers combustion and ignition velocity thus provoking the increase of unburned carbon in the ashes collected in the ESP (the Italian maximurn values of UBC for ash recovery-cement industry is 7% expected to be 5% in future regulations).
Published studies and direct experience of both ENEL and Ansaldo, show that the segregation of coal particles along the burner axis as a function of their granulometry and their feeding into the most appropriate flame zones allow significant NOx reductions with simultaneous control of unburned carbon. ENEL and Ansaldo have therefore started a development program to provide a coal/oil "Low NO_x" type burner characterized by a NOx reduction capability in the order of 50%, compared to circular burners (same order of magnitude of TEA oil/gas), but also capable of maintaining low UBC levels.
The product design goal has been defined as NOx < 650 mg/Nm^3 @ 6% 02 with UBC less than 7% when burning a medium volatile bituminous coal (i.e. South African). The work development followed the logic reported below:

- analysis of the products on the market (bibliography; analysis of existing plant data; performance analysis etc.);
- numerical-analysis (isothermal simulation of coal nozzles);
- cold physical modeling of the coal nozzle using the ENEL CONOS test rig (quantitative analysis of coal particle distribution with different coal nozzles designs - comparison to numerical analysis data);
- conceptual design of the new burner;

- small scale and full scale combustion tests (33 MW_{th} at Ansaldo Combustion Centre of Gioia del Colle);
- long-term performance tests at the ENEL Test Station in S. Gilla (~40 MW_{th})

Analysis of the Products on the Market

Work began with a review of the U.S. market, which showed a large presence of Low NOx retrofit applications diversified in type and number of Low NOx burners installed alone or coupled with other systems like OFA.
This reviewed showed some characteristics common to the different burners designs:

- two external air flows to control the flame shape and consequently the mixing between fuel and air as the prime factor for NOx control (staged combustion);
- independent controls for swirls and for total air flow;
- use of simplified air registers to improve mechanical reliability and to reduce pressure drops;
- special coal nozzles which allow segregation of coal and primary air to obtain a localized staged combustion;
- operational flexibility and possibility of field regulation of the burner critical parameters (flame shape, combustion efficiency, NOx).

All these aspects have been examined and addressed in the new burner design leading to the final design choices.

Burner Structure

The burner prototype includes the external geometry of the oil/gas TEA MARK 2 burner and has a newly developed coal nozzle located in the primary duct.
The secondary and tertiary air registers had already been studied in-depth during the TEA MK 2 (oil/gas) burner development. The results obtained provided a good understanding of the problem and the necessary know-how to interpret the experimental results and transform them into the design of the TEA -C. It was thus possible to rationally reuse the same air registers of TEA MK2 for TEA-C and only change the different coal nozzles selected as best candidates from numerical and physical modeling. The burner (fig. 9) became modular (together with TEA MK2) and standardized, thus providing margins for cost reduction and retrofit application.

Numerical Analysis

Following the published data and market analysis, an in-depth numerical 3D analysis of the different coal nozzles was performed using the FLUENT code.
The results constituted the basis for the conceptual design of the new coal nozzle and also allowed to gain valuable information from the hot full scale tests run both in Gioia del Colle and in S. Gilla. Both numerical and physical (see next paragraph) modeling provided good correlation in terms of velocity profiles and coal concentration.

Cold Physical Modeling

It has already been noted how coal segregation at burner level as a function of its fineness is of paramount importance to obtain NOx reduction and simultaneous unburned control. Consequently physical modeling has been considered necessary to confirm numerical data. An "ad hoc" test rig, located at ENEL laboratories in Livorno named CONOS, was developed and used. The rig was originally designed for calibration of innovative coal flow measuring

devices; it has been redesigned and adapted for the study and characterization of the different primary ducts, in particular for evaluating the influence of the coal pipe internals.
Fig. 10 reports a typical result in terms of effective coal distribution at the burner exit.

Combustion Tests at Gioia del Colle

Tests at Gioia del Colle can be subdivided into two distinct phases:

- A first phase when different coal nozzles (with related internals) were hot tested using an existing burner body;
- A second phase when the TEA C prototype was tested to optimize its design.

Coal Tests. The results obtained using the existing burner body have confirmed that the coal pipe internals as well as the burner exit zone to the combustion chamber are of vital importance for low NOx and simultaneous UBC control. These tests have shown that a simple impeller located at the burner exit substantially modifies the burner performance, even for a low NOx design, and that the secondary and tertiary air registers do not quantifiably modify said performance.
First tests have been run comparing the response of a typical Low NOx burner in a high-NOx (low oxygen) configuration obtained inserting at the exit an impeller (configuration A), versus TEA C, in the same configuration. As can be seen in fig. 11 similar NOx values are reached, but a definite advantage for TEA C in terms of excess O_2. This validated the assumption made of maintaining for TEA C the same secondary and tertiary air registers of TEA MK 2.
The first Low NOx configuration of TEA-C (configuration B) was intended to provide a coal segregation from primary air by forming zones with controlled stoichiometry. Results have immediately confirmed the design assumption showing the wide capability of the burner to control its performance as a function of coal nozzle settings and coal fineness (fig. 12); with this configuration parallel NOx and UBC reduction has been obtained increasing coal fineness.
Continuing the search for a geometry capable of segregating coal and providing the best compromise between NOx reduction and UBC control, a final configuration (G) has been implemented incorporating specific coal pipe internals and an innovative nozzle at pipe exit, able to create maximum coal segregation. This was done with a device whose position in respect to the exit sections of the coal created by the particular nozzle, determines a specific local air/coal ratio.
This configuration gave the best results, especially without rotary classifier (fig 13).
Reference conservative values for standard coal fineness are:

- operational excess oxygen - 3.5%;
- NOx - 650 mg/Nm^3 @ 6% O2 (about 50% reduction);
- UBC < 7% (referred to South African Coal).

Fuel Oil Tests. No. 6 oil tests have also been performed. The configurations tested were B and G, the most promising in coal combustion. The results (see fig. 14) are in good agreement with TEA oil/gas performance and show the influence of type and position of the atomizers and of primary air flow.

S. Gilla Tests

Based on the results obtained at Gioia del Colle, a prototype TEA-C burner was designed, fabricated and installed at the test section located at the bottom of the group No. 1 of the ENEL Power Station of S. Gilla (35 MWth).

The burner has the same dimensions of the one tested in Gioia del Colle and in terms of secondary and tertiary air registers was identical to the TEA MK 2 oil/gas. Combustion tests were conducted at 120% of thermal load (40 MWe) to allow boiler operation with only the bottom burner fired. Thermal load was 1.2 times the one applied in Gioia del Colle tests.
For each burner arrangement NOx, CO, SO_2 and UBC, as a function of excess oxygen and coal fineness, have been monitored.
Initially only two configurations have been tested, the reference (A) and the Low NOx (G). In configuration A, same NOx emissions as measured in Gioia del Colle, have been found.
In configuration G, the burner incorporates the innovative coal nozzle that gave the best results at Gioia del Colle.
Long term tests on the TEA-C aimed to:

- measure the temperature of the parts exposed to flame;
- assess wear and temperature stress;
- assess time stability of the performance characteristic.

Metal Temperature. Metal temperatures have been assessed on the secondary flame holder, on one of the coal nozzles and on the deflecting flaps.
At burner' s MCR and firing coal, temperatures did not exceed 400 °C. Same temperatures were measured with additional 4 tangential burners in service to assure boiler nominal load. Firing oil at burner' s MCR, the highest temperature measured on the flaps was 600°C. At half load and with 4 tangential burners in service temperature has been measured at slightly over 800 °C.
Finally with the test burner out of service and with 6 tangential burners in service, temperature data were similar to those measured at MCR.

Wear of Components. Wear of coal nozzle is recognized as a critical factor and is due to pure mechanical wear and to synergistic action of oxidation. Due to the TEA C coal nozzle design, which provides separation of air rich and coal rich flows, the wear potential is low. This assumption has been confirmed by the tests run in Gioia del Colle where the coal nozzle was built in carbon steel and did not show any significant wear after more than 500 h of service. To protect it from the wear risk the coal nozzle is built in high Chromium refractory cast alloy whereas the deflecting cone, hypothetically exposed to temperatures up to 800 °C is made by Stellite 6 Alloy.

Time stability of performance. No problems for the start-up and operation stabilization have been detected either in S. Gilla or in Gioia del Colle.

Conclusions

TEA 2 oil/gas

TEA 2 is a mature product which has replaced TEA 1 as ENEL/Ansaldo reference product for Low NOx retrofits (LNB's; OFA and Reburning).
Table 2 provides the reference list of plants already equipped with this burner. The large experience of TEA 1 guarantees that plant performance will be fully satisfactory.

TEA C

TEA C is now the reference product of ENEL/Ansaldo for coal firing applications. TEA C is in the installation phase in four plants (Table 3) and is expected to be used shortly in at least another two. Qualification is now based on single burner tests but plant data will be available starting end 1997.

The TEA C design has also the potential of retrofitting the coal pipe and coal nozzle to coal pipes of older and unsatisfactorily performing burners. A demonstration is expected at the ENEL Plant of Bastardo (75 MWe) in early 1998.

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Tab. 1 - TEA 1

PLANT	CLIENT	PLANT OUTPUT (MWe)	BOILER/ BURNER (MWt)	CONFIGURATION / FUEL	ORIGINAL NOx (mg/Nm^3 3% O_2) (6% O2 for coal)	FINAL NOx (mg/Nm^3 3% O_2) (6% O2 for coal)	OPERATION DATE	THROAT DIAM.
MONFALCONE # 3	ENEL (ITALY)	**1 x 320**	OF - 18 x 41	LNB (1) OIL	**930**	**400**	1990	42.5"
TURBIGO # 1	ENEL (ITALY)	**2 x 240**	FF - 16 x 42	LNB OIL	--	**400**	1992	40"
CASSANO # 1	AEM MILANO (ITALY)	**1 x 75**	FF - 6 x 31	REBURNING OIL & GAS	**600**	(3) **120** (4) **80**	1994	34"
PONTI SUL MINCIO # 1	ASM BRESCIA (ITALY)	**1 x 80**	FF - 9 x 21	LNB OIL & GAS	**800** **600**	(5) **400** (3) **290**	1995	30"
BRESCIA # 2	ASM BRESCIA (ITALY)	**1 x 230 t/h**	FF - 4 x 42	LNB OIL & GAS	**800** **800**	(5) **430** (3) **275**	1995	46"
ASSYUT	EGYPTIAN ELECTRICITY AUTHORITY (EGYPT)	**1 x 300**	OF - 16 x 61	LNB OIL & GAS	--	**450 (5)**	1996	50"
MEDINA	SALINE WATER CONVERSION C. (SAUDI ARABIA) (2)	**2 x 165 kg/s**	FF - 12 x 42	LNB OIL & GAS	--	**462 (5)** **318 (3)** **expected**	1997	40"
MONTALTO DI CASTRO	ENEL (ITALY)	**2 x 660**	OF - 56 x 32	LNB+OFA+GM OIL & GAS	--	**100 (4)** **preliminary result**	1997	40"
LA CASELLA # 4	ENEL (ITALY)	**1 x 320**	OF - 18 x 41	REBURNING OIL	**950**	**400 (5) LNB only** **<200 (5,7)**	1997	42.5"
KERATSINI # 8	POWER PUBBLIC CO. (GREECE)	**1 x 160**	FF - 8 x 51	REBURNING OIL & GAS	**500 (3)**	**< 200 (5,7)** **<150 (3,7)** **expected**	1997	42.5"

1) LNB = LOW NOx BURNERS
OFA = OVERFIRE AIR PORTS
GM = GAS MIXING
2) DESALINATION PLANT
3) FIRING GAS
4) FIRING GAS WITH GM
5) FIRING OIL
6) FIRING COAL
7) REBURNING

Tab. 2 - TEA 2

PLANT	CLIENT	PLANT OUTPUT (MWe)	BOILER/ BURNER (MWt)	CONFIGURATION / FUEL	ORIGINAL NOx (mg/Nm^3 3% O_2) (6% O2 for coal)	FINAL NOx (mg/Nm^3 3% O_2) (6% O2 for coal)	OPERATION DATE	THROAT DIAM.
CASSANO # 2	ENEL (ITALY)	**1 x 320**	OF - 18 x 40	REBURNING OIL & GAS	800 (5) 650 (3)	< 190 (5,7) < 170 (3,7) expected values	1998	38"
BRESCIA # 1	AEM BRESCIA (ITALY)	**1 x 175 t/h**	FF - 4 x 32	LNB (1) OIL & GAS	750 (5)	460 (5) 280 (3)	1997	34"
LA CASELLA # 3	ENEL (ITALY)	**1 x 320**	OF - 12 x 44	REBURNING OIL	950 (5)	< 200 (5,7) expected	1997	40"
LA CASELLA # 1-2	ENEL (ITALY)	**2 x 320**	OF - 12 x 44	REBURNING OIL & GAS	950 (5)	< 200 (5,7) expected	1998	40"
SERMIDE # 1-2-3-4	ENEL (ITALY)	**4 x 320**	OF - 12 x 44	REBURNING OIL & GAS	950 (5)	< 200 (5,7) expected	1998	40"
TAVAZZANO # 5-6	ENEL (ITALY)	**2 x 320**	OF - 12 x 44	REBURNING OIL & GAS	950 (5)	< 200 (5,7) expected	1997/1998	40"
CARREGADO # 5-6	CPPE (PORTUGAL)	**2x 125**	FF - 6 x 53	LNB OIL & GAS	950 (5)	< 450 (5) < 350 (3)	1997	44"

Tab. 3 - TEA C

PLANT	CLIENT	PLANT OUTPUT (MWe)	BOILER/ BURNER (MWt)	CONFIGURATION / FUEL	ORIGINAL NOx (mg/Nm^3 3% O_2) (6% O2 for coal)	FINAL NOx (mg/Nm^3 3% O_2) (6% O2 for coal)	OPERATION DATE	THROAT DIAM.
SULCIS # 3	ENEL (ITALY)	**1x 240**	FF - 24 x 26	LNB OIL & COAL	1400 (6)	< 700 (6) expected	1997	40"
VADO LIGURE # 4	ENEL (ITALY)	**1 x 320**	OF - 24 x 35	LNB OIL & COAL	1300 (6)	< 425 (6,7) expected	1998	38"
VADO LIGURE # 3	ENEL (ITALY)	**1 x 320**	OF - 30 x 28	LNB OIL & COAL	1300 (6)	< 700 (6) expected	1998	36"
WEST JAVA	DAYALISTRIK PRATAMA (INDONESIA)	**1 x 400**	OF - 30 x 44	LNB COAL		< 650 (6) expected	2000	43.5"

1) LNB = LOW NOx BURNERS
OFA = OVERFIRE AIR PORTS
GM = GAS MIXING
2) DESALINATION PLANT
3) FIRING GAS
4) FIRING GAS WITH GM
5) FIRING OIL
6) FIRING COAL
7) REBURNING

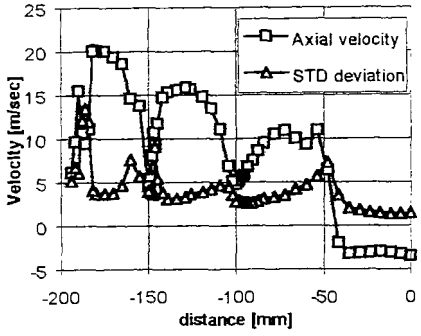


Fig. 1 - Measured velocities for a given geometry

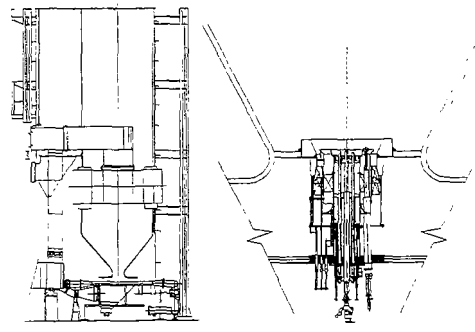
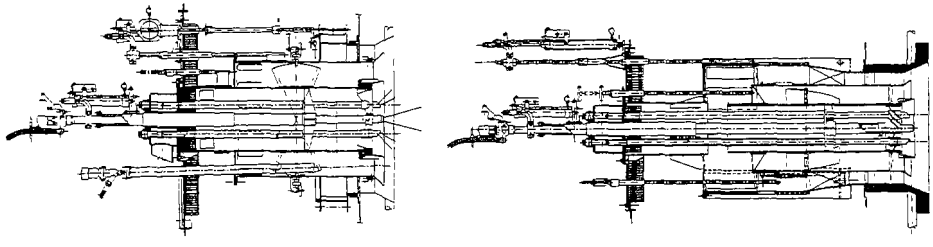


Fig. 2 - Santa Gilla Large Burner Test Facility



TEA MK 1 BURNER

TEA MK 2 BURNER

Fig. 3 - Cross section comparison for TEA 1 and 2

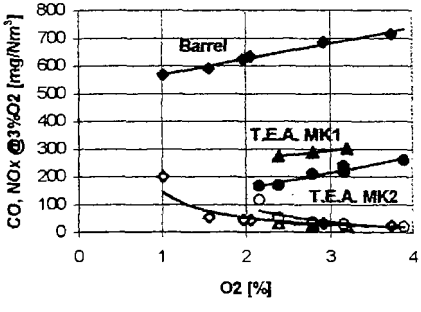


Fig. 4 - Comparison between NOx and CO emissions from TEA1, TEA2 and Barrel burners at S. Gilla

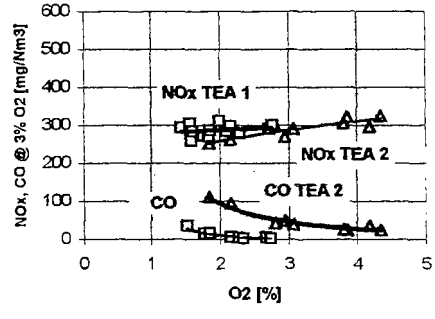


Fig. 5 - Comparison between NOx and CO emissions from TEA1 and TEA2 burners at Gioia del Colle

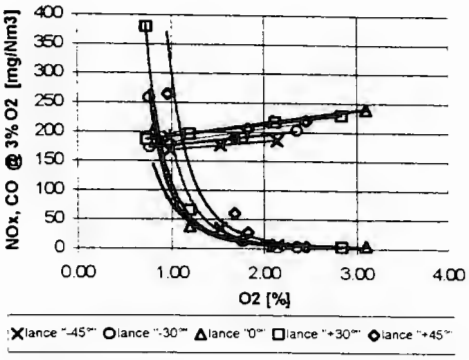


Fig. 6 - TEA2 - Gas firing with different orientation of the gas spuds

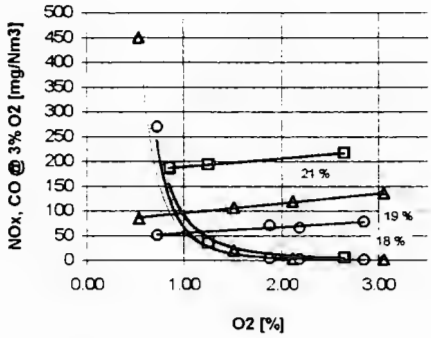


Fig. 7 - TEA2 - Gas firing - Influence of the flue gas recirculation

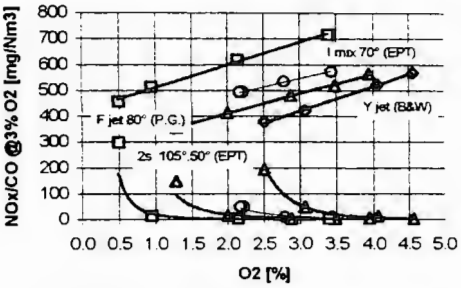


Fig. 8 - TEA2 - Orimulsion tests with different atomizers

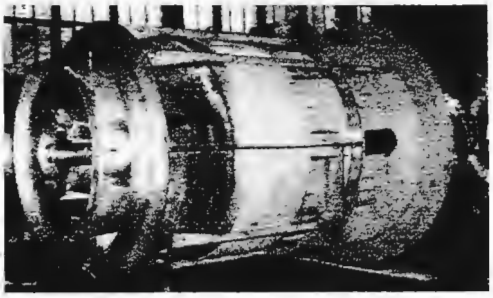
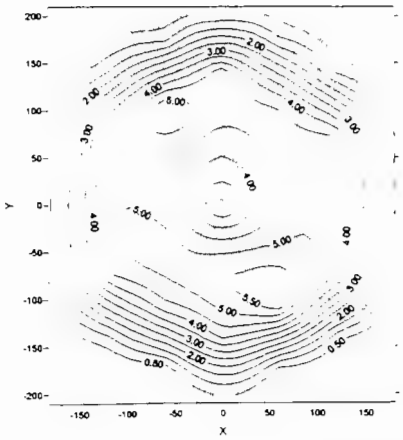


Fig. 9 - TEA C - Burner installed at Sulcis 3 (250 MWe)



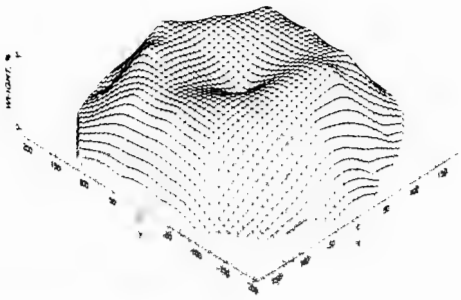


Fig. 10 - Typical results obtained with CONOS Test rig

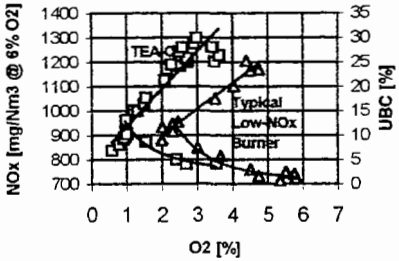


Fig. 11 - Comparison between TEA-C and a typical low-NOx burner both in configuration A

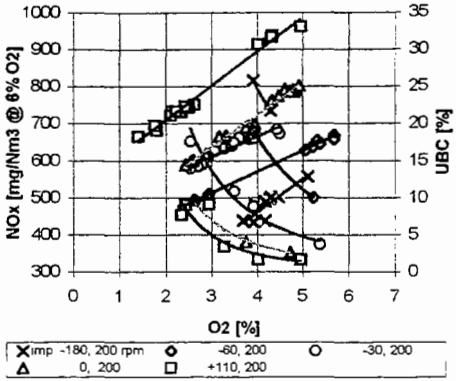


Fig. 12 - TEA-C in B configuration - Main results

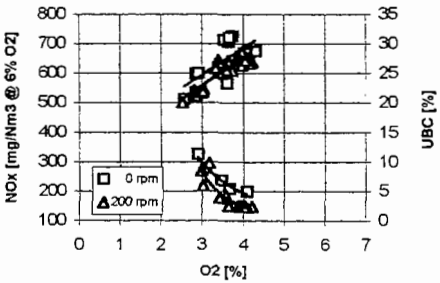


Fig. 13 - TEA-C in G configuration - Main results

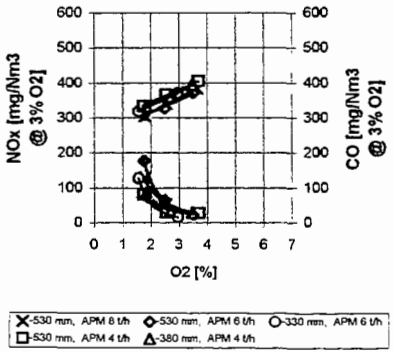


Fig. 14 - TEA-C in G configuration - Fuel oil tests

ULTRA LOW NOX OPERATION FROM A 185MW OIL AND GAS 'T' FIRED BOILER

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Abstract

Vertical air staging has been used as the principal means of reducing NOx emissions on an ultra low NOx programme being applied to the (185 MW) oil and gas 'T' fired No. 4 Unit located at Port Jefferson on Long Island. The technique, which has been given the acronym TAS (tilted air supply) was initially aimed at achieving NOx levels of 0.15 lbs/10^6 Btu, from a baseline of 0.22 lbs/10^6 Btu, when oil firing over the load range 40 - 185 MW.

Prior to the site installation the potential of the TAS NOx reduction technique was demonstrated on the full scale combustion test facility located at the International Combustion Ltd (IC Ltd) Derby, UK site, under both oil and gas firing conditions simulating the Port Jefferson No. 4 Unit operations.

The test facility demonstration was successfully translated to the site installation, meeting the NOx reduction requirements. The possibilities of further NOx reductions based on increased air staging, the utilisation of recycled flue gases and re-burn are also considered.

Plant Description

The Port Jefferson No. 4 Unit is a CE designed single drum, single cell, semi-enclosed tangentially fired boiler with four levels of steam atomised burners. Originally designed to burn bituminous coal at a MCR of 150 MW, the unit has operated on No. 6 oil since the 1960's with a MCR of 185 MW. In 1997 the burner box on a sister Unit No. 3 was modified to include close coupled over fire air (CCOFA) as an initial NOx reducing exercise targeted at NOx levels around 0.2 lbs/10^6 Btu. Based on the achievement of the targeted NOx level Unit 4 modifications were progressed using both CCOFA and TAS targeted at a 0.15 lbs/10^6 Btu NOx level.

Flue gas recirculation (FGR) is used for steam temperature control with the FGR ducted to the bottom ash hopper and the unit is also equipped with an electrostatic precipitator. A maximum particulate loading of 0.2 lbs/10^6 Btu is specified for the precipitator operation, opacity levels are typically in the 6-10% range.

The firing rate on the current fuel oil at 185 MW is 97,200 lbs/hr, superheat and re-heat steam temperatures are 1000°F and total steam flow 1,275,000 lbs/hr.

Continuous emissions monitoring (CEM) is used, as per Phase 1 of the Clean Air Act Amendments, for measurement of NOx, CO_2 and opacity levels, CO, and O_2 level measurement is also available.

NOx Reduction Technology

The original and CCOFA modified windbox arrangements are shown in Figure 1. Prior to installation of CCOFA a NOx level survey was carried out over the boiler load range 60 - 185 MW with results as shown in Table 1.

Table 1

Baseline NOx Emission Survey

Boiler Load MW	NOx Range		Mean NOx lbs/10^6 Btu
	ppm (at 3%O_2)	lbs/10^6 Btu	
60	245 - 265	0.33 - 0.36	0.345
90	210 -260	0.28 - 0.35	0.315
150	230 - 260	0.31 - 0.35	0.330
185	215 - 245	0.29 - 0.33	0.310

Following the provision of CCOFA, on Unit 3, the NOx level, at 185 MW was measured at 0.22 lbs/10^6 Btu, which represented an approximate 30% reduction in NOx compared to the pre-CCOFA modification NOx level.

The arrangement of the windbox and burners in the Port Jefferson No. 4 Unit, comprising essentially of four plenum chambers, each housing a central burner with upper and lower air nozzles with individual auxiliary air nozzles between the plenums, offered a ready adaptation to the TAS system, developed by IC Ltd in order to achieve further NOx reductions in 'T' fired boilers. The TAS system requires axial displacement of the upper and lower air nozzles in the plenum chamber away from the centrally located oil burner axis. Figure 2 showing NOx reductions achieved by applying TAS to a 'T' fired simulation in the IC Ltd combustion test facility demonstrates the potential of this technology.

Reduced burner and combustion zone stoichiometry is also an essential feature of low NOx technology, but can be a potential cause of boiler tube deterioration arising from local reducing atmospheres. To minimise this effect the auxiliary air nozzles were modified to effect their air flow in the horizontal plane in order to create an air rich atmosphere adjacent to th boiler tube walls. This offset air augments the vertical air staging effect of the TAS system and is therefore a further aid to Nox reduction.

Future requirements on Unit 4 also included natural gas firing up to 100% MCR load and therefore a gas burner was combined with the central oil burner housed in each plenum chamber.

This total system was then demonstrated on the IC Ltd Combustion test facility.

Test Rig Demonstration of the TAS Low NOx System

The IC Ltd test rig is a full-scale single burner horizontally fired facility. As such it cannot fully represent the central fireball of the 'T' firing system but can usefully represent ease of ignition, flame stability and effects of near burner conditions on emissions utilising a burner cell representative of the 'T' fired situation, as illustrated in Figure 3. This shows the centrally located fuel gun with its upper and lower air nozzles, all set horizontally in their plenum chamber, offset air nozzles are located at the top and bottom of this arrangement as per the boiler situation. Some leakage air, remote from the cell, was admitted to the test rig from the windbox in order to represent the effects of CCOFA. A basic steam atomised 'F' jet oil burner was used in the test work, Figure 4, and atomiser angles, (A in Figure 4) in the 60° - 90° range were studied, together with a fuel staged design created by clustering of the atomiser discharge orifices.

As each pair of TAS nozzles and the burner were fed by combustion air from a common plenum chamber a variety of oil burner air swirlers were used to optimise the air flow through the oil burner and to be compatible with the oil spray characteristics. The gas burner arrangement comprised central spuds close to the swirler hub to provide good pilot flames and flame stability. The majority of the gas was supplied through spuds located behind the swirler. Figure 5 shows the emission results from the optimised burner build firing oil on the test rig. These showed NOx in the 0.12 - 0.14 lbs/10^6 Btu range with CO under control down to 1.5% excess O_2. Under similar conditions the NOx levels when gas firing were in the 0.03 - 0.05 lbs/10^6 Btu range.

The required turn down ranges of 3.1 were readily demonstrated with this burner system.

During the development work the effect of oil temperature on NOx levels was tested with a range of oil temperatures from 230°F - 290°F (110°C - 143°C). With an early burner build a NOx reduction was indicated as the oil temperature increased. However, this NOx reduction did not materialise with the optimised burner build with compatible atomiser, air swirler and fuel compartment air flow.

The general conclusion from the test work was that the optimised burner system would achieve the required NOx level of 0.15 lbs/10^6 Btu on the Port Jefferson boiler and be compatible with the other operating requirements of less than 150 ppm CO and maximum particulate levels into the electrostatic precipitator of 0.2 lbs/10^6 Btu.

Site Installation

Oil Firing

Figures 3 and 6 show diagrammatic fuel compartment and detailed windbox arrangements of the site installation respectively. The fuel compartment upper and lower air nozzles were existing and therefore retained in the low Nox windbox arrangement. In a TAS system it is usual to build in a certain degree of tilt in the fuel compartment air nozzles minimising the differential tilt which has to be applied by the modified burner box tilting mechanism. In order to achieve the required tilt without interfering with adjacent components the burner nozzle geometry was altered sightly but this was shown not to affect the NOx performance of the system as demonstrated in the combustion test facility.

Based on the rig work the prediction was that site NOx levels would be in the 0.13 - 0.15 lbs/10^6 Btu range when oil firing, from a baseline NOx level of 0.22 lbs/10^6 Btu, representing an average 36% reduction in NOx. The site NOx levels achieved on oil firing are shown in Table 2 and are compared with the unmodified (baseline) NOx levels over the boiler load range 40 185 MW. These NOx levels were achieved with CO levels below 10 ppm up to 130 MW load and 10 - 15 ppm CO at 100% MCR. Superheat and re-heat temperatures at full load were reported as 1003°F and 990°F respectively. On this bases the site NOx levels achieved represent a 1 : 1 site to test facility NOx level factor.

Opacity levels were in the 5 8% range and particulate emissions during a controlled 100% MCR operating period were measured at 0.13 lbs/10^6 Btu with a NOx level recorded at 0.133 lbs/10^6 Btu, with CO at 36 ppm. All these figures were within the guarantee and site operating requirements.

Table 2

Site NOx Emissions - Oil Firing

Boiler Load MW	NOx(lbs/10^6 Btu)		
	Baseline	CCOFA Mod.	TAS & CCOFA
40			0.15
60	0.35		-
70			0.14
90	0.32		
100			0.12
130		-	0.13
150	0.33		-
180	0.31	0.22	0.14

Gas Firing

The test rig results on gas firing are shown in Figure 7 which indicates NOx levels of 0.04 ± 0.01 lbs/10^6 Btu, depending upon excess air, OFA and TAS arrangements. The high CO levels recorded in the tests would not be expected to be repeated on site and result from the absence of the 'fireball effect' in the test facility.

Figure 8 shows the gas burner arrangement in the fuel compartment of the burner test cell, this inner/outer spud configuration was found to give the more stable gas flame condition during the test rig burner development work.

Site gas firing has not yet been fully optimised but is reported to give NOx levels in the 0.09 - 0.11 lbs/10^6 Btu ranges over boiler levels 66 - 185 MW. On this basis the NOx figures represent an approximate 2 : 1 relationship between site and test rig facility NOx levels, compared with an approximate 1 : 1 achieved with oil firing. Higher site to rig ratios always result with increased thermal NOx generation within the boiler system.

Table 3 shows typical NOx results when gas firing.

Table 3

Site NOx Emission Gas Firing

Boiler Load MW	NOx lbs/10 Btu	CO pm	0_2%
66	0.09	3	4.9
91	0.09	4	2.6
185	0.11	183	0.4

No guarantees were attached to the design for gas firing at Port Jefferson, but the target should be 0.1 lbs/10^6 Btu with a maximum 150 ppm CO. This may be achieved by some fuel biassing within the burn box. Under all conditions the gas burners are reported to operate satisfactorily with good flame stability.

Further Options for NOx Reductions at Port Jefferson

The application of multiple technologies to achieve NOx reductions is subject to the law of diminishing returns. However, the results so far indicate that there is scope for further reductions in NOx at Port Jefferson.

Further optimisation of the CCOFA air staging would probably achieve a further 5 - 10% reduction of NOx, based on the levels already reported. As recycled flue gas (RFG) is ducted to the boiler hopper bottom for steam temperature control this could be usefully redirected with the burner system either bulk-mixed with the combustion air or specifically targeted around the fuel jets, a further 10 - 20% NOx reduction could result from this technique.

Depending upon the site fuel economies a permanent co-firing natural gas/fuel oil requirement could be established and NOx levels would be pro-rata to the natural gas utilised over the 0.09 - 0.14 x lbs/10^6 Btu optimises NOx range for the individual fuels.

Further fuel and air staging within the boiler could probably be used with effect in achieving significant NOx reductions. These would include biassed firing, particularly with natural gas. Other techniques which could be considered are displacing some of the combustion air from the windbox as separated over fire air (SOFA). This would allow low stoichiometry conditions (conducive in NOx reduction) to persist for a longer period within the boiler. The CCOFA SOFA balance would be used for CO and carbon in particulate control. An overall NOx reduction, on the optimised TAS system, of 10 - 20% could be expected from this technique which would require the SOFA system to handle 20 - 25% of the total combustion air supply to the boiler. A combination of RFG with SOFA has a potential for 20 - 30% NOx reduction.

A re-burn system in which both fuel and air are displaced from the main burner box could also be considered. Around 20% fuel (ideally natural gas) would be deployed in the re-burn system augmenting the low stoichiometry effect

immediately after the main burner system in the boiler. SOFA would be deployed higher in the boiler to compact combustion. On the optimised low NOx TAS system re-burn would probably effect a further 30 - 35% reduction in NOx.

The potential NOx reduction from these techniques is summarised in Table 4. SOFA and re-burn systems would be more costly as further boiler penetrations are required to accommodate the displaced air and fuel nozzles. The system fan capacities and windbox pressures would require consideration before recycled flue gas is deployed in order to effect NOx reductions.

Based on the above assumptions the indication is that combustion modification technologies are available which may enable 0.1 lbs/10^6 Btu NOx to be approached when oil firing above without recourse to chemical injection or catalytic techniques. If 0.1 lbs.10^6 Btu is the aim irrespective of fuel then co-firing or 100% gas firing depending on fuel economies, is the obvious route.

Table 4

Summary of Further Potential NOx Reduction Options

Option	Potential NOx Level (lbs/10^6 Btu)		Remarks
Co-firing Oil and Natural Gas	NOx range 0.14 - 0.09 Pro-rata with natural gas utilisation		Option of co-firing in same burner or via separate burners. Biassed firing with 100% natural gas.
	Oil	**Gas**	
RFG or SOFA	0.11 - 0.125	0.07 - 0.075	RFG ducted into windbox air supply, system pressures permitting
RFG and SOFA	0.10 0.11	0.065 - 0.07	
Re-burn	0.01 - 0.10	0.055 - 0.065	Natural gas as re-burn fuel

Conclusions

The (TAS) tilted air supply system, as demonstrated on a full-scale test facility, indicated a potential for 50% reduction in NOx from this in windbox air staging technique.

Applied to a 185 MW oil and gas 'T-fire boiler a 36% NOx reduction was obtained from a system based on air staging incorporating close-coupled over fire air (CCOFA) when oil firing.

NOx levels, when oil firing, were between 0.13 - 0.15 lbs/10^6 Btu over the boiler load range from 40 - 185 MW (21 100% MCR) from a full load baseline NOx level of 0.22 lbs/10^6 Btu. CO levels were below 40 ppm superheat and reheat temperatures at full load were 1003°F and 990°F respectively.

Opacity levels were recorded between 5 - 8% with particulate levels of 0.13 lbs/10^6 Btu at 100% MCR burner load.

The low NOx system met guaranteed performance levels in all respects.

An optional natural gas firing system has indicated potential NOx levels of 0.09 ± 0.01 lbs/10^6 Btu subject to further confirmation and burner optimisation.

Co-firing of oil and natural gas offers potential for 100% MCR boiler operation with NOx emissions in the 0.08 - 0.14 lbs/10^6 Btu range depending on the level of natural gas utilisation.

NOx reduction techniques based on further air staging (SOFA), targeted recycled flue gas or re-burn utilising natural gas offer the potential for operations at or below the 0.1 lbs/10^6 Btu Nox level.

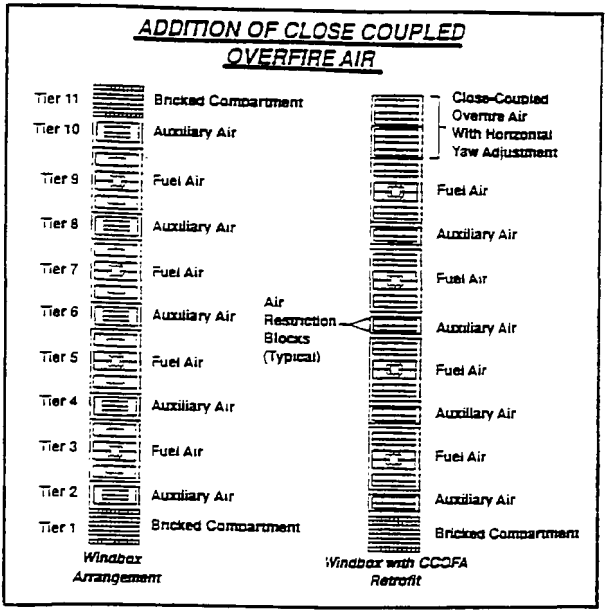

Figure 1.

Original and CCOFA Modified Windbox Arrangements.

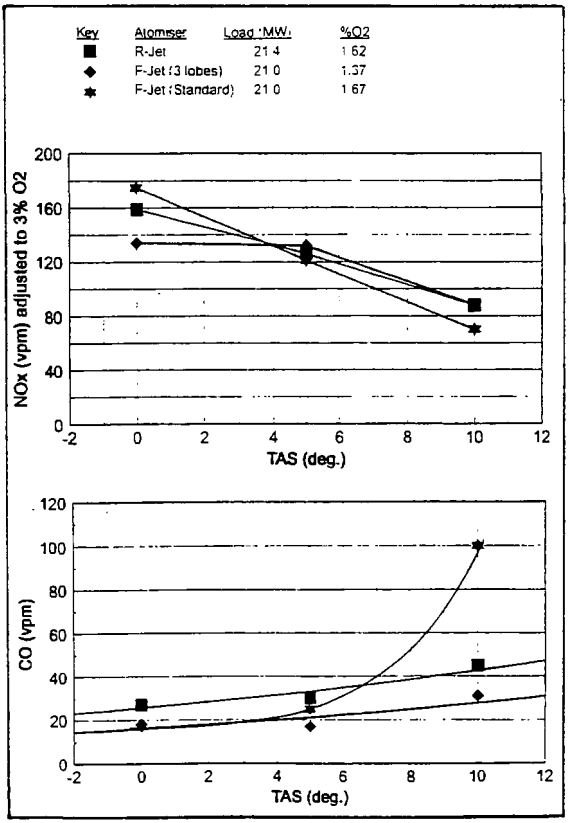

Figure 2.

NOx Reduction Potential of TAS Technology

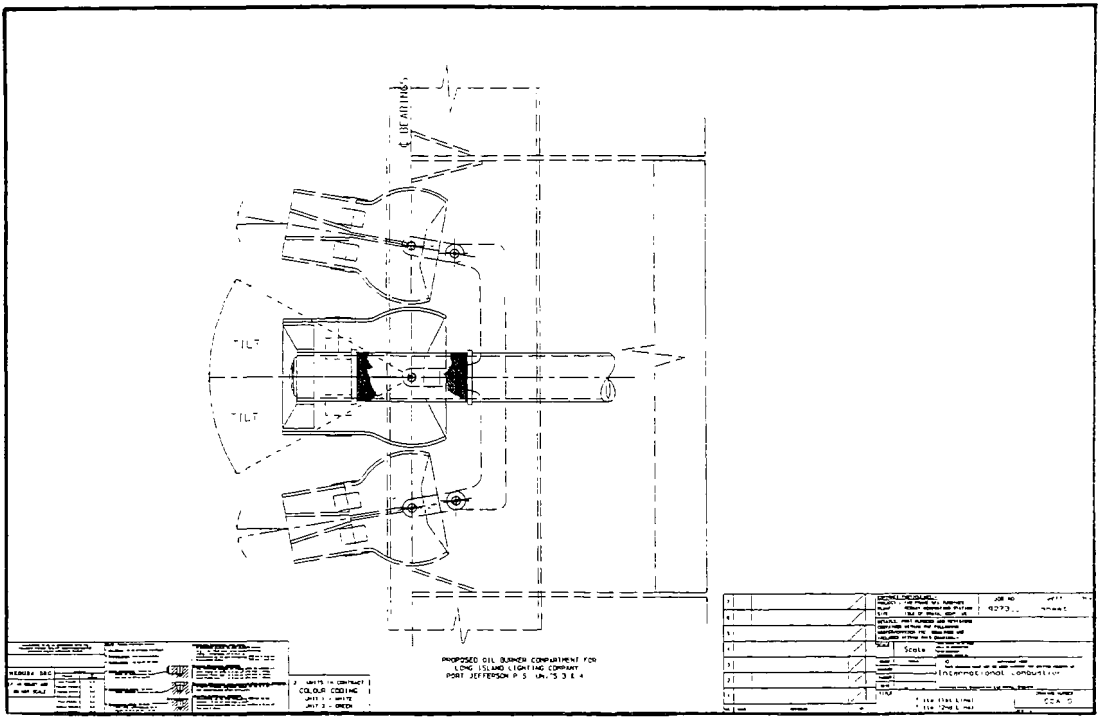

Figure 3.

Test Cell for Oil Firing.

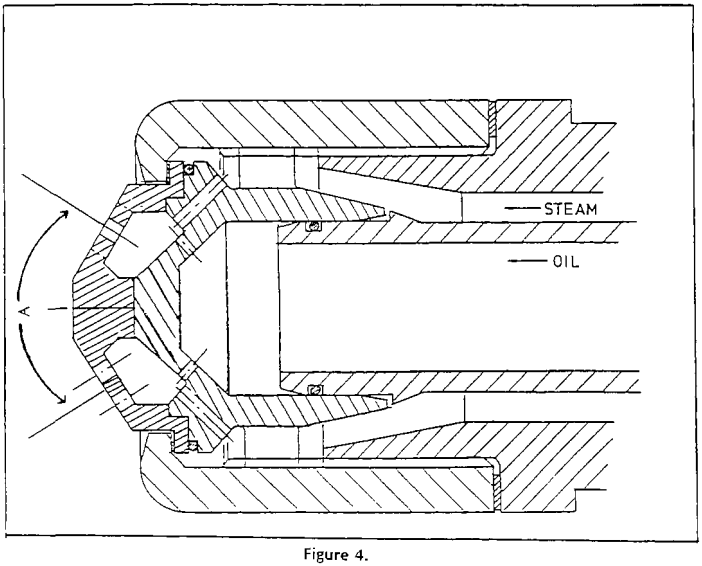

Figure 4.

F-jet Atomiser.

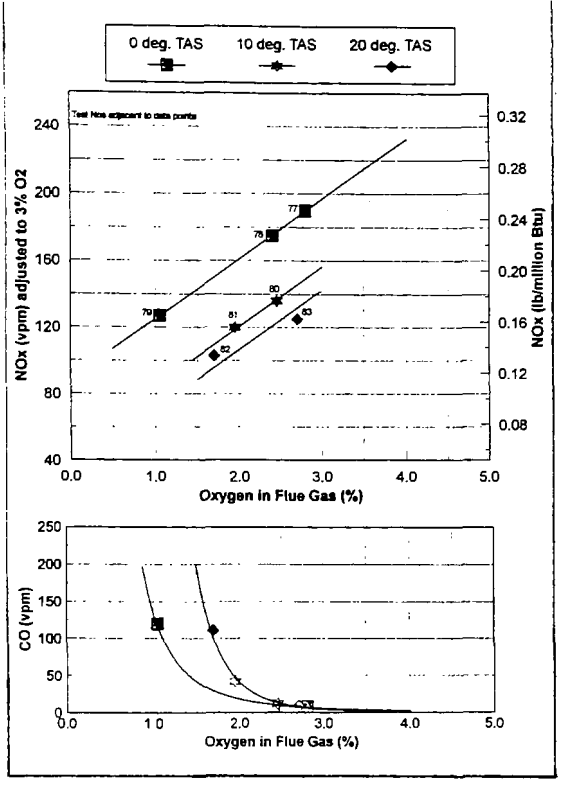

Figure 5.

LILCO Oil Firing Trials NOx and CO Emissions.

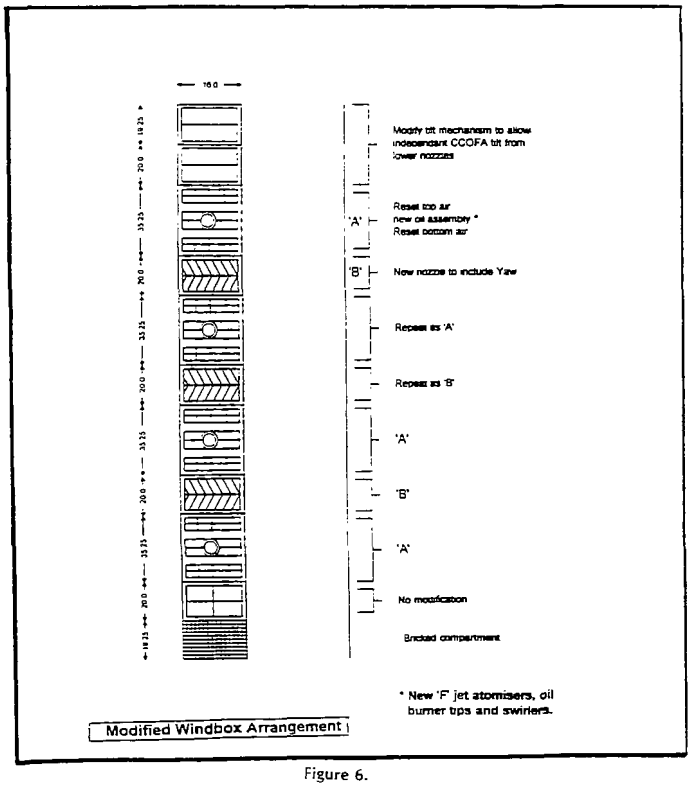

Figure 6.

Site Low NOx Windbox Arrangement.

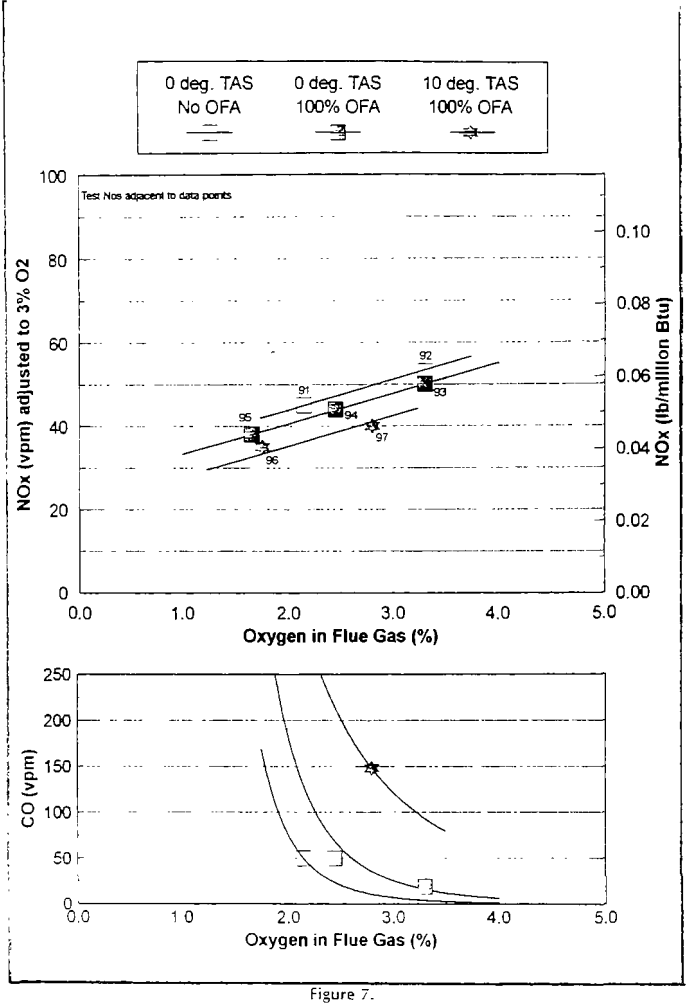

Figure 7.

LILCO Gas Firing Trials NOx and CO Emissions.

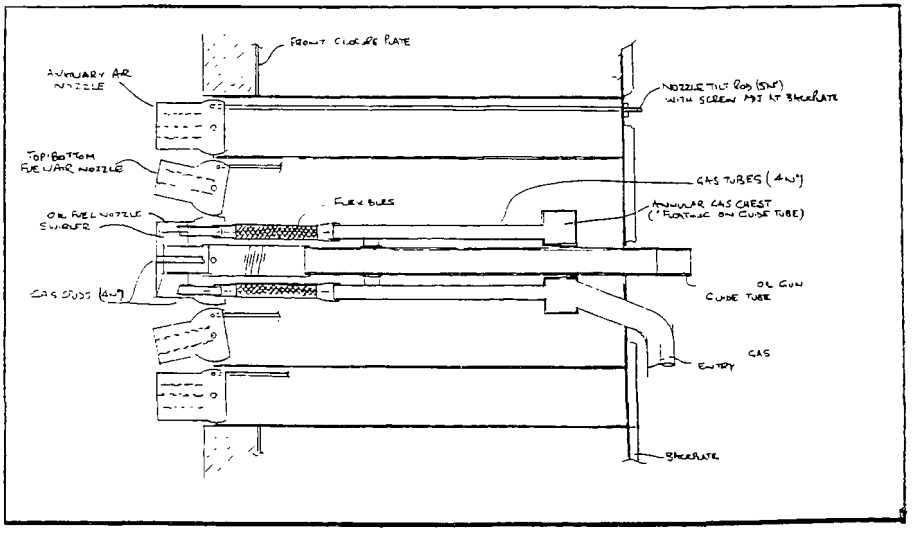

Figure 8.

Location of Gas Burner in the Test Cell.

PRELIMINARY RESULTS OF LOW NO_x (< 25 ppm) BURNER RETROFIT OF PACIFIC GAS & ELECTRIC 345-MW CONTRA COSTA UNIT 7

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Abstract

This paper details the short-term operating results of the low NO_x retrofit of Pacific Gas & Electric Co.'s 345-MW Contra Costa Unit 7, which (at time of writing) entails the lowest NO_x emission rate ever guaranteed (24 ppm) for a low NO_x utility boiler retrofit without post-combustion NO_x controls.

In April, 1997, TODD Combustion performed the turnkey supply and installation of twenty-four (24) low NO_x, gas/oil burners utilizing advanced fuel gas injection techniques and an advanced overfire air port system. Physical three-dimensional modeling was used to optimize the boiler combustion air and flue gas recirculation systems. Stone & Webster Engineering served as architect/engineer for the project, which included increasing bulk mixed flue gas recirculation from 17% to 30%.

The project approach, emissions and boiler performance results are presented in depth.

Unit Data

Contra Costa Power Plant Unit 7 is rated at 345 MWg. The boiler is a Babcock & Wilcox El Paso style radiant, single reheat, pressurized unit, rated at a main steam flow of 2,160,000 lb/hr at 2,475 psig and 1,050°F, with reheat steam temperature of 1,000°F.

The unit was originally designed to fire either natural gas or heavy fuel oil through 24 combination circular burners arranged in two rows of six burners on each of the front and rear walls, in an opposed configuration. Horizontal burner spacing is uneven to allow for two partial furnace division walls. A single row of overfire air ports is located above each of the six burner columns on each of the front and rear walls.

Flue gas recirculation is available for control of reheat steam temperatures and NO_x emission level.

The unit, used in daily load following service, was constructed in 1964.

Project Approach

The primary objective of the Contra Costa Unit 7 NO_x Retrofit Project was to engineer, procure, construct, start up and test a NO_x control system that will allow the unit to operate within PG&E's Compliance Plan to meet the requirements of the Bay Area Air Quality Management District's NO_x Regulation 9, Rule 11.

This rule allows systemwide NO_x emissions averaging of the affected PG&E Bay Area units. As a result, affected units do not have a specific NO_x limitation but average their emissions with those from other affected units to meet the systemwide, clock-hour NO_x limit. The Compliance Plan that PG&E has selected requires that Contra Costa Unit 7 be capable of operating at emissions levels in the 20 to 25 ppmvdc range by 1997. This emission range appeared to be attainable by retrofitting low NO_x burners and by upgrading the windbox FGR capability to 30% (on a flue gas mass basis).

CO emissions from Contra Costa Unit 7 are also affected by the BAAQMD rule. The rule requires operation below 400 ppmvdc during steady-state compliance source tests and below 1,000 ppmvdc during normal operation (i.e. CEMS monitoring).

The NO_x control system retrofit consists of 24 new low NO_x Dynaswirl-LN burners with natural gas biasing valves combined with the increase in the windbox flue gas recirculation (WFGR) capability to 30%. The unit's 12 existing overfire air (OFA) ports were also replaced with an advanced design.

Related project work included:

- Structural strengthening of the existing furnace, back pass, and duct work to accommodate an increase in FD fan static pressure

- Installation of a new FGR duct run on each side of the unit (complete with platforms, stairs, ladders, dampers, insulation and lagging) that operate in parallel to the existing ducts that supply recirculated flue gas to the FGR mixing plenum
- Upgrading the FD and FGR fans and motor drives
- Modifications to the existing DCS and associated burner front hardware for a fully automatic burner management system (BMS)
- Recertification of the unit's CEMS
- Miscellaneous electrical work
- Asbestos abatement

Flue Gas Recirculation

To satisfy the demands of the low NO_x burner retrofit, the FGR system had to be sized to provide 30% FGR to the windbox while providing approximately 2% FGR flow to the unit's furnace hoppers at the following conditions:

- Maximum continuous boiler rating (MCR)
- All burners in service (ABIS)
- Installation of TODD Combustion Dynaswirl-LN burners with a 3.3 inwc windbox-to-furnace pressure drop with ABIS

Prior to modifications, the existing FGR system was only capable of supplying approximately 17% FGR to the windbox. To maximize NO_x reduction with the new burners, the capabilities of the existing FGR fans had to be upgraded to provide higher pressure and flow performance.

At 30% WFGR, modifications to the existing ductwork providing flue gas flow to the FGR injection plenums were required to obtain acceptable velocities and pressure losses. These modifications included adding a new duct to each side of the unit (Figure 1). Each new duct has an approximate cross-sectional flow area of twice that of each of the existing ducts. A damper was installed in each of the new ducts to control flow in parallel with the flow control dampers in the existing system.

The pre-retrofit total FGR flow elements located in the inlet duct to each FGR fan were also removed to reduce system pressure drop. This equipment was used to indicate total FGR flow supplied to the unit's. The new flow elements that were installed employ a multi-port averaging pitot tube approach that has a lower unrecoverable flow resistance than the baseline equipment.

In addition, windbox FGR flow may now be determined separately from total flow with the installation of pressure taps to measure the differential across the FGR mixing airfoils located in the combustion air ducts. The pressure differential measured by this system is a direct indication of FGR mass flow to each side of the unit's windbox.

Each of these flow measurement systems was calibrated during tests conducted for low NO_x tuning of the boiler.

PG & E
Contra Costa Unit 7
Combustion Air and Flue Gas Recirculation Systems

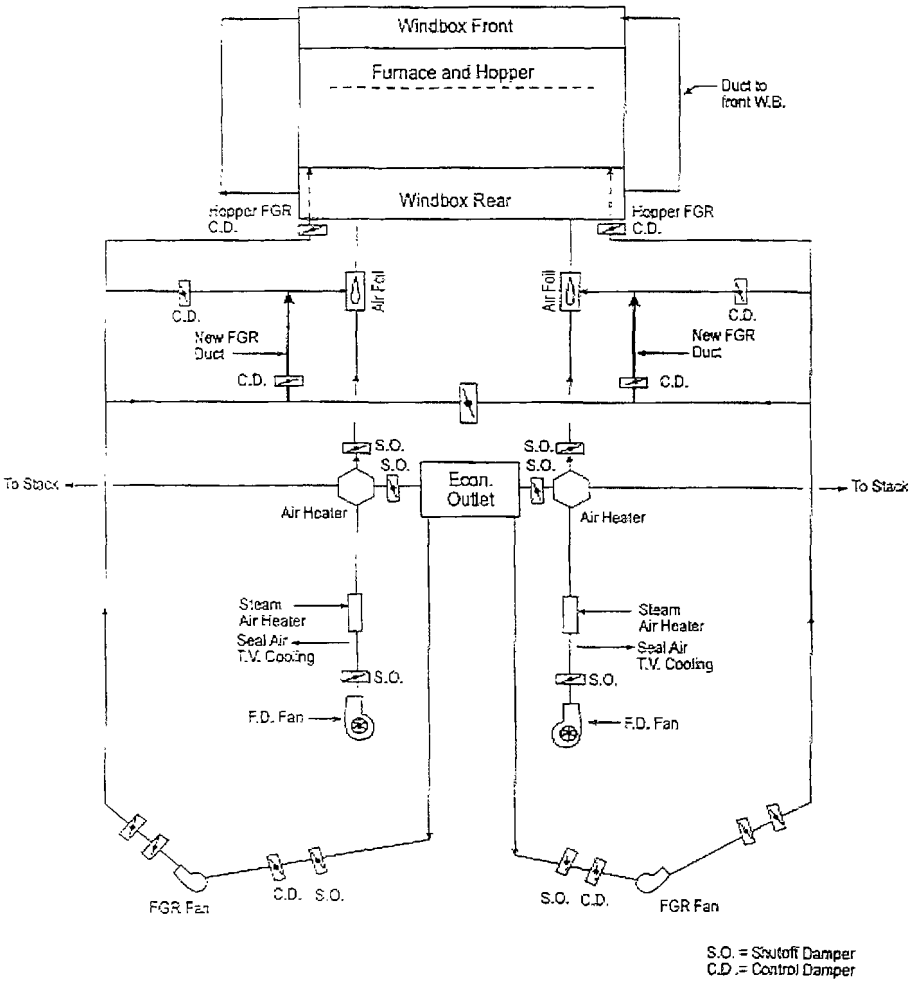

Figure 1

Boiler Performance Modeling

Performance predictions were prepared for Contra Costa Unit 7 with varying quantities of FGR using the Stone & Webster Steam Generator Performance Evaluation Program (SGPEP). The information used to baseline this mathematical model of the boiler was based principally on the data and information recorded during pre-retrofit tests conducted on the unit and on boiler design and performance characteristics existing in Stone & Webster's experience base.

The modeling results show that Unit 7 boiler performance will be affected by large changes in FGR rates. The following summarizes the important parameters and impacts identified by the SGPEP:

Furnace Exit Gas Temperature

The furnace exit gas temperature (FEGT) at MCR is predicted to drop from 2,550°F with approximately 10% FGR to 2,475°F with 30% FGR. The FEGT combined with the mass flow of flue gas leaving the furnace is an indicator of the total energy absorbed by the furnace. For a given temperature, if furnace flue gas mass flow rate increases, the energy level leaving the furnace also increases. This results in higher steam temperatures and spray flow rates due to increased heat transfer in the convection pass regions of the boiler. With the Unit 7 boiler type, it is common for the FGR rate to significantly affect convective pass performance for rates from zero to approximately 10%. This effect is considered to be due to heat transfer characteristics that result in less furnace heat absorption and a significant increase in FEGT. The combined effects of higher gas temperature and mass flow on convective pass surfaces is responsible for the design impact. At higher FGR rates, the trend in furnace heat absorption is lessened and the FEGT drops due to the bulk mixing of combustion products with an increasing quantity of flue gas. The net effect on Unit 7 of increasing flue gas recirculation rates will be increased convective pass tube metal temperatures even though the FEGT will actually decrease.

Boiler Efficiency

The Unit 7 boiler thermal efficiency is expected to drop linearly between 85.44% with 10% FGR to 85.21% with 30% FGR. This slight reduction in boiler efficiency results from the reduced heat transfer in the back passes of the boiler. Convective heat transfer (the predominant heat transfer mechanism in the boiler convective passes) is nonlinear, varying as the 0.6 power of gas mass flow. Therefore, as FGR rate increases, the heat transfer rate does not increase proportionally, resulting in higher flue gas temperature leaving the air heater and a higher dry flue gas heat loss value.

Spray Attemperation

The Unit 7 spray water attemperation flow rates in both sections of the superheater and at the inlet of the reheater will increase with increases in FGR rates. For the FGR range expected following the modifications, the primary superheater outlet spray flow rate is expected to increase by approximately 70%. The secondary superheater spray flow requirement will increase by approximately 40%, and the reheater spray flow requirement will increase by approximately 65%.

An evaluation of the spray system was performed to assess flow/pressure limits and to select required upgrades to piping, valving and nozzles.

Boiler Pressure Part Metals Analysis

As described above, an increase in FGR rate is expected to affect overall boiler performance. The temperatures of pressure part components are also affected by changes in steam flow through tubing due to changes in spray flow requirements and heat transfer rates. Based on the results of the boiler model, which provide overall thermal performance, Stone & Webster calculated critical temperatures for each superheater and reheater section.

Existing tubing material sections in the primary superheater, secondary superheater, tertiary superheater and in the reheater were considered marginal. With increased FGR, the primary superheater tube metal temperatures are expected to increase substantially due to reduced steam flow in this section as more water is withdrawn to provide spray to the secondary superheater. The outlet header and link piping material will also be affected at a the 30% FGR flow rate. There are no substantial impacts to the secondary superheater, tertiary superheater or to the reheater due to the anticipated change in FGR flow rates.

PG&E has implemented a convective sections tracking and analysis program to monitor the long term potential effects on these boiler components.

Dynaswirl-LN Burner

The Dynaswirl-LN is a parallel-flow, venturi-register gas/oil burner using fuel and air staging to achieve low NO_x, high efficiency operation with exceptional flame stability. More than 300 Dynaswirl-LNs have been installed in U.S. wall-fired, gas/oil, low NO_x utility boiler retrofits totaling over 6,000 MW.

Air Staging

Primary and secondary airflow enter the venturi register, which tends to equalize distribution and provides an axial, turbulence-free flow. Primary air, approximately 15% of total flow, exits the register through a small swirler, which creates a sub-stoichiometric primary combustion zone with a fixed ignition point that does not vary with load. The low pressure zone formed by the swirler also recirculates furnace gases within the flame pattern, reducing NO_x formation.

Secondary air, approximately 65% of total flow, exits the venturi register around the diffuser as a parallel flow, mixing further downstream. The remaining 20% of burner airflow, termed tertiary air, exits through a separate sleeve around the venturi throat, mixing still further downstream for maximum NO_x control.

Primary/secondary airflow is controlled via an "on/off" pneumatic airslide, which does not modulate with load. Tertiary airflow is controlled via a manual airslide, which is fixed in position during startup.

Fuel Staging

Gaseous fuel is injected with a combination of multiple spuds, or pokers, and a centerfire gun. The centerfire injector provides a small amount of fuel at the root of the flame. Six pokers around the periphery of the swirler inject fuel at precise locations within secondary and tertiary airflow, creating rich and lean zones within the flame. Poker orientation and drilling are keys to NO_x control.

An advanced poker arrangement developed in single-burner testing has been retrofitted to more than 100 Dynaswirl-LNs in the field, producing additional NO_x reductions of 20%. This proprietary technology was incorporated in the burner design for Contra Costa.

For No. 6 oil firing, the existing mechanically atomized oil guns were reused in the Dynaswirl-LN burners. The oil guns were lengthened at TODD's manufacturing facility and retrofitted with advanced design TODD atomizer assemblies.

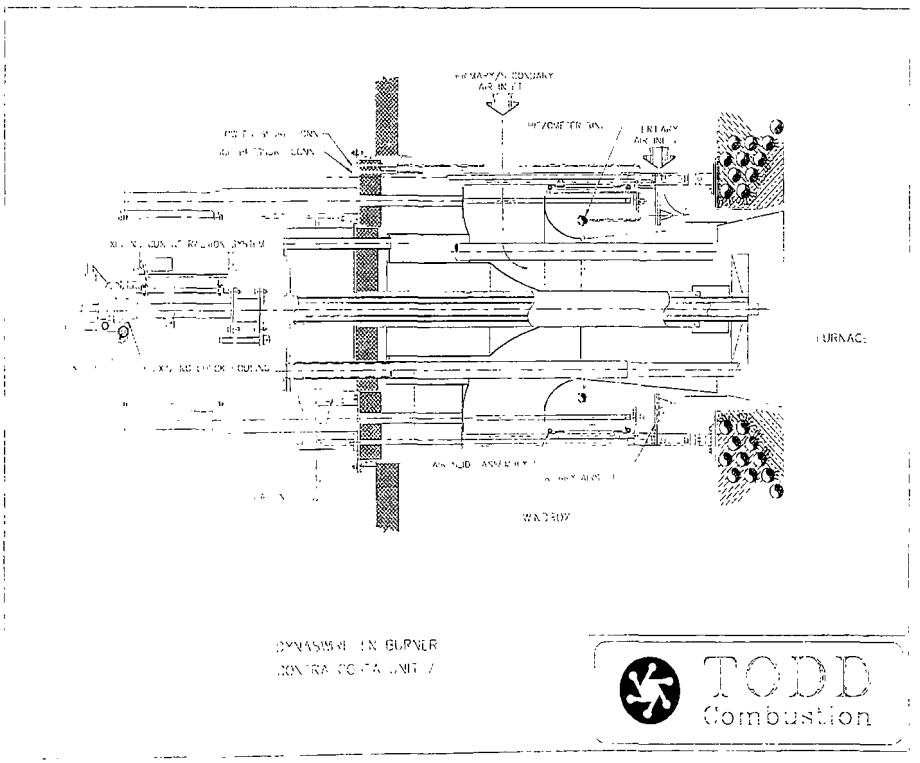

Figure 2

Overfire Air

The six OFA ports on each of the front and rear walls were replaced with TODD venturi ports. Air and FGR flow through the ports is controlled via automatic "on/off" airslides that do not modulate with load.

OFA flow is increased from a pre-retrofit maximum of approximately 14% to 27% post-retrofit. OFA port openings were not increased, and pressure drop remained the same. The new OFA system increased the momentum of the OFA ports by approximately 1.9 times, and mixing in the upper furnace was improved.

Airflow Modeling

For all TODD low NO_x retrofit projects, a physical three-dimensional model of the combustion air system is first constructed. When flowed with water containing neutral buoyancy beads illuminated by a collimated light source, basic flow patterns can be easily visualized. The model is tested with both with water and air in order to verify results. Corrections can then be made via baffles and turning vanes. The optimized baffle arrangement can then be installed in the actual unit during construction, assuring proper airflow in the field.

Physical airflow modeling has three goals: equal airflow distribution among all burners, equal inlet velocities around the periphery of each burner, and elimination of swirling airflow through each burner.

First, equal airflow distribution to all burners is key in any low NO_x retrofit. When an imbalance exists, excess O_2 must be raised to prevent formation of CO by the burner most starved for air. This unnecessarily increases NO_x formation from the other burners. By equalizing airflow distribution among all burners, excess O_2 can be minimized, which provides maximum NO_x reduction and boiler efficiency. Including FGR distribution in the modeling process further maximizes NO_x control.

Equal inlet velocities and elimination of swirl through each burner are crucial to burner performance. Because low NO_x burners rely on injection of fuel at precise locations within burner airflow, it is imperative that the proper airflow be present at these locations. Likewise, for optimum performance, the only swirl present must be that which is created by the burner itself.

No burner can be expected to simultaneously correct imbalances in the draft system *and* precisely control fuel/air mixing to minimize NO_x formation. Airflow modeling prepares the airflow for the burner, allowing the burner to precisely control fuel/air mixing for maximum NO_x reduction. This approach has freed burner designers to focus solely on NO_x control, increasing the effectiveness of known control techniques to their maximum extent.

FGR MODEL

In order to insure maximum benefit from the FGR system, a model of the FGR system and windbox was constructed. The intent of the model was to optimize the windbox FGR distribution. Equal FGR distribution to each burner has been shown to reduce NO_x without increasing total FGR rate. The relationship between NO_x and FGR is a non-linear curve, with the amount of NO_x reduction decreasing as the FGR rate increases. Therefore, while the burner receiving the least FGR produces more NO_x than a burner receiving the average FGR rate, its increased NO_x emissions are NOT offset by the burner receiving the most FGR. The net effect is an overall increase in NO_x emissions. A unit's NO_x emissions may therefore be reduced by taking FGR from the burners receiving higher than average FGR rates and redistributing it to the burners receiving below average FGR rates. The goal of the FGR model is therefore to distribute FGR equally to all burners without increasing the FGR system pressure drop. The practical limit of the model is considered to be distribution within $\pm$ 2%.

The FGR system model was built at the same 10:1 scale as the burner/windbox model and included all ductwork from the FGR fan, up to and including the pre-retrofit FGR mixing section. The FGR model was attached to the burner/windbox model. Methane was used to simulate flue gas and was introduced into the inlet of the FGR duct. The concentration of methane at the exit of each burner was then measured to determine the distribution. Modifications to the mixing slots were made, or baffles were added, with each iteration until the goal of the model was achieved. The optimum arrangement was then installed during the unit outage.

OFA Model

A separate physical three-dimensional model was constructed for the OFA system. Methane was injected in the OFA flow, but not in the burner flow. The mixture was then measured at the boiler exit, corrected for density and momentum differences, in order to verify proper burner/OFA mixing. This resulted in recommended OFA port settings for startup.

Installation

The unit outage was scheduled for eight weeks, working one shift per day with no scheduled overtime. Preoutage activities started weeks before the outage began. The major mobilization started 2 weeks before the scheduled outage. The unit was shut down and boiler work started on March 3. The work force consisted of union labor from the Building Trades at a reduced scale as part of PG&E's NO_x Reduction Project Agreement.

The work progressed mainly on schedule, and the outage mechanical work was completed on April 28. The average work force was 35 people for the burner installation and 70 people for the balance of plant work.

Checkout of the new BMS control system continued, and the boiler was fired on May 5 for test testing and refractory curing.

Startup Data

The data presented in this paper is from a limited load startup. Because the Contra Costa power plant is located on the Sacramento River, where the Striped Bass spawn each spring, the plant condenser outlet water temperature is limited to 86°F until the bass reach 38 mm, per the California Department of Fish and Game. Plant load is thus limited to maintain condenser water temperature at 86°F.

After the outage, the unit started as scheduled on May 15, 1997. Maximum load, which varies from day to day and with the tide, was often limited to 120 MW, but at times 230 MW could be reached. During this period, the project team was asked to provide a preliminary tune, develop preliminary operating curves, and observe the operation of the equipment. The data presented in this paper is from this time period. Load limitation was not released until July 5, 1997.

Airflow Modeling Validation

Burner-to-burner airflow distribution in the uncorrected model showed an as-found deviation of 49% between the two worst-case burners (+15% / -34%). In the corrected model, deviation was reduced to ± 1%.

In post-retrofit boiler testing, deviation on the unit was less than 10%, achieving the goal of ± 5%. Post-retrofit performance -- flame stability, emissions, O_2 -- remains the best proof of proper airflow within the unit.

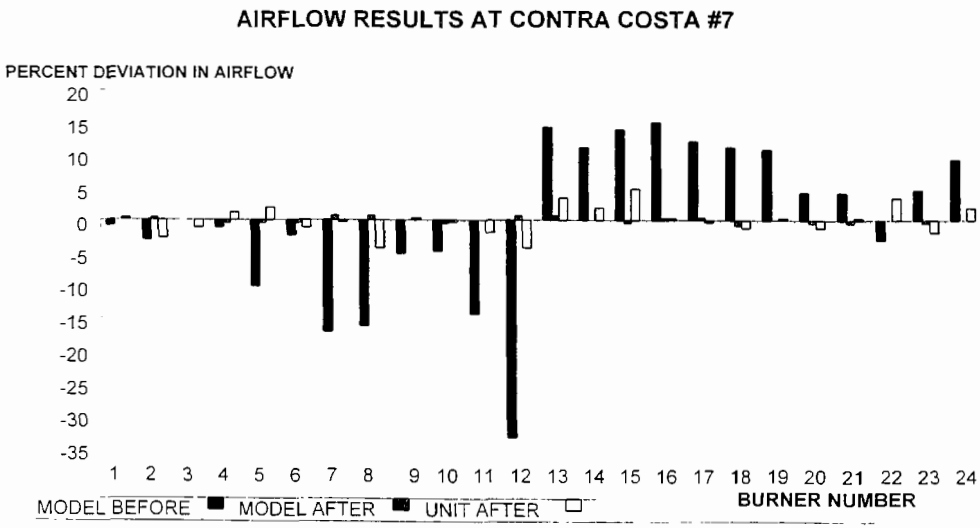

Figure 3

Turndown

Turndown capability of the burner appears excellent. During startup testing, with no adjustments, turndown of 30-to-1 was demonstrated.

Flame Stability

In addition to quantitative tests to verify airflow distribution, certain field tests are conducted with the boiler in operation to ensure flame safety and to demonstrate the correct application of flow control devices indicated by the model. These tests are the minimum gas pressure test and the maximum airflow test.

The minimum gas pressure test is the minimum burner gas pressure at which a flame remains stable. It is performed on every burner, and the primary goal is consistency of gas pressure from burner to burner. At Contra Costa, every burner lost its flame in the range of 0.25 to 0.33 in wc gas pressure with airflow at 25%. This demonstrates consistent air and fuel flow to every burner.

The maximum airflow test ensures that the flame will not blow out even under conditions of maximum airflow. This provides operations personnel with confidence that under certain worst-case conditions, the flame will not blow out. The gas pressure is raised to 8 in wc, and every burner is taken to 100% airflow to verify that it does not blow out. This minimum gas pressure can then be set with confidence that the flames will not blow out under any condition of airflow. The consistent results again demonstrate that equal airflow is being provided to each burner. All burners remained stable up to the amp limit of the FD fan motor.

Figure 4
Dynaswirl-LN Natural Gas Flames at Part Load

FGR Measurement

Accurate measurement of FGR is important because of its potentially large impact on boiler performance and NO_x reduction. The impact on boiler performance stems from changes in heat transfer that occur in the boiler. Furnace radiation decreases with higher FGR rates because the peak flame temperature is reduced; the extra gas flow increases heat transfer in the superheater, reheater and HRA. If the superheat and reheat sprays cannot reduce temperatures sufficiently to meet maximum metal temperature requirements, then FGR must be limited or the boiler surface must be modified. Also, if FGR flow cannot be accurately quantified, then the results of the retrofit are not as useful for the next project. Extra margins must be added, conservative projections must be made, and both add cost with no value. For maximum NO_x reduction, it may be necessary to add as much FGR as the boiler can tolerate. Accurate measurement of FGR flow is required for control of the boiler in optimum, low NO_x operation.

FGR Measurement Techniques

A venturi meter; multiple point pitot tube; measurement of windbox/burner O_2, CO_2 or NO_x concentrations; or simply a calculation from FGR fan amps, fan pressure drop and inlet damper position can all be utilized to measure FGR. Each of these have problems, however. A venturi meter takes space, is expensive, has a relatively high recoverable pressure drop, and the upstream and downstream duct requirements are unacceptable in a unit such as Contra Costa. Orifice meters have similar problems with higher unrecovered pressure drops.

A multiple point pitot tube has very low unrecovered pressure drop, but in an FGR duct where very low velocities are desired to minimize draft system losses, care must be taken in the design of the instrumentation system to avoid signal fluctuation due to internal duct turbulence.

The use of gas species measurements in the burners or windbox combined with combustion calculations appears to be the most accurate approach. Some types of O_2 meters are not capable of measuring O2 in the 14-19 % range, which is the approximate range needed to measure five to 40% FGR rates. High accuracy O_2 instruments may be used if carefully calibrated for this range. Measurement of NO has been used in the past to calculate windbox FGR rates because NO instruments can be easily calibrated over the range of expected values in the windbox and economizer. A problem occurs, however, at very low NO values, when the calculation of FGR becomes very sensitive to a small change in windbox NO. For example, at 24 ppm of NO in the economizer flue gas and 7 ppm of NO in the windbox, if the windbox NO increases to 8 ppm, then the change in FGR rate is 4%. Therefore, FGR can only be measured to $\pm$4% using this method. Some typical preliminary measurements of FGR by dilution for CO_2, O_2 and NO are as follows:

SPECIES	TEST #1 FGR%	TEST #2 FGR%	TEST #3 FGR%
CO_2	23	28	22
O_2	21	26	20
NO	22	13	16

By agreement, CO_2 has been chosen to document the FGR rate for this project. The FGR rate will be calculated using all three dilution species, an "S"-type pitot traverse of the FGR duct, the measurement of a commercial type pitot array, and a calculation using fan amps, fan pressure rise, a fan curve and damper position. We are committed to accurately determining the FGR rate and using the information to tune the boiler controls and evaluate the impact on NO_x and boiler performance.

Emissions Data

The following data was recorded during May's preliminary testing:

TEST #	LOAD	BLR O2	NOx, PPM	CO, PPM	FGR%	WBO2	OFA%
17-1	216	2.5	59	56	10	19.55	100
17-2	216	2.2	92	9			0
17-3	216	2.2	90	1			0
18-1	65	6.7	53	11	200 KPPH	NA	0
18-2	139	2.1	83	7	0		0
18-3	136	2.1	80	11	0		0
18-4	137	2	72	185	0		0
19-1	96	4.4	66	1			0
19-4	230	2.2	58	1	21.5	18.2	0
19-5	230	1.2	42	7	23.1	18.0	0
19-6	230	1.1	37	4	28	17.4	0
19-7	231	1.3	32	4	33.8	16.8	0
19-8	230	2.0	27	7	32.5	17.1	100
19-9	230	2.0	38	1			0
20-1	50	7.1	62	3			0
20-2	49	7.6	55	7			0
20-3	50	7.2	28	1	56.3	16.9	0
20-4	50	7.4	26	1	64	16.5	0
20-5	50	7.3	24	1	65.8	16.48	100
20-6	49	7.6	22	1			100
20-7	50	7.5	32	4	31.6	18.4	100
21-1	125	1.2	10	261	46	16.25	100
21-1A	125	1.7	14	58			100
21-2	125	2.2	16	7			100
21-3	125	2.5	19	4			100
21-4	125	2.6	18	3			100
21-5	125	2.5	13	3		15.7	100
21-6	125	2	11	7			100
22-1	128	3.6	47	4			100
2	125	1.8	69	203	56	15.06	0
3	125	1.5	75	41			0
4	129	3.2	26	1			0
5	125	8	14	15			0

CONTRA COSTA #7

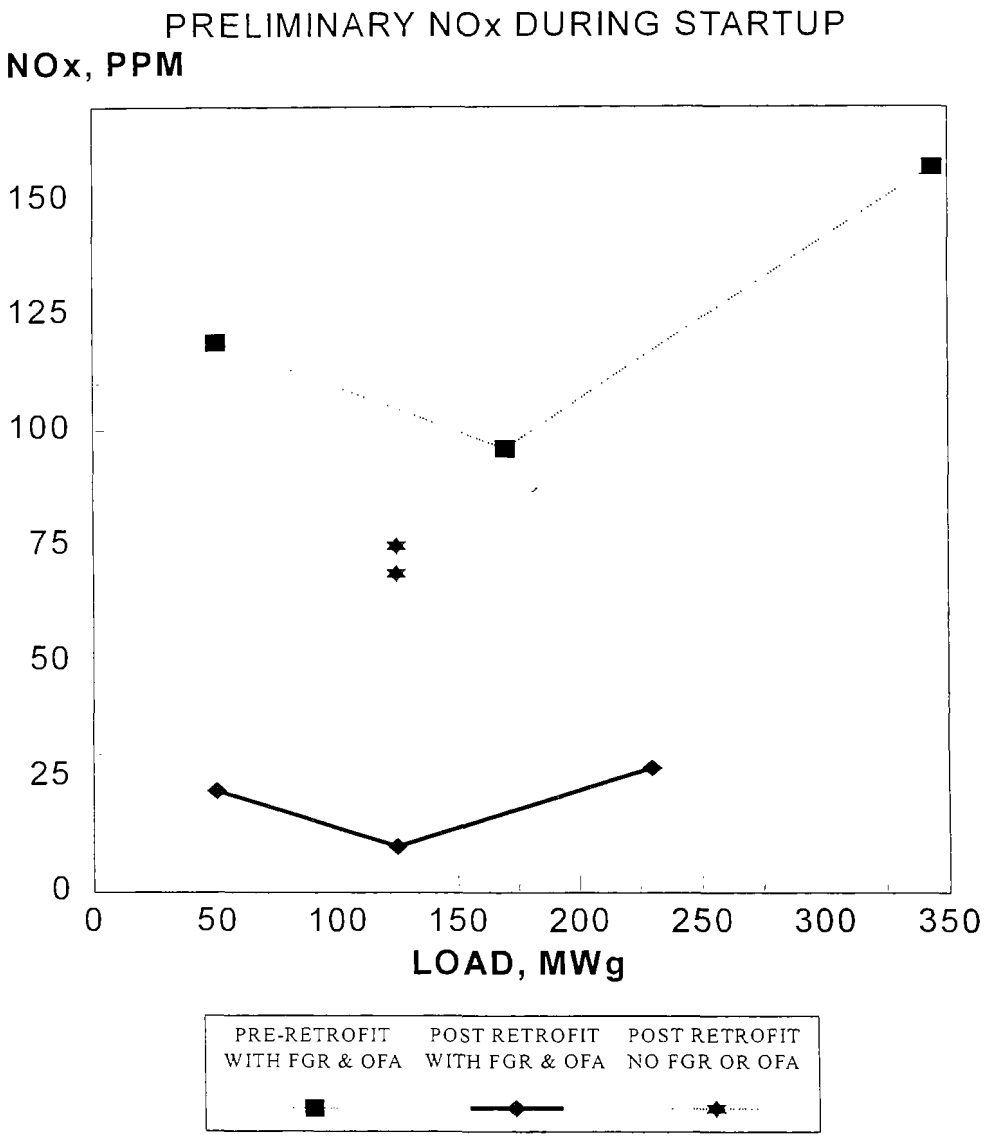

Figure 5

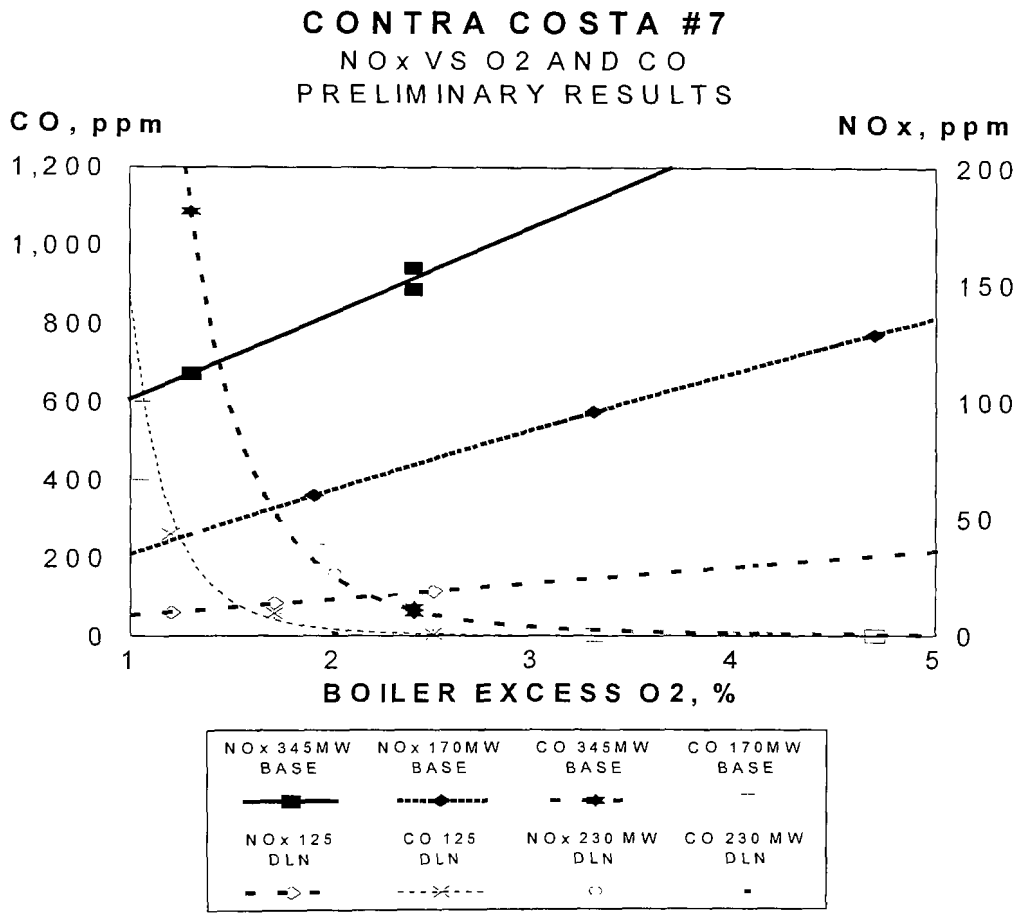

Figure 6

Full Load Projections

The preliminary testing at up to 60% load has shown that the NO_x guarantee of 24 ppm is achievable at full load. Testing at full load is scheduled for mid-summer, and the results may be presented verbally in conjunction with this paper.

NO_x is normally defined as a combination of NO and NO_2. The majority of the pollutant NO_x is NO. The fraction of NO_2 present varies with a number of operating parameters.

These relationships are being addressed, as part of this project, with an investigation into the effects of load, burners in service, excess O2 and CO emissions on NO_2 levels.

ULTRA-LOW NO_x RAPID MIX BURNER DEMONSTRATION AT CON EDISON'S 59th STREET STATION

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Abstract

Radian International, together with its licensee TODD Combustion, has developed, demonstrated, and commercially implemented the Radian Rapid Mix Burner (RMB) that is capable of producing ultra-low NO_x levels for natural gas firing. NO_x levels under 10 ppm, simultaneously with CO levels of a similar magnitude, have been achieved over the load ranges of several configurations and sizes of industrial boilers and similar gas-fired devices. Over the last three years, the RMB has been deployed and is operating on approximately 25 industrial boilers and furnaces.

Recently with the support of the Electric Power Research Institute, the Consolidated Edison Company of New York, ESEERCO, NYSERDA, and the San Diego Gas and Electric Company, the burner was installed and demonstrated in a boiler in an electric utility power plant setting. A two-burner package boiler with air preheat at Con Edison's 59th Street Station was equipped with RMBs and a flue gas recirculation system. The objective of the project was to demonstrate the achievement of sub-15 ppm NO_x levels, using staged firing and no more than 20% FGR.

The objectives of the project at 59th Street have been met. This paper gives an overview of the results.

Introduction

Radian International has developed the Rapid Mix Burner (RMB) which provides ultra-low NO_x levels for gas-fired, forced-draft boilers and other fired devices. The RMB also provides a stable, compact flame with high combustion efficiency to minimize impacts on CO and other combustibles.

Over the last three years, these performance criteria have been met on commercial RMB installations in about 25 industrial boilers and dryers, with burner sizes ranging from 1.5 to 280 MBtu/hr. Performance testing and regulatory compliance testing of these installations have proven the burner's capability to produce NO_x levels under 10 ppm (corrected to 3% O_2, dry), simultaneously with similarly low CO emissions. Some of these installations have used FGR rates over 30%, some have been in refractory-lined furnaces such that the flame operates at adiabatic temperatures, some have involved air preheat, some have utilized staged firing, and some have been multiple burner installations. In the majority of installations, the realized NO_x level was 10 ppm or less.

The RMB Design and NO_x Control Process

The RMB design is based upon three main criteria. First is the rapid and near-complete mixing of combustion air, recirculated flue gas, and fuel prior to the ignition point. This mixture is overall air rich and, since the mixing is near complete, this eliminates prompt NO_x formation which is a by-product of substoichiometric combustion. Second is the burner geometry that produces a very stable flame. And third is the use of FGR to dramatically reduce peak flame temperatures, thus bringing the production of thermal NO_x to very low levels. In addition, since the fuel and air are essentially premixed prior to the ignition point, high excess air is as effective as FGR for reducing thermal NO_x. This is a key element in using the burner in certain applications, including utility boilers.

A schematic illustrating the burner's important design concepts is shown in Figure 1. The burner consists of two concentric flow paths, or registers. In the inner register, the combustion air or air/FGR mixture enters through a burner throat and passes through a set of axial swirl vanes where the fuel is added using a grid of gas injectors built into the vanes. The fixed-vane swirler design was developed initially at the International Flame Research Foundation and refined by Radian. The location, number, and diameter of the gas injectors, in combination with the turbulence generated by the swirl vanes, provide rapid and complete mixing of the fuel and oxidant within a few inches of the fuel injection point. This arrangement produces the advantages of premixed combustion, without the negative implications of having a large, confined premixed volume.

The outer register contains straight vanes (no swirl in the outer section). These vanes also contain a built-in grid of gas injectors, as do the inner register swirl vanes. The flame from the inner burner serves to establish and anchor the flame from the outer register. Both the inner swirled and the outer axial flow portions of the burner operate at the same stoichiometry and with the same FGR rate.

The geometry of the burner, with the divergent quarl and swirling flow of the inner register, combine to generate a very stable flame that can tolerate high flue gas recirculation rates. With very high FGR, the burner can operate stably at flame temperatures low enough to generate only a few ppm of thermal NO_x.

Another important design element of the RMB is the method of gas fuel injection and the mixing with combustion air and FGR. As opposed to a diffusion-mix or staged mixing burner, the fuel-air mixing in the RMB occurs extremely quickly (hence, its name) such that near-perfect mixing is achieved prior to the flame front. A prime benefit of rapid mixing is that stoichiometry can be precisely controlled and held constant throughout the flame. This avoids zones of relatively fuel-rich stoichiometries (common to conventional burners, and especially fuel- and air-staged low-NO_x burners) which result in prompt NO_x formation. (Prompt NO_x forms very rapidly in a flame and cannot be avoided in fuel-rich flames.) Thus, the burner is capable of breaking the 20 ppm NO_x barrier which results primarily from prompt NO_x formation.

Although the RMB was designed to reach ultra-low NO_x levels even when used in applications with high air preheat temperature, higher FGR rates are required when operated in the normal firing mode. For example with 600°F air preheat, the burner achieves NO_x levels of 10 to 15 ppm using normal firing and FGR rates of 40 to 45%. Normal firing is defined as all the fuel and 10 to 15% excess air through the burner; see Figure 2. The burner is designed intentionally to operate with very high FGR rates and, as such, firing under these conditions can be done without degrading flame stability. In fact, the burner has been tested at FGR rates as high as 60% with a stable flame.

FGR rates greater than 20% can be tolerated by many industrial boilers, or by a utility boiler that was designed for the high mass flows through the convective pass. However from the standpoint of retrofitting existing utility boilers, the most FGR that can typically be tolerated at high loads is around 20%. Thus, normal RMB firing with very high FGR is not always practical for a utility boiler where ultra-low NO_x levels are needed and FGR must be limited to 20% or less. This limitation led to the development of the staged firing mode of the RMB.

RMB staged firing is based on the fundamental principle that high excess air through the burner has the same effect upon flame temperature (and thus upon NO_x formation) as does FGR. This is a normal characteristic of pre-mixed or simulated pre-mix flames. (This characteristic is opposite to that of diffusion-mix burners where higher excess air increases NO_x formation.)

The ability of the RMB to operate at very low NO_x emissions using high excess air only has been well documented in several industrial RMB installations. A 60 MBtu/hr RMB has been in continuous operation since mid-1995 in a rotary dryer application, producing NO_x emissions of 7 ppm (corrected to 3% O_2) with 60% excess air and no FGR. It is important to note that, in this dryer application, the RMB is firing into a refractory lined, adiabatic combustion chamber -- with a NO_x level of 7 ppm.

Staged firing was developed to take advantage of the RMB's high excess air NO_x characteristic. With staged firing, the burners operate at high excess air levels (50% or so), yet the overall furnace stoichiometry is similar to normal operation (10 to 20% excess air). This is accomplished

by re-routing a portion of the fuel away from the burners, but keeping the same total air flow through the burners. The rerouted fuel is injected just outside the burner envelope and mixes and burns with the high excess air left over from the burners; see Figure 3.

The operating principal of the RMB staged firing configuration is to burn as much of the fuel as possible under the high excess air, ultra-low NO_x conditions. As a result of the fundamental principle mentioned above, this is done by operating the burners air rich (under conditions similar to normal firing, but with higher excess air and with a moderate amount of FGR), where the maximum theoretical NO_x formation is very predictable. Heat is extracted from these air-rich combustion products and cool furnace recirculation products are entrained. The staged fuel is then mixed with the air-rich burner products and combustion is completed. The excess air at the boiler outlet is thus similar to that with normal firing.

In a staged firing application on a utility boiler with air preheat, about 75% of the total fuel input would be fired equally distributed among the burners. The burners would also have all the air flow. This would result in the burners operating at about 50% excess air. With 20% FGR added, the burner NO_x level would less than 10 ppm. The burner-NO_x contribution to the overall stack NO_x concentration would be 7.5 ppm (75% x 10 = 7.5). The remaining 25% of the fuel would be fired through the staged fuel injectors (near the burners) with no air. In mixing and burning with the air-rich burner products, additional NO_x would be formed from the staged fuel. For the total stack NO_x concentration to be no more than 15 ppm, the NO_x contribution from the staged fuel combustion would have to be no more than 7.5 ppm. Thus, if the NO_x formation from the staged fuel can be controlled to less than about 30 ppm (7.5/25%), overall NO_x emissions would be less than 15 ppm.

An important item in a staged firing application is the optimum location and orientation of the staged fuel injectors. The ability to achieve stack NO_x emissions of 10 to 15 ppm requires control of the NO_x generated by the staged fuel to 30 ppm or less. Ultra-low NO_x emissions from a staged firing configuration can best be achieved by injecting the fuel into a region of the furnace where cooler furnace recirculation products can first be entrained into the fuel jet. The most direct method of controlling the NO_x emissions from the staged fuel is to first entrain a large amount of relatively cool furnace gases into the fuel gas stream before mixing with the high-excess-air, higher-temperature products from the burners.

Although a given staged fuel injector location may be good for NO_x control, the configuration also must be optimized to ensure adequate CO. Also, any alteration of the heat release distribution in the furnace must not be detrimental to the boiler's steamside temperature requirements. In addition to injector location, injection angles and jet penetrations can also be used toward obtaining the optimum conditions.

Project Goals and Work Scope at 59th Street

Several of Radian and TODD's commercial RMB installations are on boilers with air preheat; and normal firing and high FGR rates are used to reach ultra-low NO_x levels. Other installations involve staged firing -- but without air preheat or FGR -- to achieve moderate NO_x levels (under 30 ppm). To demonstrate the RMB's usefulness for reaching ultra-low NO_x levels on utility

boilers, it was necessary to combine staged firing and FGR on a boiler using air preheat. This need led to the project at Con Edison's 59th Street Station.

Boiler 118 at the 59th Street Station is a Foster Wheeler D-type package boiler with a rated heat input of 176 MBtu/hr and a nominal capacity of 150,000 lb/hr of saturated steam at 550 psig and 450°F. The boiler uses two burners mounted on the front refractory wall. The boiler is equipped with a regenerative air heater that heats the combustion air to 460 to 500°F. The boiler has a forced draft and an induced draft fan for balanced draft operation of the furnace. The pertinent specifications of the boiler are shown in Table 1.

Table 1

Con Edison 59th Street Boiler 118

Boiler Manufacturer	Foster Wheeler
Boiler Type	D
Design Steam Flow	150,000 lb/hr
Steam Pressure	550 psig
Steam Temperature	450°F
Furnace Dimensions:	
Depth	31 ft - 2 in
Width	7 ft - 3 in
Height	11 ft - 0 in
Fuel Gas:	
Type	Natural gas
Higher Heating Value	1,000 Btu/scf
Pressure Available	40 psig
RMB Gas Burner Design & Operation:	
Heat Input	88 MBtu/hr per burner
Turndown	5 to 1
Gas Pressure at Burner	7 psig
Draft Loss	7 inches H_2O with 20% FGR, at rated heat input
Furnace Operating Pressure (including FGR at MCR)	0 in wg
Combustion Air Temperature	500°F
Flue Gas Temperature at Boiler Outlet	700°F

Two RMBs rated at 88 MBtu/hr each were manufactured by TODD Combustion. A general layout drawing of the burner is shown in Figure 4. The burners were built to the same design standards as used for all commercial RMBs.

The burners were installed in the boiler's existing windbox. Prior to the installation, the windbox was flow modeled by TODD for the purpose of identifying any air flow distribution problems that could impact burner performance. As a result of this modeling, the windbox was modified with baffles to assure equal air flow distribution between the two burners, and around the

circumference of each burner. In addition to the windbox baffling, a set of dampers was installed in the air duct upstream of the windbox to allow the biasing of air between the two burners. This was provided solely for experimental purposes, and is normally not within the scope (not required) of commercial projects.

To complement the burners and to provide for staged firing, staged fuel injectors were also installed on the boiler. Two injectors were installed near each burner, as illustrated in Figure 5. The injectors consisted of removable pipes that could be inserted through stuffing boxes built into the burners. These pipes were connected to the burner main gas supply, and were controlled using manual valving. Several injector nozzles of variable injection angle and hole size were fabricated to support the optimization of the staged fuel mixing with the main burner flow field.

A new flue gas recirculation system was designed and installed on the boiler, specifically for the demonstration project. A schematic of the system is shown in Figure 6. The system was configured with a hot gas fan for drawing flue gas from the boiler generating bank outlet at a temperature of approximately 700°F. The FGR fan delivered the flue gas into spargers installed within the fresh air duct connecting the air heater outlet and the windbox. The FGR supply duct was split into two legs and individual manual dampers were provided to allow the biasing of FGR between the two burners, if desired.

The overall goal of the project was to demonstrate the ability of the RMB system to reduce NO_x emissions for natural gas operation to ultra-low levels on a boiler having operating conditions representative of an electric utility boiler. The specific goals of the project were:

- To demonstrate the ability of the RMB to provide NO_x levels under 15 ppm (at 3% O_2, dry), with 450 to 500°F air preheat and no more than 20% FGR to the windbox. The burners would be operated in a staged firing mode to meet this emissions goal.

- To limit CO emissions to less than 50 ppm, simultaneously with the target NO_x levels.

- To determine the lowest NO_x levels achievable using normal firing and a nominal amount of FGR.

The demonstration testing was performed in July, 1997.

Emissions Measurements

NO_x and CO emissions, along with excess O_2 levels, were measured for the project using an extractive system and continuous emissions monitoring equipment. The monitoring system was installed in a fully enclosed, self-contained test trailer. The analyzers consisted of a Thermo-Electron Chemiluminescent Model 10S NO_x analyzer, a Siemens Ultramat non-dispersive infrared CO analyzer, and a Thermox Model FCA zirconium oxide, microprocessor based O_2 analyzer.

Samples were drawn into the test trailer through polyethylene tubing connected to sample probes installed in the boiler windbox and boiler outlet flue gas duct. (Windbox O_2 concentrations were measured to determine FGR rates.) The sample gases were flowed through a sample conditioning

system to remove moisture. The test trailer was equipped with certified gases used for calibration of all instrumentation. The instruments were calibrated periodically throughout each day of testing.

Results

The burners were put in service with ignitor fire to cure the refractory on July 3, 1997. The main flames where first established on July 8. On this same day, the fuel, air and FGR inputs were fully characterized for normal firing between 20% and 80% load (30 klb/hr and 120 klb/hr steam flow). Load was limited to 80% of the boiler's rating, in order to have sufficient FD and FGR fan capacity to permit firing at high excess air levels and FGR rates during the testing.

On July 9, the characteristic curves were loaded into the fuel, air and FGR controllers and the system was setup for automatic operation. The boiler was then ramped up and down in automatic between 20 and 80% load. During the entire phase of initial characterization and setup work, there were no instances of high CO emissions, combustion-induced vibration, or any other problems related to flame stability.

Three additional days were spent testing the boiler, and the demonstration testing was completed on July 14, 1997.

As part of the initial characterization testing, the manual dampers on the two FGR ducts were adjusted to balance the FGR flow to both burners. Except at low loads, the FGR was balanced to within 5% FGR between the upper and lower burner. No adjustment of the air balancing damper located between the air heater outlet and the windbox was required to balance the air flow between the two burners. The air flow was within 5% between the two burners.

Testing of normal firing (non-staged) was performed on July 10 and testing with staged firing was done on July 11 and 14, 1997. The NO_x emissions measured for normal and staged firing are shown in Figure 7, plotted as a function of FGR rate. With normal firing, approximately 28% FGR was required to reduce NO_x emissions to 15 ppm; and 35% FGR was needed to reduce NO_x to 10 ppm. Data are shown for operating at 75, 100, and 120 klb/hr steam flow -- for all loads, the effect of FGR on the NO_x emissions was approximately the same. This performance characteristic is typical of RMB operation in other boilers and demonstrates the insensitivity of the burner's NO_x control capability to firing rate or heat release rate.

Again referring to Figure 7, the use of staged firing resulted in similar NO_x levels being achieved, but with much less FGR. For example, 15 ppm NO_x was achieved with about 17% FGR and staged firing (versus 28% FGR with normal firing). Also of significance was that with staged firing, the NO_x level was reduced to under 40 ppm, without any FGR.

During all characterization activities and testing of both normal and staged firing, the maximum CO emissions were 5 ppm and typically less than 1 ppm.

The amount of staged fuel used was dependent on the FGR rate and varied from about 22% staged/total fuel with 20% FGR to 35% staged/total fuel without FGR. During all the staged firing tests, the main burners were adjusted to a NO_x level between 8 and 9 ppm.

NO_x emissions as a function of boiler load and FGR are plotted in Figure 8. With normal firing (i.e., no staging), the NO_x level approaches 20 ppm at 80% load with approximately 20% FGR. By using staged firing, however, it is possible to control NO_x emissions to under 15 ppm at all loads. With an FGR fan sized for full load operation, and with additional tuning of the combustion system, NO_x levels below 15 ppm up to full load would be expected.

Figure 9 compares the NO_x levels measured on Boiler 118 at 59th Street with data from the original 4 MBtu/hr RMB pilot scale development test work done at Radian International. The pilot scale testing was done on a single-burner firetube boiler at about 4 MBtu/hr. The data from the two boilers are comparable since the testing for both was done with air preheat levels between 450°F and 500°F. Data are shown for both normal and staged firing. As the figure illustrates, the results from both boilers are very similar. This comparison is significant since it demonstrates the insensitivity of the RMB's emissions characteristics to burner size, heat release rate, and burner to burner interaction.

Conclusions

The objectives of the Con Edison 59th Street Rapid Mix Burner demonstration have been met. The testing has shown the effectiveness of the Rapid Mix Burner, when operated in the staged firing mode, for controlling NO_x emissions to ultra-low levels, even with air preheat and under operating conditions acceptable for utility boilers.

- NO_x emissions under 15 ppm were achieved using 20% FGR and staged firing.
- Staged firing was shown to be an effective process for reaching, not only ultra-low NO_x levels, but also for reaching moderate NO_x levels. NO_x emissions were reduced to under 40 ppm without any FGR. This has important implications relative to significantly reducing NO_x emissions on units that either do not have FGR or where the retrofit cost of FGR would be significant.
- With normal firing (no staged firing), NO_x emissions were reduced to less than 15 ppm with just under 30% FGR.
- For all ultra-low NO_x operating conditions, the accompanying CO emission levels were typically less than 1 ppm, and a maximum of 5 ppm.

References

1. R. Christman, S. Bortz, and D. Shore, "The Radian Rapid Mix Burner for Ultra-Low NO_x Emissions" presented at the EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, Kansas City, Missouri (May 1995).

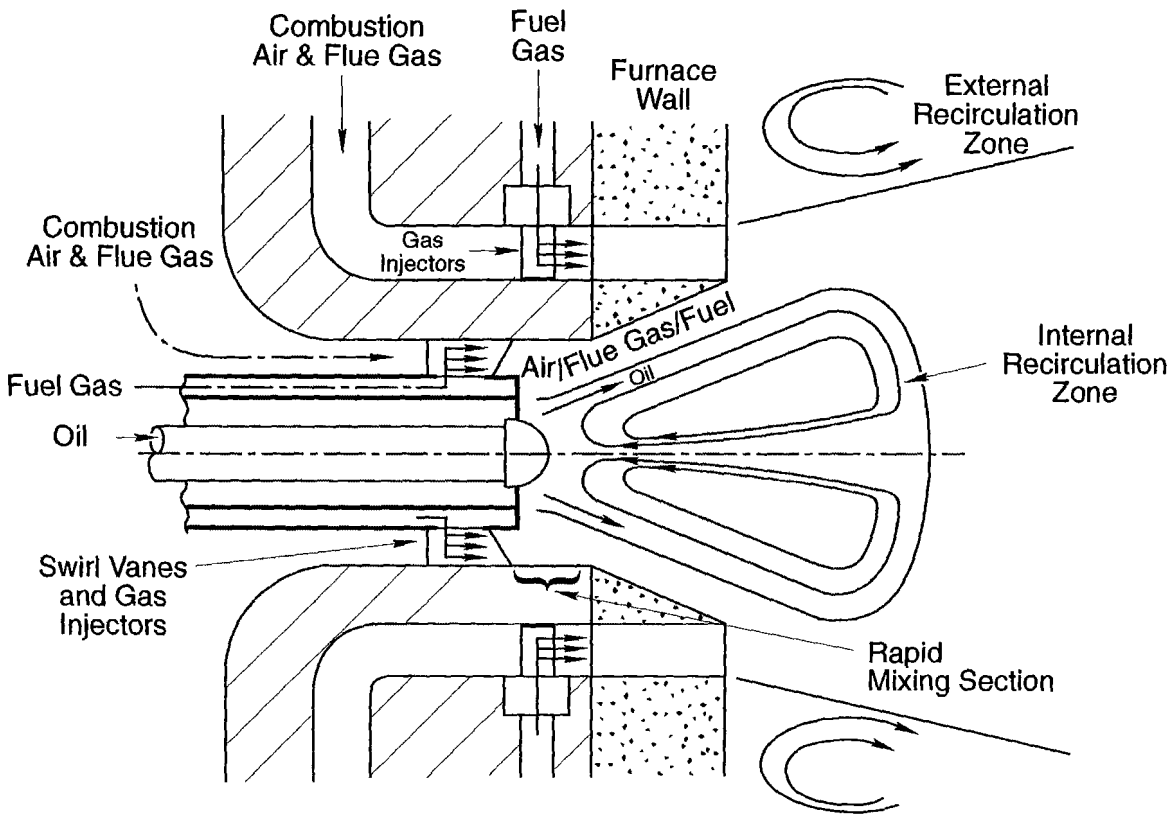


Figure 1
Radian Rapid-Mix Burner, Operating Principle

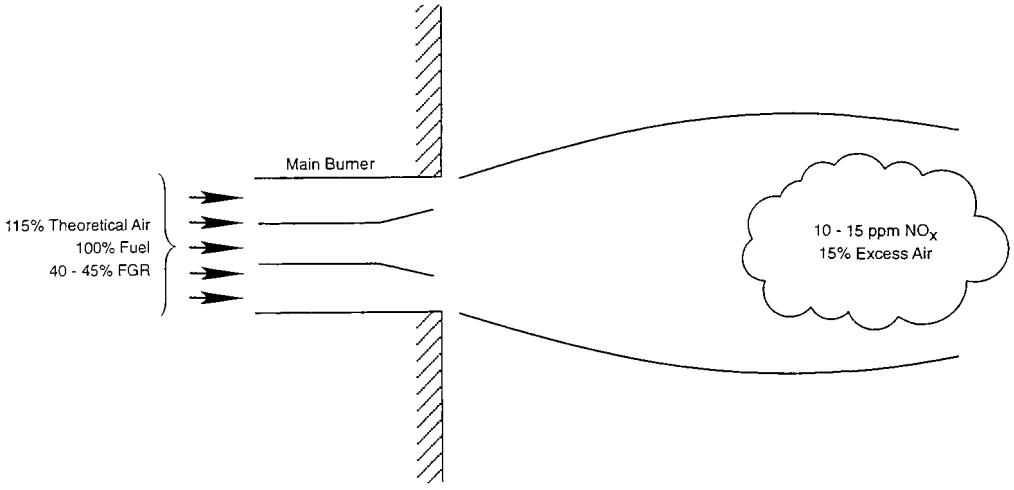


Figure 2
Normal RMB Firing

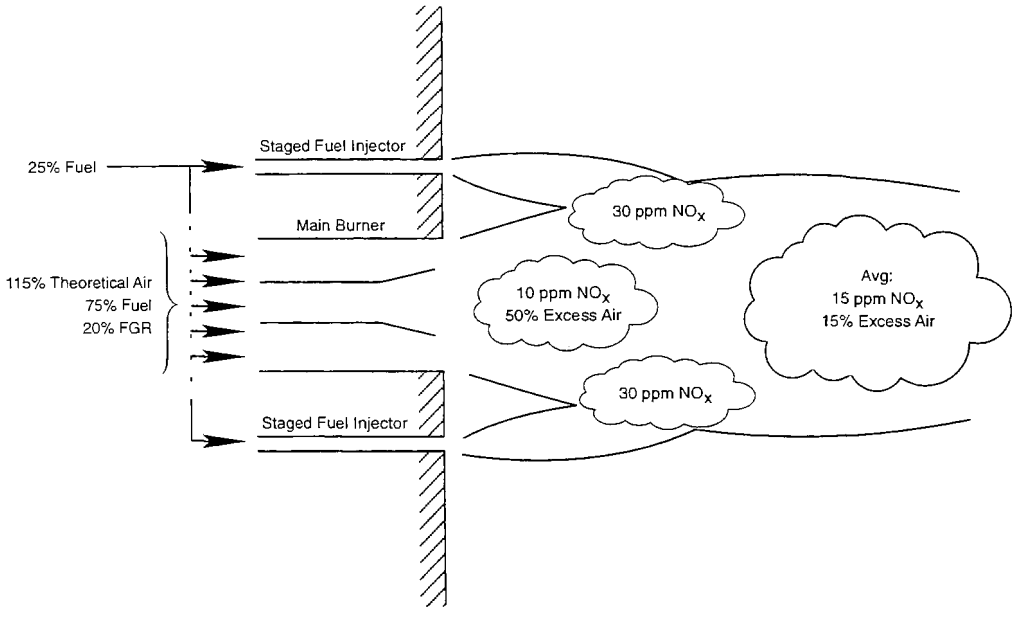


Figure 3
Staged RMB Firing

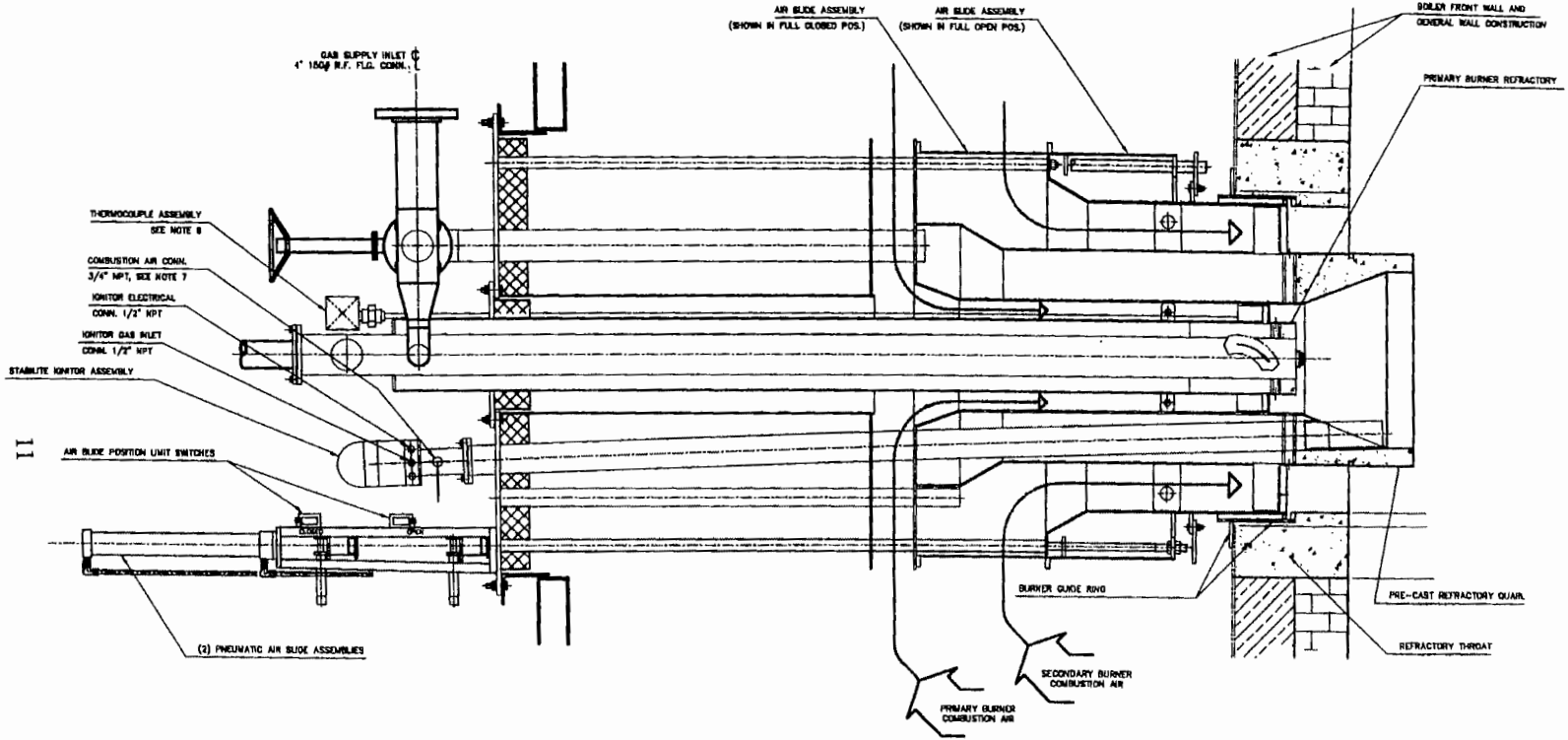
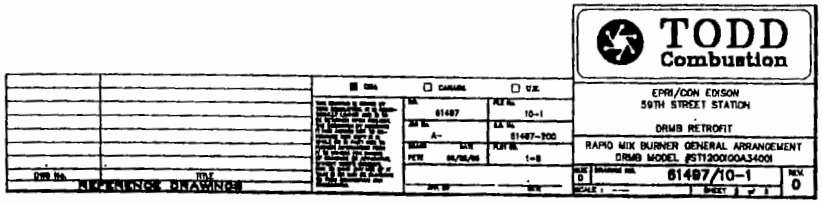


Figure 4
General Layout of RMB for 59th Street Boiler 118



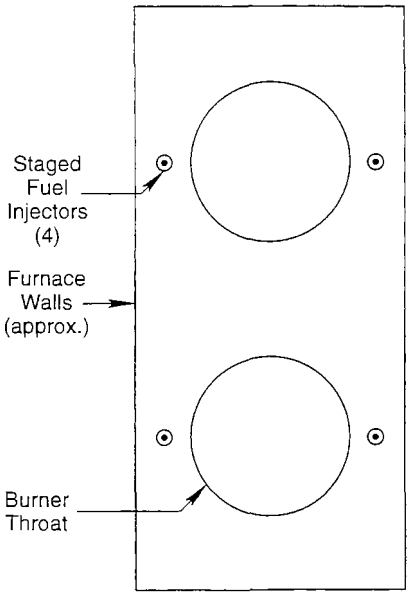


Figure 5
Boiler 118, Location of Staged Fuel Injectors on Front Wall

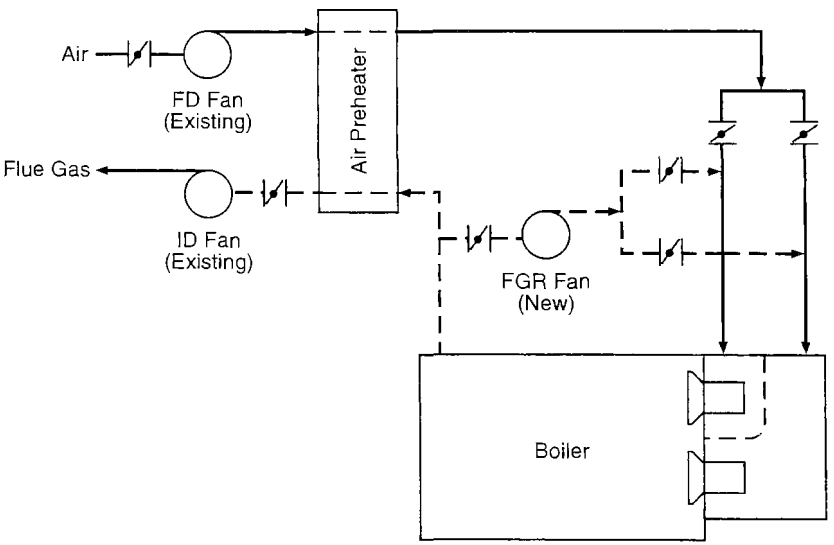


Figure 6
ConEdison - 59th Street Boiler 118 FGR System - Functional Diagram

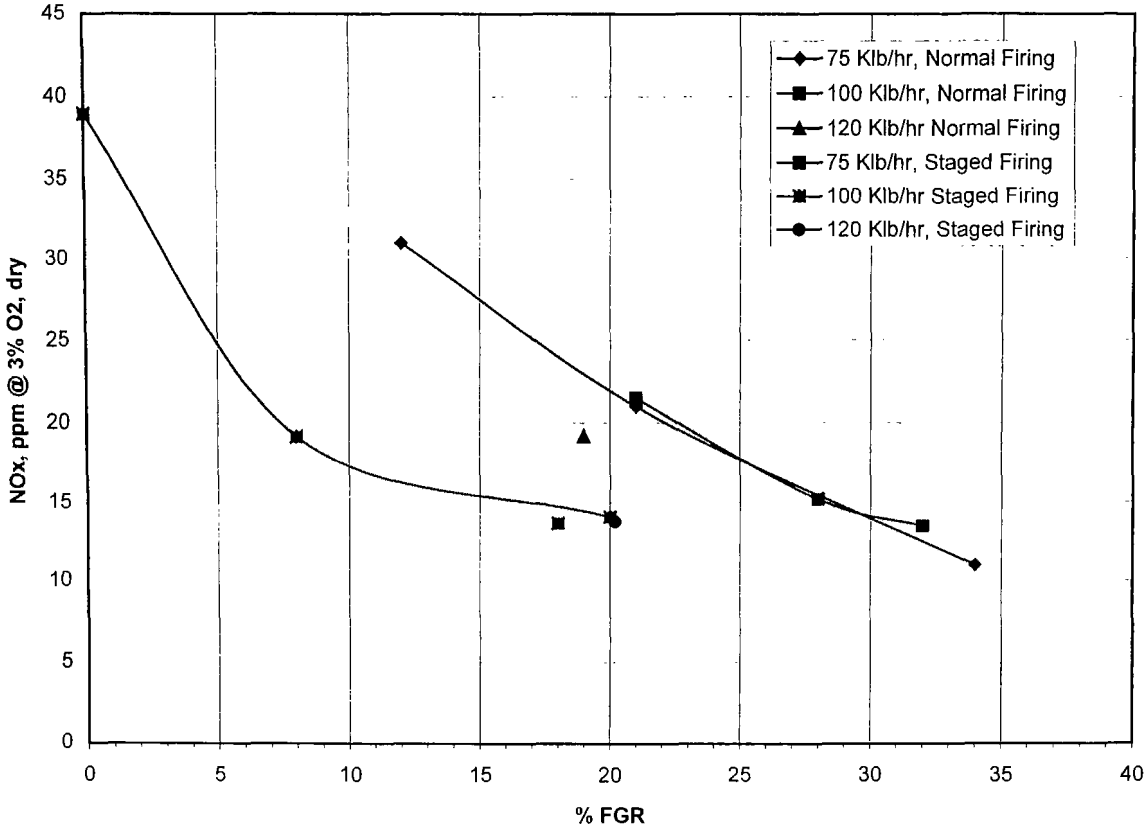


Figure 7
Boiler 118 Effect of FGR and Firing Mode on NOx Emissions with RMB

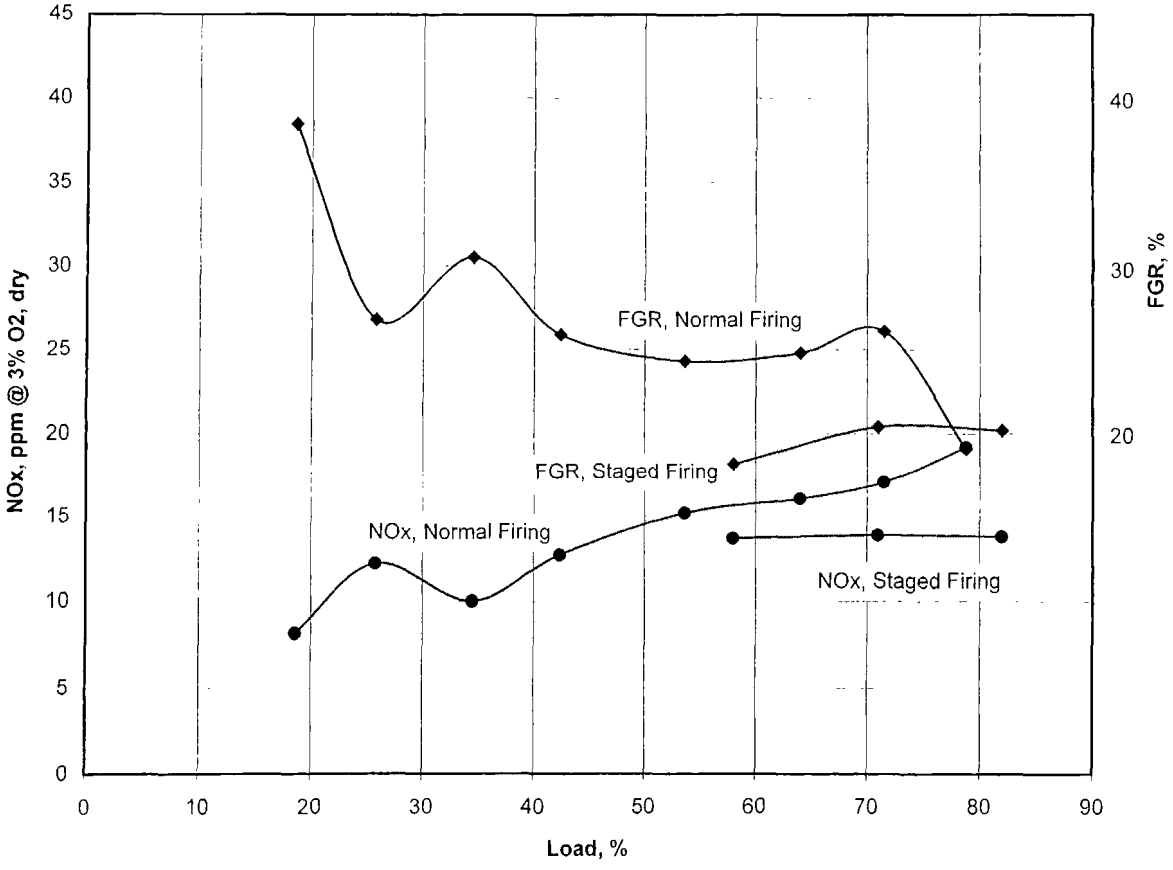


Figure 8
Boiler 118 NOx Emissions Versus Load with Normal and Staged Firing

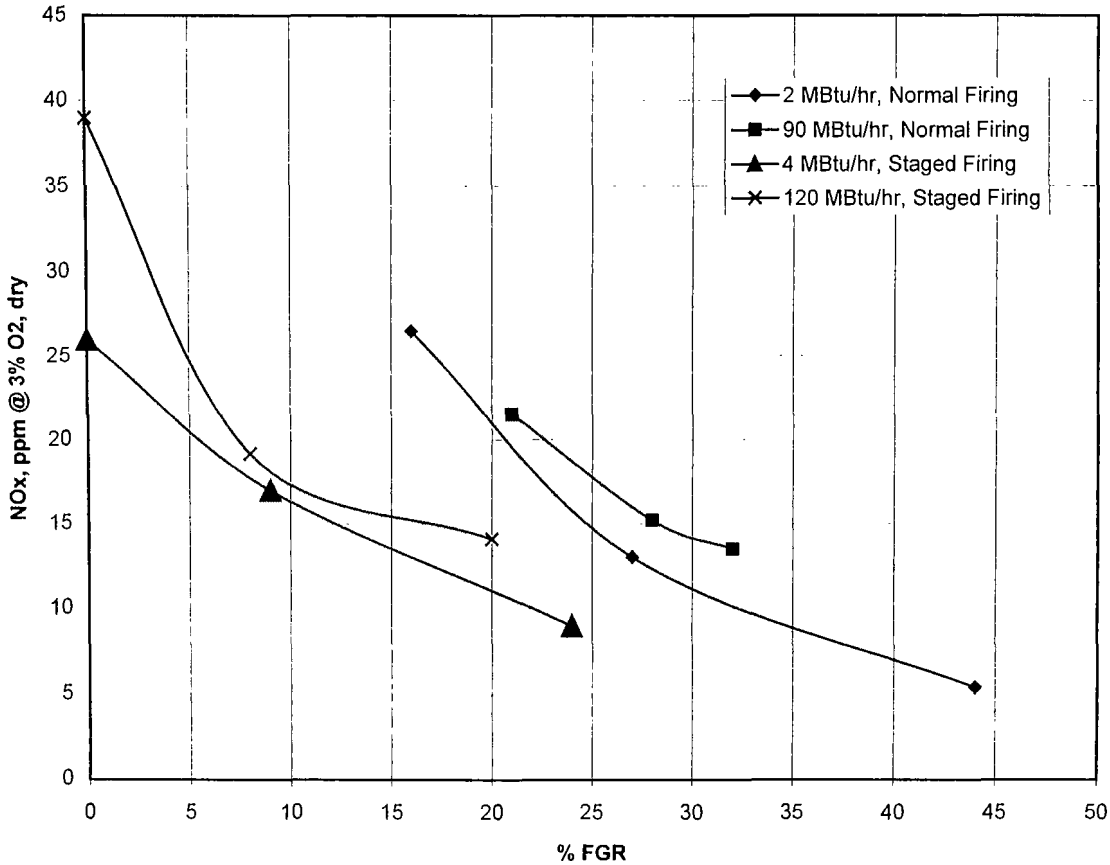


Figure 9
Comparison of Full and Pilot Scale Results

Tuesday, August 26; 8:00 a.m.
Parallel Session A:
Low-NOx Systems for Coal-Fired Boilers (Wall and Tangential)
Continued

THE INTEGRATION OF LOW NO_X CONTROL TECHNOLOGIES AT THE SOUTHERN ENERGY, INC. BIRCHWOOD POWER FACILITY

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Abstract

The Southern Energy, Inc. (SEI) Birchwood Power Facility represents the first application worldwide of the TFS 2000™ firing system and selective catalytic reduction (SCR). The installation of these state-of-the-art NO_x control technologies was necessary to meet strict Commonwealth of Virginia environmental regulations requiring a 0.10 lbs/10^6 Btu (0.043 g/MJ) NO_x emission rate based upon a 30-day rolling average. The plant successfully completed all performance and emission testing on September 24, 1996. Commercial operation began November 14, 1996. Stack NO_x emission rates are consistently maintained below 0.10 lbs/ 10^6 Btu (0.043 g/MJ).

The paper describes the integration of both in-furnace and post-combustion NO_x control technologies into the overall boiler design. Operational data depicting boiler outlet NO_x, stack NO_x and loss on ignition (LOI) are presented across the design load range from 32% to 100% boiler output. The description, arrangement, design parameters and operation of the NO_x control equipment are discussed. Novel design features include a split economizer, an air heater suitable for ammonia applications, Dynamic™ classifiers, and a multi-zone secondary air flow control system utilized for the TFS 2000™ firing system.

Introduction

The Birchwood Power Facility is a 240 MW_e coal-fired plant located on State Route 665, approximately twelve miles east of Fredericksburg, in King George County, Virginia. The cogeneration unit sells electricity to a local utility and process steam to a large greenhouse nearby.

The boiler equipment consists of a Controlled Circulation® steam generator provided by Combustion Engineering, Inc. (ABB CE). The steam generator is an indoor, balanced draft unit designed for a maximum continuous rating (MCR) of 1,571,567 lbs/hr (198 kg/s) at a superheater outlet pressure and temperature of 2465 psig (357.4 kPa) and 1005°F (540.6°C) - see Figure 1 for plant design conditions. The boiler and auxiliaries are designed for daily cycling from 32% to 100% load and sliding pressure operation. Full steam temperatures are maintained

down to 50% load. The fuel is a low sulfur, bituminous coal from West Virginia - see Figures 2 and 3. The unit has the additional capability of firing no. 2 fuel oil from startup to 15% of MCR heat input.

The SEI Birchwood plant, situated 60 miles east of Shenandoah National Park (Class I pristine area), was designed and constructed to meet some of the most stringent air emission regulations. As a result, this unit is one of the cleanest coal-fired facilities in the world.

The unit is located within an area that is either in attainment or unclassified for all criteria pollutants. Since this source has the potential to emit greater than 100 tons per year (90.7 tonnes/yr) of at least one criteria pollutant, the unit is considered a major source, and subject to the Prevention of Significant Deterioration (PSD) regulations. The PSD permit ensures that a new emission source will not cause an area to move into nonattainment status for any criteria pollutant. One of the primary PSD requirements deals with maintaining emission increments within acceptable levels for the district. This is defined as approximately 25% of the difference between the emissions for the area in a baseline year and the emissions that would produce nonattainment status. The other PSD requirement specifies that Best Available Control Technology (BACT) be installed for all emission equipment.

To comply with the Commonwealth of Virginia's emission requirements, BACT was chosen for reducing stack emissions of nitrogen oxides, sulfur oxides and particulates. The primary method used to control each of these pollutants is as follows:

Nitrogen Oxides	TFS 2000™ Firing System in combination with Selective Catalytic Reduction (SCR)
Sulfur Oxides	Spray Dryer Absorber (SDA) utilizing a slurry reagent of calcium hydroxide, $Ca(OH)_2$
Particulates	Fabric Filter (FF) with reverse air cleaning

To ensure that the Birchwood facility would not adversely impact the surrounding area, mathematical models were used to evaluate the atmospheric dispersion of the emissions from the plant. The results of these models confirmed that the air quality impact on the neighboring area was minimal. Subsequently, a permit was issued by The Commonwealth of Virginia Department of Environmental Quality in the fall of 1992.

The emission limitations specified in the permit for NO_x, SO_2 and particulates are as follows:

1. Stack nitrogen oxide (NO_x) emissions shall not exceed 0.10 lbs/10^6 Btu (0.043 g/MJ), 220 lbs/hr (0.028 kg/s) on a 30-day rolling average, and 963.6 tons/yr (874 tonnes/yr).
2. Stack sulfur dioxide emission levels shall not exceed 0.10 lbs/10^6 Btu (0.043 g/MJ), 220 lbs/hr (0.028 kg/s) on a 30-day rolling average, and 963.6 tons/yr (874 tonnes/yr). In addition, sulfur dioxide (SO_2) emissions shall be controlled by a lime spray drying system with a minimum 90% control efficiency in combination with the firing of low sulfur coal.
3. a. Particulate emissions from the boiler shall be controlled by a fabric filter system rated at 99.9 percent control efficiency.

b. Total Suspended Particulate (TSP) measured at the stack shall not exceed 0.02 lbs/10^6 Btu (0.009 g/MJ), 44.0 lbs/hr (0.006 kg/s), and 192.7 tons/yr (174.8 tonnes/yr).

c. Inhalable particulate matter (PM_{10} = particulate matter less than 10 microns) measured at the stack shall not exceed 0.018 lbs/10^6 Btu (0.008 g/MJ), 39.6 lbs/hr (0.005 kg/s), and 173.5 tons/yr (157.4 tonnes/yr).

d. Visible emissions from the boiler stack shall not exceed 10 percent opacity, except during one six minute period in any one hour, where visible emissions shall not exceed 20 percent opacity.

4. Emission limits for carbon monoxide (CO) and volatile organic compounds (VOCs) shall not exceed 0.20 lbs/10^6 Btu (0.086 g/MJ) and 0.010 lbs/10^6 Btu (0.004 g/MJ), respectively.

5. Various emission limits for inorganic pollutants such as lead, mercury, arsenic, etc. were also specified in the plant's operating permit.

Description of Plant NO_x Equipment Features

Compliance with stringent NO_x emission requirements imposed by the site operating permit had a major impact upon the design of the overall steam generator. An integrated NO_x reduction system comprised of a low NO_x TFS 2000™ tangential firing system and selective catalytic reduction (SCR) formed the basis of the BACT technologies - see Figure 4. In addition, high performance (HP) pulverizers with Dynamic™ classifiers, a split economizer section and an air heater suitable for ammonia applications were installed - see Figure 5.

TFS 2000™ Firing System

The TFS 2000™ firing system was the direct result of several years of laboratory development at Combustion Engineering[1]. This is an advanced product that evolved from the Company's standard tangential firing technology. The Birchwood firing system was designed concurrently with a successful TFS 2000™ R field retrofit demonstration[2].

While the firing systems for both plants are similar, and had a common goal to minimize in-furnace NO_x emissions as low as possible, the similarities stop there. The retrofit unit was challenged by a fast-track schedule, existing pressure part obstructions, economics and a desire to minimize impacts upon plant control operation. By comparison, the TFS 2000™ firing system for SEI Birchwood was designed for a new unit application with few restrictions. In addition, the contractual stack NO_x emission guarantee for the Birchwood site was 0.10 lbs/10^6 Btu (0.043 g/MJ), while the retrofit demonstration did not include a specific NO_x emission guarantee other than a best effort commitment.

The specific TFS 2000™ system design features that ensure high combustion efficiency and low NO_x generation are:

- Pulverized Coal Fineness Control
- Early Coal Devolatilization Control
- Concentric Firing - Offset Air Firing
- Firing Zone Stoichiometry Control including:
  - Furnace Bulk Air Staging
  - Activated Zoned Stoichiometry Controls

Pulverized Coal Fineness Control

The four 863 HP pulverizers at Birchwood are equipped with variable speed Dynamic™ classifiers. Finer coal minimizes combustible losses normally attributable to staged, low NOx processes. Finer coal can also result in closer coal ignition and lower NOx emissions by enhancing the fuel bound nitrogen yield, and promoting the reduction to elemental nitrogen. Additional benefits include fewer large coal particles striking the waterwalls and improved low load firing stability. During MCR plant acceptance tests, the Birchwood mills pulverized coal to a fineness of more than 80% passing through a 200 mesh sieve, with 0% on a 50 mesh sieve, and less than 1.5% on a 100 mesh sieve.

Early Coal Devolatilization Control

The early ignition coal nozzle tip design is another important feature of the TFS 2000™ firing system - see Figure 6. The shear bar and air deflector style tip initiates combustion early and produces a stable, devolatilizing zone at a point close to the coal nozzle tip. The ignition point, local stoichiometry, and resultant "prompt NO_x" can be better controlled with the windbox fuel air dampers behind the coal compartments.

Concentric Firing - Offset Air Firing

The concentric firing system (CFS) provides local, horizontally offset secondary air staging in the TFS 2000™ firing system. CFS is unique to tangential firing via the CFS nozzle tips - see Figure 7. This feature directs a portion of the secondary air away from the main coal stream toward the furnace waterwalls - see Figure 8. This provides more favorable low NO_x conditions in the pre-fireball region flame envelope by locally delaying secondary air entrainment into the rapidly expanding fuel/primary air streams. Horizontal air staging is also important when firing coals with slagging and corrosion characteristics. The oxidizing environment created near the waterwalls, both within and above the firing zone, helps to minimize these potentials.

The auxiliary compartments at SEI Birchwood contain two CFS nozzles surrounding a center, non-offset, straight auxiliary air nozzle - see Figure 9. These fully partitioned, three section auxiliary compartments are sized to permit biasing between the amount of offset air and straight air flowing around each coal elevation. The control system has an operator adjustable bias feature impacting the ratio of CFS to straight air flow throughout the boiler load range. With the CFS bias feature, both NO_x and unburned carbon loss performance can be adjusted.

Firing Zone Stoichiometry Control

Furnace Bulk Air Staging

Global or bulk air staging simply means injecting a portion of the combustion air above the main firing zone. This method isolates air from the devolatilization initial char combustion zone. The fuel rich chemistry promotes the formation of molecular nitrogen rather than NO_x species. In addition, significantly staged combustion reduces peak flame temperatures, also resulting in lower thermal NO_x.

Two global air staging techniques, Close Coupled Overfire Air (CCOFA), and Separated Overfire Air (SOFA), were developed through extensive pilot scale testing at ABB CE laboratory and field demonstrations. This effort has shown that while air flows directed through the SOFA

compartments more effectively minimize NO_x, a combination of both CCOFA and SOFA provide a superior system with respect to the total combustion process.

The SEI Birchwood TFS 2000™ system incorporates both global air staging techniques. Two CCOFA compartments are situated at the top of each corner windbox. Above the CCOFA are two separate, multiple compartment SOFA windboxes. The overfire air flow improves carbon burnout and assists with global NO_x emission control. The multi-level, low and high SOFA boxes (L-SOFA and H-SOFA) provide flexible staging capability throughout the boiler operating envelope - see Figure 9. These SOFA nozzles are each equipped with a manually adjusted horizontal yaw mechanism providing ±15° freedom, and are positioned as necessary to impact upper furnace mixing.

Active Zoned Stoichiometry Controls

While adequate at high boiler loads, the traditional secondary air damper control system (SADCS) does not actively attempt to control NO_x at low loads. The typical SADCS logic does not account for increases in excess air during boiler load reductions. Consequently, NO_x emissions trend upward as the boiler load decreases. NO_x emission spikes also occur during load transients and subside as the unit air flow matches fuel flow.

Today's stringent local environmental standards require continuous emission monitoring throughout the entire boiler operating envelope requiring a more sophisticated approach to secondary air control. Specifically, the location and amount of OFA flow, regardless of a particular operating condition, must become an essential part of the total system package. To address this issue, the windbox damper control for the TFS 2000™ firing system is based upon an active zoned stoichiometry control philosophy. This feature, schematically represented in Figure 10, continuously monitors and strives to maintain the combustion zone stoichiometry regardless of the unit excess air. The SADCS logic automatically opens the H-SOFA compartment dampers, then the L-SOFA dampers, followed by the CCOFA dampers to maintain programmed zones of stoichiometry throughout the boiler operating envelope. As a result, the zoned stoichiometry control system approach minimizes NO_x emissions at any load and mitigates NO_x emission spikes commonly observed during boiler load ramps.

At the Birchwood facility, the air flow through the SOFA elevations is closely monitored and controlled with an in-situ, multi-point array of total and static pressure sensors in each duct. Eight SOFA air flow meters are installed in the system. The control system logic sums the SOFA air flows on an elevation basis, yielding the total L-SOFA and H-SOFA flows. Using the L-SOFA, H-SOFA flows, coupled with the primary and secondary air flows and the total fuel flow and boiler outlet O_2, the lower furnace stoichiometry can be determined, monitored, maintained, and controlled. The system allows independent control of multiple zones by utilizing ramped functional stoichiometries, $f_1(x)$ and $f_2(x)$ throughout the boiler operating envelope. These functions are independent of the specific unit load and outlet excess air levels. Furthermore, the control system can anticipate transient load induced NO_x emission spikes by monitoring the air and fuel flow demands, while proactively modulating SOFA flows prior to measuring a change in boiler outlet O_2. The feedforward logic has an overload feature which upon sensing full H-SOFA capacity, progressively spills overfire air into the L-SOFA, and, if necessary, into the CCOFA, and finally to the main windbox. These features minimize NO_x emissions during load swings by anticipating high excess air levels, avoiding lags or delays

normally associated with extractive sampling systems, and diverting air to the proper OFA compartments. To date, the plant has operated with SOFA air flows on manual control due to flow transmitter problems.

The TFS 2000™ control system logic also includes a main firing zone (MFZ) stoichiometry override protection feature. This ensures that the main windbox auxiliary air dampers maintain control of the load specified windbox to furnace delta P regardless of the selected MFZ stoichiometry.

Arrangement - Main Windbox

The Birchwood unit is equipped with four main windboxes, one at each corner. These main windboxes include four coal elevations, each serviced by a dedicated pulverizer. The coal compartments each contain an early ignition, shear bar/air deflector style coal nozzle tip, and admit secondary or fuel air when firing pulverized coal at these elevations - see Figure 6. Dust-tight, pneumatically operated slide gates located in each coal pipe near the windbox allow isolation of the piping from the windbox and furnace for maintenance purposes. The fuel compartment secondary air dampers can be adjusted to regulate air flow to match the local volatile matter requirements, and/or shaping and positioning the ignition point.

Beneath the bottom coal elevation are two elevations of auxiliary air compartments. These two air compartments assist with lower furnace carbon burnout while providing operational flexibility throughout the entire boiler load range.

Sandwiched between these four coal elevations are three oversized auxiliary air elevations. The auxiliary air arrangements consist of two concentric firing system (CFS) fixed-offset, auxiliary air elevations surrounding either a center straight air/oil or straight air compartment. These three compartments are oversized to effectively allow biasing of air flow between the center straight air compartments and the outboard CFS style compartments.

The corner windbox assembly arrangement is schematically shown in Figure 9. All windbox nozzle tips can be tilted ± 30° from horizontal.

Oil Firing Equipment

Oil firing equipment consists of two retractable oil gun elevations equipped with a high energy arc (HEA) ignition system. The oil guns are designed for remote operation and are used to lightoff the unit, while gradually raising temperature and pressure at a controlled rate. The oil guns are a source of ignition energy for adjacent coal elevations, and provide stabilization of associated coal compartments at low loads. The oil equipment can maintain up to 15% MCR load. The high energy arc (HEA) ignitor located in each oil firing compartment ignites the oil by directing a high energy electrical discharge to the atomized oil spray/air stream.

Flame Scanner System

Scanners are provided for flame supervision and supply "flame" or "no flame" logic signals to the FSSS® furnace supervisory safeguard system. Infra-red type scanners are located in each oil gun compartment for discriminating flame indication when lighting off each oil gun. Additional flame scanners are located in each auxiliary air compartment and the top end air compartment for furnace fireball indication when firing pulverized coal.

Arrangement - Separated Overfire Air (SOFA) Box Assemblies

With the TFS 2000™ firing system, two separate, multiple compartment SOFA windbox registers per corner are strategically located above the main windboxes. Each SOFA box consists of three separate OFA nozzle elevations. These individual elevations provide the capability of fine-tuning the NO_x control stoichiometric history throughout the operating load range.

The SOFA nozzle tips have the standard ± 30° tilt capability, as well as manual horizontally adjustable ± 15° yaw capability. The SOFA yaw is intended for fine-tuning upper furnace mixing for controlling combustible emissions such as unburned carbon, carbon monoxide and hydrocarbons. Optimum tilt function and yaw settings were set during unit commissioning.

Selective Catalytic Reduction System

No other NO_x control method can match the high reduction efficiency achieved by selective catalytic reduction. This technology was chosen over other post-combustion methods such as selective non-catalytic reduction (SNCR) based upon the successful SCR operating experience in Japan and Germany. Although there was some initial concern over the applicability of SCR with U.S. coals, the Commonwealth of Virginia Department of Air Pollution Control selected SCR as BACT for the SEI project.

The SCR process uses an ammonia reagent (NH_3) over a vanadium/titanium based catalyst to reduce NO_x (primarily 95% NO) according the following equation:

$$4NO_{(g)} + 4NH_{3\,(g)} + O_{2\,(g)} \longrightarrow 4N_{2(g)} + 6H_2O_{(g)}$$

The process is effective within an approximate temperature window ranging from 572°F to 752°F (300°C to 400°C). Above 752°F (400°C), catalytic sintering becomes prominent in lowering the NO_x reduction performance. Below 572°F (300°C), the susceptibility of ammonium bisulfate (NH_4HSO_4) formation on catalyst surfaces increases. The lower temperature limitation is dependent upon the amount of SO_3 in the flue gas. For the Birchwood project, an SO_3 concentration of 11 ppmvd at 3% O_2 dry volume is predicted based upon a maximum sulfur content of 1.20% by weight in the fuel. At this level, a minimum operating temperature entering the SCR of 580°F (304.4°C) is recommended. The ammonium bisulfate reaction can be described as follows:

$$SO_{3\,(g)} + NH_{3\,(g)} + H_2O_{(g)} \longrightarrow NH_4HSO_{4\,(l)}$$

SCR systems can be effectively integrated into the overall steam generator equipment. The SCR unit at Birchwood consists of a high-dust, hot-side reactor located between a split economizer section upstream of a single air heater - see Figure 11. This location provides optimum flue gas temperatures ranging from 580°F to 752°F (304.4°C to 400°C) across a load range from 32% to 100% respectively. Below 32% load, the flow of ammonia to the system is terminated.

The Birchwood SCR uses a plate-type catalyst in a single, downflow, multi-layer reactor. The system was designed for a NO_x removal efficiency of 53% and a maximum ammonia slip of 5 ppmvd at 3% O_2. The stack outlet NO_x is maintained at less than 0.10 lbs/10^6 Btu (0.043 g/MJ). The guaranteed catalyst life is 32,000 hours from initial operation or 63 months from initial gas exposure, whichever occurs earliest.

The anhydrous ammonia system consists of a 10.000 gallon storage tank with two-100% electric vaporizers. The vaporizer assembly is installed in a natural circulation loop, taking liquid ammonia from the bottom of the tank and returning vaporized ammonia to the top. Vaporizer operation is controlled by a pressure switch on the tank. The vapor space at the top of the tank acts as a reservoir for the supply of vaporous ammonia to the system. A single dilution air skid, including ammonia flow control and shutoff valves, and two 100% dilution air blowers is located on a platform near the injection grid.

An ammonia injection grid is situated upstream of the SCR reactor in a vertical run of ductwork - see Figure 12. At this location, a diluted mixture of ammonia in air (6% ammonia by volume in air) is uniformly injected into the flue gas stream through a network of pipes and nozzles. Multiple flow control zones ensure that a uniform distribution of ammonia can be achieved before entering the first catalyst layer. External flow control valves, installed in the piping between the manifold and the grid, enables the operator to bias the ammonia flow for off-design conditions.

The SCR system was designed based upon achieving the following inlet flow conditions to the first catalyst layer:

1. Maximum flue gas temperature variations from the mean value of ± 18°F (±10°C).

2. Maximum deviation of flue gas velocity from the mean value of ± 10% for 90% of the cross-sectional area, and ± 20% for the remaining 10% of the reactor duct area.

3. Deviations in the molar ratio of ammonia to inlet NO_x less than ± 5% from the mean value.

A $^1/_{12}$th physical flow model confirmed that the design and location of the ammonia grid and gas mixer achieved these performance requirements.

One of the major concerns when operating the SCR down to 32% load is maintaining adequate temperatures to the reactor. This is important for avoiding ammonium bisulfate formation on catalyst surfaces and minimizing ammonia slip exiting the process. For the Birchwood facility, this was achieved through an external gas bypass around the secondary economizer. As is common with this arrangement, gas temperatures approaching 1000°F (537.8°C) are mixed with lower temperatures exiting the economizer to achieve the desired thermal conditions to the SCR system. A unique bulk flue gas mixer directly upstream of the ammonia injection grid was necessary to minimize gas temperature imbalances - see Figure 13.

Maintaining sufficient gas temperatures to the SCR at low loads required the installation of an economizer bypass system. The bypass duct is designed with a shutoff slide gate and a louver control damper. As shown in Figure 14, these dampers are opened at approximately 125 MW_e to provide adequate temperatures to the grid before ammonia is introduced into the process. The minimum allowable temperature for ammonia injection is 580°F (304.4°C).

As flue gas is bypassed around the economizer at lower loads, the boiler efficiency is decreased due to the higher gas temperatures exiting the air heater. A novel approach to improving boiler

efficiency during this operation is the split economizer design. Feedwater enters a cased (primary) economizer located in the ductwork exiting the SCR reactor chamber - see Figure 11. The feedwater flows through a connecting link at the exit of this primary section to the secondary economizer located in the boiler backpass. This patented design has a twofold benefit of providing higher relative boiler efficiencies and improved catalyst performance across the load range. With this arrangement, temperatures at any operating point can be optimized to enhance catalytic reactivity performance. Improvements in boiler efficiencies ranging from 0.5% to over 1.0% were realized as compared to those achieved with a single backpass economizer design - see Figure 15.

The SCR system was designed with a 30% reactor bypass with dampers at the inlet and outlet of the reactor chamber - see Figure 16. During cold startup (catalyst temperature below 300°F or 148.9°C), the inlet control damper and outlet shutoff dampers are closed. When the flue gas temperature exiting the boiler economizer approaches 400°F (204.4°C), the reactor bypass slide gate closes and the total gas flow passes over the catalyst. Ammonia injection does not occur until temperatures approaching 580°F (304.4°C) are reached. The main advantage of this arrangement is to protect the catalyst from unburned hydrocarbons, ash deposits, and low flue gas temperatures during startup and low load operation. Also, during hot restarts, the chamber can be isolated until temperatures exiting the boiler better match those internal to the reactor.

The basic function of the ammonia injection controls is to supply the proper flow of ammonia to the system. This is based upon the NO_x concentration at the inlet and outlet of the reactor, the gas flow entering, and the molar ratio of NH_3/NO_x. After a flue gas sample is analyzed for both inlet and outlet NO_x, 4-20 milliamp signals from the plant's distributed control system (DCS) are used to properly position the ammonia flow control valve. If the outlet NO_x concentration is still higher than the desired setpoint, the valve position is adjusted to increase the flow of ammonia to the system. Manual bypass valves are used in the event that the automatic valve fails or requires maintenance. A simplified schematic of the control system is shown in Figure 17.

Monitoring flue gas temperature across the SCR system is critical for preventing the formation of ammonium bisulfate deposits on catalyst surfaces. At the Birchwood facility, gas temperature is monitored at several locations including the economizer outlet, the ammonia injection grid inlet, the top of the reactor chamber and the bottom of the last catalyst layer. The primary purpose for each of these monitoring planes is described in Figure 18. In general, the permissive for injecting ammonia will not occur until a minimum temperature of 580°F (304.4°C) is obtained at each of these locations.

Another feature that is a part of the overall NO_x system design is the air heater. The air heater installed at SEI was specifically designed with materials and equipment for maintaining availability, achieving high thermal performance, and minimizing maintenance. The design addresses the potential impact of ammonium bisulfate deposits on air heater surfaces. The formation temperature of ammonium bisulfate is dependent upon the concentrations of NH_3 and SO_3 entering the air heater. Typical formation temperatures range from 400 to 450°F (204.4°C to 232.2°C). Consequently, the intermediate and cold end layers are the primary areas of concern.

The air heater for Birchwood has enameled heating surface for both the intermediate and cold end layers. Four stationary water washing devices (two each on the hot and cold end) and two soot blowers (one each on the hot and cold end) allow the operator to clean air heater surfaces. Details of the element depth, gauge, material, configuration and equipment are described and compared with a standard air heater design in Figure 19.

Plant Operation

The steam generating unit passed all performance and emission tests in September, 1996. Commercial operation of the plant occurred on November 14, 1996. From the initial first fires right through the last controlled ramping tests, the TFS 2000™ firing system performed successfully. Very little control system field tuning was required. As a result, more time was available for tuning elsewhere, and the entire commissioning process from the firing system through the SCR equipment was uneventful. For example, most of the TFS 2000™ firing system preset damper ramps for the air and fuel streams were left as initially programmed. Also, the stoichiometric flow ramps initially set for the SOFA boxes were left as originally designed. Results of initial performance testing showed the carbon in the flyash maintained below 5% over load - see Figure 20.

The Birchwood facility is cycled from full load down to minimum load (approximately 72 MW_e) on a daily basis. To assist in this plant operation, CETOPS™ Total On-Line Performance System including OTIS™ On-Line Thermal Information System and BSCA™ Boiler Stress and Conditioner Analyzer modules were installed. The OTIS™ program was expanded as part of a research and development effort to evaluate furnace heat absorption rates during operation with the TFS 2000™ firing system. The system records furnace temperatures from chordal thermocouples, as well as monitors the operation of the firing system. Specifically, the OTIS™ system data package includes individual windbox damper positions, overfire air flows, windbox to furnace differential pressures, SCR inlet NO_x emissions, SCR inlet O_2 and unit load. The system permits the remote observation of the TFS 2000™ firing system during normal load dispatch routines. In addition, the OTIS™ system has proven to be a valuable tool in evaluating operating conditions throughout boiler transients. The system provides actual plant operating information.

Since commercial operation, the plant has experienced approximately forty startups - 85% hot starts. Ramp rates on the order of 5 MW/minute have not caused stack emissions to exceed permitted requirements. As shown in Figure 21, the average inlet NO_x loading to the SCR is 0.19 lbs/10^6 Btu (0.082 g/MJ). NO_x emissions leaving the SCR system are controlled below 0.10 lbs/10^6 Btu (0.043 g/MJ). The SCR NO_x reduction efficiency ranges between 60% to 65% over the load range - see Figure 22. Ammonia consumption ranges between 80 lbs/hr (0.01 kg/s) to 50 lbs/hr (0.006 kg/s) over the load range. Ammonia consumption versus load is shown in Figure 23. Due to the continuous cycling requirements of the plant, the ammonia controls have operated primarily in manual mode.

During commissioning, ash extracted from the air heater outlet hoppers was analyzed for ammonia. The ammonia in the ash ranged from 200 to 250 ppmw. Ammonia slip is not

continuously monitored due to the poor experience of these analyzers in a dust-laden environment.

The SCR system is meeting the site's emission requirements under all operating conditions. The plant did experience ammonia leaks in the piping connections around the ammonia storage tank. These were a result of misalignment of threaded pipe connections between the tank and electric vaporizers. During the spring outage, the tank was drained and all piping on the skid welded. Threading occurring at the valves were re-cut and a compatible joint compound applied. In the future, it is recommended to maximize welded connections for all ammonia piping.

The plant experienced its first planned outage on April 26 through May 5, 1997. All SCR system components were inspected and sample catalyst plates pulled for activity testing. A visual inspection of the reactor internals revealed no significant ash buildup on catalyst surfaces. A coating of ash was seen on soot blower piping and ash accumulation plates between the modules. The ash had a grayish color with a consistency of talc. The air heater baskets showed no indication of ammonium bisulfate deposits. At this stage of the catalyst life, ammonium bisulfate formation was not expected to be a problem.

Conclusion

To date, the SEI Birchwood Power Facility has successfully maintained emission levels below 0.10 lbs/10^6 Btu (0.043 g/MJ) on a 30-day rolling average, while maintaining acceptable levels of unburned carbon and ammonia in the flyash. This has been accomplished by an integrated NO_x reduction system consisting of a TFS 2000™ staged tangential firing system and selective catalytic reduction (SCR). The success of the project is a direct result of the conservative design of the furnace, pressure parts (i.e., split economizer), pulverizers, firing system, plant controls, air heater, ductwork, dampers and SCR to ensure that emission requirements are met under all operating conditions. It is anticipated that these reliable technologies will be called upon to meet even lower regulatory NO_x emissions in the future.

References

1. J. L. Marion, D.P. Towle, R.C. Kunkel, R.C. LaFlesh, "Development of ABB CE's TFS 2000™ Tangential Firing System". EPRI/EPA 1993 Joint Symposium on Stationary Combustion NO_x Control, reprinted as TIS 8603, 1993.

2. T. Buffa, D. Marti, R.C. LaFlesh, "In-Furnace, Retrofit Ultra-Low NO_x Control Technology for Tangential, Coal-Fired Boilers: The ABB C-E Services TFS 2000™ R System", EPRI/EPA 1995 Joint Symposium on Stationary NO_x Control, reprinted as TIS 8623, 1995.

GROSS MWe	240	
PLANT LOCATION	Near Fredericksburg, VA	
UNIT TYPE	Controlled Circulation* Radiant Reheat Steam Generator	
COAL TYPE	Eastern Bituminous	
MCR STEAM FLOW	1,571,567 lb/hr	(198.0 kg/s)
SHO PRESSURE / TEMP	2465psig / 1005°F	(357.4 kPa / 540.6°C)
REHEATER STEAM FLOW	1,382,941 lb/hr	(174.3 kg/s)
RHO PRESSURE / TEMP	561.6psig/1005°F	(81.4 kPa / 540.6°C)
COMMERCIAL OPERATION DATE	November, 1996	

Figure 1: Plant Design Parameters

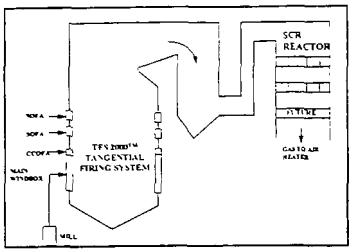

Figure 4: Low NO_x System Strategy

	Typical	Range
Volatile Matter (VM)	33.50	
Fixed Carbon (FC)	50.00	FC/VM<2.0
Ash	9.50	5 - 20
Moisture	7.00	3 - 15
Nitrogen	1.29	1.80 max.
Sulfur	0.91	0.3 - 1.2
HHV, Btu/lb	12,321	12,000 - 13,000
Kcal/kg	6,845	6,667 - 7,222

Figure 2: Typical Coal Analysis (As received, % by weight)

FIRING SYSTEM	TFS 2000™ Tangential Firing System
PULVERIZERS	Four HP 863 With DYNAMIC™ Classifiers
ECONOMIZER	Primary (Cased) and Secondary Split Economizer Design
SCR SYSTEM	Single Vertical Downflow Reactor with Plate Type Catalyst
AIR HEATER	Single Air Heater - Enameled Surface

Figure 5: Plant NO_x Design Features

Fe_2O_3	14 % max.
CaO	8 % max.
Na_2O	0.12 0.39 %
Chlorine	< 0.25 %

Figure 3: Major Constituents in the Ash (As received, % by weight)

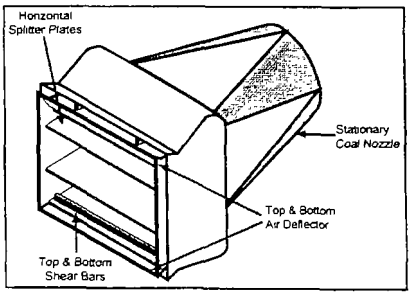

Figure 6: Coal Nozzle Tip

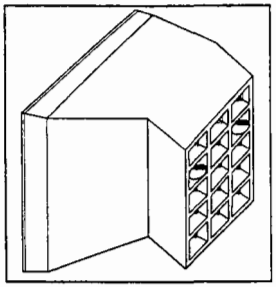

Figure 7: Concentric Air Nozzle Tip (Fixed Offset)

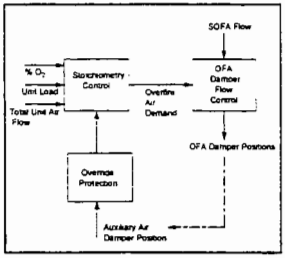

Figure 10: Zoned Stoichiometry Control Schematic

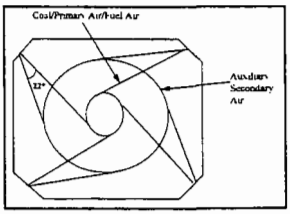

Figure 8: Tangential Firing Pattern with CFS

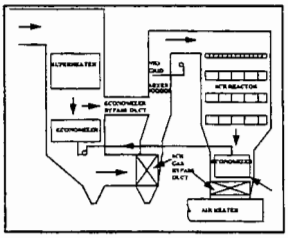

Figure 11: Schematic of SCR System Arrangement

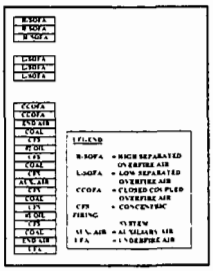

Figure 9: Schematic Diagram of TFS 2000™ Windbox Arrangement at SEI Birchwood

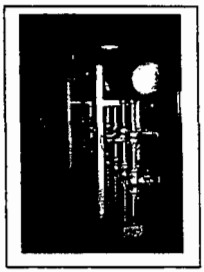

Figure 12: Ammonia Injection Grid Inlet Manifold and Piping

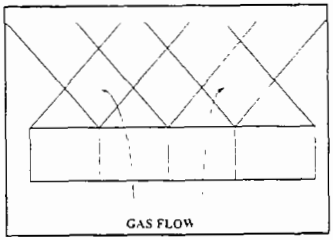

Figure 13: Static Mixer

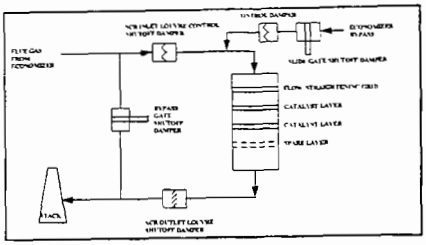

Figure 16: Damper Schematic For SCR System

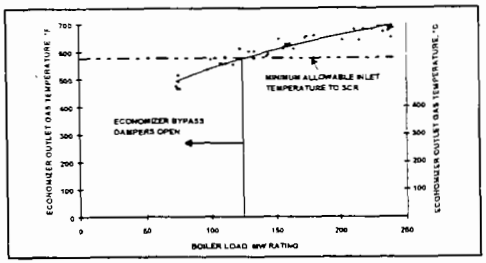

Figure 14: Economizer Outlet Gas Temperature Vs. Boiler Load

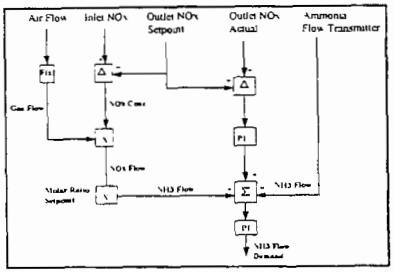

Figure 17: Ammonia Injection Control Schematic

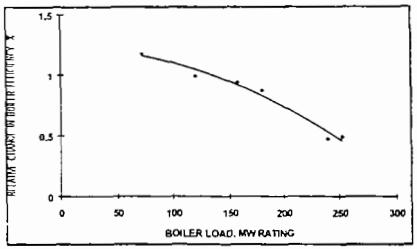

Figure 15: Relative Increase in Boiler Efficiency Vs. Boiler Load Using a Split Economizer Arrangement

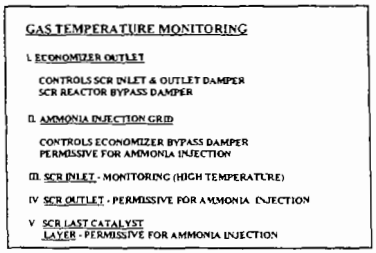

Figure 18: SCR Temperature Controls

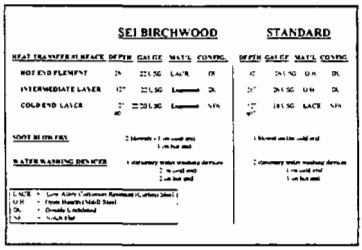

Figure 19: Comparison of the SEI Birchwood Air Heater with a Standard Air Heater Design

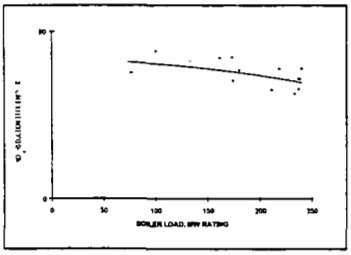

Figure 22: SCR NO_x Reduction Efficiency Vs. Boiler Load

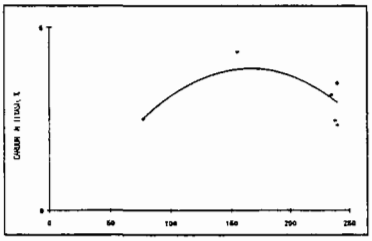

Figure 20: Carbon-in-Flyash Vs. Boiler Load

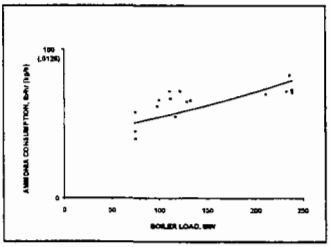

Figure 23: Ammonia Consumption Vs. Boiler Load

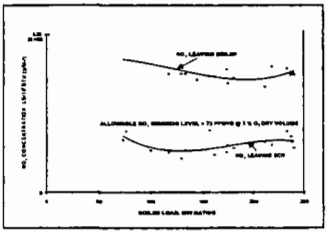

Figure 21: NO_X Emissions Vs. Boiler Load

EPRI-DOE-EPA COMBINED UTILITY AIR POLLUTANT CONTROL SYMPOSIUM
"The Mega Symposium"
August 25-29, 1997; Washington, DC

IMPACT OF COAL QUALITY AND COAL BLENDING ON NO_X EMISSIONS FOR TWO PULVERIZED COAL FIRED UNITS

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Abstract

In the Netherlands almost 45% of the electricity is generated with pulverized coal. Coals are imported from countries all over the world. Since the quality of the imported coals varies to a large extent, most of the coals are blended at a central blending facility to ensure that the specifications of the blend meet the design specifications. The impact of coal quality has been investigated in a 520 MW_e tangentially fired unit equipped with low-NO_x burners and overfire air ports. Twelve coal blends have been fired under identical circumstances. NO_x emissions and burnout characteristics have been successfully correlated with coal quality parameters and excess air ratio. In a 600 MW_e tangentially fired unit equipped with Pollution Minimum burners and overfire air ports the impact of coal blending has been investigated. A comparison of plant performance has been made for two different blending methods: blending the coals prior to pulverization (normal blending scheme) and blending the coals in the furnace by firing different coals at separate burner levels. The impact of flue gas recirculation through the burners on NO_x emissions has also been investigated with this unit.

Introduction

Since 1971 NO_x and SO_2 emissions have been under debate in licensing procedures for new and existing power plants. In the Netherlands a General Administrative Order on the emissions of NO_x, SO_2 and dust from large combustion installations came into force in 1987. This Administrative Order was revised in 1992. For new coal fired power plants, with a license granted at or later than January 1, 1990, the NO_x and SO_2 emissions were limited to a value of 200 mg/m_0^3 (at 6% O_2). From October 15, 1992 onwards the particulate emission was limited to 20 mg/m_0^3 In 1989 the NO_x and SO_2 emission by the Dutch utilities amounted to 74,000 and 45,000 tons/year, respectively. For existing large combustion plants belonging to a utility, a special agreement was made in 1990 between the government and the utilities. It was agreed to reduce NO_x emissions to 35,000 tons/year and SO_2 emissions to 18,000 tons/year by the year 2000. This agreement offered the opportunity to apply measures for NO_x reduction at those units where they are most cost-effective.

In the Netherlands there are five coal fired power stations with a total of seven coal fired units. Five units are tangentially fired and two are horizontally opposed wall fired. The total capacity of the coal fired units is 3900 MW_e. Presently all Dutch coal fired power plants are equipped with flue gas desulphurization units and low-NO_x combustion techniques. At two units selective catalytic reduction is applied as well, for a further reduction of NO_x emissions. During the past few years several programs have been performed to assess the effect of burner and boiler settings on NO_x emission, amount of unburned carbon in the fly ash and boiler efficiency and to optimize the combustion conditions. It is expected that the requirements of the year 2000 can be met with the techniques applied.

For coal firing the Netherlands are completely dependent on imported coals. Coals are imported from countries all over the world, with an emphasis on the USA, Colombia, Indonesia, Australia, Poland, South Africa, Russia and China. Presently, in order to reduce fuel costs and thereby the cost of electricity generation, an increasing amount of coal is bought on the spot market, which may be a coal of poor quality by a high ash content or a low calorific value. Blending of coals is therefore becoming an increasingly important instrument for improving the combustion behavior of the coals, meeting emissions limits and reducing costs.

In the Netherlands coal blending has been practised for many years on the power plant level and since 1992 on a national level with the commissioning of blending silos in the harbor of Rotterdam, which supplies most of the power plants, including the Maasvlakte and the Amer Power Stations, with coal blends. Because of the large variety in coal composition and the increasing amount of extreme coals it is important to assess the effect of coal composition on NO_x emission, unburned carbon in the fly ash and boiler efficiency. During the past few years several programs were performed to collect information on a wide range of coal compositions and on the effect of blending of coals that are substantially different in composition with the aim to minimize fuel costs by the combustion of low-quality coals in coal blends. In this paper the results are reported of firing 12 different coal blends at the Maasvlakte Power Station under well controlled conditions and the blending of a high-volatile with a low-volatile coal at the Amer Power Station.

Experience with correlations on NO_x and burnout

In the past several researchers tried to correlate NO_x emission with coal properties. An example is the work by Pohl et al.[1] in 1983. One of the important statements in this work was the distinction between conventional combustion and low-NO_x combustion. Pohl derived an expression for NO_x emission as a function of nitrogen content, the amount of volatile matter and the amount of fixed combustibles. For conventional combustion an increase of NO_x emission with an increase of the amount of volatiles was found, whereas for low-NO_x combustion the opposite happened: a decrease of NO_x emission with an increase of the amount of volatiles. This finding reveals the most important feature of low-NO_x combustion: the more nitrogen is released with the volatiles under well-controlled (substoichiometric) conditions, the lower the NO_x emission. Several other researchers[2-6] established the importance of parameters like the volatile content and the Fuel Ratio (fixed combustibles divided by volatile matter). A relation which is often quoted is the relation derived by Nakazawa et al.[6] for Matsushima Power Station in Japan. Matsushima Power Station has tangentially fired boilers. The relationship is expressed by:

$$NO_x \quad 100 \cdot (N \quad 0.8) + A \cdot (FR \quad 2) + 250 \tag{1}$$

with: NO_x NO_x emission (ppm, as measured)
N Nitrogen content of the coal (weight-%, dry and ash free)
A $A = 80$ for $FR < 1.6$
$A = 50$ for $FR \geq 1.6$
FR Fuel Ratio

For the burnout of coal the volatile matter content of the coal and the Fuel Ratio appear to be important parameters too. This is stated in works by Takahashi et al.[7] and Nakata et al.[3]. Nakata established the following relations for the burnout for a swirl burner:

$$U_c \quad -0.25 \cdot FR + 99.978 \tag{2}$$

and for a parallel flow burner:

$$U_c \quad -2.95 \cdot FR - 102.29 \tag{3}$$

The burnout can be converted into the amount of unburned carbon in the fly ash by the following formula:

$$UBC \quad \frac{(100 \quad U_c) \cdot (100 - Ash)}{(100 - U_c) \cdot (100 \quad Ash) + 100 \cdot Ash} \quad 100 \tag{4}$$

with: U_c Burnout (weight-%)
UBC Percentage unburned carbon in fly ash (weight-%)
Ash Ash content of coal (weight-%, dry)

Coal blending experiences

A major issue with coal blending is the question whether coal properties and combustion characteristics are additive or non-additive[8,9] The interactions between the components of the individual coals in the blend are not very well understood, which makes the evaluation of blends combustion very complex. Despite this complexity, however, only on a number of occasions serious problems were encountered with severe slagging of the burners and fouling of the superheaters in the Netherlands.

Coal quality and blend quality have a significant impact on power plant performance, with respect to efficiency, emissions, fly ash quality, slagging and fouling. Maintenance and availability are also influenced by the quality of the feedstock. Therefore, coal properties are determined in order to assess whether a specific coal or coal blend may be fired in a particular unit. The properties are determined using laboratory methods specified in national and international standards. Most of the properties of a blend are calculated as the weighted average of the values determined for the individual coals in the blend. Additive coal properties are the heating value, the proximate and ultimate analysis and the chlorine content. Coal properties which are probably non-additive are for example the Free Swelling Index, ash fusion temperatures and grindability.

Description of the boilers

Maasvlakte Power Station consists of two identical units (520 MW_e each), which are tangentially fired and have been built according the low-NO_x technique developed by Combustion Engineering[10], available in the design stage in 1982. The Maasvlakte units have been designed to supply 30% of the total combustion air through close coupled overfire air ports. In comparison with the traditional design, the volume of the boilers has been increased, together with the vertical burner distances, which lowers the average flame temperature, resulting in a decreased formation of thermal NO_x. Another advantage of such a widebody furnace is the ability to fire a large variety of coals. After a number of years of operation the static classifiers in the pulverizers were replaced with rotating classifiers in order to decrease the amount of large particles in the pulverized coal to improve burnout and to reduce NO_x emissions. The burner system of Maasvlakte consists of five burner levels: four levels are sufficient for full-load. As a result of the special agreement between the government and the utilities the Maasvlakte Power Station has to meet the emission limit of 390 mg/m_0^3 (yearly average) instead of the previous limit of 750 mg/m_0^3.

Amer Power Station consists of two units of which unit 9 (600 MW_e) is a modern tangentially pulverized coal fired unit, which was commissioned in 1993. Due to its design as a widebody furnace and its use of PM burners and 25% (close coupled) overfire air, the unit is operated below the NO_x emission limit of 400 mg/m_0^3. The mills are Babcock mills with rotating classifiers. The Pollution Minimum burner has been developed by Mitsubishi Heavy Industries (MHI). The burner system of Amer 9 consists of six levels of PM burners, one level of which is spare. Each burner consists of a burner box with three compartments, as shown in Figure 1.

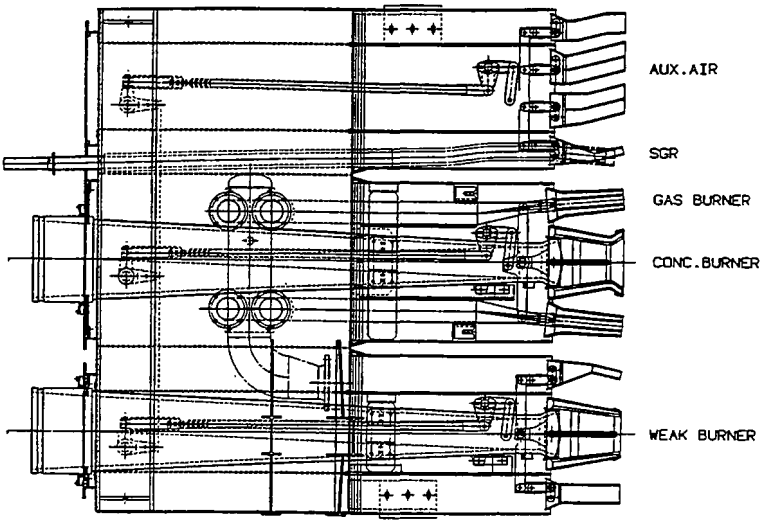

Figure 1
PM burner

The pulverized coal transported by primary air is separated in a fuel-rich and a fuel-lean flow, which are injected separately into the furnace. The fuel jets are surrounded by secondary combustion air necessary for ignition. Below and above the fuel-rich burner, gas burners and SGR ports for flue gas recirculation are located. The third compartment is used to inject auxiliary combustion air into the furnace. The principle of NO_x reduction with this burner system has been described elsewhere[11]

Objectives of test programs

In the Netherlands the coal fired power plants are facing a number of difficulties with respect to power plant operation. Each power plant has to deal with three major issues:

- variation of coal properties
- stringent emission limits
- disposal of fly ash.

The quality of coal is changing frequently. For instance, since the commissioning in 1993 unit 9 of the Amer Power Station has fired more than fifty different coals in more than 175 blends. The emissions of NO_x are strongly related to coal properties. In low-NO_x units the combustion of low-volatile coals generally results in higher NO_x emissions than high-volatile coals. In the Netherlands disposal of fly ash is not allowed. Fly ash is used for application in building materials as concrete and cement. Most of the applications require an unburned carbon content in the fly ash below 5%. Especially in early low-NO_x units like the Maasvlakte units it is difficult to meet both the emissions limit and the quality requirements of the fly ash. Moreover, power station operators also have to deal with a changing quality of the feedstock as a consequence of the coal purchase policy.

In this respect a number of research programs have been performed to obtain a better understanding of the coal quality impact on power plant performance. The objective of the test program performed at the Maasvlakte Power Station was to correlate coal quality with full-scale NO_x emissions and unburned carbon values to be able to predict these before coals are purchased and the coal blends are composed and delivered to Maasvlakte. The objective of the test programme at the Amer Power Station was to obtain information on the impact of coal blending and the blending method on NO_x emission and burnout. Two different blending schemes were investigated; blending the coals prior to feeding the coal to the boilers (the standard procedure) and firing the coals separately at different burner levels.

Results obtained with Maasvlakte trials

Prediction formulas for NO_x and unburned carbon were already used at the Maasvlakte Power Station before the pulverizers were retrofitted and equipped with rotating classifiers. The NO_x prediction was based on a formula derived from operational data of a Japanese Power Station[6]. The coefficients of this equation were adjusted by using Maasvlakte data which had been collected during normal operation[13] The formula derived was a function of nitrogen content and Fuel Ratio. The prediction showed useful results although the accuracy was sometimes rather poor. After the retrofit of the pulverizers and the consequently different operational settings of the boiler it was decided to perform new measurements with twelve coal blends of varying compositions. All measurements were performed under identical circumstances with respect to load, burners out of service, burner tilt and speed of rotating classifiers. Table 1 shows the proximate analysis of the coal blends investigated.

Table 1
Analysis of the Coals Investigated at the Maasvlakte Power Station

Blend	Moisture (wt-%)	Ash (wt-%)	VM (wt-%)	HHV (MJ/kg)	LHV (MJ/kg)	S (wt-%)	N (wt-%)	FR
A	11.0	9.0	29.9	29.06	24.97	0.32	1.52	1.68
B	11.8	8.6	28.7	25.83	24.75	0.39	1.46	1.77
C	8.9	9.0	30.5	27.17	26.10	0.47	1.13	1.69
D	13.6	7.3	31.3	25.65	24.49	0.41	0.92	1.53
E	8.1	11.0	24.5	27.90	26.91	0.41	1.24	2.30
F	13.5	8.4	30.8	25.38	24.23	0.41	1.17	1.54
G	13.9	7.8	29.9	25.85	24.69	0.48	1.17	1.62
H	11.8	9.5	28.6	26.17	25.08	0.47	1.19	1.75
I	8.5	11.0	29.7	26.81	25.76	0.61	1.20	1.71
J	7.5	9.9	29.2	27.96	26.92	0.66	1.54	1.83
K	9.0	14.1	25.8	25.58	24.61	0.57	1.55	1.98
L	9.0	12.3	26.4	26.62	25.61	0.55	1.64	1.98

The test runs were performed at two or three excess air levels to ensure that all coal blends would be compared on the same basis. The reason for this is that the oxygen content of the

flue gases is difficult to control, but is of great influence on NO_x emission. By interpolation of the NO_x curves at a certain oxygen content, NO_x emissions are comparable. Figure 2 shows the NO_x emissions for the coal blends investigated.

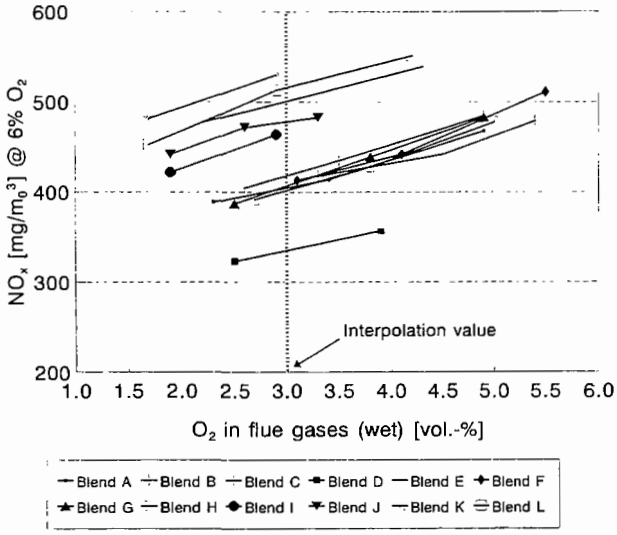

Figure 2
NO_x Emissions as a Function of Oxygen Content and Coal Quality

In this illustration the interpolation line at three percent oxygen content is also drawn. At this oxygen level NO_x emissions of all blends have been correlated with coal parameters.

The dependency of NO_x on oxygen content (i.e. excess air level) is comparable for all coal blends. An increase of the oxygen concentration in the flue gases by 1% results in an increase of NO_x emission by approximately 28 mg/m_0^3. The difficulty to operate in compliance with the emission regulations becomes clear from this illustration. The special agreement between the government and the utilities implied an emission limit of 390 mg/m_0^3 (yearly average). With most of the coal blends this is only possible with for instance, deep air staging.

NO_x has been correlated by means of the least-squares method with volatile matter content, Fuel Ratio, nitrogen content and with parameters composed of e.g. Heating Value, particle size and ash content. These correlation exercises demonstrated that the volatile matter content showed the best correlation and a simple prediction formula for NO_x emission could be derived:

$$NO_x \quad 1000 - 17.4 \cdot VM_d \tag{5}$$

with: NO_x NO_x emission (mg/m_0^3, dry @ 6% O_2)
VM_d Volatile Matter (wt.-%, dry base)

Figure 3 shows the predicted and measured NO_x emissions as a function of volatile matter content. Although some scatter is present, the prediction correlates well with the measured values.

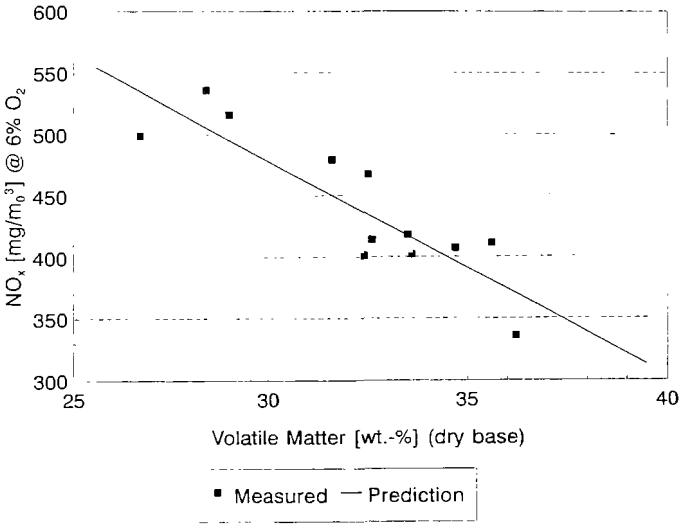

Figure 3
Predicted and Measured NO_x Emissions

A combination of nitrogen and volatile matter resulted in a small but statistically insignificant improvement. A comparable program was carried out at unit 9 of the Amer Power Station. That program showed similar results. NO_x emissions correlated very well with volatile matter, although the coefficients were different from the ones presented for the Maasvlakte Power Station.

The unburned carbon in the fly ash was also correlated with coal parameters, such as ash content, volatile matter and Fuel Ratio. It appeared, however, that no simple correlation could be found. Even the ash content did not correlate with unburned carbon. Burnout, however, showed a correlation with Fuel Ratio that fitted reasonably well. The following prediction formula could be derived:

$$U_c \quad -0.9 \cdot FR + 100{,}83 \qquad \textbf{(6)}$$

The accuracy of this prediction is less than that for the prediction of NO_x emission. The reason might be the more complicated fly ash sampling in comparison with the measurement of the NO_x concentration. The relation is, however, in agreement with those found by Nakata et al.[3] Recent experiences with the combustion of low-quality coals show that incorporation of the grindability in to the formula (by means of HGI) may improve the prediction accuracy.

Role of char nitrogen (test rig results)

An improved correlation for the NO_x emission is probably possible when the nitrogen content of the char can be included. In low-NO_x units the conversion of char-nitrogen into NO_x is probably the major contributor for NO_x. Information on this topic can be derived from KEMA experiments performed in the KEMA 1-MW_{th} coal fired test rig[14] Combustion tests were performed with a series of 12 coals. The nitrogen content in the volatiles and in the remaining char was determined by pyrolysis in a drop tube furnace at a temperature of 1200 °C.

The burner of the 1-MW_{th} test rig is an internally air staged burner (designed by the International Flame Research Foundation) and experiments have been performed without air staging and with 30% of the combustion air added as staging air downstream in the furnace. The results of the combustion tests are presented in Figure 4. The experiments without staging are referred to as 120/0; the experiments with 30% staging air are referred to as 90/30. Conversion ratios of nitrogen in the coal to NO_x have been calculated for all experiments. Figure 4 shows the conversion ratios as a function of the percentage of fuel-N released with the volatile matter. A coal with more nitrogen in the volatile matter will, in general, have a lower conversion of fuel-N to NO_x. This indicates a lower conversion of volatile nitrogen into NO_x than the conversion of char nitrogen into NO_x for both the 120/0 and the 90/30 experiments. The slope of the regression line for the 90/30 experiments in Figure 4 clearly exceeds the slope of the 120/0 regression line. This indicates that the conversion of volatile nitrogen to NO_x for the in-furnace air staging experiments is much lower than the conversion of volatile nitrogen for the 120/0 experiments and is probably close to zero.

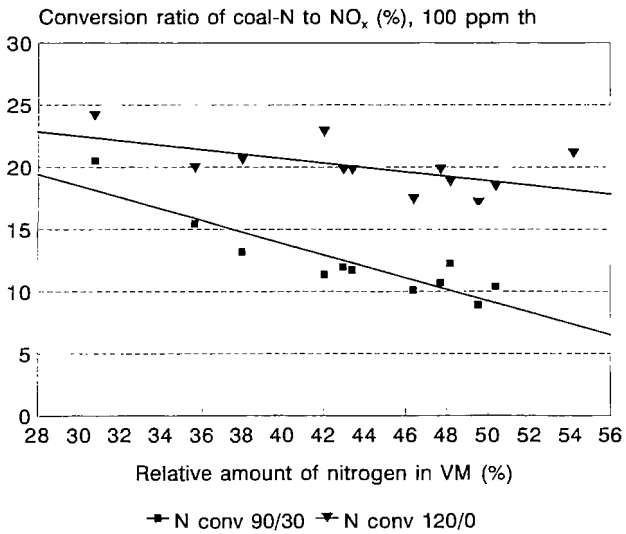

Figure 4
Conversion Ratios of Fuel-N into NO_x versus the Amount of Nitrogen in the Volatiles as a Function of the Original Amount of Nitrogen in the Coal

Assuming that the conversion of volatile nitrogen into NO_x equals zero for the in-furnace air staging experiments, it is possible to calculate the char nitrogen conversions into NO_x. A thermal NO_x of 100 ppm is assumed. These calculated conversion ratios of char-bound nitrogen into NO_x is about 20% for most of the coals, which may also be the limiting factor for NO_x reduction by combustion techniques.

Results of the test program at unit 9 of the Amer Power Station

Tests performed

A survey of the blending configurations which were tested at the Amer Power Station, is presented in Figure 5.

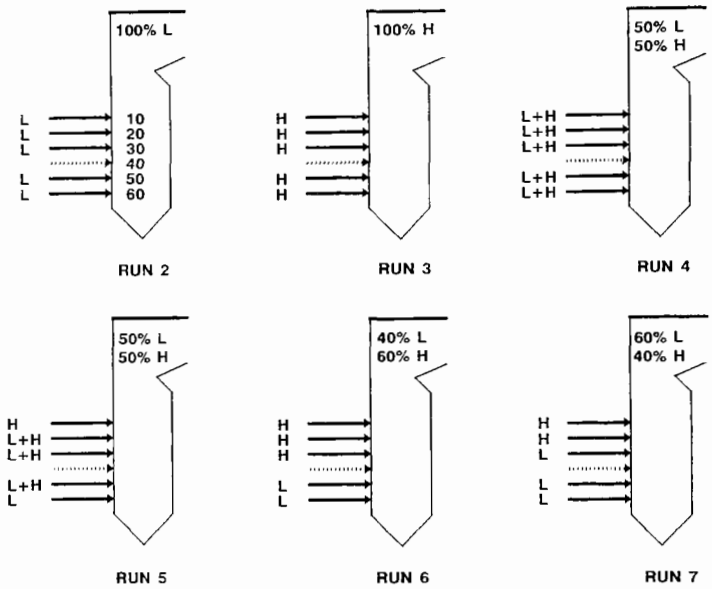

Figure 5
Overview of the Blend Tests (L = Low-Volatile, H = High-Volatile)

Normally, the five lower burner levels are used for full-load operation and burner level 10 is not operated. However, due to problems with burner level 40, it was decided for these experiments to perform all of them with burner level 40 out of service. The numbers in the illustration refer to the burner levels.

Seven runs were performed. The first run was carried out with a reference coal of a usual composition. The second and third runs were the baseline tests with the combustion of the low-volatile and high-volatile coals, respectively. In run 4 a blend of the low-volatile and

high-volatile coal was fired. The blend consisted of 50% of the low-volatile coal and 50% of the high-volatile coal (on a mass basis). The combustion modes of runs 5, 6 and 7 are illustrated in Figure 5.

Coal characteristics

Table 2 contains the characteristics of the coals investigated. The first run was carried out with a reference coal from Poland. The low-volatile coal (run 2) was from South Africa. The high-volatile coal was from Colombia.

Table 2
Proximate Analysis of the Coals

Run ► / Analysis ▼		1 (REF)	2 (L)	3 (H)
LHV	MJ/kg	24.87	25.00	25.31
Moisture	%(ar)	10.3	7.7	11.3
Ash	%(ar)	12.3	14.8	8.4
Volatiles	%(ar)	30.0	24.2	34.9
N	%(ar)	1.1	1.6	1.2
S	%(ar)	0.75	0.49	0.61
Cl	%(ar)	0.14	0.00	0.00
HGI		50	50	47

Test results

Effect of excess air on NO_x emission and UBC.

In order to be able the compare the test results at the same amount of excess air, experiments were performed to assess the effect of excess air on NO_x emissions and the amount of unburned carbon in the fly ash (UBC). The results are given in Figure 6 for the three coals and the blend of the high-volatile and low-volatile coal. The results refer to a situation with the overfire air ports completely opened. The boiler control keeps the amount of overfire air constant for a variation in excess air. Therefore, only the stoichiometry at the burners varies with an increase or decrease in excess air. As a consequence, NO_x emissions increase rapidly when excess air is increased. The low-volatile coal exhibits much higher NO_x emissions than the high-volatile coal. The nitrogen in the char reacts to NO when the overfire air is mixed with the combustion products. The amount of nitrogen in the char of the low-volatile coal is probably significantly higher than for the high-volatile coal, resulting in higher NO_x emissions for the low-volatile coal.

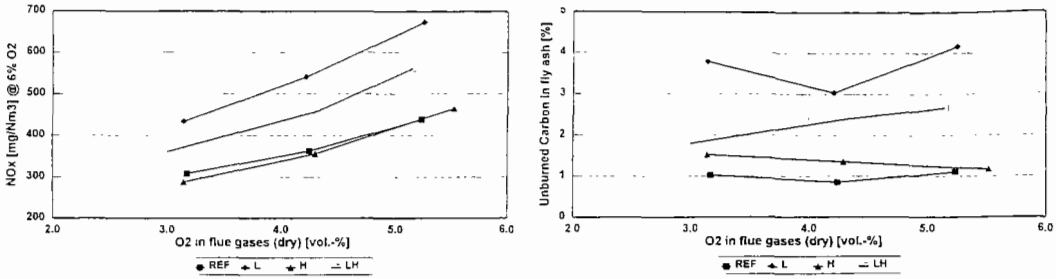

Figure 6
Influence of Excess Air Ratio on NO_x Emissions and Unburned Carbon

Figure 6 also illustrates the impact of excess air ratio on the unburned carbon content (UBC) of the fly ash. The unburned carbon content is in all cases below 5 percent. With three of the four coals the UBC is even less than 3 percent. From Figure 6 it can be seen that no clear trend exists between the oxygen content of the flue gases and the unburned carbon content. One would expect an improvement of the burnout at higher oxygen concentrations. This is only the case for the high-volatile coal. These unexpected results are probably caused by the relatively large residence time in the furnace resulting in an already high overall burnout, thereby reducing the impact of excess air. It is assumed that in this range of oxygen concentrations the burnout (or unburned carbon content) is more or less unaffected by the excess air ratio.

Influence of separate gas recirculation.

In order to test the effectiveness of flue gas recirculation by the Separate Gas Recirculation technique of MHI on NO_x reduction, some tests were carried out by replacing the recirculating flue gases with secondary combustion air, without changing the stoichiometry at the burners. Figure 7 shows the results with the reference coal. The experiments with replacing the recirculation gas by air are compared with the experiments with excess air variation. The experiments without recirculation gas were performed at two excess air ratios. As is shown in Figure 7 NO_x emissions are nearly the same with or without recirculation gas. This was also observed with the other two coals and the blend. The unburned carbon content of the fly ash slightly increased with this reference coal. With the other coals the unburned carbon content remained the same. It was concluded that the replacement of SGR with secondary air does not change the burnout significantly.

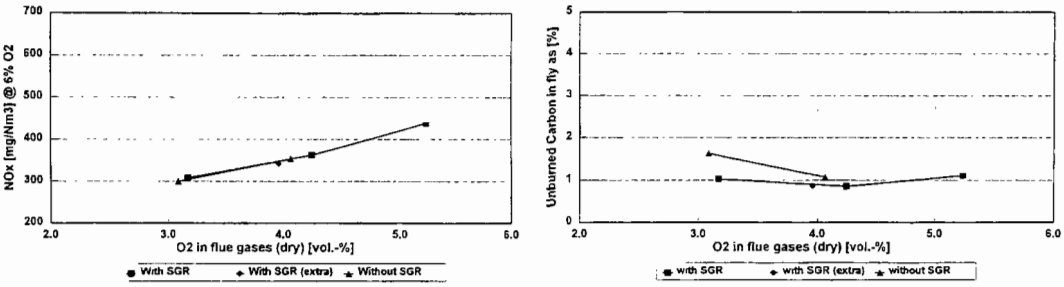

Figure 7
Impact of Recirculation Gas on NO_x Emissions and Unburned Carbon

The heat rate, however, was improved by replacing the recirculated gas at the burners by air. Boiler efficiency increased to some extent due to reduced heat loss of the flue gases and a decrease of the amount of attemperation water in the reheat cycle. The increase in nett efficiency of the unit was about 0.3% (absolute). The nett unit efficiency will rise to 42.6% in case the flue gas recirculation through the burners is switched off.

Coal blending.

Figure 8 shows the NO_x emissions as a function of the blending ratio. The data on the left and right axes represent the situations with 100% high-volatile coal (100% H) and 100% low-volatile coal (100% L), respectively.

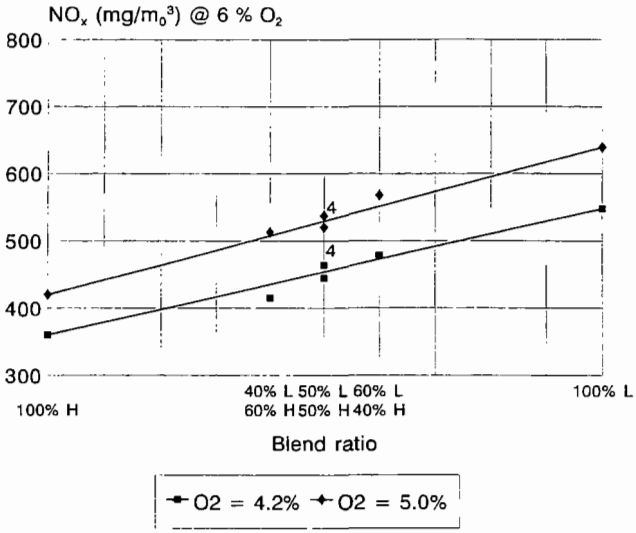

Figure 8
Blend Ratio versus NO_x Emissions for two Excess Air Ratios

Two tests are performed (runs 4 and 5) with a blend ratio of 50/50 (on a mass basis). Run 4 (stockyard blend) is indicated in Figure 8 by number 4. The data in this illustration represent an O_2 concentration of 4.2 and 5.0% in the flue gases measured before the air heater. The overfire air ports were fully opened. The O_2 concentrations of 4.2 and 5.0% are higher than the levels which are normally applied for boiler operation, resulting in this particular case in fairly high NO_x emissions, but the data collected at lower oxygen levels were less reliable than the ones presented in the illustration. It can be seen that there is an almost linear relationship between the blend ratio and the NO_x emission. It is striking that there is almost no difference in NO_x emission between blending before firing (run 4) and blending by firing the different coals at different burner levels. The results suggest that NO_x emissions of coal blends may be determined by a weighting average of the NO_x emissions of the single coals.

The effect of blending on the carbon conversion efficiency is shown in Figure 9. In order to correct for the ash content, the burnout (= % of carbon conversion) is presented, which can be calculated on the basis of the UBC data. Because of the weak correlation of oxygen content and burnout, the values for burnout have been averaged over the range of tested oxygen concentrations. The burnout is in all four blend cases slightly better than the average values based on the burnout of the single coals. It can be concluded that with this particular unit blending does not lead to a lower burnout, as is sometimes suggested in literature for firing mixtures of high-volatile and low-volatile coal[15] The (small) positive impact may be attributed to some extent to the input of the low-volatile coals on the lowest burner levels, resulting in an increase of the residence time in the furnace for these low-volatile coal particles. However, the results of run 4 were also slightly better than the calculated average, suggesting a general positive effect of blending for this particular unit.

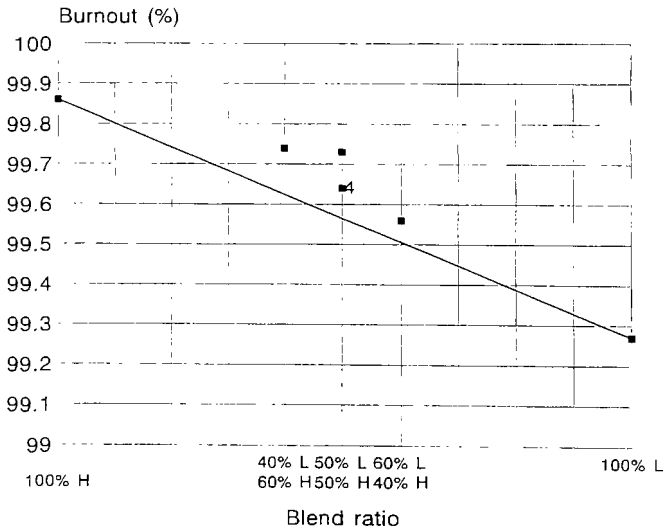

Figure 9
Blend Ratio versus Burnout

Future programmes

The correlation of NO_x emissions and coal quality parameters will be continued for other Dutch coal fired power plants. Moreover, the work on char nitrogen distribution will be continued and a correlation with full-scale data will be performed. The ultimate goal of this and other coal research in the Netherlands is to reduce fuel costs by the combustion of low-quality coals, which will also be investigated by means of field tests. This work will be supported by economic calculations performed with EPRI's Coal Quality Impact Model[16]

Conclusions

From the results of the field tests at the Maasvlakte Power Station it appears that NO_x emission and burnout can be predicted fairly well on the basis of relatively simple coal properties. The best correlation could be achieved for NO_x emission. In order to obtain a high accuracy of the burnout prediction, special attention must be paid to fly ash sampling. For the evaluation of the coal properties it appeared to be very important that the experiments were performed under very stable and well-controlled combustion conditions. An improvement of NO_x predictions appears to be possible in case the nitrogen distribution between volatiles and char is taken into account as well.

With respect to the blending experiments at unit 9 of the Amer Power Station, it can be concluded that the NO_x emission of a coal blend is the weighted average of the NO_x emissions of the single coals. The burnout of the blend is slightly better than the weighted average of the single coals for this particular unit.

Flue gas recirculation for NO_x reduction appears to be ineffective in combination with PM burner technology and deep air staging.

Acknowledgment

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REDUCED NO_X EMISSIONS FROM CERTAIN COAL BLENDS FOR UTILITY BOILERS

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Abstract

Recent pilot furnace testing of coal blends fired through a generic wall-type low NO_x burner have produced lower NO_x emissions than either coal produced alone, unlike most coal blends. This research originally was supported by a consortium of coal-related companies in Alabama, and has been augmented by a tailored collaboration between Alabama Power and EPRI. The experiments were carried out in the Southern Company Services and Southern Research Combustion Research Facility. The results of these experiments, along with their implications for full-scale use, are presented. Possible explanations for these surprising results include changed flame aerodynamics produced by the non-uniform pulverization of the coal mixtures or flame staging caused by the difference in the volatile content of the two fuels.

Introduction

More stringent environmental regulations and a more competitive business climate are changing the market conditions facing both coal users and producers. As a major producer and consumer of coal, the industrial sector of Alabama would benefit from a coordinated program which demonstrates the applicability of wide ranges of blends of Alabama coal with other fuels. Therefore, through Southern Company Services, a consortium of coal users and producers, namely Alabama Power Company and several coal suppliers that have Alabama coal interests, was formed in order to increase the marketability and competitiveness of Alabama coals. This consortium, named the Alabama Fuel Development Consortium (AFDC), consists of Alabama Power Company, U. S. Steel Mining Company, Pittsburg and Midway Coal Mining Company, and the Alabama Coal Association (represented by Drummond Coal Company and Jim Walter Resources).

The AFDC was formed in 1995, with the initial meeting held on May 5, 1995. The primary technical goals of the AFDC are: to broaden the domestic and international use of fuels produced by Alabama-based companies, to improve the fuel efficiency of energy intensive industries, and to further develop fuel-related technical expertise in the state. The initial task of the research funded by the AFDC was to explore the coal quality effects of blending Alabama coals with other coals, both domestic and international. The low-sulfur Alabama coals typically used for utility fuels have medium to low volatile content, which result in marginal NO_x emission performance. If competing western U.S. or international coals could be blended with these coals, the less desirable characteristics of each of the blended coals could be mitigated.

This paper describes a series of experiments where Alabama coals were blended with other coals and fired in a research pilot-scale furnace. Initially, a baseline Alabama coal was fired, followed by the addition of 25% by weight increments of a second coal, ending with the second coal alone. Measurements of NO_x emissions, unburned carbon in the fly ash, grinding behavior, ash deposition, SO_2 emissions, and the ability of an electrostatic precipitator to clean the particles from the flue gas was measured during the combustion experiments. Additionally, the stability of the coals and blends at low burner firing rates was measured.

Description of the Pilot-Scale Research Facility

The Southern Company and Southern Research Institute Combustion Research Facility is located on the Birmingham, Alabama, campus of Southern Research. This pilot-scale simulator of coal-fired utility boilers was designed and constructed and is operated by Southern Research under contract to Southern Company Services. The facility is jointly owned, however, Southern Research is free to use the facility to perform confidential research for other parties, including other utilities, with the payment of a facility usage fee to Southern Company Services.

The facility is described in detail elsewhere and, for brevity, will not be repeated here[1]. Basically, the facility consists of all the necessary equipment to simulate full-scale plant operations from coal handling and pulverization, through a low NO_x burner, to fly ash collection. As is common practice for research furnaces of this size, the burner is indirectly fired, that is, the coal is

pulverized and stored in a fuel bunker and then resuspended into the primary air line, using a weigh feeder. The pulverizer used in the facility is a refurbished CE Raymond bowl mill, Series 352. This mill, with a 35 inch bowl and 2 rolls, is rated at 2 tons per hour.

The furnace and pollution control parts of the facility are shown in Figure 1. The furnace is fired vertically up through a single burner mounted on the floor of the furnace. The radiant furnace is built from a series of refractory-lined, water-cooled sections, each with an inner diameter of 3.5 feet for a total furnace height of 28 feet. The furnace exit leads to a horizontal flue gas duct, which contains banks of air-cooled tubes, intended to simulate superheater tubes. After passing through this horizontal section, the flue gas continues down through a vertical duct with a series of air-cooled heat exchangers which serves to preheat the combustion air and cool the flue gas to a nominal 300°F.

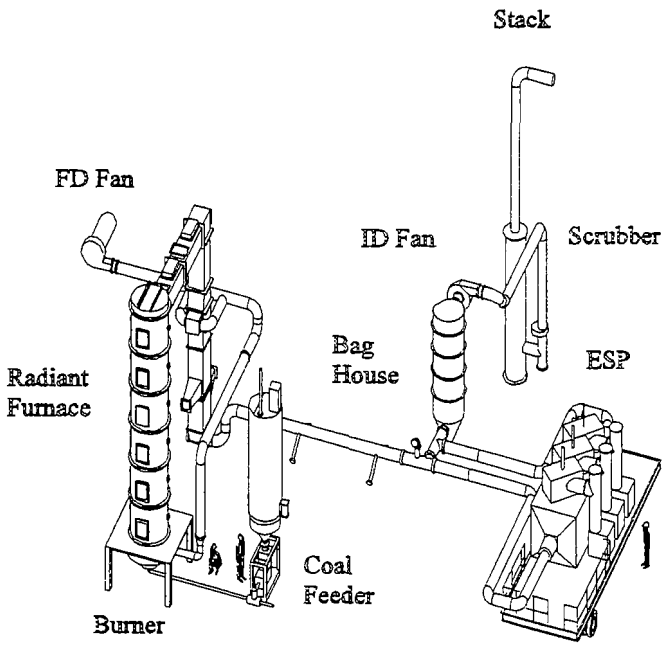

Figure 1. **The Southern Company and Southern Research Institute Combustion Research Facility**

The flue gas is then routed to a cold-side electrostatic precipitator, a pulse-jet baghouse, and a packed-column counter-flow scrubber, in series. The pilot ESP has three fields and a specific collection area of 150 ft^2/ 1000 actual cubic feet per minute flue gas. The pulse-jet baghouse is

required by the facility's air pollution permit and is used to ensure that the particulate emissions are controlled. The scrubber is also required by the permit, and uses aqueous sodium hydroxide to capture sulfur oxides.

Coals Studied

The Alabama coals of interest are generally from the Blue Creek Basin in the western part of the state. These coals are compliance fuels for sulfur content and usually have volatile content in the range of 20 to 25%. As with most lower volatile coals, these coals are marginal in meeting the NO_x emissions requirements of the 1990 Clean Air Act Amendments. Blending of these coals

Table 1
Coal and Coal Blend Analyses for the
Jim Walter #3 and Caballo Rojo Coals

	J. Walter #3	75% JW #3 25% CR	50% JW #3 50% CR	25% JW #3 75% CR	Caballo Rojo
Ultimate Analyses, as fired					
Water, %	0.67	5.08	9.52	14.57	22.61
Carbon, %	79.77	72.01	66.05	58.94	51.61
Hydrogen, %	4.09	3.94	3.92	3.77	3.37
Nitrogen, %	1.43	1.30	1.14	0.99	0.84
Sulfur, %	0.55	0.51	0.48	0.43	0.37
Ash, %	10.45	10.45	10.53	8.58	6.52
Oxygen, %	3.05	6.73	8.38	12.73	14.69
Total, %	100.0	100.0	100.0	100.0	100.0
JW #3 fraction, wt. %	100.0	72.8	49.7	26.2	0.0
Proximate Analyses, as fired					
Water, %	0.67	5.08	9.52	14.57	22.61
Ash, %	10.45	10.45	10.53	8.58	6.52
Volatiles, %	21.54	24.70	27.62	32.30	43.90
Fixed Carbon, %	67.34	59.77	52.34	44.55	26.98
Total, %	100.0	100.0	100.0	100.0	100.0
Heating Values					
As Fired, Btu/lb	13844	12523	11364	10361	9057
MAF, Btu/lb	15576	14826	14213	13481	12779
JW #3 fraction, wt. %	100.0	78.9	63.2	36.2	0.0
Grindability					
Hardgrove Index	85	75	62	56	52

with other potential fuels may mitigate this potential NO_x emissions problem. The two Alabama coals used in this study are Jim Walter #3, mined by Jim Walter Resources, and Shoal Creek, mined by Drummond Coal Company.

The coals picked to blend with these Alabama coals were Caballo Rojo, a Powder River Basin coal, and Mina Pribbenow, a Colombian coal. Both of these coals were mined by Drummond, but recently the Caballo Rojo rights were sold by Drummond. The coal blend combinations were chosen to be: blends of Jim Walter #3 with Caballo Rojo and Shoal Creek blended with Mina Pribbenow. The testing was designed to look at the range of blending possibilities and involved testing each coal as a baseline and then the two coals blended at nominally 25, 50, and 75 percent by weight.

The analyses of the Jim Walter #3, the Caballo Rojo, and the blends are presented in Table 1. As can be seen in the table, the blends vary smoothly from the Jim Walter #3 through the increasing fractions of the Caballo Rojo. As evidenced by the calculation of blend proportion from the analyses, the blends were close to the desired fractions.

The analyses of the Shoal Creek, the Mina Pribbenow, and the blends are likewise presented in Table 2. As above, the analyses of the blended coals shows a smooth variation as more Mina Pribbenow is added to the baseline Shoal Creek coal. The fraction of each coal, as estimated from the analyses agrees closely with the desired fraction.

Description of Pilot-Scale Experiments

The pilot-scale experiments were designed to test a suite of coal quality-related parameters. These parameters were prioritized as follows:

1. NO_x emissions and loss-on-ignition (LOI) of fly ash.
2. Fly ash characterization for electrostatic precipitator performance evaluation.
3. Furnace temperature distribution.
4. Flame stability measurements.
5. Pulverizer operation.
6. Ash behavior evaluations (fouling and slagging).

The scaling and operation of the pilot-scale facility in simulating full-scale plants, along with comparisons of pilot-scale data to full-scale plants, has been presented previously[2] Briefly, the simulation of full-scale units in this furnace has been quite successful for predicting NO_x emissions. For unburned carbon, the pilot furnace results are typically lower than the full-scale, but show the same trends. The well-controlled particle size of the coal fuel, along with the use of a single, well-controlled burner in the pilot furnace, are expected to give better coal conversion than a full-scale boiler with less control over air and fuel distributions.

Table 2
Coal and Coal Blend Analyses for the
Shoal Creek and Mina Pribbenow Coals

	Shoal Creek	75% SC 25% MP	50% SC 50% MP	25% SC 75% MP	Mina Pribbenow
Ultimate Analyses, as fired					
Water, %	1.78	3.32	5.06	6.29	8.00
Carbon, %	75.75	74.39	72.32	71.08	68.81
Hydrogen, %	4.49	4.53	4.58	4.68	4.52
Nitrogen, %	1.65	1.58	1.47	1.36	1.28
Sulfur, %	0.68	0.59	0.51	0.42	0.35
Ash, %	12.11	9.81	8.24	6.30	5.05
Oxygen, %	3.57	5.79	7.83	9.89	12.01
Total, %	100.0	100.0	100.0	100.0	100.0
SC fraction, wt. %	100.0	71.2	49.7	27.9	0.0
Proximate Analyses, as fired					
Water, %	1.73	3.32	5.06	6.29	8.00
Ash, %	12.11	9.81	8.24	6.30	5.05
Volatiles, %	25.45	28.52	30.57	34.28	36.28
Fixed Carbon, %	60.58	58.36	56.14	53.14	50.68
Total, %	100.0	100.0	100.0	100.0	100.0
Heating Values					
As Fired, Btu/lb	13371	13014	12694	12430	12000
MAF, Btu/lb	15526	14980	14640	14220	13798
SC fraction, wt. %	100.0	77.5	51.8	26.4	0.0
Grindability					
Hardgrove Index	75	66	55	53	45

The testing occurred in two sessions: the Jim Walter #3 and Caballo Rojo coals and blends were tested in August of 1995; while the Shoal Creek and Mina Pribbenow coals and blends were tested in December, 1995. For all of these tests, the furnace was equipped with the dual-register burner which simulates low NO_x wall-firing. The experimental sequence for each of these set of coals and coal blends was identical. The pilot furnace was brought up to thermal equilibrium by firing natural gas. Once the furnace was heated, the Alabama coal was introduced to the furnace, and, over the space of 12 hours, the fuel feed smoothly switched from gas to coal. After a few more hours of stabilization, the testing program would begin. After the testing of the Alabama coal (either Jim Walter #3 or Shoal Creek) was completed, the fuel feed would be switched to the

blend of 75% Alabama coal and 25% other coal. After testing, the process was repeated for the 50/50 and 25/75 blends, followed by the pure other coal (Caballo Rojo or Mina Pribbenow for these tests).

For each of the coals or coal blends, the initial testing was designed to explore the response of the fuel, specifically for NO_x emissions and for unburned carbon, to variations in furnace excess air. The total air supplied to the furnace was first increased, then decreased, in order to obtain NO_x data from the emissions monitoring system, with the goal of furnace exit oxygen concentrations of 3.5% for the baseline, followed by 4.5% and 2.5%. During these stable periods of operation, EPA Method 17 samples were taken at the electrostatic precipitator entrance. These samples provide the mass loading of fly ash entering the ESP, but, more importantly, they yield samples which can be analyzed for either LOI or unburned carbon. Also, during this time period, the flue gas entering the ESP is sampled for fly ash particle size using cascade impactors and the gas temperature in the upper half of the radiant furnace is measured. Additionally, the fly ash resistivity was measured *in situ* during these stable testing periods. The electrical performance of the pilot ESP was recorded during these tests, to compare to ESP computer model predictions of actual operation.

Following the NO_x and LOI testing, the stability of each fuel at lower burner firing rates was tested. The firing rate of the burner was decreased on a fixed time schedule, and the firing rate at which the flame extinguished was noted as the burner stability limit. The testing sequence was repeated to help gain confidence in this limit. The furnace exit oxygen increased as the firing rate dropped, similar to a full-scale plant. The primary air was lowered proportionally until the minimum flow to prevent coal particle fallout was reached, and was then held at that level. Similarly, the secondary air was decreased until the minimum flow was reached and then held. Following this procedure, the pilot-scale burner has the same limitations on air flow as the full-scale burners in practice.

The behavior of the various fuels was compared through the pulverizer. As with most small research furnaces, this facility is indirectly fired, that is, the coal is ground in a pulverizer and then stored in a pulverized fuel bunker and then injected into the primary air stream. Although there are safety considerations in storing pulverized fuel, the benefits of more stable operation and the use of a large, more realistic, mill outweigh these problems. Therefore, the pulverizer is isolated from the burner and can be used to measure capacity and the adjustments to produce a certain size of fuel. In these experiments, it was desired to test each fuel at the same fineness, so the mill was adjusted to produce a grind which met a standard grind of 70 % (± 2%) by weight through 200 mesh. For most of the coals, it was possible to produce this grind, but, due to a problem with our sieve shaker, the 75% Jim Walter #3 blended with 25% Caballo Rojo resulted in a grind that was slightly finer than desired, about 77% through 200 mesh. The details of the grinding behavior of the Shoal Creek and Mina Pribbenow blends are presented in the accompanying paper[3]

Finally, the behavior of the ash from the coals and blends was observed in the furnace. The facility has a series of air-cooled tubes in the convective section which mimic superheater tubes in a full-scale boiler. The buildup of ash deposits on the tubes is measured by the aerodynamic resistance of the flue gas passing through the tubes and by the difficulty in removing deposits from

the tube bank. Unfortunately, the facility does not have a slagging panel to accurately measure the behavior of a fuel for slagging. Therefore, slagging behavior is generally assessed by the nature of the ash collected as bottom ash and the rate at which it collects on the hot refractory walls of the furnace.

NO_x Emissions and Unburned Carbon Results

The measured NO_x emissions from the testing of the Jim Walter #3 and Caballo Rojo coals and blends are presented in Figure 2. The measured NO_x at increasing furnace exit oxygen levels is shown as a function of the amount of Jim Walter #3 coal present. The NO_x emissions are shown in units of both parts per million (at 3% oxygen dilution) and in pounds per million Btu. As can be seen from the figure, the NO_x generally decreases as the amount of Caballo Rojo, a Powder River Basin coal, is added. The NO_x emissions at about 75% Jim Walter #3 seem to be higher

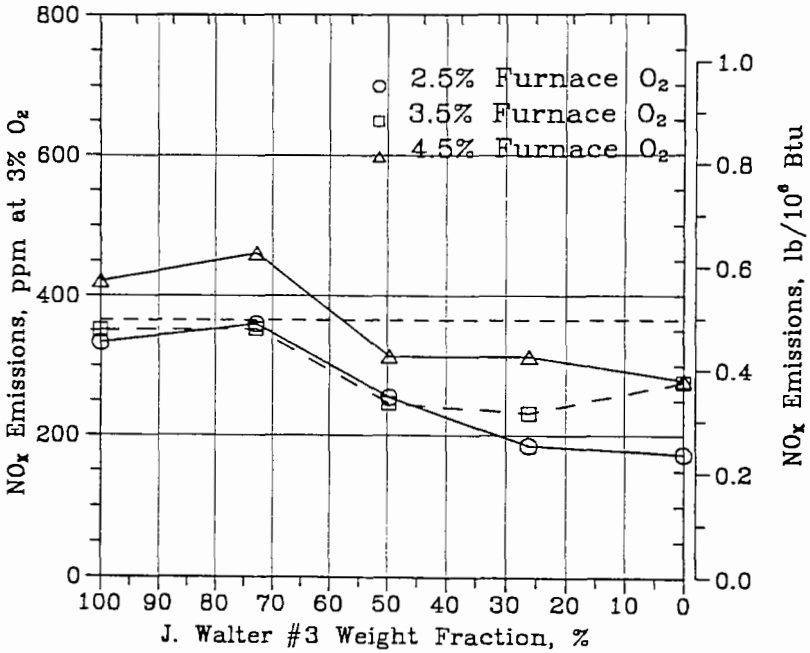

Figure 2. **NO_x emissions from Jim Walter #3 and Caballo Rojo coals and coal blends.**

than expected. As mentioned above, the pulverized coal grind in this test was slightly finer than the other tests performed. It has been generally true that finer coal particle size produces higher NO_x emissions in this furnace.

The unburned carbon from the residual fly ash is presented as Figure 3. (We generally use unburned carbon in our analyses, as it tends to be more precise when describing the efficiency of carbon conversion. Unburned carbon, if there are no sulfates present, is typically about 0.5 to 1%

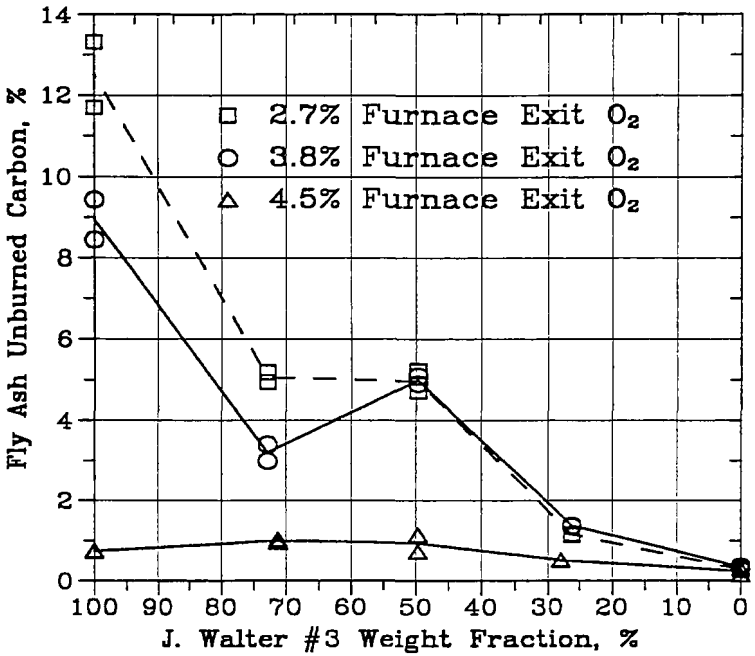

Figure 3. **Unburned carbon in fly ash from Jim Walter #3 and Caballo Rojo coals and coal blends.**

by weight less than an LOI measurement.) As above, the unburned carbon is shown for three levels of furnace exit oxygen for the increasing amount of Caballo Rojo in the fuel input. As expected, the amount of unburned carbon in the fly ash decreases as more Caballo Rojo is added to the fuel. The fuel blend with about 25% Caballo Rojo shows an unburned carbon level lower than a general linear trend would show. As mentioned above, this result is consistent with a finer grind of the fuel, which would cause increased NO_x and decreased unburned carbon.
With the exception of the 25% Caballo Rojo, these blends show a linear trend of both NO_x emissions and unburned carbon as one fuel is gradually displaced by the other coal. Conventional wisdom is to estimate the performance of coal blends as a imaginary fuel that appears to be the weighted average of the two parent fuels, and this blend seems to behave in that manner.

The NO_x emissions measured in the testing of the Shoal Creek and Mina Pribbenow coals and their blends are presented in Figure 4. These results are surprising in that they show NO_x emissions from most of the blends are lower than either coal alone. It was expected that the blends would follow the linear blending rule, as was seen in the blends described above. The NO_x

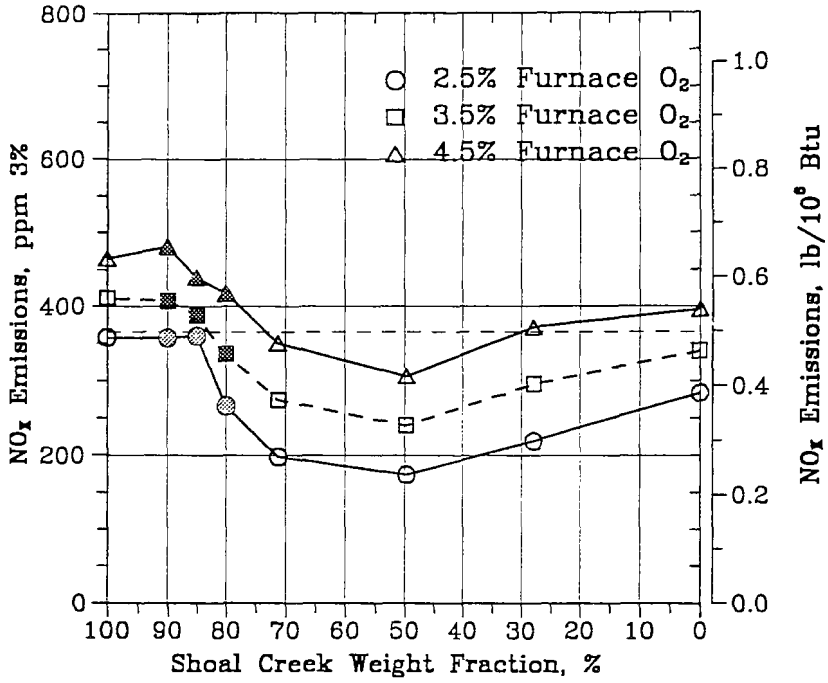

Figure 4. **NO_x emissions from Shoal Creek and Mina Pribbenow coals and coal blends.**

reduction is most apparent at the 50% blend point, but is also observed at the 25% and 75% Mina Pribbenow values. A repeat experiment of the blends in the 80 to 90 percent Shoal Creek range, as shown in Figure 4 as solid symbols, seems to confirm the NO_x emissions data. The addition of a small amount of Mina Pribbenow coal, which moves the blend from 85% to 70% Shoal Creek, seems to make the NO_x reduction start. It seems that 10% Mina Pribbenow coal does not affect the NO_x emissions, but the bulk of the reduction occurs with a blend of only 30% Mina Pribbenow coal.

The unburned carbon results, presented as Figure 5, show an increase with the addition of 25% Mina Pribbenow, followed by a gradual decrease to levels that are lower than the Shoal Creek coal alone. Due to the difficulties in comparing data in the Jim Walter #3 and Caballo Rojo blends caused by particle size fluctuations, a great deal of effort was used to ensure similar particle sizes

for all five test fuels in the Shoal Creek and Mina Pribbenow campaign. The repeat experiment of the blends between 80 and 90 percent Shoal Creek are consistent with the earlier data points. All of the unburned carbon results are consistent with the observed NO_x emissions values, in that the unburned carbon increases as the NO_x emissions are decreased.

The NO_x results of the Shoal Creek and Mina Pribbenow coal blend tests were unusual, and were difficult to understand. However, there is a report in the literature from Germany that shows the same sort of behavior for a blend of two coals[4]. In the reported experiments, a blend of two coals, with an unspecified blend ratio, was fired in a pilot-scale furnace at increasing overfire air flows. Similar to the data here, the blend produced lower NO_x emissions than either coal alone.

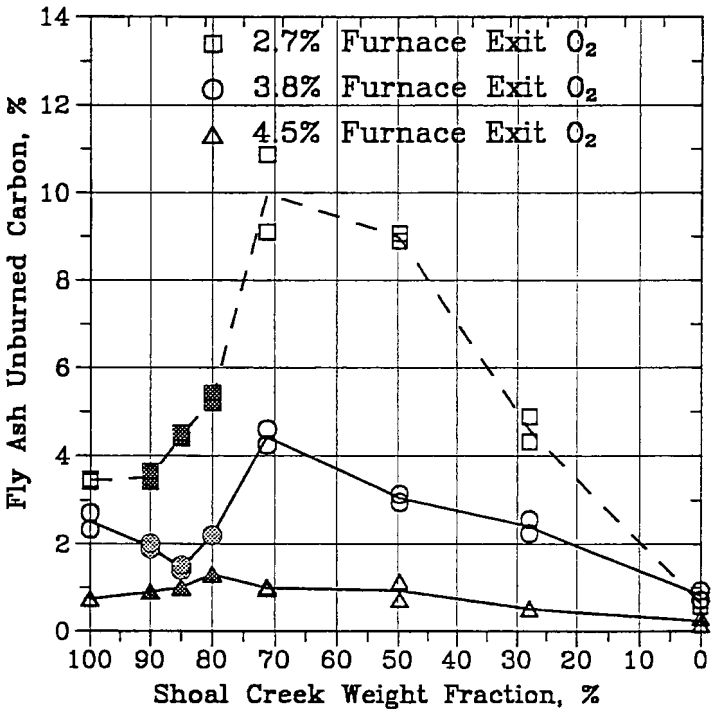

Figure 5. **Unburned carbon in the fly ash from Shoal Creek and Mina Pribbenow coals and coal blends.**

Unfortunately, there is not enough detail given to help understand the results, with such factors as blend ratio, neat coal analyses, blended fuel analyses, and unburned carbon or LOI not reported.

This NO_x reduction is thought to be produced by a particle size segregation of the two coals from pulverization. Previous work at Pennsylvania State University has shown that in grinding of a coal blend, the coal with the lower Hardgrove Index will be found in the larger sizes at a fraction higher than the bulk blend composition[5]. Conversely, the coal with the higher Hardgrove Index

will then be found to predominate in the smaller particle sizes. Indeed, a vitrinite reflectivity analysis of sieved fractions of the three Shoal Creek and Mina Pribbenow blends shows the Shoal Creek dominating the smallest size and the Mina Pribbenow in the largest sizes. This is illustrated graphically in Figure 6.

The NO_x reduction seen in these blends is likely caused by internal staging of the flame by aerodynamics of the different coal particles. The higher volatile Mina Pribbenow coal, concentrated in the larger particles, will be injected into the flame with higher momentum. These particles, due to the higher momentum, will penetrate farther into the furnace, all the time releasing volatiles to the general cloud of smaller, burning Shoal Creek coal particles. This

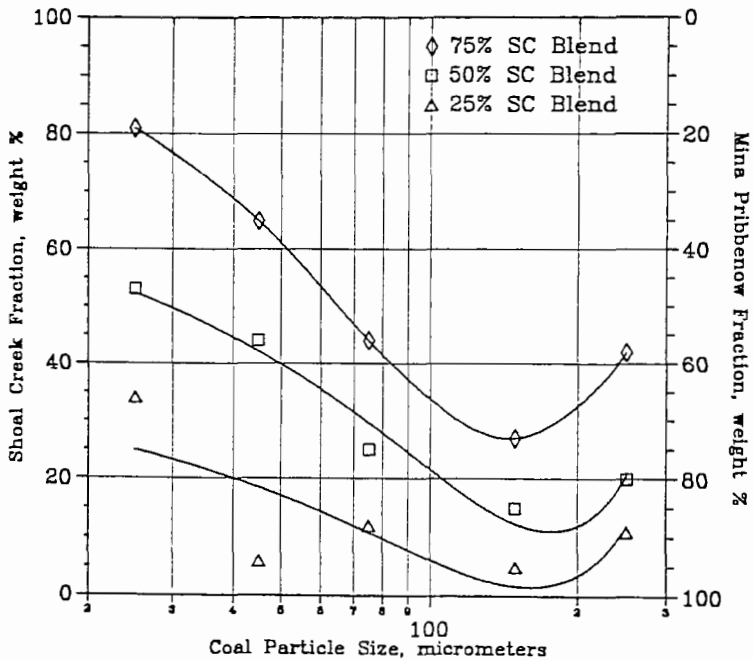

Figure 6. **Fractions of each coal for different sizes in the Shoal Creek and Mina Pribbenow blends.**

volatile release would provide the hydrocarbon radicals necessary to reduce NO_x formed by the Shoal Creek coal particles back to N_2. It may be possible to produce a blend of pulverized fuel by mixing together two coals pulverized alone, so that the effects of flame aerodynamics and coal milling can be separated. Then, a coal with high volatiles that may have better burnout characteristics, can be placed into a blend in the larger sizes, with a low volatile coal in the smaller pulverized coal fractions.

Conclusions

A series of experiments was performed in a pilot-scale combustion research facility, intended to evaluate fuels from lower volatile Alabama coals blended with a Powder River Basin and a South American coal. The NO_x emissions and unburned carbon in fly ash for the Jim Walter #3 and Caballo Rojo coal blends showed nearly linear behavior, with the exception of the 25% by weight Caballo Rojo which had a finer coal particle size.

The results from the firing of blends produced by adding Mina Pribbenow coal, a Colombian coal, to Alabama's Shoal Creek coal, were surprising. The NO_x emissions produced in the combustion of the blends were lower than for either coal alone. This behavior has been seen by other researchers with other coals, and it was observed that pulverization separates the coals into a coarser fraction of the harder Mina Pribbenow coal and a finer fraction of the soft Shoal Creek. The authors speculate that concentration of the more volatile coal in the larger sizes of the pulverized fuel produces an internal staging of the low NO_x burner flame, where the volatiles from the Mina Pribbenow are supplied to the burning cloud of smaller Shoal Creek coal particles. The unburned carbon results were consistent with the NO_x emissions, where the blends produced more unburned carbon than either coal alone. The coal blends were harder to pulverize than the Shoal Creek coal, but this was expected due to the harder nature of the Mina Pribbenow coal.

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Effect of Low NOX Firing Conditions on

Increased Carbon in Ash and Water wall Corrosion Rates

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Abstract

Operating experience with low NO_X firing systems suggests that, although NO_X emissions may be within acceptable limits, these firing systems can create conditions that lead to unacceptable levels of carbon in the fly ash and high water wall corrosion rates. A reacting computational fluids dynamics code which includes the physics and chemistry of particle transport and deposition, coal devolatilization and char oxidation, and both fuel and thermal NO formation has been used to determine how NO_X emissions can be maintained at the same low levels without attendant operational problems.

Simulations have been made for both corner and wall fired boilers retrofitted with low NO_X firing systems for both the pre- and post- retrofit designs. Detailed simulations have been made for conditions within the coal nozzle to ensure that input conditions for the complete boiler model are known. This is particularly important when considering the near field of low NO_X firing systems. The paper demonstrates that the effects of char deactivation must be taken into account if accurate predictions of carbon burnout are required in full scale systems. Comparisons are made of local conditions on the water wall in the firing zone that can cause increased water wall corrosion rates. These local conditions include reducing gas composition, net heat flux, particle deposition rates and the temperature and composition of the particles being deposited as a function of location.

Introduction

The ability of computer models to simulate coal combustion in real systems has improved considerably over the last decade, not only because of improvements in the physical and chemical models, but also due to computer hardware capabilities that have improved dramatically over the same period. Although several industries have made extensive use of computer simulations, only recently has the utility industry begun to accept their value. This is due in part to the fact that the models can now simulate real hardware rather than just simple test combustors. Computer simulation reduces the cost of hardware development by providing insight and giving an indication of the limiting performance if the equipment were to be operated under ideal conditions. Simulations do not eliminate the need for experimental programs prior to demonstrations, but they can provide valuable insight into complex processes.

Many coal-fired units retrofitted with low NO_X firing systems are experiencing problems due to increased carbon in the fly ash or increased water wall wastage. Although the magnitude of the increase in unburned carbon is system and coal dependent, it appears that any significant reduction in the emissions of nitrogen oxides is always accompanied by an increase in the amount of unburned carbon in the fly ash. Low NO_X firing systems are designed to increase the residence time of coal particles in a fuel rich environment. Thus it might be expected that there is insufficient time at temperature to ensure complete carbon oxidation in a low NOX firing system.

Low NO_X firing systems can create conditions on the water walls that exacerbate wastage rates. It is thought that fireside corrosion of water wall tubes in coal fired boilers is primarily caused by high CO conditions close to the wall, causing aggressive sulfidizing conditions. The deleterious effect of reducing conditions, including the presence of species such as H_2S, is through the formation of iron sulfide (FeS) lamellae in the magnetite (Fe_3O_4) on the tube surfaces. These sulfide lamellae are less protective than magnetite causing an increase in the rate of metal loss. The presence of unburned coal particles in the wall deposits has been connected with accelerated corrosion because of the generation, locally, of more extreme reducing conditions. Coal particles may also be important in transporting species such as sulfur to the walls, although the pyritic component is thought to arrive as segregated molten spheres of FeS. High levels of heat flux are also thought to enhance corrosion rates. They may do so by promoting slagging which restricts oxygen ingress to the scale and hence makes the conditions at the tube surface more sulfidizing.

Simulation of pre- and post-retrofit designs have been made for two boilers fitted with low NOX firing systems. This paper concentrates on the conditions that might lead to increases in water wall wastage and unburned carbon.

Simulations

Model Description

The reacting computational code *GLACIER* was used in this study. *GLACIER* is based on software developed over the last fifteen years by Smith and co-workers [1-4]. Particular emphasis has been placed on simulating coal combustion and pollutant formation. The fluid dynamic properties of the gases and particulate matter flowing through a combustion chamber are computed to determine the convective and diffusive mixing of energy and relevant chemical species. The flow and chemical reactions are influenced by the radiative heat transfer that is generated by the combustion process. The radiative heat transfer influences the local devolatilization and heterogeneous combustion of the particles, the local gas temperature and thus the local fluid dynamics. Computations include full mass, momentum and energy coupling between the gas and particles as well as full coupling between turbulent fluid flow, chemical reactions and radiative and convective heat transfer. Two submodels are particularly relevant to this paper: particle transport and char burnout.

Particle Transport

GLACIER models particle transport in turbulent flows based on an extension of stochastic process modeling and turbulence theory. This model provides excellent resolution of particle-phase transport, reactions and deposition while retaining computational efficiency.

In this approach, the particle mechanics are solved by following the mean path or trajectory for a discretized group or cloud of particles in a Lagrangian frame of reference. Particle mass and momentum sources are converted from a Lagrangian to an Eulerian reference frame where they are coupled with gas phase fluid mechanics. The dispersion of the particle cloud is based on statistics gathered from the turbulent flow field. The dispersion model requires no adjustable parameters beyond specification of the turbulent flow field itself and is independent of any particular turbulence model. The description of the turbulent flow field required by the model is in terms of the mean square velocities and Lagrangian correlation functions, available in terms of parameters from the k-e gas turbulence model and particle properties. All particles are assumed to be spherical.

This model has been evaluated by comparison to exact solutions, the most accurate alternative models, and experimental data. It reproduced the exact solutions both numerically and as analytical functions. These analytical solutions have been used as calibrations for some of the most accurate models of particle transport in turbulent flows. In a comparison to turbulent dispersion data collected under nine different flow

conditions, the model predicted the experimental data of all nine cases within the experimental error [5].

The particle transport model allows for particles to stick (deposit) or bounce off water walls and steam tubes depending on the local particle temperature, size, etc. As various particles are removed from the flow domain, the cloud statistics are adjusted accordingly to reflect the change in particle momentum, dispersion, etc.

Char Burnout Modeling

GLACIER includes a char oxidation model with a mean oxidation rate and a new Carbon Burnout Kinetic (CBK) model which has been recently added. CBK is a coal general formulation designed to evaluate the total extent of carbon burnout and flyash carbon content for pulverized coal particles with known temperature/oxygen histories. The CBK model comprises the following four main components:

- The single-film char oxidation model of Mitchell and coworkers [6,7]. In the current version of CBK, the original published correlations have been modified to accommodate thermal annealing and statistical kinetic submodel integration and have been extended to include finite kinetics for lignites.
- A submodel of statistical variations in reactivity and char density among single pulverized fuel particles [8].
- A submodel of thermal char deactivation, or thermal annealing, adapted from the model proposed by Suuberg [9]. In this submodel the char reactivity is a variable whose value depends on temperature and time. CBK incorporates the thermal annealing model in full, differential form capable of accommodating a wide range of non-isothermal temperature histories. As discussed in detail elsewhere [10], the thermal annealing submodel is defined by three parameters determined by evaluation of a collection of thermal deactivation data from relevant literature, including recent data generated in collaboration with Imperial College [11].
- A physical property submodel describing diameter/density changes during combustion, fragmentation, and mineral inhibition in the late stages of combustion.

The comprehensive CBK model was used in a series of one-dimensional reacting flow simulations to better understand the roles of the various individual phenomena described in the code on the overall prediction of carbon burnout. The thermal annealing submodel was found to have a large effect on reactivities and burnout levels at combustion temperatures and times typical of pulverized-coal fired boilers. The submodel of statistical kinetics and densities has a small effect throughout most of burnout, but contributes significantly to the long tails observed in laboratory burnout curves. Finally, the submodel of carbon/mineral interactions contributes substantially to the long burnout tails. None of these individual component submodels can be deleted from CBK without some loss of general predictive capability. For boiler applications however, coarse binning can be used in the submodel of statistical kinetics and densities without introducing significant error. The CBK model was successfully fit

to six sets of long-residence-time data taken in the heated-wall reactor at Sandia National Laboratories. Based on global model predictions along with the kinetic data presented by Mitchell et al, [6], the single-particle temperature predictions in the statistical kinetic model and the successful prediction of low reactivities in residual carbon samples [12], it can be claimed that CBK describes all of the significant features of the Sandia char combustion database.

In order to prepare this model for integration into a comprehensive CFD code, careful sensitivity analyses were carried out in an effort to reduce the computational demands of the thermal annealing submodel. Numerous test cases were examined to find the optimal limits of integration and step size, considering both accuracy and speed.

In order to facilitate an evaluation of the usefulness of CBK in a reacting, multi-phase, CFD code, CBK and GLACIER have been modified to accept/provide appropriate data for transferal between the two codes. Fuel specific quantities (GLACIER inputs) are shared and ensemble averaged values for oxygen concentration, gas temperature, and radiative environment temperature for statistical particle "clouds" (GLACIER calculation results) are input to CBK. CBK has been modified to compile results for each particle cloud and to determine and output total unburned carbon in flyash.

Boilers Simulated

The lower furnace of two boilers, Hammond Unit 4 and Keystone Unit 2, have been modeled.

Keystone Unit 2 is a Combustion Engineering, Inc. Combined Circulation Balanced Draft Divided Furnace Steam Generator rated at 850 MW consisting of two identical tangential fired furnaces. Each of four burner stacks consists of eight levels of coal burners alternating with air inlets. In 1994, the unit was retrofitted with an ABB C-E Services, Inc. Low NOx Concentric Firing System (LNCFS) Level III . The LNCFS Level III system utilizes both Close Coupled Over Fire Air (CCOFA) and Separated Overfire Air (SOFA). The low NOx retrofit has put Keystone Unit 2 in compliance with Federal Government NOx emission regulations, but at the expense of increases in both water wall tube corrosion and LOI. Corrosion rates of up to 50-70 mil/year have been observed in certain regions of the front and back waterwalls at CCOFA and SOFA inlet port elevations. One furnace (Furnace "B") was modeled up to the nose with a 660,000 node Computational Fluid Dynamics (CFD) grid. ABB measured coal flow rates are used in the model with sufficient combustion air for an excess O2 level of 3.5% at the superheater entrance. Combustion air is distributed according to inlet areas. Water wall fluid temperatures are used with a thermal resistance model to control wall heat transfer.

Georgia Power's Hammond Unit 4 is a 500 MWe opposed wall-fired facility with 24 burners. Prior to low-NOx retrofit, the unit included Foster-Wheeler's Intervane burners. After retrofitting, the unit included Foster Wheeler's Controlled-Flow/Split-Flame burner, advanced overfire air (an independent windbox stream for improved penetration/control) through 8 directly opposed ports, and 4 underfire air ports. This furnace was simulated with a symmetry plane along the vertical center from front to rear with more than 480,000 computational nodes. Burner velocity and particle distribution inputs as well as near burner mesh resolution have been guided by detailed coal pipe and complete individual burner simulations.

Coals

Table 1 provides details of the coal composition and particle size distribution used in the simulations.

Table 1. Coal properties

Coal Proximate Analysis

Composition	Keystone	Hammond
Fixed Carbon	46.6 %	52.7 %
Volatile Matter	35.0 %	33.5 %
Ash	12.2 %	9.8 %
Moisture	6.2 %	4.3 %

Coal Ultimate Analysis

Species	Keystone	Hammond
C	69.3 %	72.4 %
H	4.6 %	4.7 %
O	4.6 %	5.7 %
N	1.3 %	1.4 %
S	1.8 %	1.7 %

Keystone Particle Size Distribution

Particle Diameter	Mass Fraction
6 mm	0.17
18 mm	0.15
31 mm	0.11
43 mm	0.10
60 mm	0.15
85 mm	0.10
120 mm	0.12
175 mm	0.05
250 mm	0.05

Water Wall Corrosion

GLACIER does not predict corrosion rates but, if a computer model is to provide insight into the cause of accelerated water wall corrosion under low NO_X firing conditions and allow an evaluation of potential solutions, it must provide an accurate picture of conditions close to the wall including:

- Local gas concentrations including carbon monoxide, hydrogen sulfide and sulfur dioxide.
- Heat flux to the wall, because this can affect deposit formation and slagging.
- Particle deposition rates at the wall.
- Carbon and sulfur content of the particles being deposited at the wall.
- Deposition rates of FeS particles present in the coal stream.

Measured corrosion rates in the Keystone boiler are highest on the front and rear walls, above the close coupled over fire air, in the region of the separated over fire air, and lower on the side and center walls. Comparison of the pre- and post-retrofit simulations indicate that: 1) in the regions of highest corrosion, heat fluxes are higher in the post- than the pre-retrofit conditions; 2) the regions of highest corrosion do not correlate with highest H_2S concentrations close to the wall, but they do correlate to regions with steep gradients in oxygen concentration both along and perpendicular to the wall, and 3) on both the front and rear walls the regions of high corrosion correlate closely with the fraction of unburned carbon in the wall deposit. Figure 1 compares the fraction of unburned carbon in the wall deposit on the rear wall for the pre- and post-retrofit simulations. Shown also are measured wastage rates. The simulations suggest that high corrosion rates in excess of 50 mils/year occur in regions of the water wall were there are high gradients in gas concentrations. In these simulations the gas cell closest to the wall (whose scale is on the order of 2.5 inches) may be oxidizing but one or two cells into the furnace there may be very high concentrations of H_2S. This suggests that intermittency (variation from oxidizing to reducing conditions) may be a key factor accelerating corrosion rates. The simulations also suggest that high concentrations of unburned carbon in the wall deposit accelerate corrosion rates perhaps because of the creation of highly localized reducing conditions but perhaps they are also indicative of the presence of FeS deposition.

Figure 2 compares the burnout history for one particle cloud starting from the same location in the fuel injector for both the pre- and post-retrofit cases. Figures 2a and b show two particle sizes entering from the burners on the front wall at level six near the center wall. The smaller particle does not burnout in the post-retrofit case. Figure 2c presents the same information but for a particle cloud entering from the front side nozzle at the same level. This particle cloud burns out very rapidly in both the pre- and post-retrofit cases.

Carbon Burnout

Simulation of the Hammond furnace required detailed modeling of the coal injector, and this detailed modeling provided improved inputs and guidance in terms of mesh resolution. These simulations were performed on geometries with and without the tangential inlet section. In order to obtain adequate resolution for the anti-roping bars, the following results from the exit of the tangential entry were mapped onto the inlet of a more detailed simulation of the convergent section of the coal pipe:

- Tangential velocity at the inlet to the convergent section was determined from the results of the model of the tangential inlet was used.

- Particle loading computed based on the mass density and velocity distributions from the results of the model of the tangential inlet.

Each computational node from the previous mesh was taken as the location for a particle cloud starting location (~700 positions). Figure 3 illustrates the effects of the coal nozzle on various size particles. The gray surface in the center is the movable sleeve in the center of the coal pipe. The cross sectional planes are colored to illustrate variations in particle mass density and the black lines/circles display a few typical particle cloud trajectories. (The line is the statistical mean position, while the circles represent the variance about that mean.) The larger particles from every starting location quickly reach the wall and pass axially through the coal pipe in the valleys between anti-roping bars. The smaller particles tend to follow the flow and rarely hit the anti-roping bars. The intermediate size particles, which include the majority of the total mass, impact the roping bars, but do not remain in the valleys. This tends to more evenly distribute these particles. Another effect of this design is to segregate the intermediate and large particles into the ellipses, as opposed to the annulus. Since the exit area of the annulus and the ellipses are similar, the proportion of smaller particles exiting the ellipses/annulus are also similar. Another feature of this coal pipe, despite the presence of the anti-roping bars, is the maldistribution in the angular direction. The colors in the image represent the log of mass density and show significant variability in the exit plane.

Accurate simulation of coal devolatilization and char oxidation in a boiler enable one to estimate carbon burnout levels in a furnace. Simulations of the Hammond unit were performed to compare the results of conventional and more complex (CBK) char oxidation models. A summary of the results for two simulations (pre- and post- low NOx retrofit) with the two approaches to modeling carbon burnout are presented in Table 2.

Table 2 Burnout at the Nose for Several Simulations.

	Pre-retrofit	Post-retrofit
GLACIER	96.4%	95.1%
GLACIER with CBK	95.1%	89.3%

As expected the burnout for the post-retrofit simulation is lower irrespective of the char oxidation model used. The results with CBK however indicate two differences between the models. First, the burnout is lower with CBK. Second, the change from pre- to post-retrofit is significantly greater than with the less complex model. Test data from the actual boiler indicates a fairly large difference in burnout should exist.

Figure 4 presents the burnout for these four calculations as a function of particle size. The noticeable difference between the pre- and post- retrofit cases is clear for all particle sizes. However, these data also point out an interesting feature of the size dependence. In the pre-retrofit case it is clear that much of the unburned carbon results from the largest size fractions. However, in the post-retrofit case the dependence of burnout on initial size is much less non-linear, suggesting that removing the largest fraction with improved size classification may be less effective for a post-retrofit situation.

The importance of the relationship between char reactivity and particle temperature/oxygen concentration history can be seen by following identical particles in pre- and post- retrofit simulations. The effect of the low NOx burners and staged air addition is clear. The oxygen is completely consumed in the near burner region and consequently the normalized reaction rate drops to zero. The particle has completely burned in the pre-retrofit case before its post-retrofit equivalent encounters the overfire air and begins to oxidize. In addition, during this time the post-retrofit particle can be thermally annealed further reducing its capability to achieve high levels of burnout.

GLACIER tracks statistical representations of particle trajectories or particle clouds that are uniquely identified by their starting location and particle size. Information is therefore available to determine the burnout of particles issuing from each individual burner in the Hammond unit. Figure 5 illustrates these results for each burner on both walls of the pre- and post- retrofit cases.

The pre-retrofit case displays the obvious trend considering the effects of residence time in the boiler. i.e., the upper rows tend to result in more unburned carbon, with no unburned carbon resulting from the bottom row. Front/rear and inside/outside

differences are small. The post-retrofit simulation however displays more complicated results:

- The inner columns of burners produce minimal unburned carbon.
- While the bottom row again produces no unburned carbon, the middle row results in the highest levels.
- The rear wall results in significantly higher unburned carbon levels than the front wall.

These results suggest that the particle paths and oxygen concentration/temperature fields are complicated by the presence of the low NOx burners and overfire air.

CONCLUSION

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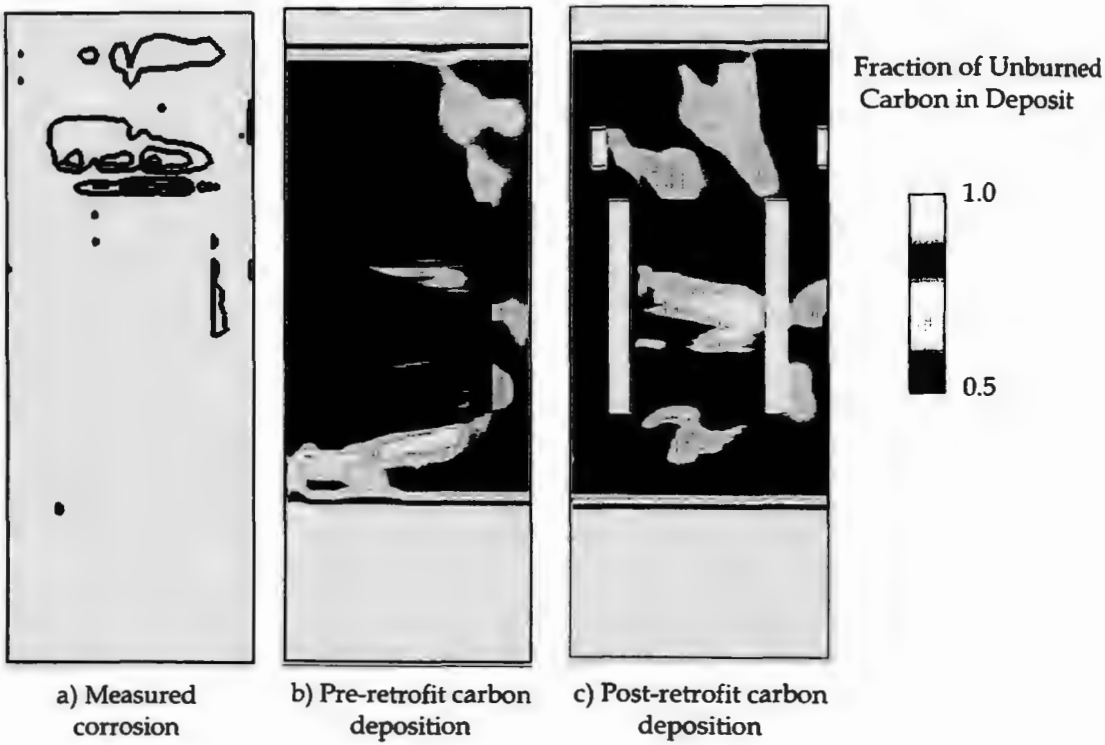
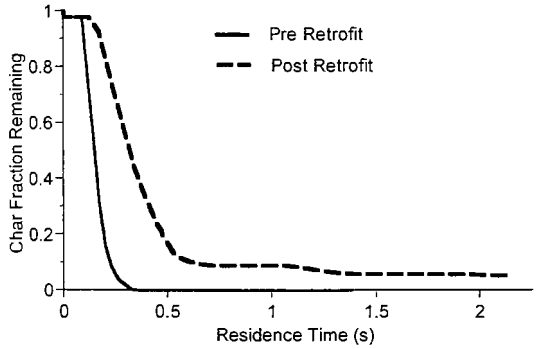
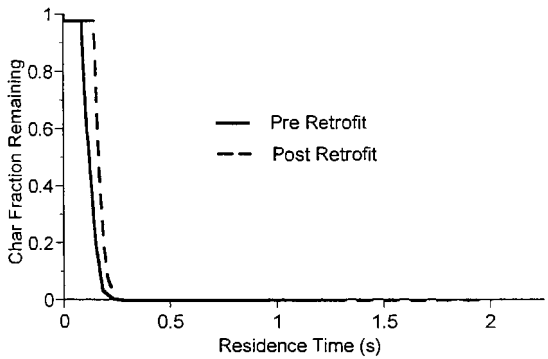


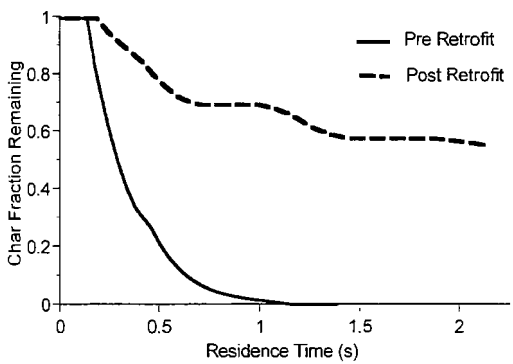
Figure 1. Measured back wall corrosion and the fraction of unburned carbon in back wall deposit.



a) 43 micron coal particle entering from the front center level 6 coal nozzle.



b) 85 micron coal particle entering from the front center level 6 coal nozzle.



a) 43 micron coal particle entering from the front side level 6 coal nozzle.

Figure 2. Fractional char remaining as a function of residence time.

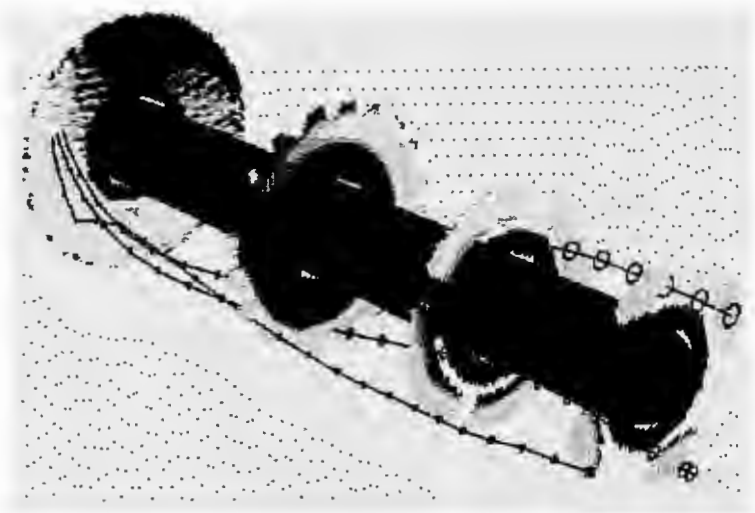


Figure 3. Simulated burnout as a function of particle size for pre- and post-retrofit boilers using conventional and CBK char oxidation model

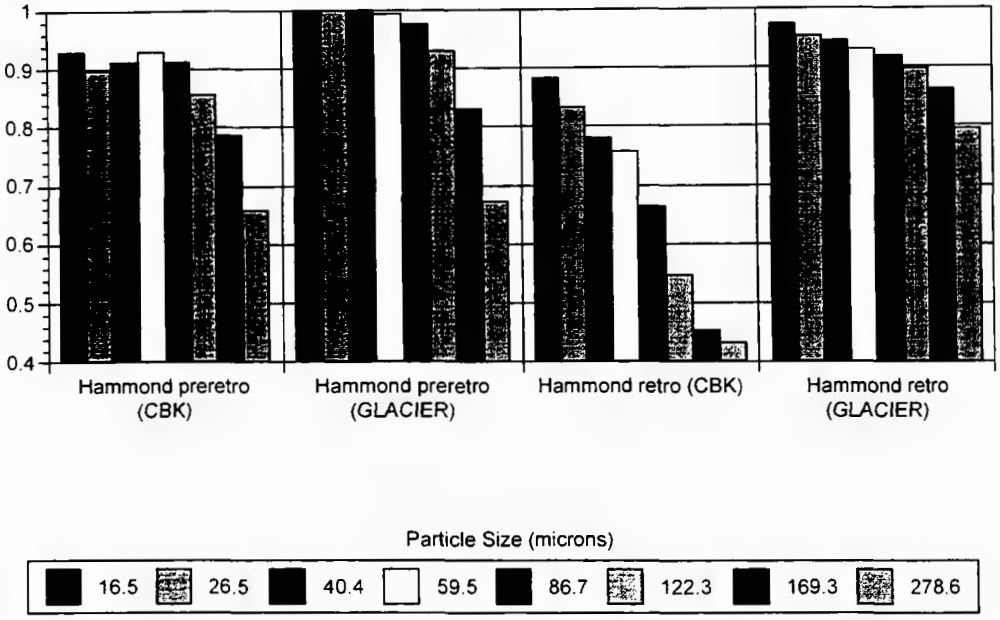


Figure 4. Simulated burnout as a function of particle size for pre- and post-retrofit boilers using conventional and CBK char oxidation model

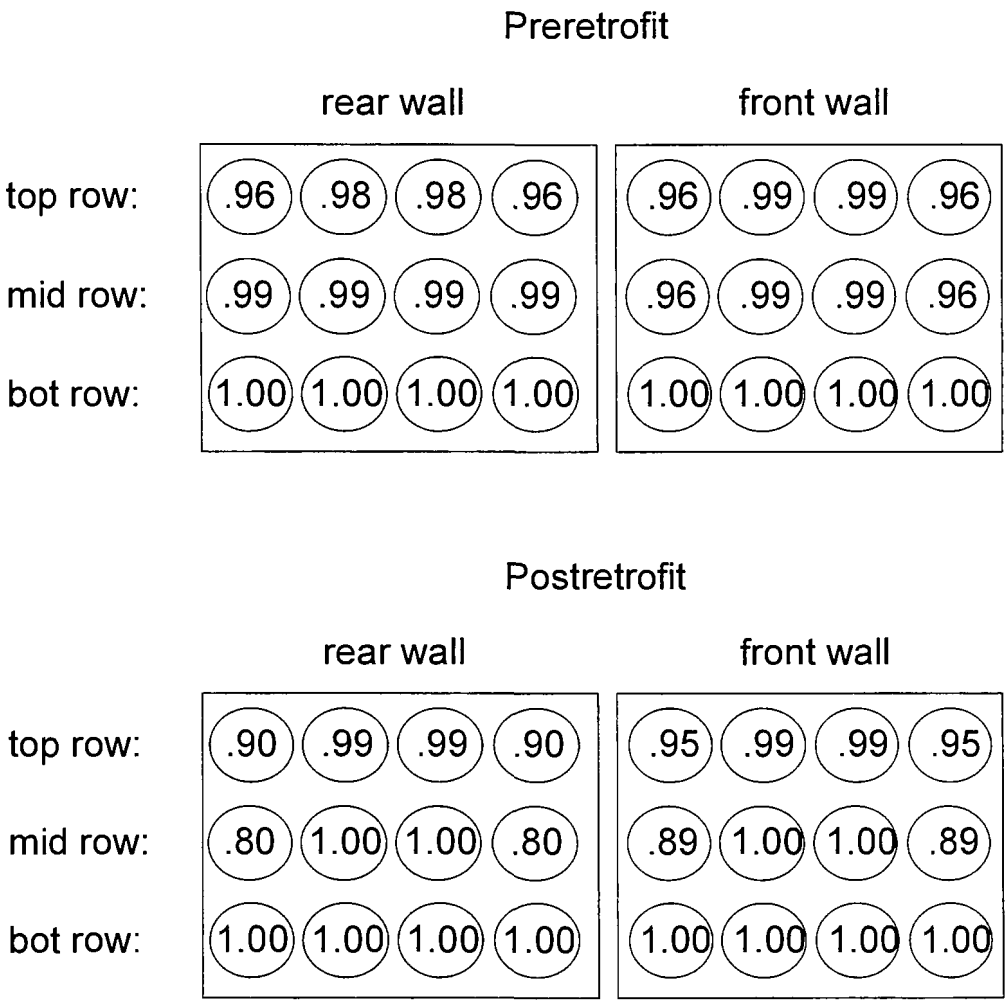


Figure 5. Burnout of coal particles from each burner in the pre-and post- retrofit simulations.

Assess Coal Quality Impacts on NO_x and LOI with EPRI's NO_x-LOI Predictor

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Abstract

EPRI is developing a software tool that allows utilities to predict coal quality impacts on NO_x emissions and LOI. The model requires only standard coal analysis as inputs (proximate and ultimate analysis, Hargrove grindability index). Given the coal properties for the baseline coal and alternate coal, along with baseline boiler performance data (NO_x and LOI), the model predicts changes in NO_x emissions and LOI due to a switch to the alternate coal. In addition to the LOI predictions using the standard coal properties, the software also contains an LOI prediction based on a gray scale reflectance test of a coal sample.

A beta version of the NO_x model has been undergoing evaluation by utility companies for about a year. The LOI part of the model has recently been incorporated into the software and beta tests initiated.

The paper describes the software, approaches used to model NO_x and LOI, how the software can be used, and recent results.

Introduction

In response to the 1990 Clean Air Act Amendments, many utilities are implementing low NO_x burners to reduce NO_x. At the same time, utilities are switching coals either for SO_2 compliance or for economic reasons. With low NO_x combustion systems, coal quality has become a more important consideration. These combustion systems have, in general, made the combustion process more sensitive to coal quality in terms of combustion efficiency and ash carbon content (or loss on ignition, LOI). Similarly, for units that are just meeting NO_x compliance, a change in coal characteristics can potentially impact NO_x compliance.

To support utilities making quick decisions on coal purchases, EPRI is developing a NO_x-LOI Predictor. This is a Windows® based tool that has the potential of large cost savings to a utility

by avoiding coals that are inappropriate from either a NO_x or LOI basis. The software is intended as a simple tool to quickly screen the performance of a number of coals relative to the current coal being burned in a particular boiler.

It should be pointed out that both NO_x production and LOI involve many complex processes that are dependent not only on coal characteristics, but also on the boiler and burner design and operating parameters. It was not the intent of the NO_x-LOI Predictor to predict NO_x and LOI given coal, boiler and operating characteristics. Rather the NO_x-LOI Predictor starts with the known performance of a unit in terms of measured NO_x emissions and LOI for the coal currently being used. Given this known baseline performance, the program then predicts how the performance will change in terms of NO_x and LOI when an alternate coal is burned under the same operating conditions. Based on the user's past experience with particular furnaces, the initial estimate from the NO_x-LOI Predictor for baseline operating conditions can be adjusted for varying operating conditions (i.e., O_2, load, burner tilts, etc.).

The NO_x portion of the model has been under evaluation by selected utilities for about a year. The LOI part has recently been incorporated and evaluation of the LOI predictions have just begun. This paper will provide an overview of the methodology used for the NO_x and LOI predictions and present recent results obtained from the model.

Structure of the NO_x Prediction

Many previous studies have attempted to relate NO_x emissions using conventional coal properties. While these previous efforts have shown qualitative trends, they have not been able to make quantitative predictions of coal quality effects. A number of factors contributed to this inability to develop predictive correlations. First, NO_x emissions depend both on operating parameters and fuel properties, and it can be difficult to separate these two effects. Secondly, most of the prior efforts have relied on the use of conventional fuel properties, specifically, the ASTM proximate and ultimate analysis. While the ASTM proximate analysis provides a general indication of differences in fuel properties, it is widely known that the ASTM proximate analysis does not accurately describe the processes coal particles undergo in large flame. Under the high heating rate conditions experienced by a pulverized coal particle in a utility furnace, the volatile yield and nitrogen release with the volatiles can be substantially different than indicated by the ASTM proximate analysis. Both of these quantities can have a major impact on NO_x formation processes.

The current structure of the NO_x prediction portion of the software is still correlation based. However, at the inception of this project it was felt that, to improve the predictive capability of the coal property effects on NO_x, it would be necessary to use coal properties for high heating rate conditions. Initially, there was thought given to using test results from a high heating rate device such as a drop tube furnace[1] or an electrically heated grid[2] as an input to the NO_x model. While this was technically feasible, having to perform a nonconventional test on a coal was not attractive from the standpoint of quickly screening a large number of potential coals.

To eliminate the need for a special coal test, it was decided to incorporate a coal devolatilization model into the NO_x Predictor. There have been three phenomenological coal network models that have been recently under development[3,4,5] These three models represent devolatilization as a depolymerization process that disintegrates the coal's macromolecular structure into smaller volatile fragments with subsequent reintegration of larger intermediates into char. For the current application, the FLASHCHAIN model developed by Niksa[3] was chosen for incorporation into the NO_x Predictor. FLASHCHAIN was chosen for two primary reasons. First, it was at the highest stage of development at the start of the project with the capability of accurately predicting not only volatile yield, but also volatile nitrogen evolution. Secondly, FLASHCHAIN requires that no special tests be conducted on the coal; the only coal-specific information needed by FLASHCHAIN is the proximate and ultimate analysis of the coal. FLASHCHAIN also resolves the partitioning among char-N, tar-N and HCN.

Prior to proceeding with FLASHCHAIN for this application, it was subjected to blind evaluations against the total weight loss and char nitrogen contents from nine (9) coals that were measured in a drop tube furnace[1]. In these cases only the coal properties and thermal histories were available in advance to enable the FLASHCHAIN simulations, yet the predictions matched the measured values within experimental uncertainties in all but one case.

In the calculation process, FLASHCHAIN has one adjustable parameter. This parameter is used to match the FLASHCHAIN prediction with the ASTM volatiles under a low heating rate condition. With this parameter fixed, FLASHCHAIN then calculates devolatilization for pulverized coal flame conditions. Full FLASHCHAIN simulations of the coals' behavior under flame conditions require only a few seconds on modern personal computers.

As indicated above, the NO_x Predictor portion of the program uses a correlation-based methodology. Figure 1 shows the structure of the NO_x-LOI predictor. The user enters the proximate and ultimate analyses of the currently fired coal and the coals to be screened. In addition, the NO_x levels with the baseline coal are also entered along with basic information on the unit (i.e., firing configuration, low-NO_x burners, overfire air, pre- or post-NSPS, etc.). After the coal and boiler information are input, the program processes each coal through the FLASHCHAIN model which calculates volatile gas yield, volatile tar yield, tar nitrogen yield and HCN production.

The FLASHCHAIN results are then used along with a series of correlations to predict the expected change in NO_x emissions for the alternate coal. The correlations were developed using numerous sets of pilot scale data available in the literature[1,7] The correlations relate the measured pilot-scale NO_x emissions to the FLASHCHAIN parameters (volatile yield, tar nitrogen, HCN and char nitrogen). A challenge was to then be able to relate the fuel property effects correlated at pilot scale to a specific full scale boiler. Since all utility boilers currently monitor NO_x, the measured baseline NO_x was used to relate the pilot scale correlations to a specific full scale unit. This was done by defining a reference NO_x level that the baseline coal would produce at the pilot scale. In essence, the baseline NO_x level is used to calibrate the correlation.

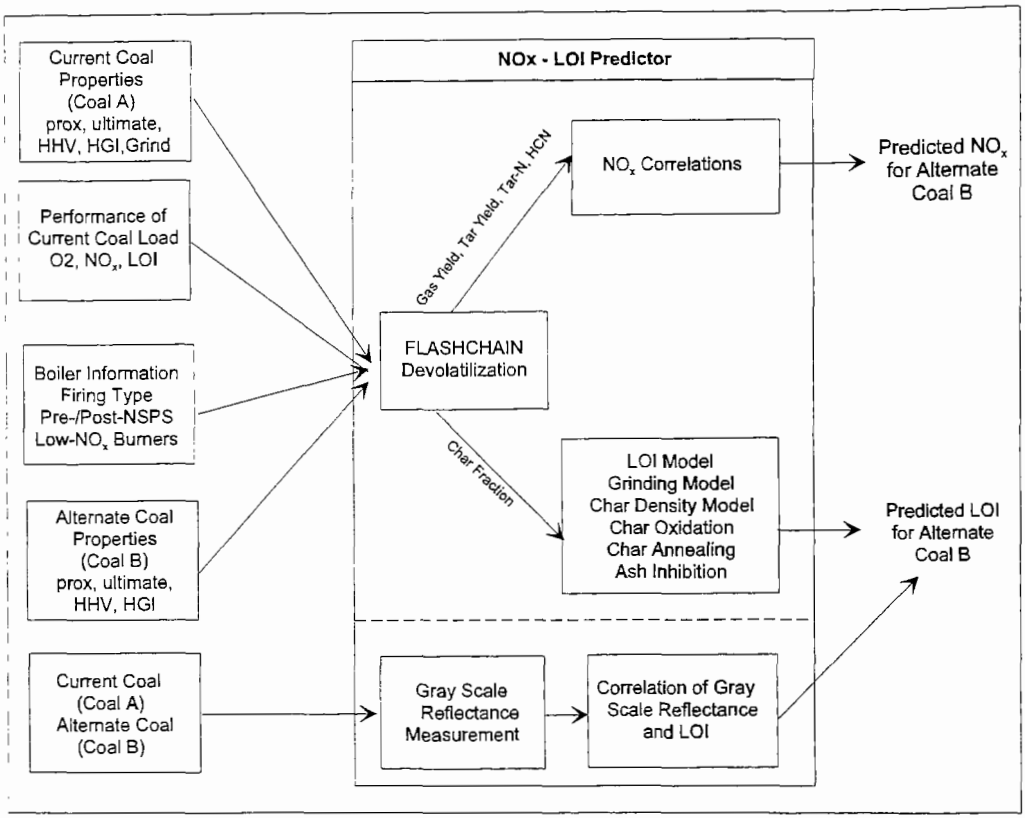

Figure 1. Structure of the NO_x-LOI Predictor

Structure of the LOI Prediction

Currently there are two methodologies incorporated into the software for predicting LOI. One is phenomenologically based, and the second is based on a petrographic gray scale reflectance measurement of a coal sample[8]

Phenomenologically Based LOI Predictor

While the NO_x prediction is based on correlation, the LOI prediction model incorporated into the NO_x-LOI Predictor is phenomenologically based. The primary elements of the LOI prediction model include:

- coal grinding submodel
- char formation submodel (FLASHCHAIN)
- char density submodel

- char oxidation submodel (CBK)
  - single-film char oxidation kinetics
  - thermal annealing
  - ash inhibition

Figure 1 shows the structure of the LOI Predictor. The grinding model estimates the coal grind size for the alternate coal given the Hargrove Grindability Index (HGI) of the base coal and alternate coal, and the grind size of the base coal (% <200 mesh and % >50 mesh). The model uses this data to calculate a Rosin-Rammler slope and estimate of the top size for the base coal ($d\text{-}_{top\ size}$ > d of 99.99% of mass). The grinding model then calculates the pulverizer throughput for the alternate coal using the heating values of the coals. A new fineness, in terms of the percent through 200 mesh is then calculated using full scale pulverizer correlations. These correlations are in the form of percent passing 200 mesh as a function of HGI and throughput. The alternate coal size distribution is then calculated using the new 200 mesh fineness and assuming a constant top size for the pulverizer. If the user prefers, the LOI prediction can also be performed by holding the coal size distribution constant.

The next step in the calculation is coal devolatilization and char formation. This part of the calculation is done using the FLASHCHAIN model discussed above. FLASHCHAIN is used to calculate the fraction of the coal that ends up as char. A rank dependant correlation is used to determine the initial char density.

Char oxidation is calculated using a single-film model of char oxidation kinetics that also includes provisions for thermal annealing of the char throughout the oxidation process (CBK) and ash inhibition.

A key feature of the char oxidation model is its ability to describe long residence time char oxidation; this is important for predicting LOI since we are dealing with the last fraction of the carbon left to burn. A single global char oxidation model will basically predict zero LOI; whereas the CBK model, which includes char annealing and ash inhibition, can simulate the late stages of char oxidation[9]. The char oxidation is assumed to occur as it travels in plug flow through the furnace. In the LOI predictor, the user specifies the oxygen concentration and the model has an adjustable parameter to account for incomplete mixing in the furnace.

Similar to the NO_x prediction, the LOI prediction scales the results relative to the baseline LOI value. Internal calibration parameters are used to match the LOI from the baseline coal and the model then uses these parameters to calculate the LOI for the alternate coal.

Reactives Index Based LOI Prediction

Previous attempts to relate combustion behavior to maceral content[10,11] and rank[12] alone have met with limited success, except where the range of coals studied has been limited. Maceral content alone does not take into account either the variation of the vitrinite macerals with rank or the variation of the reflectance and, therefore, reactivity of inertinites[10] Similarly, rank alone does not account for the variations in maceral content that can occur, especially where the coals are

from different geological origins. The Reactives Index was developed to overcome these problems and to provide an automated technique which removes the subjectivity of manual maceral analysis.

The Reactives Index is based on producing a gray-scale histogram of the coal sample, viewed under a microscope, using image analysis. This idea was first proposed by Riepe and Steller[13] and has been further developed at Nottingham University to enable the analysis of the liptinite in coal[14], where there is a close similarity between the gray-scale of the liptinite and the resin used to mount the coal sample. In essence, the analysis of the sample is carried out in both white light and blue light to produce a histogram similar to that shown in Figure 2. In Figure 2, the gray scale histogram of the whole coal is given starting with the synthetic liptinite column on the left hand side. The thicker line in the figure represents the cumulative curve over the gray-scale range. A cut-off is made at a gray-scale of 190, and it is assumed that all material with a gray-scale greater than 190 is "unreactive" in the combustion process. The Reactive Index is defined as the mass percentage of coal with a gray-scale reflectance value greater than 190 on a standardized scale. Note that in this paper "Reactives Index" and "% 190 unreactives" are used interchangeably.

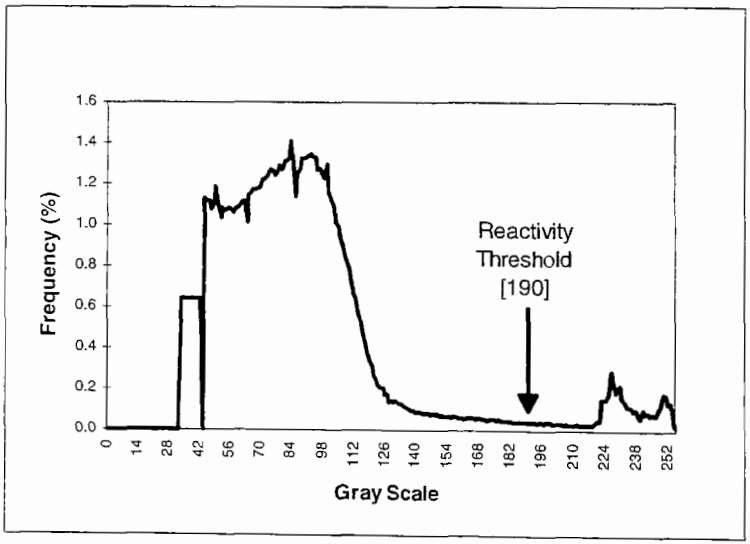

Figure 2. A Typical Reactivity (Gray Scale Histogram) Assessment Profile

The image-analysis technique used is simple and rapid to apply, and also removes subjectivity from the analysis. Including block preparation, polishing and analysis, a result can be obtained in about one hour. The histogram gray-scale is standardized using a light source of known intensity, any variations in the gray-scale of the vitrinite due to rank and variations in inertinite due to reflectance are shown in the results. Thus, a high-rank vitrinite will give a peak at a higher gray-scale inferring a lower reactivity. Similarly, some inertinites are shown to be more

reactive as their position in the histogram is at a lower gray-scale. In this way, it is possible to infer that some inertinite material is potentially more reactive than some vitrinite material.

A relationship between the Reactives Index and combustibles remaining were established for 17 coals burned in PowerGen's 1 MW Combustion Test Facility (CTF). These coals covered a wide range of geological origin, rank and maceral composition. This correlation is shown in Figure 3. Figure 3 shows the relationship between the Reactives Index and combustibles remaining, which is the percentage of dry ash-free coal which is not burned (determined using an ash tracer technique). The combustibles remaining can be related to the more normally measured loss on ignition (LOI):

$$\text{Combustibles remaining } \% = 100 \left(\frac{A \times LOI}{(100 - A)(100 - LOI)} \right) \quad (1)$$

A = Ash content of coal, % dry
LOI = Loss-on-ignition, % dry

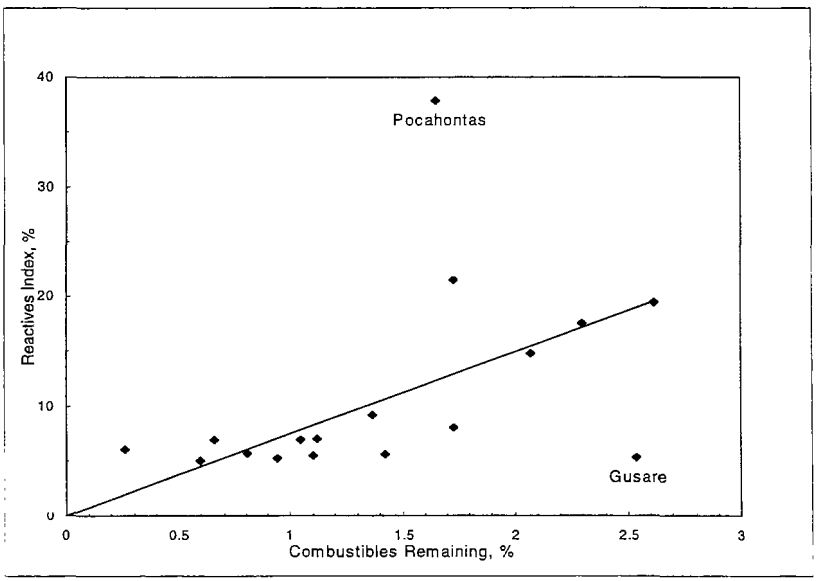

Figure 3. Relationship between the Reactives Index and Combustibles Remaining[8]

The correlation between the parameters shown in Figure 3 exhibits two clear outliers. The first is Gusare coal which performed much worse than would be predicted from the 190 Unreactives. This was partly due to the large quantity of oversize material, 4.1% >212mm, which was found in the pulverized coal from this coal, compared with a norm of less than 1% >212mm for most of the other coals. The other outlier was Pocahontas which has a much higher rank than all of the other coals considered. It has been reported that this low volatile content coal can be burned in a

station designed for normal high volatile content bituminous coal resulting in only a small increase in "carbon loss"[15] This finding is in line with the CTF test results obtained in this study which indicate that higher rank vitrinite is more reactive than what the Reactives Index would predict. Pocahontas is, however, not a coal that would normally be burned in a power station.

Having established a relationship between the Reactives Index and combustibles remaining, the Reactives Index can then be used to calculate the effect of a coal change from a baseline to alternate coal on LOI. As with the NO_x prediction and phenomenological LOI prediction, the Reactives Index technique also uses the baseline coals Reactives Index and LOI to essentially calibrate the algorithm. For example, suppose that burning a baseline coal at a specific power plant under standard conditions gives an LOI of 8%; using the known ash content, say 10% dry, this is equivalent to a combustibles loss of 0.936% Assuming the baseline coal has a Reactives Index of 7%, a plant-specific "calibration line" relating Reactives Index to combustibles loss can be drawn through the origin and the point for the baseline coal. Then for any alternative "unknown" coal supply, given the Reactives Index, the combustibles loss can be read of this line and the equivalent LOI value calculated from the dry ash content of the alternative coal.

It should also be noted that the Reactives Index technique was developed to assess the burnout characteristics of bituminous coals and is not easy to apply to low rank coals. Low rank coals have inertinite type structures that have the same coloration as vitrinite. Low rank coals also have low reflectance, making it difficult to separate the main vitrinite peak from the resin peak.

Preliminary Results

Beta tests for the NO_x-LOI Predictor are currently underway. The NO_x Predictor part of the model has undergone tests for approximately one year, while the LOI prediction has recently been incorporated into the program and testing just begun. The following subsections will present preliminary results from both the NO_x and LOI prediction portions of the program.

NO_x Predictions

Before presenting the NO_x prediction results, it should be reiterated that when validating the predictions, NO_x data is needed from the baseline and alternate coal for the same firing conditions. Depending on the boiler type, this would include:

- load
- O_2
- mills in service
- level of overfire air
- burner tilts
- burner damper settings

If test data is not available under identical conditions, then it is recommended that the results be adjusted to make the comparison on as common a basis as feasible. For instance, a difference in the flue gas O_2 concentration of 1% can change NO_x on a tangentially-fired boiler and wall-fired boiler by 30-50 ppm and 60-90 ppm, respectively. Likewise, a change in burner tilt can impact

NO_x on the order of a 1-2 ppm per degree of tilt change. In many cases, small changes in operating parameters may be equal to or grater than the fuel parameter effects.

To illustrate the use of the NO_x Predictor, the program was used to predict the expected changes in NO_x during a test burn of a Power River Basin (PRB) coal at Public Service Company of Colorado's Arapahoe Unit 4. This boiler has been the site of a DOE Clean Coal Technology III program, and has undergone extensive testing with the baseline coal. A two week PRB test burn was conducted at the unit during which no changes were made to the combustion hardware or pulverizers. Arapahoe Unit 4 is a 100 MW roof-fired boiler that was retrofit with Babcock & Wilcox XCL burners and overfire air as part of the DOE clean coal project. The baseline coal is a Colorado bituminous coal. Table 1 shows the NO_x predictions along with the actual NO_x data obtained during the PRB test burn.

Table 1
NO_x Predictions for PSCo Arapahoe Unit 4

	Base Coal	PRB Coal	
Load % MCR	Actual NO_x ppmc	Actual NO_x ppmc	Predicted NO_x ppmc
60%	300	205	206
80%	260	185	181
100%	292	219	201

As can be seen in Table 1, the predicted NO_x levels for the PRB coal are in good agreement with the measured values, even though the substantially different composition of the PRB and baseline coals are responsible for large differences in the respective NO_x levels.

The NO_x prediction portion of the model was also used to predict the NO_x at Dairyland Power's Genoa 3 Unit. This T-fired unit burns a blend of bituminous and PRB coal. The results of these predictions are shown in Figure 4. In this figure, the filled symbols are CEM NO_x data for varying PRB blends and a load of nominally 70% MCR. The dotted line in Figure 4 is a least square fit to the CEM data. The open symbols with the solid line are the NO_x predictions. For the NO_x predictions, the 40% PRB blend was taken as the baseline coal in the NO_x Predictor program. The NO_x predictions for this unit are in good agreement with the measurements. It should be noted that for this case, little operating data was available: load, CEM NO_x, CEM CO_2 and the blend ratio. Some of the variation in the data points plotted in Figure 4 could be due to variations in other operating parameters (i.e., burner tilts, mill patterns, etc).

As part of the Beta tests, PowerGen has evaluated the NO_x predictions for T-fired units using data from their Fiddlers Ferry Power Station. Fiddlers Ferry comprises four 500 MW (electrical) tangentially fired boilers fitted with an ICL low-NO_x concentric firing system. The coal burns

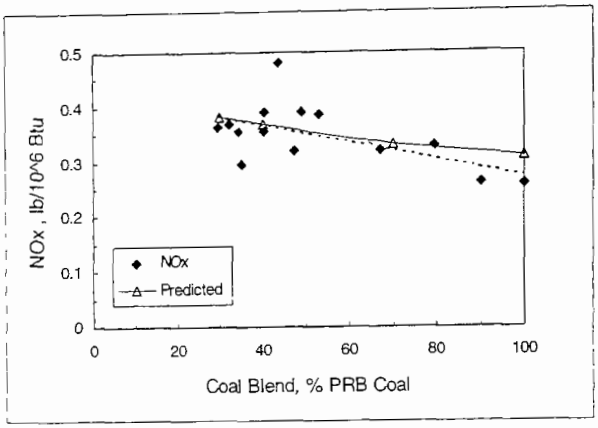

Figure 4. NO_x Predictions for a PRB Coal Blend

were carried out on Units 2 and 4. These units were entered into the NO_x Predictor as separate boilers. Six blends of three coals (UK coal, US coal and Colombian coal) were tested. One coal blend from each unit was used as a baseline to predict NO_x emissions from the other two blends burned on that unit. NO_x data are only available at a few excess oxygen levels which are not identical for the different coals. Values for NO_x emissions from the six coal blends at the same excess oxygen level are required to compare the measured and predicted expected values. To accommodate this, values for NO_x at 6% and 7% excess oxygen have been extrapolated from a graph of NO_x versus excess O_2 levels. The test data and predicted NO_x levels are plotted in Figure 5. The predicted and measured NO_x are in good agreement.

The NO_x predictions, shown in Figure 5, illustrate another feature of the NO_x Predictor. The NO_x-LOI Predictor predicts the NO_x for the alternate coal for the same operating conditions as the baseline coal. However, for numerous reasons, it may not be possible to operate the boiler at the same set of boiler parameters as for the base coal. For instance, it may be necessary to operate at a higher excess O_2 level. The sensitivity of the alternate coal NO_x to O_2 can be predicted if the NO versus O_2 behavior is known for the base coal. This is illustrated in Figure 5 where PowerGen used the NO_x emissions at two O_2 levels to predict the NO_x versus O_2 curve for the alternate coal.

Figure 6 summarizes the predictions that have been made for both T-fired and wall-fired units over a range of NO_x levels from 200 to 900 ppm. The predicted capability of the correlations is quite good.

Since the NO_x predictions are correlation based, improved accuracy is anticipated as the Beta testing proceeds and more data becomes available to refine the correlations.

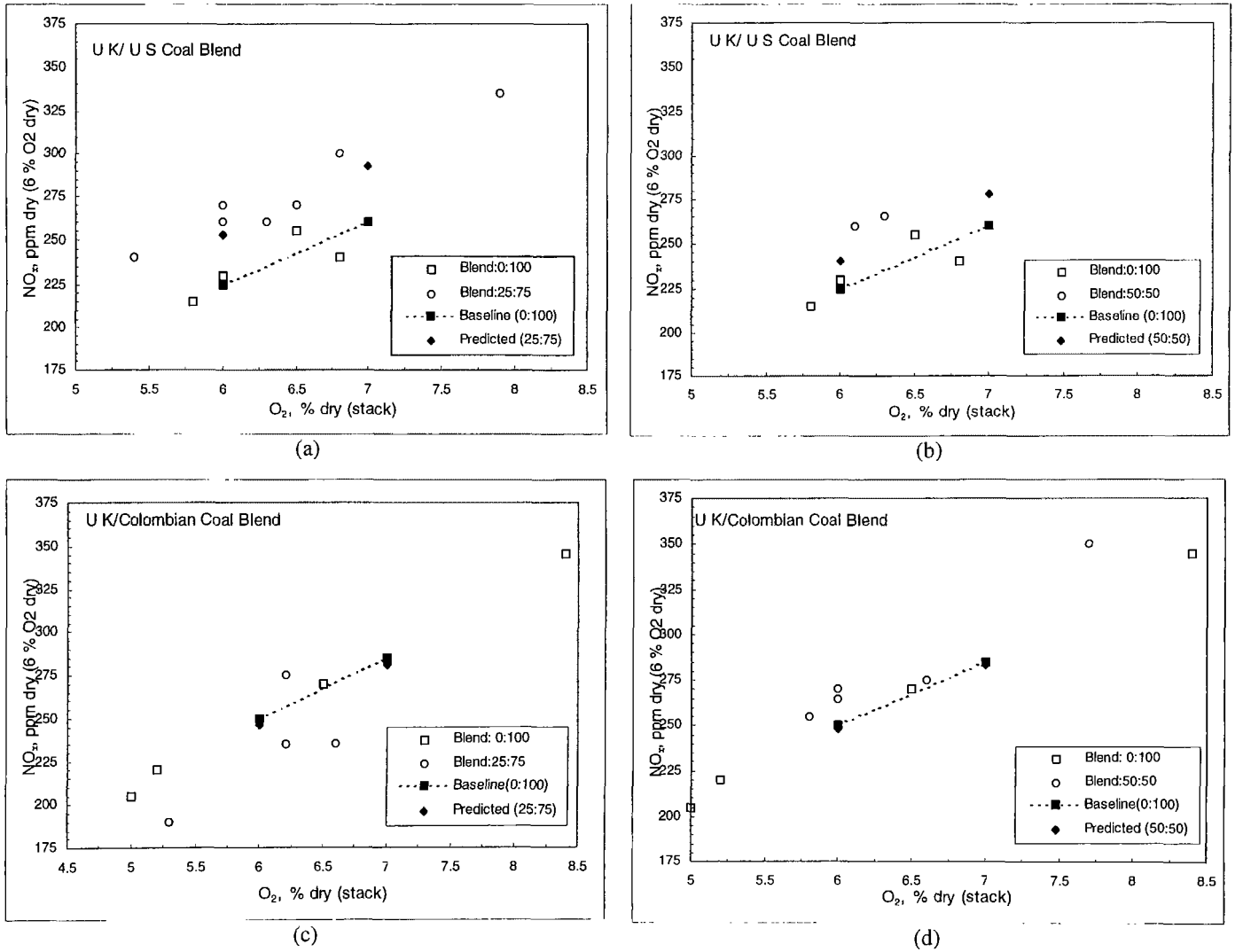

Figure 5. Comparison of Predicted and Measured NO_x at PowerGen's Fiddlers Ferry Power Station (500 MW T-fired)

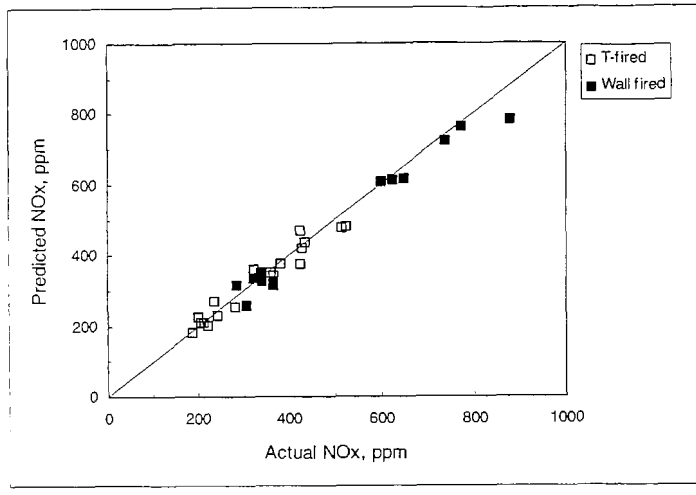

Figure 6. Summary of Tangentially-fired NO_x Predictions

LOI Predictions

The LOI predictions have only recently been added to the program and only preliminary comparisons have been made. As discussed above, the program contains two methods to predict LOI; a model and a petrographic (gray-scale Reactives Index) coal analysis. Predictions to date are only based on the phenomenological model.

The results to date from the phenomenological LOI prediction model are plotted in Figure 7. The program gives the user two choices in making the predictions. The user can either choose to have the alternate coal's particle size be the same as the baseline coal ("constant coal size"), or allow the program to modify the coal particle size based on the Hargrove Grindability Index (HGI) ("estimated coal size"). These two options were included to cover two scenarios. The constant coal size assumes that the utility would adjust the mill parameters for the alternate coal to obtain the same grind as with the baseline coal. The estimated particle size basically assumes that no changes are made to the pulverizers and a new particle size is estimated based on the change in HGI and throughput between the baseline and alternate coal. As can be seen in Figure 7, the initial LOI prediction results are encouraging. In all but a couple of the cases, the predicted trends are the same as the actual measurements and the magnitude of the changes are in reasonable agreement. Better precision is anticipated as the database expands.

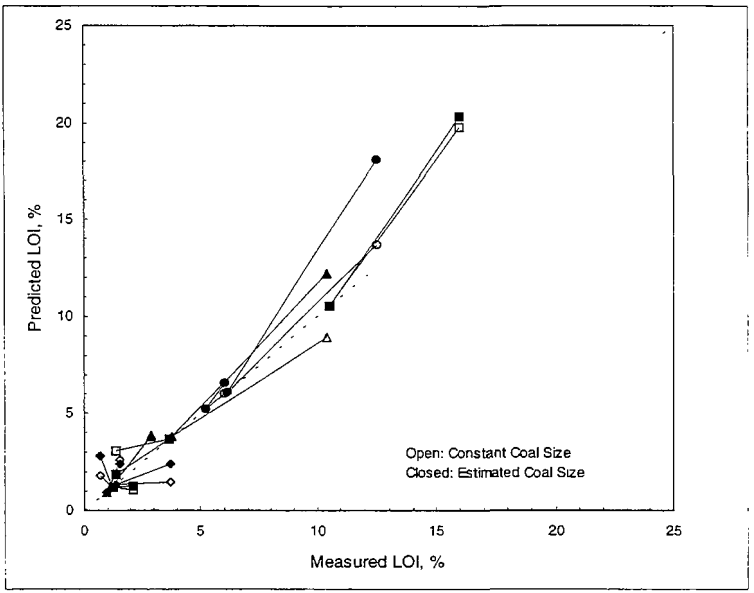

Figure 7. Preliminary Results from the LOI Predictor

Conclusions

A Windows® based software program has been developed to quickly screen coal quality effects on NO_x and LOI. The NO_x predictions have been validated for T-fired units. The wall-fired correlations have recently been revised and are undergoing further testing. The LOI portion of the model has just been included and initial testing begun. The LOI predictions utilized two approaches: (1) a char oxidation based model and (2) a petrographic coal test. The initial LOI test results with the char oxidation based model are also very encouraging.

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FIELD EXPERIENCE -- REBURN NO_X CONTROL

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Abstract

This paper presents the results of five full scale applications of reburn technology to control NO_x emissions. With reburn, a hydrocarbon fuel is injected above the burners to produce a slightly fuel rich zone where NO_x is reduced. Overfire air injection completes the combustion process. The applications include boilers of wall, tangential, and cyclone firing configurations firing gas and coal both as the primary fuel and as the reburn fuel with baseline NO_x ranging from 0.13 to 1.4 lb/10^6 Btu. NO_x was reduced by 58-77% over this range of applications. Additional information is presented on new developments in reburn including Advanced Reburn which integrates reburn with nitrogen agent (ammonia or urea) injection, the use of Orimulsion™ as a reburn fuel and a reburn application involving multiple reburn fuels (gas, oil and coal).

Introduction

The Clean Air Act Amendment of 1990 (CAAA), established the framework for NO_x emission regulations to mitigate ozone non attainment areas and acid rain. Over the last seven years, EPA has developed most of the specific NO_x regulations authorized by the CAAA. For applications where low NO_x burners can meet the NO_x reduction requirements, they are generally the

technology of choice based on cost. However, now that many of the specific CAAA regulations have been finalized, it is clear that in many applications low NO_x burners alone will not be capable of meeting the requirements due to unavailability of low NO_x burners (such as for cyclones), performance problems with low NO_x burners (such as carbon loss or tube wall wastage), or insufficient NO_x reduction to meet CAAA requirements.

This paper presents recent field experience with reburn, a combustion modification NO_x control technology. Reburn can be applied to virtually any unit firing any fuel. NO_x reduction is typically in the range of 50-70%. Reburn can be integrated with nitrogen agent injection and other technologies for even greater NO_x reduction.

Reburn NO_X Control Technology

The concept of NO_x reduction via reactions with hydrocarbon fuels has been recognized for some time[1]. Over the last seventeen years, EER has developed a considerable reburn data base consisting of extensive pilot scale tests, a number of full scale applications (discussed in this and previous papers)[2] and a design methodology which can be used to apply reburn and project performance for a wide range of applications[3]. Based on this extensive experience, EER offers reburn as a commercial NO_x control product with commercial guarantees.

Basic Reburn Process

Reburn is a NO_x control technology whereby NO_x is reduced by reaction with hydrocarbon fuel fragments[1] The reburn process is illustrated in Figure 1 for a front wall fired boiler. In applying reburn, no physical changes to the main burners or cyclones are required. The burners are simply turned down and operated with the lowest excess air commensurate with acceptable lower furnace performance considering such factors as flame stability, carbon loss, slag tapping and ash deposition. Reburn fuel is injected above the main combustion zone to produce a slightly fuel rich reburn zone where most of the NO_x reduction occurs. Maximum NO_x reduction performance is typically achieved with the reburn zone operating in the range of 90 percent theoretical air. Above the reburn zone, overfire air is injected to complete combustion.

Reburn Design Considerations

Due to the substantial design differences among existing boilers and furnaces and NO_x control requirements which vary with local requirements, reburn must be custom designed to match site specific factors. EER's reburn design methodology utilizes both analytical and physical models to design the optimum configuration based on site specific factors and to project performance[3].

Firing Configuration. Because reburn does not require modifications to the main combustion system, it can be applied to virtually any combustion system. This paper discusses applications to boilers of wall, tangential, and cyclone firing configurations. Reburn can also be applied to industrial furnaces such as glass furnaces[4] and steel reheating furnaces. Applying reburn to hot furnaces with high baseline NO_x levels is particularly attractive since both factors speed up the

NO_x reduction reactions. This reduces the amount of reburn fuel and the size of the reburn zone required to achieve a specific NO_x goal.

Main and Reburn Fuel Characteristics. Since reburn involves no physical changes to the main combustion system, it can be applied to furnaces fired with any fuel (coal, oil, gas, Orimulsion™ etc.). Except for potential costs of the reburn fuel itself, gas is the preferred reburn fuel. It produces the greatest NO_x reduction per unit reburn fuel injected, has no ash or sulfur and requires no pulverization or atomization. The disadvantage of gas is that its cost generally exceeds that of other boiler fuels. The cost and availability of gas are the key factors which encourage consideration of other reburn fuels. For example, on coal fired units, the use of pulverized coal as the reburn fuel avoids any cost penalty of the reburn fuel over the main fuel. Other fuels of interest include oil on oil-fired units and Orimulsion™ which will be discussed further below.

Furnace Volume. There must be sufficient space above the burners or cyclones to install the reburn components and to produce adequate residence time in the reburn and burnout zones. By designing the reburn fuel and overfire air injectors for rapid mixing, space requirements are in the range typically available on full scale utility boilers. EER has designed gas reburn systems for numerous boilers and has yet to find a commercial system where the residence time was inadequate. As presented below, EER has achieved NO_x reduction as high as 70% in a cyclone application with effective reburn zone residence time of only 0.25 seconds. While such applications are feasible, with longer residence times the amount of reburn fuel required to achieve a specific NO_x control goal is reduced and carbon loss is improved, particularly with coal reburn.

Reburn Fuel Injectors. The reburn fuel injectors should be located close to the upper firing elevation but leaving enough space above the burners to achieve essentially complete combustion in the flames from the main burners prior to introduction of the reburn fuel. For maximum NO_x reduction, the reburn fuel should be injected so as to penetrate across the furnace depth and mix rapidly with the furnace gases. Since the amount of reburn fuel injected is small compared to the furnace gas flowrate, achieving penetration and rapid mixing is a challenge, especially for larger furnaces. Penetration and mixing can be enhanced by increasing the momentum of the injected stream via a carrier gas or by high velocity injection.

In designing the reburn fuel injectors, it is desirable to minimize (and ideally eliminate) any oxygen introduced with the reburn fuel. This oxygen must be consumed by additional reburn fuel to achieve the desired reburn zone stoichiometry. For gas reburn, EER's first generation systems used flue gas as the carrier. The momentum of the flue gas stream provided good penetration and mixing and the low oxygen content only slightly increased the reburn fuel requirement. EER's second generation systems utilize the pressure available in the gas pipeline to produce high velocity reburn jets, totally eliminating additional oxygen and thus minimizing the reburn fuel requirement. EER has applied this high pressure injection technique to two units (wall- and tangentially-fired) as discussed below.

For coal as the reburn fuel, a gaseous carrier is required for pneumatic transport. Flue gas is preferred over air to minimize the reburn fuel quantity as discussed above.

Overfire Air Ports. Most of the primary fuel char oxidation occurs in the oxygen rich primary combustion zone. The burnout zone completes combustion of the reburn fuel. For gas reburn, this is primarily CO oxidation. For fuels which contain fixed carbon, such as coal and Orimulsion™, this includes CO as well as carbon in the flyash.

The overfire air ports must be located to balance the NO_x reduction performance of the reburn zone with the combustion efficiency of the burnout zone. Generally this trade off is optimized by locating the overfire air ports substantially higher in the furnace than for conventional overfire air applications but well below the furnace exit.

As with the gas injectors, the overfire air ports need to be designed for rapid and complete mixing. EER utilizes dual concentric zone overfire air ports with swirl control. This arrangement allows the injection velocity to be controlled independent of flowrate, a key advantage where the reburn fuel is varied to control NO_x emission level.

Flame Sensing and Controls EER's reburn control approach is to integrate the reburn system with the normal boiler controls for fully automated operation. Depending on the NO_x control goal, the reburn fuel injection can be fixed or varied in response to boiler operating conditions and/or NO_x emissions. The fuel injection controls include both permissives and trips to ensure safe operation. Since the gas injection does not produce a visible flame, conventional scanners are ineffective. Instead, furnace temperature is used as the primary permissive/trip for reburn system operation. This approach has been fully effective in five reburn applications and has been reviewed and approved by Factory Mutual and Hartford Steam for those specific applications. As an active member of the National Fire Protection Association (NFPA), EER has taken a lead role in proposing modifications to the current safety codes which will provide guidelines for future applications.

Retrofit Applications

EER has retrofitted reburn to five coal fired boilers as listed in Table 1. The discussion below describes how the reburn systems were integrated into the boilers. The subsequent section discusses the reburn performance including both NO_x reduction and boiler impacts.

Gas reburn was installed on Illinois Power's Hennepin Unit 1; a tangentially-fired boiler with three elevations of tilting burners. Figure 2 is a side sectional view of the boiler showing the location of the gas injectors and overfire air ports. The Hennepin furnace has a relatively large space between the upper row of burners and the furnace arch. This allowed the gas reburn system to be designed with a generous reburn zone. The reburn fuel was injected along with flue gas through corner nozzles near the top of the windbox. The overfire air ports were located on the furnace walls near the corners below the arch. Single passage overfire air ports were utilized without swirl. No overfire air booster fan was required.

Gas reburn was installed on City Water, Light and Power's Lakeside Unit 7, a cyclone-fired unit with two cyclone burners discharging into an open furnace. Figure 3 shows how the gas reburn components were integrated into the Lakeside furnace. This reburn application was challenging. The diverging furnace produced a highly stratified flow field with the combustion products moving in a jet up the rear wall creating a large recirculation zone. The available residence time for the reburn zone in this high speed flow was limited to 0.25 seconds.

The gas injectors were positioned along the rear wall and side walls just above the furnace stud line. Although the penetration distance was short, the short residence time dictated rapid mixing; flue gas was used as a carrier. The overfire air was injected from the real wall in the upper furnace through single passage ports. To minimize entrainment into the recirculation zone, high injection velocities were used. The high combustion air pressure in this cyclone unit was adequate without a booster fan.

Gas reburn was installed on Public Service of Colorado's Cherokee Station; a front wall fired unit with a partial division wall. It was integrated with low NO_x burners which were installed at the same time. Figure 4 shows how the gas reburn components were integrated into the Cherokee furnace. In the initial design, the reburn fuel was injected with a flue gas carrier via ports on the front and rear furnace walls above the top burner row. Single passage overfire air ports were positioned on the front wall just below the arch. This configuration was subsequently upgraded to EER's second generation reburn system. The gas injectors were modified to eliminate flue gas and to use the pressure in the gas pipeline to penetrate and mix the gas across the furnace. The overfire air ports were replaced with a dual concentric zone design for additional control at low gas injection rates.

Gas reburn was installed on New York State Electric and Gas' Greenidge Unit 6; a tangentially fired unit similar to Hennepin but somewhat larger. Figure 5 shows the location of the gas and overfire air injectors. This was the second application of EER's second generation reburn components. Comparison of the Hennepin and Greenidge side sectional drawings shows the similarity of the reburn design. Figure 6 is an isometric view of the exterior of the boiler showing the arrangement of the reburn components.

A micronized coal reburn system was installed on Eastman Kodak's Boiler 15; a cyclone-fired unit. Figure 7 shows the locations of the reburn and overfire air injectors in the furnace and Figure 8 is an isometric showing the location of the components. In contrast to the Lakeside furnace, the Kodak cyclone furnaces discharge through screen tubes before entering the main furnace. The reburn coal was injected into the main furnace just above the screen tubes. Micronized coal was produced by two Fuller Micromills, high speed impact mills with separate classifiers. The coal fineness was nominally 85% through 325 mesh. To minimize the oxygen introduced into the reburn zone, flue gas was used as the carrier gas. A portion of the flue gas was supplied to the mills and the rest was supplied to the injectors to optimize penetration and mixing. While the nominal full load reburn fuel requirement could be met with one Micromill, two Micromills were supplied to enhance fineness under normal operating conditions and to allow for operation with a mill out for maintenance. To achieve this flexible operation, the outputs of both mills were combined and then split into the individual pipes supplying each

reburn fuel injector. EER's dual concentric overfire air ports were utilized without an overfire air booster fan due to the high secondary air pressure available in this unit.

Performance Summary

The NO_x control performance of the gas reburn systems applied to the Hennepin, Lakeside and Cherokee units has been discussed in detail in a previous paper[2] Figures 9 and 10 show the NO_x emissions for the two newest reburn applications, gas reburn at Greenidge and coal reburn at Kodak, respectively.

NO_x emission reduction at the Greenidge unit is required under both Title 1 and Title 4 of the CAAA. The most stringent requirement is under Title 1 where NYSEG must meet a system-wide daily NO_x emission cap. The baseline NO_x emission from the Greenidge tangentially-fired unit was 0.62 lb/10^6 Btu. As shown in Figure 9, NO_x emissions decreased as the reburn gas injection rate increased which is typical for all reburn systems. EER's performance guarantee for this commercial system was 0.30 lb/10^6 Btu and was achieved at a gas firing rate of about 13%. NO_x emissions decreased further to as low as 0.22 lb/10^6 Btu at 23% gas which corresponds to 65% reduction from baseline. As discussed below, EER is upgrading the gas reburn system to advanced gas reburn by integrating an ammonia injection system. This is expected to reduce NO_x to about 0.15 lb/10^6 Btu while decreasing the gas firing rate, thus improving cost effectiveness.

As with Greenidge, Kodak's NO_x control requirements stem from both Title 1 and Title 4 of the CAAA with the Title 1 requirements being the more stringent. The baseline NO_x emissions from the Kodak cyclone fired unit were 1.4 lb/10^6 Btu. The NO_x decrease as the coal injection rate was increased is shown in Figure 10. EER's performance guarantee of 0.6 lb/10^6 Btu was achieved at about 13% reburn fuel. Minimum NO_x emissions of 0.45 lb/10^6 Btu have been measured to date in short term tests. Additional testing is now in progress and will culminate in a 51-day compliance test by the end of 1997.

Figure 11 compares the NO_x control results for the five reburn installations. Two of the installations, Cherokee and Hennepin were tested with both gas and coal primary fuels. NO_x emissions (lb/10^6 Btu) are plotted as a function of the NO_x reduction (%). In this format, each reburn application is represented by a line showing the full range of possible NO_x control. Baseline emissions correspond to 0% NO_x reduction and for 100% NO_x reduction the NO_x emission is 0.00 lb/10^6 Btu, by definition. The points on the line show the reburn performance during short term tests and, in the case of three units, one year tests. Each application is labeled with the site, the firing configuration, and the primary fuel fired through the burners or cyclones.

These data represent a wide range of applications:

- Firing configuration — Cyclone, Wall, and Tangential
- Capacity — 33 to 158 MW net
- Baseline NO_x — 0.13 to 1.4 lb/10^6 Btu
- Primary fuel — Coal and gas

- Reburn fuel Coal and gas

All of the short term data are in the range of 58-77% reduction. During the long term tests, NO_x reductions were about 10% less. Close examination of Figure 11 will reveal that the differences in NO_x control performance cannot be related to the variables listed above. The similarity of NO_x reduction for this wide range of applications is a result of tuning the design and operation of the reburn system to meet site specific factors.

Based on the results of these five applications, reburn generally has minimal impacts on boiler performance, but the results are site specific. Typical experience is summarized below:

- CO Emissions CO emissions depend primarily on the design of the overfire air subsystem. EER's overfire air design provides for rapid mixing of the overfire air across the furnace cross section and has been successful in maintaining CO emissions acceptably low, typically comparable to baseline and less than 100 ppm.

- Carbon Loss Carbon in the ash may increase 1-2 percentage points for gas reburn due to the low temperature at the point of final overfire air addition which leads to lower char oxidation rates. With coal reburn, carbon loss is more of a problem since the reburn coal is fired under oxygen deficient conditions and much of the char oxidation must occur in the upper furnace region after addition of overfire air.

- Thermal Effects The redistribution of fuel and air in the furnace with reburn can alter the furnace heat absorption profile resulting in some changes in thermal performance. In most cases, design point steam temperatures have been achieved within the capability of the burner tilt or attemperation systems. Boiler efficiency is typically reduced by 1-2% due to the hydrogen content of gas for gas reburn and carbon loss for coal reburn.

- Ash Deposition No significant ash deposition problems have occurred in any of the reburn retrofits. In some cases, eyebrows have formed around the reburn fuel injectors and/or overfire air ports. EER now offers a self-cleaning port option (patent pending) to handle any such ash deposition problems. This involves integration of a sootblower with the fuel injectors and/or overfire air ports as may be required.

- Durability The potential for tube wastage, particularly in the reburn zone, was a significant concern on early retrofits. No increased tube wastage has been measured on any of EER's reburn installations several of which have included extensive destructive and nondestructive tests[5].

Costs

The retrofit costs for reburn systems are highly site specific. Preliminary engineering must be completed prior to an accurate cost estimate. The typical retrofit cost for gas reburn applied to a medium size (300 MW) boiler is about 10-15 $/kW. This represents a considerable decrease compared to previous published costs and is a result of experience and the cost savings of EER's

second generation system. This is the total cost including equipment, installation, and owner costs. Equipment alone is typically about half. The cost increases if flue gas is used to transport the gas or if an overfire air booster fan is required. Cost decreases (on a $/kW basis) for larger units. For coal reburn, the typical retrofit costs are about 10 $/kW higher.

Current Activities

Additional Utility Reburn Applications

Work is in progress on six additional reburn retrofits to utility boilers at three sites as follows:

- Tennessee Valley Authority Allen Station These three 330 MW cyclone-fired units are subject to the new CAAA Title 4 NO_x limit of 0.86 lb/10^6 Btu. EER is providing gas reburn systems to achieve this NO_x level with minimum gas requirement.

- Baltimore Gas and Electric Crane Station These two 200 MW cyclone-fired units are within the Northeast Ozone Transport Region (NEOTR) and thus must comply with Title 1 NO_x reduction requirements as well as the Title 4 requirements discussed above. EER is providing gas reburn systems designed to maximize NO_x reduction.

- Ladyzhin Station, Ukraine This 300 MW opposed wall-fired wet bottom unit fires a mixture of high ash bituminous and brown coals. The reburn system is multi-fuel with capability to handle gas, oil, and pulverized coal. NO_x reduction of over 50% is expected with pulverized coal reburn with greater NO_x reduction for oil and gas.

Reburn Technology Development

The development of reburn technology is continuing. The improvements involve integration of reburn with other technologies and alternate reburn fuels.

- Advanced Reburn The integration of reburn with injection of a nitrogen agent (N-Agent), such as ammonia or urea, is termed Advanced Reburn. The N-Agent injection can be integrated in a number of ways depending on the boiler configuration including injection into the reburn zone, with the overfire air, and downstream of the overfire air. EER developed this technology in the 1980s through pilot scale and is currently conducting the first full scale demonstration at NYSEG's Greenidge Station. To date, NO_x has been reduced to about 0.2 lb/10^6 Btu firing about 10% gas. Testing is still in progress with the goal of reaching 0.15 lb/10^6 Btu. Development is continuing as part of a DOE project discussed in another paper at this Conference[6]

- Orimulsion™ Reburn Orimulsion™ is an emulsified bitumen fuel produced in Venezuela. It has firing characteristics similar to fuel oil. EER has tested Orimulsion™ as a reburn fuel and found its NO_x reduction performance to be superior to pulverized coal and nearly as good as natural gas. In Orimulsion™ reburn, the Orimulsion™ is atomized similar to fuel oil and injected along with a carrier gas to promote mixing and

dispersion. EER is currently conducting a full-scale demonstration of Orimulsion™ reburn on a US utility boiler.

Conclusions

In conclusion, reburn has been applied successfully to five boilers covering the range of 33 to 158 MW net capacity with tangential, wall, and cyclone firing configurations operating with coal and gas both as the primary fuels and as the reburn fuels. NO_x emissions reductions of 58-77% have been achieved. No significant operational or durability problems have been encountered. These results demonstrate the potential for reburn to meet a wide range of CAAA requirements. Work is in progress on 1,700 MW of additional reburn retrofits.

Acknowledgments

The authors wish to acknowledge the support of the five utility and industrial plants where reburn systems were installed: City Water, Light and Power, Eastman Kodak, Illinois Power, New York State Electric and Gas, and Public Service of Colorado. The support of the operating staff at these plants was outstanding. In addition, the following organizations provided funding support for work discussed in this paper: US Department of Energy (Agreement Nos. DE-FC22-87PC79796 and DE-FC22-90PC90547), Gas Research Institute (Contract Nos. 5087-254-149, 5090-254-1994 and 5096-290-3652), State of Illinois Department of Energy and Natural Resources, Electric Power Research Institute (Agreement No. RP2916-23), and Colorado Interstate Gas.

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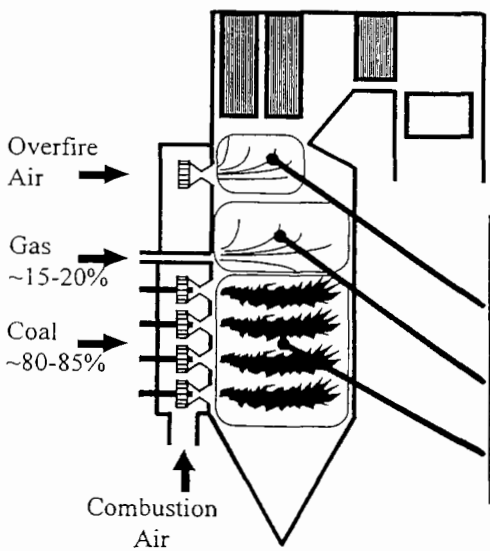
Table 1. Full Scale Reburn Application Summary Table

	Illinois Power, Hennepin Station	City Water Light & Power, Lakeside	Public Service of Colorado, Cherokee	New York State Electric & Gas, Greenidge	Kodak Park
Unit No.	1	7	3	6	15
Firing Configuration	Tangential	Cyclone	Front	Tangential	Cyclone
Boiler Manufacturer	CE	B&W	B&W	CE	B&W
Full Load, MW (net)	71	33	158	104	40
Burners	12 (corners)	2	16	16 (corners)	2
Burner Type	Tilting	Cyclone	Low-NOx	Tilting	Cyclone
Primary Fuel	Coal	Coal	Coal	Coal	Coal
Coal	Illinois Bit	Illinois Bit	Colorado Bit	Pittsburgh Seam	Federal
% Sulfer in Coal	2.8	3.6	0.4	1.8	2.25
Reburn Fuel	Gas	Gas	Gas	Gas	Coal



Zone	Conditions	NO_x Reduction
Burnout	Normal Excess Air	No Change
Reburning	Slightly Fuel Rich	H_xC_y Reactions
Main Combustion	Low Excess Air	Reduced Load Reduced Excess Air

Figure 1. Typical Gas Reburning Installation on a Wall Fired Boiler

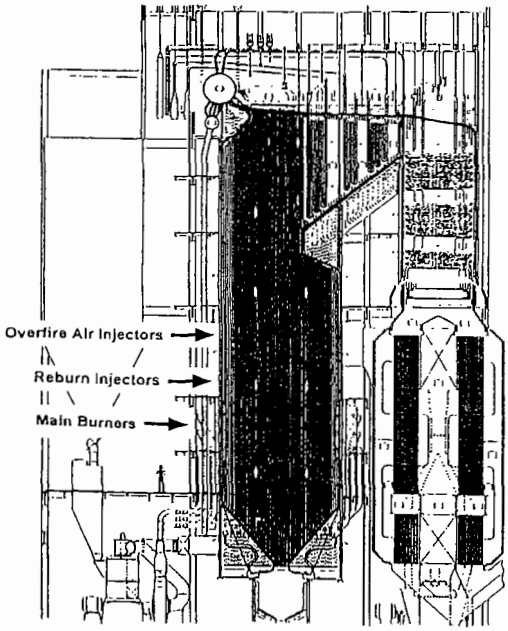


Figure 2. Hennepin: Side Sectional View Showing Gas Reburning Components

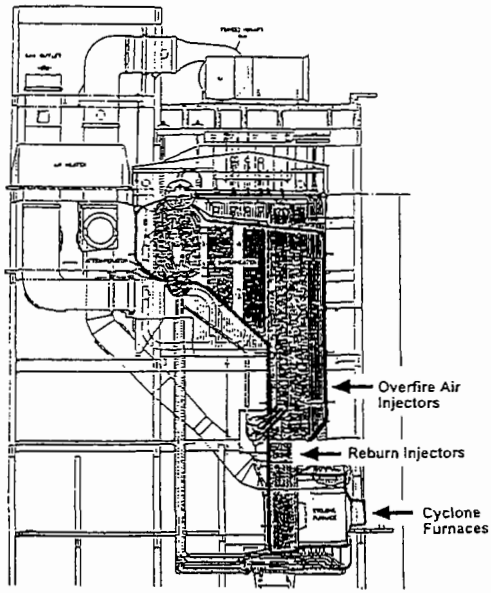


Figure 3. Lakeside: Side Sectional View Showing Gas Reburning Components

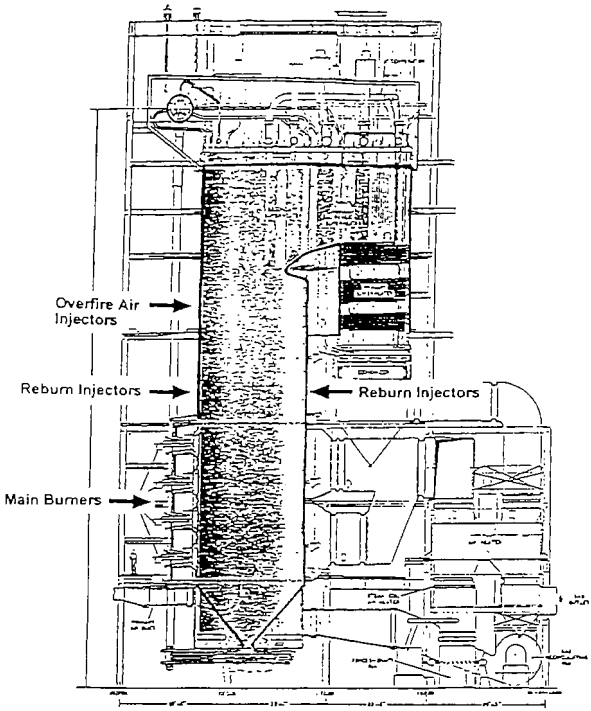


Figure 4. Cherokee: Side Sectional View Showing Gas Reburning Components

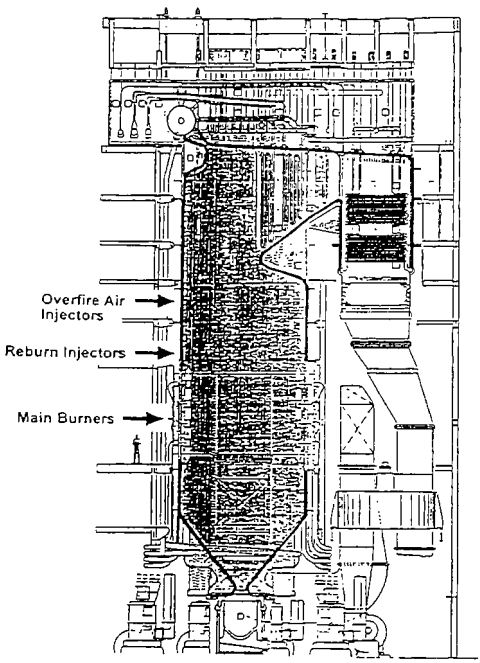


Figure 5. Greenidge: Side Sectional View Showing Gas Reburning Components

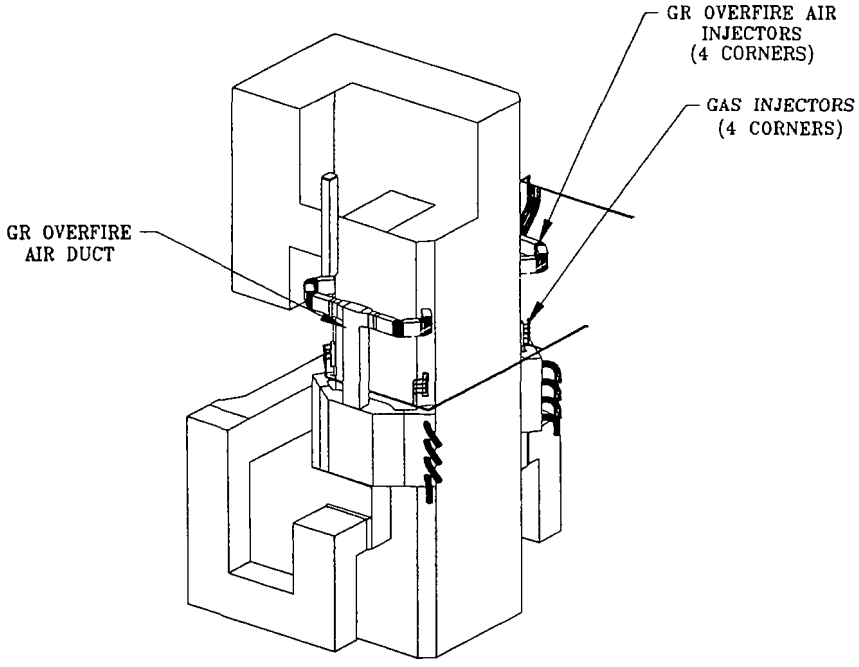


Figure 6. Greenidge: Isometric View of Gas Reburning Installation

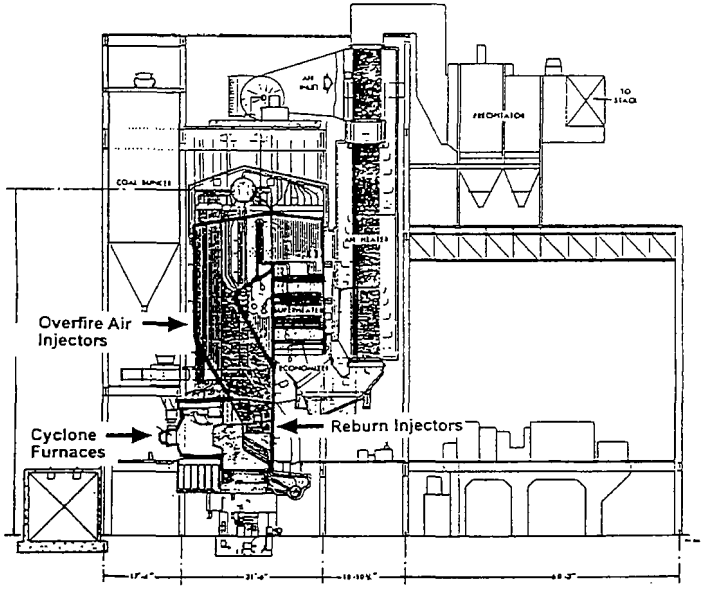


Figure 7. Kodak: Side Sectional View Showing Micronized Coal Reburning Components

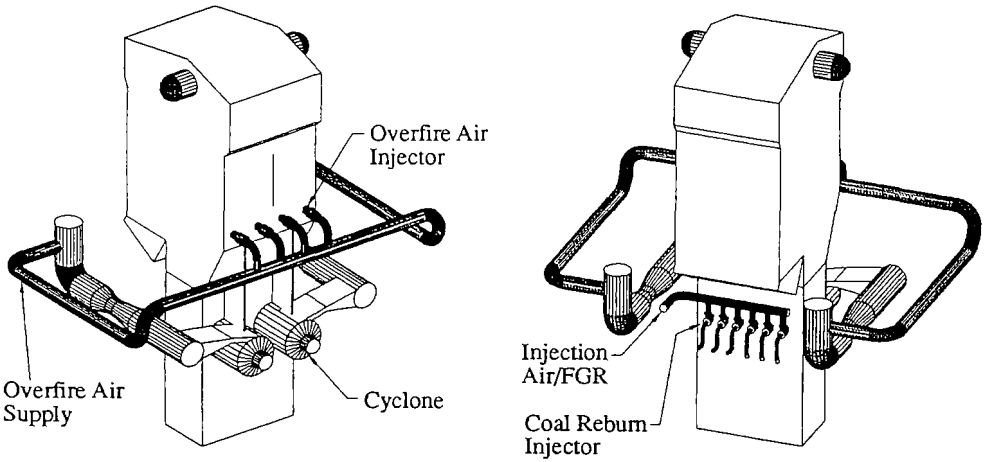


Figure 8. Kodak: Isometric View of Micronized Coal Reburning Installation

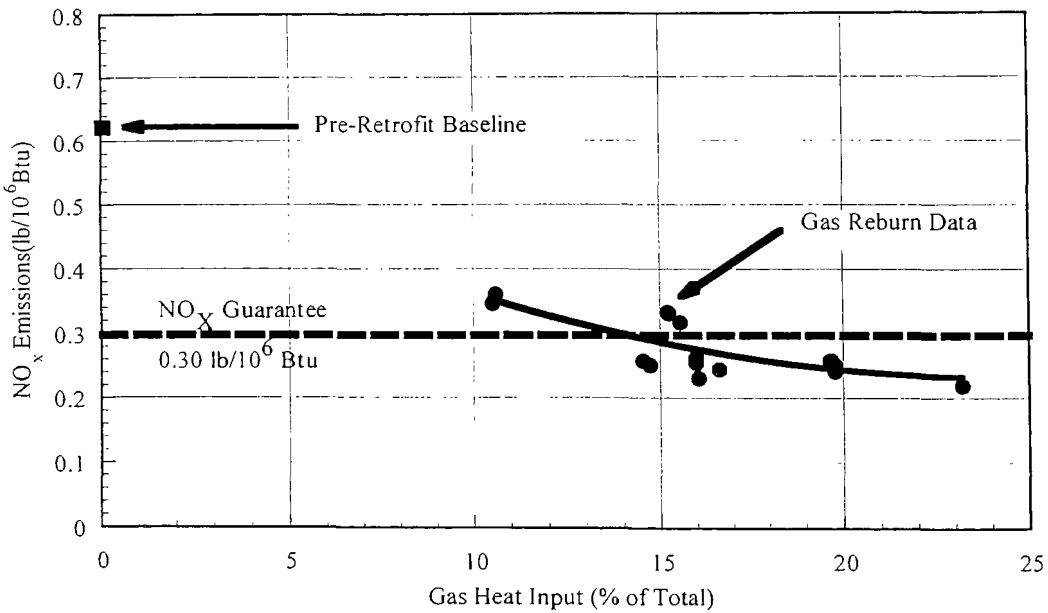


Figure 9. Greenidge: Gas Reburning NO_x Data

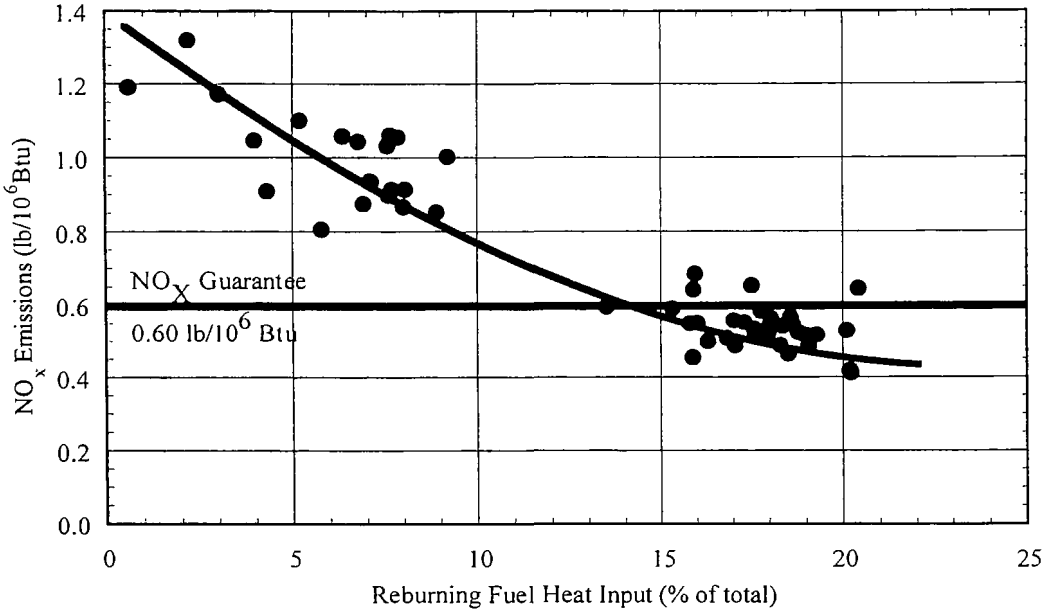


Figure 10. Kodak: Micronized Coal Reburning NO_x Data

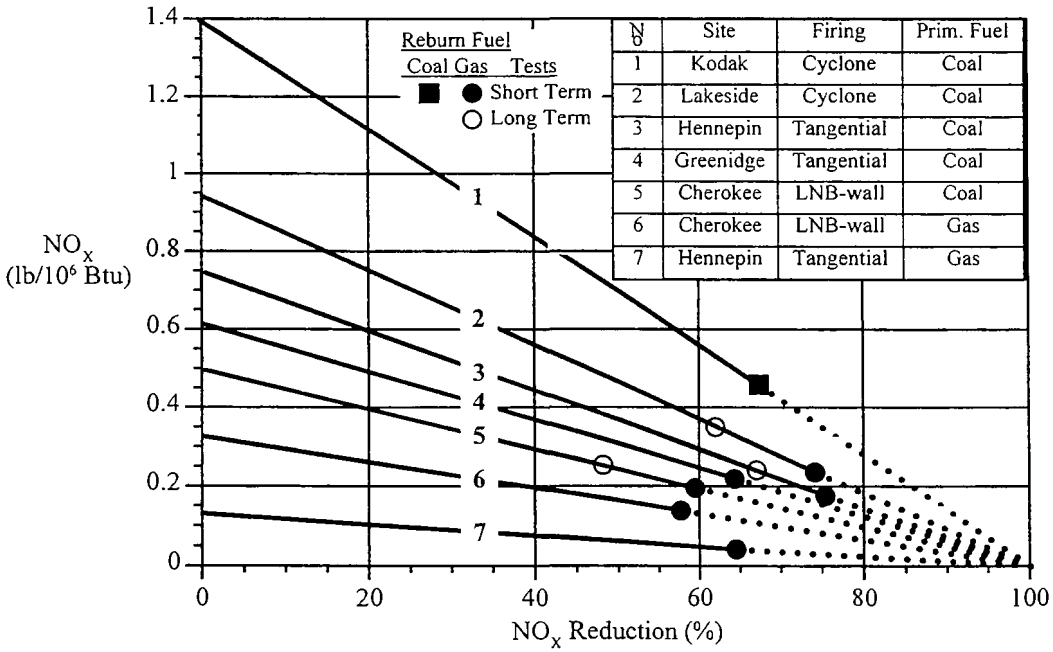


Figure 11. Full Scale Reburning NO_x Control Overview

EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium
The "MEGA" Symposium
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COMMERCIAL DEMONSTRATION OF METHANE de-NOX® REBURN TECHNOLOGY ON A COAL-FIRED STOKER BOILER

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Isaac Chan, Gas Research Institute,
David Hall, Cogentrix of Richmond,
Tim Loviska, Detroit Stoker Company

Abstract

The Institute of Gas Technology (IGT), with support from the gas industry has developed the patented (1,2) METHANE de-NOX® reburning process for stokers to reduce NO_x emissions to levels set by current EPA regulations. In contrast to conventional reburning, where the reburn fuel is injected above the combustion zone to create a fuel-rich reburn zone, with METHANE de-NOX®, natural gas is injected directly into the combustion zone above the grate; this results in a reduction of NO_x formed in the coal bed and also limits its formation through decomposition of NO_x precursors to form molecular nitrogen rather than nitrogen oxides.

Earlier the METHANE de-NOX® process was field tested at the Olmsted County Waste-to-Energy facility in Rochester, Minnesota, and at two incineration plants in Japan. Compared to baseline levels, about 60% NO_x reduction and an increase in boiler efficiency were achieved.

Since July 1996, IGT, Detroit Stoker Company, and Cogentrix have successfully demonstrated the METHANE de-NOX® technology in long-term operation on a 360 MMBtu/h coal-fired stoker boiler at a 240 MW cogeneration plant in Richmond, Virginia. Baseline and retrofit tests, CFD modeling, and long-term testing and demonstration were conducted. NO_x reduction of 60% using 8% natural gas heat input was achieved over the regular boiler load range of 40 to 100%. The boiler is in compliance for both NO_x and CO regulations without the use of selective noncatalitic reduction (SNCR) which was the NO_x control technology for this boiler. Compared to SNCR the reburn system provides: 1) the same or better NO_x reduction; 2) an increase in boiler efficiency of about 2%; 3) CO_2 reduction; 4) elimination of ammonia slip; 5) improved boiler start-up, load change, maintenance and operation; 6) annualized plant cost benefit of about $1.5 to 2.5 million depending on plant capacity factor.

Background

Thousands of stoker boilers in the United States firing coal, municipal solid waste (MSW), biomass, and refuse derived fuel (RDF) have gaseous and particulate emissions, erosion, slagging, and fouling. Environmental regulations are becoming more restrictive (1990 Clean Air Act Amendments) and ultimately will require industries to retrofit many existing solid fuel-burning operations, such as stoker boilers, with technologies that will allow them to meet new emission requirements for NO_x, CO, total hydrocarbons (THC), sulfur dioxide (SO_2), particulate, and other pollutants.

Cogentrix, an independent power producer headquartered in Charlotte, North Carolina, owns and operates 10 cogeneration facilities in North Carolina, Virginia, and Pennsylvania. The largest and newest facility is located in Richmond, Virginia. It is a 240 gross MW coal-fired facility serving Virginia Power and a local fiber and chemical plant. The Richmond plant contains eight spreader stoker coal fired boilers, rated at 285,000 lb/h each. The boilers are ABB VU40 type, burning low sulfur coal from Eastern Kentucky. Each of the eight boilers at the Richmond plant was originally equipped with a urea based SNCR system (NOxOUT). Since initial plant start-up in the Spring of 1992 there have been problems related to the operation of the SNCR system. Each boiler is also equipped with a spray-dryer flue-gas desulfurization (FGD) system with a pulse-jet fabric filter downstream for particulate removal.

The plant is a fully dispatchable facility and operates through automatic generation control (AGC) from the Virginia Power operating center. AGC allows the plant electric output to be controlled remotely by the Virginia power system operator. Boiler loads are rarely constant, as plant electric output is varied to match system demand. At low system demand levels, electrical production ceases; however, steam is still required by the fiber and chemical plant. During these periods, the boilers are operated without the benefit of the regenerative feedwater heating cycle used when producing electricity. The challenges in applying downstream NOx control to a unit that varies widely in load has been previously published (3,4).

As indicated, a urea-based SNCR system is used for NOx control. Because the SNCR reaction is limited to a temperature window of about 1600 to 1950 F, multiple levels of injectors are required for complete furnace coverage. Initially, water dilution of the urea was controlled by a relief valve on the discharge of the water dilution pump. Water and urea were then pumped to the boiler local-zone control panels, where steam was used for atomization, and the mixture injected into the furnace. Urea solution is metered to maintain NOx emissions, as measured by continuous emissions monitors (CEM), at a target value of 0.29 lb/MMBtu. No instrumentation is provided to monitor ammonia slip in the boiler.

The SNCR is put into service at about 30% load (88,500 lb/h steam). At this load, only one level of injectors is in service. The system requires manual rotation of the injectors

as load increases. At still higher loads (above 70%), a second level of injectors is manually inserted into the furnace. As load decreases, the second level of injectors is manually withdrawn from the furnace. As load further decreases, the injectors on the first level are manually rotated to their original position.

Initial operation of the SNCR system began during plant startup in the Spring of 1992. By September of 1992, fabric filter (baghouse) differential pressures gradually increased from a normal range of 4.0 to 6.5 inches water to over 12 inches water. This increase restricted boiler air flow to the point where rated boiler load was no longer attainable. Analysis of the bags revealed dense agglomeration of hygroscopic salts, which adhered stubbornly to the filter surface.

In addition to the buildup of material on the filter bags, the first boiler inspection in March, 1993, revealed hard deposits plugging the tubular air heaters and plating the economizers.

Operational experience at similar Cogentrix plants provided some insight into the problem at the Richmond plant. A plant similar to Richmond, with the same type of the coal-fired stoker boilers but without an SNCR system, had been on line for about seven years and never experienced any of the fabric-filter problems plaguing at the Richmond plant. Also tubular air heaters and economizers experienced erosion, but not pluggage.

Plant personnel suspected that high levels of ammonia slip from the SNCR system might be occurring. With permission from the state of Virginia, the SNCR system was removed from two of the eight boilers. With the SNCR system operating, fabric-filter differential pressure would begin to increase within two weeks, and within four weeks the pressure would approach nine to ten inches water at rated load. After six weeks, the boiler would have to be taken out of service and the filter bags washed.

Boilers operating without SNCR, displayed no change in the differential pressure of the fabric filter. During that period, the boilers were operated at about 89% of rated capacity. When urea injection commenced again, differential pressure had begun to increase within one week.

Through late summer and early fall of 1993, more problems surfaced with the boiler tubular air heaters and economizers. Exit gas temperatures increased 20 to 30 degrees F, and pressure differential across the air heaters also increased, suggesting a worsening of the deposition in these areas.

In October 1994, IGT as the technology developer together with Detroit Stoker Company, the manufacturing partner, and Cogentrix of Richmond, the host site, were awarded a contract by the Gas Research Institute to retrofit a boiler with the patented METHANE de-NOX® reburn process. The ultimate goal of the project was to validate and deploy in a full-scale utility boiler a concept that has been proven to be technically and

economically feasible but required further experience with full-scale systems to ensure operational practicality and broad utility and industrial acceptance in order that such technology is selected for long term use. Cofunding of this project was provided by IGT Sustaining Membership Program (SMP) as well as several large gas/utility companies. In-kind funding was provided by Detroit Stoker Company and Cogentrix of Richmond. The City of Richmond supplied the natural gas line to the plant at no cost to the project.

METHANE de-NOX® Concept for Solid Fuel-Fired Stokers

Conventional reburning is a process in which additional fuel (e.g., natural gas) is injected into the products of complete combustion so as to eliminate the excess oxygen and provide hydrocarbon radicals. These radicals react with NO_x as the source of oxygen, thereby reducing it to molecular nitrogen. The reburn process requires relatively high temperature and sufficient residence time. At the end of the reburn zone, overfire air is injected to create a burnout zone. This process has been successfully applied, using natural gas as a reburning fuel, to pulverized coal and cyclonic coal-fired combustors (5). Over 50% of NO_x reduction was demonstrated during long term operation. If conventional reburning is applied to the stoker, then the combustion volume will be divided into four zones: two combustion zones (coal bed and combustion zone above the bed in the lower furnace), reburn and burnout zones. In this case at least three levels of injection are required, two for overfire air and one for natural gas as reburning fuel. The overall height of coal-fired stokers is usually not very large. For example, the elevation of Cogentrix boilers from the grate to platen superheater is only about 35 feet. It is practically impossible to install and ensure effective processing of two combustion zones, reburn and burnout zones in such furnace. The total residence time of combustion products in the furnace is about 2.5 seconds, but the reburn zone alone requires about 1 second for effective mixing and reacting of reburn fuel with the combustion products.

The METHANE de-NOX® reburning process, developed by IGT with support from the gas industry and GRI, for stoker fired combustors is shown in Figure 1. In this case, natural gas as a reburning fuel is injected just above the coal bed. Compared to conventional reburning the METHANE de-NOX® process requires only three zones instead of four, and two levels of injection instead of three. Injected natural gas not only reduces NO_x formed in the coal bed, but also limits its formation because a significant portion of the NO_x precursors are decomposed and react to form molecular nitrogen. A reduction in the number of zones and injection levels provides sufficient residence time for reburning and burnout. The METHANE de-NOX® process was evaluated on a pilot-scale combustor at Riley Stoker's facility (6), and twice field tested during 1991 at the Olmsted County Municipal Waste Combustion facility in Rochester, Minnesota (7), and during 1995 and 1996 at the incineration plants in Japan (8). The tests at Olmsted County achieved an average reduction of 60% of NO_x and 50% of CO compared to baseline levels when injecting 13% natural gas. In Japan, 55% of NO_x reduction was achieved with 7% of natural gas. A significant increase in boiler efficiency (about 3%) was also demonstrated at the Olmsted Country 100 ton/d MSW boiler.

The major advantages of METHANE de-NOX® compared to the existing SNCR are:

- The same or better NO_x reduction in the range of 60 to 70%
- Increase in boiler efficiency by 1 to 2%
- Annualized cost benefit of about $340,000 for a 360 MMBtu/h boiler
- Additional environmental benefits due to the reduction of CO_2, SO_x, particulate, and hydrocarbons, and the elimination of ammonia slip
- Improvement in plant operation for start-up and load changing regimes
- Exclusion of boiler outages for baghouse, economizer and air heater cleaning
- Elimination of chemicals such as urea, ammonia, etc., for combustion product treatment

Baseline Testing and Modeling

Baseline, full and partial load testing were conducted on one of the eight stoker units at the Richmond site. During baseline tests, the SNCR system was shut down per a prior agreement between Cogentrix and the Virginia Department of Environmental Quality. The goals of the baseline tests were to: obtain baseline data for METHANE de-NOX® system design, determine the location of NO_x formation in the furnace, estimate the ratio of fuel bound/thermal NO_x, evaluate furnace gas composition and temperature profiles, determine the effect of major operating parameters on emissions and furnace temperatures, and define the effect of high excess air on superheated steam temperature and boiler capacity. The variable parameters of the baseline tests were: combustion zone stoichiometry, total excess air, undergrate and overfire air split, undergrate air distribution, and coal heat input. A total of 16 tests were conducted as part of the baseline test plan. Two loads were tested, 60 and 100%, total excess air was varied with oxygen concentrations in flue gas from 1 to 8%. Undergrate to overfire air ratio was varied from 70/30 to 90/10. Undergrate air distribution was varied via positioning of four dampers on each side of the stoker unit. Baseline test measurements included basic boiler performance, spreader stoker performance, furnace gas compositions and temperatures, coal and ash sample analyses, and emissions data. In-furnace data were obtained at three elevations using water-cooled probes. Data were obtained above the grate, in the middle of the furnace, and at the exit of the furnace. The main finding of baseline tests was that it should be possible to reduce NO_x emissions by at least 50% using METHANE de-NOX® reburning technology. Certain results of baseline testing were presented at the AFRC 96 (9).

A typical output of the computational fluid dynamic (CFD) model (developed by B&W) of the boiler furnace at Richmond utilizing METHANE de-NOX® reburn is shown in Figure 2. Calculated average NO_x concentrations as a function of elevation are shown which indicate that total NO_x concentration decreases rapidly from about 425 ppm to about 150 ppm, (@ 3% O_2), there is about 65% reduction. The model indicates that most of the NO_x is from the fuel bound and only about 20% is thermal NO_x. In the figure, an elevation of 118 feet corresponds to the grate level.

Retrofit Testing

During the spring and summer of 1996, the METHANE de-NOX® reburn system was installed on the stoker boiler and prepared for continuous operation. The reburn system consists of a natural gas supply system, flue gas recirculation system(FGR) and also includes a modification of one row of overfire air nozzles without any retrofit of the boiler waterwall tubes.

Retrofit testing was conducted at the Richmond site in July and August 1996. The SNCR system was shut off per a prior agreement between Cogentrix and the Virginia Department of Environmental Quality, as it was for baseline testing. The major goals of the retrofit tests were to: validate and deploy the METHANE de-NOX® reburn process for a coal-fired stoker boiler, and determine the operating parameters for the reburn system and retrofitted boiler for continuous operation. The variable parameters of the retrofit tests were: combustion zone stoichiometry, total heat input, natural gas input and distribution, FGR input and distribution, total excess air, and undergrate/overfire air split. Nineteen retrofit tests were conducted according to the test plan and matrix. Four loads were tested, 40, 60, 80, and 100%; natural gas input was varied from 5 to 25% with different distribution between the injection levels. The FGR flow was in the range of 10 to 35% and also with different distribution. The total excess air was varied with O_2 concentration in the flue gas at the furnace exit from 2 to 5%, and undergrate/overfire air ratio was in the range of 15 to 32% at different boiler loads. The retrofit test measurements included the same volume of parameters as for baseline test, but in addition flue gas composition and temperature were measured at the boiler exit.

The main retrofit test result is that the METHANE de-NOX® reburn process was able to reduce NOx up to 70% and allowed operation of the coal-fired stoker boiler in compliance with the Virginia Department of Environmental Quality NOx and CO regulations without any urea injection.

Selected retrofit test results are shown in Figures 3 to 7. The effect of primary combustion zone stoichiometry in the coal bed on the NO_x in the center above the grate for two loads, 60 and 100%, is presented in Figure 3, and on natural gas input required to maintain NO_x at the boiler exit in compliance is shown in Figure 4. The primary combustion air/coal ratio has a significant effect on NO_x above the coal bed, and with load increase, the NO_x level above the grate increases also, Figure 3. Larger natural gas input allows keeping higher undergrate air to coal ratio which assures effective operation of the grate, Figure 4. The NO_x distribution versus furnace elevation at 100% load for different natural gas inputs is given in Figure 5. The reburning zone is located somewhere between the 120 and 130 feet elevations, and after the reburning zone the NO_x concentration is nearly unchanged.

The effect of natural gas input on NO_x emissions is shown in Figure 6. When the natural gas portion in the total heat input is increased, NO_x at the furnace exit decreases, and this effect is more pronounced at the higher load. The required FGR flow for different boiler loads is presented in Figure 7. At full load only 9% FGR is required for reburn process, and the portion of undergrate FGR is about 2%. As the boiler load decreases the percentage of undergrate FGR increases to replace the extra undergrate air used for regular grate operation at partial loads.

In March 1997 the METHANE de-NOX® reburn system was modified. The FGR withdrawal was switched from the exit of the dust collector to the ID fan discharge. The capital cost of the modified system is significantly lower compared to the original system. The modified reburn system was extensively tested and the results were compared with the retrofit tests in August 1996.

During all retrofit tests, the boiler operating data were continuously collected through the boiler's distributed control system. The boiler operating parameters and performance for the tests in August 1996 (Aug'96) and March 1997 (Mar'97) and for four loads, 40, 60, 80, and 100%, are shown in the Table 1. With about 6 to 8% natural gas injection, NOx was maintained in the range of 0.28-0.29 lb/MMBtu and CO emission was less than 0.09 lb/MMBtu. The Virginia state regulations are: NOx < 0.30 lb/MMBtu and CO < 0.20 lb/MMBtu. The O_2 at the furnace exit was about 3% at full load and increased to 5% at 40% load. These oxygen levels are much lower than boiler design oxygen concentrations, especially at partial load. As a result of this, stack losses were significantly decreased and boiler thermal efficiency increased by about 2%.

For all retrofit tests, the boiler thermal efficiency was in the range 88.7 89.8 % with no decline at partial loads. The improvement of boiler performance is an important feature of the METHANE de-NOX® reburn system.

Carbon in bottom ash was from 5 to 10 % for Aug'96 and from 7 to 9 % for Mar'97 tests. But carbon in fly ash was significantly lower for the Mar'97 compared to Aug'96 tests, 10 to 15 % compared to 20 to 35 %.

Pressure drops for the secondary and primary economizers, and air heater were practically the same for tests in Aug'96 and Mar'97. The increase in baghouse pressure drop is because of the FGR flowing through the baghouse in the modified reburn system.

After completion of retrofit testing, the METHANE de-NOX® reburn system was put in permanent long-term operation.

Long-Term Testing

Since July 1996, the METHANE de-NOX® reburn system has being continuously operated at Cogentrix plant in Richmond, Virginia. During this period, the SNCR system has not been employed, and NO_x and CO emissions have been within the limits of the air permit issued by the Virginia Department of Environmental Quality.

From August 1996 to July 1997 long-term testing of the METHANE de-NOX® reburn system was conducted. The major goals of these tests were to : validate the reburn technology in long-term permanent operation including load swings and different upset conditions; determine the combination of boiler operating parameters which provides the best boiler performance; collect essential data to design the commercial reburn system for the other seven boilers at Cogentrix in Richmond; and confirm operational practicality and cost-effectiveness of the METHANE de-NOX® reburn technology for other potential customers nationwide.

A special procedure for data collection and processing was developed. Total of 168 operating parameters during each test were collected through the boiler I & C system. The tests were conducted at stable load and load swings in the range of 40 to 100 %, during boiler regular maintenance, and at the most of the upset conditions.

Based on the tests results, the best combination of operating parameters was selected and set up in the boiler control system for permanent operation. Table 2 shows selected boiler operating parameters and performance for four months during the one year period, from August 1996 to July 1997. The data present average parameters at the maximum load for the month. NO_x and CO are within the required limits, and O_2 is about 3 % at full load and about 4 % at 80 % load. Boiler thermal efficiency was in the range 88.4 - 89.0 % which is for about 2 % higher than baseline efficiency. Pressure drops through the boiler firesides and baghouse were stable. No fouling has occurred in the economizer, air heater, dust collector, or baghouse. During this period, no expenses have been incurred for urea, maintenance of SNCR equipment, or cleaning of boiler firesides and baghouse. Implementation of the METHANE de-NOX® has provided improvement of the boiler long-term reliability and significant reduction in operating costs.

Due to favorable results of retrofit and long-term testing, Cogentrix decided to install the METHANE de-NOX® reburn system on the other seven boilers, one boiler to be retrofitted in 1997, and the remaining six - during 1998-99.

Conclusions

Based on the results of retrofit test and one year continuous operation, the METHANE de-NOX® reburn technology is an attractive alternative to SNCR for emissions reduction in coal-fired stoker boilers and provides improvement in boiler operating performance and thermal efficiency. IGT has licensed to Detroit Stoker Company the IGT's reburning technology for deployment nationwide. At the present time, companies are allowed to take credit for operating a boiler below the permitted emission level and this presents another motivation to reduce NO_x emissions using METHANE de-NOX®

Acknowledgments

Many sponsors played important roles in the development of the METHANE de-NOX® technology for coal-fired stoker boilers. The authors wish to acknowledge the City of Richmond for supplying the natural gas line at no cost to the project, and the financial support of Columbia Gas Distribution Companies, Consumers Power, Indiana Gas Company, Inc., North Carolina Natural Gas Corporation, and Texas Gas Transmission Corporation. Personnel of Cogentrix warrant special mention for allowing interruption of commercial operations to enthusiastically support and vigorously assist in the implementation of the retrofit.

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Table 1. Boiler operating parameters and performance for August 1996 and March 1997

LOAD, %	40	60	80	100
O2, %, furnace	4.58 / 5.29	3.97 / 4.94	3.41 / 4.11	2.89 / 3.23
CO, lb/MMBtu	0.06 / 0.06	0.05 / 0.13	0.04 / NA	0.07 / NA
NOx, lb/MMBtu	0.28 / 0.29	0.29 / 0.28	0.28 / 0.27	0.29 / 0.29
NG, % input	8.3 / 8.0	7.3 / 6.3	7.6 / 6.5	8.3 / 6.3
Bottom ash carbon, %	9.8 / 7.4	5.0 / 7.5	5.6 / 9.2	7.7 / 8.4
Carbon in flyash (DC2), %	31.3 / 15.0	21.9 / 10.8	19.8 / 12.5	35.4 / 10.2
Boiler thermal efficiency, %	88.7 / 89.6	89.0 / 89.8	89.5 / 88.8	88.9 / 89.0
Pressure drop (inch H2O) for:				
Secondary Economizer	0.9 / 0.7	1.0 / 1.0	1.5 / 1.2	1.9 / 1.7
Primary Economizer and Air Heater	2.0 / 1.5	2.3 / 2.2	3.4 / 2.8	4.5 / 4.1
Baghouse	2.2 / 3.4	3.5 / 4.8	4.6 / 5.4	6.7 / 8.2

Note: a/b; a - data for August 1996, b - data for March 1997

Table 2. Boiler operating parameters and performance for August'96 through July'97

Month	Aug'96	Oct'96	Mar'97	Jul'97
Boiler steam flow, klbs/h	290.0	213.1	257.0	299.8
O2, %, furnace	2.9	4.1	3.5	2.5
CO, lb/MMBtu	0.07	0.08	0.08	0.14
NOx, lb/MMBtu	0.29	0.30	0.29	0.28
NG, % input	8.3	4.2	6.3	4.0
Boiler thermal efficiency, %	88.9	88.4	89.0	88.8
Pressure drop (inch H2O) for:				
Secondary Economizer	1.9	1.7	1.7	1.7
Primary Economizer and Air Heater	4.5	4.0	4.2	4.2
Baghouse	6.7	4.8	8.2	6.4

NO_x Regulation: 0.30 lb/MMBtu
CO Regulation: 0.20 lb/MMBtu

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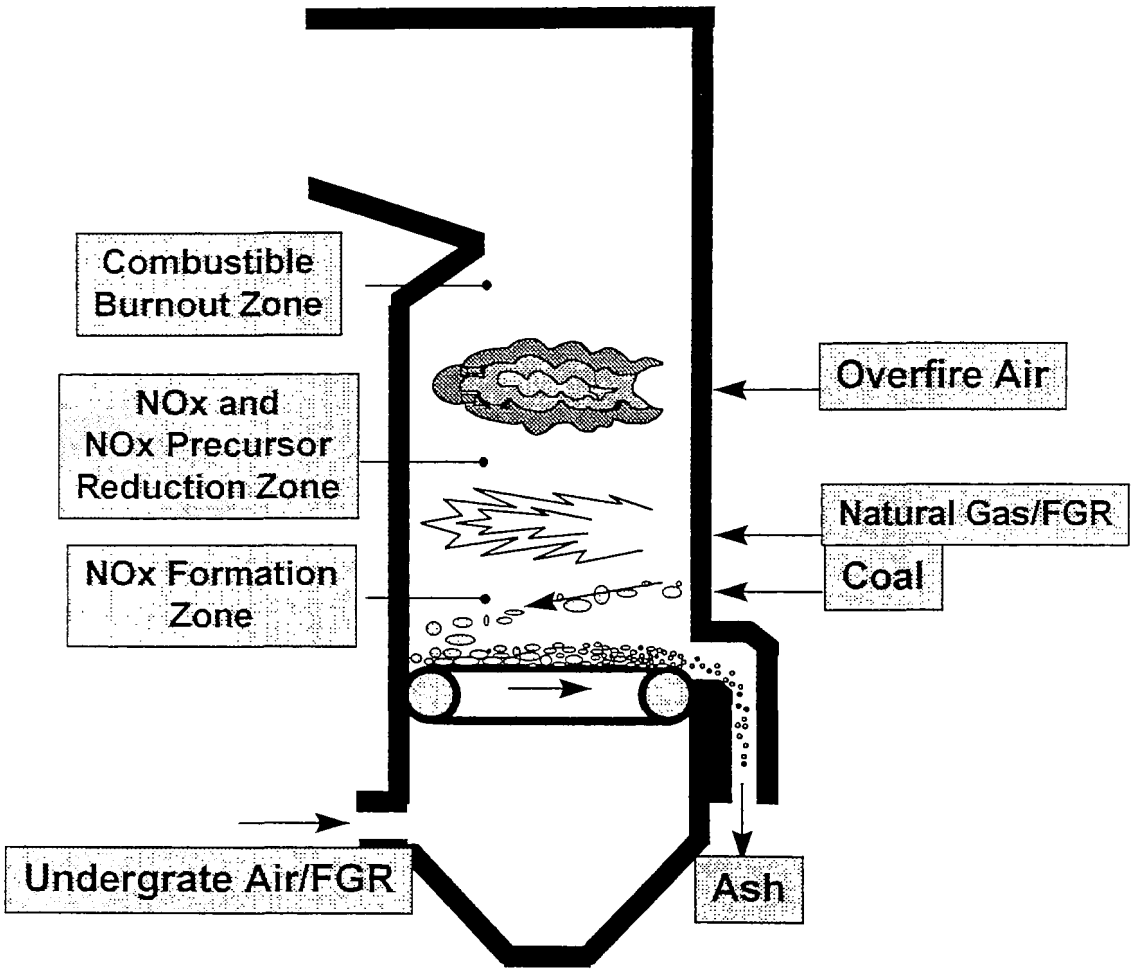

Figure 1. Spreader stoker boiler with METHANE de-NOX^{SM} reburn

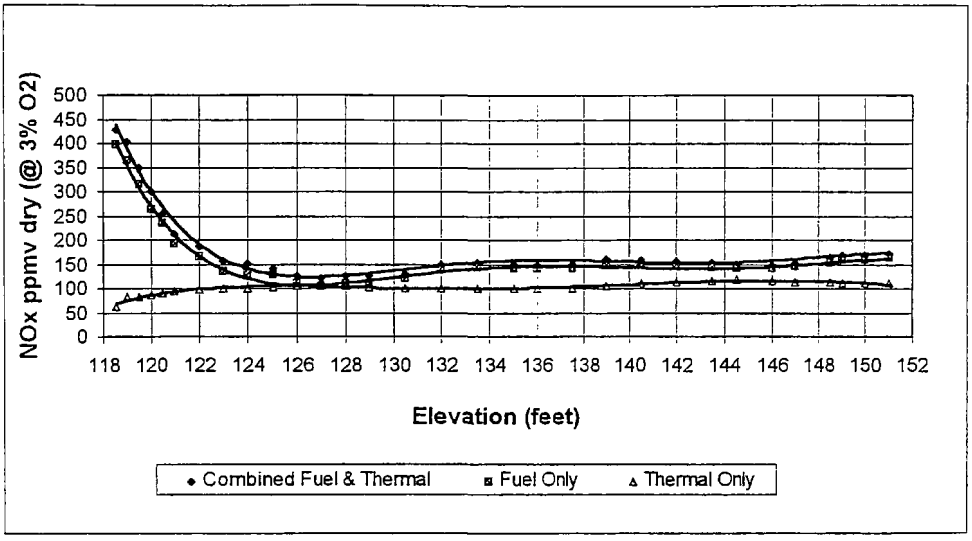

Figure 2. Average NOx concentration versus elevation

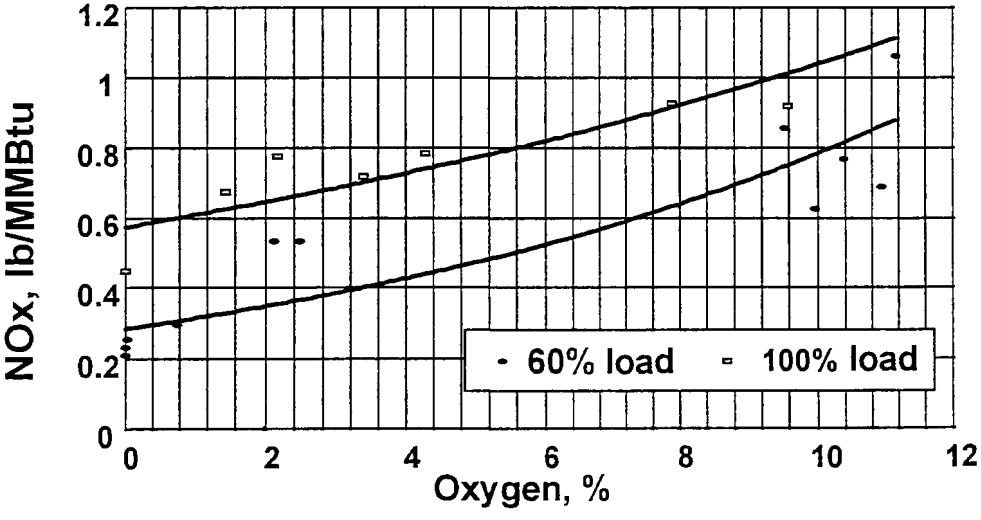

Figure 3. Effect of oxygen on NOx above the grate at elevation 122'

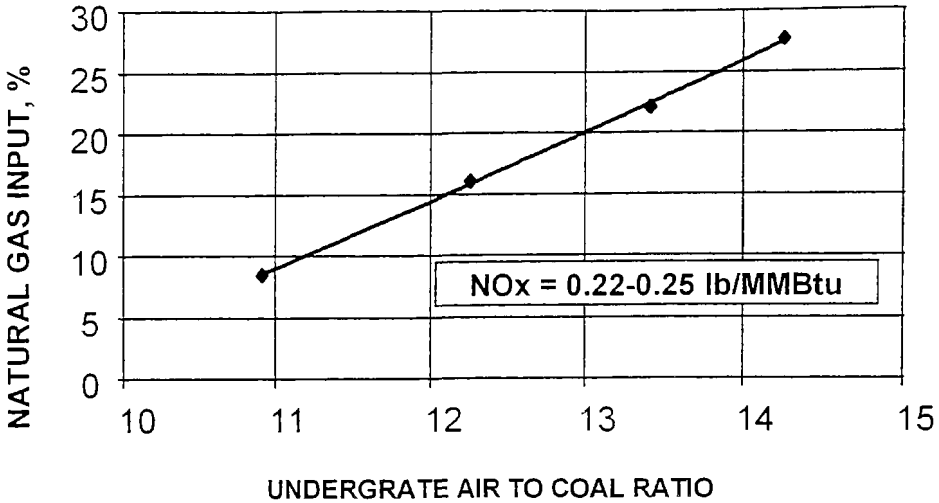

Figure 4. Effect of natural gas input on grate stoichiometry

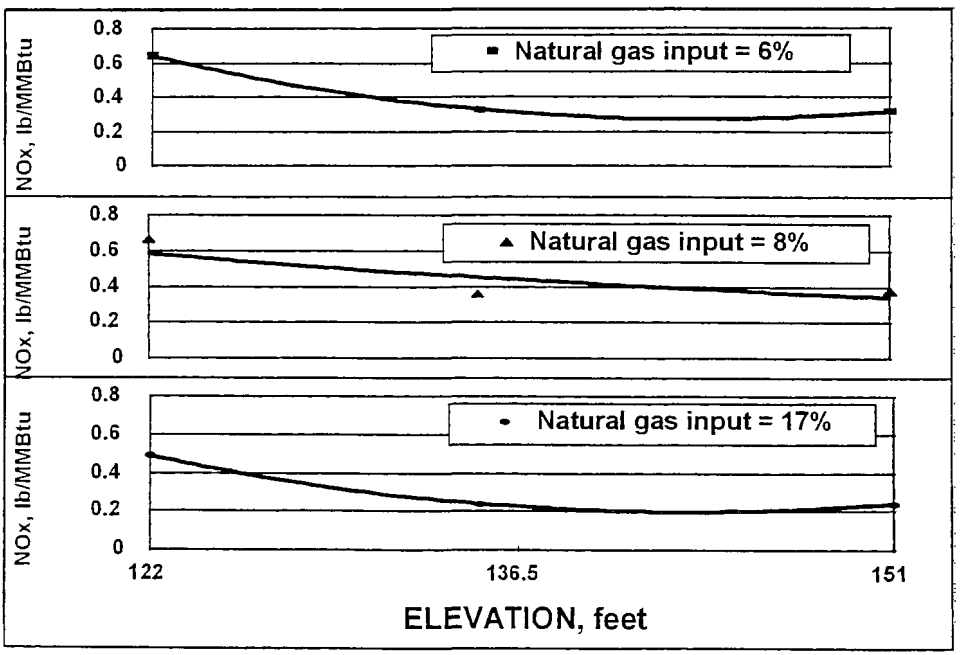

Figure 5. NOx versus elevation for 100% load

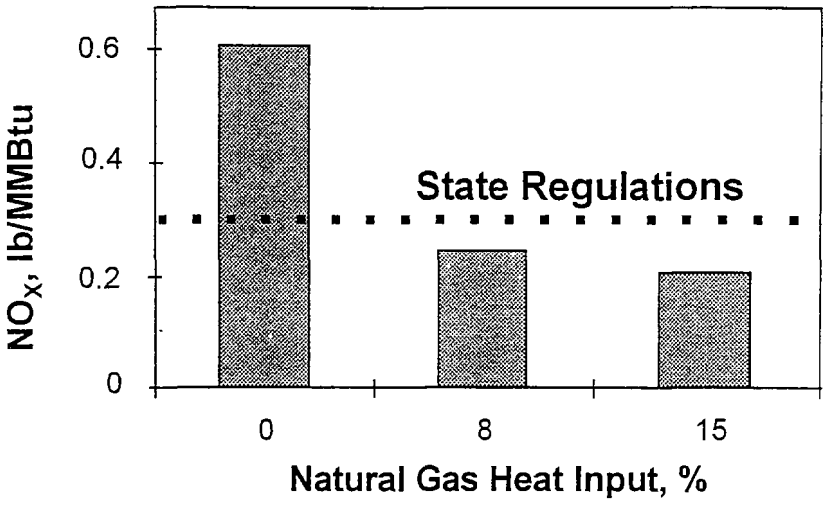

Figure 6. NOx reduction by METHANE de-NOX reburning

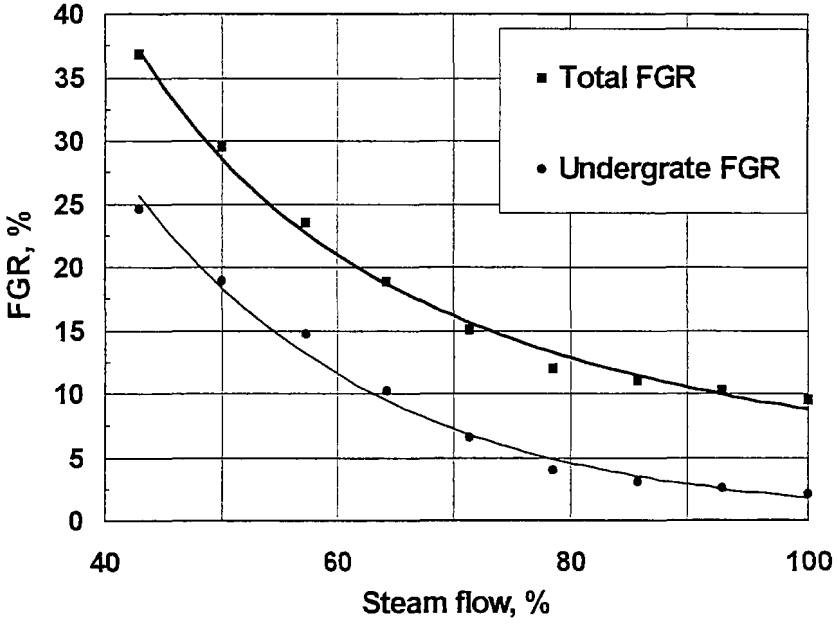

Figure 7. FGR flow versus boiler load

Tuesday, August 26; 8:00 a.m.
Parallel Session B:
Selective Noncatalytic Reduction

USING RETRACTABLE LANCES TO MAXIMIZE SNCR PERFORMANCE

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Abstract

Public Service Company of Colorado, the U.S. Department of Energy, and the Electric Power Research Institute sponsored a demonstration of the Integrated Dry NO_x/SO_2 emissions Control System. This project demonstrated 70% NO_x and SO_2 reduction by integrating up to five different emission control systems. The project was conducted on a 100 MWe coal-fired boiler located in Denver, Colorado.

One important component of the project is the selective non-catalytic reduction (SNCR) system used to increase NO_x reduction beyond that possible with combustion modifications alone. Initial testing of the SNCR system demonstrated up to 45% NO_x reduction while controlling ammonia slip to 10 ppm at full load; low load performance was limited to only 11% NO_x reduction at an equivalent ammonia slip. To improve low load performance, NOELL's Advanced Retractable Injection Lance (ARIL) was installed. The lance is unique as it may be rotated to inject the liquid urea solution into the correct flue gas temperature range to maximize NO_x reduction. This lance greatly improved low load performance and obtained up to 50% NO_x reduction at 50 MWe. The ARIL lances met all performance expectations but experienced permanent bending due to the very high flue gas temperatures at the injection location. This was remedied by adding cooling slots. A second retractable lance design, provided by Diamond Power Specialty Company (DPSC), was also tested. This lance was designed to use evaporative cooling to provide additional cooling and reduce lance bending. The DPSC lance solved many of the operational issues, but obtained slightly lower NO_x reduction at equivalent ammonia slips. While the lances operated differently, the information gathered during this demonstration provides the data necessary to help select the appropriate location and lance design to maximize NO_x removal based on site-specific factors of both lance designs.

Introduction

Public Service Company of Colorado (PSCC) was selected by DOE for a CTT-III project in December 1989 to demonstrate an Integrated Dry NO_x/SO_2 Emissions Control System. The Electric Power Research Institute also cofunded the project. The demonstration project took place at PSCC's Arapahoe Unit 4, a 100 MWe top-fired unit which fires a low sulfur (0.4%) Colorado bituminous coal as its main fuel, but also has 100% natural gas capability.

The Integrated Dry NO_x/SO_2 Emissions Control System combines five major control technologies to form an integrated system to control both NO_x and SO_2 emissions. The system uses low-NO_x burners, overfire air, and urea injection to reduce NO_x emissions, and dry sorbent injection using either sodium- or calcium-based reagents with (or without) humidification to control SO_2 emissions. The goal of the project was to reduce NO_x and SO_2 emissions by up to 70%. The combustion modifications were expected to reduce NO_x by 50%, and the SNCR system was expected to increase the total NO_x reduction to 70%. Dry Sorbent Injection was expected to provide 50% removal of the SO_2 emissions while using calcium-based reagents. Because sodium is much more reactive than calcium, it was expected to provide SO_2 removals of up to 70%.

Prior publications presented results of the performance of the individual technologies and Reference 1 provides an overall summary of the project. This paper will present recent results focused on improving the load performance of the SNCR system.

SNCR System

The purpose of the SNCR system at Arapahoe was two-fold. First, to further reduce the final NO_x emissions obtained with the combustion modification so that the goal of 70% NO_x removal could be achieved. Second, the SNCR system is an important part of the integrated system interacting synergistically with the dry sodium injection system. During this program, it was shown that when both systems are used simultaneously, both NO_2 emissions from the sodium system and NH_3 slip from the SNCR system are reduced.

When the SNCR system was originally designed and installed, it incorporated two levels of wall injectors with 10 injectors at each level. These two separate levels were intended to provide load following capability. The locations of these two levels were based on flue gas temperature measurements made with the original combustion system. However, the retrofit low-NO_x combustion system resulted in a decrease in the furnace exit gas temperature of nominally 200°F. This decrease in temperature moved the cooler injection level out of the SNCR temperature window. With only one operational injection level, the load-following performance of the system was compromised. For a 10 ppm NH_3 slip limit, low load NO_x reductions were limited to 11%.

Two approaches were pursued to improve the low load performance of the SNCR system. First, short-term testing showed ammonia to be more effective than urea at low loads. Although ammonia was more effective than urea, it remained desirable to store urea due to safety concerns. A system was installed that allows on-line conversion of urea into ammonia compounds. The

on-line conversion system improved low load performance, but the improvement was not as large as desired at the lowest load (60 MWe).

More recently, NOELL, Inc. (the original supplier of the SNCR system) suggested an additional injection location in a higher temperature region of the furnace. Because no unit outages were planned, the only option for incorporating an additional injection level was to utilize two existing (but unused) sootblower ports in conjunction with NOELL's Advanced Retractable Injection Lances (ARILs). This location was chosen because the ports existed, not because the temperatures were ideal for SNCR.

The SNCR system uses NOELL's proprietary dual-fluid injection nozzles to distribute the urea uniformly into the boiler. A centrifugal compressor is used to supply a large volume of medium-pressure air to the injection nozzles. The large quantity of air helps to atomize the urea solution as well as provide energy to rapidly mix the atomized solution with the combustion products.

Figure 1 shows the location of the new ARIL lances relative to the two original SNCR injection locations. Level 2 is the location that became unusable as a result of the flue gas temperature decrease after the low-NO_x combustion system retrofit. The ARIL system consists of two retractable lances and two retractable lance drive mechanisms. Each lance is nominally 4 inches in diameter and approximately 20 feet in length. Each lance has a single row of nine injection nozzles spaced on two-foot centers. A single division wall separates the Arapahoe Unit 4 furnace into east and west halves, each with a width of approximately 20 feet. When each lance is inserted, the first and last nozzles are nominally one foot away from the division and outside walls, respectively.

Each injection nozzle is composed of a fixed air orifice (nominally one-inch in diameter), and a replaceable liquid orifice. The liquid orifices are designed for easy removal and cleaning. This ability to change nozzles also allows adjustments in the chemical injection pattern along the length of the lance in order to compensate for any significant maldistributions of flue gas velocity, temperature, or baseline NO_x concentration.

Two separate internal liquid piping circuits are used to direct the chemical to the individual injection nozzles in each lance. The four nozzles near the tip of the lance are supplied by one circuit, and the remaining five are supplied by the other. This provides the ability to bias the chemical flow between the "inside" and "outside" halves of each side of the furnace in order to compensate for various coal mill out-of-service patterns. Each lance is also supplied with a pair of internal thermocouples for detecting inside metal temperatures at the tip of the lance.

The retractable lance drive mechanisms were supplied by Diamond Power Specialty Co. (DPSC). The drives are Model IK 525's which have been modified for the liquid and air supply parts. Both remote (automatic) and/or local (manual) insertion and retraction operations are accomplished with the standard IK electric motor and gearbox drive system. A local control panel is provided on each ARIL lance drive mechanism. Each panel contains a programmable logic controller for the lance install/retract sequencing and safety interlocks. Each lance can be rotated either manually at the panel, or automatically by the control system during load-following operation. One of the key features of the ARIL lance system is its ability to rotate the lances. As

will be discussed, this feature provides a high degree of flexibility in optimizing SNCR performance by varying the flue gas temperature at the injection location by simply rotating the lance.

In addition to NOELL's ARIL lances, an alternate lance design, supplied by Diamond Power Specialty Company, was also evaluated. This alternate lance design represented a simplification to the original ARIL design. The liquid solution is injected through a single pressure atomizer located in the air supply pipe ahead of the lance. This eliminates the internal liquid piping, and spraying at the lance inlet provides evaporative cooling to help cool the lance. The DPSC lance design also eliminated a telescopic device used in the ARIL lance design. The telescope worked well, but contains seals that require replacement due to normal abrasion that occurs during the insert and retract process. In addition, the design prevents air and liquid from being injected in the local region around the boiler when the lances are retracted.

SNCR Lance Performance Results

The recent test work has focused on the performance of the SNCR lances, both the NOELL ARIL lances and the alternate DPSC lance, in order to enhance low load performance of the SNCR system. The majority of the testing was performed with the NOELL ARIL lances. As such, the results will focus on the ARIL test results along with a comparison of performance between the NOELL ARIL and DPSC lances.

ARIL Lances

Prior to incorporating the ARIL lances into the SNCR control system, a series of parametric tests was conducted to define the optimum injection angle at each load. As shown in Figure 1, each lance can rotate to inject urea into a different region of the furnace in order to follow the SNCR temperature window as the boiler load changes. The minimum injection angle is 22° (0° corresponds to injection vertically downward), at which point the chemical is injected parallel to the tube wall located below the lances. Smaller injection angles are not used to avoid direct liquid impingement on these tubes. An injection angle of 90° corresponds to injection straight across the furnace toward the front wall, and an angle greater than 90° results in injection of the solution in a direction up toward the roof-mounted burners.

While the primary focus of the parametric tests was to define the injection angle versus load, the tests also investigated the effects of:

- coal mill out-of-service patterns
- coal mill biasing
- biasing the urea flow along the length of the lances
- independent adjustment of the injection angles for each lance

The results of these tests are described below.

Effect of Lance Angle

One of the primary attributes of the ARIL lance system is the inherent flexibility of accessing the optimum flue gas temperature location by simply rotating the lance. Figure 2 shows the effect of varying the lance injection angle at loads of 43 and 50 MWe. All of the tests shown in these figures were performed at a N/NO_x ratio of 1.0, with two mills in service. At 43 MWe, varying the injection angle had little effect on NO_x removal, and the maximum removal occurred at an angle of 35 degrees (Figure 3a). However, Figure 2a shows that the lance angle had a large effect on NH_3 slip; decreasing from 46 ppm at an angle of 22° to under 5 ppm at an angle of 135° This overall behavior at 43 MWe suggests that, on average, injection is occurring just on the high side of the SNCR temperature window. In fact, the optimum temperature, in terms of NO_x removal, appears to correspond to an angle of 35°. However, since it is desirable to maintain the NH_3 slip less than 10 ppm, an injection angle of 90° is a more appropriate operating angle at this load.

At a slightly higher load of 50 MWe (Figure 2b), the effect of lance injection angle was markedly different. At this load, where the average flue gas temperatures were higher, injection angle had little effect on NH_3 slip. However, at the higher temperature, lance angle had a large effect on NO_x removal. The relative insensitivity of the NH_3 slip and large sensitivity of the NO_x removal to lance angle suggests that at 50 MWe, chemical injection is occurring far on the high side of the SNCR temperature window for injection angles ranging from 22° to 135°.

The results at 43 and 50 MWe shown in Figure 2 illustrate how varying lance angle can be used to optimize the SNCR performance over the load range. As the load increases, the preferred injection angle will decrease. Again, the minimum angle is 22°, where the chemical is injected parallel to the tube sheet located below the lances.

Performance over the Load Range

The SNCR performance using the ARIL lances over the load range from 43 to 80 MWe is shown in Figure 3. Note that for this particular lance location, the flue gas temperatures are too high for the lances to be effective at loads greater than 80 MWe. As the load increases, the preferred lance angle decreases in order to inject the urea into a lower temperature region.

As discussed above, at 43 MWe with an angle of 90°, injection occurred on average just on the high temperature side of the window. At $N/NO_x = 1$, NO_x removals were 35% with less than 10 ppm NH_3 slip. At 50 MWe, a 45° injection angle was on average at a better location in the SNCR window, with NO_x removals of 40% and NH_3 slip less of 5 ppm at $N/NO_x = 1$. As the load increased to 60 MWe, a decrease in lance angle to 34° resulted in SNCR performance similar to a load of 43 MWe. At higher loads of 70 and 80 MWe, injection was clearly occurring on the high side of the temperature window. Note that the NH_3 slip at 80 MWe was higher than the slip at 70 MWe even though the chemical was injected into a region of higher overall temperature. This effect was a result of temperature stratification in the furnace, and the way in which the stratification varies with different coal mill patterns. This effect is discussed in more detail below. However, the data in Figures 2 and 3 clearly show that the lances have markedly improved the low-load performance of the SNCR system.

Effect of Boiler Operation on SNCR Performance

As mentioned above, local changes in temperature due to variations in boiler operating parameters (excess O_2, mill pattern, mill biases, etc.) can have a major impact on SNCR performance. This is particularly true at Arapahoe Unit 4 where the 12 burners are located on the roof of the furnace. Each of the four coal mills feeds three burners, two burners on one side of the furnace and a single burner on the other side of the furnace. Since the furnace has a division wall, there is an imbalance in heat release across the furnace, and a corresponding variation in flue gas temperature, when only three mills are in service. These temperature variations impact the performance of both the wall injectors and the ARIL lances. The effect will be illustrated by looking at the performance of the ARIL lances with varying mill out-of-service patterns. During normal operation, Arapahoe Unit 4 operates with four mills in service over the load range from 80 to 110 MWe (although the unit can operate up to 100 MWe with only 3 mills). From 60 to 80 MWe, the unit typically operates with three mills in service. Below 60 MWe, the unit is usually operated with only two mills in service. Figure 4 shows the overall impact of various mill out-of-service patterns on SNCR performance at 60 MWe. As can be seen, NO_x removals varied from 30% to 52% (@ $N/NO_x = 1.5$) depending on which particular mill was out-of-service. Comparably, the NH_3 slip varied from under 5 ppm to over 30 ppm with different mill-in-service patterns. This behavior made overall optimization of the SNCR system quite challenging.

In addition to the temperature variations that occur with the various mill out-of-service patterns, day-to-day variations can occur as a result of changes in the performance of the individual mills, or changes in any other variables which affect the flue gas temperature distribution. Three operational changes were investigated to deal with these types of temperature variations.

- varying the urea flow along the length of each lance
- independently varying each lance angle
- biasing the in-service coal mills

Varying the urea flow between the two liquid zones in each lance provided minor improvements in the performance of the SNCR system. Independently varying the lance angles as a function of the mill-in-service pattern also provided minor improvements. Unfortunately the implementation of either of these strategies would significantly complicate the automatic control system. On the other hand, biasing the in-service coal mills, which is relatively easy to implement, resulted in major improvements in the performance of the SNCR system. Arapahoe Unit 4 is equipped with four O_2 monitors at the economizer exit. Biasing the coal mills to provide a balanced O_2 distribution at this location is a fairly simple exercise for the boiler control operator. Figure 5 shows the improvements in SNCR performance that can be achieved by biasing the coal mills. These tests were performed at a load of 60 MWe with both lances at an injection angle of 22° and A mill out-of-service. The "biased" condition in Figure 5 corresponds to a negative 10% bias on B mill and D mill, and a positive 10% bias on C mill. This has the net effect of moving coal from the east side to the west side of the furnace to compensate for A mill being out-of-service. Biasing the mills increased NO_x removals from nominally 27% to 42% at an NH_3 slip limit of 10 ppm.

Alternate DPSC Lance

While the NO_x removal performance of the ARIL lances has been good, their location in the furnace has resulted in some operational problems. At this particular location in the furnace, the lances are exposed to a large differential heating between the top and bottom surfaces. The top surface receives a high radiant load from the burners, while the bottom of the lance radiantly communicates with the relatively cold tube wall immediately below. This uneven heating pattern causes a great amount of thermal expansion along the upper surface, and the lances bend downward toward the tubes. Within 30 minutes of insertion, the tip of each lance would drop by approximately 12 to 18 inches. Within less than six weeks of operation, the lances became permanently bent, making insertion and retraction difficult. This was partially addressed by adding additional cooling slots at the end of the lance.

An alternate lance design supplied by Diamond Power Specialty Company (DPSC) was also evaluated. As mentioned previously, this design sprays the urea solution through a single atomizer at the entrance to the lance. This provides evaporative cooling to supplement the air cooling. The evaporative cooling was expected to help minimize the lance bending discussed above.

Because of both system and time constraints, the test program was abbreviated compared to the parametric tests with the ARIL lances. The DPSC lance exhibited the same general characteristics as the ARIL lances in terms of load following capability. In presenting the test results for the DPSC, an emphasis will be made on comparing the performance of the DPSC and ARIL lances. One of the primary differences in the two lance designs is the manner in which the liquid is introduced. The ARIL lance has an internal liquid circuit that distributes liquid to each injection nozzle along the lance. On the other hand, the DPSC lance uses a single atomizer to spray liquid into the lance's air stream at the entrance to the lance. This simplifies the lance design and provides evaporative cooling in the lance. However, with the single atomizer, there was some impingement on the lance wall. This resulted in a portion of the liquid flowing down the center of the lance. A portion of this liquid literally dripped off the edge of the injection hole and a portion was entrained by the injection air and re-atomized. This re-atomized portion of the liquid should have a larger drop size distribution than the sprays from the ARIL lances. With a larger drop size distribution, it was expected that longer vaporization times would be needed along with higher temperatures. Thus, for comparable performance, it was expected that the DPSC lance would require a larger injection angle than the ARIL lance. Further, the portion of the liquid that drips toward the screen tubes should not result in much NO_x reduction; rather this liquid should be a source of NH_3 slip.

The ARIL and DPSC lance performances are compared in Figures 6 and 7 for loads of 60 MWe and 70 MWe, respectively. For both the DPSC and ARIL lance tests, the C mill was out-of-service and the total liquid flow rate was 4 gpm. At 60 MWe and an injection angle of 22 degrees, the NO_x reduction with the ARIL lance was a little lower than the DPSC lance at injection angles of 34-65 degrees. However, the NH_3 slip with the DPSC lance was higher than the ARIL lance except at an angle of 65° As expected, the DPSC lance required a higher injection angle of 45 to 65 degrees to produce the same NH_3 slip characteristics as the ARIL lance at 22 degrees. This supports the arguments above in terms of the coarser overall

atomization with the DPSC lance, and the need to inject into a higher temperature region (i.e., larger injection angle).

Similar results are seen in Figure 7 for a boiler load of 70 MWe; except the NO_x reduction was higher with the ARIL lance at 22 degrees than the DPSC lance at 45 degrees. At an injection angle of 22 degrees, the NH_3 slip with the ARIL lances was comparable to the DPSC lance at an injection angle of 65 degrees.

The above comparisons were done at a common N/NO ratio and illustrate the general process temperature characteristics of the two different lances. For automatic operation, the real question is what NO_x reduction can be achieved at a specified NH_3 slip limit (i.e., 10 ppm) and at what urea injection rate (i.e., N/NO_x ratio). This comparison is made in Table 1 using the data from Figures 7 and 8.

Table 1

Achievable NO_x Reduction at a 10 ppm NH_3 Slip Limit
(C Mill OOS, Total Liquid Flow Rate: 4 gpm)

	Load			
	60 MWe		**70 MWe**	
	ΔNO_x (%)	**N/NO (molar)**	**ΔNO_x (%)**	**N/NO (molar)**
ARIL (22 degrees)	36	1.75	43	2.6
DPSC (34 degrees)	30	1.1		
DPSC (45 degrees)	36	1.25	32	1.8
DPSC (65 degrees)	42	2.8	35	2.7

At 60 MWe, Table 1 indicates that the DPSC lance can achieve comparable NO_x reduction at an angle of 45 degrees, compared to the ARIL lance at an injection angle of 22 degrees, and at a lower N/NO ratio. At the higher load of 70 MWe, the ARIL lance can achieve 43% reduction at N/NO=2.7 compared to 35% for the DPSC lance operating at an angle of 65 degrees.

Overall, the NO_x reduction and NH_3 slip performance of both lances was quite good, and either lance design enhances the low load performance of the SNCR system. In general, the DPSC lance requires the urea to be injected into a higher temperature (i.e., larger injection angle) than the ARIL lance. Because of this difference in temperature characteristic, the relative performance depends on loads. At 60 MWe, the DPSC lance has a slight advantage being able to match the NO_x reduction of the ARIL lance, but at a lower N/NO_x ratio. However, at 70 MWe, the ARIL lance can achieve a higher NO_x reduction. Again, the relative performances of the two lance designs will also be dependent on the coal mill pattern, which could not be investigated during the DPSC lance test period because C mill was out of service for maintenance.

Overall SNCR System Performance

The parametric tests were conducted to determine at which loads the lances should be used, as well as the optimum injection angle for each of these loads. Based on the parametric tests, the control system has been set up to operate with the Level 1 wall injectors at loads above 80 MWe. Below 80 MWe, the ARIL lances are used. Figure 8 compares the NO_x removal over the load range for injection at the two locations with an NH_3 slip limit of 10 ppm. It is evident that the installation of the ARIL lances has improved low-load performance of the SNCR system. Currently, NO_x removals of more than 30% are achievable over the load range with less than 10 ppm NH_3 slip. The minimum NO_x removal of 30% occurs at 80 MWe, which corresponds to the point where the temperature becomes too high for the ARIL lances and too low for the Level 1 injectors. Comparable performance can be expected from the DPSC lances. However, some additional parametric tests, or accumulated long-term data, are needed to define optimum conditions at some of the lower loads.

Conclusions

Public Service Company of Colorado, in cooperation with the U.S. Department of Energy and the Electric Power Research Institute, has installed the Integrated Dry NO_x/SO_2 Emissions Control System. Conclusions associated with the recent work to enhance the low load performance of the SNCR system include:

- With the addition of retractable lances to the SNCR system (either the NOELL ARIL lances or alternate DPSC lances), low load performance of the system urea-based SNCR system was improved. NO_x removals of 30 to 52% with an ammonia slip limit of 10 ppm are achievable over the load range. This increases total system NO_x reduction to greater than 80% at full load, significantly exceeding the project goal of 70%.

- The ability to follow the temperature window by rotating the lances has been demonstrated and also proved to be an important feature in optimizing the performance of the SNCR system.

- The DPSC lance design overcame some of the design shortcomings of the ARIL lance. Specifically, (1) eliminating the telescope for the air supply, (2) minimizing air and liquid spraying outside of the boiler during insertion and retraction, and (3) minimizing bending.

- For comparable performance, the DPSC lances required a higher injection angle (i.e., higher temperature) than the ARIL lances. This was attributed to a larger drop size from the DPSC lances.

- Atomization was not complete with the DPSC lances, resulting in a portion of the liquid exiting the injection holes as a liquid stream.

- Mill-out-of-service pattern can have a major impact on NO_x reductions and NH_3 slip with the lances. This was most easily accommodated by having the operators bias the in-service mills to provide a more uniform temperature distribution across the furnace.

References

1. T. Hunt, et al., *Performance of the Integrated Dry NO_x/SO_2 Emissions Control System,* Fourth Annual Clean Coal Technology Conference, (September 1995) Denver, CO.

Disclaimer

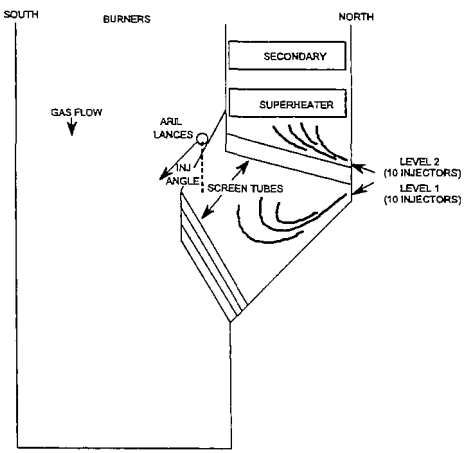
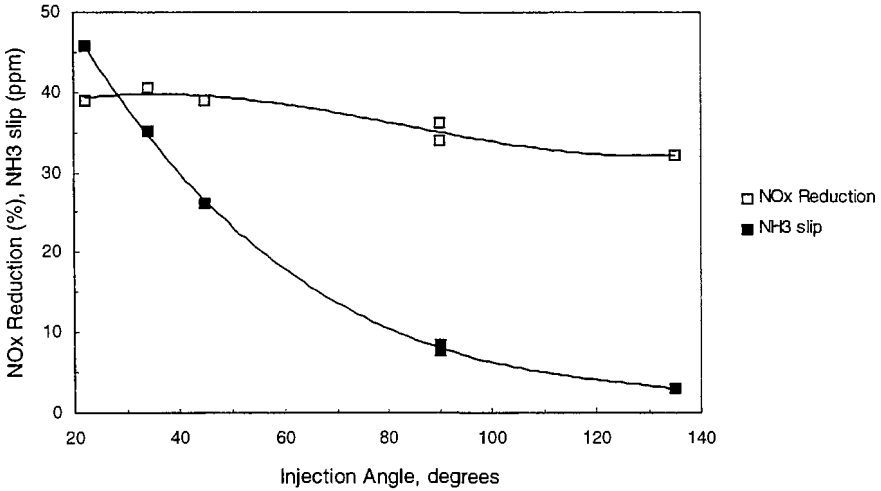
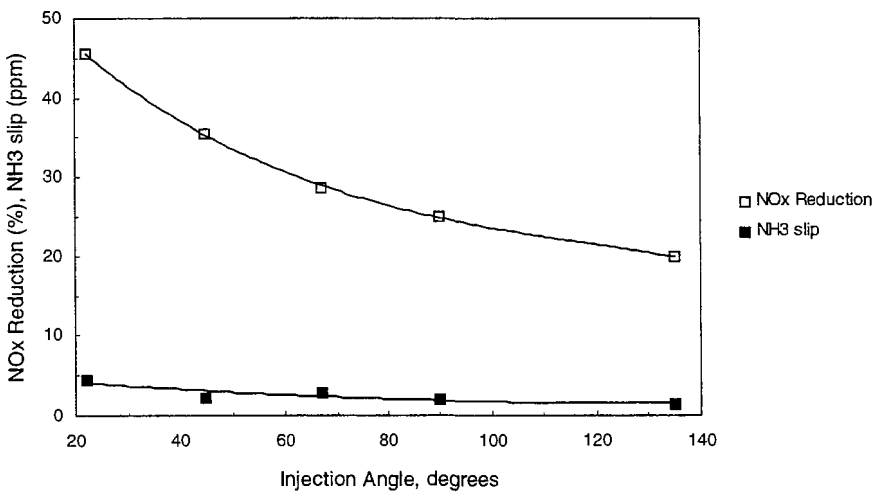


Figure 1. SNCR Injection Locations

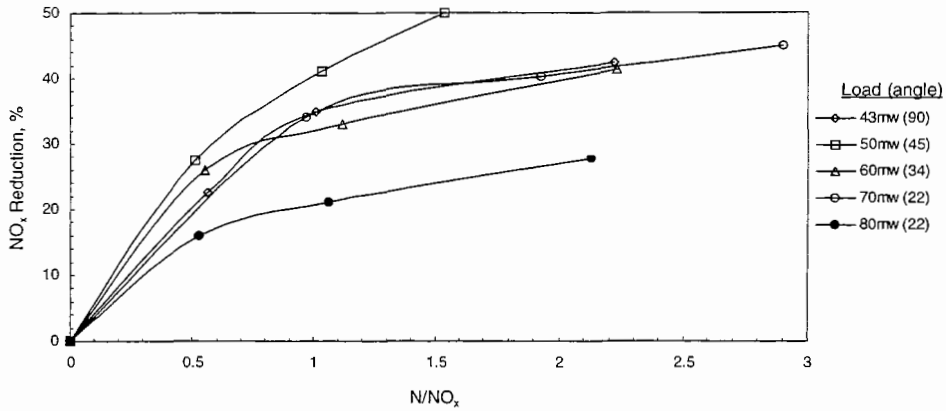


(a) Boiler Load: 43 MWe

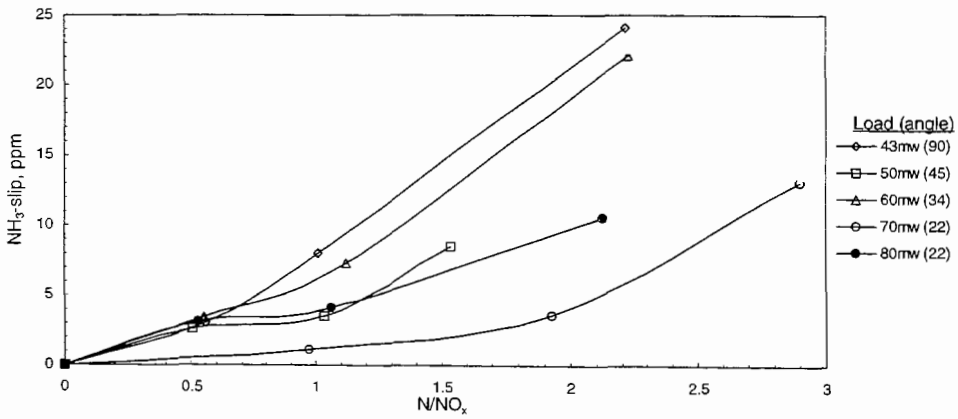


(b) Boiler Load: 50 MWe

Figure 2. Effect of Injection Angle on NO_x Removal and NH_3 slip
(Loads: 43 and 50 MWe, $N/NO_x = 1.0$)



(a) NO_x Removal



(b) NH_3 Slip

Figure 3. ARIL Lance Performance Over the Load Range: 43 to 80 MWe

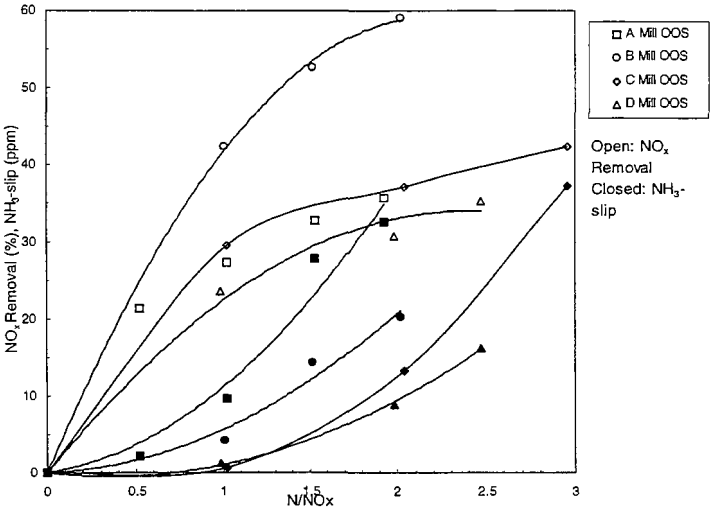


Figure 4. Effect of Mill-in-Service Pattern on
ARIL Lance Performance at 60 MWe (22° Injection Angle)

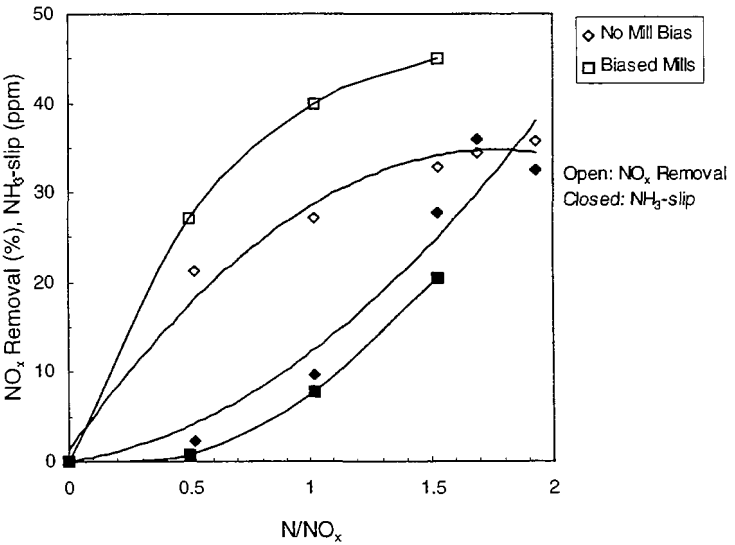


Figure 5. Effect of Coal Mill Bias on ARIL Lance Performance at 60 MWe
(A Mill OOS, 22° Injection Angle)

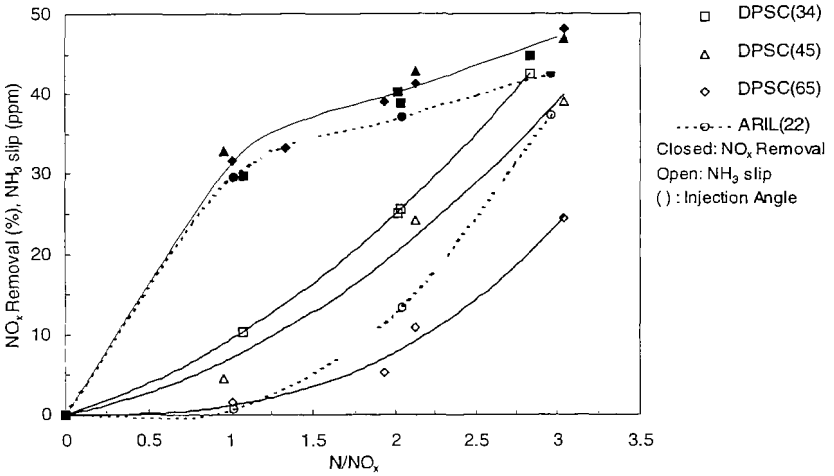


Figure 6. Comparison of the DPSC and ARIL Lance Performance at 60 MWe (C Mill OOS, Total Liquid Flow Rate: 4 gpm)

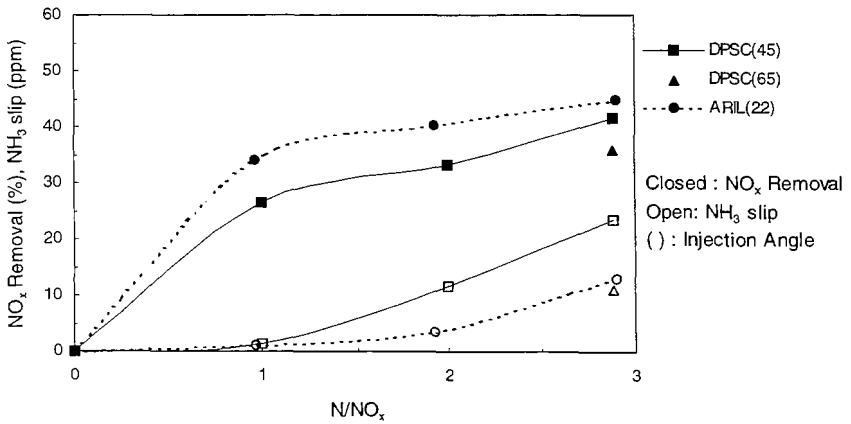


Figure 7. Comparison of the DPSC and ARIL Lance Performance at 70 MWe (C Mill OOS, Total Liquid Flow Rate: 4 gpm)

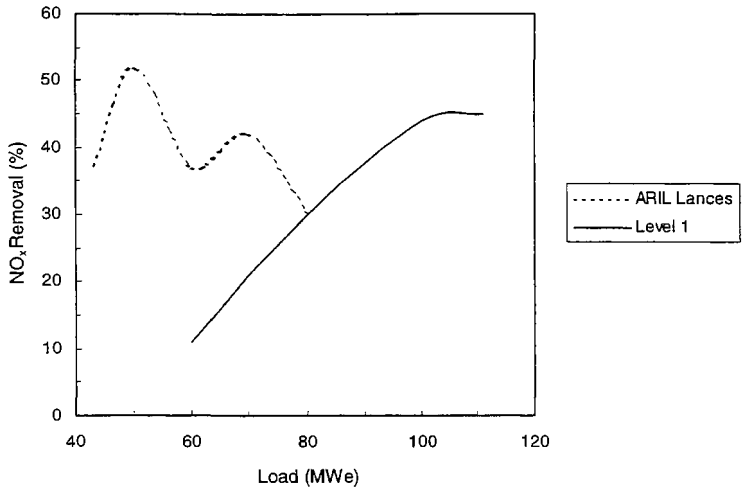


Figure 8. NO_x Removal as a Function of Load for an NH_3 Slip Limit of 10 ppm

SNCR RETROFIT EXPERIENCE ON FOUR GAS- AND COAL-FIRED BOILERS IN TCHAIKOVSKY, RUSSIA

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Abstract

Allied Environmental Technologies (ALENTEC) has recently installed SNCR systems on four gas- and coal-fired boilers. These boilers are owned by PERMENERGO, and are located 800 miles east of Moscow in Tchaikovsky, Russia. These sister units have a maximum continuous rating of 420 tonnes steam per hour (882,000 pounds per hour).

The SNCR systems were designed and fabricated in the United States by WAHLCO, Inc. The designs were based on HVT and gaseous emissions measurements made on site at the initiation of the project. The design was subsequently fine-tuned by computational fluid dynamics (CFD) modeling performed by Reaction Engineering International. The client dictated that only existing penetrations could be used for injection ports, which limited the final SNCR system design flexibility.

This paper presents the SNCR system design specific, modeling predictions and field test results. Also discussed are the logistics and challenges of performing complex engineering projects in the former Soviet Union.

Overview

Allied Environmental Technologies, Inc. (ALENTEC) was awarded a contract to install urea-based Selective Non-Catalytic Reduction (SNCR) systems on four gas- and coal-fired boilers located in Russia. These boilers are owned by PERMENERGO and are located 800 miles east of Moscow in Tchaikovsky, Russia. The project will comprise four tasks, as follows, upon completion:

- Task 1 -- Furnace temperature distribution measurements
- Task 2 -- Computation Fluid Dynamics (CFD) modeling

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- Task 3 -- System Design, fabrication and installation
- Task 4 -- Start-up and optimization testing

To date, Tasks 1 through 3 have been completed, as well as the initial portion of Task 4.

SNCR System Description

Tchaikovsky Units 1 through 4 are sister units having a maximum continuous rating of 420 tonnes steam per hour (882,000 pounds per hour). The units are opposed-wall-fired units, each having one row of six burners on both the front and back furnace walls. The boilers are a balanced draft design. The units fire natural gas as their primary fuel and coal as a back-up. Baseline full load NO_x emissions varied from 139 to 152 ppm_c (ppm, dry at 6% O_2) when firing natural gas. When firing coal, baseline NO_x emissions were 558 ppm_c at a load of 398 TPH.

The SNCR systems installed on Tchaikovsky Units 1 and 2 are of the "high energy" type. These systems utilize low pressure steam as the carrier fluid. The design steam flow is 4,400 kg/hour at full load, which represents approximately 1.5 percent of the total combustion products flow. Each unit incorporates three (3) injection levels on the front wall, in addition to two (2) levels of side wall injectors. Figure 1 shows a schematic view of the boiler and Figure 2 shows the location of the injectors at each level.

A nominal 50% urea solution is prepared on-site from bulk urea solids. After mixing, the solution is pumped to a storage tank in the boiler house. Each of the four individual SNCR systems is supplied by this tank. Urea flow is set according to a flow versus load curve generated during the start-up/optimization testing.

Because the client dictated that only existing penetrations could be used for injection ports, the final system design flexibility was limited. To overcome these limitations, the final system design incorporated two individual injectors in each available front wall port. The design of these injectors allows them to be independently rotated in order to provide the best possible mixing between the injected urea and the combustion products.

Test Results

The test results presented below include the HVT tests, the CFD tests and the field start-up and optimization tests. Each of these test series is discussed below.

High Velocity Thermocouple (HVT) Tests

The field testing tasks of this program required the measurement of both temperature and gaseous emissions. Temperature measurements were made using a high velocity thermocouple (HVT) probe. This HVT was of a standard water-cooled design utilizing a single radiation shield. Suction power was provided by an air-powered vacuum eductor. The HVT probe also incorporated the capability of providing a flue gas sample from the aspirated thermocouple

location. During the temperature measurement task, gaseous emissions of NO, CO and O_2 were measured using a NOVA Model 2000 portable combustion analyzer. This analyzer utilizes electrochemical "fuel cell" type sensors to measure species concentrations.

The HVT tests were conducted over a nominal load range of 210-400 tones/hour (TPH) when firing natural gas. The nominal test load range for coal firing was 300-400 TPH. Each unit was operated in a "normal" firing configuration during the HVT testing; no attempts were made to balance fuel and/or air flows, or to otherwise alter unit operation.

The desired temperature range for urea injection is nominally 930C to 1150C, with the maximum NO_x reduction performance achieved at a temperature of 1010C [1]. However, operation at below-optimum temperatures results in high NH_3 slip levels. For this reason, it is desirable to operate at or above the optimum injection temperature. Thus, the desired injection temperature range for this project is between 1010 and 1150C.

Figure 3 shows average furnace gas temperatures plotted versus load. Data are included for both levels D and E from Units 1 and 2 while firing natural gas. Average temperatures at Level E varied from 1023C to 802C, while average temperatures at Level D varied from 1152C to 865C over the load range tested while firing natural gas. The difference between maximum and minimum temperatures at a given load ranged from 118C to 283C, and varied with the measurement location and load. The degree of stratification can also be characterized by calculating the standard deviation of measurements made at a given level and load. For natural gas firing, the standard deviations ranged between 32C and 67C. These data indicate that Level D may provide the preferred temperature zone from loads of about 270-370 TPH. At loads in excess of 370 TPH, Level E appears to be in the preferred temperature region.

Figure 3 also shows average temperature plotted versus load for the coal firing tests performed on Unit 4. These test data are divided into two groups; tests performed on September 13 and 14 and tests performed September 18 through 20. Temperatures at Level E averaged 870C and 956C at a nominal load of 350 TPH for the two test series. The corresponding temperatures at Level D averaged 1003C and 1074C. Temperature stratification was more pronounced when firing coal, ranging from 45C to 133C.

The data show that temperatures increased during this five day time period between the two sets of measurements. Coal was initially fired in Unit 4 during the first week of September, allowing about one week of seasoning before the initial testing. The second set of coal tests was performed five days after the initial coal tests were completed. During this time period, average gas temperatures increased by about 65C at Level D to 85C at Level E. It appears that the measured increases in gas temperatures were due to the gradual build-up of ash deposits on the heat transfer surfaces, since soot blowers are not used (or needed) on the Tchaikovsky boilers. These variations in temperature with time may adversely impact SNCR performance if coal is fired for extended periods of time.

A typical temperature contour plot for the gas-fired tests is shown in Figure 4. This shows a characteristic saddle-shaped profile for these units. The profile showed two temperature peaks

near the furnace center of 1070 to 1090C at a load of 370 TPH. From the center, gas temperatures dropped as either furnace side wall was approached.

Emissions measurements made during the HVT testing showed that NO emissions varied from 113 ppm_c to 152 ppm_c across the load range at Level E when firing natural gas. (Note that in this paper, ppm_c is equal to ppm, dry, corrected to 6% O_2., which is the measurement standard at the utility site.) When firing coal, NO_x emissions at Level E varied from 290 ppm_c to 558 ppm_c. CO emissions at Level E were less than 40 ppm when firing natural gas and less than 90 ppm when firing coal.

Computational Fluid Dynamics Modeling

Computational fluid dynamics (CFD) modeling was performed by Reaction Engineering International (REI) to evaluate reagent mixing and SNCR performance. REI developed a reduced mechanism for gas-phase SNCR chemistry, which was used to quantify NO_x reductions. The reduced mechanism of seven (7) reactions and individual rate constants were developed so that the mechanism could be incorporated into a CFD code[2] This model accurately describes the SNCR chemistry as indicated by comparison of process performance relative to predictions obtained using a complete chemical mechanism. The SNCR submodel was incorporated into GLACIER, a computer code which solves the governing fluid mechanics and reaction equations in an Eulerian framework. Reference 3 provides further details regarding this model.

Prior to completing the system design, four cases were modeled for full boiler load as follows:

- Case 0 -- Urea injection at Level E, front wall
- Case 1 -- Urea injection at Levels D and E, front wall
- Case 2 -- Urea injection at Levels D and E, front and side walls
- Case 3 -- Case 2 with dual injectors in front wall ports and different side wall injection locations

Table 1 provides the performance estimates for each of these cases. These data show that Case 3 presented the most flexibility in terms of NO_x reduction and NH_3 slip.

The CFD model was divided into two parts; a lower furnace model and an upper furnace model. The initial modeling of the lower furnace showed that thermal boundary conditions had to be varied between units in order to replicate the field test results. The boundary conditions modified included the furnace wall emissivity. In one case, the furnace wall emissivity corresponded to that expected for a gas-fires boiler, while the other case required a furnace wall emissivity that corresponded to a dirty wall environment that could have resulted from previous coal firing. This work provided good agreement between the field measurements and the CFD lower furnace model.

The lower furnace model conditions were then used as the inlet conditions for the upper furnace model. The initial upper furnace work (Cases 0-2) showed that over half of the gas at the furnace outlet plane (FOP) had molar N/NO ratios less than 0.5 or greater than 3.5. This led to the

Table 1
CFD Modeling Results

Case	Injection	NSR	Outlet NO_x ppm @ 6% O_2	NO_x Reduction, %	NH_3 Slip ppm @ 3% O_2
0	Level E, 12 front wall injectors	0.8	113	28	9
1	Levels D&E, 12 front wall injectors	0.8	130	17	7
2	Levels D&E; 12 front, 6 side injectors	1.2	108	31	17
3	Levels D&E; 16 front, 6 side injectors	1.1	112	29	14

Case 3 configuration, in which the injectors were redistributed along the front and side walls using existing ports. The Case 3 configuration provided improved reagent mixing, as measured by the increase in the number of areas at the FOP having molar N/NO ratios between 0.5 and 3.5.

Figure 5 shows NO_x reduction and ammonia slip distributions in the outlet plane for Case 3. These data, presented as contour plots, show that NO_x reductions were predicted to be highest at the center of the boiler, and lower toward the edges with an increase right at the side walls due to the effects of the side wall injection. The corresponding NH_3 slip data show peaks near the edges of the boiler which correlate to low temperature regions in the furnace.

Another way to look at the CFD results is to plot NO_x reduction and NH_3 slip versus the N/NO ratio in each cell at the exit plane. This is shown in Figure 6 for Case 3. The degree of vertical scatter indicates the amount of temperature stratification present, while the range of N/NO ratios provides an indication of the "mixedness" at the exit plane. Note that the N/NO ratio ranges from 0 to about 3.5 at the exit plane. The NO_x reduction values fall in a fairly narrow band when plotted versus N/NO ratio. However, the NH_3 slip falls into two general bands. One group shows NH_3 slip less than 10 ppm for N/NO ratios up to 3.5, indicating a high temperature region. Conversely, there are a number of points showing high NH_3 slip levels, corresponding to temperatures on the low side of the SNCR temperature window. This figure shows that nearly the same NO_x reductions could be achieved with two different ammonia slip levels. This behavior may be characteristic of the two-level injection scheme, where the lower level provides lower NH_3 slip levels due to the higher gas temperatures encountered in that injection zone.

Field Tests

To date, tests have been performed on Units 1 and 2 while firing natural gas. Plans call for completion of the Unit 1 gas testing, as well as coal testing on another unit in the Fall of 1997.

Logistical problems have resulted in the test program proceeding slower than originally planned. Table 2 shows the analyzers and analysis methods used during the field testing.

Table 2
Emission Measurement Methods

Specie	Analyzer	Analysis Method
NO	Siemens Ultramat 5E	Nondispersive infrared
CO	Fuji ZRH	Nondispersive infrared
CO_2	Fuji ZRH	Nondispersive infrared
O_2	Teledyne 326	Electrochemical fuel cell
NH_3	Wet Chemical	Ion specific electrode

Initial testing began on Unit 2 in the Spring of 1997. However, the wrong injectors were installed at the center ports on the front wall due to a misunderstanding between plant personnel and the on-site engineer. Due to this derivation from the system design, performance on this unit was not as expected, so the testing efforts were redirected to Unit 1. The Unit 1 installation included double injectors in all front wall ports as the final design had specified. Unit 1 data are limited, since only three days of testing were permitted due to a condensed test schedule resulting from an unscheduled unit outage.

The early Unit 2 testing was limited by the inability to accurately control urea flows to the in-service injectors. Figure 7 shows NO_x reduction and NH_3 slip plotted versus the molar N/NO ratio. These data show that NO_x reductions in excess of 35 percent were achieved at a molar N/NO ratio of 2.0. The corresponding NH_3 slip at these conditions was in the range of 25 to 32 ppm. The NO_x reduction profiles showed that the reductions were highest near the furnace side walls, while they were measurably lower in the center of the furnace. These data suggest that the NO_x removals may have been compromised by the installation of the single injectors on the front wall of Unit 2.

The Unit 1 tests were performed at a load of 360 TPH, which is 86% of the rated load of 420 TPH. NO_x removals on Unit 1 ranged from 39 to 47% with molar N/NO ratios of 1.5 to 2.1, as shown in Figure 8, when injecting at Level D. Tests conducted with urea injection at Level E showed NO_x reductions of 42% at a molar N/NO ratio of 2. Injection utilizing both Levels D and E resulted in NO_x reductions of 42 to 46% at a molar N/NO ratio of 2.0, depending on the specific injector pattern used.

Ammonia (NH_3) slip levels are also plotted versus molar N/NO ratio in Figure 8. At a molar N/NO ratio of 2, NH_3 emissions varied from 32 ppm when injection at Level D to nearly 70 ppm when injection at Level E. The high ammonia slip encountered when injection at Level E may indicate that the E level is too cold for injection at the 360 TPH load. When injection at both Levels D and E, ammonia slip varied from 46 to 65 ppm at a molar N/NO ratio of 2.

NO_x reduction profiles were obtained by measuring both pre- and post-injection NO_x emissions at each of the 12 sample points at the economizer exit sample grid. Figure 9 shows NO_x reduction profiles for a test performed using Level D injection at a molar N/NO ratio of 1.5. The data show that the achievable NO_x reductions were highest on the outside walls and dropped significantly to the boiler center. For example, injection at Level D resulted in NO_x reductions at the walls averaging 51%, while NO_x reductions at the four innermost points averaged only 24%.

Comparison of CFD and Field Test Results

The results of the Case 3 CFD modeling and the Unit 1 field test are shown together in Figure 10. Both NO_x reduction and NH_3 slip are plotted versus N/NO ratio. These data show that the CFD modeling are field test results correlated well on an overall basis. A subsequent comparison of the CFD modeling and field test results shows that there are some differences in the details. It is hoped that the testing scheduled for Fall 1997 will provide additional data which can resolve these differences. In the interim, however, it appears that the CFD modeling provided a good approximation of the overall field test results.

Project Logistics

As discussed previously, this project involved the design, fabrication and installation of four SNCR systems in Tchaikovsky, Russia. The design and fabrication of the SNCR skids was performed in Santa Ana, California by WAHLCO, Inc. These skids were fabricated so that two systems were installed in a single container. Each container contained the required pumps, liquid metering systems, control valves and piping for two SNCR systems. The SNCR injectors and associated mixing equipment were also designed and fabricated in California. ALENTEC designed the urea mixing and storage systems, and supervised their construction at the plant site. The plant was responsible for connecting the containers to the urea storage and water supply systems, and installing the piping from the container to the individual injection levels on each boiler.

Language was not the barrier originally thought, since the plant provided an experienced translator for the duration of the project. The primary delays in the project involved difficulties in getting the SNCR system through customs in Moscow. Once on site, the plant staff did an admirable job installing the SNCR systems. The primary on-site problem was a lack of spare parts. Spare parts were a week or more away, at best, due to the relatively remote location of the plant.

Acknowledgements

The authors wish to acknowledge the hospitality extended by Mr. Potapov, the Plant Manager. His cooperation allowed all parts of the project to proceed smoothly. Mr. Alexi Grebnev, the Chief Plant Engineer, also provided invaluable assistance in the installation and start-up of the SNCR systems. Finally, Mr. Nicolai Oschepkov did an excellent job of translating, which

allowed the project to proceed smoothly. All members of the plant staff should also be commended for their efforts in completing a successful retrofit.

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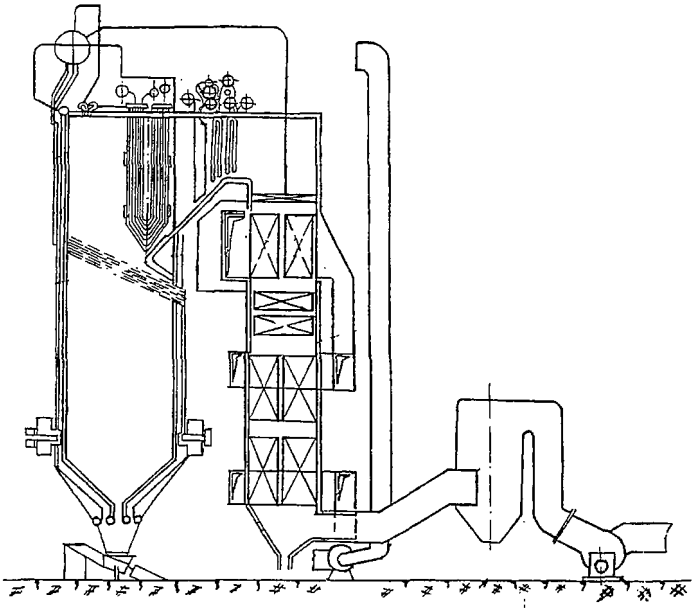


Figure 1. Tchaikovsky Units 1-4 Boiler Schematic Drawing

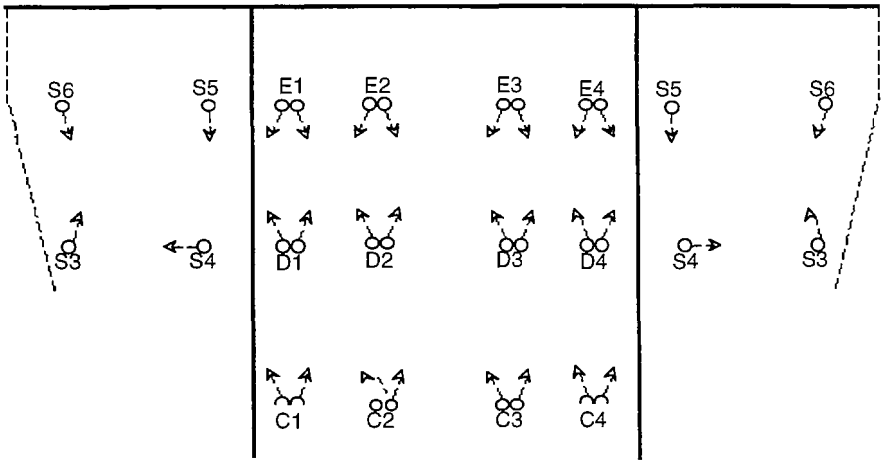


Figure 2. SNCR Injector Schematic

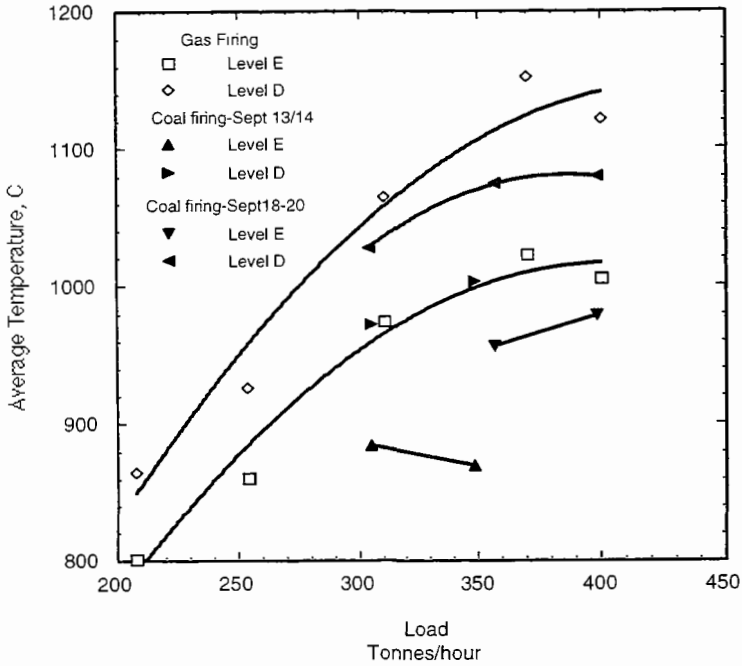


Figure 3. Furnace Gas Temperature versus Load. Tchaikovsky Units 1, 2 and 4

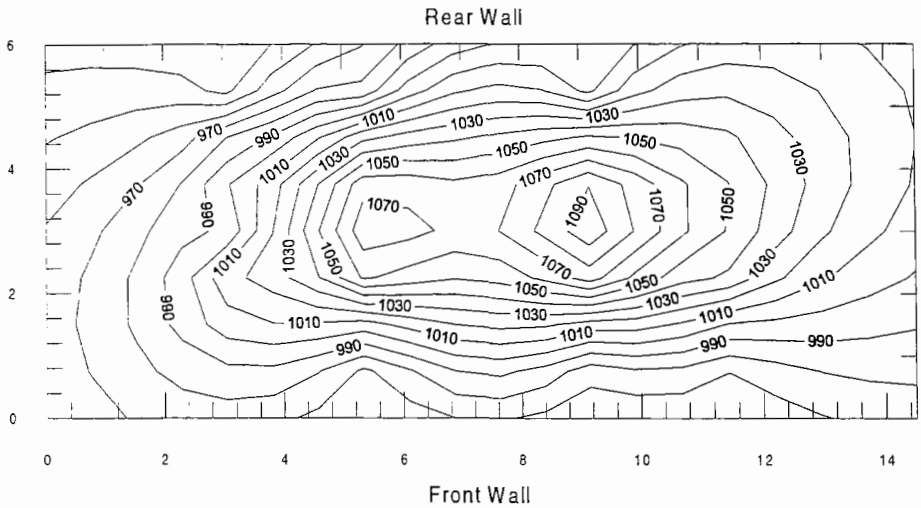
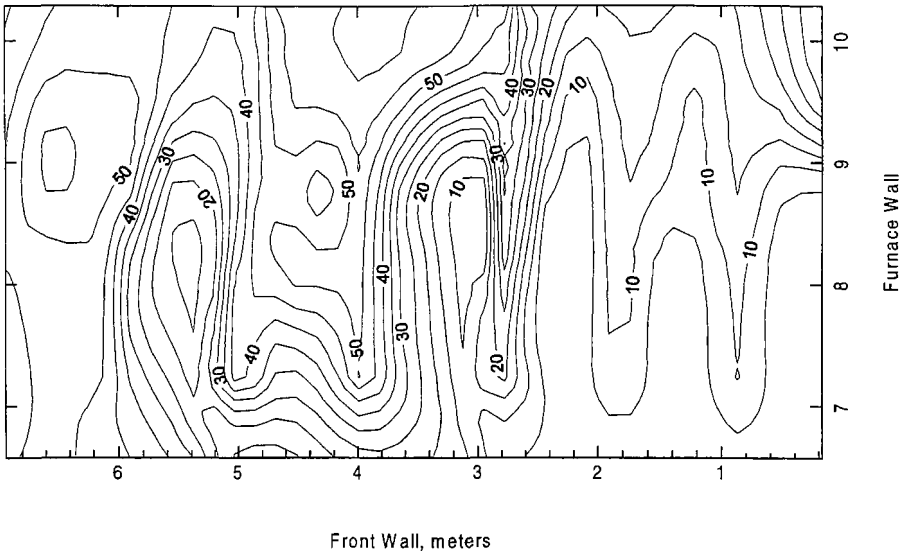
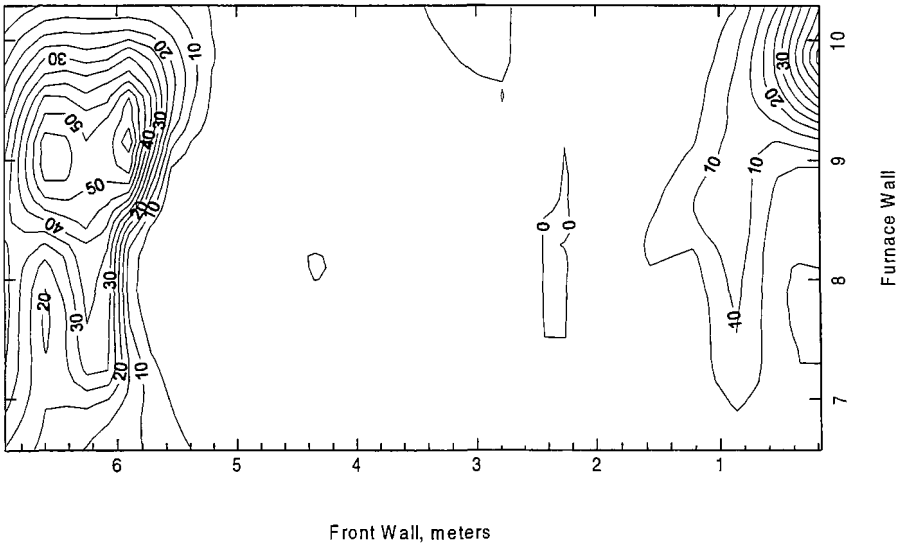


Figure 4. Measured Temperature Contour Plot, Tchaikovsky Unit 2, 370 TPH, Natural Gas Fuel



NO_x Reduction Profile



NH_3 Slip Distribution Profile

Figure 5. NO_x Reduction and NH_3 Slip Distribution Profiles.
CFD Modeling, Full Load, Natural Gas, Case 3

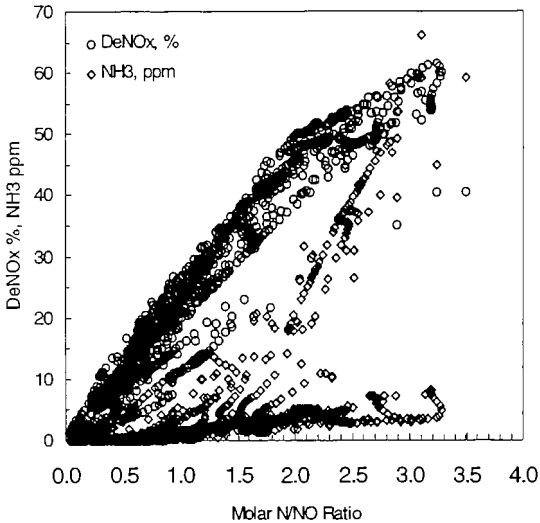


Figure 6. NO_x Reduction and NH_3 Slip versus Molar N/NO Ratio.
CFD Modeling, Full Load, Natural Gas, Case 3

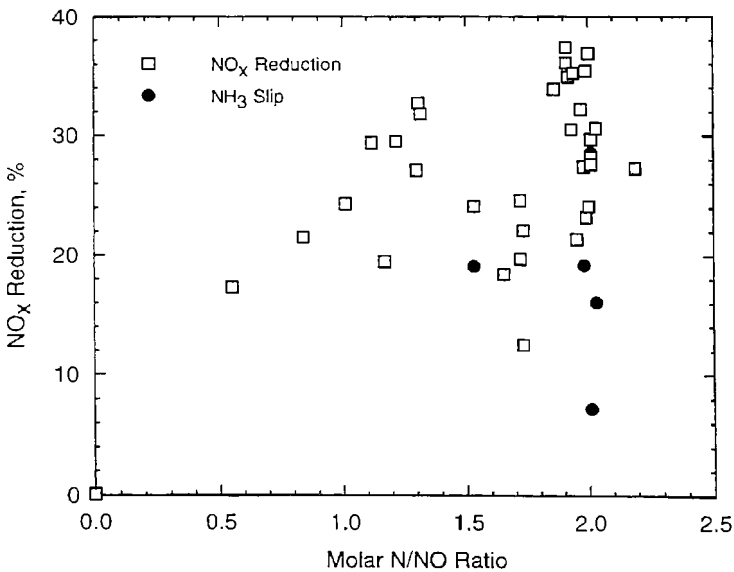


Figure 7. NO_x Removal and NH_3 Slip versus Molar N/NO Ratio.
Tchaikovsky Unit 2, 400 TPH, Natural Gas

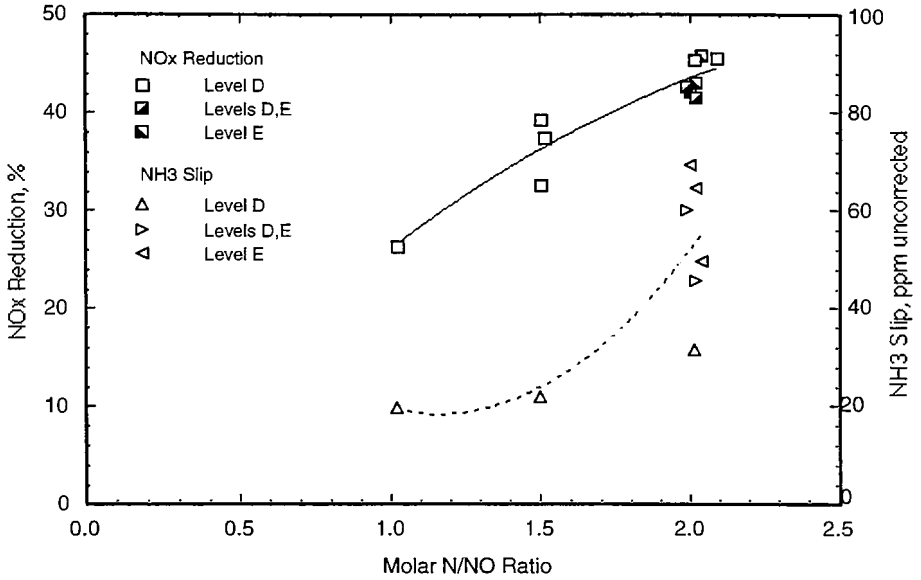


Figure 8. NO_x Removal and NH_3 Slip versus Molar N/NO Ratio.
Tchaikovsky Unit 1, 360 TPH, Natural Gas

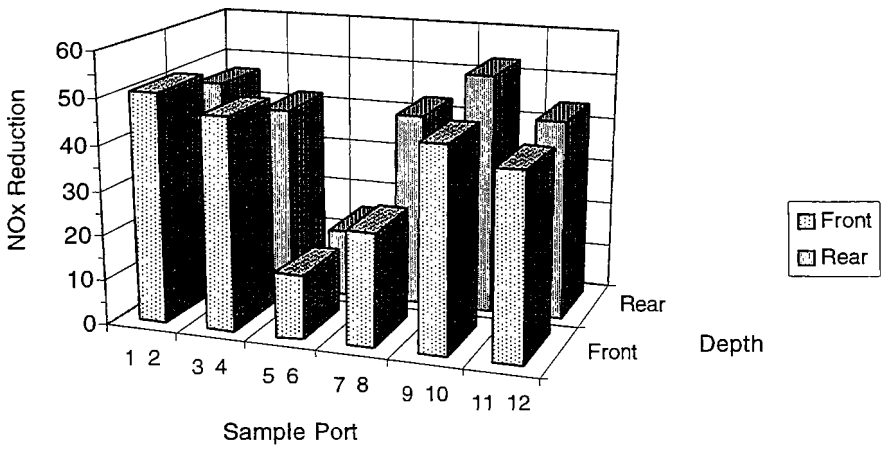


Figure 9. NO_x Reduction Profile. Tchaikovsky Unit 1, Level D Injection
360 TPH, Natural Gas, N/NO = 2.0

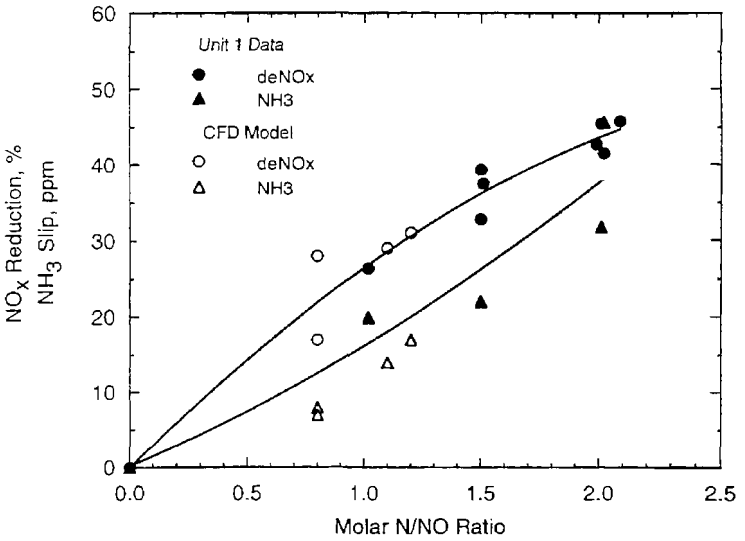


Figure 10. Comparison of CFD and Field Test Results

DESIGN AND CHARACTERIZATION OF A UREA-BASED SNCR SYSTEM FOR A UTILITY BOILER

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Abstract

As part of an overall compliance plan to reduce NO_x emissions, Delmarva Power has installed a urea-based Selective Non-Catalytic Reduction (SNCR) system on their Edge Moor Unit #3 boiler. The unit is a tangentially fired pulverized coal boiler, nominally rated at 84 MW_e. The baseline NO_x for Edge Moor #3 was 0.54 lb/MMBTU. Under Phase I of the 1990 Clean Air Act Amendments (CAAA) and, as stipulated by Delaware law, the NO_x emission limit was 0.38 lb/MMBTU.

Research-Cottrell provided design engineering and start-up services for the SNCR system, while Lehigh University's Energy Research Center conducted further system characterization. Start-up testing demonstrated that the system can achieve compliance levels across the load range of 45% to 100% MCR while maintaining ammonia slip below 15 ppmv. Characterization testing demonstrated the capacity of the system for NO_x reductions for the range of boiler conditions typical of full load operation. A theoretical model was used to help in the interpretation of characterization test results and for fine-tuning of the system.

Introduction

Edge Moor Unit #3 (EM3) is a Combustion Engineering tangentially-fired, balanced draft boiler with a nominal rating of 84 MW_e that was first placed in service in 1954. The unit fires eastern

Presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Washington, DC, August 1997

bituminous coal as its primary fuel, but has the capability of firing oil #6 and natural gas backup fuels, especially during the ozone season. A side view of the boiler is shown in Figure 1.

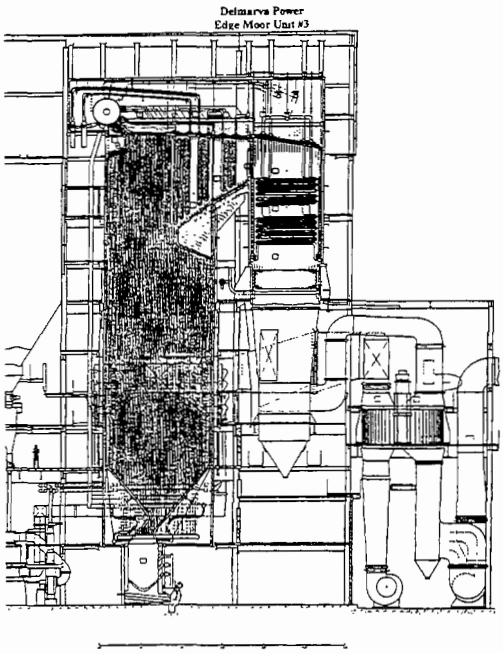

Figure 1

Although Delaware's Reasonably Available Control Technology (RACT) requirements for control of NO_x called for installation of combustion control, primarily Low-NO_x Burners (LNB), Delmarva Power decided to install a SNCR system on a demonstration basis to evaluate its performance in preparation for more stringent emission limits required for CAAA's Phase II.

Urea-based SNCR is a post-combustion process that reduces NO_x by injecting a controlled amount of an aqueous urea reagent into the boiler. Once the urea evaporates and comes into contact with the NO_x in the flue gas, gas-phase chemical reactions take place that convert the nitrogen oxides into harmless molecular nitrogen, water and carbon dioxide. A narrow temperature range (or "window") of about 500°F is required for an effective NO_x reduction.

The design of an SNCR system takes into account several factors, including boiler conditions, process requirements and site specific constraints. Boiler conditions that impact SNCR design include fuel properties, load range, capacity factor, furnace geometry, and conditions of the flue gas, such as temperature and gas velocity profiles and chemical constituents. All of these conditions are considered during the System Design Phase, which is a necessary prerequisite to obtaining an effective design. In this phase, a combination of Computational Fluid Dynamics (CFD) and Chemical Kinetics Models is used, incorporating specialized droplet evaporation and chemical reaction routines. The system is further designed to allow some system control tuning during the Start-up Phase.

Theoretically, NO_x reduction in excess of 60% is achievable under ideal conditions of residence time and flue gas temperatures in the range of 1600 to 2100°F. Higher NO_x reductions are limited by un-reacted NH_3 (ammonia slip) and they vary depending on boiler types and fuels [1,2]. In a full scale boiler or furnace, the reduction of NO_x by urea injection is dependent on a number of boiler specific parameters [3]. In particular, these include the stoichiometry of the chemical process (baseline NO_x and reagent injection ratios), carbon monoxide and excess O_2 levels, and the temperature and velocity fields immediately downstream of the point of injection, since these parameters determine mixing requirements, droplet evaporation rates, and the actual temperature history and residence time available for reaction. Hence, it is important to characterize the SNCR system for the typical range of boiler operating conditions.

This paper describes the System Design Phase and system provided and it discusses the results of the Start-up Phase testing and further system characterization. The purpose of the Characterization Phase was to obtain information which could be used for fine-tuning the SNCR system and to determine the sensitivity of the SNCR system performance to changes in key boiler parameters. A computer model of the SNCR chemical process was validated with experimental data from this boiler. The model was used to complement the understanding of the experimental results.

SNCR System Design

Process Modeling

Process simulation is based on combustion and SNCR process computer models. Boiler dimensions, boiler configuration, and fuel composition analysis are some of the inputs used for the setup of the models. Temperature measurements of EM3's flue gas were taken at various boiler depths and elevations to provide validation process data for the model results. Simultaneous readings of NO_x, CO and O_2 levels at some of these elevations were also obtained. NO_x reduction model results were generated for four boiler operating conditions:

Case 1: **84 MW_e Firing Coal** - NO_x baseline = 0.59 lb/MMBTU, O_2 = 4.1% by vol., CO = 100 ppmv.

Case 2: **81 MW_e Firing Coal and #6 Oil** - NO_x baseline = 0.61 lb/MMBTU, O_2 = 4.6% by vol., CO = 140 ppmv.

Case 3: **66 MW_e Firing Coal** - NO_x baseline = 0.59 lb/MMBTU, O_2 = 6.3% by vol., CO = 80 ppmv.

Case 4: **39 MW_e Firing Coal** - NO_x baseline = 0.68 lb/MMBTU, O_2 = 7.1% by vol., CO = 40 ppmv.

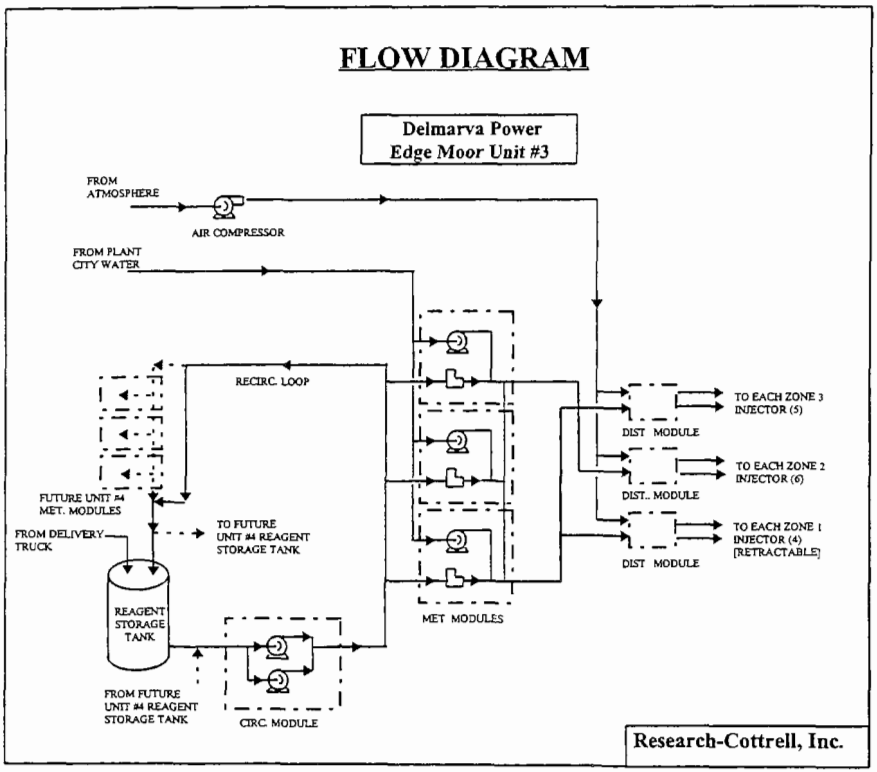

Figure 2

Temperature/emissions mapping and process modeling, along with subsequent engineering began in November 1994. Modeling results were used to predict the performance of the SNCR process and identify an optimum temperature range for reagent injection. The results of the

modeling effort also provided a basis for selecting an injection strategy that provided the best opportunity for maximum NO_x reduction and minimum ammonia slip. Three levels or "zones" of injection were chosen, with each zone located at a particular boiler elevation, allowing the system to track the desired temperature window at different boiler loads. For each case, the target NO_x was set at 0.38 lb/MMBTU and ammonia slip was limited to 15 ppmv.

Equipment Design and System Control

The major system components, as shown in Figure 2, include one truck unloading station, one reagent storage tank, one circulation module and recirculation loop, three metering modules, three distribution modules, one air compressor, and fifteen injectors. A 50% by weight aqueous urea solution is delivered by truck and loaded into the storage tank. At this concentration, the reagent must be kept at a temperature above 60°F to prevent crystallization. Most of the heat required is supplied by an in-line heater, which is integral to the circulation module. A recirculation loop also helps to prevent dead legs and maintains the reagent well mixed in the storage tank. The equipment was delivered to the plant in September 1995 and installation (by Others) occurred during a scheduled four-week outage beginning in October and extending into November 1995.

At the metering modules, the urea is regulated and then diluted with water to allow greater coverage across the boiler. Two of the metering modules provide independent control of each injection zone and operate normally in manual or automatic mode; the third is on stand by. The distribution modules regulate the flow of diluted urea and air to each injector. Flow rates and pressures are set manually during start-up. The injectors are dual fluid type, whereby low pressure service quality air (< 100 psig), supplied by a dedicated air compressor, is used to atomize the diluted urea and cool the injectors.

Zones 2 and 3 contain six and five wall-mounted injectors, respectively, and are intended for operation at mid- and high-boiler load (Cases 1, 2 and 3). Zone 1 has four retractable injectors for use at low-load (Case 4). These injectors are automatically retracted from the boiler via a pneumatic mechanism during higher loads to protect and extend the life of the injectors. Several new boiler ports were added to accommodate insertion of the injectors.

The amount of urea sent to the injectors is regulated by means of a dc-driven pump, which receives a signal from a local control panel during manual mode or from the existing DCS when the remote automatic mode is selected. Based on boiler parameters, i.e., fuel and steam flow, the urea pumping rate is set to a predefined value to meet the required target NO_x emission. Then, to adjust and minimize chemical consumption, a NO_x signal from the CEM's is used as a feed forward signal to initiate a PID loop.

Unique Project Design Highlights

Due to the demonstration nature of the project and in an attempt to fully understand and maximize the benefits of the technology, Delmarva Power took a more experimental approach in the design of the system. As a result, several unique benefits were derived:

- Vendor Supplied A/E Tasks - Delmarva used Research-Cottrell for several A/E key tasks related to the SNCR system. These included location of the unloading station and storage tank and rest of equipment and interface points, determination of power feed tie-ins, identification of suitable ammonia monitors, and updating of existing drawings.

- Modifications of Existing CEM's - In recognition of the possible plugging of CEM sample probes by ammonia slip from the SNCR system, KVB (the supplier of the CEM system for this boiler) re-engineered the CEM's to assure proper operation in this situation.

- Application of Mechanically Attached Fittings - Victaulic Pressfit fittings were installed on all field interconnect air, water, and diluted urea piping instead of welded fittings to reduce construction costs.

SNCR System Start-Up Testing

As part of the start-up effort, undertaken in December 1995, Research-Cottrell tested the SNCR system at the four cases identified earlier. For each case, a suitable chemical pumping rate was chosen based on process modeling results to achieve the desired NO_x reduction and ammonia slip. Then, by varying zone of injection, injector orientation, spray patterns, and urea flow, the system was tuned so as to minimize reagent consumption. Figures 3, 4 and 5 show the results of this system tuning for the low-, mid- and high-load cases, respectively, while burning coal (a small proportion of landfill gas was co-fired).

For the low-load case (39 MW_e), urea flows in excess of 60 gph are required to reduce NO_x below the target level (0.38 lb/MMBTU). Higher urea flows are required for the mid- and high-loads (66 and 88 MW_e respectively). Urea flows as high as 110 and 115 gph, respectively, are needed to achieve target NO_x levels at these loads. The similarity in urea requirements for these two loads is due to the differences in baseline NO_x resulting from the test conditions, which resulted in 37% NO_x reduction at mid-load and 44% NO_x reduction at high-load. On an equal NO_x baseline basis, the urea requirements for high loads should be higher than for mid loads.

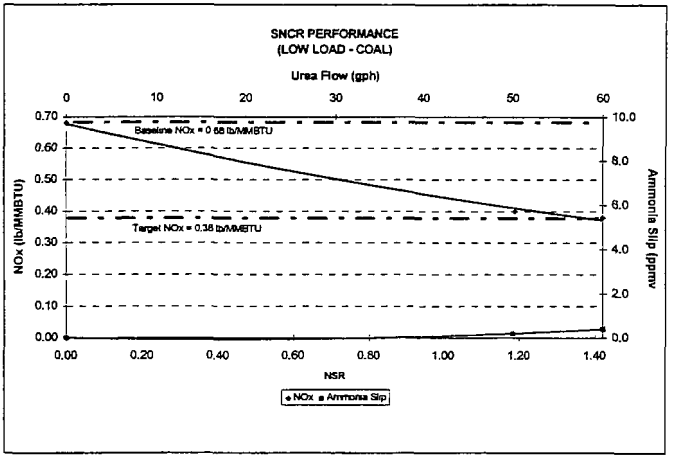

Figure 3

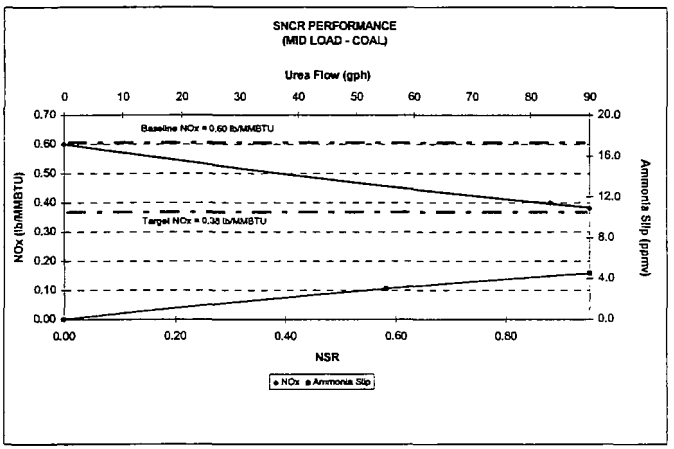

Figure 4

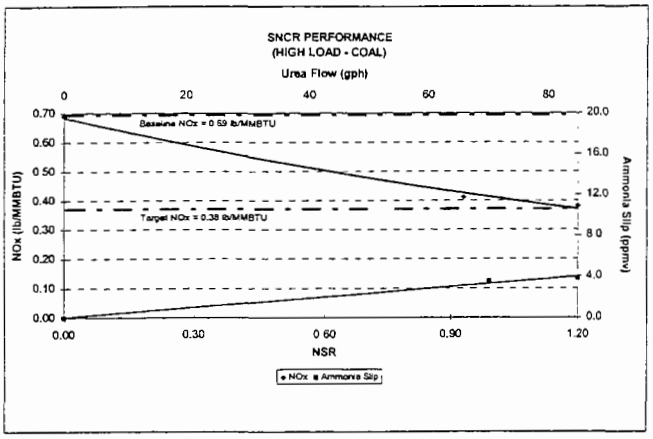

Figure 5

Given the values of NSR's (the ratio of the actual mole ratio of urea to uncontrolled NO_x divided by the Stochiometric ratio for theoretically 100% NO_x reduction and 100% chemical utilization) used, ammonia slip is not a concern at low-loads. Ammonia levels in the stack start to increase at NSR's higher than 1.20. However, for all NSR's tested, the ammonia slip was below the 15 ppmv limit.

The results of the Start-up Phase indicate the importance of understanding the theoretical and physical performance of the SNCR system in terms of NO_x reduction and ammonia slip, since this understanding can be used to permit the system to operate within the prescribed ranges of NO_x reduction under off-design conditions. SNCR system characterization testing followed the testing done under the Start-up Phase. To help in the understanding of the test results, a computer code developed by Lehigh University and Research-Cottrell was used. This code (referred to as the chemical kinetics model, CKM) is a homogeneous gas phase computer model of the SNCR chemical process and it can be used for the prediction of flue gas NO_x reduction and NH_3 slip.

SNCR Computer Model

The SNCR numerical model describes an ideal, one-dimensional plug flow, with the temperature history approximated by a linear profile. The model further assumes the reagent has already been atomized and the droplets are fully evaporated. Urea decomposition was modeled as an instantaneous one-step breakdown to NH_3 and HNCO. The physics of this problem is defined by a set of ordinary differential equations. The chemistry used is a detailed chemical kinetics

scheme composed of 105 reversible reactions and 24 species. This scheme includes the ammonia and isocyanic acid oxidation reactions and the wet-CO oxidation reactions.

Figure 6 shows the comparison between reduced NO_x measurements and the model results for this unit operated at full load conditions. The data corresponds to urea single zone injection. Input to the theoretical model included CEM measurements of NO_x, CO, CO_2, and O_2; urea injection flow; and temperature information obtained with an optical temperature probe. No measurable ammonia slip occurred with the temperatures and NSR's used in these measurements.

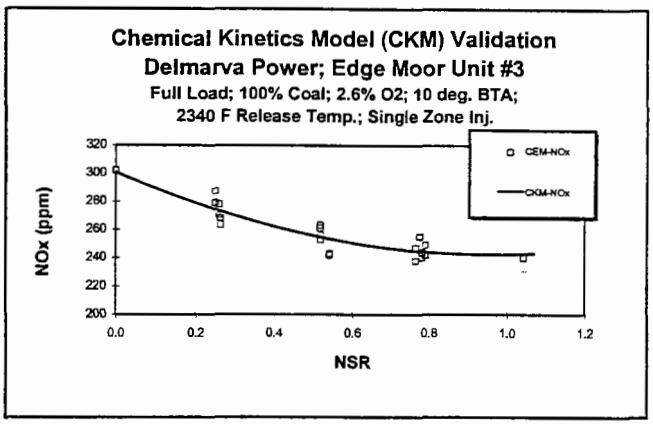

Figure 6

SNCR System Characterization

In order to characterize the performance of the system under typical ranges of boiler operating conditions and to obtain more performance data which could be used for system fine-tuning, Delmarva initiated an ongoing data gathering program. As part of this effort Lehigh University's Energy Research Center performed theoretical calculations and carried out field tests to characterize the factors affecting performance of the SNCR system. Since Delmarva intends to operate the unit's SNCR capability only during the summer months, the system characterization was performed after the first summer of operation (1996). Further system characterization is expected to continue in the following summers. Future characterization tests will evaluate the long term impacts of the SNCR system on boiler operation, such as possible pluggage of downstream heat exchange surfaces and CEM's due to ammonium bisulfate, fly ash contamination due to ammonia slip and any changes in unit heat rate.

Injection Zones Characterization

Testing for the Characterization Phase was done at full load. At full load the temperature distribution in the boiler is such that only injectors in Zone 2 and 3 are effective because they are located at elevations where gas temperatures are in the proper range for significant NO_x reduction. Testing at different urea flow rates for each individual zone and for both zones in combination indicated that the reduction of NO_x emissions and production of ammonia slip per unit of urea flow is higher for Zone 3 (located at a higher elevation) than for Zone 2.

Figure 7 shows the percent NO_x reduction and NH_3 slip versus the fraction of the total urea flow injected into Zone 2 for a total reagent flow of 80 gph. The graph shows that the NO_x reduction and ammonia slip increases as the fraction of urea introduced through Zone 2 is lowered from 1.0 to 0.4. Additional test results and computer simulation results showed that the NO_x reduction eventually decreases if the fraction of Zone 2 urea flow is lowered beneath an optimal level, the exact value of which is dependent upon operating conditions in the boiler (Figure 8). This is the consequence of the lower gas temperatures associated with the downstream zone (Zone 3). Furthermore, for both zones, the NO_x reduction is more efficient during the early stages of urea injection. That is, the slope of the NO_x versus urea curve is steeper at lower urea flow rates,

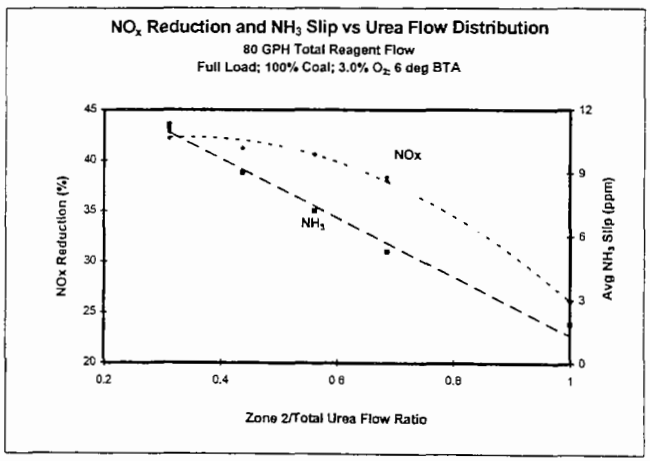

Figure 7

flattening out as higher rates of reagent are introduced. The optimum division of flow between zones would depend on the needed NO_x reduction and the required ammonia slip limit.

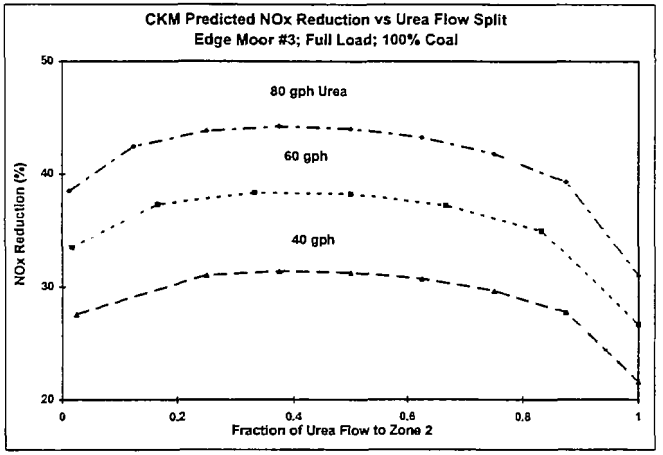

Figure 8

Numerical model results indicate that a partition of about 40% urea to Zone 2 and 60 percent to Zone 3 maximizes NO_x reduction at full load (Figure 8).

Affect of Furnace Parameters on SNCR Performance

Additional SNCR system characterization was performed at full load to determine the sensitivity of the SNCR process to furnace conditions represented by two key boiler parameters: burner tilt angle and furnace O_2. Figure 9 shows the effect of lowering burner tilt at fixed economizer O_2, from +10 degrees to 0 degrees (typical burner tilt range for full load to maintain steam temperatures), on the reduced NO_x level versus urea flow rate curve. Urea injection was limited to Zone 2. The results indicate that the trending in SNCR system performance is similar for both conditions, however, better performance is obtained at lower burner tilt angles. For all tests ammonia slip was less than 5 ppmv.

The computer code was used to interpret the experimental results. Lower burner tilt angles are associated with lower baseline NO_x levels and lower gas temperatures. Furnace gas temperature measurements in the vicinity of the injection zone, carried out with the optical probe, indicated an increase in average (line-of-sight averages across the furnace plane) gas temperature of

approximately 80°F by raising the burner tilt angle 10 degrees. Figure 10 shows the results of the computer simulation in terms of NO_x reduction and ammonia slip for different values of NSR and gas temperature. This system was designed to operate on the "right side" of the NO_x

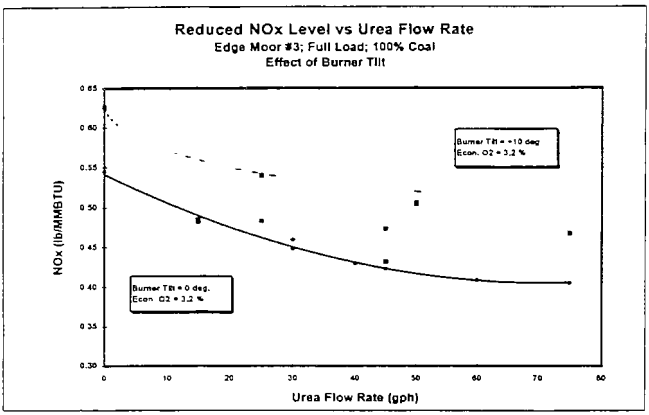

Figure 9

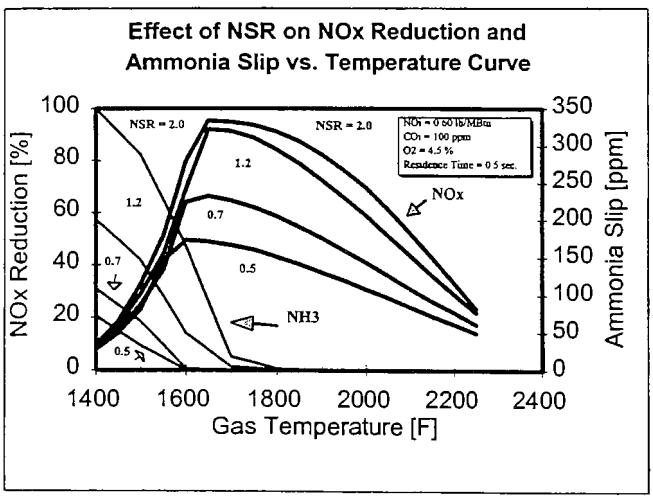

Figure 10

reduction versus temperature curve (which is the region where ammonia slip is negligible). On this side of the curve, better performance is achieved at relatively lower temperatures. Additionally, for a constant urea flow rate, a lower baseline NO_x will translate in a higher NSR which also results in better SNCR system performance.

Figure 11 shows the effect of two levels of furnace oxygen (indicated by economizer O_2 levels of 3.2 and 2.6%) on reduced NO_x for fixed burner tilt angle (+10°). This range of O_2 is typical of the variation of O_2, at full load. Again, only urea injection to Zone 2 was considered. The trending in SNCR system performance is similar for both O_2 levels in terms of the amount of urea required to achieve a particular NO_x level.

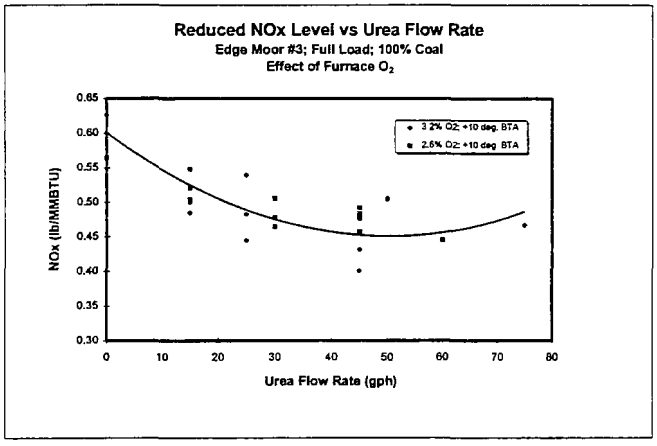

Figure 11

The results indicate that the SNCR system performance remains essentially unaffected by O_2 variations at full load. Although the baseline NO_x was reduced by lowering O_2, the decrease of oxygen in the furnace has an effect on the furnace gas temperature distribution which offsets the NO_x reduction. The CKM was used to investigate the effect of reducing O_2 in the SNCR chemical process. Figure 12 shows the sensitivity of the NO_x reduction versus gas temperature curve to furnace O_2. This indicates excess O_2 is a second order variable. An increase in O_2, from 0.8 to 6.6%, did not impact the NO_x reduction performance at temperatures below 2000°F. At temperatures greater than 2000°F, the change in O_2 considered (3.2 to 2.6%) has a negligible impact on the SNCR chemical process. For this set of tests, ammonia slip was also less than 5 ppmv.

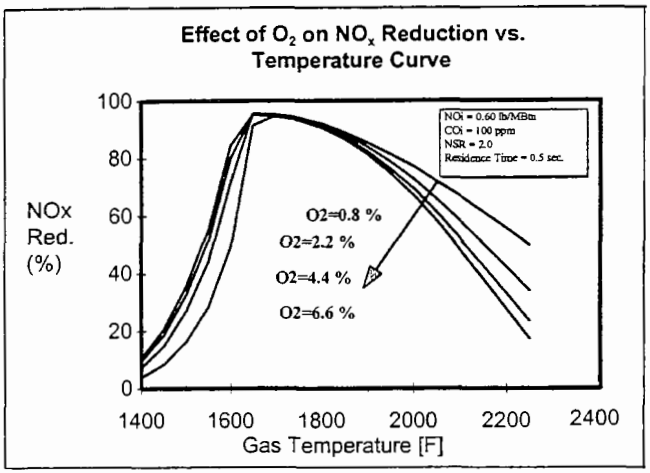

Figure 12

Summary

Installation and start-up tests of an SNCR system at Delmarva Power's 84 MW_e Edge Moor Unit #3 have demonstrated the capability of the system to reduce NO_x to required Delaware RACT compliance levels for tangentially-fired utility boilers. For coal-firing and a load range of 45% to 100% MCR, ammonia slip remained below 15 ppmv. Start-up and Characterization tests provided useful information to be used for fine-tuning the urea-based SNCR NO_x control system. A theoretical model was used to help in the interpretation of characterization test results and for analysis of several parameters which impact process performance. Results of this analysis and testing demonstrated the capacity of the system to achieve NO_x reductions for the range of boiler conditions typical of full load operation.

Acknowledgments

The work presented in this paper was funded by Delmarva Power. The authors would like to acknowledge the cooperation of the Delmarva's 1995 Clean Air Compliance Project Team, led by D. Skedzielewski and M. Zoccola, the engineering effort of R. Casill, J. Staudt, S. Kozma and B. Patel at Research-Cottrell, and the design-phase process modeling assistance by Nalco Fuel Tech. Lehigh University gratefully acknowledges the technical direction provided by M. D'Agostini and E. Levy of the Energy Research Center.

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Enhanced NOxOUT® Control
Salem Harbor
Unit #3

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Abstract

The NOxOUT System installed on Unit #3 at New England Power's Salem Harbor station has undergone a controls upgrade. The changes resulted in significantly lower reagent consumption and lower ammonia slip. This paper discusses this latest control approach and the benefits realized.

In order to implement the control changes, new hardware and new software were installed with minimal intrusion in the plant routine operation. The new hardware includes state-of-the art ammonia and temperature monitors, a pressure control on the fluid injectors and computer upgrade. New software takes advantage of furnace temperature enhancing the original steam feed-forward signal, and takes advantage of ammonia measurements enhancing in-furnace chemical distribution. Furnace temperature is also utilized to minimize ammonia spiking during rapid unit transients and to guide operators on improved sootblower usage.

This successful upgrade has provided NEP's operators the ability to operate with significantly lower reagent consumption (a savings of over 50%).

1. INTRODUCTION

New England Power (NEP) elected in 1993 to reduce NOx emissions at their Salem Harbor Station, Units #1, #2, and #3 through the installation of Nalco Fuel Tech's (NFT) NOxOUT SNCR technology. These units are permitted on the basis of individually maintaining a 24-hour calendar day average NOx level of 0.33 lbs/MMBtu. The SNCR equipment installation and start-up on Unit #3 occurred in the third quarter of 1993 and was followed by installation and start-up of low-NOx burners with separated overfire air. Combined, these technologies have demonstrated consistent compliance with mandated controlled NOx level while firing coal from a wide variety of sources.

In 1994, NEP investigated the applicability of continuous temperature and ammonia emission monitors for the ultimate purpose of integrating these signals into the SNCR control logic to improve overall SNCR system performance and lower operating cost. Spectrum Diagnostix, Inc. (SDx), a BOVAR company, manufactures the temperature and ammonia monitor equipment. Testing by SDx with a SpectraTemp® continuous FEGT monitor and a SpectraScan continuous ammonia monitors on units #1 & #2 yielded the following conclusions:

- Reagent was injected at the upper end of the temperature window for NOx reduction at full load resulting in low utilization (15 to 22%) especially with a dirty furnace (at the tail end of a sootblowing cycle)
- At low loads, reagent was injected at lower temperatures with better residence times resulting in utilization which was higher (30 to 35%)
- Ammonia slip was prevalent during load transients where temperatures tended to be low and the system control was slow to call for decreases in reagent flow
- Furnace sootblowing decreased FEGT and improved reagent utilization at all loads
- Keeping FEGT below 2020°F at full load increased reagent utilization to 26%
- Keeping FEGT below 1880°F at 70% load increased reagent utilization to 42%

NEP agreed to a commercial upgrade of system control for Salem Harbor Unit #3 provided a payback based on reagent savings would be demonstrated. The principal objectives of the enhanced NOxOUT System control were to allow Salem Harbor Unit #3 to meet its NOx emission limit of 0.33 lb/MMBtu while reducing the consumption of NOxOUT reagent.

NEP organized a team to execute the upgrade and demonstrate improvements. Four test series were conducted as shown in Table 1.

Table 1. Purpose of Each Test Series

Test Series	Purpose
Baseline Tests	Determine as-found NOxOUT consumption, NH_3 slip, and flyash ammonia content relative to boiler operation.
Control System Optimization	Tune the new system control to minimize reagent consumption in response to temperature and NH_3
Control System Demonstration	Quantify improvements in NOxOUT consumption, NH_3 slip, and flyash contamination as well as control system reliability over a one-month period
Final System Tuning	Incorporate any further system improvements mutually approved by NFT and NEP as a result of the demonstration.

Nalco Fuel Tech (NFT) designed modifications to the original NOxOUT System and worked with NEP to install the new equipment and software. Quinapoxet Solutions worked with NEP and NFT to plan the program, collect and analyze data, and interpret results. The program objectives were to quantify chemical consumption and document boiler and NOxOUT System performance before (baseline) and after (demonstration) instruments and controls were upgraded, especially cost of NOx control. The program included 24 days of baseline observing performance of original system control and 35 days of demonstration.

2. BASELINE TEST

Salem Harbor Unit 3 is a front fired unit rated at 155 MW. The unit has been equipped with four levels of NOxOUT injectors as well as low-NOx burners and overfire air to control NOx emissions below 0.33 lb/MMBtu. A complete division wall front to back divides the furnace into two chambers. Since low-NOx burners were installed, the unit has had difficulty achieving designed reheat steam temperature due to lower furnace exit gas temperature. Furnace sootblowing was historically performed when primary superheated steam temperatures became high enough to cause tube overheating (primary steam temperature approaching 950°F). Prior to the test program, furnace sootblowers were operated only a few times per week.

2.1 Baseline Reagent Consumption

Historical data taken during 1995 and 1996 indicated that reagent consumption varied significantly from day to day, averaging 70 to 200 GPH. Average reagent consumption for Unit #3 is about 125 GPH. Reagent consumption on the first day of baseline testing was about 112 GPH averaged over the 24-hour period. On the second day, the operators blew all 35 furnace sootblowers, and reagent

consumption at full load immediately dropped to about 62 GPH. As a result, operators changed their furnace sootblowing practices during the rest of the baseline test in order to better control NOx.

Table 2. Historical and baseline sootblower operations

Prior to 30 September	Baseline
Used IR sootblowers 1-2 times per week	Used IR sootblowers nearly every day
Blew all 36 sootblowers in rapid succession	Usually blew 8 sootblowers at a time
Purpose of sootblowing was to reduce primary superheat temperature or improve Low-NOx burner performance	Purpose of sootblowing was to reduce reagent consumption

Historical data was used to determine reagent consumption with the original control system. During the baseline, on days with active sootblowing, the reagent consumption averaged around 70 to 80 GPH while on days with no sootblowing, reagent consumption was 100 to 110 GPH. Historically consumption averaged 125 GPH.

The plant began collecting baseline data on 30 September 1996 at 3:00 p.m. Figure 1 shows hourly average load, NOx emissions, and reagent consumption for the first day and a half of baseline testing. Full load reagent consumption started at 120 GPH, but steadily climbed to nearly 160 GPH by mid-morning on 1 October 1996. At 80% load, reagent consumption dropped to a range between 65 and 75 GPH. Baseline testing changed focus after 9:50 a.m. on 1 October 1996. All 36 furnace IR sootblowers were blown in rapid succession. Removing slag from the furnace walls had three immediate effects:

1. Reagent flow decreased immediately to 65 GPH, the minimum flow allowed by the original system control. Reagent flow could have gone even lower as evidenced by a subsequent decrease in NOx from 0.31 to 0.29 lb/MMBtu.

2. Superheat attemperator spray flows decreased from 52,000 to 13,500 lb/hr, while primary SH steam temperature decreased from 908°F to 850°F Secondary SH steam temperature remained at 1000°F

3. North side reheat steam temperature which is normally 1000°F ranged from 983°F to 996°F for the next 8 hours after sootblowing. The south side reheat steam temperature remained at 1000°F

These results confirm a loss of reheat temperature with IR sootblowing and a major reduction in reagent consumption. Also notice how loss of air staging of the low NOx burners affects reagent flow.

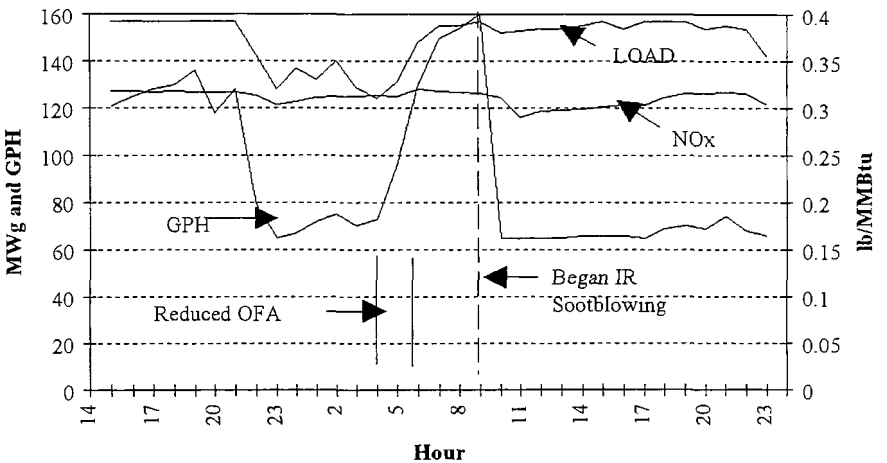

Figure 1. Baseline data, 1 October 1996

No furnace wall sootblowing was performed for the next 4 days. As shown in Figure 2, reagent consumption increased gradually over time. Twenty-four hours after sootblowing, reagent flows were up to 100 GPH at full load. These data offer great promise for improved NOx control cost-effectiveness with minimal impact on boiler performance. Extensive furnace wall sootblowing caused slight decrease in reheat steam temperature for a few hours, while the reduction in reagent consumption persisted for days.

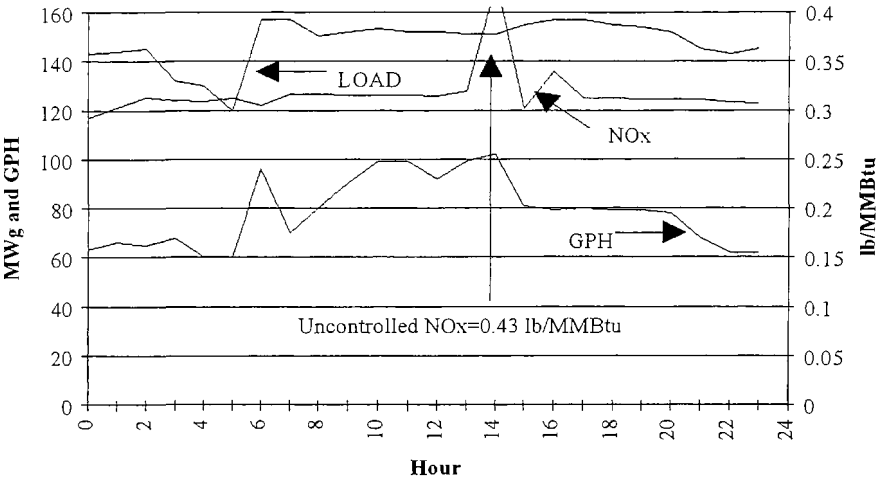

Figure 2. Baseline data, 2 October 1996

The next IR sootblowing occurred on 6 October 1996. As indicated on Figure 3, IR blowers 1 through 8 (lower burner elevation) were used during a load increase. About 2 hours later, IR blowers 9 through 16 (upper burner elevation) were blown after the unit had reached full load. Reheater long retractable blowers were actuated in conjunction with each IR sootblowing cycle in order to maximize heat transfer to the reheat steam and thus minimize any decrease in reheat steam temperature.

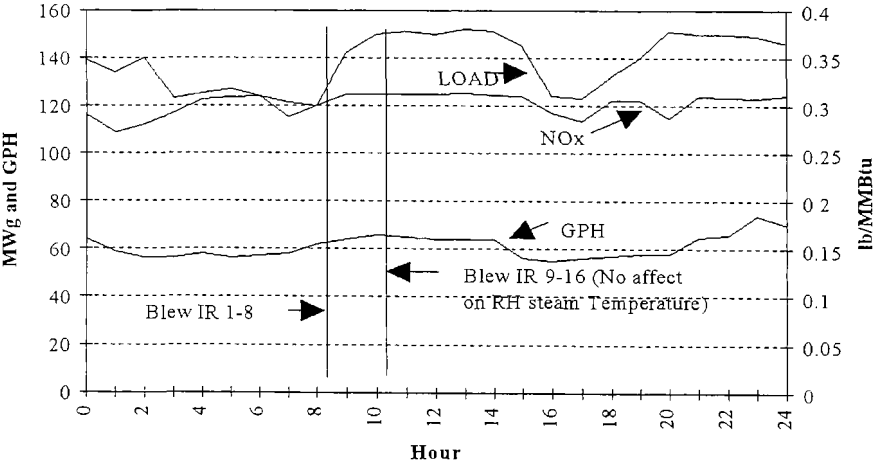

Figure 3. Baseline data, 6 October 1996 (Sunday)

The results of this particular sootblowing test was:

1. Reagent usage was reduced to 70 GPH.
2. No effect on RH steam temperature.

From 6 October 1996 on, the Salem Harbor operators began to use sootblowing to minimize reagent consumption. Furnace sootblowing was performed 25 times over the next 18 days of baseline testing (as compared to 1 to 2 times per week prior to baseline testing). As a result, reagent consumption remained low. For the 24 days of baseline testing, the average daily chemical consumption was about 2050 gallons per day (85 GPH).

2.2 Baseline Furnace Temperature

On 9 October 1996, one SpectraTemp continuous FEGT monitor was installed on the north side of the furnace and connected to the NOxOUT data acquisition system. The original system control was translated into the new system control, so temperature was not yet integrated actively into the control scheme, however, operators could now monitor north-side temperature and relate IR sootblowing to temperature as well as NOxOUT System performance. Table 3 shows typical furnace temperature and O_2 profiles obtained by the plant. Higher temperatures and lower O_2 concentrations occur on the south side of the furnace both indicate higher fuel flow to the south side burners.

Table 3. Unit #3 HVT Test (24 May 1996)

South									North				
Probe Length	2	4	6	8	10	12	14	16	10	8	6	4	2
% O_2	2.5	2.6	3.3	3.8	4.0	3.1	2.3	2.5	4.9	6.0	6.7	7.3	7.0
Temp, °F	1990	2014	2022	2026	2039	2058	2041	1936	1915	1915	1880	1865	1900

Figure 4 shows the trend of instantaneous FEGT measurements with total steam flow during the baseline tests. It can be seen that full load FEGT ranged from 1950°F to 2100°F with all mills in service. The time between sootblowing events was the primary factor affecting the exit gas temperature. Baseline data were reviewed to identify relationships between the furnace exit temperatures and load, mills in service, and sootblowing. Transient performance was also studied.

Figure 4 shows a linear decrease in FEGT with load down to a total steam flow of about 750,000 lb/hr steam flow. Further load reduction requires removing a mill (usually Mill 4 which feeds the bottom row of burners). At this transition point, the furnace exit gas temperature increases dramatically.

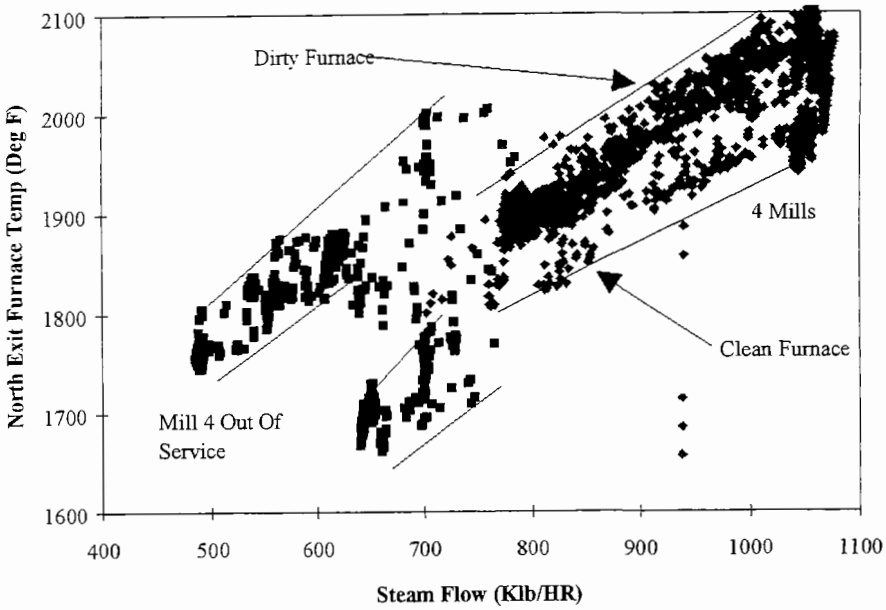

Figure 4. Relationship between FEGT and Steam Flow, 18 to 24 October, 1996

Table 4. Baseline sootblower observations (high load)

Main Steam (Klb/Hr)	Auxiliary (Klb/Hr)	Total Steam (Klb/Hr)	FEGT, °F	Comments
1040-1045	7.5	1048-1053	2006-2052	Clean Furnace
1045-1050	12.4	1057-1062	1985-2029	Clean Furnace
1037-1041	12.5	1050-1054	2088-2098	No Sootblowing for 24 Hr
1025-1027	12.5	1038-1040	2039-2047	No Sootblowing for 35 Hr
1027-1030	27	1054-1057	2060-2074	No Sootblowing for 48 Hr
1026-1037	28	1054-1065	2041-2067	No Sootblowing for 60 Hr
1042-1049	0	1042-1049	1951-1988	Clean Furnace
1037-1045	0	1037-1045	1976-2015	Clean Furnace
1026-1040	0	1026-1040	2020-2067	No Sootblowing all Day

Note: Each data entry above represents a minimum 2 hours operation at 154 to 156 MWg

2.3 Effects of Mill Configurations

When a mill is removed from service, the excess air level tends to be higher than when firing all four mills. This is because air flow to any burners taken out of service is kept at a minimum cooling flow. Higher windbox-to furnace differential

pressure exist when a mill is out of service and air flows must be controlled between the overfire air system and firing burners. Minimum boiler load during baseline tests was about 70 MW (460,000 lb/hr steam flow) with the upper three mills in service.

The unit also operated for 3 days with Mill 2 (top row of burners) out of service during baseline testing. Load was held relatively constant during top-mill-out operation, ranging from 125 to 145 MW. Oil guns were inserted into the top burners and lighted off for a few occasions when loads above 150 Mw were required. Figure 5 shows hourly average load, NOx, FEGT, and reagent consumption during top-mill-out operation. Note that NOx emissions and reagent consumption were very low.

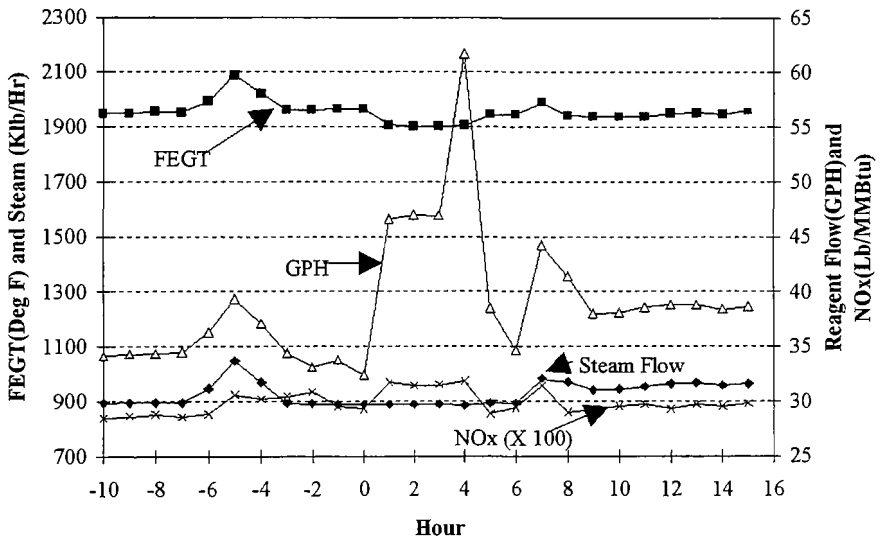

Figure 5. Baseline data, hourly averages, 14 and 15 October, 1996 (top mill OOS)

Figure 5 shows excellent NOx control. NOx remained well below setpoint most times. Reagent flow was at minimum and NOx emissions averaged less the 0.3 lb/MMBtu for the 3-day period (0.27 lb/MMBTu on 13 and 14 October 1996; 0.30 lb/MMBtu on 15 October 1996).

2.4 Transient Load Operation

The first generation NOxOUT System control was optimized without benefit of more sootblowing performed during this baseline study. The control of reagent flow was tuned for higher temperatures causing lower reagent utilization. NOx

was therefore generally over-controlled during the baseline test period because reagent flows characterized against the steam flow were too high.
Figure 6 shows a baseline load reduction transient where the unit goes from 150 to 70 MW (1000 to 480 Klb/hr steam flow) in about 1 hour. As load decreases, furnace temperature also decreases. NOx emissions decrease from about 0.29 to 0.26 lb/MMBtu indicating higher than desirable reagent flows throughout the transient. NH_3 slip increased from 12 ppm to about 40 ppm during a flush of the upper level in service. NH_3 slip dropped once the upper level of injection is taken out of service. Approximately five minutes later, when Mill 4 is taken out of service, temperature increases from 1890°F to 2000°F and the upper level of injectors go back into service. As load is reduced further, NH_3 slip climbs to 20 to 30 ppmv range.

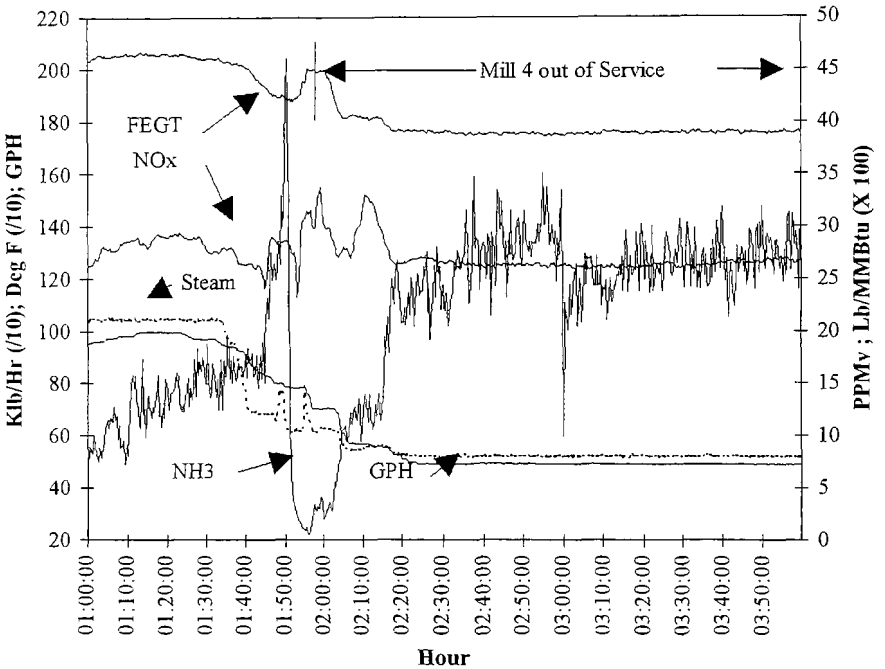

Figure 6. Rapid load decrease, 20 October 1996. NOx is over-controlled.

Similar problems occurred when load was increased. This first generation NOxOUT System control also had room for improvement in the area of tracking load transients, especially at load points where the system control switches reagent injection level. An instability occurred at a steam flow of 800,000 lb/hr (about 75% load), as shown in Figure 7 The original system control calls for a shift in injector level at this load. During baseline tests, operators attempted to hold 75% load for several hours during which time steam flow crossed 800,000

lb/hr a total of five times in 90 minutes. Each time that upper injectors went into service, the system control called for a reagent flow increase (this due to the minimum flow required for two metering modules). Since temperature was constant at about 1900°F, the additional reagent flow reduced NOx and caused a 30 to 40 ppmv ammonia spike. The system control was slow to correct for these changes based on trimming the flow rate in response to NOx emissions. This was improved upon by including furnace exit temperature in the reagent flow control feedforward signal.

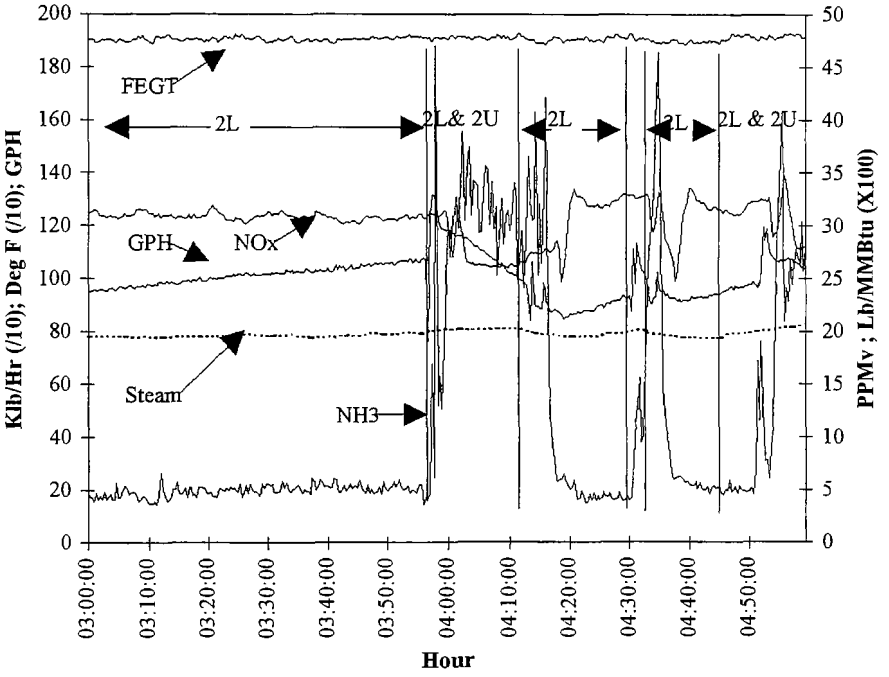

Figure 7. Instability occurred when going to second injector level

3. SYSTEM CONTROL CHANGES

NFT incorporated mechanical, instrument, and software changes into the NOxOUT System control in order to reduce reagent consumption. These changes were implemented without affecting unit operation (no loss of unit availability).

The original NOxOUT System included four injection levels, two upper levels which were serviced by one metering module, and two lower levels which were serviced independently by a second metering module. Two adjacent injector levels operate at all but the lowest load on Unit #3. The metering modules ran in

parallel only when the middle two zones were in service. Also, each metering module regulated liquid discharge pressure to injector levels with one (local mechanical) pressure setting which was constant for all load ranges.

Wall injectors utilized at Salem Harbor rely on droplet trajectory into the furnace for proper reagent distribution. These injectors are twin fluid injectors with air as atomizing medium. Stored NOxOUT reagent is 50% by weight aqueous urea. Water is used as a carrier of the reagent. Metering modules proportion the proper amount of stored reagent and water, mix the two and forward them to injectors at the proper liquid pressure for reagent distribution. At a given atomizing pressure, liquid pressure at each injector may be lowered to provide finer droplets with less furnace penetration and more upstream release of the NOx-reducing reagent, or liquid pressure may be increased to provide coarser droplets with more furnace penetration and more downstream release of the NOx-reducing reagent. The original system provided one pressure setting throughout the load range.

The original NOxOUT System utilized an Allen-Bradley PLC 500 series controller with a computer interface for operators. The computer was programmed using FactoryLink® software on a DOS computer. NFT designs the NOxOUT System utilizing a modular approach. Unit #3 at Salem Harbor has a dedicated Circulation Module which heats and circulates stored reagent from storage to two Metering Modules and back to storage. The Metering Modules proportion and mix reagent and water and forward the liquid at proper pressure to Distribution Modules. Each wall injector is supplied with regulated air and liquid from the Distribution Modules. The system incorporates motor operated valves in field piping properly interconnecting the various modules.

Operators monitor and control the system by a set of active computer screens specifically designed by NFT for this purpose using the FactoryLink program. In the fully automated mode, the system starts and stops (injector levels are brought into and out of service, pump and valves operate sequentially, reagent feed rates set and track) automatically throughout the normal operating range of boiler load as dictated by a set of characterized tables. Alarm functions, safety/trip functions, and trending of important NOxOUT System data are also performed. The operators modified NOx setpoints and/or reagent feed rates in the normal course of automatic operation.

The NOxOUT Process is designed to minimally influence or dictate the operation of the boiler. The number of mills in service determine which characterized table is active in the automatic mode (there are four separately characterized 16-segment tables: <2 mill, 2 mill, 3 mill, and 4 mill). Within each characterized 16-segment table, boiler steam flow (turbine plus auxiliary flow) is used to determine indirectly the furnace condition and select the default NOx setpoint, injector levels in service, maximum reagent flow for each Metering Module, and minimum

reagent flow for each Metering Module (this is often referred to as the feed-forward signal). Within flow ranges, reagent feed rate is controlled up or down by comparing actual NOx to active NOx setpoint utilizing a system proportional/integral (PI) loop controller programmed in the Allen-Bradley (this is often referred to as the feed-back signal). Tuning of these control features relies on repeatable furnace temperature and velocity profiles with feed-forward conditions. This repeatability is affected by sootblowing, fuel characteristics, mill condition, burner and overfire air operation, excess air and cycle efficiency among other things.

3.1 Mechanical Changes

Low-NOx burners with overfire air were installed and the uppermost level of injectors taken permanently out of service. This left three injection levels. NFT increased the NOxOUT System operating flexibility by piping a new remote-set pressure regulator on each of two metering modules. Injector distribution piping was modified by utilizing original upper injector zone valve to alternatively supply the middle injection level such that two operating levels of injectors could be supplied separately by parallel operating metering modules over the broadest load range possible.

The original NOxOUT System control allowed only one liquid pressure setting from each metering module to cover the entire load range through levels that the metering module supplied. The modified system allowed control of spray patterns at each level in service (with the upgraded pressure controls) and level-to-level biasing of reagent treatment over a wider range of parallel metering module operation (with the upgraded zone piping).

3.2 Added Instrumentation

SDx supplied two continuous optical temperature monitors (SpectraTemp) and two online gas phase ammonia slip monitors (SpectraScan) used as new inputs in the modified NOxOUT System control.

SpectraTemp detects radiation, primarily at visible wavelengths, emitted by the ash particles passing through a narrow field of view. Ash particles are typically smaller than 30μm diameter and thermally equilibrate with surrounding gas in microseconds, accurately reflecting local gas temperature.

SpectraScan is a tunable diode laser-based instrument. The wavelength of energy emitted by the laser is repeatedly and rapidly altered through one absorption line for ammonia. When the laser is tuned to be off of the absorption line, the transmitted power is higher than when it is on the line. Measurement of relative amplitudes of off-line to on-line transmission yields a precise value of ammonia gas concentration along the measurement path. The laser wavelength

is scanned across the absorption line at a frequency of 1 MHz, causing the detector to output a signal that contains a 2 MHz amplitude modulation. This signal is processed to determine concentration of gas phase ammonia.

Two new temperature monitors were mounted at the furnace exit plane, one on the north side and one on the south. NFT installed a pneumatically operated knifegate isolation valve interlocked with instrument cooling air supply for instrument protection. Two new ammonia monitors were installed in the ducts at the economizer outlet, one on the north duct and one on the south. NEP installed the vacuum system for these monitors.

3.3 Software Changes

The Allen-Bradley and FactoryLink software were modified and updated. New software is designed to be operated in the same way as the original program but with additional features activated and tuned in small, progressive increments. This permitted commissioning updated system control with minimum impact on operations. The unit was available for normal operation throughout installation and start-up.

Segmented tables were replaced with characterized curves (four point and ten point) based on a selectable feed-forward signal (steam flow and/or furnace exit temperature) defining default NOx setpoint, injector level(s) in service, reagent flow rates, and metering module default liquid discharge pressures.

Temperature inputs are also used in an innovative manner to allow for response to rapid furnace transients (formerly resulting in over-treatment of NOx and ammonia spikes). Droplet trajectory control of twin-fluid wall injectors is possible by altering either atomizing air pressure or liquid pressure to injectors in service. Air pressure is set at the distribution module and manually maintained within a narrow operating range. Decreasing liquid pressure with fixed air pressure causes a finer droplet pattern which does not penetrate and travel as far downstream in furnace gases. By manipulating liquid pressure, precise and immediate control of treatment zone distribution is possible. This is used as a means of tracking rapid furnace transients. Should a sudden precipitous reduction occur in furnace temperature (such as is encountered when a mill trips, coal feed bridges, etc.), liquid pressure to injectors is immediately reduced, raising temperature where reagent is released and minimizing liquid feed during the short-lived transient. Change in temperature inputs (a derivative control) is used to track these transients and automatically move liquid pressure as required.

Ammonia inputs are used to bias reagent feed between two parallel operating levels. This is why reconfiguration of interconnecting piping to injection levels was important. A new system proportional/integral/derivative control was

programmed into the Allen-Bradley. This control compares ammonia slip setpoint to average ammonia measured and adjusts a small (up to approximately 5%) amount of reagent to the more downstream (cooler) zone of treatment. This feature maximizes reagent utilization at a given furnace condition within acceptable slip limits.

Other NOxOUT System control features were also added. Daily running NOx average emission is calculated and utilized in two control features to minimize reagent consumption by avoiding unnecessary over-treatment during a 24-hour compliance period. The first feature takes advantage of the fact that less reagent consumption is required at low load to achieve NOx than at high load. The furnace is cooler at low load and therefore lower injector level(s) are operated (this provides more residence time at lower temperatures for NOx reduction reactions to occur attendant with higher reagent utilization and less unwanted ammonia slip). This fact was taken into consideration in the original system control by characterizing lower setpoints at lower loads. In the original control, NOx setpoints were characterized below compliance level at all loads to assure daily compliance with room for operating comfort regardless of load profile. The updated system control tracks the running daily average thus taking into account load profile and automatically relieves the setpoint at high load operation while maintaining room for operating comfort. The second feature takes advantage of the fact that, since NOx is kept below compliance level on average throughout the day, at some point late in the day, compliance could be met even without reagent flow. Once this compliance level is realized, the new feature minimizes reagent flow.

Table 5. Software changes initiated prior to the demonstration period.

Original System Control	**Upgraded System Control**
Initial flow rate selected by look-up table based on steam flow and mills in service.	Initial flow rate calculated based on steam flow and mills in service (85-90%)as well as temperature (10-15%).
Look-up table values for chemical flow established previously for hot-furnace operation.	10-point curves calculate reagent flow. Values reduced after reviewing sootblower performance data.
Injector liquid pressure constant	Injector pressure characterized with load and varies with rate of FEGT change. Rapid temperature decrease results in reduced pressure (thus reducing both chemical flow and droplet size).
Injector level selected by look-up tables based on steam flow and mills in service.	Option to let temperature drive injector level was installed but not used.

No automatic flow bias to different injector elevations.	Bias reagent flow from higher elevation (cooler) to lower elevation (hotter) if NH_3 values exceed setting
NOx setpoint selected automatically based on steam flow and mill in service. Operator override possible.	Same as before, but with a new screen showing daily average NOx and projected average if current setpoint is maintained. Automated optional high load setpoint and end-of-day trim reduce reagent flow to minimum values.
System response time set to avoid instabilities given original inputs.	System response time shortened to take advantage of new inputs.

4. DEMONSTRATION TEST

Demonstration tests started on 24 October 1996 and were completed on 27 November 1996, a total of 35 days. The first question to be answered is "How boiler operation during the demonstration tests compare to the 24 days of baseline testing?" Average daily boiler operating parameters for each test period are compared in Table 6.

Table 6. Comparison of Boiler Operating Conditions

Boiler Operating Parameter	Daily Average During Baseline	Daily Average During Demonstration
Load, MW	144.2	140.9
Capacity Factor, %	93	91
CO, ppmv	35.6	40.5
Aux. Steam, Klb/hr	8.7	13.1
SH Spray, Klb/hr	25.4	15.0
RH Spray, Klb/hr	0.5	0.4
RH Temperature (S), °F	997	993
RH Temperature (N), °F	990	979
SSH Temperature (S), °F	1000	999
SSH Temperature (N), °F	998	994
PSH Temperature (S), °F	879	870
PSH Temperature (N), °F	878	861
IR Sootblows/Day	8.6	23.0
NOx, lb/MMBtu	0.301	0.316

Average daily load was about 3 MW higher during baseline, but this difference is not considered significant. The capacity factor for Unit #3 was comparable for both periods. Table 6 shows that steam cycle efficiency was negatively affected

during the demonstration. Evidence for less efficient operation is the decrease in steam temperatures. There are three reasons for lower steam temperatures:

1. The demonstration program included a few days of firing wet coal.

2. The last 3 weeks of the demonstration period, Unit #3 operated without one of its feedwater heaters.

3. Furnace IR sootblowing increased by nearly a factor of 3 during the demonstration tests.

Of the three factors, the sootblowing increase had the largest effect on NOxOUT System control. Table 7 shows the load profiles for each period. This table shows that the unit operated at full load a little more frequently during the demonstration test period, but also spent more time at minimum load. Since reagent consumption is the highest at full load, the load profiles are not expected to cause a measurable difference in NOxOUT System performance between baseline and demonstration periods.

Table 7 Comparison of Boiler Load Profiles

	% TIME OPERATING	
LOAD RANGE	**BASELINE**	**DEMONSTRATION**
150-157 MW	54.1	56.7
140-149.9 MW	16.2	12.5
130-139.9 MW	14.7	10.5
120-129.9 MW	08.3	07.2
100-119.9 MW	04.4	06.7
70-99.9 MW	02.3	06.4
Total:	**100.0**	**100.0**

5. Conclusions

The demonstration quantified the amount of reagent that can be saved as a result of using sootblowers more often and implementing new features designed into the NOxOUT System controls. Figure 8 shows daily reagent consumption for both baseline and demonstration periods as well as resulting yearly cost associated with reagent usage. Baseline reagent consumption without benefit of increased furnace sootblowing was about 2500 gal/day (an aveage of 104 GPH). It could be argued that historical reagent usage is higher than 2500 gal/day; consumption of 3000 gal/day is consistent with the Unit #3 share based on MW rating.

Increased sootblowing frequency allowed reagent consumption to be reduced to 1500 to 2000 gal/day before new system control features were implemented. Average reagent consumption was around 1920 gal/day (80 GPH) during the baseline, a reduction of at least 23% from the as-found NOxOUT System performance and 36% from historical values. Low furnace temperatures and system control improvements held reagent consumption between 650 and 1500 gal/day (27 to 62 GPH), a total reduction of 40 to 74%.

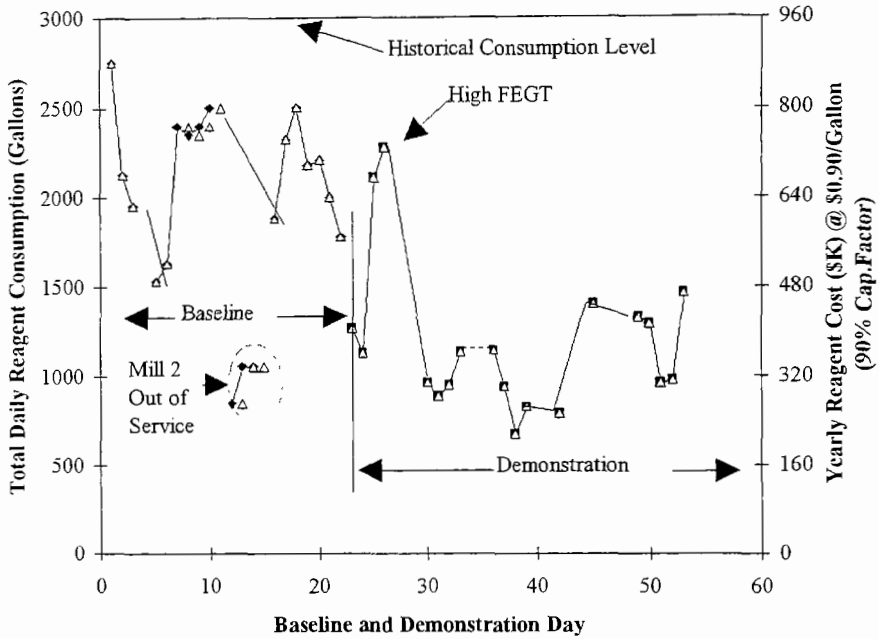

Figure 8. Daily reagent Consumption and Cost Estimate

Cost savings are achievable with minimal cost impact on boiler performance, but the increase in sootblowing resulted in a decrease in reheat steam temperature, especially on the north side of the unit. Occasional IR sootblowing for much of the baseline accompanied by blowing the reheater using retractable IK blowers prevented sudden decreases in reheat steam temperature.

Once NOxOUT System control modifications were implemented, response to furnace transients was improved. Figure 9 shows data from a rapid load reduction from about 130 MW to 70 MW within 30 minutes. Even though FEGT spiked when Mill 4 was removed from service, NOx held setpoint value of 0.315 lb/MMBtu except during a 15 minute span where even a reagent flow rate of 25 GPH was too high. These operating results are a vast improvement over baseline results from a similar transient shown previously in Figure 10.

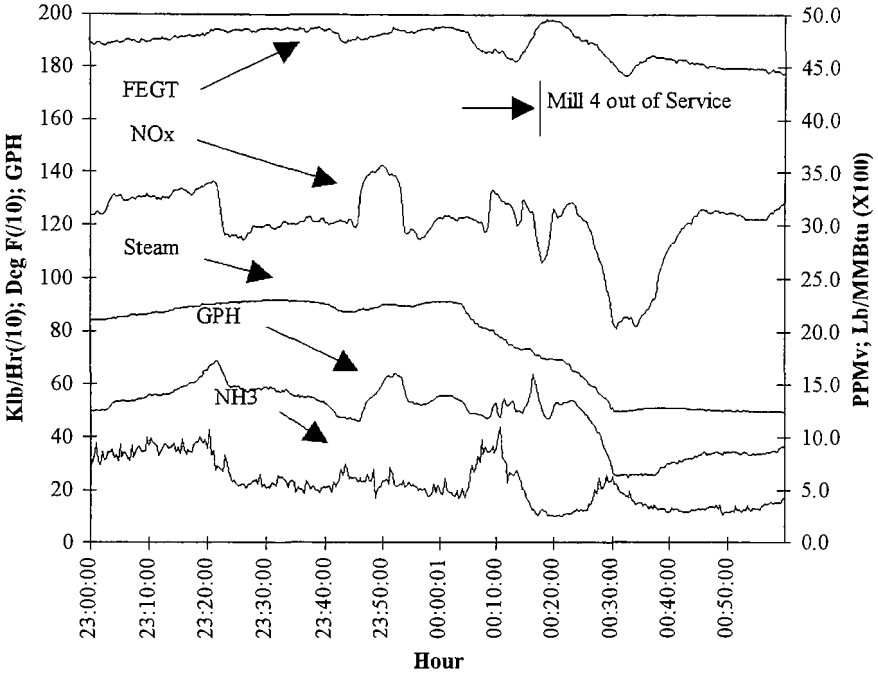

Figure 9. Load reduction transient after control improvements, 23 & 24 October 1996.

The demonstration period showed additional savings resulting from less reagent consumption. Average daily chemical consumption rates were controlled to the 30 to 60 GPH range for a total reduction in reagent consumption of 40% to 70%. Thus, about half the benefit was due to more frequent sootblowing and half was due to changes in the software and hardware. Reagent cost savings as a result of the NOxOUT System control upgrade realized on any particular day is very much dependent on the load profile. On average, the demonstrated savings were in the range of 25% over the 30-day period studied. This savings is estimated to be attributable as follows:

• Responsive feed forward signal upon load reductions	5%
• Better reagent distribution control	5%
• Relief of high load NOx setpoint	10%
• End-of-day trim	5%
Total:	25%

Figure 10 shows an estimated stoichiometric ratio as a function of load and reagent flow. It can be seen that at demonstrated reagent consumption rates, the NSR stays around 0.6 for all loads. Figure 11 shows data in mills/KWh.

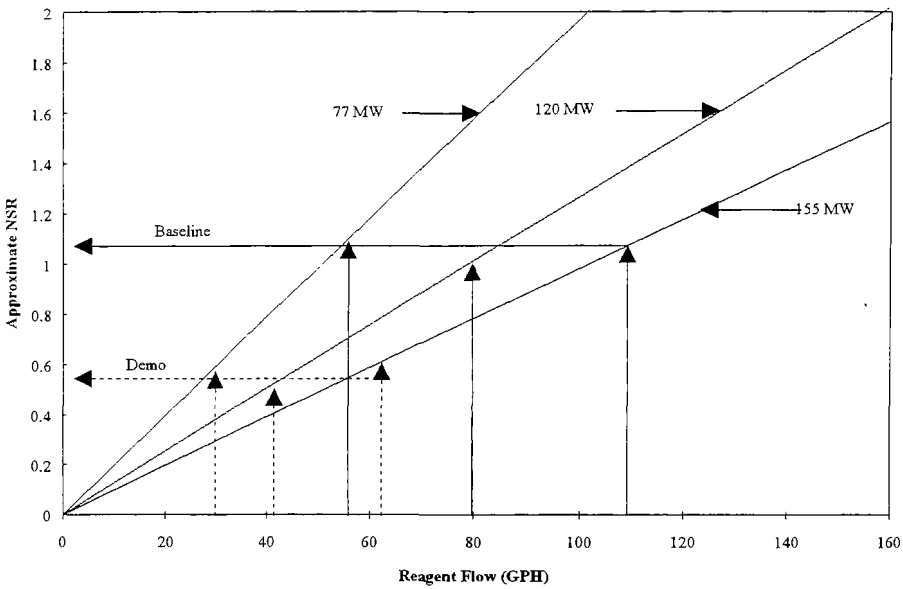

Figure 10. Normalized stoichiometric ratio (NSR) for Salem Harbor Unit #3

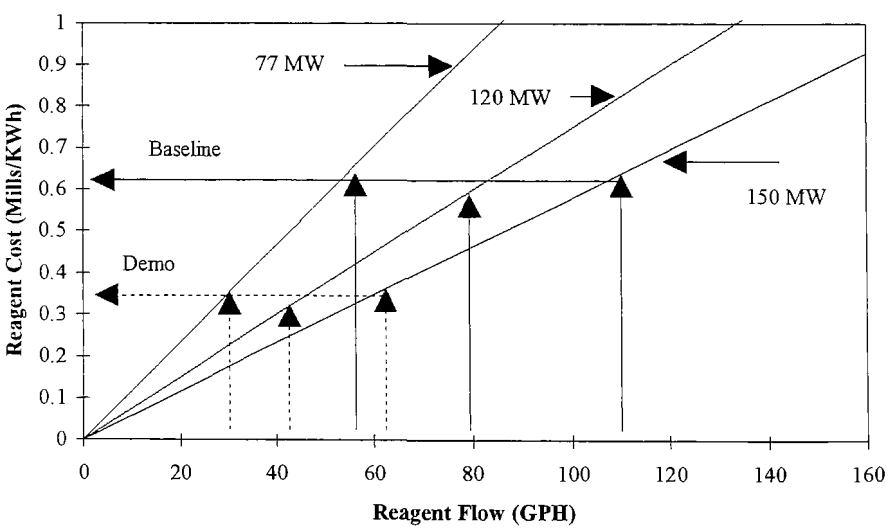

Figure 11. Reagent costs in mills/KWh

Derivation and Application of A Global SNCR Model in Maximizing NO_x Reduction

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ABSTRACT

Selective Non-Catalytic Reduction (SNCR) is one of the methods used in NO_x reduction for utility boilers. It has been found that if the SNCR is not well designed, operated, or installed, ammonia slips can be generated from SNCR. Although significant research has been conducted, no universal tool exists to optimize SNCR processes.

At Laboratories (PD&T) a global SNCR chemical kinetic scheme was used. The global HNCO kinetics was derived from about 327 elementary steps. The mechanism includes thermal NO_x, prompt NO_x, fuel NO_x, SNCR by ammonia, SNCR by urea, and reburning. A good agreement with the experimental data was found in calculating NO_x reduction by the mechanism. The main characteristics of SNCR process such as ammonia slip, temperature window effects, and NO_x generation were also demonstrated in the calculation. The global SNCR mechanism was applied to identify the keys in optimizing SNCR processes.

INTRODUCTION

Selective Non-Catalytic NO_x Reduction (SNCR) is a process in which a chemical reagent is injected into the post-flame region to reduce nitric oxides (NO_x) emissions. The ammonia-based SNCR process was first invented by Lyon (1978). EXXON and other companies subsequently developed a similar process using urea (H_2NCONH_2) as the reagent. SNCR processes have been widely implemented by industry as a low-cost NO_x abatement strategy. SNCR can be used in a stand-alone mode or in conjunction with other NO_x control processes such as the SCR process.

Chemical kinetics and fluid dynamics are two key factors that influence the efficiency of the SNCR process. The mixing rate of reagent with the exhaust gases plays an important role in providing the molecular contact of ammonia or urea with NO_x, and depending on the local temperature and species concentrations; the chemical kinetics of SNCR results in a certain amount of NO reduction. Therefore, the performance of SNCR processes strongly relies on the amount of reagent injected, the location and number of injector nozzles and the operating conditions of a boiler, such as load, fuel type, and excess-air level. The optimum performance level of an SNCR process will vary with operating conditions. Computer modeling of SNCR processes can be used to assist in the design of an SNCR system, and ultimately, to provide information to optimize SNCR operation for a given injection configuration.

A global SNCR chemical kinetic scheme is developed in this paper and implemented to a pilot scale facility (Figure 1). The global SNCR kinetic model was validated and applied to the PD&T's Boiler Simulated Facility (BSF) (Figure 2). The global kinetic rate constants of the ammonia-based SNCR process were obtained from the literature; three options of ammonia global chemistry were available (De Soete 1973, Duo et al. 1992). For a urea-based SNCR process, the decomposition of urea into ammonia and cyanuric acid (HNCO) must also be considered. In other words, the global pathway of the urea-based SNCR process must integrate ammonia chemistry with urea decomposition and HNCO kinetics in an appropriate manner. In this paper, global HNCO kinetic rate constants were correlated from detailed HNCO chemistry simulations by the CHEMKIN® program, a computer program utilized to calculate complex chemical kinetics (Kee et al. 1993). The global rate expression for the NO formation pathway is

$$r_{HNCO \rightarrow NO} = k_{HNCO \rightarrow NO} X_{HNCO} X_{O_2} \tag{1}$$

and the global rate expression for the NO reduction pathway is

$$r_{HNCO \rightarrow N_2} = k_{HNCO \rightarrow N_2} X_{HNCO} X_{NO} \tag{2}$$

where X_{HNCO}, X_{O_2}, X_{N_2}, and X_{NO} are molar fractions of species HNCO, O_2, N_2, and NO, respectively. The sensitivity of the SNCR submodel to aerodynamic patterns, species concentrations, and temperature was evaluated via a commercial CFD software package. The SNCR kinetic submodel was applied in a post-processing mode.

The velocity and temperature calculation were made by using the k-ε turbulence model. Species concentrations and reaction terms were calculated by employing the Magnussen Eddy Breakup Turbulence Model. Since the probability density function model doesn't account for the temperature effect, using the PDF (Probability Density Function) turbulence model produced very poor representation of SNCR kinetics-turbulence interactions. Hence the results represented in this paper have been obtained without using the turbulence model.

Three SNCR case predictions were compared with the test data from PD&T's Boiler Simulation Facility (BSF) corresponding to the aqueous urea mass in the injected reagent streams concentrations of 0.59%, 1.03%, and 1.44%. The three normalized stoichiometric ratios (NSR) of urea to untreated NO_x in the flue gas are 0.7, 1.21, and 1.7, respectively. The NO_x predictions were within 16% of the test data, and a similar agreement was observed in predictions of ammonia slip.

The SNCR global kinetic model was derived by the methodology developed by Chen et al. (1996), Chen et al. (1996), and Chen (1994). The comparisons of predictions and test data show that the global kinetics and correlated rate constants are appropriate. In the computational results, the strong dependence of SNCR processes on fluid dynamics has been illustrated and it indicates the potential application of the SNCR model to assist in the design and operation of the process. The rate constants of HNCO are correlated from limited simulations of HNCO chemistry. It has been observed experimentally that some major species such as H_2O, CO_2, and CO play a significant role in the SNCR processes under certain conditions. An assessment of the significance of those species should be studied systematically by using the CHEMKIN® program and other computer programs. The turbulence model in the commercial code does not include the temperature window, and the development of a turbulence model is also needed. The application and evaluation of the SNCR model is certainly helpful to gain more confidence in the SNCR model.

BACKGROUND

Chemistry schemes

Integration of chemical kinetics within a CFD computational code has proven to be a difficult task for many years. Primarily two types of chemical kinetics have been used: (1), elementary chemical kinetics, and (2), empirical kinetics by data correlation. The elementary chemical kinetics approach is more comprehensive and fundamental, and it may include hundreds of reaction steps depending on which chemical process is considered. The full SNCR mechanism includes more than 200 elementary steps and 50 species, consequently, to obtain species evolution profiles within a reasonable time, the calculation of reactions must be made by stand-alone computer codes such as CHEMKIN®. It is unrealistic to apply the elementary chemistry to CFD computations because the number of elementary steps and species requires substantial computer resources. Although some strategies, such as reduced mechanisms, have been used, empirical correlations are typically considered to be acceptable for CFD computations in industrial applications.

Typically, empirical correlation has been generated from test data gathered from perfect stirred reactors (PSR), or laminar premixed reactors. The generation and application of empirical correlations has always been favored in industry because of the simplicity of directly extracting the correlation data from the test facilities. The accuracy of empirical correlation has oftentimes been questioned because the results may include some fluid dynamic or mixing effects. A combination of elementary kinetics and empirical correlation, as proposed in this paper, may overcome some of the disadvantages of both schemes.

SNCR elementary kinetics

In the last decade, significant progress has been achieved in understanding NO_x and SNCR chemistry. In NO_x chemistry, there are numerous intermediate species and radicals that can significantly affect the product distribution. Miller and Bowman (1989) compiled about 200 elementary steps for nitrogen chemistry in conjunction with O, H, OH, and simple hydrocarbon reaction steps. NO_x is formed in combustion predominantly via three distinct mechanisms: thermal-NO, prompt-NO, and fuel-NO. When an appreciable amount of fuel nitrogen exists as for example in coal combustion, fuel-NO is dominant in NO formation. The fact that fuel nitrogen does not convert to NO completely indicates that the reaction rates of competitive reaction steps are comparable in NO_x formation. Therefore, reaction conditions may be controlled to favor low NO_x formation or even NO_x reduction.

Several reaction pathways have been identified that contribute to NO_x reduction. One of these involves the conversion of NO_x to nitrogenous intermediates, which under certain conditions produce N_2, rather than NO_x. Because of the high activation energy required to oxidize N_2, a portion of the intermediate nitrogenous species is reduced preferably to N_2. In Selective Non-Catalytic NO_x Reduction (SNCR), ammonia or urea is introduced to reduce NO_x chemically to N_2 by amine radicals (NH_i) and cyanuric nitrogen radicals (HNCO) (Miller and Bowman 1989, Glarborg, et al. 1994).

At temperatures above 600 K, ammonia dissociates into amine free radicals by the following reaction steps (Miller and Bowman 1989)

$$NH_3 \rightarrow NH_2 + H \qquad (3)$$

$$NH_2 \rightarrow NH + H \qquad (4)$$

and the conversion of NH_3 to final products NO and N_2, the major routes from elementary chemical steps have been identified as follow

$$HNO + OH \rightarrow NO + H_2O \quad (5)$$

and

$$NH_2 + NO \rightarrow NNH + OH \quad (6)$$

or

$$NH_2 + NO \rightarrow N_2 + H + OH \quad (7)$$

In the temperature range of interest (900 K-1350 K), the rates of reactions (5), (6), and (7) are of the same order of magnitude, and reactions (5) and (6) are competitive steps in the formation or reduction of NO. At low temperatures, the reduction steps (6) and (7) have slightly higher reaction rates, and the overall outcome favors NO_x reduction When the temperature is above 1300 K, NO formation reaction (5) is dominant (Miller and Fisk 1987, Miller and Bowman 1989). The competition of the formation and reduction rates of NO_x results in a bell-shaped effect of temperature on NO_x reduction. At lower temperatures, the reduction reactions (6) and (7) are dominant and NO reduction rate increases with temperature; at about 1250 K, formation rates from reaction (5) become significant, and NO reduction rate decreases. Hence, a maximum NO reduction at about 1250 K is observed.

The urea-based reagent dissociates to the primary reactants, i.e., ammonia (NH_3) and isocyanic acid (HNCO). The chemistry of the urea-based SNCR process has temperature characteristics that are similar to those of the NH_3-based SNCR process. A slightly-wider temperature window has been observed in the case of the urea-based process (Teixeira and Muzio 1987). The NH_3 derived from the urea follows the same reaction pathways as given previously in reactions (5), (6), and (7). About 70% of the total HNCO released from urea is postulated to form NCO, then to N_2 and NO_x by reactions (8)-(11), (Lyon and Cole 1990, and Caton and Siebbers 1990)

$$HNCO + OH \rightarrow NCO + H_2O \quad (8)$$

$$NCO + O \rightarrow NO + CO \quad (9)$$

$$NCO + NO \rightarrow N_2O + CO \quad (10)$$

$$N_2O + M \rightarrow N_2 + O + M \qquad M\text{=third body species} \quad (11)$$

Since NCO reacts with both NO and O, to form N_2 and NO, respectively, HNCO ultimately contributes to the reduction and formation of NO_x depending upon reaction conditions such as concentrations and temperature. Caton and Siebbers (1990) reported that the temperature window for NO_x reduction of HNCO is from 820 to 1340 K; Jodal et al. (1990) reported that temperature window of urea is from 1023 K to 1373 K, and, furthermore, found a significant amount of N_2O (up to 85 ppm) in the products. Some elementary HNCO steps were also added by Lyon and Cole (1990) and Glarborg et al. (1990), to the SNCR mechanism and the simulations showed significant improvement in predictions with experimental data steps (Lyon and Cole 1990, Glarborg et al. 1990).

In recent years, significant progress has been made in understanding ammonia and urea chemistry. It is now well-known that ammonia and urea SNCR processes have similar characteristics, such as a defined temperature window and a characteristic ammonia slip, although they have different reaction sequences. Urea may have a slightly wider temperature window, with a temperature range about 50 K higher.

Ammonia global kinetics

An empirical global rate for SNCR kinetics should represent the basic characteristics of an SNCR process, which include

1. Temperature window effects
2. NO_x and oxygen concentration effects
3. Reagent concentration effects
4. Ammonia slip
5. Effects of additives

Normally, these characteristics, combined with an analysis of fundamental chemistry, constitutes the basis of an empirical or global kinetic rate expression formulation. De Soete (1973) conducted premixed flow tests by adding ammonia into premixed flames; H_2, CH_4 and C_2H_2 were used as fuel and NO was also added in some tests. Through his tests, De Soete hypothesized two competing reaction steps in ammonia global reactions, and the rate constants were correlated from his measurements (De Soete 1973)

$$r_{NH_3-N_2} = k_{NH_3-N_2} X_{NH_3} X_{NO} \tag{12}$$

$$r_{NH_3-NO} = k_{NH_3-NO} X_{NH_3} X_{O_2} \tag{13}$$

After years of research in ammonia chemistry, another set of global NH_3-NO reaction rates were developed specifically for an ammonia-based SNCR process by Duo et al. (1992). The correlation was made from premixed reacting flow data conducted by Duo et al. (1992), in which the constant reactor temperature was controlled between 1140 K and 1335 K at inlet concentrations of 5.16×10^{-3} mol/m^3 of NO, 8.45×10^{-3} mol/m^3 of NH_3 and 0.405 mol/m^3 of O_2. The volume fractions of reactants were varied by adjusting the mass flow rates of reactants at the inlets. Unfortunately, although the urea-based SNCR process had been used for years, no global HNCO correlation was found in the literature.

In summary, several global rate expressions and rate constants for ammonia-based SNCR processes have been identified in the literature. However, rate expressions and rate constants for the global HNCO pathway have not been found and the development of the global HNCO pathway is needed to complete the SNCR model.

GLOBAL HNCO KINETICS

Two approaches are available to obtain a global HNCO rate constant: (1) correlate the rate constants from *experimental data*, or (2) to correlate the rate constants from *computed species profiles* using the CHEMKIN® program with elementary chemical reaction steps. The later option was chosen in this case simply because of the excessive time and cost required to collect experimental data. Global kinetic rate constants are typically correlated from perfect stirred reactor data/calculation or premixed reacting flow reactor data/calculations to minimize the mixing effects. The CHEMKIN® library of software programs was developed for this purpose and is appropriate to be used for those simulations (Kee et al. 1993).

Formulation of rate expressions

To correlate a global rate constant, a postulated or presumed rate expression must be formulated, and then the dependence of the rate constant on species concentrations can be established. Based on the study of NO_x and SNCR elementary chemistry elucidated above,

the formulation of urea and HNCO rate expressions is somewhat intuitive. Basically, three rate expressions are hypothesized; the urea dissociation step, the HNCO oxidation step, and the HNCO reduction steps. The urea dissociation rate is an initiation rate for the reactions, and following the dissociation of urea, there are four parallel reactions, two global NH_3 pathways (i.e., reduction and oxidation), and two HNCO pathways. The rates from either De Soete (1973) or Duo et al. (1990) may be used for the global NH_3 reactions. Two parallel reaction rate constants of HNCO are correlated later in this section.

Dissociation rate When heated, urea dissociates into various products at different temperature levels. At temperatures below 80 C, urea forms cyanuric acid and carbon dioxide at a relatively slow rate:

$$6(H_2N\text{-}CO\text{-}NH_2) \rightarrow C_3N_3(NH_2)_3 + 3CO_2 \qquad (14)$$

When the temperature is increased above 80 C, ammonia is released quickly via the expression:

$$3(H_2N\text{-}CO\text{-}NH_2) \rightarrow C_2N_3(OH)_3 + NH_3 \qquad (15a)$$

At temperatures above 200 C, the dissociation of urea proceeds quickly and only HNCO and NH_3 are produced:

$$H_2N\text{-}CO\text{-}NH_2 \rightarrow HNCO + NH_3 \qquad (15b)$$

Since the temperature is well above 200 C in the post-combustion region, only the dissociation rate for reaction (15b) is considered in this effort, and it can be formulated as follow,

$$r_{urea} = k_{urea} C_{urea} \qquad (16)$$

where C_{urea} is the molar concentration of urea in the gaseous phase.

HNCO->NO reaction rate HNCO formed from dissociation of urea reacts with oxygen to form NO_x as described in reactions (8) and (9).

By assuming that oxygen dissociation and HNCO to NCO are fast reactions, the global rate expression of HNCO oxidation to NO is readily available from reaction steps (8) and (9)

$$r_{HNCO-NO} = k_{HNCO-NO} C_{HNCO} C_{O_2} \qquad (17)$$

where C_i is the molar concentration of species I. Alternatively, Eq. (17) can be expressed in terms of mole fractions

$$r_{HNCO-NO} = k_{HNCO-NO} X_{HNCO} X_{O_2} \qquad (18)$$

HNCO->N_2 reaction rate From reactions (8), (10), and (11), again with a similar assumption made for the oxidation step, the global HNCO reduction rate expression can be written as follows:

$$r_{HNCO-N_2} = k_{HNCO-N_2} C_{HNCO} C_{NO} \qquad (19)$$

or write in a mole fraction form

$$r_{HNCO-N_2} = k_{HNCO-N_2} X_{HNCO} X_{NO} \tag{20}$$

Correlation of rate constants

In the present method, the global rate constants were correlated by utilizing the species concentrations and first derivatives of the species concentrations with time (i.e., the effective rates) from CHEMKIN® simulations (Figure 3).

Dissociation rate constants The rate constants of urea dissociation were correlated from the experimental data published by Siebbers and Caton (1992).

HNCO->N_2 reaction rate constants The global reduction rate of HNCO to N_2 was correlated from the CHEMKIN® simulations of elementary kinetics. The simulations were conducted at a temperature from 700 K to 1700 K, 0.0 to 2500 ppm of CO, 0.0 to 20% of O_2 concentrations, and 1E-5 to 0.1 sec of residence time. The NO level and HNCO level were maintained at 400 ppm and 480 ppm, respectively. The species profiles for the global reduction rate constants were obtained by assuming the similarity of ammonia global kinetics and HNCO global kinetics (Figures 3 and 4).

HNCO->NO reaction rate constants The species profiles for the global oxidation rate constants were obtained by assuming the similarity of ammonia global kinetics and HNCO global kinetics.

VALIDATION AND APPLICATION

Several 2-D and 3-D cases of BSF tests were simulated at PD&T in 1992 (Rini et al. 1993) in which the flow effects and reagent distributions were investigated (Figure 5). In their study, the HFOP inlet flow mal-distribution had a significant impact on the injection process, and a massive recirculation zone over the arch appeared to capture a large amount of the reagents injected. However, the reagent injected near the top of the upper furnace was characterized by a short residence time and was quickly exhausted from the domain (Rini et al. 1993). The simulations from 3-D non-isothermal cases exhibited results similar to the 2-D cases. The chemistry modeling effort consisted of an "idealized" 90-step mechanism solved by CHEMKIN®. No mixing coupling between the flow modeling and chemistry modeling was reported. (The use of a 90-step mechanism within the context of a CFD code should be considered to be computationally prohibitive).

The flow field investigation by Rini et al. (1993) emphasized the significance of the coupling of the SNCR chemistry and the flow field. In this context, the development of the global SNCR kinetic model may be considered to be a continuation of the 1993 effort. In the present study, the global SNCR model was applied to the BSF upper furnace. The global kinetic model was tuned in order to promote greater predictive confidence in the application of the SNCR model to industrial problems..

The BSF upper furnace case has 42x72x120 cells and the species profiles computed from the BSF lower furnace case were patched at the inlet cross section of the BSF upper furnace (Figure 6). The temperature was corrected accordingly to match the measurements from BSF tests because the SNCR kinetic model was very sensitive to local temperature. Three NSRs (normalized stoichiometric ratio) were computed and used as the baseline cases to tune the SNCR model. The definition of NSR was given by Rini et al. (1993) as

$$\text{NSR} = \text{inlet urea mole fraction/inlet } NO_x \text{ mole fraction} \tag{21}$$

Three NSR levels were tested 0.7, 1.21, and 1.7, corresponding to mass fractions of urea as 0.59%, 1.03% and 1.44%, respectively (Figure 7). A mass weighted average temperature at the inlet cross section was constant in the three cases set at 1630 K, and the oxygen concentration was maintained at 3.2%. Although the predictions gave a reasonable trend, some discrepancies existed when the global reaction rate constants from this study were used. After a careful review of the SNCR model integrated in the commercial CFD program, a tuning of kinetic rate constants was made to match the test data. The predictions by the original and tuned rate constants, and the experimental data are tabulated below

NSR	*NO_x (ppmv) (Original rate constants)*	*NO_x (ppmv) (Tuned rate constants)*	*NO_x (ppm) (Experimental data)*
0.71	162	134.8	115
1.21	103	92.3	85
1.7	89.7	83.4	75

In Figure 7, comparisons of NO_x and NH_3 are illustrated, and the error of NO_x predictions is from 16% to 9%. Comparisons show a good trend in the agreement of ammonia slip and NO_x reduction dependence on the amount of reagent injected. NO_x predictions showed satisfactory levels while ammonia was under-predicted (Figure 7). A parametric CFD calculation was conducted to assess the sensitivity of the global SNCR kinetic model (Figures 8, 9, 10, 11). Furthermore, fluctuation of the measurements of ammonia slip was observed under the same test conditions. Under the same test conditions, the spikes of ammonia concentration were observed up to 53 ppm (Rini et al. 1993).

SUMMARY

The SNCR processes have been commercially applied in the abatement of NO_x emissions of boilers. However, the performance of an SNCR system relies on many factors, as indicated in the literature. The motivation to understand those factors has two-fold: 1. to reduce by-products such as NH_3 and N_2O, and 2. to achieve the maximum NO_x reduction. Computer modeling of an SNCR process can assist the understanding thereof at a relatively lower cost.

The key of modeling an SNCR system is the formulation of a chemical kinetic model. In this project, a global chemical kinetic model was developed to include both NH_3 and urea reagents. The global rate constants of HNCO were correlated from simulations of elementary nitrogenous chemical steps. The global SNCR model was integrated into the commercial CFD computer program as a post-processor, and the coupling of transport effects and kinetic effects can be investigated. A substantial effort has been made to debug and test the SNCR model and a tuning of the global rate constants of HNCO was made to 'best-fit' the measurements on PD&T's BSF. The comparisons of predictions and data show that the SNCR model appropriately reflects the characteristics of a SNCR system with regard to temperature window and ammonia slip.

As with all mathematics models, limitations exist in the SNCR model and further development of the SNCR model is needed. The global rate constants of the SNCR model are correlated under certain reaction conditions. The tests and simulations for NH_3 and HNCO rate constants were done at a high NO_x level and oxidized environment. Although those rate constants can be further evaluated by the method used, it is suggested that the SNCR model be used when NO_x level is not very low (>100 ppm) and in an oxidized environment.

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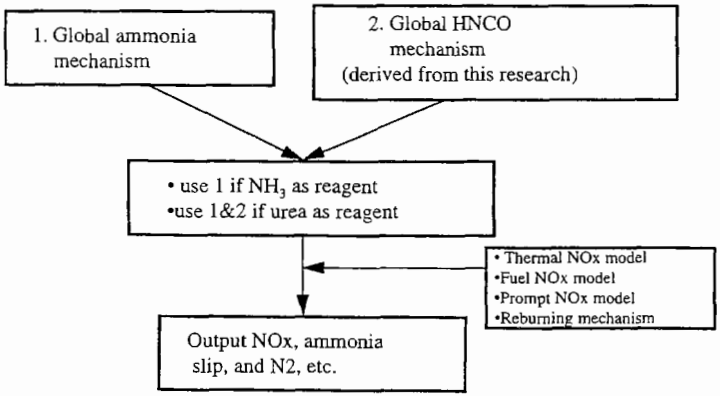

Figure 1 Global SNCR Kinetic Model

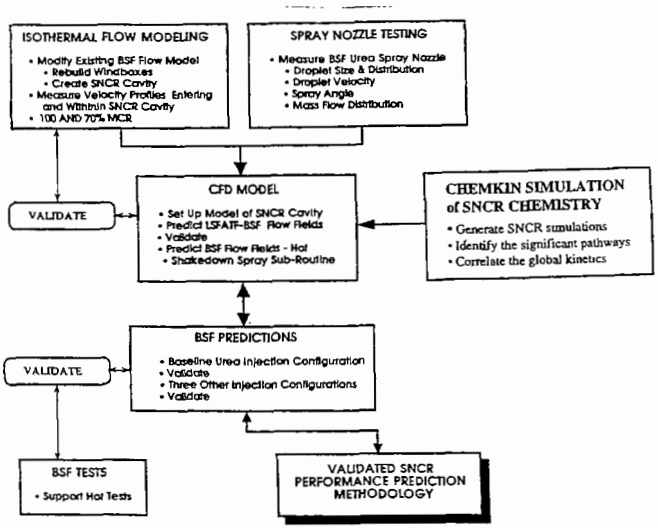

Figure 2 Derivation and Validation of Global SNCR Kinetic Model

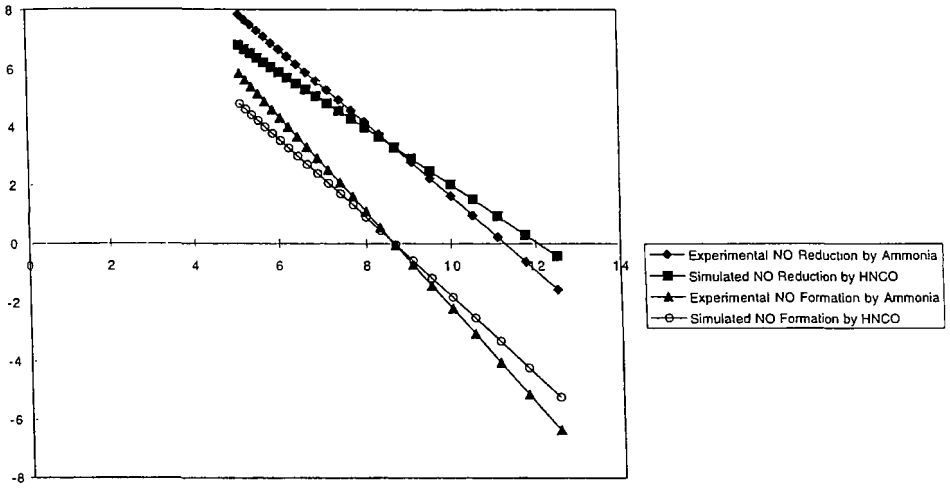

Figure 3 Correlation of HNCO rate Constants

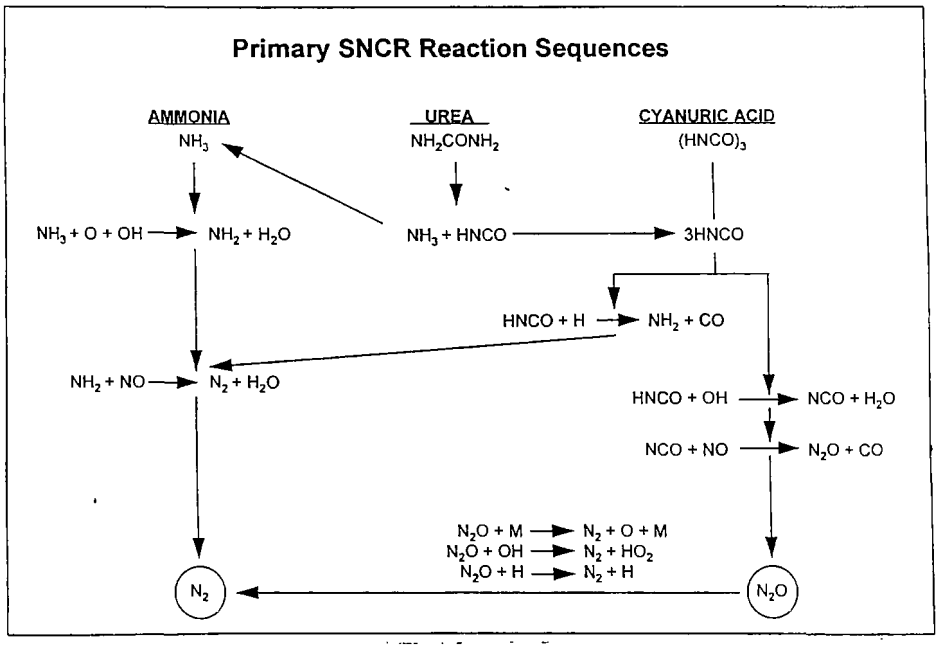

Figure 4 SNCR Pathways

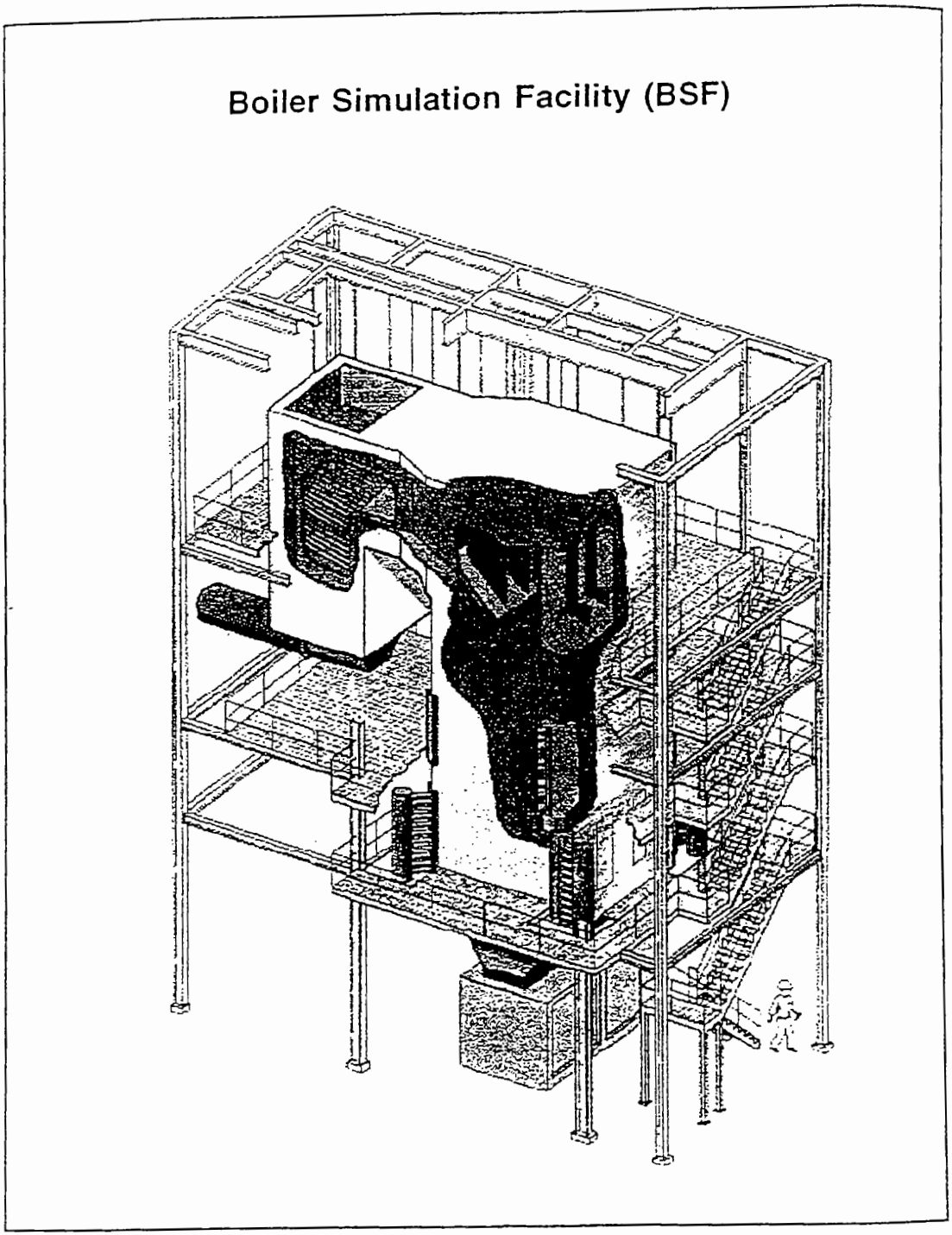

Figure 5 Boiler Simulated Facility (BSF)

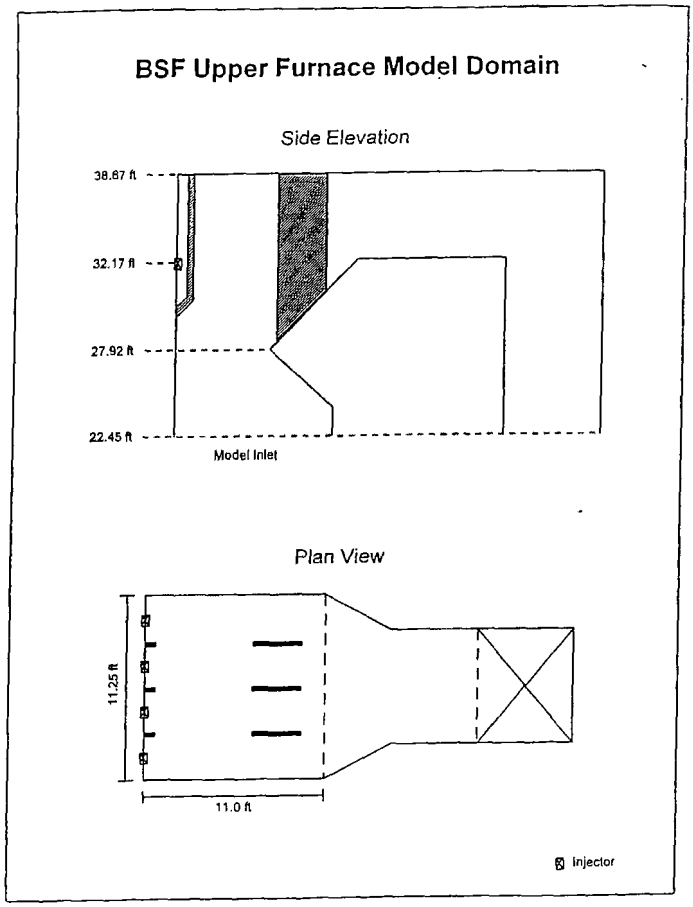

Figure 6 BSF Computational Model

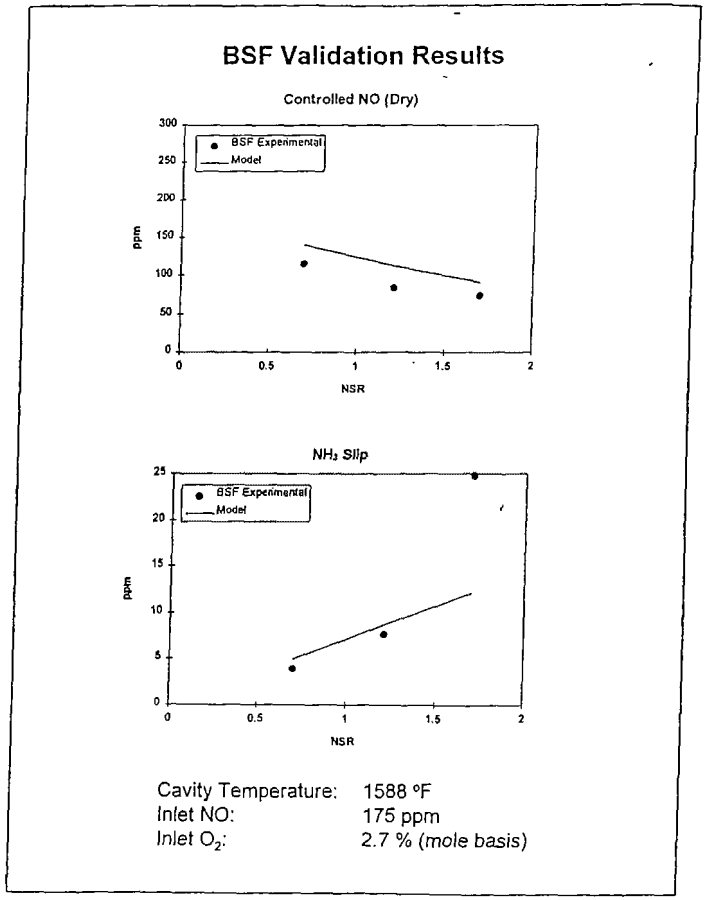

Figure 7 Global SNCR Model Validation

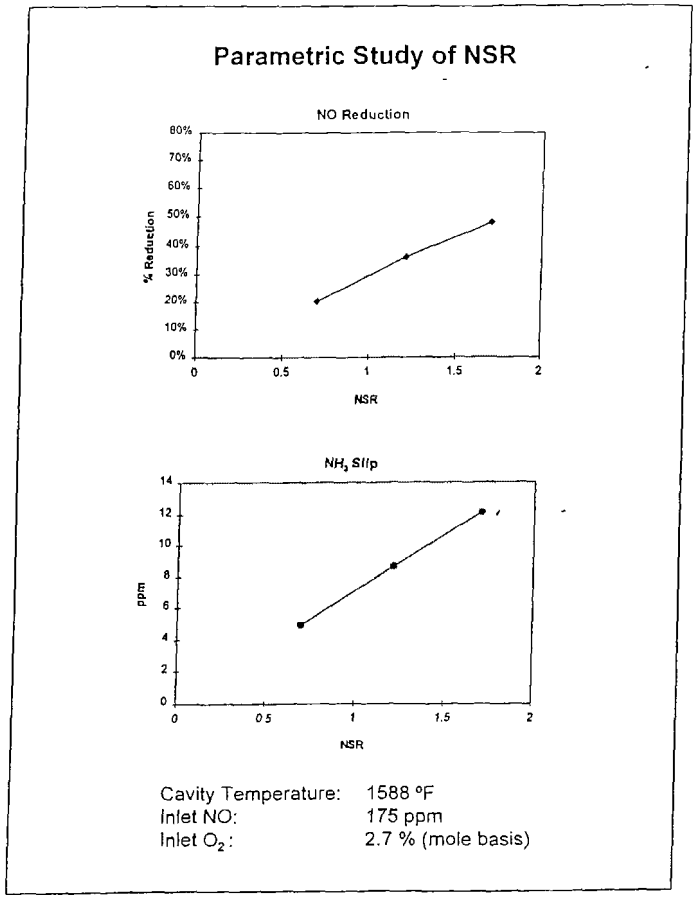

Figure 8 Parametric Study of NSR

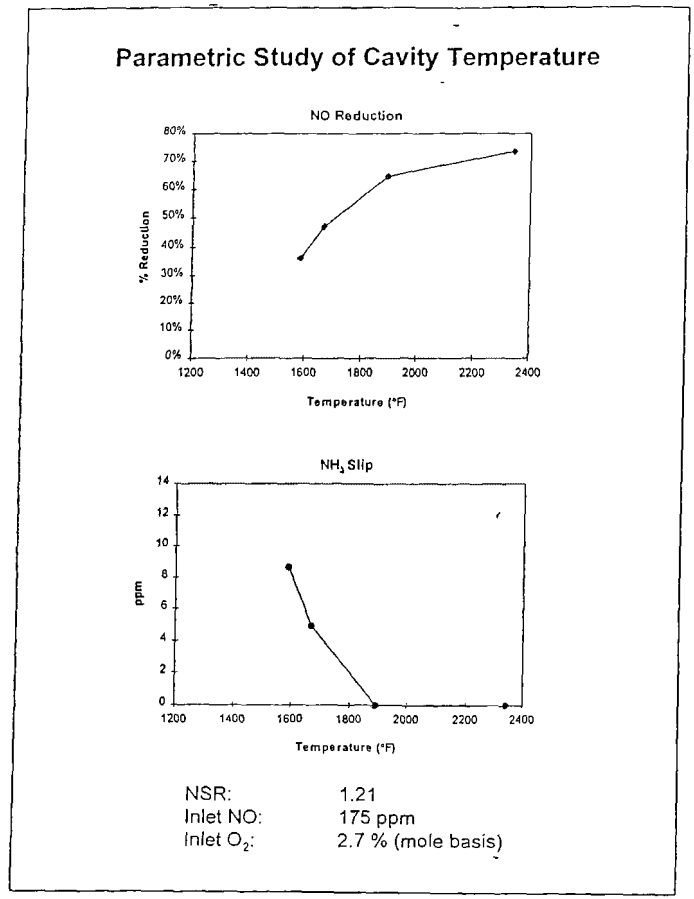

Figure 9 Parametric Study of Cavity Temperature

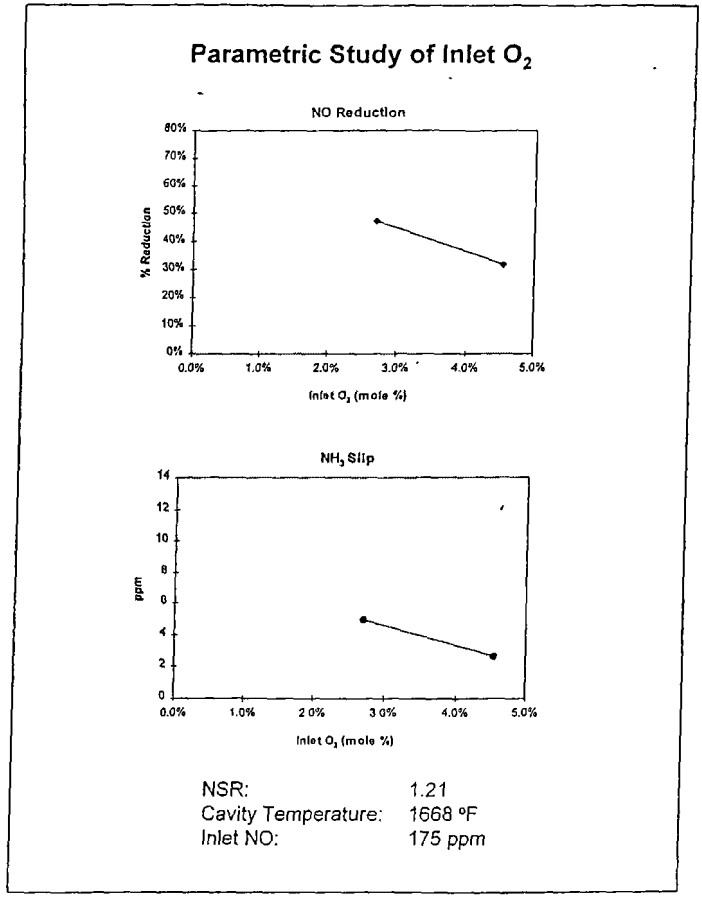

Figure 10 Parametric Study of Inlet O_2

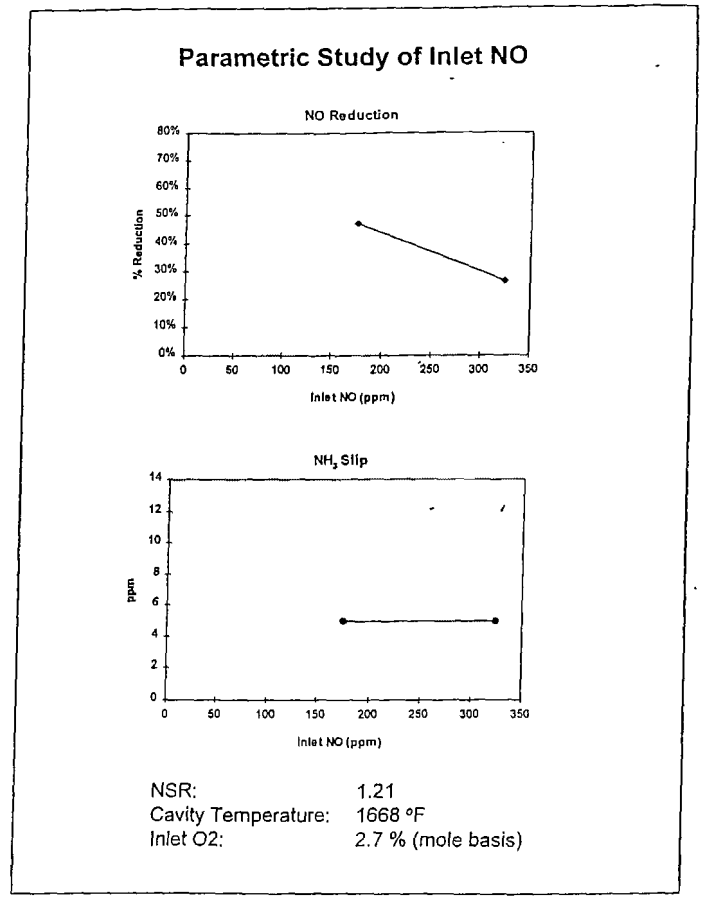

Figure 11 Parametric Study of Inlet NO

In Field Results of SNCR/SCR Hybrid on a Group 1 Boiler in the Ozone Transport Region

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Abstract

A full scale SNCR/SCR Hybrid system, NOxOUT CASCADE, has been designed and is being installed at the GPU GENCO Seward Station, Unit #15 boiler. The Seward Station hybrid system is a combination of a redesigned existing SNCR with a new downstream SCR. Significant improvements in chemical utilization and overall NOx reduction have been seen in preliminary testing of the SNCR when ammonia slip was permitted to increase above normal operational limits.

The integrated system was designed using advanced computational fluid dynamics and cold flow modeling techniques. The units two air pre-heater ducts were retrofit with different types of catalyst, honeycomb in one and plate in the other. Reactor and duct internals were designed to compensate for an existing ash loading imbalance, temperature and velocity variation, and a difference in the SCR pressure drop between the two ducts.

Introduction

The Clean Air Act Amendments of 1990 have given rise to a wave of technology development that anticipates meeting clean air challenges. In the first half of this decade, the U.S. witnessed the retrofit of low NOx burners on coal, oil, and gas-fired boilers. Additionally, there were new developments in air staging technologies, gas reburn demonstrations under the Clean Coal Technology Program, in-field applications of SNCR retrofit on various types of utility boilers, and even a retrofit application of SCR on a cyclone coal-fired boiler. Industry observers predict large costs will be borne by major sources to meet the air quality goals in some Phase II provisions of the Act. In preparation for "life beyond Phase I," field development is now being focused on effective combinations of NOx controls. Potentially, two or more available means of

NOx control can be compatibly combined to reduce NOx wherein the end result is more cost effective than the sum of its parts. Hybrid combinations of SNCR and SCR are a particularly flexible method for effecting moderate to deep reductions of NOx at cost ranges typically below those of a fully-engineered SCR retrofit.

This paper presents a discussion of the implementation of a SNCR/SCR hybrid at the GPU GENCO Seward Station and the expected increase in NOx reduction performance and chemical utilization. The design was based on minimizing the total life cycle cost while achieving the required control.

Cascade Methodology and Theory

NOxOUT CASCADE® is a combination of a redesigned SNCR and downstream SCR, hybridized to provide improvements in chemical utilization and overall NOx reduction. The two NOx reduction technologies each provide process strengths which make the hybrid combination more flexible and effective than the sum of its parts.

Selective Non-Catalytic Reduction (SNCR) is typically applied in the furnace, where relatively high temperatures serve to initiate the breakdown of urea to form the transient species which lead to effective NOx reduction. The technology is limited to temperatures high enough to insure very low ammonia breakthrough. At very high furnace temperatures, however, performance can be lessened by competing reactions which either consume effective chemical or lead to NOx formation. Modified SNCR takes advantage of a downstream "ammonia sink" by injecting chemical in cooler regions where NOx reduction and chemical utilization improve dramatically.

Selective Catalytic Reduction (SCR) is typically performed in much cooler flue gas passes where the oxidation potential of nitrogen species is minimized. The catalytic surface provides sites which permit the ammonia and NOx to react at nearly perfect utilization. The extent of NOx reduction is limited by the local ammonia to NOx ratio, the flue gas temperature, and the size of the catalyst reactor. The catalyst size is limited by the available space, an increase in pressure drop, the oxidation of SO_2 to SO_3, and the cost of the precious metal components.

NOxOUT CASCADE® utilizes lower temperature SNCR injection to provide substantially improved NOx reduction performance while generating somewhat higher ammonia slip. The ammonia slip feeds a small SCR reactor which removes the slip and reduces NOx while limiting the costs associated with a larger catalyst. For example, a CASCADE system which achieves 65% overall NOx reduction (50% reduction with SNCR and an additional 30% SCR reduction) requires less than one third the catalyst required for 65% SCR reduction. The smaller catalyst converts proportionally less SO_2 to SO_3 and decreases the pressure drop by the same fraction.

System Design

Hybrid SNCR/SCR NOx reduction systems can be engineered in several forms. Clearly, it is possible to install a commercial SNCR system for furnace reductions of NOx, and install a

commercial SCR system downstream of the economizer on the same unit for removal of the remaining NOx, and enjoy deep levels of NOx reduction with the combined system. For the purpose of semantic clarity, one might consider the foregoing system "combined SNCR/SCR" while reserving the "hybrid" description for units which utilize the ammonia slip from the SNCR process as the sole NOx reductant entering the downstream SCR.

Hybridized SNCR/SCR can assume several configurations depending upon the level of overall NOx reduction desired and unit configuration. Both factors combined lead to differences in catalyst dimensions and, therefore, catalyst contributions to the total capital requirement. Various configurations for consideration would be SNCR with:

- catalytic air heater
- "in-duct" SCR-existing duct dimensions
- "in-duct" SCR-expanded duct dimensions
- reactor-housed SCR
- combination of "in-duct" SCRs with catalytic air heater

Prior literature[1] surveyed the above combined technologies listing benefits and potential drawbacks of combining the technologies. It primarily reported from a technological feasibility viewpoint where a specific requirement for SCR is presumed. It is important to view the potential application of hybridized SNCR/SCR from an economic standpoint, particularly in the case where combustion modifications have already been employed.

Besides assuming several physical configurations, hybrid SNCR/SCR can be operated in different ways. Among the many considerations for the choice of designated hybrid operation are:

- What is the desired level of NOx reduction?
- What are the NH_3 slip and SO_2 oxidation constraints?
- What volume catalyst can fit in the existing ductwork where face velocity will be within catalyst manufacturer specifications?
- What level of additional pressure drop is tolerable by the present fan?
- Are NOx reduction requirements incremental?
- What structural steel/ductwork changes must be made to support the catalyst?
- What is the expected/guaranteed life of the catalyst?
- What deviation from ideal reductant distribution is tolerable for the NOx limit?

It is obvious that total capital requirement for the catalyst retrofit will increase as the catalyst size and retrofit complexity increase. The key to minimizing life cycle NOx reduction costs is to find the appropriate balance between annualized capital charges and operating costs for the remaining life of the system. The challenge for SCR retrofit is to minimize the capital requirement. The challenge for SNCR use is minimization of reagent required. Designing hybrid SNCR/SCR systems suggests optimization of these costs over the life cycle for a specific level of NOx reduction

Chemical Utilization

In post-combustion NOx control processes, NOx reduction is achieved at a given Normalized Stoichiometric Ratio, or NSR. Simply put, NSR refers to the ratio of chemical reductant applied to the amount of NOx existing in the flue gas. With SCR, ammonia is typically the reductant and is typically applied at an NSR of one for deep reductions. In other words, one mole of NH_3 is applied per mole of NOx. If only a 75% NOx reduction was required, the NH_3 NSR would be approximately 0.75. In non-catalytic systems, the reductant is applied in broader ranges of NSR because of relatively lower NOx reduction efficiency compared to catalytic systems. In commercial practice, NSRs range from 0.6-2.0. When urea is used for SNCR systems, an NSR of 1.0 means 0.5 mole urea is applied for 1.0 mole NOx because urea has two nitrogen moieties for reaction with NOx.

Chemical utilization is a quantification of NOx reduction efficiency expressed by:

$$\text{Utilization} = \text{NOx Reduction [\%]} / \text{NSR}$$

In other words, if each lb-mole of injected urea or ammonia reduces NOx to the theoretical maximum amount[2], utilization is 100%. One hundred percent chemical utilization is approached in SCR systems, but in SNCR system values range from 30-60%. In commercial post-combustion NOx control systems, maximizing utilization, all other things being equal, minimizes life cycle operating costs.

Figure 1 schematically depicts the enabling effect of downstream catalyst (down-sized or otherwise) on SNCR performance in a hybrid system. SNCR NOx reduction occurs in a defined temperature window, roughly bell-shaped with maximum SNCR NOx reduction occurring at the top, or plateau of the bell. In a commercial "stand-alone" SNCR system, performance is optimized by operating at the "right side of the slope" in the temperature window curve[3] (in Area A). In this region, the hot side of the performance maximum, ammonia slip is very low or non-existent. This is often an operating constraint imposed by the source owner. In contrast, the SNCR component of the hybrid system operates best at the plateau which is lower temperature. In this region (Area B), SNCR NOx reduction is higher and some ammonia slip is produced. The ammonia slip is available to reduce NOx in a catalyst system downstream. When operated in this manner, SNCR NOx reduction is maximized (compared to its stand-alone performance) and additional NOx reduction occurs in the catalyst portion, fueled by the generated ammonia slip.

Hybrid systems can be designed to operate in the cooler zone (Area C - the "left side of the slope") which will produce more ammonia slip than the other regions. In this scenario, SNCR NOx reduction is less than maximal and SCR NOx reduction increases until limited by catalyst space velocity. Overall system NOx reductions beyond 75% would typically require this type of operation and require catalyst reactor dimensions that would not be possible to fit in existing duct space.

Hybrid systems can be designed to maximize SNCR performance while "existing duct" SCR controls the ammonia slip (Area B). Reagent utilization for NOx reduction can increase dramatically compared to stand-alone SNCR because of the reasons stated above. Therefore, reagent cost per unit of NOx reduced is lower with the hybrid system than with stand-alone SNCR. Current operators of SNCR systems consider these questions in the design stage for prospective hybrid systems:

- What is the expected additional reduction of NOx for a constant urea (reagent) flow?
- What is the expected reagent flow reduction for constant NOx reduction?

Field Testing

The NOxOUT SNCR/SCR Hybrid process was tested at Public Service Electric and Gas, Mercer Station[4]. The unit, which had an existing SNCR system, was partially retrofitted with an expanded duct catalyst as part of a study of SCR, combined SNCR-SCR, and Hybrid SNCR/SCR. In this preliminary work it was shown that deeper than design reductions in NOx were possible through modification of the SNCR system with less than design chemical (urea) flow rates. This was achieved by decreasing the effective chemical release temperature in the furnace.

The by-product of this temperature shift, excessive ammonia slip, was utilized in the SCR reactor where further NOx reduction was achieved and ammonia slip levels were reduced to within acceptable limits. Although the SCR reactor was large enough to provide greater than 85% NOx reduction on its own, it was shown that ammonia and NOx distributions to the catalyst were sufficiently uniform to allow for a substantial reduction in catalyst volume without adversely affecting the process.

The next logical step in the development of SNCR/SCR hybridization is full-scale application to a utility boiler with a small catalyst used primarily for ammonia slip control.

GPU GENCO - Seward Station

A Hybrid SNCR/SCR system has been designed for GPU GENCO, Seward Station, Boiler #15. This unit is a Combustion Engineering, coal burning, tangentially fired boiler rated at 148 MW gross electrical output, Figure 2. Current minimum load is 106 MWg, but it may become necessary to operate at loads as low as 74 MWg (50% MCR).

A commercial NOxOUT® SNCR has been installed at Seward Station. The system provided the required NOx reduction from a 1990 baseline of approximately 0.78 lb/10^6 Btu to 0.45 lb/10^6 Btu with less than 5 ppmv slip. High concentrations of SO_2, and therefore SO_3, as well as cool air pre-heater exit temperatures combined to make this installation particularly sensitive to

ammonium salt formation. It is currently being operated at reduced efficiency (approximately 0.5 lb/10^6 Btu) to produce less than 2 ppmv ammonia slip. As much as 75% of the chemical is injected into the furnace where utilization is relatively low. The remaining chemical is injected behind the super heater tubes, above the arch, through multi-nozzle lances which provide excellent chemical distribution and extremely high chemical utilization.

This unit is an excellent candidate for hybrid SNCR/SCR reduction. Using the cooler zone alone in limited testing, deep reductions in NOx have been possible with decreased chemical flow and reasonable ammonia slip (at or below 20 ppmv). A small in-duct SCR reactor was necessary to remove 90% of the ammonia slip and provide additional NOx reduction. SCR experience on coal fired units has been limited but recent independent testing has shown that new catalyst formulations are able to withstand the harsh environment.

Seward Station Cascade Design

Design has been completed for the Seward Station Cascade commercial demonstration. Available space for two small reactor vessels, one in each of the right and left side ducts, was located between the economizer hoppers and the air pre-heater inlets. The duct design was completed to provide the proper average inlet and outlet conditions as specified by the catalyst vendors selected. Two independent catalyst vendors were selected.

A static mixing grid and turning vanes have been recommended to decrease the known and predicted gas and solid flow imbalances in the unit. Design of these duct internals was completed using both computational fluid dynamic (CFD) and cold-flow models. CFD techniques were used to model the high temperature gases, Figures 3 and 4. The virtual environment permits non-intrusive measurement and an evaluation of a wide variety of duct configurations. Cold-flow modeling, however, can more closely approximate the actual geometry and provides important measurements necessary for scale-up. Both modeling tools have provided valuable insight into the design of constrained-space reactor vessels.

The catalytic rate of SO_3 generation is particularly important in this case because of the current air pre-heater sensitivities to ammonium salt formation. The catalyst vendors have specified minimum operating temperatures above which ammonium salt formation and deposition on the catalyst face will be avoided. Flue gas mixing and turning vanes have been designed to reduce temperature variations and eliminate localized cool spots.

Maximum performance in a full-scale SCR requires uniform ammonia to NOx ratios across the face of the catalyst. The ammonia slip to the SCR in a CASCADE system, however, will be significantly lower than the NOx at all points in the flow. Performance degradation due to variations in NH_3 concentration will, therefore, be greatly reduced. More importantly, any ammonia slip at or below design maximums will be significantly reduced. Both Cold-flow and CFD modeling have shown that the gases concentrations are well mixed at the entrance to the catalyst.

Seward Station Cascade Expected Performance

Public Service Electric & Gas (PSE&G) and Nalco Fuel Tech concluded an evaluation of combined SNCR/SCR NOx reduction as part of a demonstration of post combustion NOx control on the Mercer Station pulverized coal, wet bottom utility boiler in 1993. This Hybrid system utilized the urea based NOxOUT® SNCR process to provide both in furnace NOx reduction and sufficient ammonia to feed a downstream reaction catalyst bed. The Hybrid urea process achieved precatalytic reduction of approximately 50 % firing full load coal and a maximum of 67 % firing gas. These results have shown significant increases in chemical utilization, from 32 % to 63 % for full load firing coal, as compared to stand alone SNCR

The Cascade system at Seward Station is expected to provide overall NOx reduction of at least 55%, to 0.35 lb/10^6 Btu, from the 1990 baseline at less than 2 ppmv ammonia slip. The primary injection zone will be significantly cooler and the chemical utilization is expected to increase dramatically from the current SNCR system. Overall chemical flow is not expected to increase.

Expected performance data is summarized in Table 1. NOxOUT® SNCR performance was initially designed to achieve 42% reduction with an NSR of 1.3 and a resulting chemical utilization of 33%. Based on preliminary testing, NOxOUT CASCADE® performance is expected to increase to at least 55% reduction with an NSR of 1.2, a decrease in chemical flow, and a resulting overall chemical utilization in excess of 45%.

Pending the results of complete testing later this year, which will verify the performance estimates of the catalyst vendors, it will be possible to achieve 65% overall NOx reduction with the addition of catalyst to the reactor vessel. This new design may also require additional convective pass chemical injection, but the total chemical flow rate is not expected to increase significantly.

Beyond Phase I

Phase II of NOx controls in the United States currently refers to "beyond RACT" controls in ozone nonattainment areas or transport regions, as well as to the statutory acid rain provisions. While the acid rain provisions require that NOx limits be promulgated for remaining utility boilers (from Phase I) by January 1, 2000, other requirements are anticipated by May of 1999 for units which must reduce NOx for ozone-related reasons. The "Phase II" requirements will be moderate NOx reductions[5] beyond "RACT" (largely low NOx burners or other combustion modifications), and they will only be required during "ozone season" -- five months out of the year. According to the referenced Memorandum of Understanding[6], more controls may be required in Phase III in 2003.

Such a part-time control requirement, on units already employing primary controls which reduce NOx to 0.38-0.50 lb/10^6Btu, complicates the consideration of minimizing life cycle control costs.

Life-cycle Costs

The use of hybrid SNCR/SCR systems permits "tailoring" NOx reduction and life-cycle cost to the potentially complex future requirements of NOx reduction for ozone mitigation. The total life cycle cost of the modified SNCR/SCR NOx reduction process is a function of chemical utilization and catalyst size and capital requirement. Very high NOx reductions, of perhaps 90%, require a substantial catalyst volume. This system cannot be placed in existing duct dimensions and will always require, at the very least, major modifications. A modified SNCR/SCR system, providing between 50-60% precatalytic reduction, would require between 75-80% further NOx reduction to achieve 90% overall. This would still demand 88% of the original catalyst volume. Similarly, for an overall NOx reduction of 75%, a stand-alone SCR system requires approximately 88% of the original high reduction catalytic volume. (These design computations are graphed in Figure 5.)

A modified SNCR/SCR process would conceptually be effective for approximately 75% overall NOx reduction. Precatalytic SNCR reduction of 50-60% requires only 38-50% SCR reduction, and no more than half of the original catalyst volume as designed for 90% reduction. This is also only 57% of the catalyst volume required for stand-alone SCR targeted at 75% overall reduction. An "in-duct" catalyst may be used on a site-specific basis to fulfill this half-sized volume requirement.

Prior work at the plant site in development of the commercial-scale SNCR system which exists there indicated that 42% NOx reduction was achieved within the 5 ppmv NH_3 slip constraint. To achieve this level of reduction with a permanent, commercial system required approximately $14/kW capital. Design NSR for urea reagent is approximately 1.3 for the 42% reduction. Equivalently, this is 33% utilization at full load with substantial improvements at lower load.

By contrast, the full-scale SCR installed for the PSE&G demonstration of SCR technology was capable of achieving 90% NOx reduction and more for the several-month investigation. Installed capital cost for the retrofit was reported to be $90/kW.[7]

The field demonstration of that hybrid SNCR/SCR system verified that on a coal-fired unit, the SNCR-related cost performance can be improved substantially. This installation of in-duct (existing duct) catalyst on a pulverized coal-fired unit provides a basis of broad applicability to the various types of boilers within this population.

Conclusions

1. A Hybrid SNCR/SCR system has been designed for a full scale retrofit of a tangentially fired coal boiler in the Ozone Transport Region.

2. Two types of catalyst have been incorporated into the design to provide insight into the achievable performance of various small in-duct reactors.

3. Extensive CFD and cold flow modeling has been completed to provide the required temperature, velocity, and ash distribution profiles required by the catalyst vendors.

4. Chemical utilization and NOx reduction are expected to increase dramatically as compared to stand-alone SNCR.

5. Hybrid SNCR/SCR is capable of addressing the control requirements for many coal-fired boilers in the Ozone Transport Region with up to 75% NOx reduction.

References

1. Jantzen and K. Zammit, "Hybrid SCR," presented at EPRI/EPA NOx Symposium, Kansas City, 1995.
2. For NH_3, this is lb-mole NOx; for urea the value is two moles of NOx.
3. U.S. Patent 4,780,289, issued 1988.
4. Wallace, A. J., Huhmann, A., Boyle, J. M., Albanese, V. M., "Evaluation of Hybrid SNCR/SCR for NOx Abatement on a Utility Boiler," Power-Gen '95, Anaheim, CA, December, 1995.
5. Ozone Transport Commission Memorandum of Understanding, Newport, RI, September 27, 1994.
6. Ibid.
7. Presentation to Ozone Transport Assessment Group, Strategy and Controls Subgroup, Washington, DC, August 24, 1995.

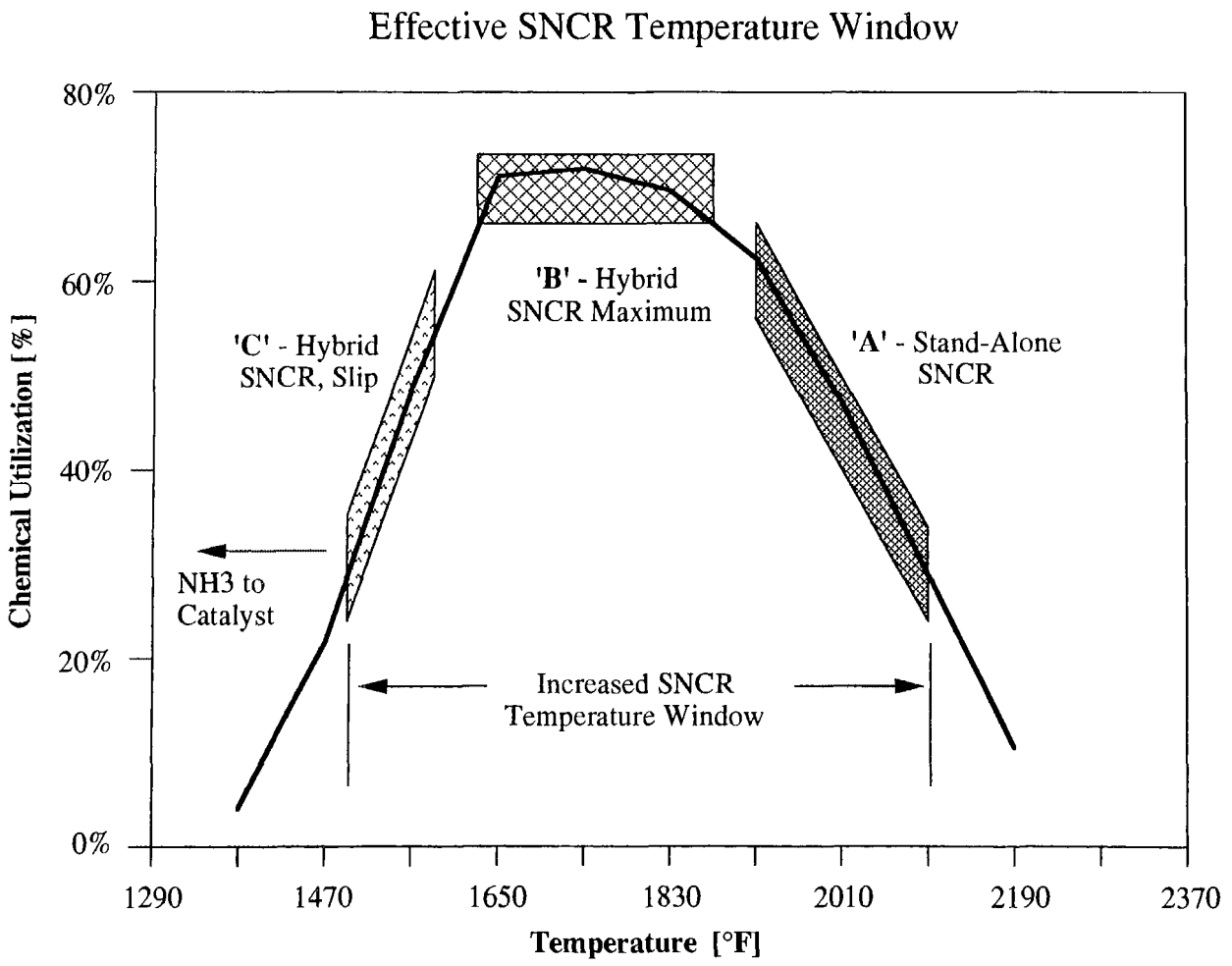


Figure 1. Hybrid SNCR/SCR yields improved performance.
Total reagent utilization approaches 100 %

Side Sectional Temperature and Velocity Profiles
GPU-GENCO Seward Station.

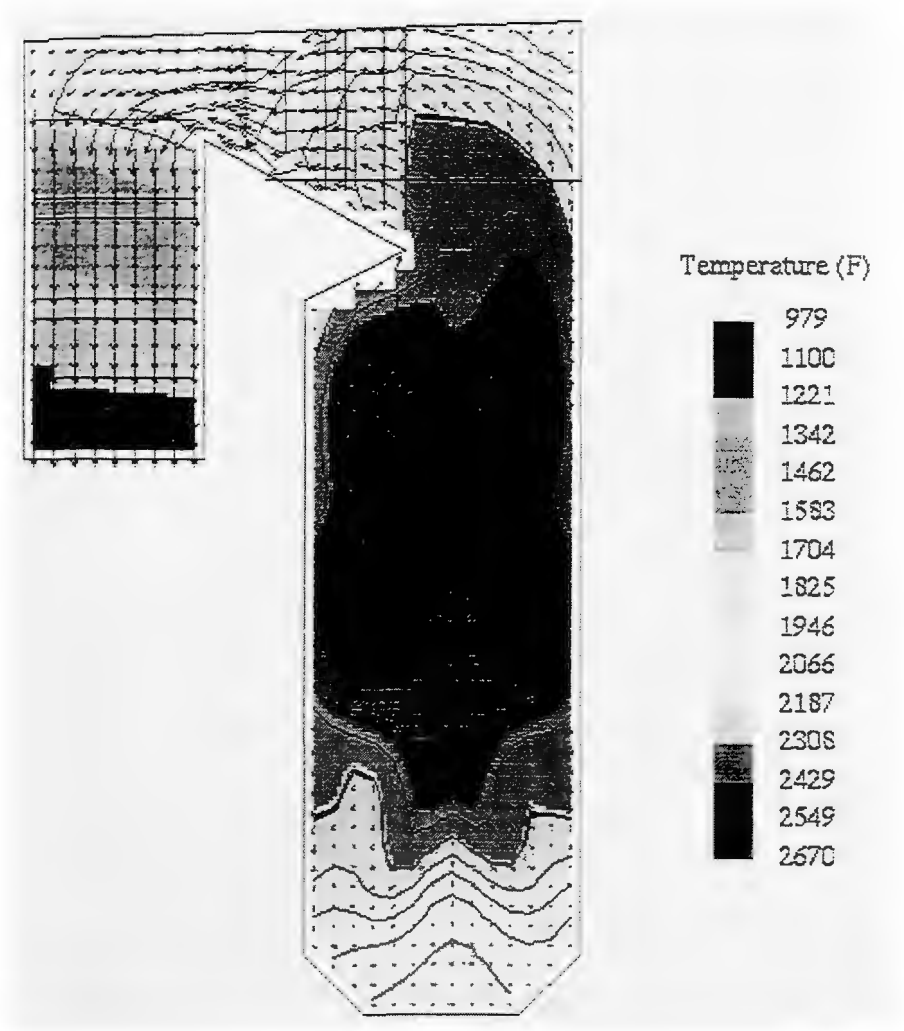
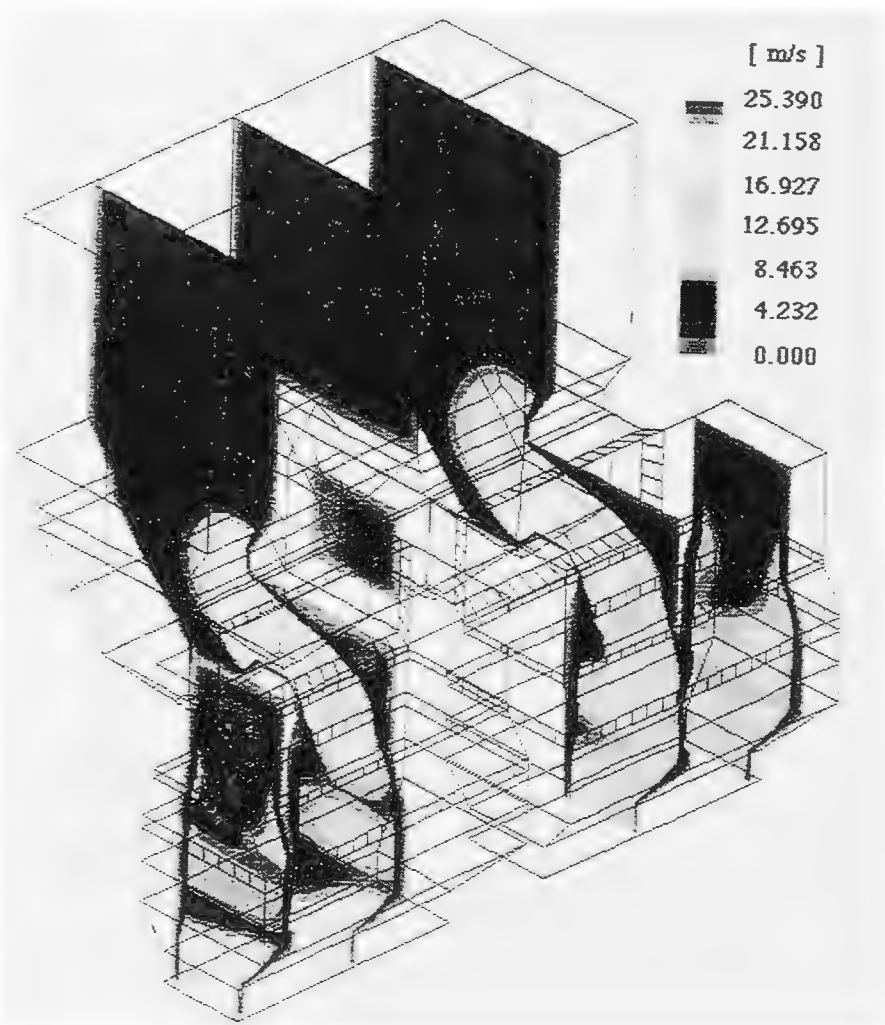


Figure 2. Side Sectional Temperature Profile of GPU-GENCO Seward Station.
Unit #15 Temperature and Velocities at 148 MWg, Full Load.

Figure 3. GPU GENCO - Seward Station
CASCADE® Duct Velocity Contours



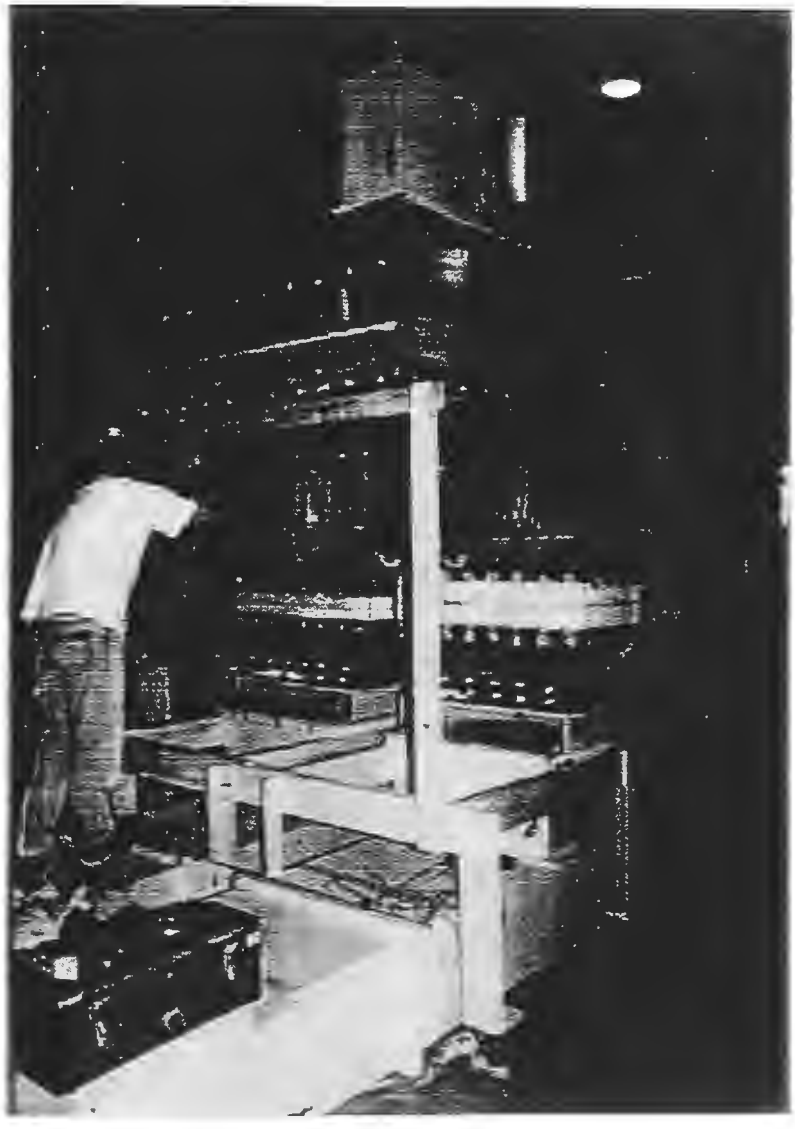


Figure 4. Cold Flow Modeling of GPU GENCO Seward Station SCR Ducts.

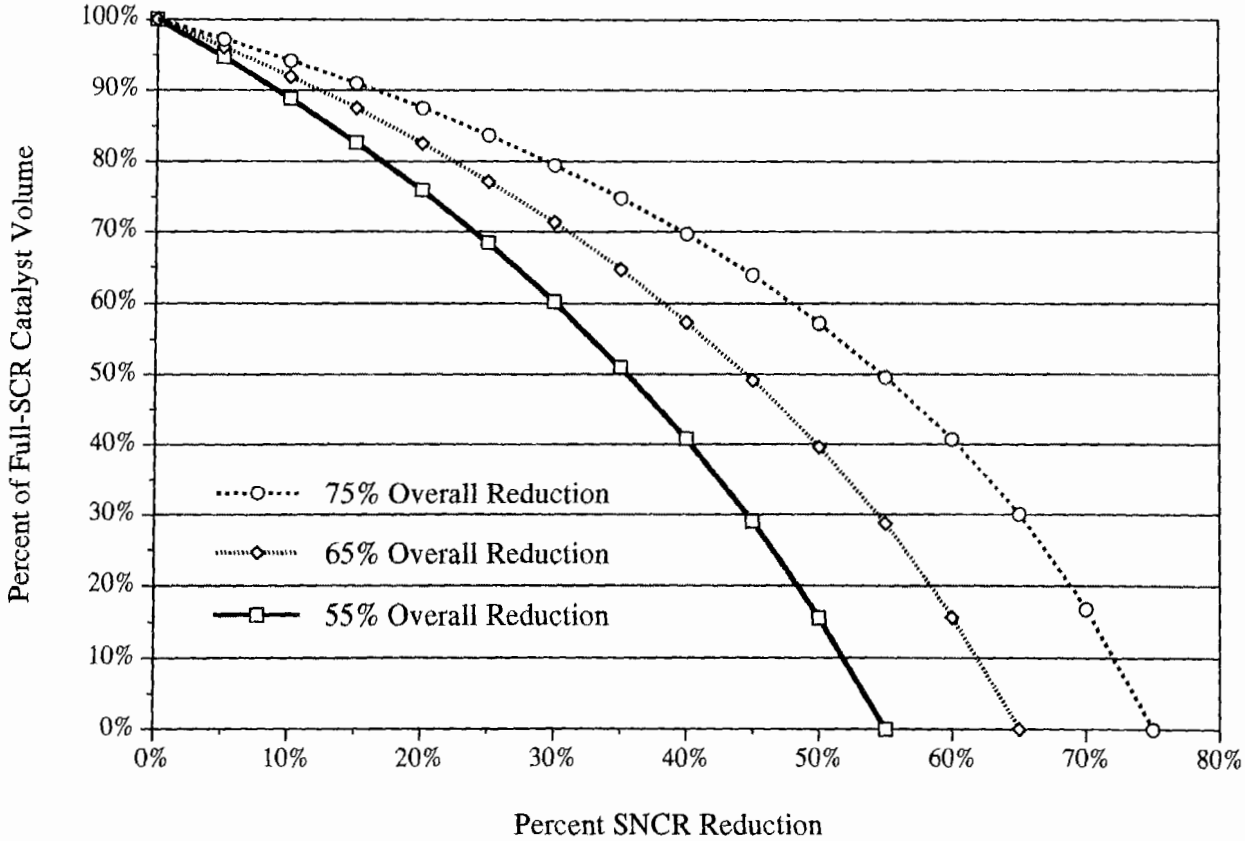


Figure 5. NOxOUT CASCADE® Fraction of Full-Scale SCR Catalyst Volume Needed to Achieve the Specified Overall NOx Reductions

Table 1. GPU-GENCO Seward Station CASCADE®

Unit #15	Case =>	147 MWg Coal	106 MWg Coal	74 MWg Coal
GHI	[10^6 Btu/hr]	1457.0	1096.0	800.0
Flue Gas Flow	[SCFH - wet]	19,387,898	15,381,054	11,560,650
NOx Before NOxOUT®	[ppmvdc]	554	554	554
	[lb/10^6Btu]	0.780	0.780	0.780
	[lb/hr]	1136.4	854.8	624.0
Modified NOxOUT® System				
NOx After NOxOUT®	[ppmvdc]	256	256	256
	[lb/10^6Btu]	0.360	0.360	0.360
NOxOUT® Reduction	[%]	53.8%	53.8%	53.8%
Chemical Utilization	[%]	45.0%	45.0%	45.0%
NSR		1.20	1.20	1.20
SCR System				
Final NOx	[ppmvdc]	240	232	217
Overall Reduction	[%]	56.7%	58.2%	60.9%
SCR Reduction	[%]	6.3%	9.3%	15.3%
Overall Utilization	[%]	47.4%	48.6%	50.9%
NH3 at Catalyst Entrance	[ppmvdc]	18	26	41
Final Ammonia Slip	[ppmvdc]	2	2	2
Space Velocity	[1/hr]	13071	10370	7794
Catalyst Volume	[ft3]	1483.2	1483.3	1483.2
	[m3]	42.0	42.0	42.0
Actual Gas Temperature	[°F]	600	600	600
Face Velocity	[ft/s]	18.4	14.6	11.0

STATIONARY SOURCE NO_X CONTROL USING PULSE-CORONA INDUCED PLASMA

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Abstract

ADA Technologies designed, built, laboratory tested, and installed an innovative 300 acfm pilot-scale nonthermal plasma NO_x control system on a stationary Air Force jet engine testing facility. The Air Force sponsored this program in response to EPA's designation of these units as stationary sources. This application to gas turbine NO_x control is challenging because of low temperatures, large volume (up to 4,000,000 acfm), low NO_x concentrations (4 to 35 ppm_v), and the sensitivity of the engines to backpressure. ADA's pilot system uses pulse-corona discharge technology to treat flue gases. The laboratory and field testing showed that some NO_x removal was achieved initially, possibly by reduction of NO to N_2, and further NO was oxidized to NO_2 or higher oxidation states. A scrubber removes NO_2 from the flue gas after it passes through the corona discharge region. Overall NO_x removals on the order of 50% were achieved.

Introduction

Jet engine test cells (JETCs) are structures designed to hold jet engines, provide a uniform environment, and suppress noise during static operational tests following maintenance or overhaul. These test facilities are used by the Air Force, Navy, and Army, as well as civilian airline companies and jet engine manufacturers. Jet exhaust contains nitrogen oxide (NO_x), soot particles, carbon monoxide (CO), and hydrocarbons (HC). Control of emissions from these facilities presents a real challenge because the emission is intermittent and because the engine is only minimally tolerant of back pressure (or flow resistance).

The control of acid rain precursors, SO_2 and NO_x, has been the subject of regulations for a number of years. The 1990 Clean Air Act Amendments have specifically targeted significant additional control of NO_x emissions. Jet engines are classified by EPA as stationary sources only when operating in a JETC. A typical Air Force JETC emits approximately 10 to 20 tons/year of NO_x emissions. EPA is considering imposing regulations in the near future that would require decreasing net emissions of NO_x from these static-firing test facilities.

There are a variety of designs for JETCs but the most common design incorporates an air-augmentor tube downstream of the engine exhaust to cool the exhaust gases. As the exhaust

gases flow into the augmentor tube, ambient air is drawn from outside into the tube to mix with the exhaust gases. In addition to cooling the gases, the augmentor tube also dissipates a portion of the kinetic energy of the exhaust blast.

Conventional NO_x control technologies are not well-suited to the jet engine test cell application because of its rapid and extreme changes in flue gas compositions and flow rates, high dilution (low concentration), low temperature, high flow rates, and sensitivity to back pressure. These characteristics of the exhaust gases preclude using any conventional back-end NO_x control technology such as Selective Catalytic Reduction (SCR) and Selective NonCatalytic Reduction (SNCR). Combustion modifications, or front-end emission control, are also precluded in a highly tuned process such as a jet engine.

The work described in this paper is the result of a two-phase Small Business Innovation Research (SBIR) program sponsored by Armstrong Laboratory. The Air Force was interested in investigating the technical and economic feasibility of an efficient emissions control strategy for jet engine test cells which does not impact the performance of the jet engines. The primary target emission was NO_x, however the additional benefits of using the same control device for other emissions was also of interest. The overall purpose of this SBIR program was to develop a cost-effective technology for control of NO_x from jet engine test cells using the pulse-corona-induced plasma process (PCIP). The Phase I program demonstrated that the PCIP process was technically feasible on the laboratory scale and capable of 90% NO_x removal under simulated jet engine test cell conditions.

The Phase II program was designed to provide a sound basis for projecting the economics of a full-scale application of PCIP technology on a jet engine test cell. This was accomplished by developing the data necessary to design a full-scale system based on actual field test results of a sub-scale system. The sub-scale system tested in Phase II was representative of the geometric configuration typical of a full-scale module. Tests defined operating conditions, power requirements, emissions control capability, and waste characterization.

An overview of Air Force research to control NO_x emissions from JETCs (1) summarizes a variety of technologies to achieve this goal. Modifications to the combustor are precluded based on performance impacts or potential physical damage. Armstrong Laboratory has sponsored seven independent projects (apart from this nonthermal plasma program) which address exhaust gas treatment options. These include exhaust-gas reburning, noncatalytic reduction with additives, metal-based catalytic reduction, photocatalytic decomposition, electrocatalysts, and a solid sorbent bed of magnesium oxide coated on vermiculite.

Technical Approach

This two-phase program advanced the technology from the laboratory to a sub-scale field demonstration on an Air Force JETC. Initial work in Phase I consisted of proof-of-concept testing to demonstrate that ADA's pulse-corona-induced plasma (PCIP) system design could destroy NO_x in a simulated JETC-exhaust gas. Phase II was designed to further the development of this technology by scaling up the design, establishing system operating conditions in the laboratory on a bench-scale jet engine, and then transferring this knowledge to the field tests.

In Phase I corona reaction cells were constructed that treated up to about 10 acfm. Gas input to the cell was provided by an exhaust gas simulation system. Measurements were made by real-time continuous emissions monitoring analyzers, including ADA's photodiode array analyzer.

Initial investigations in Phase II defined the parameters of JETC operation and investigated the reaction products of the PCIP system. JETCs have intermittent operation, and as mentioned above, have an extremely time-dependent and wide range of operating conditions. They are also sensitive to back pressure and any other performance impacts. Laboratory work at ADA Technologies was directed towards characterizing the chemistry of the process and determining what additives could potentially be combined with the PCIP system to promote the NO_x control process.

The chemistry of the process required better definition to ensure that PCIP was applicable to the flue gas stream of interest, without producing an undesirable secondary emission. ADA performed laboratory experiments to determine what products were generated by the pulser and to evaluate whether a chemical additive would promote the NO_x control chemistry.

This laboratory work was incorporated into the design, construction, laboratory testing, modification, and field testing of a subscale PCIP system. The subscale unit treated a slipstream of exhaust from an Air Force jet engine test cell. Ideally, the entire subscale test program would have been conducted on a slipstream from a test cell. However, since the test cell is not operated at steady-state conditions for extended periods of time, testing of the subscale system was performed at ADA's laboratory using flue gases generated by a small turbojet engine. These tests were designed to provide the data necessary to design a full-scale commercial system and accurately estimate the costs of the system.

It is very difficult to reliably scale up an electrostatic device from one geometric configuration to another of different size or shape. This does not mean that it is not possible to obtain meaningful information from subscale testing. It just requires that care be taken in design of the subscale system to account for such critical dimensions as tube diameter, electrode geometry, electrode spacing, length of treatment zone, and gas velocity.

The subscale test system design was based around one full-scale corona tube, treating up to 500 acfm of exhaust. By not changing any critical dimensions, one may easily extend the results obtained on a one-tube system to a device with many identical components in parallel.

Initial screening tests were conducted using a bench-scale turbojet engine firing Air Force JP-8 fuel. This engine was run at steady state conditions for long periods in order to make the necessary measurements to characterize the plasma process. These tests provided a data base of information that was very valuable in designing the full-scale system. In addition, the PCIP subscale system design was modified based on these test results.

Once sufficient tests at ADA's laboratory were conducted to characterize the process, the subscale system was interfaced to a slipstream of an operating jet engine test cell at Nellis Air Force Base. A series of tests were then performed to evaluate the performance of the plasma system under actual JETC operating conditions.

Pulse-Corona-Induced Plasma Technology

The PCIP process uses a plasma to destroy NO_x at relative low temperatures (*i.e.*, < 200 °F). The process involves application of a very sharp-rising, narrow-pulse high voltage to a corona system to produce intense streamer coronas, which bridge across the electrode gap. Streamer corona is the avalanche of electrons generated near a high-voltage wire due to intense gradients in the

electric field. Many characteristics of the process make it ideal for the jet engine test cell application.

Nonthermal Plasmas. Nonequilibrium plasmas produce chemically active radicals that react with pollutant molecules to oxidize or reduce the pollutants to more benign or easily collectible forms. The plasma can be generated by discharge reactors or electron beams. The goal is for electrons in the gas stream to attain a high temperature (high energy), while ion and molecular temperatures remain low. In a plasma system it is only the electrons that can produce chemically active radicals ($N\cdot$, $O\cdot$, $O_2^{\cdot}$, O_2*, O_3, OH, etc.). The various plasma excitation processes are designed to apply the energy directly to accelerating electrons. This selective heating of electrons is produced by using a very-high-frequency excitation in the MHz and GHz range, or by extremely short pulses of high voltage.

Research efforts in the late 1970s and early 1980s resulted in the development of the Pulse-Corona-Induced Plasma Chemical Process (PPCP), which differed from other plasma processes since it could be applied at normal temperature and pressure conditions. The sharp-rising, narrow-pulse, high-voltage corona system produces intense streamer coronas, which bridge across the electrode gap. The corona electrode serves as a stable trigger element of streamer corona.

With this process, all the energy is used to accelerate only electrons because the duration of the high electric field is too short to accelerate the ions, which have a much greater mass. The rise in the ion/molecule temperature through electron bombardment is minimized by providing sufficient time between pulses to allow cooling of the ions which have been partially heated through electron collision. The pulse frequency commonly used is in the range of 50 to 500 Hz. This results in a highly nonequilibrium plasma characterized by very high electron temperatures and low ion/molecule temperatures. The PPCP process has been proven by Masuda, among others, to be an effective mechanism for the treatment of NO_x, SO_2, Hg vapor, volatile organic compounds, odors, and other hazardous and toxic vapors (2,3,4,5,6).

Previous testing has been performed using laboratory setups and small pilot-scale devices by researchers. Masuda found that positive corona was much more effective than negative corona. He concluded that this observation was more a function of the shape of the corona than the quantity of energy produced. Negative corona forms in individual "tufts" whereas positive corona is more continuous between the wire and the outer cylinder so that the entire reaction chamber can be fully utilized for radical formation.

Keping, *et al.*, (7) and testing at ADA Technologies (8) have confirmed the findings of Masuda that near-complete destruction of NO_x occurs at very high field strengths and that positive corona was 10 times more effective than negative corona. In addition, Keping presented several key findings regarding NO_x destruction:

- NO_x removal efficiency is inversely proportional to initial NO_x concentration, and greater than 99% removal can be obtained at concentrations less than 200 ppm.
- NO_x removal efficiency increases with increased pulse frequency.

Laboratory reactor experiments also demonstrated that NO_x removal was inversely proportional to temperature and that the best NO_x removal occurred at temperatures below 50 °C. All of these

findings indicate that the approach is a good one for NO_x treatment of a dilute, low-temperature gas stream such as JETC exhaust.

Features of the Corona-Discharge Reactor. The PPCP process is a subset of corona-discharge reactor (CDR) technology. CDR can be viewed as a reaction system in which electrical energy is delivered to a gas stream to initiate or enhance the rate of beneficial chemical reactions. Such reactors are also referred to as electrical-discharge tubes or reactors in the literature and they have been employed in the past to prepare a variety of chemical compounds at laboratory and small commercial scale.

Other process systems that are similar to this concept include the electrostatic precipitator (ESP), which is employed to remove particulate matter from flue gas streams, and the ozone generator, which is used to produce chemically reactive ozone in an air or oxygen feed stream. In practice, the operation of an ESP typically results in both the collection of particulate matter and the generation of varying amounts of ozone, and so the ESP may be viewed as both a particulate emissions control device and a low-efficiency ozonizer.

Both ESPs and ozone generators have been developed to the point where systems are available in scales ranging from laboratory-scale to full-industrial-scale units. In ESPs, this amounts to systems capable of handling hundreds of thousands of cubic feet per minute of flue gas, while in ozone generators, output capacities can be measured in tons per day of ozone in the largest units.

Whether we compare the ESP or the ozone generator to the proposed CDR, the fundamental similarity resides in the fact that all three systems utilize electrical energy input to promote chemical reactions.

Table 1 shows several of the primary variables that impact the performance of the CDR and that are thus candidates for evaluation in optimizing the operation of the reactor to meet specific goals (in this case, the destruction of NO_x in flue gas).

Table 1
Variables Impacting CDR Performance

Applied Voltage	Pressure
Frequency and Duration of Applied Current	Temperature
Electrode/Ground Configuration	Gas Flow Rate
Chamber size	Gas Composition

Equipment Description

Figure 1 shows the final layout of the subscale system as configured at ADA's laboratory after extensive testing and modification. The subsections below describe the major components of the system.

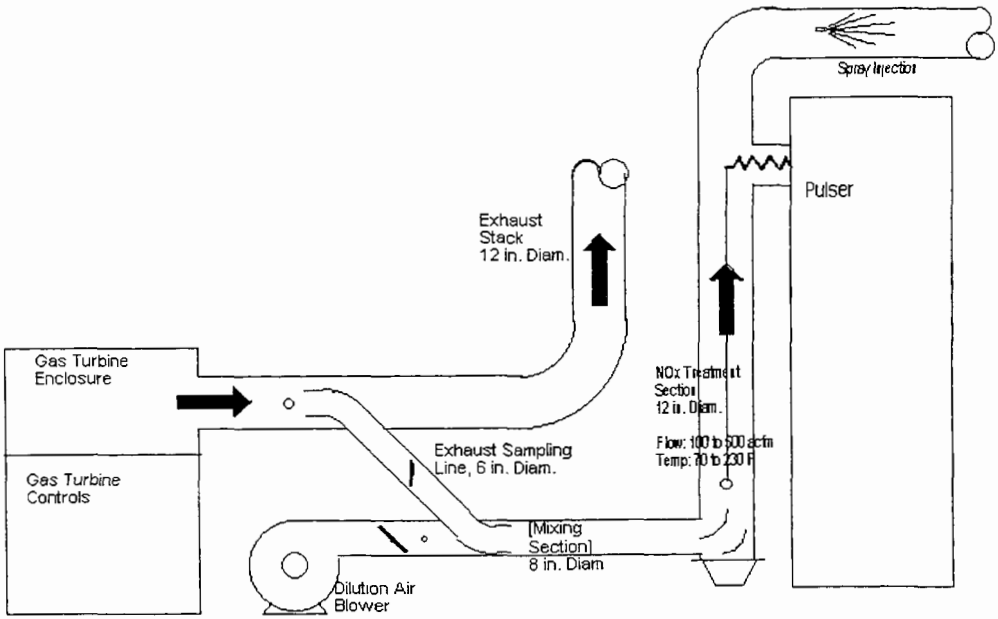

Figure 1
Subscale System as Installed at ADA's Laboratory

Reaction Cell and Pulsed Power Supply

Figure 2 shows an electrical schematic of the pulse-corona generator, which includes a DC high-voltage (HV) power supply, a pulse generator and a tubular corona-discharge reactor (CDR). A slipstream of the exhaust gas from the jet engine was forced through the CDR, in which the plasma was formed by applying a HV pulse to the corona electrode. The exhaust gas composition, temperature, and flow rate were measured before and after the gas passed through the tube to determine the effects of the plasma. Various currents and voltages were also measured to determine the electrical requirements of the system.

The DC HV power supply was a Hipotronics 220-V AC model 8150-65, which has rated maximum outputs of 150 kV, 65mA, and 10 kW. It consisted of an HV oil-filled tank and a rack-mounted control panel. The oil-filled tank contained all the HV components such as the transformer, capacitors, resistor to measure output voltage, and diode strings which can be reversed to change output polarity. The control panel contained a motor-driven variable-voltage transformer that controlled the primary voltage on the HV transformer in the tank and, therefore, the HV output to the pulse generator. The power off/on switches, circuit breakers, HV off/on switches, external interlock circuits and other safety features were in the control panel. Also, the DC analog meters in the panel measure the DC HV output voltage (V_{dc}) and current (I_{dc}) as shown in Figure 2. The high-voltage resistor, R_V, in the voltage-measuring circuit was actually located in the oil tank. The current-sampling resistor, R_I, was in the ground return side of the HV circuit. A data logger was connected in parallel with the two analog meters to automatically

measure HV output voltage (V_D) and current (I_D). This instrument was of very limited use because of the large transients encountered in HV pulse generation.

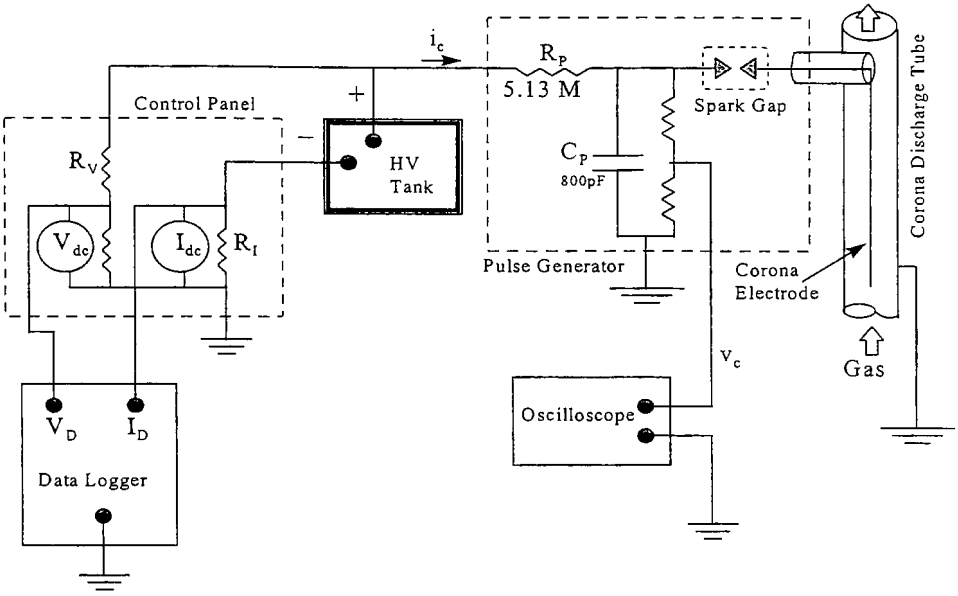

Figure 2
Electrical Schematic of Pulser and Corona Discharge

The pulse generator was built by Ion Physics and was 4 feet wide, 5 feet deep and 12 feet high. Although the unit was quite large due to the large spacing required for high voltage in air, it contained essentially three components. The resistor, R_p, in series with the capacitor, C_p, consisted of three 1.71-megaohm resistors in series and it limited the capacitor charging current, i_c. C_p consisted of two 400-pF capacitors in parallel and had a maximum voltage rating of 80 kV. The charging rate for the capacitor can be either increased or decreased by removing or adding resistors or capacitors in appropriate configurations. The spark gap consisted of two movable blocks of carbon enclosed in a Lucite™ chamber filled with a CO_2 atmosphere. The spacing between the carbon blocks was adjusted by an external motor, this spacing determines the voltage at which the spark gap breaks down. A voltage divider was connected across the capacitor C_p. The output of the voltage divider was connected to an oscilloscope (as shown in Figure 2) in an attempt to measure the capacitor-voltage waveform v_c. Since the voltage divider was not frequency-compensated, the peak and minimum values of the sawtooth-shaped waveform could only be estimated. However, the pulse period could be determined from the waveform but this period was not constant from pulse to pulse because of variations in the breakdown of the spark gap.

The output of the spark gap was connected to the corona electrode by a ¼-inch rod through an HV insulator. The corona electrode is inside an 11.75 inch ID steel tube. The tube was carefully grounded to reduce transient signals that occur on all grounds when the spark gap breaks down or

there is sparking from corona electrode to tube. The corona electrode extended 7.5 feet along the tube which determined the active volume for the pulse-corona. It is centered by the rod through the HV insulator at the top and a Teflon™ bar at the lower end. The corona electrode could be removed and replaced by electrodes of various diameters and surfaces to determine the effects of the electrode on pulse-corona generation. Gas flowed into the bottom of the corona chamber and out the top. The treatment time of the gas could be varied by changing gas velocity.

Instrumentation

Exhaust gas composition measurements were made using Thermo Environmental NO_x analyzers and a Servomex O_2 and CO combined analyzer. Type K thermocouples were used throughout the system for temperature measurements. These parameters were logged continuously during tests at Nellis AFB on both a Campbell data logger and a Hotmux input box (for temperature logging by computer). This continuous logging was essential given the rapid changes in flue-gas composition, flow rate, and temperature that the system underwent during on-site tests. Tedlar™ bag samples for hydrocarbons were analyzed for total methane and total nonmethane hydrocarbons, and condensation nuclei particle counter measurements of particle size were made on selected tests. Pressure drop through the CDR was measured with a Magnehelic pressure gage, and flow rate was determined using pitot traverses and with a hot-wire anemometer.

Jet Engines Tested

The engine which ADA used for testing in our laboratory was an SR-30 turbine manufactured by Turbine Technologies, Ltd. The turbine is capable of generating 32 pounds of thrust at an exhaust mass flow of 0.84 lb/sec. A single-stage radial compressor feeds a reverse-flow annular combustor can, and the hot gases expand through an axial-vane turbine. This engine provided exhaust gas flow rates that exceeded our requirements, and a slipstream of the exhaust was treated in the CDR. The temperature and composition of the gas were representative of JETC applications, except that the thermal NO_x production was low because of the lower temperature attained in a small-scale turbine. NO was added to the exhaust stream to overcome this and provide an entirely representative exhaust stream for treatment.

Engines tested at Nellis Air Force Base were all from F-15 and F-16 aircraft. We tested three engine models: F100-PW-100, -220, and -229. Each of these engines has an afterburner, and is typically tested at loads from idle through afterburner operation.

Scrubber Design

The initial subscale system design included the option to inject gases or liquids into the flue gas upstream of the corona-discharge reactor. Since the goal was an economic evaluation of the technology, chemical reactions which would promote NO_x removal and reduce the power costs associated with the CDR were desirable. Liquid spray prior to the corona was tested and eliminated because of interference with corona generation and inadequate residence time for the spray to distribute through the flue gases. The residence time is short because the droplets, as particles, are precipitated out in the corona-discharge tube.

The final configuration of the spray system, as shown in Figure 1, includes a spray/scrubber downstream from the CDR. This configuration included a mist-eliminating material, a high-

pressure pump and nozzle injector, and recycling of the spray fluid. Several spray liquor compositions were tested based on the results of laboratory tests.

An alternative scrubber configuration was a packed-tower design which treated a small fraction of the total flow through the CDR. This "scrubber tower" test apparatus bubbled gas through 100 to 200 mL of solution. The tower was a 3-inch diameter, 7-inch high cylinder. Evaporative cooler pad material was layered in the container to provide extended surface area for contact of liquid with flue gas.

Results and Discussion

Laboratory testing of the system yielded setpoints for electrode design, polarity (positive), capacitance, peak corona voltage (which was controllable by varying the spark gap distance), and power supply voltage (kV). Laboratory test variables also included flue-gas flow rate and NO_x concentration, dilution of flue gas with ambient air, turbine load (which affects flue-gas composition), gaseous and liquid injectants, and scrubbing using the spray tower or solid sorbents. From these laboratory results, we calculated the eV/molecule NO removed, and obtained target removal rates for comparison with field tests. These variables were selected in order to characterize the performance of the system under conditions representative of Air Force hush houses.

Variables included in the Air Force JETC field tests were: flue-gas flow rate, spray injection and the scrubber tower, power supply kV, engine load, and three engine types. The measurements made during these tests are discussed below with the test results.

Testing at ADA's laboratory yielded energy consumptions of 40 to 100 eV/molecule once the system was optimized. The energy consumption calculated is for conversion of NO to higher oxides (+4, +5), not necessarily elimination of NO_x. We found that about 90% of the NO entering the pulser would oxidize. The balance was presumably reduced to elemental nitrogen. We then focused our work on eliminating the N^{+4} and N^{+5} through chemical scrubbing. Although the project was not set up to engineer a scrubbing system, we did have enough success with the configurations tested to prove the concept. The economics of the full-scale system were based on a spray-tower configuration, and costing was done based on this type of equipment at JETC scale. Exhaust gas flow rates from a JETC are as high as four million cubic feet per minute, which is the same order of magnitude as a utility power plant.

PCIP System Design Improvements

Four electrodes were tested. The 7.5-foot-long corona electrodes were installed in the CDR and tested individually. They were: a smooth 1/8-inch-diameter rod, a coarsely threaded ¼-inch-diameter rod, a smooth ½-inch-diameter tube, and a constructed electrode consisting of 1.5-inch-diameter washers spaced 0.7 inch apart by smooth spacers. Statistical analysis of all data generated was performed and the electrode design was found to have only a small contribution to the effectiveness of the system at oxidizing NO. However, the range of electrical conditions that could be realized without significant sparkover varied for the different electrodes. We selected the ¼-inch diameter threaded rod as the best electrode, and used this design for the majority of laboratory tests and for all field tests. Positive polarity corona was found to be much more effective than negative polarity.

Tests were conducted both on turbine flue gas and on ambient air. Treating turbine flue gas was found to be much more effective. This may be due to the influence of hydrocarbons in the flue gas, which has been observed by others to enhance cold plasma's capability to remove NO (9).

Products of the Corona-Discharge Reactor

Initial test results showed that conversion of NO to higher oxides of nitrogen (N^{+4} and N^{+5}) was successful using ADA's wire-in-cylinder design. The conversion is a function of energy input, and at the concentration levels for the jet engine test cell application, 100% conversion is within the capability of this equipment.

The pulser converts a small percentage of NO_x to species other than NO_2 or NO_3^-. This small percentage is seen by our analyzer as a reduction in total NO_x. Reductive as well as oxidative radicals are present in the corona, so the other species to which NO is converted may be N_2O_5, or N_2. The chemiluminescent NO_x analyzer measures total oxides of nitrogen, including NO_2 and NO_3^-, separately from NO. The pulser converts most of the NO into these higher oxides.

Elimination of Higher Oxides of Nitrogen. Laboratory testing was directed toward defining an optimal scrubbing solution. The test procedure was to inject NO_2 through a solution in a bubbler to determine the solution's scrubbing capability. We simultaneously measured the pH and the NO_3^- concentration in the solution as well as the inlet and outlet NO_2 concentration. Several reagents were tested to determine their scrubbing capability. The three successful candidates were sodium hydroxide, hydrogen peroxide, and sodium thiosulfate. For example, the laboratory tests of various peroxide solutions yielded 37 to 40% NO_2 removal when bubbling NO_2 through the solution. Once these were demonstrated in the laboratory, they were then combined with the spray- and scrubber-tower designs to determine their success in directly treating the flue gas stream after treatment by the CDR.

Once oxidation of NO to higher oxides was achieved by the pulser, tests focused on elimination of the NO_2. Tests were typically run with a baseline (inlet) value of 25 ppm NO_x in the flue gas, which is representative of Air Force jet engine test cell conditions. The pulser operation was set up to convert about 90% of the NO to NO_2. The results which were critical to the direction of the program are discussed below. Several candidate scrubbing techniques demonstrated high removal rates (>80%) of NO_x in the laboratory when combined with CDR exhaust treatment.

Gaseous Injection and Sorbent Beds

Ammonia injection removed NO_x when used in conjunction with the pulser; the disadvantage was that high excess ammonia was required, resulting in gaseous ammonia emission equal or greater than the NO_x emission. Storage and handling of ammonia is also a serious issue for Air Force bases.

Injection of hydrocarbons into the flue gas was tried on a small scale and did not have major impact on pulser operation nor on effectiveness of NO-to-NO_2 conversion. The hydrocarbons tested were methane and propane, injected into ambient air (fan operation) rather than turbine flue gases. Concentration ratios of hydrocarbon to NO_x ranged from 2:1 to 8:1. However, it is likely that the unburned hydrocarbons in the turbine flue gases did improve CDR performance. This was observed as an influence of turbine load on the test results (lower load corresponding to higher unburned hydrocarbons).

A sorbent bed was also tested in the sample line to the CEMS. This was a packed cylinder of material through which flue gas passed prior to measurement by the NO_x analyzer. This experiment successfully removed about 6 ppm (32%) of the NO_2 with vermiculite in the sorbent bed. The residence time of the flue gas in the bed was approximately seven seconds. Pressure drop was high through the packed sorbent bed, on the order of 20 inches of H_2O.

Liquid Scrubbers

The CEM scrubber tower was used to test the successful NO_2-scrubbing chemicals on actual flue gas.

Sodium Thiosulfate: $Na_2S_2O_3$ at 0.1 *M* concentration in water was the most successful scrubber. It resulted in removal of as much as 80% of the NO_x when used in combination with the pulser. A proposed mechanism for scrubbing of NO_2 by sodium thiosulfate is summarized below:

$$Na_2S_2O_3 + \frac{1}{2}O_2 + NO_2 \rightarrow 2\ Na^+ + \frac{1}{2}S_4O_6^{-2} + NO_3^-$$

A weaker solution of sodium thiosulfate (0.01 *M*) was also tested successfully. This resulted in 75% NO_x removal. The pH of sodium thiosulfate solution was very close to neutral.

Sodium Hydroxide: NaOH at 0.1 *M* was almost as effective at removing NO_x. 70 to 75% removal was observed. Weaker solutions of 0.01 and 0.05 *M* were tested also, resulting in 56 and 64% NO_x removal, respectively. The pH of the most-dilute NaOH solution was above 11.

Hydrogen Peroxide: 3% H_2O_2 resulted in greater than 60% NO_x removal.

The laboratory tests with solution injected directly into the flue gas showed limited success. Under conditions which included low flue-gas flow rate and relatively high NO_2 concentration, the spray removed on the order of 10% of the NO_2 from the gas stream. Normal laboratory test conditions, which most closely match a full-scale system, included approximately 25 ppm of NO_x in 300 to 400 acfm flue gas. When flow rates were cut to about a third, and NO_2 concentrations were increased to 34 to 55 ppm, the effect of the spray was confirmed (i.e., 10% NO_2 removal). These changes effectively decreased the gas-to-liquid ratio, and demonstrated that an engineered spray system is technically feasible. Based on these results, we selected a spray tower design for the cost estimate of the full-scale system.

Field Results from Testing at Nellis Air Force Base

A typical firing of a jet engine in a test cell involves operating the engine at several thrust levels from idle to full load with afterburning. The load on the engine may be held for several seconds to several minutes before proceeding to the next load. There is a prescribed series of operating conditions which each engine is put through to obtain data for an Air Force "Acceptance Test." Figure 3 shows typical emissions from an Air Force jet engine during an Acceptance Test. The engines tested were Pratt & Whitney engines from F-15 and F-16 aircraft.

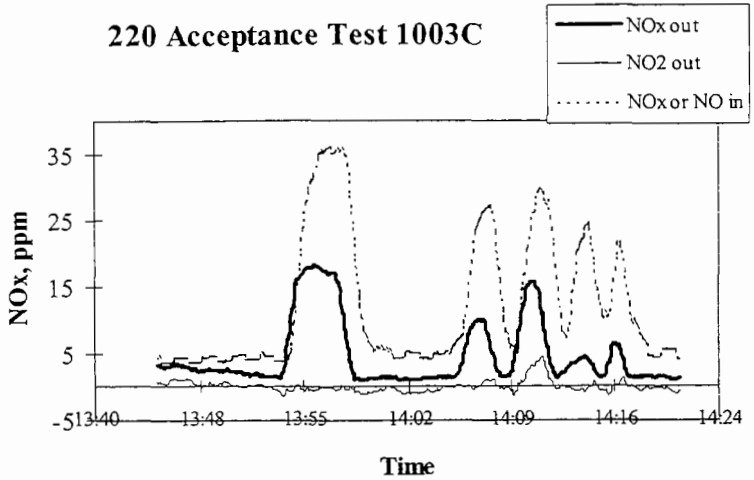

Figure 3
Typical NO_x Emissions During Acceptance Run and Controlled Emissions

The slipstream was drawn through five 2-inch diameter ports in the 4-inch diameter probe tubing, through a fan, and then into the corona-discharge pipe. The flue gas then passed through mist eliminator material to prevent liquid from reaching the corona region, and then through the spray section. Measurements made during testing used the same equipment as during laboratory testing, and included the parameters listed below:

PCIP Inlet and Outlet: NO, NO_x, CO, O_2, particle sizing, hydrocarbons, temperature

PCIP Operation: Supply kV and mA, pulse rate, pressure drop, flow rate

Jet Engine Operation: Load, fuel flow, N2 rpm (high-pressure compressor speed)

In 10 days of on-site testing, 29 tests were conducted. These tests characterized the flue gas from three engine types, the F100-PW-100, -220, and -229. Each of these engines is routinely tested in the hush house and is used interchangeably in F-15 and F-16 aircraft. Testing was conducted during standard hush house operation, called "acceptance" tests, during troubleshooting of engines, and during periods of extended operation at idle, military, or afterburner loads. These extended periods of operation were requested by ADA and enabled us to observe the effects of varying such operating conditions of our system as flow rate, pulser power, and spray injection. Based on these results, we examined NO oxidation by the pulser and spray/scrubber effectiveness for NO_2 removal, and we were able to target operating conditions for acceptance tests.

A sample of data from one of the final on-site tests is shown in Figure 3. This test run represented typical acceptance test conditions. NO_x removal was on the order of 50% for this test. Flue-gas flow rate, pulser power, and scrubber liquid composition were set based on previous test results. Table 2 shows a summary of operating parameters and calculated values from this test run. These data were a result of optimizing the system over several days at Nellis to determine gaseous flow rate, pulser power level, and scrubber configuration.

Table 2
Summary of PCIP System Operation

Engine Load	Inlet NO_x ppm	ppm NO_2 Converted by Pulser	eV/molecule	Scrubber effectiveness %	NO_x Emitted ppm
Idle	4	3		100	1
Military	27	17	55	100	10
Afterburner	36	20	55	100	16

Hydrocarbons were measured simultaneously at the pulser inlet and outlet during an engine startup burning "pickling oil," a preservative used in long-term engine storage. These startups are quite smoky, since oil must be burned out of the fuel lines for 30 to 50 seconds. The results of a single Tedlar™ bag pair taken under this condition showed that the CDR system (without scrubber) was removing nonmethane hydrocarbons. Methane in both inlet and outlet samples was 2.1 ppmv, but nonmethane hydrocarbons were 10.3 ppmv at the inlet, and <1 ppmv at the outlet of the CDR. Hydrocarbon bag samples were also taken at steady load conditions on JP-8 fuel. These were taken on two different days, and results varied somewhat. Bags sampled on September 30 indicated that nonmethane hydrocarbons were decreased by the pulser by one to three ppm from inlet levels of two to five ppm. Methane hydrocarbons were again unchanged. Bags sampled on October 2, however, indicated that inlet and outlet nonmethane hydrocarbons were consistently 0.5 ppm to 1.0, not varying with load. Overall, the data indicate that the CDR removes nonmethane hydrocarbons from the exhaust stream. They also indicate that volatile hydrocarbons present in the exhaust are quite low, and vary with operating conditions.

The fast response time and durability of our system did prove to be effective in the JETC application. We successfully performed sufficient testing at Nellis to develop full-scale economic projections, as described in the section below.

Conclusions and Economics of Full-Scale Implementation

The system consists of two major components: the CDR, which oxidizes NO to higher oxides of nitrogen, and the scrubber, which chemically eliminates the $N^{+4}$and N^{+5} The design is targeted at four million actual cubic feet per minute flue gas flow, and utilizes data obtained from the Nellis field test results to determine removal efficiencies and operating costs.

The assumptions used to specify the design of the corona reactor section is based upon a reactor residence time of 1.3 seconds, a reactor height of 30 feet, 25 ppm NO oxidized by the pulser, 20 ppm NO_x removed, and scrubbing with a 0.01 *M* sodium thiosulfate solution. The gas exiting the scrubber section is targeted to contain 10 ppm of NO and 5 ppm of NO_2. The captured NO_2 will exit the scrubber as a dilute nitrate salt.

A mass balance of the system is shown in Figure 4. Table 3 shows a summary of the capital and operating costs for the system. The energy needed per NO molecule oxidized (55 eV) and the required oxidation of 20 ppm yields a high-voltage-power requirement of 14 MW. This pulsed high-voltage power can be obtained from 28 individual 500-kW supplies.

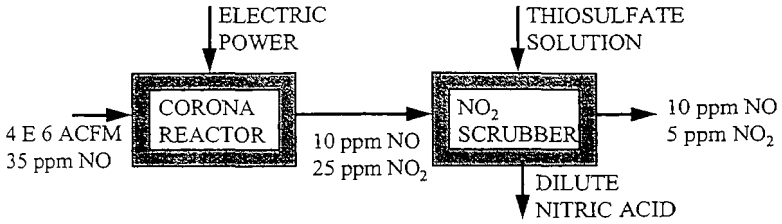

Figure 4
Full-Scale Mass Balance for PCIP and Scrubber System

Table 3
Projected Full-Scale Capital and Operating Costs Summary

Equipment Capital Cost	$109,200,000	
Capital Recovery Cost	14,196,000	
Operation Hours per Week	10	50
O&M Yearly Cost	523,600	2,618,000
Annualized Cost	$14,719,600	$16,814,000
$/lb NO_x Removed	$56 to $343	$11 to $69

A spray tower design for NO_2 scrubbing was chosen over a packed design to minimize pressure drop. To minimize total height (essential near a flight line) and to make use of the corona reactor outside walls, the scrubber will wrap around the corona reactor. To maintain the concentration of nitrate in solution at 5%, a flow of 10 gpm will be withdrawn. Since sodium thiosulfate will be simultaneously depleted, it will be replaced at a rate of 12 lb/hr.

The annualized cost of the system is mainly composed of capital recovery, which is principally a function of the overall capital cost. The largest single cost item is power supply ($28,000,000), and this cost is dependent upon the energy requirement for the oxidation of NO.

The cost per pound of NO_x removed is also shown in Table 3. Since the bulk of the annualized cost is capital, longer operating hours quickly translate into a more-cost-effective system. However, as typical JETC operating periods are an hour or two, 50 hours/week is an unrealistically high number. For comparison, NO_x offset values are on the order of $10,000/ton, or $5/lb.

The range of costs per pound of NO_x is attributable to different assumptions on the varying operating conditions of JETCs. Both concentration of NO_x and flue-gas flow rate vary enormously, making an integral average difficult to estimate without continuous measurement. For an emission rate of 20 tons NO_x per year, the cost is estimated to be $343/lb NO_x. For the maximum emission rate possible in 10 hours of weekly operation (continual operation at full

load, which is not normal JETC operation), the cost drops to \$56/lb NO_x. The actual cost for a typical JETC would likely fall between these two estimates.

Other Applications of CDR Technology

While the JETC application is not an ideal application of this technology, clearly some other types of gases will be treatable using this technology. The results we obtained in the field were very consistent with those from the laboratory, an indication that the design we selected is scaleable. This is encouraging, and we are continuing to examine other potential applications such as destruction of air toxics, and simultaneous destruction of more than one pollutant.

Acknowledgments

The authors would like to thank Dennis Helfritch of Environmental Elements Corporation for his help on this program, including analysis and writeups of laboratory and economic data. We would also like to thank the hush house crew at Nellis Air Force Base.

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Tuesday, August 26; 8:00 a.m.
Parallel Session C:
Low NOx Systems for Gas/Oil-Fired Boilers
Continued

APPLICATIONS OF REACH TECHNOLOGY TO REDUCE NOX AND PARTICULATE MATTER EMISSIONS AT OIL-FIRED BOILERS

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Abstract

Reduced Emissions and Advanced Combustion Hardware (REACH) Technology has been retrofitted to 115 gas- and oil-fired boilers of different designs and capacities to reduce NOx and particulate matter (PM) emissions. The total installed capacity using REACH is presently 17,000-MWe worldwide. Combustion and emissions performance equivalent to that available for new, low-NOx burners has been achieved at costs between $0.25 and $1/kW depending on the unit size. Two versions of REACH are commercially available: (1) Combustion Performance REACH (CP-REACH) for solving a variety of site-specific boiler performance, maintenance, and operating problems related to poor combustion conditions, and (2) Low-NOx REACH (LN-REACH) which provides simultaneous reductions in NOx and PM emissions, while retaining the performance and operating advantages of CP-REACH. This paper describes recent LN-REACH applications using Segmented V-Jet atomizers (patented) at Collins Unit 4 of ComEd, a 550-MW, opposed-wall fired boiler, and at Kahe Unit 6 of Hawaiian Electric Company (HECO), a 140-MW, single-wall-fired boiler. Also described is a CP-REACH application to reduce PM emissions at a 365 metric tons/hr (approximately 100-MW), tangential-fired boiler at the Montova Plant of Frene in Italy.

Results at Collins Unit 4 showed that LN-REACH reduced NOx emissions from 0.55 to 0.30 lb/MBtu (883 to 481 mg/Nm^3) at 500-MW without overfire air (OFA) and flue gas recirculation (FGR). The application of OFA and 7% FGR further reduced NOx emissions to 0.21 lb/MBtu (338 mg/Nm^3) with 10% opacity. At Kahe Unit 6, NOx emissions at full load were reduced 13% below levels achieved with a combination of 1st-generation LN-REACH, OFA and FGR, i.e., from 0.22 to 0.19 lb/MBtu (353 to 306 mg/Nm^3) with 10% opacity. For the tangential-fired boiler, CP-REACH reduced PM emissions from 0.11 to 0.04 lb/MBtu (200 to 60 mg/Nm^3) without an increase in NOx emissions (which were approximately 0.45 lb/MBtu, or 725 mg/Nm^3).

Introduction

Reduced Emissions and Advanced Combustion Hardware (REACH) Technology was developed jointly by Electric Power Technologies, Inc., (EPT), the Electric Power Research Institute (EPRI), the Empire State Electric Energy Research Corporation in New York (ESEERCO), and Consolidated Edison Company of New York for retrofit to existing burners to solve a variety of site-specific boiler problems related to poor combustion conditions, including high stack opacity, high unburned carbon and NOx emissions, acidic stack fallout, flame impingement, poor boiler turndown, and high excess oxygen(1).

The main elements of REACH are oil atomizers and flame stabilizers. The design philosophy for REACH was that it: (1) can be retrofit to the existing range of burner and boiler designs to maximize applicability, and (2) retain as much as possible of the original burner to realize cost advantages relative to other retrofit options (e.g., complete burner replacement). Consistent with this philosophy, REACH adapts to the major existing components of a burner.

Oil Atomization

REACH oil atomizers are custom-designed to adapt to the existing oil supply conditions (i.e., pressure, temperature, and capacity)(2). For steam-atomized systems REACH uses internal-mix (I-Mix) atomizers, which produce superior spray quality compared to other common atomizer designs.[1]

For reducing NOx emissions in steam-atomized systems a novel atomizer design was developed — the Segmented V-Jet atomizer (patented) — which divides the oil spray into distinct segments at the base of the flame. For mechanically-atomized burners, REACH oil atomizers can be designed to operate at supply pressures from 200 to 1,300 psig. Special low-NOx mechanical atomizers that produce oil spray characteristics conditions similar to the Segmented V-Jet atomizer are also available.

Flame Stabilizers

For flame stabilization and aerodynamic control of fuel and air mixing, REACH uses a compound-curved-vane swirler (CVS) for applications on both wall- and tangential-fired boilers(2). The CVS provides better performance than conventional diffusers and flat-bladed swirlers that are commonly in use. The CVS flame stabilizers supplied with REACH are custom-designed to produce the proper

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[1]The quality of the oil spray is characterized by Sauter Mean Diameter (SMD), which is defined as the diameter of a hypothetical droplet that has the same surface-to-volume ratio as that of the total spray. SMD is most often used to characterize oil sprays because it is relevant to evaporation and combustion of oil droplets.

entrainment and swirl of combustion air at the discharge plane of the burner, and to match the oil spray of the REACH oil atomizer.

REACH Technology

Two versions of REACH have been applied in a number of commercial applications. Combustion Performance REACH (CP-REACH) is designed to reduce PM emissions and opacity and to provide operational improvements including increased burner turndown, reduced excess air requirements, improved flame stability, and elimination of flame impingement on furnace walls. Low-NOx REACH (LN-REACH) is specifically aimed at retrofit projects where NOx reduction is the major goal. The key difference between CP-REACH and LN-REACH is the design of the oil atomizer. Boilers equipped with CP-REACH can be easily converted to LN-REACH. Detailed descriptions of these technologies and commercial applications have been published elsewhere[3-6].

Adapting REACH to existing boilers typically requires the custom design of retrofittable oil atomizers and flame stabilizers. The major components of the burner are retained, and significant changes to air registers, burner auxiliary equipment, pumping and heating equipment, or combustion controls are not required. In some instances, the burners have been changed from mechanical to steam atomization. EPT has designed and supplied REACH for more than 115 boilers totaling 17,000-MWe of generating capacity. In a typical retrofit project, REACH atomizers and flame stabilizers can typically be supplied within 6-8 weeks, and installed during a 3-5 day boiler outage. Alternatively, REACH technology may be incorporated in the design of new burners.

REACH technology has been licensed from EPRI by EPT, COEN Company, and Ansaldo Energia.

This paper describes results from three recent REACH applications. Two are LN-REACH projects: (1) Collins Unit 4 of ComEd, a 550-MW, opposed-wall fired boiler; and (2) Kahe Unit 6 of Hawaiian Electric Company (HECO), a 140-MW, single-wall-fired boiler. The third is a CP-REACH application at a 365 metric tons/hr (approximately 100-MW), tangential-fired boiler at the Montova Unit B6 of Frene in Italy.

Boiler Descriptions

Descriptions of the three boilers which were retrofitted with REACH are provided below.

Collins Unit 4 of ComEd

Collins Unit 4 is an opposed-wall-fired boiler manufactured by the Babcock & Wilcox Company and operated by ComEd. The unit has a gross generating capacity of 550-MW, and is equipped with windbox flue gas recirculation (FGR) and overfire air (OFA). The boiler was originally designed to burn No. 6 fuel oil (only), and is equipped with 28 dual-register burners. The burner arrangement is two elevations of seven burners each on the front and rear walls. A dividing plate in the windbox separates the two burner elevations. However, there are no dampers to bias combustion air between the burner elevations. There are seven OFA ports on each firing wall, with one port above each burner column. Combustion air for the OFA ports is supplied from the windbox for the top burner elevation. When 100% open, the OFA system is designed to divert approximately 11% of the total combustion air flow to the OFA ports. The unit was converted to gas and oil operation by EPT in 1996[4].

CP-REACH was retrofitted by EPT in 1991 to improve oil atomization and combustion performance. The retrofit included: (1) replacement of Y-jet atomizers with internal-mix atomizers, (2) replacement of diffusers with compound-curve-vane swirlers for flame stabilization, and (3) conversion of the atomization steam system from constant steam pressure at 150 psig to constant steam-to-oil differential pressure of 10 psid over the load range. As part of a gas conversion project performed in 1996, EPT retrofitted LN-REACH flame stabilizers and low-NOx, Segmented V-Jet oil atomizers. Results with the Segmented V-Jet oil atomizers are presented in this paper.

Kahe Unit 6 of Hawaiian Electric Company

Kahe Unit 6 is a single-wall-fired boiler manufactured by the Babcock & Wilcox Company and operated by HECO. The unit has a gross generating capacity of 146-MW, and is equipped with windbox FGR and OFA. The OFA system was designed to divert up to 30% of the total combustion air to six OFA ports located on the front and rear boiler walls (three ports per wall). The boiler burns No. 6 fuel oil (only), and is equipped with nine PG-DRB burners in a 3 x 3 array on the front wall[7].

The original oil atomizers supplied by the boiler manufacturer were capable of meeting the NOx emissions limit of 0.23 lb/MBtu (370 mg/Nm^3) when used with maximum FGR and OFA. However, there was no operating margin with the 20% opacity limit to allow for variability in operation or oil properties. First-generation, LN-REACH atomizers were retrofitted by EPT in 1990 to improve oil atomization and combustion performance. Results showed that the NOx emissions limit could be met with reduced levels of OFA and FGR and with significantly lower opacity (10-13%). In the spring of 1997, EPT retrofitted low-NOx, Segmented V-Jet oil atomizers. The objective was to increase the margin of compliance with the NOx and opacity limits. Results with the Segmented V-Jet oil atomizers are presented in this paper.

Mantova Unit B6 of Frene in Italy

Mantova Unit B6 is a tangential-fired boiler manufactured by Franco Tosi and operated by Frene of the ENI Group in Italy. The unit has a steam generating capacity of 365 metric tons/hr (approximately 100-MW), and is not equipped with windbox FGR. However, the boiler does have a small, close-coupled OFA compartment above each burner in the top elevation. The boiler is capable of burning No. 6 fuel oil and natural gas, and has four burner elevations and 16 burners. Each burner has single fuel-air compartment and auxiliary-air compartments immediately above and below the fuel-air compartment. The auxiliary-air compartments between the 2nd/3rd and 3rd/4th elevations are bricked shut. To avoid excessive opacity (smoking) the unit is normally operated with the fuel-air compartment dampers 100% open, and the functional auxiliary-air compartment dampers virtually closed (i.e., 10% open for cooling).

In 1997 EPT installed CP-REACH flame stabilizers and internal-mix oil atomizers to reduce PM emissions. The CP-REACH retrofit included: (1) replacement of Y-jet atomizers with internal-mix atomizers, (2) replacement of diffusers with compound-curve-vane swirlers and extenders for flame stabilization, and (3) conversion of the atomization steam system from constant steam pressure at 150 psig to constant steam-to-oil differential pressure of 10 psid over the load range, and (4) reactivation of the close-coupled OFA. To increase swirler flow entrainment, extender assemblies (i.e., bluff-body rings) were attached to the exit of the fuel-air nozzles to increase airflow turbulence and promote the formation of a strong internal recirculation zone.

REACH Characterization Tests and Measurement Methods

The REACH installations at the three boilers were commercial applications. Consequently, tests to optimize combustion and emissions performance emphasized development of operational guidelines over the load range for the plant operators, instead of parametric tests to characterize the sensitivity of NOx and PM emissions to FGR, OFA, excess O_2, etc.

At Collins Unit 4, a multi-point extractive system was used to obtain flue gas samples for analysis of NOx, CO, CO_2, and O_2. Samples were extracted from probes installed in the "A" (north) and the "B" (south) flue gas ducts immediately upstream of the air heaters. Gaseous samples were obtained from probes installed in four ports in each duct. Three sampling probes were installed in each port (long-, intermediate-, and short-length probes). Thus, samples were obtained from 24 points in the flue gas duct, ensuring a representative sample of the boiler exhaust gases. Twenty-four sample lines were strung from the probes to a mobile emissions monitoring laboratory that was located at the ground level adjacent to the unit. The gas samples were conditioned to remove water, and were then directed to emission monitors.

NOx, CO, CO_2, and O_2 were measured using EPA continuous monitoring procedures, and EPA certified calibration gases. O_2 was measured with a Servomex Model 570A instrument, CO_2 with a ACS Model 3300 instrument, CO with a TECO Model 48 instrument, and NOx with a TECO Model 10A chemiluminescence instrument. Opacity was measured with the plant continuous emissions monitor system (CEMS).

At Kahe Unit 6 and Montova Unit B6, the plant CEMS were used for measurement of NOx, excess O_2, and opacity.

Results

The objectives of the LN-REACH retrofits at Collins Unit 4 and Kahe Unit 6 were to reduce NOx emissions without increasing PM emissions and opacity. The CP-REACH retrofit at Montova Unit B6 was intended to reduce PM emissions without increasing NOx emissions. Results are presented below.

Collins Unit 4

As described above, CP-REACH was retrofitted at Collins Unit 4 in 1991 to improve oil atomization and combustion performance. The CP-REACH retrofit eliminated high opacity which caused derating of the unit.

As part of the gas conversion project at Collins Unit 4, EPT supplied new LN-REACH flame stabilizers and replaced the CP-REACH internal-mix atomizers with Segmented V-Jet atomizers. Figure 1 compares NOx emissions vs. load for CP-REACH and LN-REACH, and also shows results from parametric tests to characterize the effects of OFA and FGR on NOx emissions. For CP-REACH, NOx emissions without OFA and FGR varied from 0.35 lb/MBtu at 300-MW to approximately 0.6 lb/MBtu at 540-MW. The downward-pointing arrows at 525-MW show the beneficial effects of: (1) opening the OFA ports, which reduced NOx emissions to approximately 0.46 lb/MBtu, and (2) combining OFA with approximately 7% FGR (using one GR fan), which further decreased NOx emissions to 0.31 lb/MBtu. NOx emissions less than 0.30 lb/MBtu could be achieved with CP-REACH at full load by operating two GR fans to deliver 10-12% FGR.

With LN-REACH, NOx emissions without OFA and FGR varied from 0.18 lb/MBtu at 300-MW to approximately 0.30 lb/MBtu at 500-MW (the maximum load possible during the tests due to boiler feed pump problems). The downward-pointing arrows at 500-MW show that OFA reduced NOx emissions to 0.26 lb/MBtu, and OFA combined with approximately 7% FGR (one GR fan) further decreased NOx emissions to 0.21 lb/MBtu. Opacity was less than 10% over the load range. Emissions compliance tests performed with LN-REACH at a later date showed NOx emissions of 0.25 lb/MBtu at 550-MW with the OFA ports open and 7% FGR. Opacity was 10-13%.

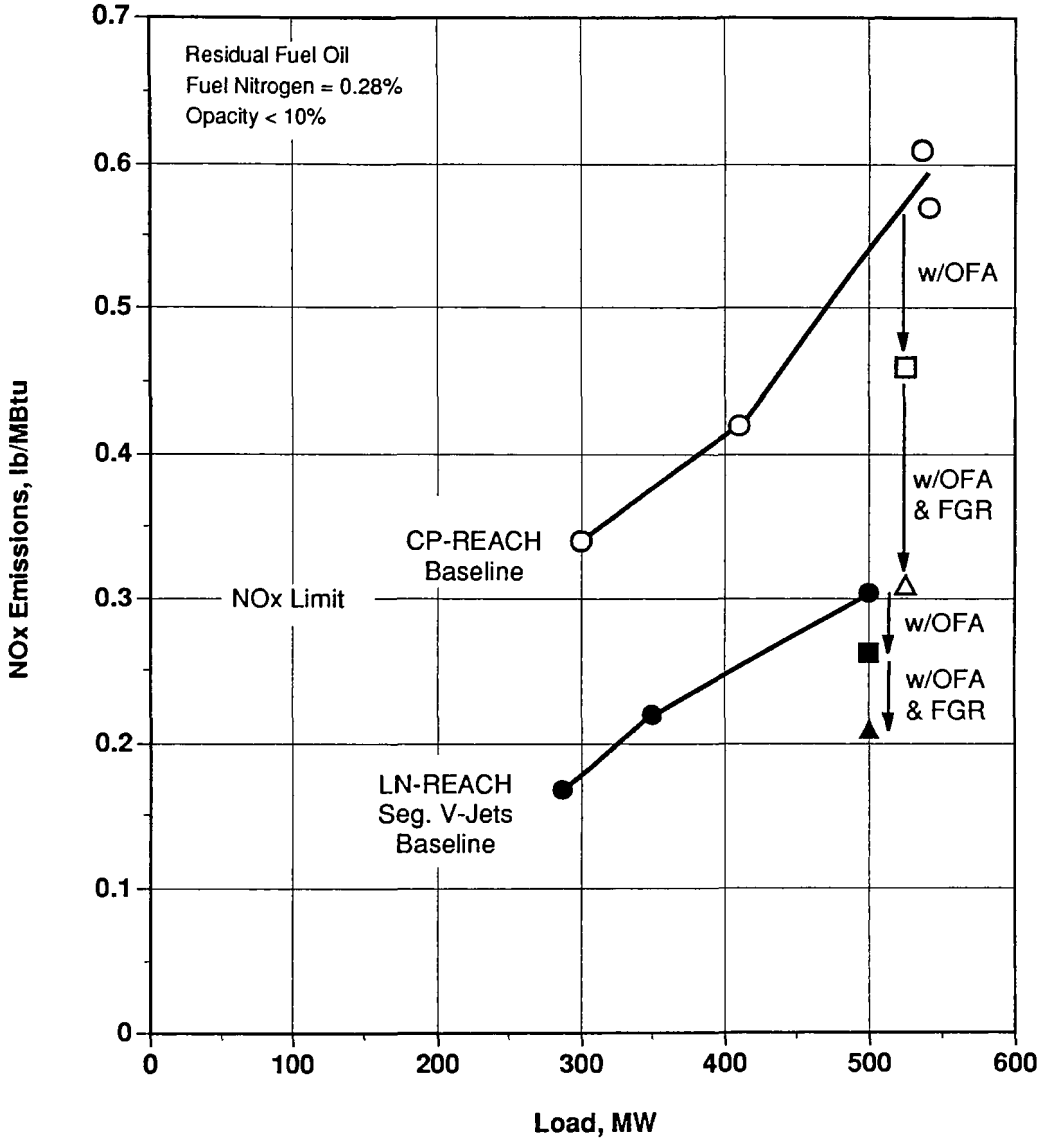

Figure 1. NOx emissions vs. load for Collins Unit 4 with CP-REACH (open symbols) and LN-REACH with Segmented V-Jet atomizers (closed symbols) The solid lines represent baseline NOx emissions without FGR and OFA. The singular data points show NOx reductions achieved at 540-MW for CP-REACH and 500-MW for LN-REACH with OFA (squares) and OFA + 7% FGR (triangles). The Segmented V-Jet atomizers alone (baseline) reduced NOx emissions by 45%. Adding OFA and FGR further reduced NOx emissions by 32%.

The reductions in NOx emissions with LN-REACH were substantial. At 500-MW without OFA and FGR, LN-REACH delivered a 45% reduction in NOx emissions compared to CP-REACH. With OFA and 7% FGR, LN-REACH achieved a 32% reduction in NOx emissions compared to CP-REACH. A major advantage of LN-REACH in this application was that NOx emissions compliance was achieved without OFA and FGR below 490-MW. At higher loads, plant operators had the flexibility to choose either OFA or FGR to meet the NOx emissions limit depending upon steam temperature or other operational considerations. In any case, there was sufficient NOx and opacity compliance margin available to allow for variations in fuel composition (e.g., fuel nitrogen) and boiler operation (e.g., only one GR fan). The experience at Collins Unit 4 showed that for boilers not equipped with OFA and FGR, LN-REACH can achieve significant reductions in NOx emissions at very low cost, i.e., about $0.25/kW.

Kahe Unit 6

LN-REACH Segmented V-Jet atomizers were installed in Kahe Unit 6 in April 1997. Figure 2 compares NOx emissions vs. load for the Segmented V-Jets and the first-generation LN-REACH atomizers installed in 1990. The data were obtained with approximately 15% OFA and 12% FGR. Results showed that the Segmented V-Jet atomizers reduced NOx emissions at maximum load from 0.22 to 0.19 lb/MBtu (approximately 13%). At lower loads, the reduction in NOx emissions by using the Segmented V-Jet atomizers was approximately 20%. As was the case at Collins Unit 4, the lower NOx emissions with LN-REACH allowed plant operators to meet the NOx and opacity limits with less than the maximum OFA and FGR, thus providing a margin to allow for variations in fuel composition and boiler operation.

Montova Unit B6

CP-REACH flame stabilizers, extenders, and internal-mix atomizers were installed in Montova Unit B6 in January 1997, and tests to characterize particulate matter (PM) and NOx emissions were performed in February 1997. As summarized in Figure 3, PM emissions with CP-REACH were reduced by 70% to 56 mg/Nm^3 (0.036 lb/MBtu) from 200 mg/Nm^3 (0.11 lb/MBtu). NOx emissions remained essentially unchanged at 715-735 mg/Nm^3.[2]

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[2]The NOx and PM emissions reported for the original operating condition were "typical values" provided by Frene based on historical data, and were not results from specific tests performed as part of the REACH retrofit.

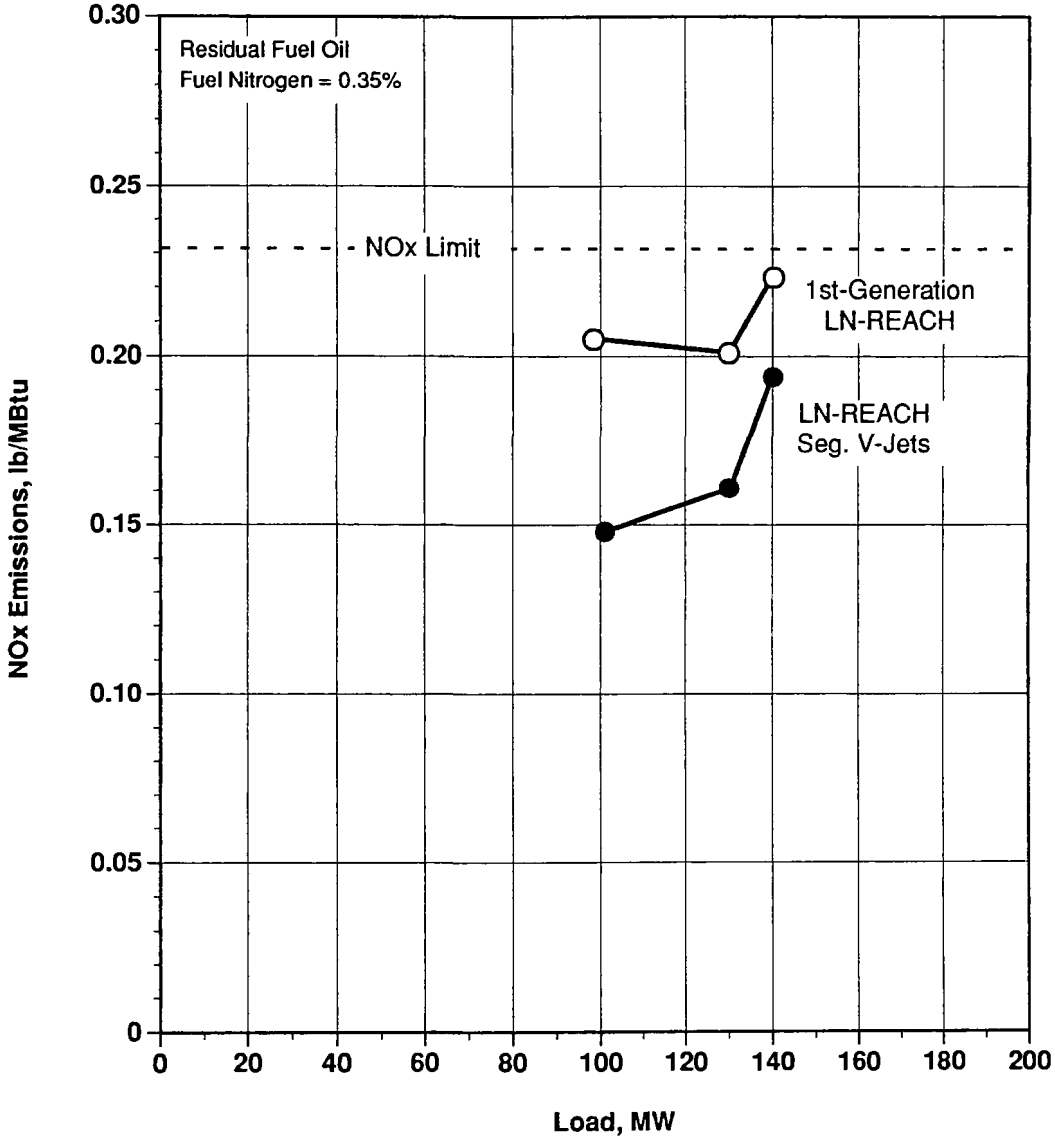

Figure 2. NOx emissions vs. load for Kahe Unit 6 with 1st-generation LN-REACH (open symbols) and LN-REACH with Segmented V-Jet atomizers (closed symbols). The data were collected with 15% OFA and 12% FGR to the windbox. The Segmented V-Jets reduced NOx emissions by 13% compared to the 1st-generation LN-REACH atomizers. Opacity at full load was 11-13% for the 1st-generation LN-REACH compared to 8-10% with the Segmented V-Jets.

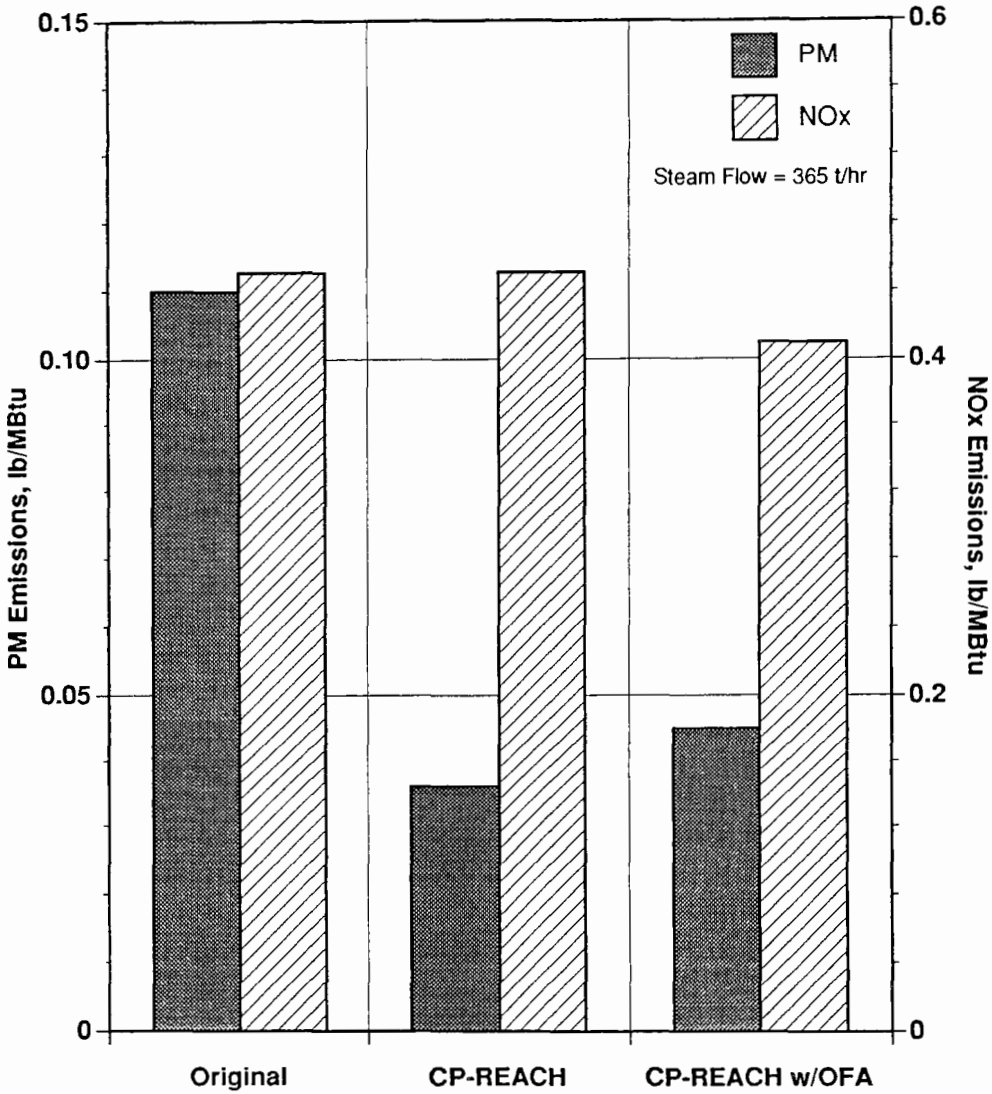

Figure 3. PM and NOx emissions at Montova Unit B6 with the original combustion equipment (left) and CP-REACH. The CP-REACH data shown on the far right were obtained with the dampers 50% open on the close-coupled OFA compartments above the top burner elevation. Prior to installation of CP-REACH it was not feasible to open the OFA compartment dampers due to high opacity.

Figure 3 also shows the effect on NOx emissions of opening the auxiliary-air compartments above the top burner elevation. As discussed previously, to avoid high opacity the boiler was normally operated with the fuel-air compartment dampers 100% open and the functional auxiliary air compartments 10% open (for cooling) on all the burners. As shown in the figure, setting the auxiliary air compartments above the top burner elevation to 50% open reduced NOx emissions by approximately 9% from 0.45 to 0.41 lb/MBtu (725 to 660 mg/Nm^3) with a very slight increase in PM emissions from 56 to 69 mg/Nm^3 (0.036 to 0.045 lb/MBtu). This result was not surprising, and suggests that further biasing of combustion air to the auxiliary-air compartments in the top elevation or application of LN-REACH at Montova Unit B6 would be effective in lowering NOx emissions.

Conclusions

LN-REACH applications using Segmented V-Jet atomizers (patented) at Collins Unit 4, a 550-MW, opposed-wall fired boiler, and Kahe Unit 6, a 140-MW, single-wall-fired boiler, showed significant reductions in NOx emissions without increases in opacity or PM emissions. At Collins Unit 4, LN-REACH reduced NOx emissions at 500-MW from 0.55 to 0.30 lb/MBtu (883 to 481 mg/Nm^3) without OFA and FGR. The application of OFA and 7% FGR further reduced NOx emissions to 0.21 lb/MBtu (338 mg/Nm^3) with 10% opacity. At Kahe Unit 6, NOx emissions were reduced 13% below levels achieved with a combination of 1st-generation LN-REACH, OFA and FGR, i.e., from 0.22 to 0.19 lb/MBtu (354 to 306 mg/Nm^3) with 10% opacity. At both plants the lower NOx emissions with LN-REACH allowed plant operators to meet the NOx and opacity emissions limits over the load range with less than the maximum OFA and FGR, and thus providing a margin to allow for variations in fuel composition and boiler operation.

CP-REACH flame stabilizers, extenders, and internal-mix atomizers were installed in Montova Unit B6 of Frene in Italy in January 1997. Compared to emissions with the original combustion equipment, PM emissions with CP-REACH were reduced by 70% to 56 mg/Nm^3 (0.036 lb/MBtu) from 200 mg/Nm^3 (0.11 lb/MBtu). NOx emissions remained essentially unchanged at 715-735 mg/Nm^3.

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REDUCING NOx EMISSIONS IN A NATURAL GAS-FIRED UTILITY BOILER USING COMPUTATIONAL FLUID DYNAMICS

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Abstract

The Delta Power Plant, Pittsburg Unit #7 was simulated using computational fluid dynamics with the goal of reducing NOx emissions and improving combustion efficiency. Pittsburg Unit #7 is a 700 Mw boiler burning natural gas with a tangential firing system, separated overfire air, and flue gas recirculation (FGR). Under standard operating conditions at MCR, typical NOx and CO emissions at 3% O2 were 75 ppm and 65 ppm, respectively. Baseline test data obtained from the unit at loads of 650, 450, and 170 Mw was used to calibrate the numerical model. The model was then used to investigate the effect of operational parameters, e.g., the quantity and location of FGR, the amount of SOFA, etc., on the boiler emissions of NOx and CO. Model results suggest that a 50% reduction in NOx emissions is possible without exceeding the CO target or negatively impacting boiler performance. A physical cold flow model was generated to study and improve the mixing of the FGR and the combustion air entering the windbox. Post modification testing of Unit 7 achieved NOx emissions of less than 40 ppm.

Introduction

A project was initiated in 1996 by Pacific Gas and Electric with the objective of reducing NOx emissions and improving combustion efficiency of the Delta Power Plant, Pittsburg Unit 7. Pittsburg Unit 7 is a 700 Mw boiler burning natural gas with a tangential firing system, separated overfire air, and flue gas recirculation (FGR). Under standard operating conditions at MCR, typical NOx and CO emissions at 3% O2 were 75 ppm and 65 ppm, respectively. The project

goal was to reduce NOx below 50 ppm without increasing CO emissions or negatively impacting boiler performance and to do so with the minimum possible capital cost. To achieve this goal, a program was developed that included baseline testing in Unit 7 and both physical flow and computational fluid dynamics modeling. Stone and Webster Engineering Corporation was a consultant on the project and oversaw the baseline testing as well as the computational fluid dynamics CFD (performed at ABB Power Plant Laboratories) and physical flow (performed at NELS in Buffalo, NY) modeling efforts.

Unit 7 is a tangentially fired, Combined Circulation® unit capable of producing 5,360,400 lbs/hr of steam at 3,818 psig and 1,005 °F and reheat 4,510,240 lbs/hr of steam from 585 °F to 1005 °F. Natural gas is fired through 5 burner elevations, each containing 4 gas nozzles. Combustion air is supplied through two separate ducts by forced draft fans. In each duct, the combustion air passes through an air heater, after which approximately 12% of the air is diverted for the separated overfire air (SOFA). The remaining combustion air is mixed with flue gas (FGR) before being injected into the windbox. Unit 7 typically operates with 30% FGR and 2% excess oxygen.

Unit 7 baseline testing, performed at 650, 450, and 170 MW suggested flow rate and gas composition imbalances in the furnace. Velocity traverses were performed in the air ducts to determine the quantity of overfire air and FGR to each side of the furnace and the flow rate of combustion air/FGR entering each corner of the furnace. Flow imbalances of up to 20% were measured from corner to corner. Gas species measurements in each of the burner compartments revealed that the FGR was not uniformly mixing with the combustion air before entering the windboxes.

A physical cold flow model of Unit 7 was constructed to simulate the mixing of the combustion air and the FGR. The model extended from the outlet flanges of the FD and FGR fans through the furnace to the cavity above the boiler's primary superheater and reheater sections. The model was used to identify potential modifications that would optimize the unit's air/FGR flow balance to improve combustion performance and allow reduction of NOx emissions. A numerical model of Pittsburg Unit 7 was generated using a commercially available CFD code and ABB Combustion Engineering, Inc.'s (ABB CE) proprietary NOx model. The numerical model was used to investigate the effect of potential operating condition modifications on NOx and CO emissions. The model was used to estimate the potential NOx reduction that could be obtained by properly mixing the FGR and the combustion air and to determine the effect of other potential modifications, including: FGR biasing between burner elevations, fuel biasing, and quantity of separated overfire air (SOFA).

This paper describes both the physical cold flow model and the numerical model of Pittsburg Unit 7, compares the numerical model predictions to the baseline test measurements, and presents the results of the parametric study to determine the effect of potential operating variables on emissions. Results are also presented from the field testing after the implementation of the improved FGR mixing system.

Physical Cold Flow Modeling

A physical cold flow simulation model (CFM) of Unit 7 was constructed and tested to simulate the existing combustion air/FGR flow balance through the unit's burners and SOFA ports. The principle objective of this model study was to identify potential modifications that would optimize the unit's air/FGR flow balance to improve combustion performance and allow reduction of NOx emissions without significantly increasing draft system pressure drop.

This objective appeared reasonable, based on test data obtained from Unit 7 that revealed a maldistribution of FGR concentration in the unit's windbox at the four burner corners (Figure 1). Additional measurements in the combustion air/FGR mixture flowing to each of the unit's twenty individual burners (five burners per corner) also confirmed the poor distributions presented in the figure. These data indicated that proportionally higher recirculated flue gas concentrations were present near the bottom of the front burner windboxes resulting in higher FGR rates in the bottom burners compared to the middle and upper burners in these corners. The FGR gradient was substantially different in the rear burner windboxes showing much lower FGR flow rates to the center of each windbox compared to either the upper or lower region. The poor mixing of the FGR and the combustion air led to measured oxygen concentrations ranging from 14.2 to 20.8% on a dry basis. The CFM was used to confirm and further evaluate these findings and to develop draft system flow management modifications for the full scale unit.

The physical model used in this work was constructed primarily of clear plastic and sheet metal and was built to a 1/9 scale. The model extended from the outlet flanges of the FD and FGR fans through the furnace to the cavity above the boiler's primary superheater and reheater sections. Combustion air and recirculated flue gas were simulated in the model by ambient air and heated air, respectively. Flow visualization techniques were used in the model to aid in identification of gross imbalances while velocity and static pressure measurements were used to document improvements resulting from iterative draft system modifications. These measurements were also used to confirm that the specification requirements regarding flow uniformity and acceptable pressure drop increases were met.

Tests of the CFM confirmed field measured FGR concentration distributions and validated the model's baseline simulation accuracy. Subsequent additional tests identified key factors affecting FGR distribution and allowed development of recommended modifications that could be applied to the full scale unit's draft system. These modifications consisted principally of minor alterations to the FGR supply ducts and nozzles to improve injection velocity and distribution of recirculated flue gas as it entered the combustion air ducts upstream of the burners. The results of these modifications to the full scale unit will be discussed later in this paper.

Numerical Model Description

A numerical model of Pittsburg Unit 7 was generated to identify the potential reduction in NOx emissions as a result of improving the mixing of the FGR and the combustion air and to evaluate increasing the quantity of FGR and the effect of the amount of SOFA on NOx reduction. The model was used to determine the potential NOx reduction of the different concepts and their effect on CO emissions and superheater tube metal temperatures. The simulations were performed using a commercially available CFD code. NOx predictions were made using a proprietary ABB CE NOx model that was incorporated into the CFD code as a post processor.

The CFD code is a general purpose computer code for modeling fluid flow, heat transfer, and combustion for a user specified geometry. It uses a control volume-based technique to solve the differential equations governing the reacting flow problem and uses the SIMPLE (Semi-Implicit Method for Pressure-Linked Equations) algorithm (1) to solve for the pressure-velocity coupling. Eulerian transport equations are solved for pressure, each of the components of velocity (U, V, and W), turbulence, enthalpy, radiation, and gas species. The k-e turbulence model (2) was used for all simulations performed in this study. Conservation equations were solved for both the product and reactant species (natural gas, O_2, CO, CO_2, and H_2O), while N_2 was calculated by difference. A generalized finite rate formulation was used to model the complex chemical reactions. A 2-step reaction mechanism was used with the natural gas reacting with O_2 in the first step to form CO, which was subsequently oxidized to CO_2. For each reaction, both the Arrhenius rate and the mixing rate from the eddy breakup model of Magnussen and Hjertager (3) are calculated. The reaction rate is assumed to be the limiting (slowest) rate, which is then used to calculate the source terms for the species and enthalpy equations.

Unit 7 was simulated using a body-fitted grid of approximately 250,000 cells to resolve the furnace and firing system geometry. The unit was simulated up through the vertical outlet plane of the furnace, including the superheater division panels, the superheater platen, and the superheater pendant. The grid was extended at the furnace outlet to prevent flow recirculation which would prevent overall convergence of the model. The windbox was modeled with 4 gas nozzles per burner compartment, resulting in 20 gas nozzles per corner. The free area of each gas nozzle was maintained in the model, although the aspect ratio of the nozzles was decreased to minimize the number of grid cells required to model the windbox. The species composition of the combustion air/FGR mixture was assumed to be constant for each burner compartment. For the baseline test simulations, each burner compartment was assumed to have the measured gas species composition.

The superheater division panels were modeled as walls with a specified steam temperature, thermal resistance, and emissivity. The superheater tube banks were modeled as anisotropic porous media for the flow calculations. Inertial resistance factors (loss coefficients per unit length) were calculated for each of the superheater tube banks as a function of tube spacing. Heat was extracted in the superheater tube banks by specifying an average steam temperature and calculating local heat transfer coefficients. The furnace walls were modeled with a thermal resistance boundary condition. An average waterwall fluid temperature was specified, as were

the wall emissivity and the thermal resistance. The thermal resistance was set to account for the tube metal resistance as well as the soot that may be present on the boiler walls.

The ABB CE NOx model was incorporated into the commercial code as a post processor using user defined subroutines. The NOx model uses global reaction rates for thermal NO, prompt NO, and fuel NO (4). The model also accounts for NOx destruction through the reburning mechanism (5). The dominant mechanism for NOx formation in gas combustion is thermal NO. The thermal NO was calculated using a partial equilibrium assumption for the atomic O with a rate that was calculated from studies performed at ABB using the CHEMKIN (6) code. The turbulent mixing process adds fluctuations in both temperature and gas phase species concentrations. As the temperature and species concentrations have a nonlinear contribution to NO formation, significant errors may result if the fluctuations are ignored when predicting the rate of NOx formation. A probability density function (PDF) method (7-8) was used to account for the turbulent fluctuations using a beta function for the shape of the PDF.

The CFD simulations were run on an 8-processor workstation and typically required 2 days of cpu time to converge each case. Once the solution was obtained to the combustion problem, the NOx model was run as a post processor.

Numerical Model Calibration/Validation

The baseline field tests were used to calibrate the numerical model and verify that the model was accurately simulating the observed combustion behavior in the furnace. Baseline tests were performed in Unit 7 at 3 loads, nominally 650, 450, and 170 MW. The data obtained for each test condition included boiler emissions, windbox flow rates and gas species compositions, and high velocity temperature probe measurements made near the horizontal furnace outlet plane.

The 650 MW case was used to calibrate the numerical model. The calibration included determining the appropriate waterwall thermal resistance and setting the standard deviation of the PDF in the NOx model to reasonably match the measured NOx values. ABB CE's Reheat Boiler program (9), a 1-dimensional boiler simulation model, was used to calculate the expected horizontal furnace outlet temperature (at the boiler nose) for each of the 3 baseline test cases. The Reheat Boiler program performs a heat balance around the boiler using the measured water and steam flows, temperatures, etc. where available, and using estimates of unmeasured input parameters based on historical experience. The thermal resistance of the furnace walls was adjusted in the numerical model for the 650 MW simulation in order to match the predicted furnace outlet temperature to the value calculated from the Reheat Boiler program.

The calibration procedure was needed to account for both unknown wall boundary conditions and approximations made in both the physical models in the code and the numerical representation of the furnace (e.g., the lack of a good soot model and the simplification of the gas burners and the tube banks which can not be resolved with a reasonable grid size). The 2 reduced

load cases were then simulated using the same physical properties and wall resistance as the 650 MW case. The results for the reduced load cases were in good agreement with experimental measurements, suggesting that the parameters used in the numerical model were adequate.

Baseline Test Input Data

The total natural gas and combustion air flow rates are listed in Table 1, along with the average % FGR and SOFA for each of the 3 baseline cases. The % FGR is defined as the quantity of recirculated flue gas divided by the total air and fuel flow. The % excess oxygen reported in the table is on a dry basis. Table 2 presents the measured air flow rates for each corner of the furnace. Note the significant imbalance in air flow distribution between the north and south sides of the boiler. The SOFA also showed a north to south bias (front to rear). The gas species compositions measured in each burner compartment indicated that the FGR was not uniformly mixing with the combustion air before entering the windboxes. There was a bias of FGR to the bottom and top elevations and to corners 1 and 2 (see Figure 1). The gas compositions measured at each burner compartment were used as input to the numerical model.

Table 1. Baseline Test Data: Furnace Flow Rates

Load (MW)	*Natural Gas [SCFH x E-3]*	*Comb. Air [SCFH x E-6]*	*% FGR*	*% SOFA*	*% Oxygen*
650	6307	70.3	31	12	1.9
450	4356	52.0	44	14	3.5
170	1850	28.2	47	14	7.3

Table 2. Baseline Test Data: Individual Windbox Flow Rates

Load (MW)	*Corner 1 - NE [SCFH x E-6]*	*Corner 2 - NW [SCFH x E-6]*	*Corner 3 - SE [SCFH x E-6]*	*Corner 4 - SW [SCFH x E-6]*
650	22.4	24.8	30.2	25.8
450	18.6	21.7	27.7	26.8
170	9.0	10.2	11.7	11.8

Results of Baseline Simulations

Table 3 shows the gas temperatures predicted by the numerical model (CFD) and ABB's Reheat Boiler Program. The 2 temperatures were within 50°F of each other for all loads indicating that the numerical model was accurately predicting the heat extraction in the radiant section of the

boiler. To check the models, high velocity temperature probe measurements were made through ports at the 119' level, approximately 4.5' above the horizontal furnace outlet plane. Figures 2-3 compare the measured gas temperatures to the model predictions for each of the 3 baseline test cases. Ports 1 and 2 are on the west (right) side of the furnace. Port 1 is between the platen and pendant superheater sections and Port 2 is on the north side of the furnace between the superheater division panels. As shown in the figures, the model shows good correlation with the measured trends in outlet temperature as a function of load. Exact agreement between the model and the measurements was not expected as the measurements were made at an elevation in the furnace where heat is being extracted from the gas by the superheater sections. The numerical model made some simplifying assumptions about the superheater sections as it was not feasible or necessary to model them in detail. As most of the NOx generation occurs in the lower furnace, the approximations made in the convective heat transfer regions of the boiler had little effect on the gaseous emissions predicted by the model. Figures 2-3 do, however, demonstrate that the numerical model is predicting reasonable temperature trends as a function of load.

Table 3. Baseline Model Results: Horizontal furnace outlet temperature predictions (°F)

Load (MW)	*Reheat Boiler Program*	*Numerical Model*
650	2466	2465
450	2174	2220
170	1681	1671

After the baseline combustion simulations were converged, the NOx model was run on each case. As shown in Table 4, the NOx model was predicting from 4-8 ppm lower NOx on a dry basis than was measured for the baseline cases. However, the trend in NOx emissions as a function of load was accurately predicted by the model. Note that these were as measured values and were not corrected to 3% oxygen. The numerical model predicted outlet CO concentrations that were significantly higher than the measured values. The high CO concentrations predicted by the model are due, in part, to the fact that the model ends at the vertical outlet plane of the furnace where the gas temperature is on the order of 1700 °F for the 650 MW test. Significant CO oxidation can still occur at this temperature. Inaccuracies in the CO oxidation rate and the Magnussen mixing constants may also contribute to the high levels of CO as the predicted CO is very sensitive to these parameters. However, it was felt that the model would adequately predict the trends in CO emissions as a function of operating conditions. All of the CO predictions reported in this document were normalized by the factor required to match the baseline 650 MW prediction to the measured value. As shown in Table 4, the model still overpredicts the CO emissions at the lower loads where it was measured to be 1 ppm.

An examination of the CO emissions in the furnace simulations shows high CO levels coming from the SW corner of the furnace due to low oxygen levels in that corner. This results in high temperatures and CO levels along the back wall of the furnace. Poor mixing of the SOFA also occurs in that corner as the SOFA nozzles are on the side walls of the furnace and not in the corners. High levels of CO are predicted to occur at both side walls of the furnace as the gas

enters the convective pass, consistent with field observations. As will be shown in the following section, a more uniform mixing of the FGR will reduce the regions of high stoichiometry in the windbox and subsequently reduce the NOx emissions.

Table 4. Baseline Test Results: NOx and CO predicted vs. measured

	NOx - dry PPM		*CO - dry PPM*	
Load (MW)	Measured	Predicted	Measured	Predicted*
650	65	61	56	56
450	28	23	1	18
170	22	14	1	15

* Normalized to 650 MW measured value.

Effect of Operating Conditions on Predicted NOx Emissions

A full load case (700 MW) was generated with the numerical model by scaling up the 650 MW baseline test case. This full load case was used as the basis for performing an optimization study to determine which variables had the largest effect on NOx emissions in an attempt to optimize the boiler for NOx emissions without adversely affecting the combustion efficiency or causing overheating of superheater tubes. This section reports the model results for several variables that were studied including: air flow distribution, quantity of FGR, FGR biasing, and quantity of SOFA.

Combustion Air Flow Distribution

Under standard operation, Unit 7 has significant flow imbalances in both the main windbox and the SOFA. Poor mixing of the FGR also causes large variations in the oxygen concentration from burner to burner. Three simulations were performed to understand the relative importance of balancing the windbox flow rates vs. improving the FGR mixing. One case used the composition distribution as measured in 650 MW baseline test, but with uniform mass flow rates through each windbox (Uniform Flow). The second case had uniform gas species compositions (30% FGR), but the mass flow rates as measured in 650 MW baseline test (Uniform Composition). The third case had both uniform flow rates and compositions.

Table 5 lists the predicted NOx and CO emissions for the three cases described above in addition to the full load case. Note that predicted NOx emissions are essentially half the baseline values when a uniform FGR mixing is assumed. By reducing the high oxygen concentration (20 %) that some of the burners were experiencing under the baseline conditions, the NOx emissions were dramatically reduced. The oxygen concentration of the uniformly mixed cases was approximately 17.5%, corresponding to 30% FGR. Note that there was little change in the predicted NOx

concentration as a function of the mass splits between the corners. Correcting the 15-20% imbalance in the mass flow rates of combustion air/FGR to the windboxes would have less effect on NOx emissions than improving the mixing of the FGR and the combustion air. The local oxygen concentration at the burner seemed to determine NOx emissions. The CO emissions, on the other hand, were impacted by both the composition and the mass flow distribution in the furnace. Optimum CO emissions were obtained with both uniform composition and flow as the very fuel rich regions were eliminated.

Table 5. Numerical model predictions for the air flow distribution cases

	NOx [ppm dry]	*CO [ppm dry]*	*HFOT [°F]*	*Platen SH [°F]*	*Pendant SH [°F]*
Full Load	69	72	2501	2121	1803
Uniform Flow	83	90	2490	2107	1794
Uniform Composition	34	106	2488	2103	1788
Uniform Flow and Composition	33	59	2481	2094	1781

FGR Quantity

Table 6 presents the model results when the quantity of FGR was varied from 15-45 %. All of the tests assumed that both the mass flow rates and the gas species compositions were uniform in the windbox. The 30% FGR case is the Uniform Flow and Composition case listed in the previous table. Decreasing the FGR to 15% causes a dramatic increase in NOx emissions due to the increased local oxygen concentration and gas temperatures. The NOx emissions drop as the quantity of FGR is increased, while the CO emissions increase as shown in Table 6.

Table 6. Numerical model predictions for the % FGR cases

	NOx [ppm dry]	*CO [ppm dry]*	*HFOT [°F]*	*Platen SH [°F]*	*Pendant SH [°F]*
15 % FGR	115	43	2546	2110	1788
30 % FGR	33	59	2481	2094	1781
35 % FGR	24	58	2460	2076	1781
45 % FGR	21	88	2404	2062	1772

The furnace outlet and superheater temperatures also decrease with increasing amounts of FGR. This decrease in temperature is due to the increased mass of recirculated gas that must be heated

and does not imply that there will be less problems associated with overheating in the superheater sections. In fact, the predicted quantity of heat absorbed by the waterwalls below the furnace nose decreases by 19% as the FGR is increased from 30 to 45%. Increasing FGR lowers the gas temperature and reduces the radiative heat transfer to the waterwalls. Decreasing the FGR to 15% causes an increase in lower furnace absorption of 16%. Note that these values may not accurately reflect the quantitative changes that will occur in the boiler due to inaccuracies in the radiation model, especially due to the presence of soot. However, the trend of decreased lower furnace absorption with increasing FGR is real.

FGR Biasing

The numerical model was also applied to a series of test conditions where the quantity of FGR was varied as a function of elevation. The gas velocity of each burner compartment was assumed to be constant while the species composition was varied as a function of elevation. Table 7 lists the test conditions that were investigated, along with the model predictions. As illustrated in the table, biasing the FGR in the numerical model was not beneficial from an emissions standpoint. As the temperature in the boiler is determined by the gas phase stoichiometry, the temperature profile in the furnace can be manipulated by biasing the FGR. Moving more of the FGR to the top burner elevations helps to lower the peak gas temperatures in the furnace which are typically near the top of the windbox. The gas temperatures at the bottom elevations are increased, resulting in a more uniform temperature profile in the furnace as the bottom elevations are typically cooler due to the increased waterwall surface of the hopper, etc.

Table 7. Numerical model predictions for the FGR biasing cases

FGR Biasing Scheme	*NOx [ppm dry]*	*CO [ppm dry]*	*HFOT [°F]*	*Platen SH [°F]*	*Pendant SH [°F]*
Large bias to top	71	185	2467	2083	1779
Large bias to bottom	44	250	2521	2128	1806
Small bias to top	37	76	2478	2089	1781
Uniform distribution	33	59	2481	2094	1781

Even though the peak gas temperatures in the boiler were decreased with FGR biasing, the NOx emissions were not improved. The predicted NOx emissions were more sensitive to the burner stoichiometry than to the temperature. Under uniform flow and composition conditions the average gas phase stoichiometry in the lower windbox is just slightly fuel rich. Decreasing the FGR to 25% increased the local burner stoichiometry sufficiently to increase NOx due to an increase in local gas stoichiometry near the burner. The effect was more dramatic with increased FGR biasing as illustrated in Table 7. Even though the temperature profile was more uniform with 15% FGR in the bottom elevations, the concentration of NOx increased as there was a fuel

lean core in the center of the furnace with a longer residence time for NOx formation. CO emissions also increased with increased biasing of the FGR.

SOFA Quantity

The predicted NOx emissions decrease slightly with increasing SOFA as illustrated in Table 8. The additional SOFA was uniformly removed from the windbox, maintaining the same quantity of FGR (30%). The model predicts that the CO emissions increase significantly as the quantity of overfire air is increased. The increase in CO is a result of poor mixing of the overfire air. Note that increasing the quantity of SOFA would require significant modifications to the overfire air system, resulting in a significant capital cost.

Table 8. Numerical model predictions for the % SOFA cases, assuming uniform inputs

% SOFA	*NOx [ppm dry]*	*CO [ppm dry]*	*HFOT [°F]*	*Platen SH [°F]*	*Pendant SH [°F]*
12 %	33	59	2481	2094	1781
15 %	30	114	2478	2096	1785
20 %	26	404	2501	2098	1790

In summary, the CFD study suggested that the most significant reduction in NOx emissions could be obtained by simply obtaining a uniform distribution of FGR within the windbox. If a uniform distribution of FGR could not be obtained, the model suggested that it was beneficial to have the higher quantities of FGR in the bottom burners. The model also showed that the potential reductions in NOx emissions did not justify the additional cost required to balance the mass flow rates to each corner of the furnace and to increase the quantity of SOFA. The improved FGR distribution should also decrease CO emissions and have little effect on the superheater tube metal temperatures.

Results of Flow Management Modifications on Unit 7

Implementation of the FGR mixing system modifications that were developed through investigation of the physical cold flow model resulted in substantial improvement in the unit's windbox and burner FGR flow distributions. These improvements contributed to more balanced combustion and lower NOx emissions on the unit. Figure 4 presents windbox FGR distribution data taken after flow management modifications were installed. A comparison of Figure 4 distributions with those presented in Figure 1 clearly demonstrates a significant improvement in FGR concentration gradient.

This enhanced balance of FGR and combustion air to each of the unit's twenty burners resulted in a significant reduction in full load NOx emissions. Figure 5 presents Unit 7 NOx emissions as a function of FGR rate for pre- and post-modifications operation. Note that some of the scatter in the data is a result of variations in the percent of excess air. However, the data show that for relatively low FGR rates, pre- and post-modification emissions are comparable; but as FGR rate increases, NOx emissions are observed to be much lower after the draft system modifications were installed compared to baseline operation. These results suggest that as the unit's flue gas recirculation rate increased prior to these draft system modifications, the combustion air/FGR imbalance became worse. This effect substantially diminished the NOx reduction benefit that may now be derived from operating at higher FGR rates. (Please note that following draft system modifications, it was not possible to test Unit 7 at lower loads due to utility system load requirements.) The reductions in NOx emissions with the improved FGR distribution and the quantity of overfire air are consistent with the CFD predictions.

Conclusions

Reductions in NOx emissions of almost 50% were achieved in PG&E's Pittsburg Unit 7 as a result of an optimization project that combined field testing, CFD modeling, and physical cold flow modeling. Field testing revealed a maldistribution of FGR in the combustion air to the windbox as a function of both corner and elevation and flow rate imbalances of up to 20% in both the combustion air and the SOFA. CFD models of the unit accurately simulated 3 baseline test cases, performed at 650, 450, and 170 MW. The CFD model was then used to quantify the potential reduction in NOx emissions that could be expected if the FGR and the combustion air were uniformly mixed (approximately 50%). The CFD model was also used to investigate the effects of biasing the FGR as a function of elevation, balancing the mass flow rates to each windbox and SOFA compartment, and increasing the quantity of SOFA and FGR. The NOx model was used to identify the primary boiler input parameters which have large effects on NOx reduction. Predictions showed that increasing the quantity of FGR could decrease NOx emissions, but that both CO emissions and superheater tube metal temperatures may increase. The potential decrease in NOx emissions obtained by increasing the quantity of SOFA did not justify the capital cost of modifying the SOFA system.

The physical flow model was used to develop draft system flow management modifications for the full scale unit to improve the mixing of the FGR and the combustion air. The modifications led to more uniform FGR distributions in the windboxes, and ultimately reductions in NOx emissions of approximately 50%. This project demonstrates the potential for significant reductions in NOx emissions in utility boilers by simply tuning the unit. Field testing, computational fluid dynamics, and physical cold flow modeling can be used together as a means to understand and improve the performance of a utility boiler.

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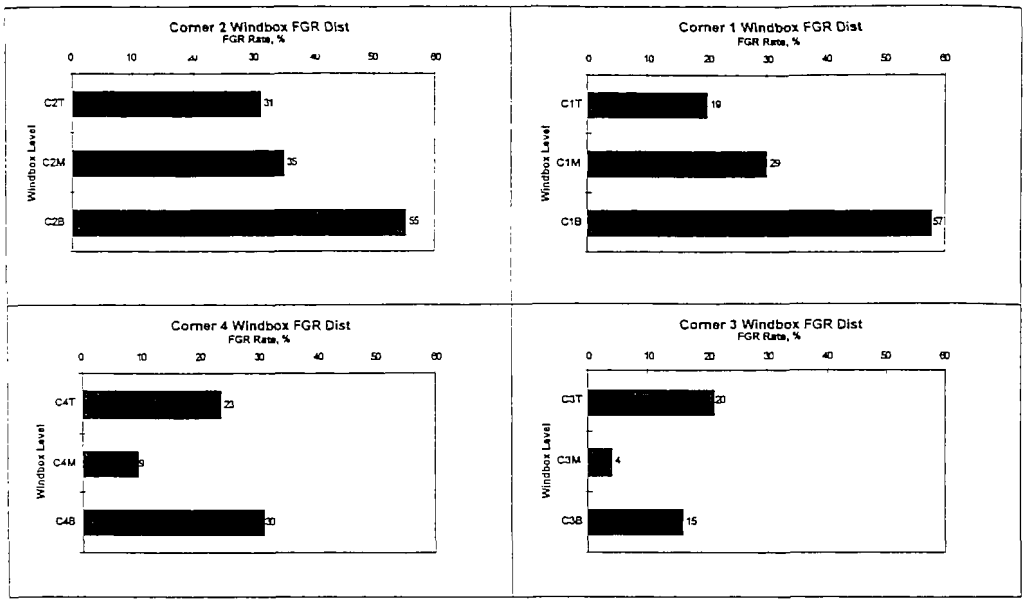

Figure 1. Measured FGR distribution for 650 MW baseline test.

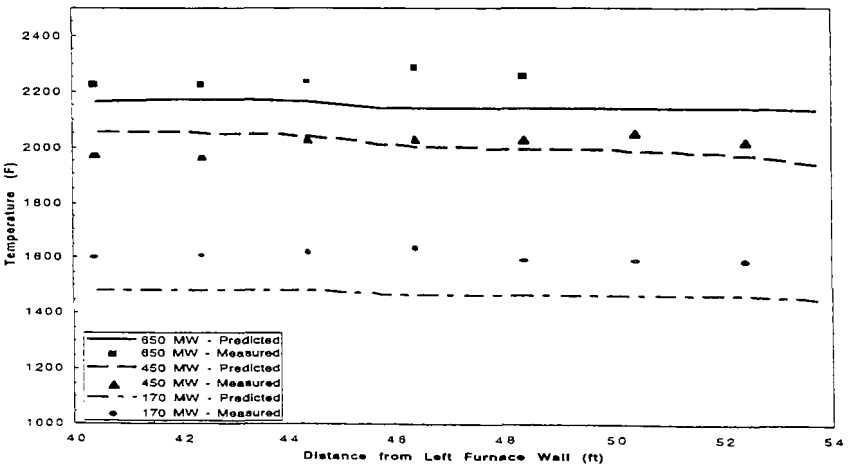

Figure 2. Comparison of predicted and measured gas temperatures (°F) for Port 1.

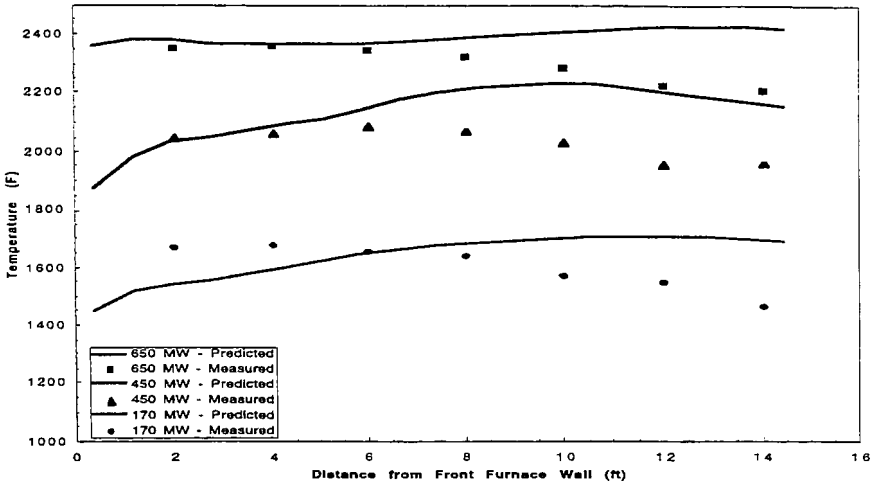

Figure 3. Comparison of predicted and measured gas temperatures (°F) for Port 2.

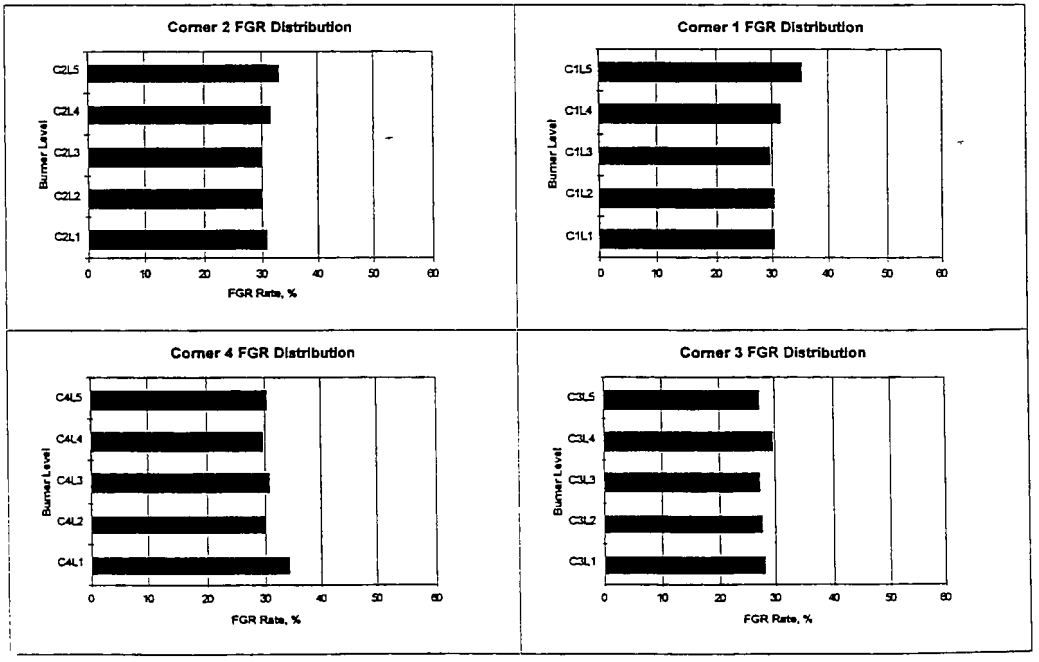

Figure 4. Measured FGR distribution for 650 MW post-modification test.

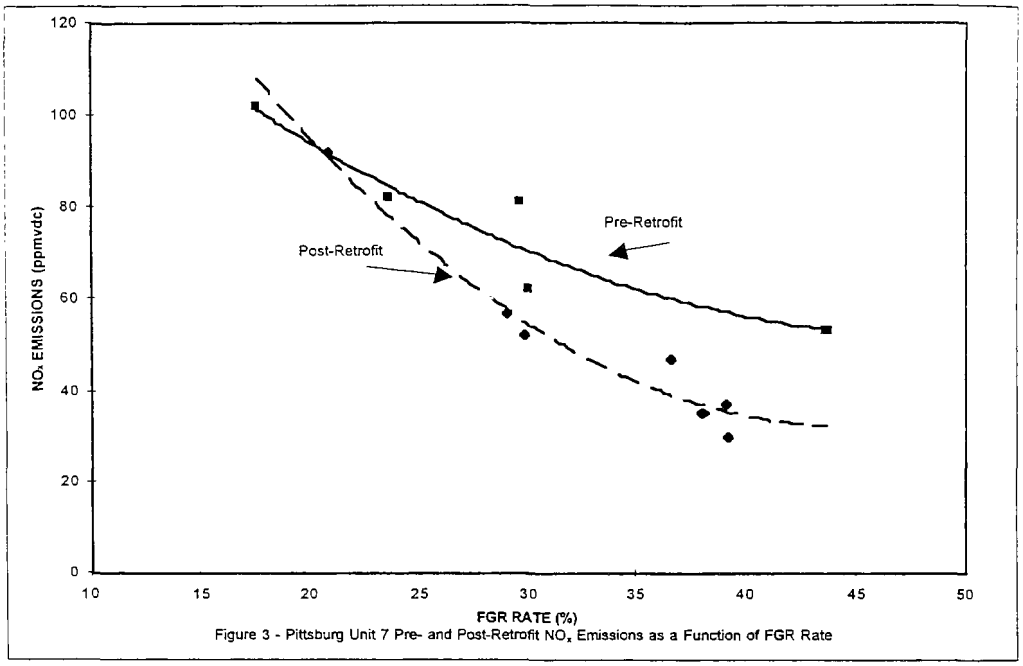

Figure 5. Measured NOx emissions as a function of FGR quantity.

Tuesday, August 26; 1:00 p.m.
Parallel Session A:
Cyclones - Combustion NOx Controls

COMPUTER MODELING OF CYCLONE BARRELS

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Abstract

Computer simulations of cyclone barrels and an opposed wall cyclone-fired furnace have been used to further the understanding of cyclone barrel combustion and to evaluate the NOx reduction potential of modifications to cyclone barrel operation. This paper describes the cyclone barrel model and the simulations that were carried out to determine cost effective nitric oxide control options both for the barrel and the furnace. The simulations indicate that the conditions within the cyclone barrel are far from well mixed. This observation is supported by gas temperature and species concentration measurements in two cyclone barrel types. Comparison of model predictions with two data sets of temperature and gas species concentrations indicated very good qualitative agreement and acceptable quantitative agreement between the model predictions and measured properties. NOx formed in the furnace section of opposed wall cyclone-fired boilers can be significant and is dependent on the thermal environment in the lower furnace. The simulations indicated the potential reductions that could be achieved through the application of several techniques including: fuel switching, flue gas recirculation, water injection, barrel biasing and barrel staging.

Introduction

There are 105 operating, cyclone-equipped utility boilers burning a range of fuels including high sulfur bituminous coals, lignites and blends. These boilers represent approximately 14 percent of pre-New Source Performance Standards (NSPS) coal-fired generating capacity and they contribute approximately 21 percent of the total NOx emitted. Although the majority of cyclone units are 20-30 years old, utilities plan to operate many of these units for at least an additional 10-20 years. Low NOx firing systems typical of pulverized coal fired boilers may not be applicable to cyclone-fired boilers because of their unique design. Selective catalytic reduction,

selective non-catalytic reduction and reburning technologies can reduce NOx emissions from cyclone-fired boilers, but at high capital and/or operating costs.

The EPRI Cyclone NOx Control Interest Group (CNCIG) decided that a numerical simulation tool could be used to assess the potential NOx reductions resulting from modifications to cyclone barrel operation. The approach selected was to extend the capabilities of an existing reacting computational fluid dynamics code, *GLACIER*, to include the features that are necessary to describe the physical and chemical phenomena controlling combustion in a cyclone barrel typical of those used by CNCIG members. Originally the program envisioned three components:

- Construct a model to simulate a single cyclone barrel at the Sioux Station of the Union Electric Company.
- Evaluate the model for a baseline case and determine the sensitivity of the results to both model and input parameters.
- Use the model to explore cost effective options to control NOx formation within the barrel.

During the study, the importance of NO formation within the furnace was recognized and a fourth component was added:

- Integrate the barrel model with a furnace model to assess NOx control options for those cyclone-fired boilers which produce significant levels of NO in the furnace.

While the cyclone barrel model was being developed data were obtained [1] on the conditions within cyclone barrels. Gas species and temperature data probes were inserted through the site port of several cyclone barrels at the Sioux Plant [2] These data indicate that conditions within the barrel are not well mixed and there are very fuel rich regions with very high carbon monoxide concentrations. Further validation of the model was obtained by comparing predictions with measurements for a lignite fired cyclone barrel at the Leland Olds Station of Basin Electric. This paper compares these data with the results obtained from the numerical simulations. Also, several modifications to barrel operation were simulated and the impact on NO formation in the barrel as well as other aspects of barrel operation such as slag freezing and corrosion potential are addressed. The paper ends by presenting results from simulations of the lower furnace using a combined barrel-furnace model of the Sioux Plant.

Model Background

GLACIER is based on software developed over the last fifteen years by Smith and co-workers [3-6] Particular emphasis has been placed on simulating coal combustion and pollutant formation. *GLACIER* includes full mass, momentum and energy coupling between the gas and particles as well as full coupling between turbulent fluid flow, chemical reactions, radiative and convective heat transfer, and finite-rate NO formation.

When predicting the mean concentrations of NO in coal-fired combustors, the effects of both turbulence and finite-rate chemistry are important. *GLACIER* can reliably compute the relative

effects of fuel, thermal, and prompt NO as a function of local stoichiometry and temperature. A reburning mechanism is also included through reactions involving NO and fuel species.

Prior to this study *GLACIER* had been used extensively for the prediction of pulverized coal flames. Several modifications were made to enable accurate simulation of cyclone combustion. These were primarily associated with improved particle transport and deposition models that enabled particle flow in the burner and their subsequent deposition and reaction in the slag layer to be simulated more accurately. In addition four basic assumptions were made:

1. When a particle was deposited in the slag layer its burning time was small compared to the slag flowing velocity and all the coal off-gases were released at that location.

2. The refractory coated walls were adiabatic until they reached a temperature equal to the calculated T_{80} for the coal being fired.

3. Coal particles did not stick to the wall but experienced an elastic collision if the wall temperature or the particle temperature was less than the calculated T_{250}.

4. Even the largest particles were isothermal, this means that no volatiles evolved before the particle was completely dry.

Computational Results

The modified *GLACIER* computer model was used to simulate a single barrel among the cyclones in service at the Union Electric Sioux Plant. The ten foot diameter barrel is fitted with a radial burner and fires a 70/30 blend of Powder River Basin/Illinois No. 6 coal. The model used twenty four particle starting locations with eight discrete particle sizes for each coal type. Table 1 summarizes the input conditions for the Sioux cyclone.

The flow field in the cyclone barrel is dominated by the secondary air flow which enters tangentially as do the coal, primary and tertiary air streams in the radial burner. All three streams rotate in the same direction but the primary air stream is directed at the point at which the vertical coal chute enters the burner. The coal is delivered with a very small amount of air and there is a small air flow along the axis of the burner from the tertiary air duct. There are two recirculation zones within the barrel, one at the exit of the burner and the other along the wall of the cyclone close to the burner end wall. The general flow is tangential until the gases accelerate axially as they exit the divergent throat. Since all the secondary air enters through a single duct it is not surprising that the flow field is not symmetric. Figure 1 shows the computed radial temperature distribution at three radial planes corresponding to locations: a) close to the burner; b) in the region where the secondary air enters the barrel, and c) close to the divergent throat. The gas temperature field illustrates the highly stratified flow that exist throughout the barrel, even as the gases exit the divergent throat they are not completely mixed. The secondary air flow rolls around the wall creating a scroll effect as it entrains the coal gases from the wall. The high temperature zones occur on the boundary of the air stream as it mixes and reacts with the rich coal gases.

Table 1

Summary of Input Conditions for the Sioux Cyclone Barrel

COAL		AIR	
Composition (wt%)	70/30 PRB/Illinois #6 Blend	Barrel Stoichiometry	S.R.=1.16 (3% O_2)
Moisture	24.6%	Total Feed Rate	178.3 tons/hr
Ash	6.6%	Air Temperature	615 F
C,H,O,N,S	68.8%	Pri/tert/sec flow split	12/3/85 %
Feed Rate	22.5 tons/hr		
Firing Rate	413 MMBTU/hr		
T_{250} Slagging Temp	2388 F		
Particle Size	16-3000 μm		

Figure 1 also shows that there is ignition close to the burner exit. Apparently, this occurs due to two separate phenomena. The coal feed contains some fines. In this simulation the coal field was characterized by discrete "bins" for both coal types and it should be remembered that the Powder River Basin Coal has a much higher moisture content than the Illinois coal. Only the smallest particles dry and devolatilize close to the burner, but these small particles are essential for the creation of heat release close to the burner. The second phenomenon is associated with the deposition of coal particles on the divergent burner end wall of the cyclone. Some coal particles impinge on the end wall which is hot enough to have running slag, therefore in this model they stick and can react. Sensitivity studies were carried to study these phenomena. Either removing the small particles or preventing deposition on the end wall by changing the burner flow field resulted in the heat release being pushed to the back of the cyclone.

Examination of the computed results for the baseline case indicates the following:

- Only the smallest coal particles burn in suspension because the large particles do not dry before they are deposited on the walls. This a consequence of the isothermal particle assumption and probably underestimates the volatile release before the particles are deposited.

- Because the flow within the cyclone is segregated there are both fuel rich and fuel lean regions throughout the barrel. There are extremely rich regions close to walls, i.e., equivalence ratios in excess of 4. The location of these regions are determined by the particle deposition pattern.

- The paths taken by the particles in the cyclone depend on the particle size and their starting location in the coal chute. Coal particles that are not diverted radially as they exit the burner tend to get caught up in the axial flow and corkscrew through the divergent exit.

- Nitric oxide appears to be formed in four regions within the barrel:

  — as the coal fines burn close to the burner exit, NO is formed primarily by the fuel NO mechanism;

  — in the region close to the wall NO is formed from the fuel nitrogen that evolves with the coal gases even though some of locations are extremely fuel rich;

  — as the fuel rich products from the coal contact the combustion air stream gas temperatures increase and thermal NO is formed as the gases exit the barrel;

  — there is a region around the reentrant throat where both thermal and fuel NO are formed.

The same model was used to simulate a cyclone barrel burning lignite at the Leland Olds Station (LOS). Lignite cyclones are nearly identical to the cyclones burning bituminous and sub-bituminous coals, but there are differences. The burner of the lignite cyclone is a scroll burner whereas the bituminous and sub-bituminous cyclones use a radial or vortex burner. The difference in burner design comes from the necessity to use two stages of drying for the lignite coals before it enters the cyclone burner. The two-stage drying configuration normally removes approximately 10% of the moisture. One of the lignite-fired cyclone barrels at the LOS was simulated. The overall firing rate was 330 MMBtu/hr with 10% excess air. The air flow split between the primary, secondary and tertiary streams was 16.6/81.9/1.5 percent. Measurements indicated that the coal composition varied by size fraction and the particle size distribution varied with location in the coal delivery pipe. These variations were included in the model inputs.

Figure 2 presents a contour plot of the predicted gas temperatures in the LOS cyclone on a vertical plane through the barrel axis. Peak temperatures within the lignite-fired cyclone are below those predicted for the barrel fired with the coal blend but the predictions again indicate that conditions within the barrel are not well mixed.

Comparison with Data

Sioux Cyclone Barrel

Figures 3, 4 and 5 compare the measured data with the computed gas temperature, oxygen, CO and NO concentration. The probe path angled down from the top of the burner to the bottom of the divergent exit and the data are shown as a function of probe insertion distance along this path. Data were obtained from several barrels operating at the same nominal conditions over a period of several days. Figure 3 compares measured temperature and oxygen concentration with the computed values. Two data sets are shown for the measured oxygen concentration corresponding

to measurements taken on different days but in the same barrel. Figure 4 and 5 compare CO and NO, respectively. Considering that the model indicates very steep gradients in both temperature and species concentration throughout the barrel the agreement between the measured data and computed results is very good. The qualitative trends are in very good agreement and the quantitative agreement is acceptable. Several observations concerning the data comparison can be made:

1. The two data sets for oxygen probably reflect a slight change in operating conditions that affected the location of the ignition zone near the burner. In the computer simulation it was relatively easy to move the heat release to the back of the cyclone but the presence of coal fines and/or deposition of coal particles on the front wall influenced early ignition.

2. The measured CO concentrations are higher than those predicted by the model but the measurements support the concept that there are very rich regions within the barrel creating naturally staged conditions.

3. Two measured data sets are presented in Figure 5 to show that the measured dip in NO that occurred at the eleven foot insertion point was not an anomaly. However, even when the reburning mechanism was included the model did not duplicate this dip in NO concentration.

Very little effort was expended to improve the agreement between the data and the predictions because it was felt that considering the complexity of the cyclone combustion process, and the difficulty of ensuring that the cyclones operate at a fixed and known conditions that the level of agreement was more than sufficient to validate the model.

Leland Olds Cyclone Barrel

Figures 6 and 7 compare data taken through cyclone measurement ports 1 and 2, respectively. As with the Sioux barrel, both the data and the predictions indicate that conditions within the barrel are far from well mixed. The temperature contours in the vertical axial plane give an indication of how unmixed the gases are even as they pass through the reentrant throat. This is illustrated also by the gas species concentrations. It should be remembered that this discussion is limited to a comparison of measurement and predictions in one vertical plane. The flow in the barrel is not symmetric and there are large gradients in temperature and species concentration in the radial planes. Considering the conditions within the barrel and the accuracy of probe positioning which the qualitative agreement between data and predictions is very good.

Port 1 allowed measurements to be made along the barrel axis and data are available for two cyclones. With the exception of CO concentration the measured data follows the same general trends. The oxygen concentration decreases from the burner and both the temperature and NO concentration increase with distance from the burner. However in cyclone #9 the oxygen concentration decreases to zero while the corresponding measured CO concentrations are very high. Cyclone #8 did not exhibit the same behavior. Oxygen concentrations were higher and the CO level was uniformly low along the axis. It should be noted that the cyclone with the higher measured gas temperature and oxygen concentration, cyclone #8, does not give higher NO values.

Sensitivity studies carried out with the cyclone model suggested one possible reason for the variation between cyclones and also between measurements and predictions. The simulations indicate that there is a recirculation zone at the burner whose size and strength is dependent on the tertiary air flow. Figure 8 shows predicted flow fields in the region near the burner exit for low tertiary air flow. Increasing the tertiary air flow reduces the size and strength of the recirculation which in turn reduces the amount of hot gases that flow back towards the burner. This results in delayed ignition and higher oxygen concentrations on the burner axis near to the burner. The coal distribution is controlled by the primary air flow and the variation in tertiary air has almost no impact on the majority of the coal particle dispersion. Only the smallest particles, which do ignite close to the burner are affected. Considering that the tertiary air flow accounts for only 1.5% of the total air flow it is reasonable to expect that there will be cyclone to cyclone variations.

Both the predicted temperature and the NO concentrations are sensitive to the coal moisture content and this could account for the differences in measurements and predictions shown in Figures 6 and 7. It should be remembered that these simulations are restricted to the barrel. NO can be formed in the lower furnace as the combustion products exit the cyclone. Furnace NO will be less significant with lignite than with bituminous coals because of the lower adiabatic temperature. The predicted NO formed in the barrel is 0.89 lbsNOx / MMBtu.

NO_x Control Options for Cyclone-Fired Boilers

The cyclone barrel model was used to evaluate the impact of relatively simple operational and design changes on NO formation within the barrel. In most cases the changes that were evaluated were considered to be extreme limit cases in order to quickly eliminate options that were not promising.

Operational Changes

Three operational changes were considered from the baseline operation: a) change the coal grind to a finer distribution typical of an advanced crusher design, b) operate at high excess air level, and c) switch from the blended coal to all Illinois coal. The final option was included not because the NO formation was expected to reduce but to give an idea of the models ability to predict the effect of fuel switching. Figure 9 compares the NO emitted from the barrel for these cases. None of these changes had a significant effect on the amount on NO formed in the barrel.

Design Changes

The design variations investigated were:

- Two variations in the air split between the primary/tertiary/air streams flow. The low primary air case (LP) had a 10/2.5/87.5% split and the high primary air case (HP) had a 14/3.5/82.5% split. The baseline flow split was 12/3/85%.

- The secondary duct was divided into three equal sections and air was transferred from the section nearest the burner to the section nearest the exit, in the baseline case the flow was uniform throughout the secondary duct. Two biased secondary air flow cases were run: a) -15%/normal/+15% (Spl15) and b) -75%/normal/+75% (Spl75).

- A case (VSpl) was run with an imaginary flow diverter placed along the length of the secondary duct to divert one third of the flow towards the cyclone axis.

- The geometry of the coal chute was changed in one case (Chute), the length was doubled and width halved.

The computed results for these design changes are presented in Figure 10. None of these design changes had a major influence on the NO formed in the cyclone. The flow diverter design did reduce NO but resulted in significantly poorer cyclone performance in terms of slag tapping and particle carryover.

Staging, FGR and Water Injection

Figure 11 shows the influence of barrel stoichiometric ratio on nitric oxide production in the barrel. NO emissions decrease with decreasing stoichiometric ratio. Figure 12 shows the effect of adding flue gas recirculation (FGR) to the secondary air. NO decreases with increasing FGR. Also shown in Figure 12 is one prediction for liquid water injection along the barrel axis. The amount of water added was thermally equivalent to 5% FGR and the predicted emissions are within 5 ppm. Examination of the computations indicated that 20% FGR almost eliminated thermal NO formation. The model predicts that greater than fifty percent of the NO that is produced in the barrel is produced by the thermal mechanism accounting for the effectiveness of FGR.

Operational Impacts

Figure 13 shows the influence of staging and FGR on several factors that were used to monitor cyclone performance other than NO. The percentage of wall area with a temperature less than the calculated T_{250} was used to give an indication of problems associated with slag freezing. Although 20% FGR gave a significant reduction in NO, the wall surface area that was frozen doubled over the baseline condition. Corrosion is also a potential problem when cyclones are staged. Two parameters that are associated with production of iron sulfide were used to assess corrosion potential: (1) the wall surface area covered by gas with a stoichiometric ratio less than 0.6 and (2) the wall surface area with a temperature greater that 2550 °F. If these indicators are acceptable then neither staging nor FGR appears to increase the potential for corrosion.

Furnace NO_x

The discussion so far has dealt exclusively with the NO that is formed within the cyclone barrel. In all the cases considered to date the heat loss through the barrel wall was between 1.5 and 5% of the heat input. Also, the exhaust gases contain significant levels of CO that will react as the

combustion gases mix in the main furnace. Since the heat loss in the barrel is small thermal NO formation will continue in the furnace and the amount produced will depend on the thermal conditions experienced by these gases in the furnace. To evaluate the potential importance of furnace NO a model of the Sioux furnace was constructed that coupled the barrel outlet conditions to the ten barrel opposed wall-fired furnace. The unmixedness at the barrel exit was interpolated onto the less refined computational grid required to model the complete furnace which contained more than 502,000 computational cells.

The Sioux furnace operates normally with FGR addition through gas recirculation ducts and gas tempering ports. Figure 14 compares predicted furnace emissions for four NOx control options - FGR, water injection, staging and biasing - with the baseline case. In the staged case all the barrels were operated at a stoichiometric ratio of 0.9 and the remaining combustion air added through the gas recirculation ports. In the two biased cases the upper cyclones were operated at SR = 1.4 and the lower cyclones at SR = 0.9 and 0.95, respectively. Consequently for the 0.9/1.4 case there was also a reduction in overall excess air. It can be seen that staging could be very effective in reducing NO but any of the other techniques could also be used to obtain modest reductions in NO emissions.

Conclusion

A model of NOx formation in the barrel of a coal-fired cyclone has been developed and used to explore control options that involve simple variations in barrel operating conditions. Comparison of model predictions with a data set of measured temperature and gas species concentrations indicated very good qualitative agreement and acceptable quantitative agreement. Model results show the cyclone to be poorly mixed and very stratified with large regions which are either very fuel or air rich.

Because a cyclone barrel operates with very little heat loss, thermal NO is a significant fraction of the NO formed in the barrel and, since it is necessary to combust almost all of the carbon in the barrel, exit gas temperature is almost unaffected by the simple design and operational changes considered to date. Therefore, thermal NO formation which occurs primarily as the combustion products exit the barrel also is not affected. Injection of recirculated flue gas reduces the temperature and can have a major impact on NO emissions from the barrel but the reduced temperatures could have a detrimental affect on cyclone operability because the slag may freeze or become difficult to tap due to significant increases in viscosity. Staging produces less significant NO reduction due to the existence of very fuel rich regions in the cyclone barrel which continue to produce NO regardless of the degree of staging. Staging and FGR both show a potential for reducing overall NO levels in the boiler due to lower cyclone exit temperatures. Based on the current criteria, use of staging and FGR do not seem to increase the corrosion potential within the cyclone.

Results of coupling the cyclone exit gases with a furnace model indicated NOx formed in the furnace of opposed wall-fired cyclone boilers can be significant. Staging and biasing appear to be viable NO emission control options but the effects of staging on the water wall corrosion need to be evaluated. Water addition could be a low cost alternative if minimal reductions are required.

References

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Figure 1. Radial Temperature Distribution at Three Axial Locations Illustrating the Stratified Conditions in the Barrel: a) near burner outlet, b) secondary air inlet, c) near cyclone outlet.

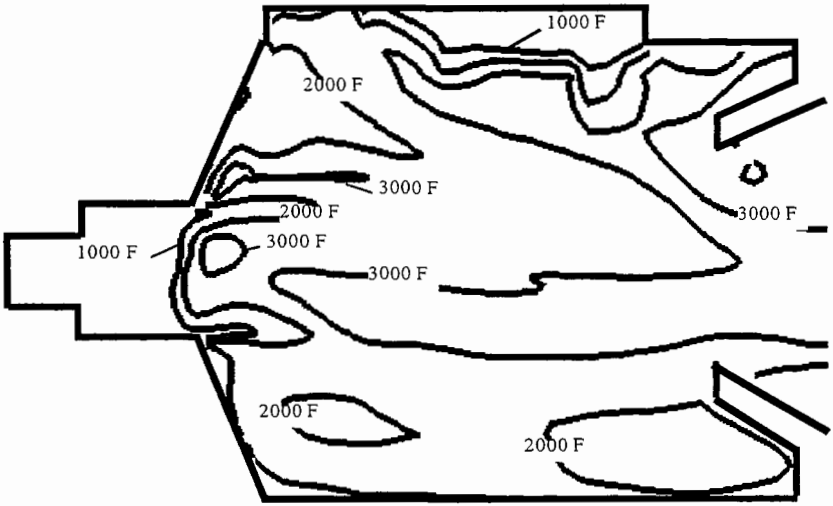

Figure 2. Predicted Gas Temperature Contours in Leland Olds Station (LOS) Cyclone.

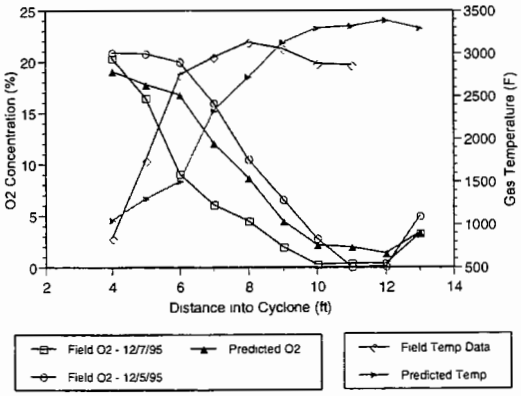

Figure 3. Comparison of O_2 and Temperature Data for Sioux Cyclone.

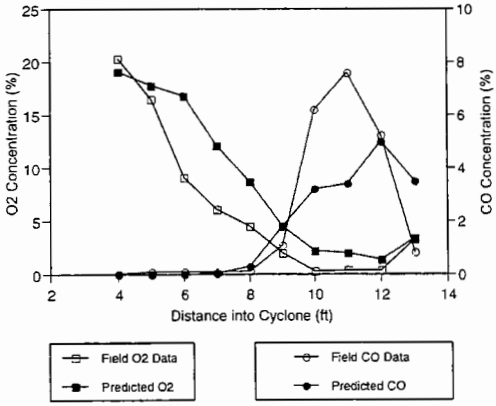

Figure 4. Comparison of O_2 and CO Data for Sioux Cyclone.

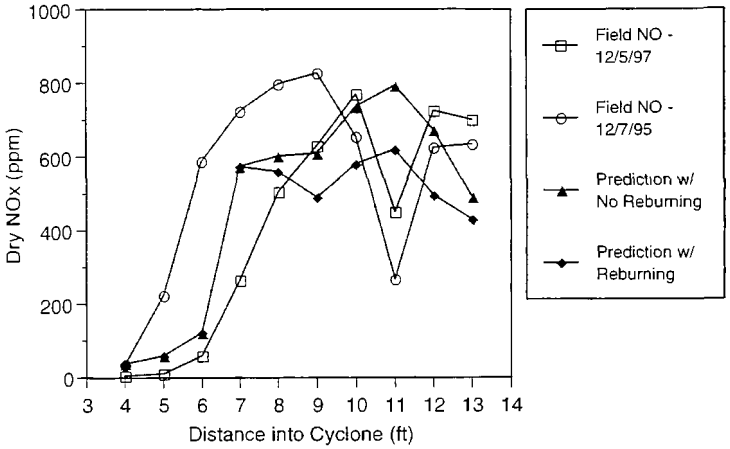

Figure 5. Comparison of NO Data for Sioux Cyclone.

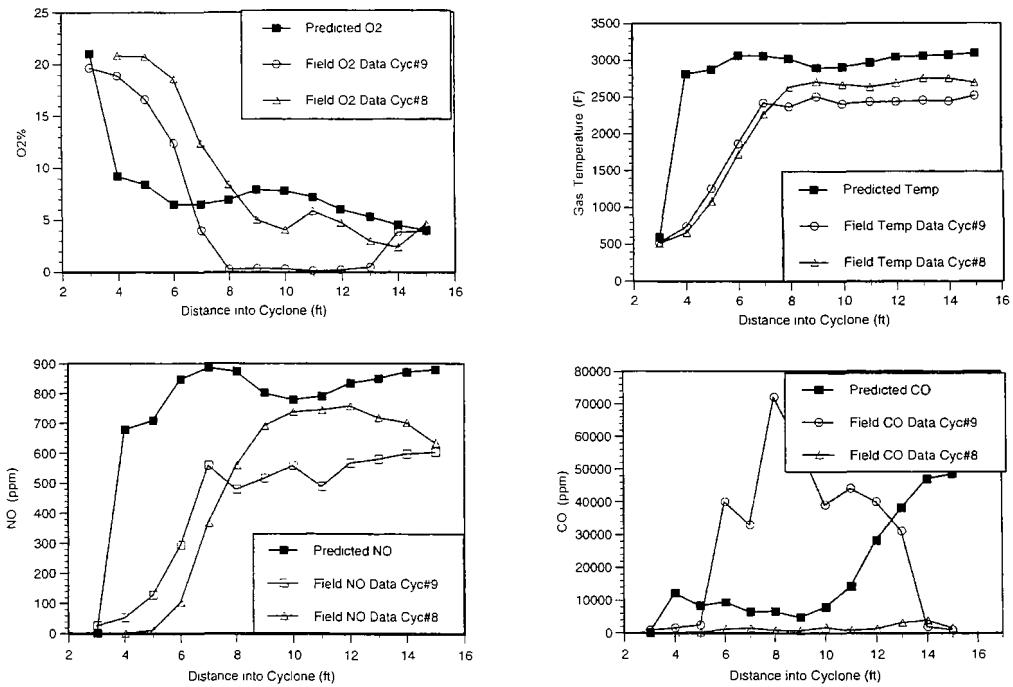

Figure 6. Port 1 Data Comparisons for Leland Olds Cyclone.

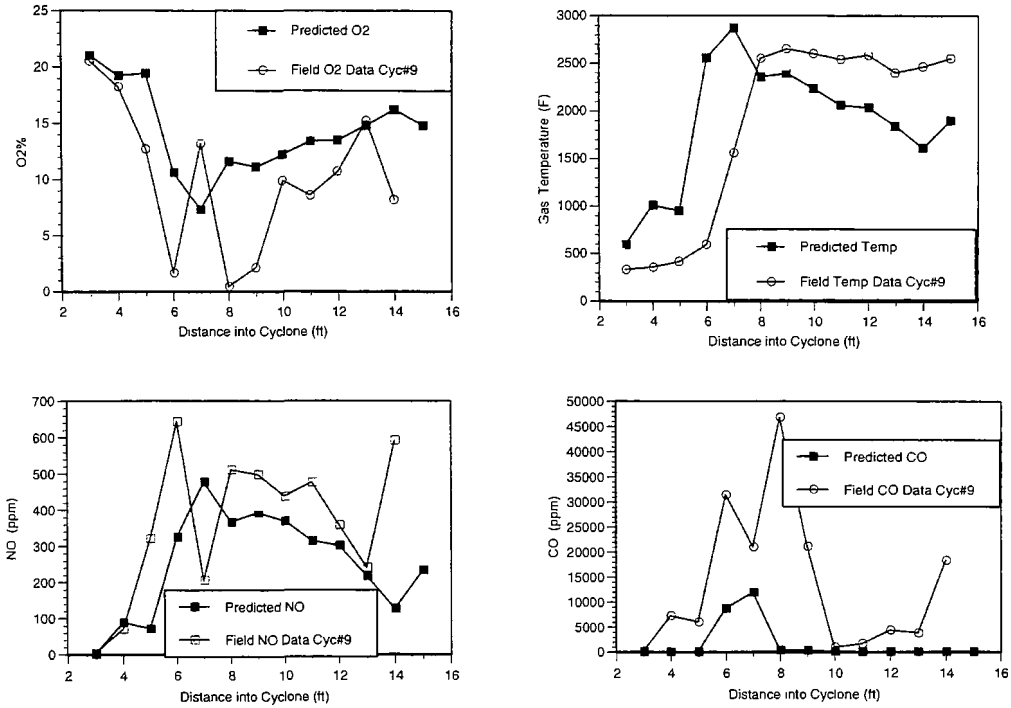

Figure 7. Port 2 Data Comparisons for Leland Olds Cyclone.

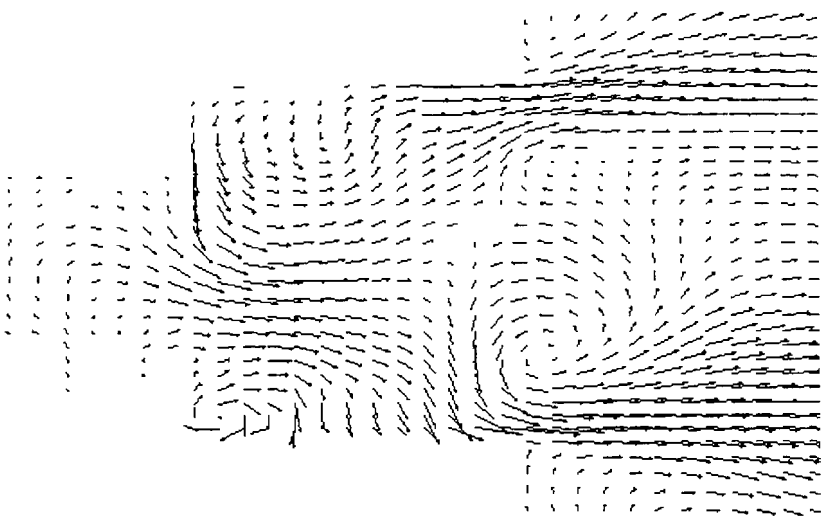

Figure 8. Burner Flow Patterns with ~1.5% Tertiary Air Flow for LOS Cyclone.

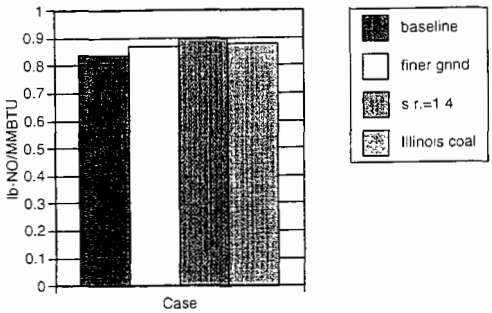

Figure 9. NO Results for Sioux Cyclone Operational Changes.

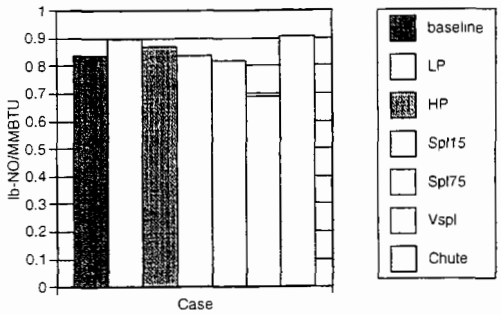

Figure 10. NO Results for Sioux Cyclone Design Changes.

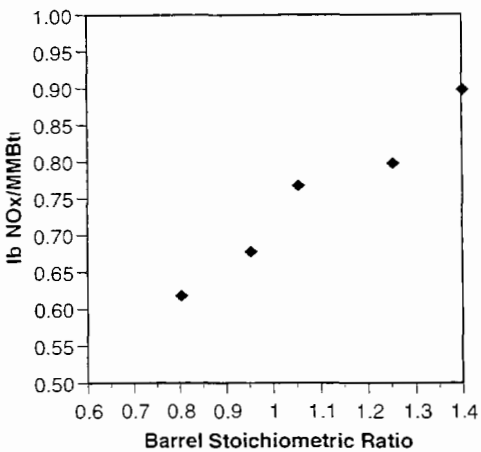

Figure 11. NO Results versus Sioux Barrel Stoichiometry.

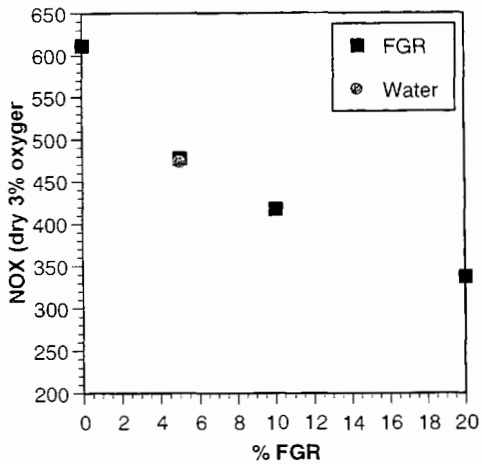

Figure 12. NO Results for Sioux Cases Involving FGR and Water Injection.

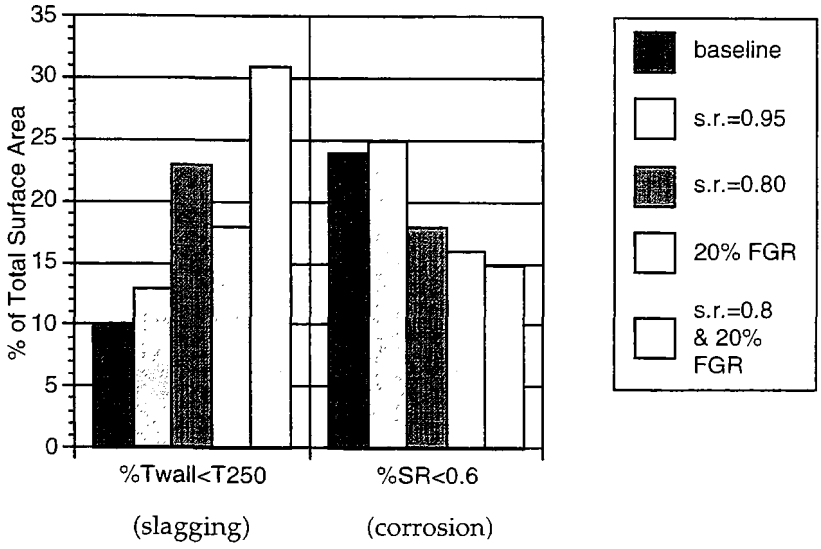

Figure 13. Predicted Impact of Staging and FGR on Sioux Cyclone Slag Tapping (% surface with $T<T_{250}$), and Corrosion Potential (% surface with T>2550 F and gas stoichiometric ratio<0.6).

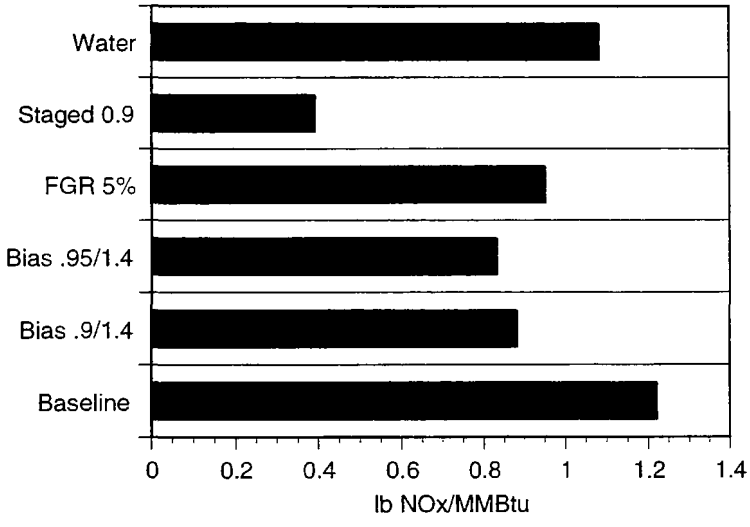

Figure 14. Sioux Furnace NOx Emissions for Various NOx Reduction Strategies.

SHORT-TERM NO_x EMISSION REDUCTIONS WITH COMBUSTION MODIFICATIONS ON LOW TO MEDIUM SULFUR COAL-FIRED CYCLONE BOILERS

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Abstract

In anticipation of Title IV - Phase II NO_x limit mandates for cyclone boilers, several utilities initiated a Cyclone NO_x Control Interest Group (CNCIG) in 1994 under the co-sponsorship of the Electric Power Research Institute's (EPRI's) NO_x Target. Due to the limited number of demonstrated NO_x control technologies available to cyclone boilers, CNCIG established an engineering approach to explore, evaluate, and demonstrate promising alternatives for cyclone NO_x control. The current paper presents preliminary results from an ongoing investigation of combustion modification approaches to NO_x reduction implemented through biasing of

combustion air at full load, and simulating overfire air operation at reduced load. An overview of the following areas is presented:

- cyclone boiler operating characteristics and limitations
- issues associated with sub-stoichiometric cyclone barrel operation,
- test programs developed to address these issues,
- test data gathered to date by two utilities from nominal 600 MW cyclone boilers, and
- remaining issues to be addressed by ongoing test activities.

Biased cyclone operation resultant in sub-stoichiometric conditions, though promising in achieving nominal 15% - 20% NO_x reductions at full load, and 35% - 50% NO_x reductions at minimum load through a simulated overfire air firing configuration, can pose significant near-term and long-term risk to the boiler. Prior to long term implementation of combustion modifications as part of an overall NO_x compliance strategy, it is essential that these risks be quantified so as not to impair the long term operability and reliability of the boilers.

Background

Cyclone boilers were first developed in the late 1940s to take advantage of the inherent characteristics of certain fuels that were problematic when fired in pulverized coal design boilers. These coals exhibited low ash fusion temperatures which caused slagging on furnace walls when burned in a typical pulverized coal boiler. Furthermore, it was not economical to design larger furnace volumes that would allow the slag to cool sufficiently before impinging on the furnace walls. Babcock & Wilcox (B&W) developed the cyclone boiler in order to take advantage of the slagging tendency of the fuel by burning the coal at a high heat release rate in the cyclones. In cyclone boilers, combustion occurs within a water-cooled horizontal cylinder attached to the outside of the furnace. Coal is gravity fed into the radial design burner tangentially in the same rotation as the primary air (Figure 1). By appropriate partitioning of the primary and tertiary air flows, the flame location relative to the burner can be adjusted. The main combustion air enters through the secondary air damper which extends nominally 60% of the length of the cyclone barrel. Firing of high moisture subbituminous coals has prompted some modifications to the base design, with blanking plates installed over the first third of the secondary air duct, and reduction of the tertiary air to the point where it only provides cooling of the burner front. These changes are all focused at increasing the residence time of the coal for drying, devolatilization, and ignition in the near burner region.

By burning the fuel at high turbulence and temperature, the coal ash is removed as molten slag, thereby reducing the fly ash content of the flue gas and required furnace size. Overall air-rich conditions were proscribed for the combustion chamber to ensure that the molten slag did not corrode the cyclone boiler tubes. However, under these air-rich conditions, the high turbulence and temperature present in cyclones produce relatively high levels of NO_x emissions. Although NO_x formation can be minimized by reducing temperature and available oxygen during the combustion process, this is difficult to do in cyclone boilers without promoting corrosion, or freezing of the slag layer, as well as increasing levels of fly ash and unburned carbon. Although

existing cyclone boilers were grandfathered under the original Clean Air Act of 1970, B&W stopped production due to the inability of cyclone boilers to achieve New Source Performance Standards for NO_x emissions at a cost comparable to pulverized coal-fired boilers.

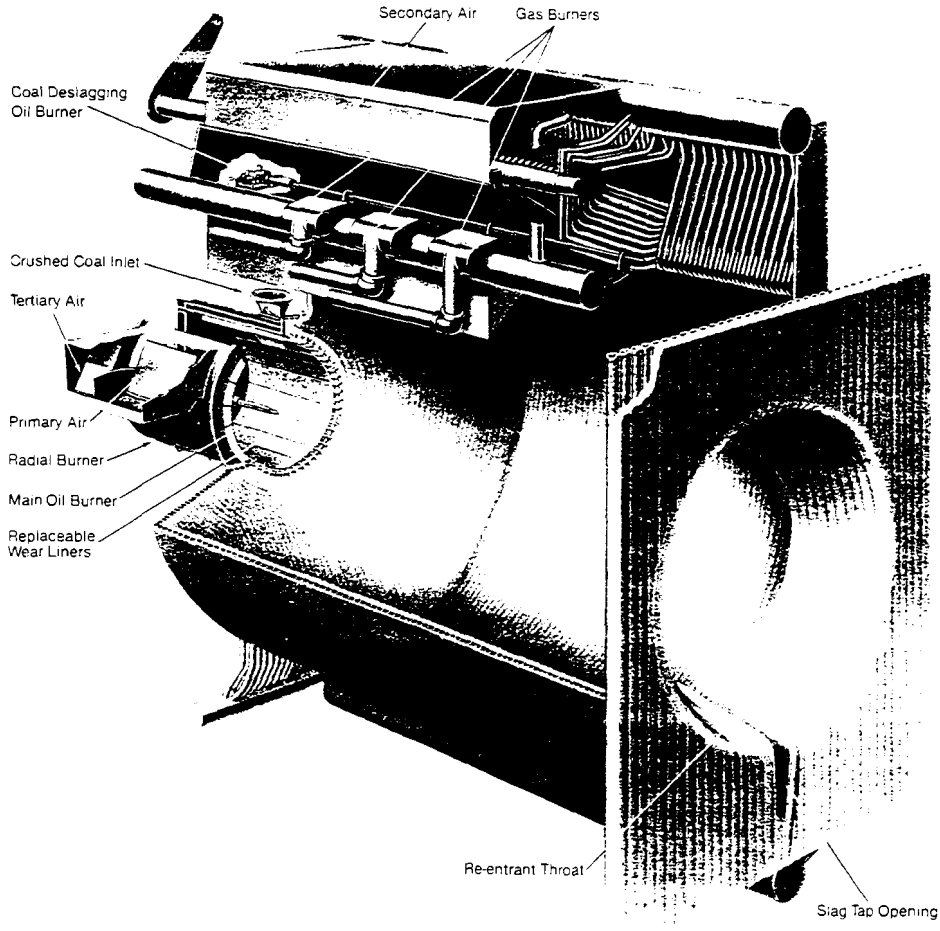


Figure 1
Schematic of Radial Burner Design Cyclone Barrel (Steam, 1992)

Title IV of the 1990 Clean Air Act Amendments (CAAA) targeted reduction of NO_x and SO_2 emissions from the coal-fired boiler population grandfathered under the initial Clean Air Act. NO_x emission targets for tangential and wall-fired boilers were based upon a hardware modification that retrofit low NO_x burner technology. The design characteristics of cyclone

boilers, however, are not conducive to the application of standard low NO_x burner technology. In recognition of the limited NO_x control options for cyclone boilers, several Department of Energy (DOE) co-sponsored Clean Coal Technology programs demonstrated the application of both gas and coal reburning on cyclone units. In addition, Title I of the 1990 CAAA has resulted in the implementation of commercial selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems for NO_x control on cyclone boilers located in the ozone transport region in the Northeast. The relative cost of these technologies, however, has been demonstrated to be relatively high, and as emission control strategies represent added costs to the generation of power, there are currently strong incentives to minimize the costs of compliance. Toward this end, several utilities are investigating the NO_x reduction potential of combustion modifications, in conjunction with the associated operational impacts and limitations, which may include slag tapping impairment and accelerated tube wall corrosion.

Coal-Fired Cyclone Boiler NO_x Emissions

Unlike most pulverized coal-fired boilers, in which fuel NO_x contributions predominate, cyclone boiler NO_x emissions appear to stem from both fuel and thermal NO_x in near equivalent proportions. The combustion intensity per unit volume in a 10-foot diameter cyclone combustor is typically 450,000 Btu/hr-ft3, whereas the typical heat release in a pulverized coal-fired unit is 20,000 Btu/hr-ft3. In addition, the heat absorption through the cyclone combustor walls is relatively low (< 10%), primarily because of the small surface area, and the insulating effect of the liquid slag layer. A majority of the crushed coal is burned on the wall in a cyclone, as opposed to suspension burning in a pulverized coal-fired boiler. The high combustion intensities and long residence times at peak temperatures in a cyclone are conducive to slag flow, but also contribute to high thermal NO_x formation and fuel bound nitrogen conversion. Assessments of baseline coal-fired cyclone boiler NO_x emissions have indicated that they can range from 0.85 - 2.7 lb/MBtu. This broad range in the cyclone boiler population baseline emissions is indicative that a number of factors contribute to NO_x formation, among which include:

- fuel type (bituminous, subbituminous, coal blend, or lignite),
- unit size and configuration (screened furnace, open furnace with target wall, and opposed wall)

For example, bituminous coal-fired cyclones trend toward higher NO_x emissions with increased unit size (Figure 2). Contrary to this trend, however, are cyclones fired with a high moisture, and more friable coal (subbituminous or lignite), which exhibit an apparent insensitivity to NO_x emissions that is likely due to the reduced peak flame temperatures attainable within the cyclone barrel. The moisture acts as a diluent to reduce the peak flame temperature, while the coal friability can result in a larger fraction of coal fines. As the coal fine fraction increases, a greater proportion of the coal is burned in suspension as opposed to at the wall of the cyclone barrel, thereby reducing the heat release within the cyclone barrel. The resultant reduced peak flame temperatures limit the thermal NO_x contribution to the total NO_x.

Demonstrated NO_x control technologies for cyclone boilers to date have taken the tact of letting the NO_x form within the cyclone in order to minimize impacts to the cyclone operation. The flue gas is subsequently made reducing through reburning fuel addition, or treated with ammonia or urea, to react with the NO_x to form molecular nitrogen. An alternative approach is to limit the oxygen availability within the cyclone barrel so as to limit the formation of nitrogen oxides. Although this can be accomplished on larger cyclones by biasing combustion air from the lower tier cyclones to the upper tier cyclones, or ultimately through incorporation of an overfire air system, it is limited by the ability of the cyclone to maintain tapping of the slag flow from the barrel and lower furnace, as well as by potential accelerated corrosion of tube wall surfaces from hydrogen sulfide or pyritic iron. The following discusses issues associated with biased cyclone firing operation and preliminary results obtained from two nominal 600 MW units firing an Illinois bituminous coal and a Western subbituminous coal.

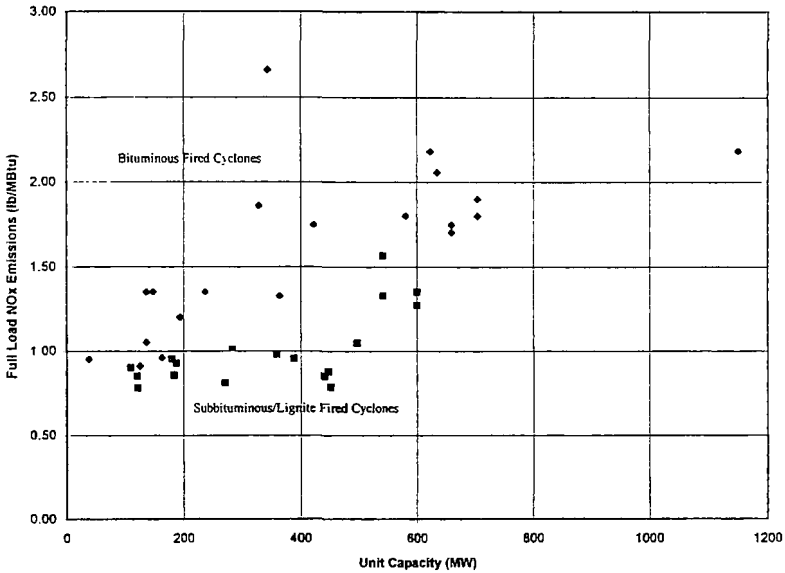


Figure 2
Comparison of Full Load NO_x Emissions from
Coal-Fired Cyclone Boilers as a Function of Coal Type

Cyclone Boiler Operating Limitations

The primary parameters/issues involved in defining the cyclone boiler process operating envelope for combustion modifications implemented through either biased firing at full load or simulated OFA at low load include:

- coal properties (heating value, moisture content, ash properties)
- first stage stoichiometry
  - fan operating limits under bias conditions
- slag tapping
- tube wall corrosion
- carbon carryover/utilization

Coal Properties

The coal properties define the operating limits that will likely be encountered first. Illinois bituminous coals are relatively high in sulfur and iron, and thus present the greatest risk from molten iron, iron sulfide, and/or hydrogen sulfide attack of water wall tubes. The relatively high ash fusion temperatures typically provide sufficient margin relative to slag tapping considerations. Western subbituminous coals, on the other hand, have moisture contents ranging between 25% - 30%, which result in combustion temperatures several hundred degrees Fahrenheit cooler and associated slag tapping constraints. A comparison of the coal properties fired at Associated Electric Cooperative's New Madrid Station and Illinois Power's Baldwin Station is presented in Table 1.

Table 1

Comparison of Coal Properties at New Madrid and Baldwin Stations

	Associated Electric Cooperative New Madrid	**Illinois Power Baldwin**
Proximate (as Received)		
Moisture	27.24%	14.86%
Ash	4.63%	11.33%
Volatiles	33.23%	
Fixed Carbon	34.90%	
Heating Value	8,689	10,541
Ultimate (% dry)		
Ash	6.37%	13.31%
Hydrogen	4.98%	4.95%
Carbon	70.93%	68.76%
Nitrogen	1.00%	1.34%
Sulfur	0.32%	3.39%
Oxygen	16.40%	8.25%
Mineral Analysis		
Ferric Oxide	5.47%	13.52%
Sulfur Trioxide	11.27%	2.99%
Base/Acid Ratio	0.707	0.330
Slag Viscosity (T_{250}, F)	2,200	2,500

First Stage Stoichiometry

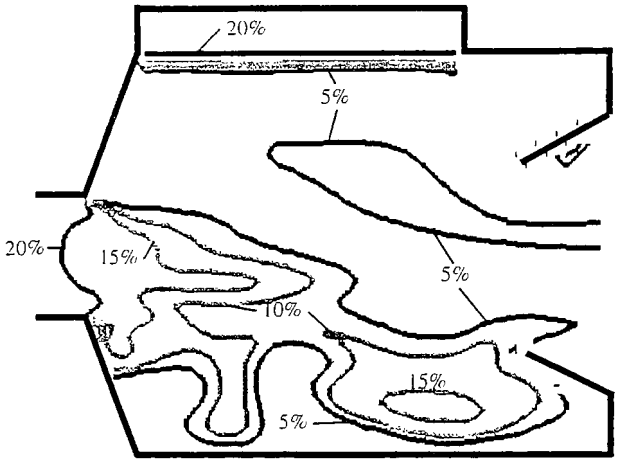
Cyclone biasing is implemented by reducing the secondary air on lower level cyclones, and increasing the air flow by the same amount on the upper level cyclones so as to maintain the same boiler excess oxygen content. The extent to which cyclone biasing can be implemented, however, is limited by the amount of air that can be introduced through the upper level cyclones, and the windbox/furnace pressure differential capability of the forced draft fans. In addition, the slag tapping characteristics in both the overall fuel rich and oxidizing cyclones can limit the degree of biasing implemented. Although similar in base design, New Madrid was capable of achieving a lower cyclone level stoichiometry at full load of nominally 90%, whereas Baldwin was limited to 100% theoretical air. As the NO_x reduction potential is proportional to the long term stoichiometry that is achievable in the lower level cyclones and furnace, it should be noted that results from one unit are not necessarily applicable to other units.

Slag Tapping

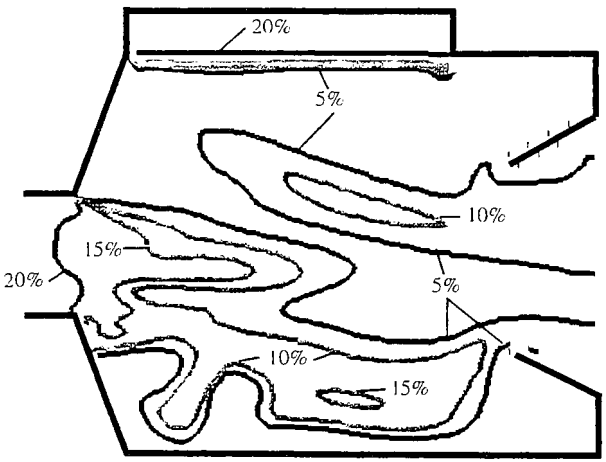
Continuous slag tapping is critical to the long term operation of the cyclone. Once the slag flow becomes impaired, the barrel will fill with slag up to the reentrant throat, resulting in the cyclone being taken out-of-service. The boiler may also need to be taken out of service if the buildup occurs in multiple cyclone and cannot be resolved through operational changes. Current utility practice for curing slag tapping issues is empirically based. Slag tapping problems encountered with Western coals have typically been addressed by temporarily firing the problematic cyclone with a higher heat content fuel, or blend. The greater heat release per mass of fuel results in increased combustion temperatures, which in conjunction with potential benefits from the blending of a low and high fusion slag, frequently restores proper tapping. Problems tapping slag with bituminous coals, on the other hand, typically incorporate modification of cyclone airflows to increase the combustion temperature and reduce the slag viscosity. Modification of cyclone airflows to restore proper slag tapping can compromise NO_x reduction benefits from biased cyclone operation. Thus, short term results obtained under controlled conditions represent a higher bound on the NO_x reduction potential, with actual long term performance contingent upon required system operation to address upset and transient conditions.

Water Wall Corrosion

The principle causes of water wall corrosion and forced outages in cyclone boilers are the (1) formation of liquid iron, (2) formation of liquid FeS, and/or (3) sulfidation attack by H_2S rich flue gas. Each of these compounds is due to the occurrence of locally reducing conditions. Based on numerical modeling studies and physical measurements within cyclones reported by Adams, et. al. (1997), it has been shown that the cyclone barrels exhibit highly stratified regions of fuel rich and oxidizing zones, irrespective of the overall stoichiometry over a range of 0.9 - 1.15 stoichiometry (Figure 3). To substantiate potential impacts from changes in iron formation, biasing tests at Baldwin incorporated collection of slag samples, with subsequent analyses of the slag composition. To address lower furnace corrosion potential from sulfidation attack, hydrogen sulfide (H_2S) analyses were conducted on flue gas samples extracted from the lower furnace.



Staged, S.R.=0.95



Baseline, S.R.=1.15

Figure 3
Numerical Modeling Prediction of Cyclone Barrel Oxygen Contours Along the Midplane
(Glacier Code-Reaction Engineering International, 1997)

An important aspect that can only be addressed through longer term operation of the boiler, is exposure of metal surfaces to alternating reducing and oxidizing environments, as well as temporary excursions in reducing compounds during upset conditions not typically observed during short term tests under controlled conditions. For example, during tests at Baldwin Station, continuous operation of the cyclones under full load biased firing conditions resulted in a spike in the hydrogen sulfide concentration in excess of full scale (>200 ppm). The spike was attributable to a lower level cyclone being lost due to coal feed plugging with resultant increases in the coal fed to the remaining 13 cyclones. Operationally, this resulted in further reductions in the cyclone barrel stoichiometry since the fuel feed system controls responded to maintain load faster than the airflow controls to the individual cyclone barrels. The reducing conditions in the lower furnace were thus increased temporarily with concomitant increases in reducing compounds such as hydrogen sulfide.

Carbon Carryover/Utilization

Finally, increased mass flow through the upper level cyclones, or incomplete combustion within the furnace during full load biasing can result in increased carbon carryover into the particulate collection device. Due to the reduced furnace size of cyclone boilers, there is less residence time available to complete the suspension burning of coal particles escaping the cyclone barrels. Also, because of the significant removal of ash as slag, only 40% - 50% of the ash is captured as fly ash. Thus, any increase in carbon can represent a significant increase in the unburned carbon content. For example, assuming 60% capture of ash as slag, a 10% unburned carbon level in the fly ash would be equivalent to a 4% unburned carbon level from a pulverized coal boiler in which all of the ash appears as fly ash. Although the economic impact from the unburned carbon levels may be moderate, increased carbon levels in the fly ash can lead to precipitator fires and increased forced outage time. In addition, units with marginal precipitators could experience increased opacity due to the increase in ash resistivity and reduced collection efficiency.

Approach

A test approach was developed so as to collect sufficient unit operating information to:

- evaluate potential operational and combustion modification approaches for reducing NO_x emissions,
- assess current potential operating limitations due to slag tapping and furnace wall corrosion, or equipment limitations due to fan cyclone biasing capabilities, and
- establish short term NO_x versus load emission profiles under baseline and modified operating procedures for incorporation into emissions averaging scenarios.

Please note that the initial short term tests were targeted at providing proof-of-concept for any NO_x reduction potential, as well as to identify any short term operating limitations. Based on the results from these tests, longer term tests would then be considered to evaluate longer term operating limitations and NO_x reduction performance over a range of coal, weather, and unit conditions. Also to be factored into the evaluation of the combustion modification approach for

achieving NO_x reductions are the incremental costs associated with possible long term corrosion of water wall panels, as well as other adverse operational issues.

In order to establish individual cyclone stoichiometries, it is necessary to have primary/tertiary and secondary air flows monitored, as well as the coal flow. Both New Madrid Unit 2 and Baldwin Unit 1 have gravimetric feeders and distributed control systems that monitor the differential pressures across the bellmouth and primary/tertiary air ducts for each of the cyclone barrels. The airflows were then tabulated based upon calibrated K-factors for each cyclone barrel and the following equation:

Mass Flow Rate (lb/hr) = K * [Pressure Diff (i.w.c.) * Density (lb/ft3)]

The cyclone barrel stoichiometries were then tabulated based upon the measured air coal flows, and the calculated theoretical air/coal ratio determined from the coal analysis.

So as not to jeopardize unit operability, initial tests focused on single cyclone tests in which the stoichiometry was modified over a range of conditions. These tests provided an indication of the maximum stoichiometry achievable under a given windbox to furnace pressure differential and maximum percent open damper settings. Based upon these airflows, fuel rich stoichiometries were calculated that would maintain a constant overall boiler excess oxygen level. Observations were then performed over fuel rich to fuel lean conditions regarding slag tapping characteristics, flame quality, and temperature. Although cyclone barrel measurements were performed at New Madrid Station, results confirmed numerical modeling information in which a relatively unmixed flow field was found to exist within the cyclone barrel. As a result, cyclone barrel measurements indicated fuel rich and fuel lean regions within the barrel, irrespective of overall operating conditions. Thus, measurements within the cyclone barrel were not conducive to providing insights regarding changes to species composition as the line of sight access available from the view port passed through highly stratified flow fields.

Based upon successful operation of individual cyclone barrels over the range of stoichiometries of interest, the entire unit was biased at full load for a limited period of time. All biasing was accomplished through the available bias controls, with the degree of bias limited by the amount of air that could be introduced through the top level cyclones. A simulated overfire air test was also conducted at a minimum load, in which the top level of cyclones were out-of-service, which served as overfire air ports for introduction of burnout air. Comparisons between baseline and biased operation were made for the following parameters:

- cyclone barrel temperature,
- lower furnace hydrogen sulfide concentrations,
- oxygen, CO, and NO_x variation at the economizer outlet.
- unburned carbon in ash

Unit Descriptions

New Madrid Unit 2

New Madrid Unit 2 became operational in 1977 with a design nameplate rating of 4,365,000 lbs/hr primary steam generation at 1,005 F and 2,400 psig throttle pressure. Reheat steam generation is 3,995,000 at 1,005 F and 635 psig. The unit is equipped with fourteen ten-foot diameter cyclone barrels having radial design burners. The cyclone barrels are staggered three over four, with seven on each side of the furnace.

Although initially designed to be fired with Illinois coal, New Madrid Generating Station has fired Western subbituminous coal since mid-1994. As part of the fuel switch to low-sulfur Western coal, blanking plates were installed in the front of the secondary air inlets to each of the cyclone barrels. The purpose of the blanking plates is to increase retention of the coal within the cyclone barrel.

Flue gas recirculation fans were originally supplied for steam temperature control, but were removed prior to 1984, with the furnace penetrations being tubed over. Additional heat transfer surface, sootblowers, and water blowers were added to enable full load operation by controlling the furnace exit gas temperature (FEGT) within limits with Western coal. Convective pass plugging with the low-sulfur Western coals has been experienced, with changes being made in the unit control logic to limit a calculated FEGT to 2,450 F.

Fly ash is disposed of dry in a 70 acre pond. The electrostatic precipitators have ample capacity with permit limits for opacity of 40%, and current CEMS opacity readings of nominally 15% under baseline full load operating conditions.

Baldwin Unit 1

Baldwin Unit 1 became operational in 1970 with a design nameplate rating of 4,200,000 lbs/hr primary steam generation at 1,005 F and 2,620 psig throttle pressure. Reheat steam generation is 3,787,000 lbs/hr at 1,005 F and 549 psig. Similar to New Madrid, the unit is equipped with fourteen ten-foot diameter cyclone barrels having radial design burners. The cyclone barrels are staggered three over four, with seven on each side of the furnace. The unit is capable of achieving full load with 13 of 14 cyclones in service enabling feeder and coal pipe maintenance while on-line. A side-view schematic is presented in Figure 4.

The unit was designed to be fired with Illinois coal, although it has purchased a washed coal to remove pyritic sulfur since 1973. Steam temperature control is provided by attemperation and flue gas recirculation. The unit is balanced draft, and since the incorporation of a baffle plate at the economizer outlet to increase ash retention in the hopper, the unit is limited in load to near 595 MW due to induced draft fan limitations.

Fly ash is disposed of locally in a man-made pond. The electrostatic precipitators have marginal capacity with permit limits for opacity of 30%, and current CEMS readings of nominally 20%

under baseline operation. ESP limitations are important, as increased carbon content in the ash can exacerbate particulate collection performance and result in increased opacity.

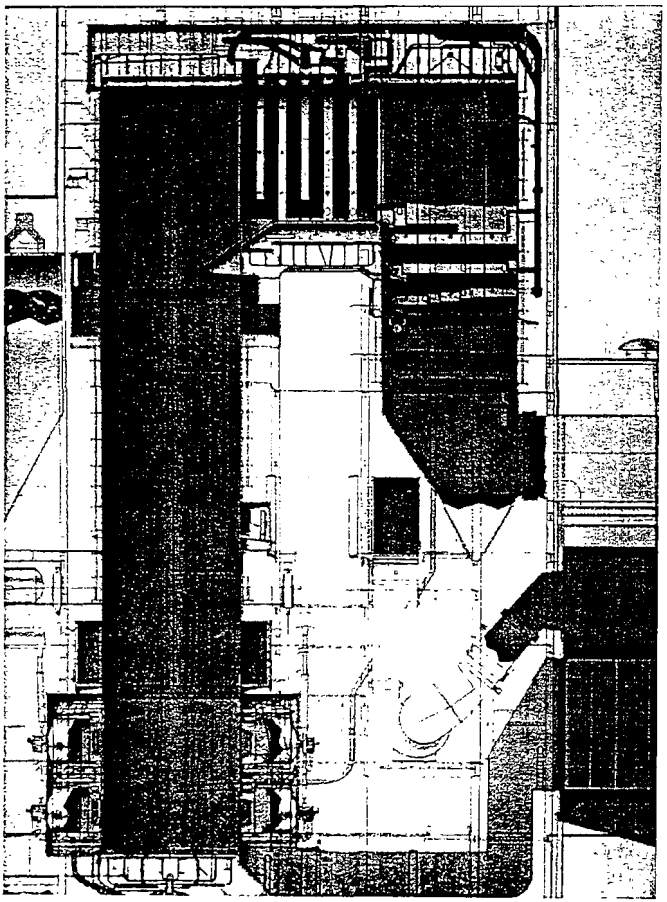


Figure 3
Side View Schematic, Illinois Power Baldwin Unit 1

New Madrid Unit 2 Cyclone Bias Results

Baseline and biased cyclone tests were conducted at 585 MW, 445 MW, and 350 MW in order to document operating and emissions profiles under controlled conditions over the load range. Based upon the three loads tested (Figure 5), the baseline NO_x exhibited a sensitivity of 0.57% delta NO_x per percent reduction in maximum continuous rating. This NO_x sensitivity to load is

NO_x reductions of nominally 18% were achieved at full load when the lower level cyclones were biased to 90% stoichiometric levels, with the balance of air introduced through the upper tier cyclones. As indicated in Table 2, however, NO_x reductions were found to increase from 18% at 585 MW to 35% at 350 MW with all lower level cyclones operated at 90% stoichiometry and a varying number of cyclones operating in the upper level. The increased NO_x reductions at lower load, for a given reduction in lower tier cyclone stoichiometry, is attributed to the fewer number of cyclones operating under fuel lean conditions in the upper level cyclones. All six upper level cyclones were in service during full load operation of 585 MW, while only two cyclones in the upper level were operated at 445 MW, and no upper level cyclones were in service at the low load condition of 350 MW. The increased stoichiometry within the fuel lean cyclones increased the partial pressure of oxygen available for fuel nitrogen conversion and thermal NO_x formation. Thus, some of the NO_x reductions achieved through reduced operating stoichiometries in the lower level cyclones was offset by increased NO_x formation in the upper level cyclones. The low load test approximates the percentage NO_x reduction achievable if all cyclones were able to be operated under reduced stoichiometry conditions of 90%.

Table 2

Summary of NO_x Reductions with Cyclone Biasing as a Function of Load at New Madrid

Load (MW)	**Lower Tier Cyclone Stoichiometry (# Operating Cyclones)**	**Upper Tier Cyclone Stoichiometry (# Operating Cyclones)**	**NO_x Reduction Relative to Baseline (%)**
585	.89 (8)	1.49 (6)	18%
445	.87 (8)	1.44 (2)	27%
350	.88 (8)	Not Applicable (0)	35%

To begin the process of assessing potential long term operating impacts and costs attributed to biased cyclone operation, lower furnace hydrogen sulfide, economizer outlet carbon monoxide, and ash LOI measurements were performed and compared with baseline values. These results are summarized in Table 3. Hydrogen sulfide measurements in the lower furnace under biased operation indicated a ten fold increase from baseline levels of 2 - 3 ppm to 20 - 30 ppm. Carbon monoxide concentrations at the economizer outlet were not found to change significantly, thereby indicating complete combustion within the furnace, even under biased operation. In all cases, CO measurements across the 24-point sampling grid were less than 50 ppmv. Contour plots of the excess oxygen levels at the economizer outlet were also indicative of relatively uniform combustion within the furnace, in spite of the potential for combustion air stratification due to biasing.

consistent with other coal-fired cyclone boilers of similar size. It should be noted that the data collected was obtained with a different number of operating cyclones, although each cyclone in service was fired at similar heat input rates per cyclone. Thus, heat release rates within operating cyclones were constant over the three loads tested, while heat release within the furnace volume decreased. The reductions in NO_x observed as the load was reduced is thus likely representative of lower thermal NO_x formation in the furnace.

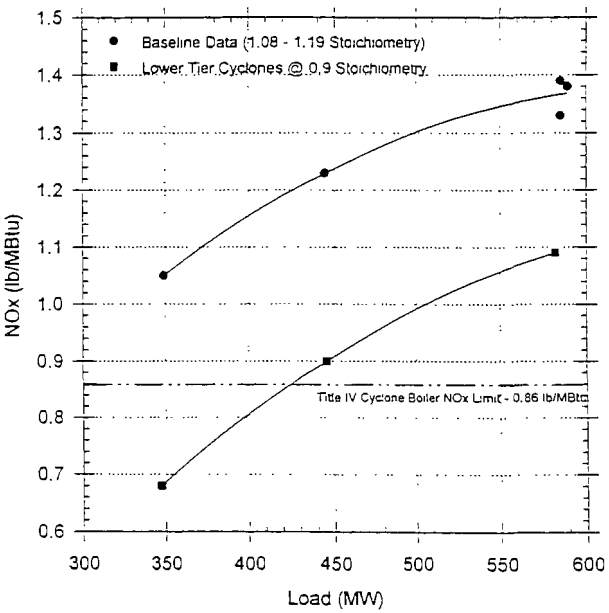


Figure 5
Short Term NO_x versus Load Curves for New Madrid Unit 2

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Table 3

Summary of Biased Firing Impacts on H_2S, CO, and LOI at New Madrid

Load (MW)	**Lower Furnace H_2S (ppmv)**	**Economizer Exit CO (ppmv)**	**ESP Hopper LOI (weight %)**
585	22.2-28.4	19	13%
350	25.3-28.6	22	4%

Baldwin Unit 1 Cyclone Bias Results

Baseline and biased cyclone tests were conducted in June and July at 590 MW and 340 MW in order to document operating and emissions profiles under controlled conditions over the load range. Complete analysis of the results was not completed for incorporation into the current paper, although NO_x reductions at full load (595 MW) were on the order of 17%, while under simulated overfire air conditions at 340 MW load achieved 50% NO_x reduction. Hydrogen sulfide measurements in the lower furnace ranged from 30 to 90 ppm while the lower level cyclones were operated at a stoichiometry of 90%. Additional analyses are examining slag composition for changes in the different forms of iron relative to baseline and biased firing operation. It is important to note that these tests, although of 8 - 10 hour duration, are still short term in nature, and conducted under controlled conditions as the units were not under load following operation.

Summary and Future Plans

Although cyclone biasing at full load indicated 15% - 20% NO_x reductions were achievable, the tests were conducted over relatively short periods of time, and under controlled conditions. Long term tests are planned for New Madrid Unit 2 to determine a more representative NO_x reduction potential under normal load dispatch conditions, as well as operating impacts from slag tapping and potential accelerated water wall wastage. Pending a complete analysis of the results from the short term evaluation of biased firing and simulated overfire air, Baldwin Station will evaluate the prudency of proceeding with a longer term demonstration with a relatively high sulfur and iron coal. Simulated overfire air tests at reduced load indicate an increased NO_x reduction potential on the order of 35% - 50%, albeit tempered by similar long term operating concerns expressed above for biasing. It is premature to speculate on the operating and maintenance cost impacts associated with combustion modifications until longer duration tests are completed. At this point in time, indications justify continued investigations, with evaluations proceeding.

Acknowledgements

The authors wish to thank all of the New Madrid and the Baldwin staff for all their assistance during the testing. Also, we aknowledge the expert efforts of CONSOL who conducted lab analysis at Baldwin. Illinois Power further thanks both the State of Illinois and EPRI for cofunding the test program at Baldwin.

COMBUSTION TEMPERING DEMONSTRATION

ON A CYCLONE UNIT FOR NO_X CONTROL

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Abstract

Cyclone furnace NO_X reductions up to 22% with 0.5% heat rate penalty were achieved using a recently developed process called Combustion Tempering. Test data indicates higher NO_X reductions are probable. A detailed test program was performed on Public Service Company of New Hampshire's Merrimack Station Unit 1 for the purpose of controlling NO_X emissions using RJM's patented technology "Combustion Tempering." Combustion tempering consists of targeting cooling streams to specific areas in the cyclone for the reduction of NO_X. In a cyclone furnace, thermal NO_X is a large portion of the total NO_X generated. Thermal NO_X is formed at elevated temperatures coincident with O_2 interaction. CFD modeling results identified specific zones of thermal NO_X production within the cyclone that comprise over 60% of the total NO_X produced by the cyclone. These zones are small on a volume basis and require little cooling medium to significantly reduce the zone temperature. Model results indicated that a limited amount of cooling in a single targeted zone would result in a 25% reduction in NO_X. Short term testing confirmed the correlation with model results. Cooling the largest single zone during the test period produced NO_X reductions ranging from 18% to 22%. There was no operational impact on cyclone operation and no apparent increase in coal flow during the testing period. Projected costs for a commercial system on this unit at a 22% NO_X reduction are $131/ton of NO_X removed based on $2.50/KW installed cost. Model results indicate cooling multiple zones will increase the NO_X reduction to 35%.

Background

Public Service of New Hampshire's Merrimack Station is located in the Town of Bow, New Hampshire on the Merrimack River. Merrimack Unit 1 is a drum type Babcock & Wilcox cyclone fired boiler designed for 815,000 lb/hr of steam at 1800 psig and 1005°F main steam and 1005°F reheat steam. The boiler has three cyclones arranged one over two. The boiler was built in 1960 and designed for firing coal. A side view of the boiler is shown in Figure 1.
Title I of the 1990 Clean Air Act requires that Unit 1 make a significant reduction in the emission of nitrous oxide (NO_X). Regulations imposed by the State of New Hampshire instituted a NO_X limit of 0.92 lb/mmBtu. Uncontrolled NO_X emissions on this unit range between 1.3 and 1.5 lb/mmBtu depending upon coal blend and furnace cleanliness. Public Service of New Hampshire performed an evaluation of the unit and installed an ammonia based SNCR System for the reduction of NO_X. Operation of SNCR technology proved somewhat successful but is costly to operate.

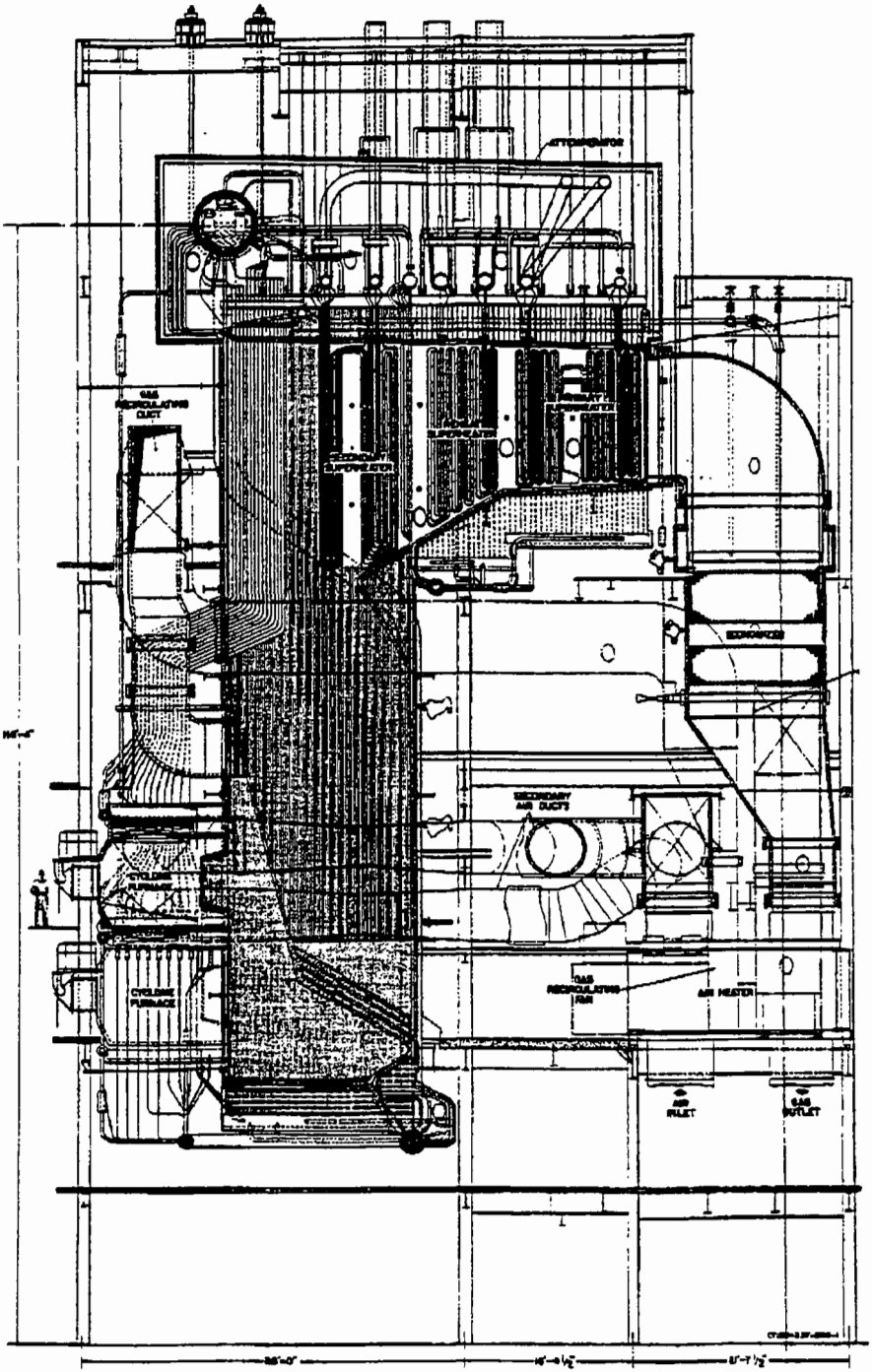
Public Service of New Hampshire and RJM Corporation agreed to cost share the development and demonstration of Combustion Tempering as a NO_X control technology for Unit 1. The focus was to reduce NO_X emissions at an operational cost significantly less than the SNCR System. An SNCR System has injection rates ranging from 1% - 2.5% of flue gas flow. A parameter of the program was to maintain combustion tempering flows below that of the SNCR System. In addition, the technology must not impact the cyclone combustion process and slag tapping characteristics.

Technology Development Program

The development of combustion tempering technology occurred over the past two years. Step 1 focused on modeling one of the three cyclones on Unit 1. The general cyclone operating conditions used as model inputs were as follows:

Table 1
Cyclone Operating Parameters

Coal Flow, lb/hr	30,000
Secondary Airflow, lb/hr	240,000
Primary Airflow, lb/hr	60,000
Seal Airflow, lb/hr	6,000
Water Circuit Temperature, °F	600
Secondary Air Temperature, °F	550
Primary Air Temperature, °F	550
Water Circuit Pressure, psig	2,500



Public Service Company of New Hampshire
Merrimack Steam Plant - Unit No. 1
Bow, New Hampshire

Figure 1

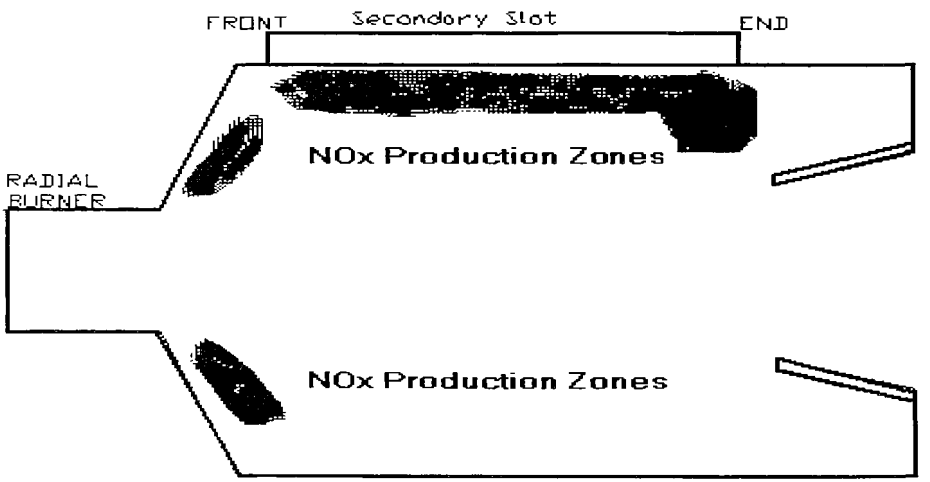
The coal used in the model was a blend of the coals used in Unit 1 and the proximate analysis is listed in Table 2.

Table 2
Coal Analysis

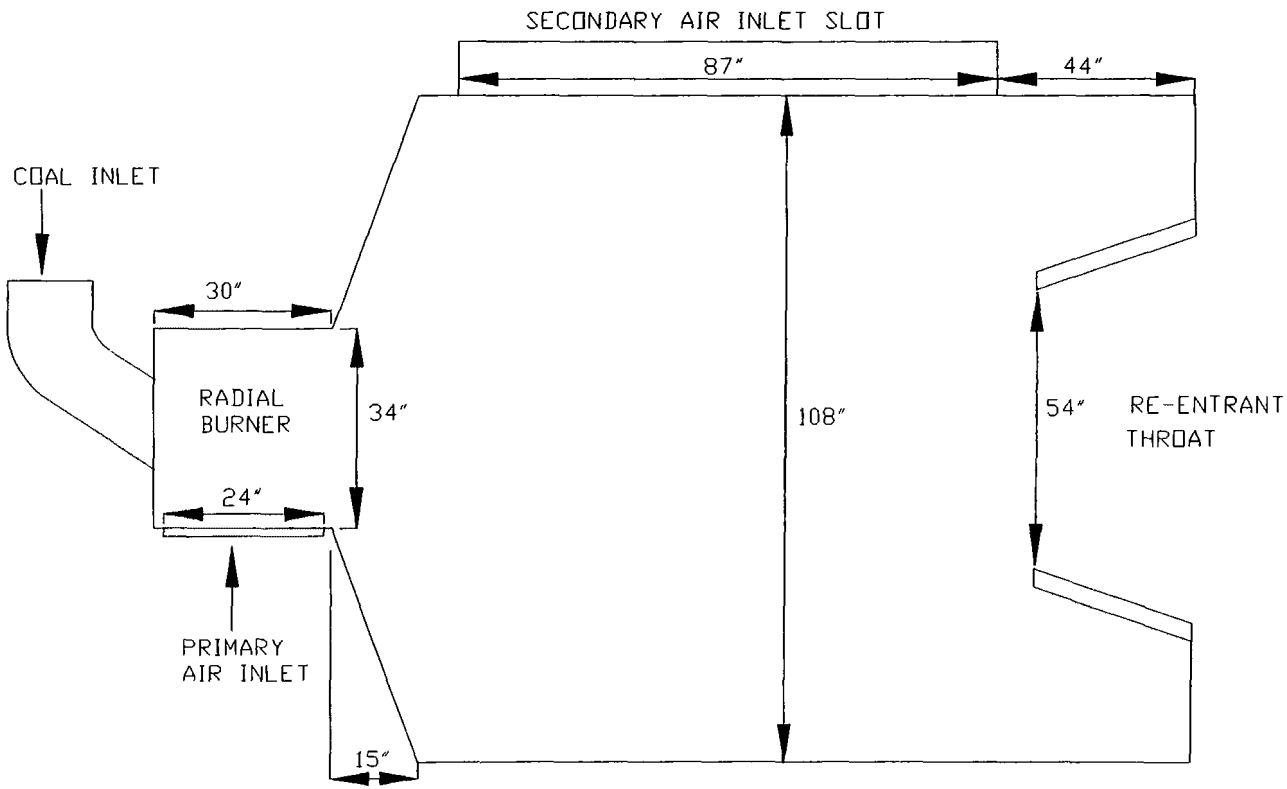
Coal Type	High Sulfur	Low Sulfur	50/50 Blend
% Moisture	6.30	14.0	10.15
% Ash	6.23	5.0	5.62
% Volatile Matter	37.11	34.0	35.56
% Fixed Carbon	50.36	47.0	48.68
HHV, Btu/lb	13,340	11,500	12,240
% Sulfur	2.53	0.5	1.52

CFD Modeling

RJM Corporation used Fluent CFD and NO_X software to model the cyclone combustion process and identify the cyclone NO_X profile. A baseline model was developed that reflected the combustion characteristics of the Unit 1 cyclone. The geometry of the model is shown in Figure 2. Multiple high NO_X areas were identified within the cyclone as shown below.



Over 60% of the total NO_X occurs in a targetable number of areas. Each of the targetable zones were reduced 100°F to represent the impact of a cooling media on that zone. Total heat loss due to the cooling is 0.5%. The model predicted a 25% NO_X emissions reduction within a single



CYCLONE GEOMETRY

FIGURE 2

combustion tempered zone. Because of the various modeling assumptions involved (coal volatilization and burnout characteristics, coal sizing and distribution, coal composition, turbulence modeling, combustion rate constants, etc.) the model NO_X results were used in comparing trends and in quantifying the relative effectiveness of the combustion tempering technology rather than predicting absolute NO_X emission levels.

Water was injected into the model at the two major NO_X locations at various droplet sizes. Table 3 illustrates a summary of the model results.

Table 3
Summary of Model Results

NO_X Production Zones	Water Spray (gpm)	Droplet Size (microns)	NO_X Reduction (%)
Radial Burner Exit	4	30	10
Radial Burner Exit	4	50	17
Radial Burner Exit	4	70	15
Secondary Slot	4	30	21
Secondary Slot	4	50	25
Secondary Slot	4	70	17

Based on modeling results, an evaluation was made of the possible Combustion Tempering approaches and a test program was developed.

Field Testing

A month long field test was conducted on all three cyclones of Unit 1. The focus of testing was to determine the following:

- Confirm the location of the largest controllable cyclone NO_X zones.
- Determine the NO_X reductions achievable on a per cyclone basis with optimum cooling media distribution.
- Measure the total NO_X reduction achievable cooling a portion of all three cyclones.
- Verify the correlation between CFD modeling and field test data.
- Observe the effect on combustion process and cyclone slag tapping characteristics.
- Determine the effect of Combustion Tempering on fly ash LOI.

Water was sprayed into various locations of Merrimack Unit No. 1's three cyclones to determine the effectiveness for NO_X control. Existing ports were utilized which limited the access to the optimum zones. The majority of the water spray tests were directed into the two zones identified by the cyclone CFD model. Limited testing was performed on other zones in an attempt to identify the size and locations of the NO_X production zones in the cyclone. The unit's Continuous Emission Monitor (CEM) was used to measure NO_X emissions. Testing initially focused on spraying water into zones in one cyclone to find the location that provided the peak NO_X reduction. Three probes were used to spray into the peak zone of each cyclone to determine the overall unit NO_X reduction.

Three air atomized probes were developed that would produce a consistent water droplet size. Atomizing air pressure could be controlled to vary the droplet size from the probes. A relationship between droplet size and NO_X reduction was established and compared against the model results.

Testing results varied due to coal blending and the furnace soot blowing cycle. Multiple tests were run to determine the average conditions.

Coal Blending

The unit blends various low, medium, and high sulfur coals depending on price and SO_2 cap requirements. The coal used during the test period was a 50/50 blend of medium sulfur and high sulfur coal. Coal blending is done in the yard on a "blade by blade" basis during the bunkering period. The blended coal is not considered a homogeneous mixture. The medium sulfur coal, when burned on its own, produces higher baseline NO_X. The shift in the baseline NO_X trend is due to differing percentages of blended coal burned throughout the day.

Unit Soot Blowing

Soot blowing is performed every four hours for a one hour and fifteen minute period. At the end of the period the furnace is in a "clean" condition and the baseline NO_X is lowered anywhere from 3% to 5% from the "dirty" condition. RJM Corporation has conducted in-cyclone NO_X measurements on similar front fired cyclone units and found that 90% of the total NO_X produced is from the cyclone in the "clean" condition. As the furnace walls become sooted, the NO_X generation within the furnace increases and the percent reduction achieved from combustion tempering decreases.

Test Results

Conclusions from field testing are summarized as follows:

- A total NO_X reduction of 18% to 22% was achieved when cooling a portion of a single controllable NO_X zone in each cyclone. Results varied as unit soot blowing cycles affected boiler cleanliness.

- The heat rate penalty was 0.5% at a 22% NO_X reduction.
- The combustion tempering flow at 22% NO_X reduction was equivalent to .5% of the total flue gas flow, significantly below that of the SNCR System.
- All three cyclones added proportionally to the total NO_X output of the unit.
- The NO_X reduction achieved from one cyclone was additive to reductions achieved from the other cyclones.
- Controllable zones of NO_X production existed in the cyclone that matched the CFD modeling results.
- NO_X reductions achieved in one zone was additive to a second zone within the same cyclone.
- Testing also demonstrated that higher NO_X reductions were probable at higher Combustion Tempering rates by targeting multiple combustion tempering zones.
- Slag tapping was unaffected by the Combustion Tempering process.
- Fly ash LOI was unchanged by the Combustion Tempering process.

Visual observations of the cyclone tapping were made throughout the test period and no impact was observed. Testing was conducted for 8 to 10 hour periods during the month long tests. At all times the unit was run at full load operation with air and fuel inlet conditions that matched the model input conditions. Multiple tests were run at the baseline condition followed by tempering tests to verify the quantity of the NO_X reduction. Figure 3 illustrates the average NO_X reductions achieved when tempering one NO_X zone in all three cyclones and the modeling projected NO_X reductions with cooling multiple locations in each of the three cyclones.

Test Series I

The first series of tests were conducted by spraying water through a center axis port in the cyclone burner at three different insertion depths. These were 50", 60" and 70" as measured from the probe tip to the end of the view port at the radial burner where the probe was inserted. Table 4 summarizes the unit NO_X reduction achieved when spraying into one of the three cyclones.

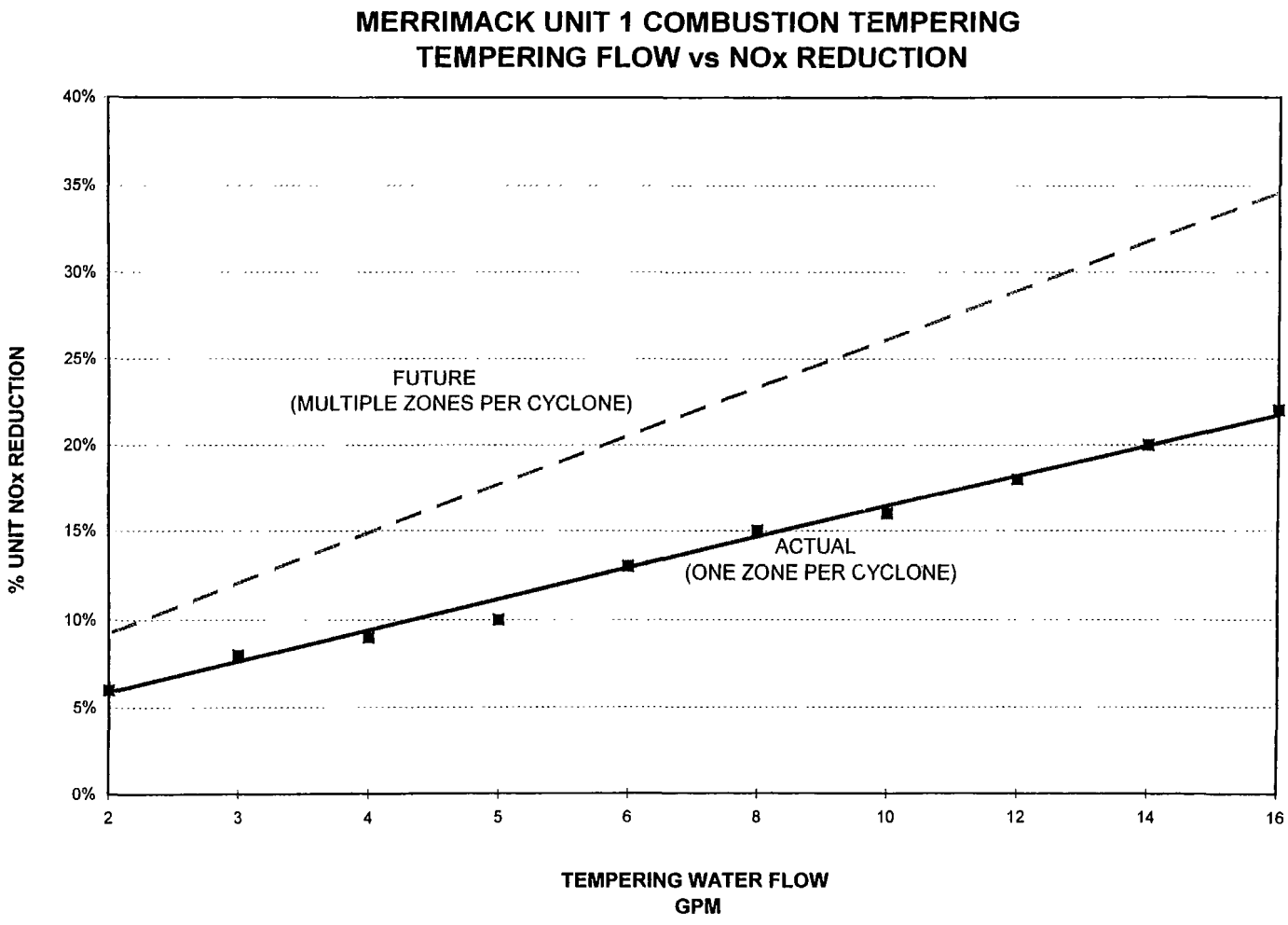

MERRIMACK UNIT 1 COMBUSTION TEMPERING
TEMPERING FLOW vs NOx REDUCTION
% UNIT NOx REDUCTION
40%
35%
30%
25%
20%
15%
10%
5%
0%
FUTURE
(MULTIPLE ZONES PER CYCLONE)
ACTUAL
(ONE ZONE PER CYCLONE)
2
3
4
5
6
8
10
12
14
16
TEMPERING WATER FLOW
GPM

FIGURE 3

Table 4
Combustion Tempering through Center Axis Port in One Cyclone

Insertion Depth (″)	Water Spray (gpm)	Droplet Size (microns)	NO_X Reduction (%)
50	4	50	2
50	4	70	2
50	4	30	3
60	4	50	3
70	4	50	2
70	12	300	10

Test Series II

The probe was then bent to allow water injection into the NO_X production zone predicted by the CFD model at the radial burner outlet. Controlling the spray of the water into target zones produced up to three times the NO_X reduction as non directed spray. Table 5 is a summary of these test results.

Table 5
Targeted Combustion Tempering in One Cyclone

Insertion Depth (″)	Water Spray (gpm)	Droplet Size (microns)	NO_X Reduction (%)
50	4	50	6
60	4	50	6
70	4	30	6
70	4	50	7
70	4	70	8
70	4	90	8

Though the results looked promising, after two hours of use the spray nozzle was severely caked with coal and required cleaning. This location was tested on the other two cyclones with similar results. Due to the constant cleaning requirement of the spray nozzle, testing was redirected to the secondary air slot region.

Test Series III

Additional testing was conducted along the secondary air slot of each of the three cyclones. A probe was inserted through the ignitor viewing port and water was sprayed at various zones along the slot. Different probe tips were used that produced different spray types and angles. A summary of a set of tests of one cyclone is listed in Table 6.

Table 6
Combustion Tempering at the Secondary Air Slot in One Cyclone

Insertion Depth (″)	Water Spray (gpm)	Droplet Size (microns)	NO_X Reduction (%)
40	4	50	5
50	4	50	6
60	4	50	6
70	5	50	7
80	5	50	8
80	5	70	7
80	5	80	6

The insertion depth was measured from the atomizer tip to the view port face. Higher flow rates were required at the longer insertion depths to prevent the test probe from overheating. After several hours of testing the probe was removed and inspected for damage. The probe was clean and no visual damage could be detected. A downward fan spray pattern was found to work the best as other patterns tested did not provide adequate coverage which limited the NO_X reduction.

Each of the tests were repeated on the other two cyclones with similar results. A summary of the NO_X reductions achieved for each of the zones tested in cyclone A are shown in Figure 4.

Three Cyclone Testing

One probe was inserted into each of the three cyclones to determine the maximum achievable NO_X reduction. All probes were located along the secondary slot. Due to mechanical interferences between the probe and piping outside B cyclone, it was not possible to insert the probe at the optimum location. See Table 7.

Table 7
Combustion Tempering at the Secondary Air Slot in All Three Cyclones

Insertion Depth (″) Cyclone			Water Spray (gpm)	Droplet Size (microns)	NO_X Reduction (%)
A	B	C			
80	50	80	16	50	21.5
80	50	80	16	50	22
80	50	80	16	50	18
80	50	80	16	50	20

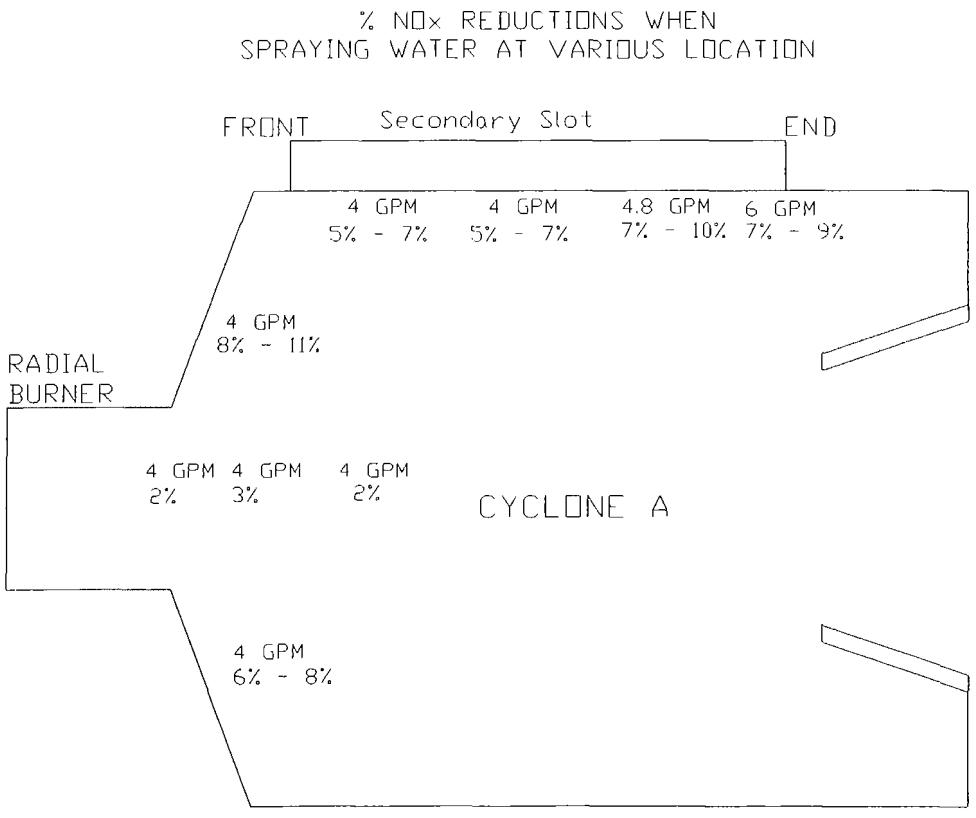

% NOx REDUCTIONS WHEN
SPRAYING WATER AT VARIOUS LOCATION
FRONT
Secondary Slot
END
4 GPM
5% - 7%
4 GPM
5% - 7%
4.8 GPM
7% - 10%
6 GPM
7% - 9%
4 GPM
8% - 11%
RADIAL
BURNER
4 GPM
2%
4 GPM
3%
4 GPM
2%
CYCLONE A
4 GPM
6% - 8%

FIGURE 4

As previously noted the total reduction would vary based on the unit soot blowing cycle and the coal blend on a given day. Total NO_X reductions varied between 18% to 22% for the testing period. The reductions were stable, repeatable and additive to the reduction achieved with the SNCR System.

Multi-Zone Testing

Multiple zones were tested in a single cyclone to determine if the reductions were additive. Probes were inserted to spray water into two separate zones along the secondary air slot (Sec), one at the 50″ insertion depth and the other at the 80″ insertion depth. A third probe was inserted through the radial burner (Rad) at the 50″ insertion depth and bent to spray a targeted zone. Data was taken with various combinations to determine the effect as shown in Table 8.

Table 8
Targeted Multiple Zones in One Cyclone

No. of Probes & Location	Tempering Flow Rate (gpm)	NO_X Reduction (%)
1 Rad	4	7
1 Rad, 1 Sec	8	12
1 Rad, 2 Sec	14	15
2 Sec	10	10
1 Sec	4	5

It is suspected that some spray overlap occurs when spraying into multiple zones that decreases the Combustion Tempering efficiency.

Long Term Testing

Following the series of month long tests, a long term test was conducted to determine if spray hardware could last in the optimum tested spray location. The hardware used for the testing was permanently installed in October 1996 for a six month test in two of the three cyclones. The orientation of the spray was altered from the original tested orientation since an optimal access port location was not able to be installed without a unit outage. This orientation and elimination of spray in one cyclone limited the achievable NO_X reduction to a total of 7% to 10%. Following the six month test period, the hardware was inspected and found to be worn but totally functional.

Projected Costs

A commercial Combustion Tempering system has been estimated to cost $2.50/KW for this size unit. This cost would reduce to an estimated $1.30/KW for units in excess of 500 MW. Costs include modeling, engineering, injection hardware, pumping and metering skid, installation, and start-up. On this 130 MW unit, costs would be $131/ton of NO_X reduced based on a 22% NO_X reduction.

The existing ammonia based SNCR System annualized costs are approximately $700/ton of NO_X reduced based on a 35% NO_X reduction. Combining a urea based SNCR System with Combustion Tempering to obtain the same targeted 35% NO_X reduction would reduce the annualized cost to $350/ton of NO_X reduced. Combining the technologies has the potential of yielding NO_X reductions of 60 - 65% from baseline NO_X levels at a cost of $454/ton of NO_X reduced.

REDUCTION OF NOx EMISSIONS WITH CYCLONE BURNERS BY BIASING OF COMBUSTION AIR

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Abstract

Northern States Power Company (NSP) has conducted tests to evaluate cyclone air flow biasing to reduce NOx emissions at Unit 1 of the Allen S. King Generating Station. King Unit 1 is a 600-MW opposed-wall, cyclone-fired boiler with 12 cyclone burners and two elevations on each wall (three burners per elevation). The test program compared NOx emissions with a dirty furnace (significant wall ash deposits) to a clean, water-washed furnace. At 500-MW with a dirty furnace, NOx emissions were 1.38 lb/MBtu with 12 cyclones in service and 2.5 percent excess O_2 at the boiler exit. NOx emissions were 1.23 lb/MBtu at the same operating conditions with a clean furnace (an 11 percent reduction in NOx emissions). Tests to evaluate the effect of secondary air flow biasing were conducted with both a dirty and clean furnace and with the stoichiometry of the cyclones in the bottom elevation reduced to 0.90 (fuel rich). Secondary air biasing with a dirty furnace reduced NOx emissions 17 percent from 1.38 to 1.14 lb/MBtu, whereas NOx emissions with a clean furnace were lowered by 24 percent from 1.23 to 0.94 lb/MBtu. Secondary air biasing had no significant impact on boiler operations. Boiler exit CO remained unchanged, and

there were slight increases in furnace exit gas temperature and carbon in the ash. Electrostatic precipitator operation and stack opacity were not affected.

Analysis of flue gas samples along the furnace walls below the bottom cyclone elevation and above the top elevation showed that with and without secondary air biasing, excess O_2 was greater than 1.0 percent, hydrogen sulfide (H_2S) was generally less than 50 ppm, and carbon monoxide (CO) was less than 1,000 ppm. Higher concentrations of CO and H_2S were measured in the center of the furnace in the proximity of the biased cyclone's reentrant throat. However, the concentrations measured do not pose a significant concern for increased tube wall wastage. Based on these positive results, NSP is planning to operate King Unit 1 with secondary air biasing for an extended period to obtain long-term data on NOx emissions and waterwall impacts.

Introduction

Northern States Power Company (NSP) is a member of the EPRI Cyclone NOx Controls Interest Group (CINCIG). CINCIG has sponsored modeling and experimental work at other utility companies to evaluate the potential of cyclone burner secondary air biasing for reducing NOx emissions[1] Results from this work showed that reductions in NOx emissions of greater than 20 percent were possible with air biasing. Based on these promising results, NSP elected to further evaluate the secondary air biasing as a NOx reduction technique on its cyclone fired boilers for potential implementation.

NSP has elected to utilize a system-wide averaging NOx emission plan, instead of meeting specific NOx emission limits on individual power plants. The use of secondary air biasing to reduce NOx emissions on NSP's cyclone boilers fits within the needs of NSP's system-wide NOx emission averaging plan.

Electric Power Technologies, Inc. (EPT) worked with NSP to develop a test program to evaluate the feasibility of utilizing secondary air flow biasing to reduce NOx emissions at Unit 1 of the Allen S. King Station. The purpose of the tests was to determine the NOx emission reductions possible, the amount of lower cyclone air biasing required, and effects on boiler operations and performance, ash deposition, opacity, and potential waterwall tube wastage due to production of reducing combustion conditions by measurement of hydrogen sulfide (H_2S) and carbon monoxide (CO).

King Unit 1 Description

King Unit 1 is a 600-MW opposed-wall, cyclone-fired, supercritical boiler manufactured by Babcock & Wilcox Company. The unit was commissioned in 1968 and has a boiler nameplate rating of 3,873,000 lb/hr of steam flow at 1,005°F superheat temperature and 3,675 psig when burning Illinois bituminous coal. The design reheat steam temperature is 1,005°F at 676 psig. The unit was originally supplied with flue gas recirculation and gas tempering. The flue gas recirculation has been removed, but flue gas tempering is operational to control furnace exit flue gas temperature (FEGT). Tempering flue gas enters the furnace through 12 access ports, six per front wall and six per rear wall, located just below the furnace exit. The furnace has four rows of steam wall sootblowers. There are 12 waterlances installed and spaced evenly between the steam wall blowers on the 2nd and 4th elevations.

King Unit 1 has twelve, 10-ft cyclones with radial burners. The cyclones are arranged in two elevations of three cyclones each on the front wall and rear wall (12 cyclones total). Combustion air to the cyclones is supplied through an open, wraparound windbox. Combustion air enters each cyclone as primary air, tertiary air, and secondary air.

The original fuel supply for this unit was a high-sulfur, Illinois bituminous coal. Following promulgation of federal regulations to reduce sulfur dioxide emissions, the fuel supply at King was changed to blends of low-sulfur, western subbituminous coals and petroleum coke. Currently, King burns a blend of 70 percent Wyoming subbituminous coal, 20 percent Montana subbituminous coal, and 10 percent petroleum coke.

Measurement Methods

Measurements of flue gas composition were performed at the boiler exit and within the primary furnace. At the boiler exit, a multi-point extractive system was used to obtain flue gas samples for analysis of NOx, CO, CO_2, H_2S and excess O_2. Samples were extracted from each of two flue gas ducts upstream of the air heater. Individual sample lines transported the flue gas samples to a mobile emissions laboratory located at ground level below the flue gas ducts. The gas samples were conditioned to remove water and directed to emission monitors. Excess O_2, CO, CO_2, NOx, and H_2S were measured using EPA continuous monitoring procedures and EPA certified gases. Excess O_2 was measured with a Servomex Model 570A monitor, CO_2 with a ACS Model 3300 instrument, CO with a TECO Model 48 and 48H, NOx with a TECO Model 10A chemiluminescence monitor, and H_2S with a Western Research Model 922 SO_2/H_2S photometric (UV absorption) analyzer. Hydrogen sulfide measurements were augmented by using EPA Method 11 (Determination of Hydrogen Sulfide Content of Fuel Gas Stream in Petroleum Refinery) as a quality control check. Opacity was monitored by the plant continuous

emission monitor system (CEMS). Flyash samples were collected by Cegrit flyash samplers installed in each boiler outlet duct upstream of the air heater, as well as from collection hoppers in the electrostatic precipitator (ESP).

Water-cooled probes were used to collect flue gas samples from the furnace and to measure flue gas temperatures. The temperature measurements were primarily conducted at the furnace exit to monitor any changes in FEGT resulting from secondary air biasing. The temperatures were made with a high velocity thermocouple (HVT) consisting of multiple shields and a Type R thermocouple. King Unit 1 has two optical pyrometers located at the furnace exit plane, one each on the sidewalls. The HVT temperature measurements were used to check the reliability and accuracy of the pyrometers early in the test program. Further, furnace flue gas temperature, internal cyclone temperature, and cyclone and furnace floor slag temperature measurements were made with a Raytek Raynger 3i portable optical pyrometer. Measurements of H2S, O2, and CO were performed along the waterwall tube surfaces in the furnace to determine the degree of furnace reducing conditions. The primary sampling locations were in the lower furnace along the furnace floor, outside the cyclone reentrant throats, and along waterwall surfaces above the upper cyclone row in the middle furnace. The flue gas sampled from each furnace location was directed to the mobile emission laboratory, conditioned, and analyzed.

Calculation of Secondary Air Flow Biasing

Secondary air flow biasing was determined by using the coal flow and total air flow indicators from the boiler control system for each cyclone. The indications of air and coal flow are used to calculate an air/fuel ratio for each cyclone which is displayed on monitors in the control room. During preliminary tests of secondary air biasing, diverted secondary air from the lower cyclones produced over-range air flow measurements in the secondary air flow transmitters for the upper cyclones. Subsequently, the secondary air flow transmitters/meters on the upper cyclones were respanned to accommodate the increased air flow.

The degree of secondary air flow biasing was calculated from each cyclone air flow meter, as well as theoretical air and excess air values derived from an average fuel analysis. King Unit 1 operates at approximately 2.5 percent excess O2 as measured at the boiler outlet. This corresponds to about 15 percent excess air (stoichiometry of 1.15). Using data from the cyclone air flow meters, a uniform baseline secondary air flow to all cyclones results in an air/fuel ratio of 7.83 lb air/lb coal. The theoretical (stoichiometry of 1.0) air flow was calculated to be 6.81 lb air/lb coal. Secondary air flow biasing reduced the air/fuel ratio to cyclone(s) in the lower elevation to approximately 6.1 lb air/lb coal, equivalent to a stoichiometry of 0.90.

Results

Baseline NOx emissions

The King test program was conducted in two separate phases: the first test occurred prior to the Spring 1997 outage and the second test following the Spring outage. From a combustion perspective, a primary difference in the two periods was the condition of the furnace walls. During the outage, the walls were cleaned of sintered coal ash and areas of encrusted flyash accumulations. These deposits act as insulators and inhibit convection and radiation heat transfer to the furnace walls, thereby increasing the flue gas temperature in the lower and middle primary furnace regions and NOx emissions. Figure 1 illustrates the effect of furnace cleanliness on NOx emissions at 500-MW with 12 cyclones in service and 2.5 percent excess O_2 at the boiler exit. Prior to the spring outage NOx emissions were measured to be 1.38 lb/MBtu with a "dirty" furnace. Following the spring outage, NOx emissions were reduced by approximately 11 percent to 1.23 lb/MBtu at the same operating conditions except with a "clean" furnace. Figure 1 also shows that baseline NOx emissions were 1.38 lb/MBtu at 550-MW with 12 cyclones in-service, 2.5 percent excess O_2, and with a clean furnace. This result indicates that washing the waterwalls in the furnace permitted load to be increased by 50-MW with no change in NOx emissions. Because of the significant effect of furnace cleanliness, NOx emission data in this paper are referenced to clean or dirty furnace wall conditions.

Effect of Secondary Air Flow Biasing on NOx Emissions

Air flow biasing was accomplished by reducing secondary air flow to the lower elevation cyclones and redistributing the air to the upper elevation cyclones. Thus, the cyclones in the lower elevations were operated fuel-rich (stoichiometry < 1.0) and the cyclones in the upper elevation air-rich (stoichiometry > 1.0). All of the biasing tests were with a lower cyclone stoichiometry of approximately 0.90 and a stoichiometry of 1.40 in the upper cyclones.

Figure 2 summarizes the results with all 12 cyclones in service. At 500-MW with a dirty-furnace, secondary air flow biasing reduced NOx emissions by 17 percent to 1.14 lb/MBtu. At 500-MW with a clean furnace, secondary air biasing reduced NOx emissions by approximately 24 percent to 0.94 lb/MBtu. Further, at 550-MW with a clean furnace, secondary air flow biasing lowered NOx emissions by 26 percent to 1.02 lb/MBtu.

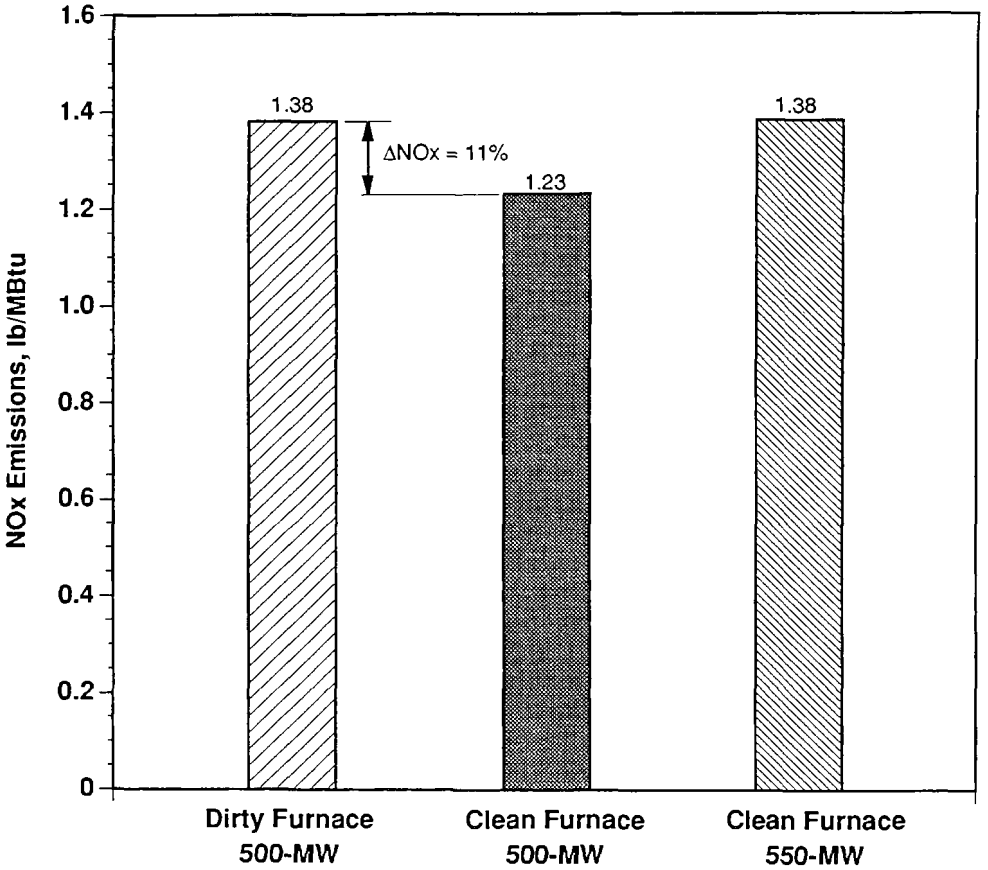

Figure 1. Comparison of baseline NOx emissions at King Unit 1 with uniform air flow to the cyclone burners (i.e., no air biasing) for a dirty boiler (left) and a clean boiler (center and right). Data were obtained with 12 cyclones in service and excess O2 of 2.5 percent.

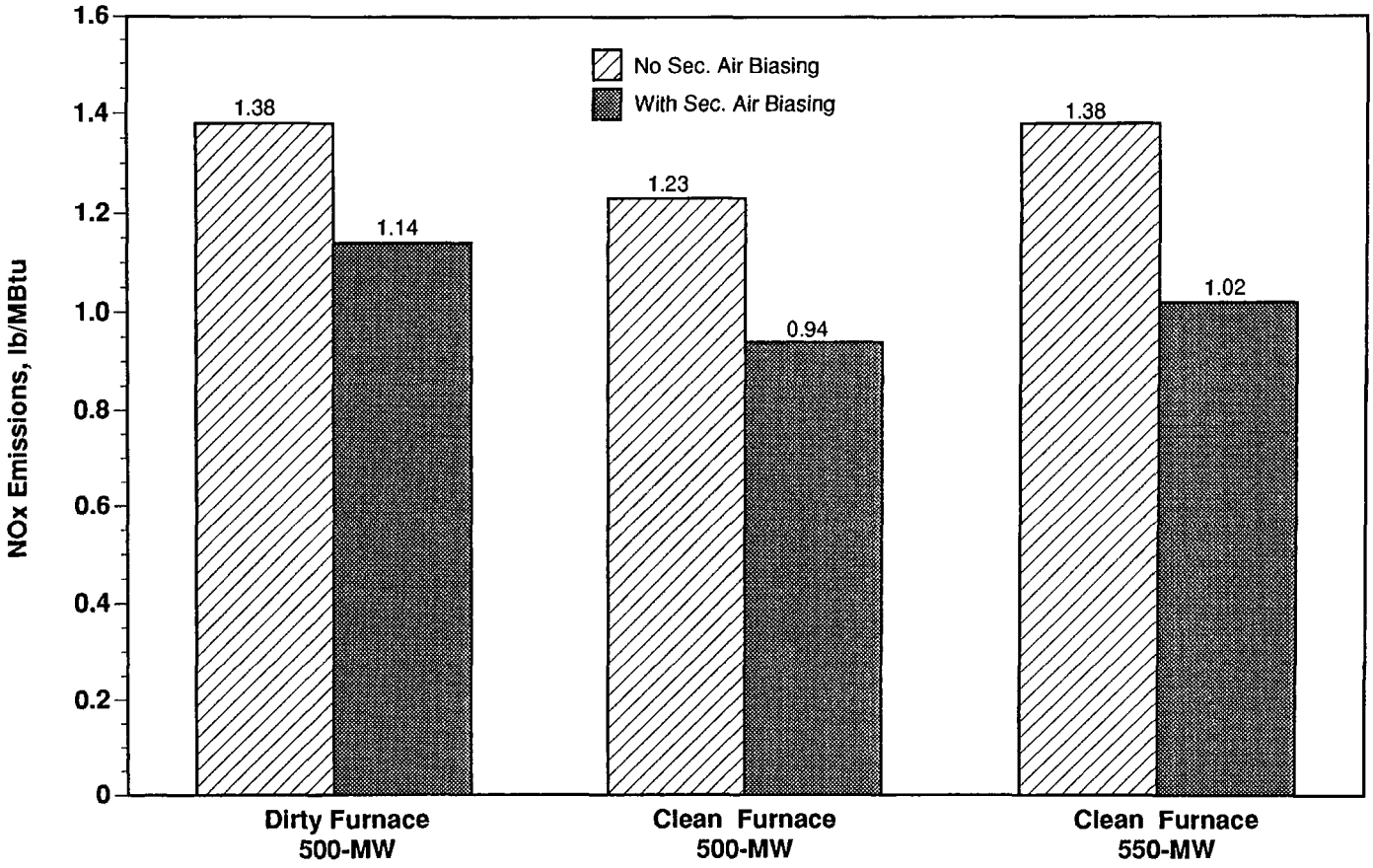

Figure 2. Effect of secondary air biasing on NOx emissions at King Unit 1 with a dirty furnace (left) and clean furnace (center and right). Data are with 12 cyclones in service.

Secondary Air Flow Biasing with Cyclones Out-of-Service Effect

With uniform secondary air flow to all cyclones, operating with a cyclone(s) out-of-service poses no air flow difficulties in the operating cyclones. However, when secondary air is biased from the lower cyclones, all of the diverted combustion air must pass through the upper cyclones to maintain the same overall boiler air flow. At high boiler loads, the operating cyclones in the top elevations cannot accommodate all of the diverted combustion air due to air flow meter over-range conditions. Therefore, the combustion air not accounted for by the operating cyclones must be passed through the out-of-service cyclones. Tests were performed with a dirty boiler to determine the effect of the diverted air on NOx emissions. Figure 3 compares the effects of: (1) secondary air biasing, and (2) biasing with cyclones out of service. At 500-MW with one cyclone-out-of-service and approximately 7 percent of the combustion air flow flowing through the out-of-service cyclone, NOx emissions were 0.97 lb/MBtu, or 29 percent below baseline NOx emissions of 1.38 lb/MBtu, and 15 percent lower than NOx emissions with biasing alone (1.14 lb/MBtu). At 500-MW with two cyclones out-of-service and approximately 13 percent of the combustion air passing through the out-of-service cyclones, NOx emissions were essentially the same at 0.98 lb/MBtu. It is not certain why NOx emissions were not reduced by operation with two cyclones out of service. It is possible that the actual air flow flowing through the two cyclones was not consistent with the calculated values, and thus less air was diverted to the cyclones than expected, or that the air distribution in the furnace was non-uniform and not conducive to further NOx reductions.

Effects of Biased Secondary Air Flow on Boiler Operations

The use of biased secondary air flows as a viable operating condition to reduce NOx emissions depends on secondary effects which may effect boiler performance and operations. King Unit 1 is prone to severe slagging and fouling ash deposition which can significantly curtail high load generation. Moreover, flyash produced at King is sold and any degradation of flyash quality may jeopardize this product stream. Effects on boiler efficiency, cyclone and furnace bottom slag tapping, ESP operations, and stack opacity also must be considered.

Overall Boiler Operations. No significant changes in boiler operation were observed during the air flow biasing test periods. Superheat and reheat steam temperatures were in line with normal operations, and there was no abnormally high attemperator spray flows. Sootblowing progressed in the normal cleaning patterns, and there was no increase in opacity.

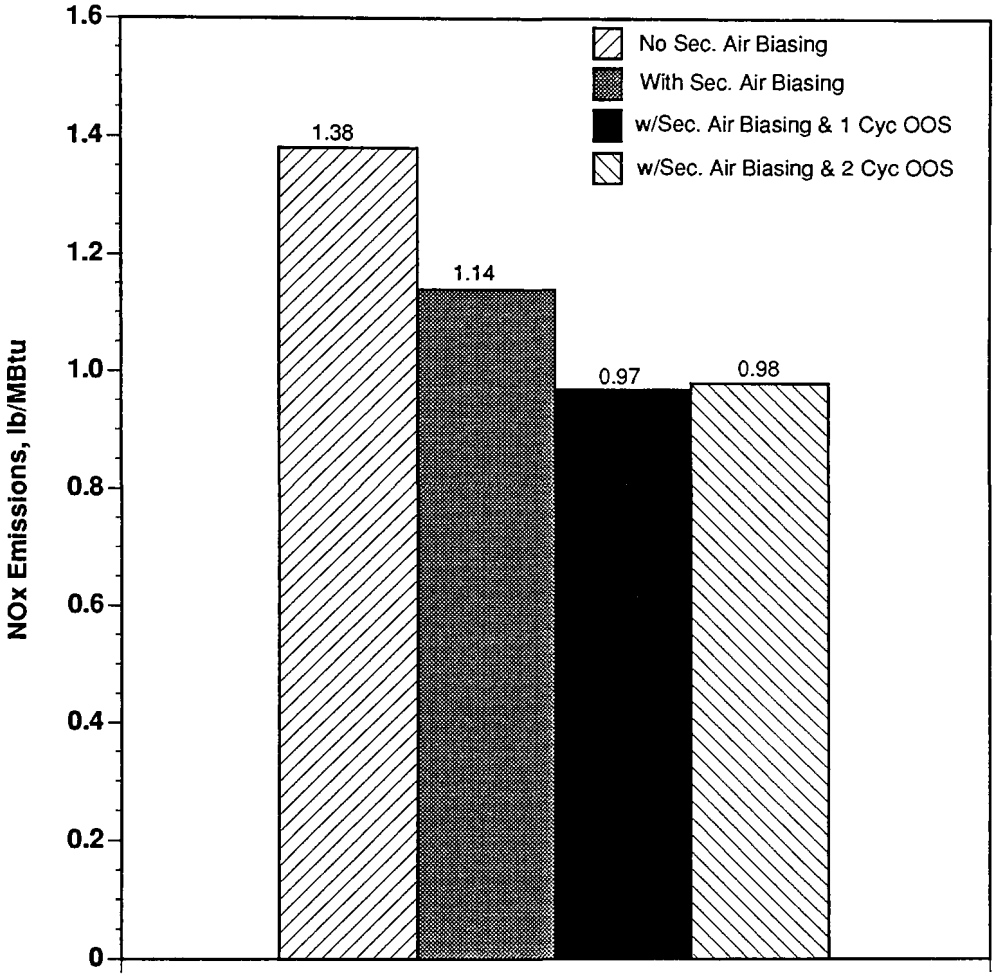

Figure 3. Effect of secondary air biasing and cyclones out of service on NOx emissions at King Unit 1. The data were obtained at 500-MW with a dirty furnace and with one cyclone out of service (third from left) and two cyclones out of service (right) and the secondary air dampers open.

Furnace Exit Flue Gas Temperatures (FEGT). The slagging and fouling experienced at King is mainly due to the high concentrations of alkali compounds in the coal ash, i.e., calcium and sodium, and is strongly dependent on localized flue gas temperatures. Flue gas temperatures at the furnace exit, reheat section outlet, and primary superheater outlet are used by the plant to assess boiler conditions and are adjusted based on historical operating experience. Baseline FEGT's at 500-MW measured with a water-cooled HVT probe were 1,983°F and 1,990°F on the north and south sides of the furnace respectively. Following secondary air flow biasing, both side traverses showed a slight increase in FEGT. For example, the north side averaged 2,030°F, an increase of approximately 50°F, and the south side showed an increase of around 25°F with a temperature of 2,013°F. The FEGTs measured were within current plant operating guidelines. The plant pyrometers located at the furnace exit also indicated a slight increase in flue gas temperatures. Additional flue gas temperature measurements by stationary in-situ thermocouples at the reheat outlet and primary superheater outlet showed no appreciable change in flue gas temperatures between balanced and biased secondary air flow operations.

Slag Temperature Measurements. Pyrometer temperature readings of the slag tapping from the lower cyclones and the slag pooling on the furnace floor indicated that temperature increased when secondary air was biased away from the cyclones in the lower elevation. The higher temperatures keeps slag viscosity low and slag flowing with no observable problems. Some "angel hair" slag was visible at the floor tap holes, but did not present any operating problems.

Flyash Unburned Carbon. Flyash samples were collected from three locations: (1) Cegrit samples installed at the air heater inlet ducts; (2) ESP inlet hoppers; and (3) ESP outlet hoppers. The Cegrit samples are an in-situ flyash sample collected from the centerline of the flue gas duct. A baseline sample (i.e., no biasing) had an average carbon content of 8.58 percent. With secondary air biasing, carbon-in-ash increased slightly to 10.8 percent with 12 cyclones in-service, and decreased slightly to 7 percent with 11 cyclones in-service. Overall, there was no significant change in unburned carbon. At the ESP inlet section, carbon-in-ash was approximately 7.9 percent for baseline operation and 13 percent with secondary air biasing. Carbon-in-ash at the ESP outlet section showed no appreciable difference when operating in the balanced (2.82 percent carbon) or biased (3.10 percent carbon) air flow configurations. Although the flyash carbon levels increased during the air flow biasing tests, they were still within an acceptable range for disposal. A summary of unburned carbon results is shown below:

Boiler Load (MW)	Test Condition (*cyclones I/S)	Carbon-in-Ash (average) Cegrit AH Inlet (% carbon)	ESP AH Outlet (% carbon)	ESP Outlet (% carbon)
500	Base (12*)	8.58	7.86	2.82
500	Bias (12)	10.84	-----	-----
500	Bias (11)	7.03	12.89	3.05
500	Bias (10)	----	13.00	3.16

Effect of Secondary Air Flow Biasing on Flue Gas Composition

A primary concern with secondary air flow biasing is the potential for producing localized reducing flue gas regions and the presence of hydrogen sulfide (H_2S). Water-cooled probes were utilized to extract flue gas from various sections of the primary furnace. The flue gas samples were directed to the mobile emission test van, conditioned, and analyzed. Extensive flue gas sampling was performed in the lower furnace below the lower cyclone reentrant throats. The traverse path was oriented along the furnace centerline and just below the cyclone centerline. Additional flue gas sampling was performed above the upper cyclone elevations in the middle furnace region. In this area, special attention was given to the centerwall areas along the front waterwall, rear waterwall, and sidewalls.

Figure 4 presents O_2, CO, and H_2S data from flue gas sample traverses with and without secondary air biasing at three locations in the furnace: (1) lower furnace, (2) above the cyclones, and (3) in the middle furnace. The data were collected with all 12 cyclones in service and 2.5 percent excess O_2 at the furnace exit.

Lower Furnace Test Results. Figure 4 (left) compares O_2, CO, and H_2S measurements in the lower furnace at 550-MW. The data show that by reducing the secondary air to the lower cyclones to achieve a stoichiometry of 0.9, the average O_2 decreased from 1.7 to 1.3 percent, CO increased from 0.6 to 3.6 percent, and H_2S increased from 121 to 252 ppm. Along the probe traverse path, flue gas composition changed as the probe extended farther into the furnace. With no air biasing, the lowest O_2 measured was 0.3 percent, the highest CO was 1.5 percent, and the highest H_2S concentration was 214 ppm. With secondary air biasing, the lowest O_2 observed was 0.1 percent; the highest CO was 7.6 percent; and the highest H_2S concentration was 818 ppm. These values all occurred in the central areas of the lower furnace, approximately 7-ft. from the waterwall surface and in the proximity of the cyclone reentrant throat exit and cyclone exit flue gas wash. Along the waterwalls during both operating conditions O_2 ranged from 2.2 to 3.4 percent, CO varied from 0.1 to 0.6 percent, and the H_2S concentrations ranged from 11 to 40 ppm.

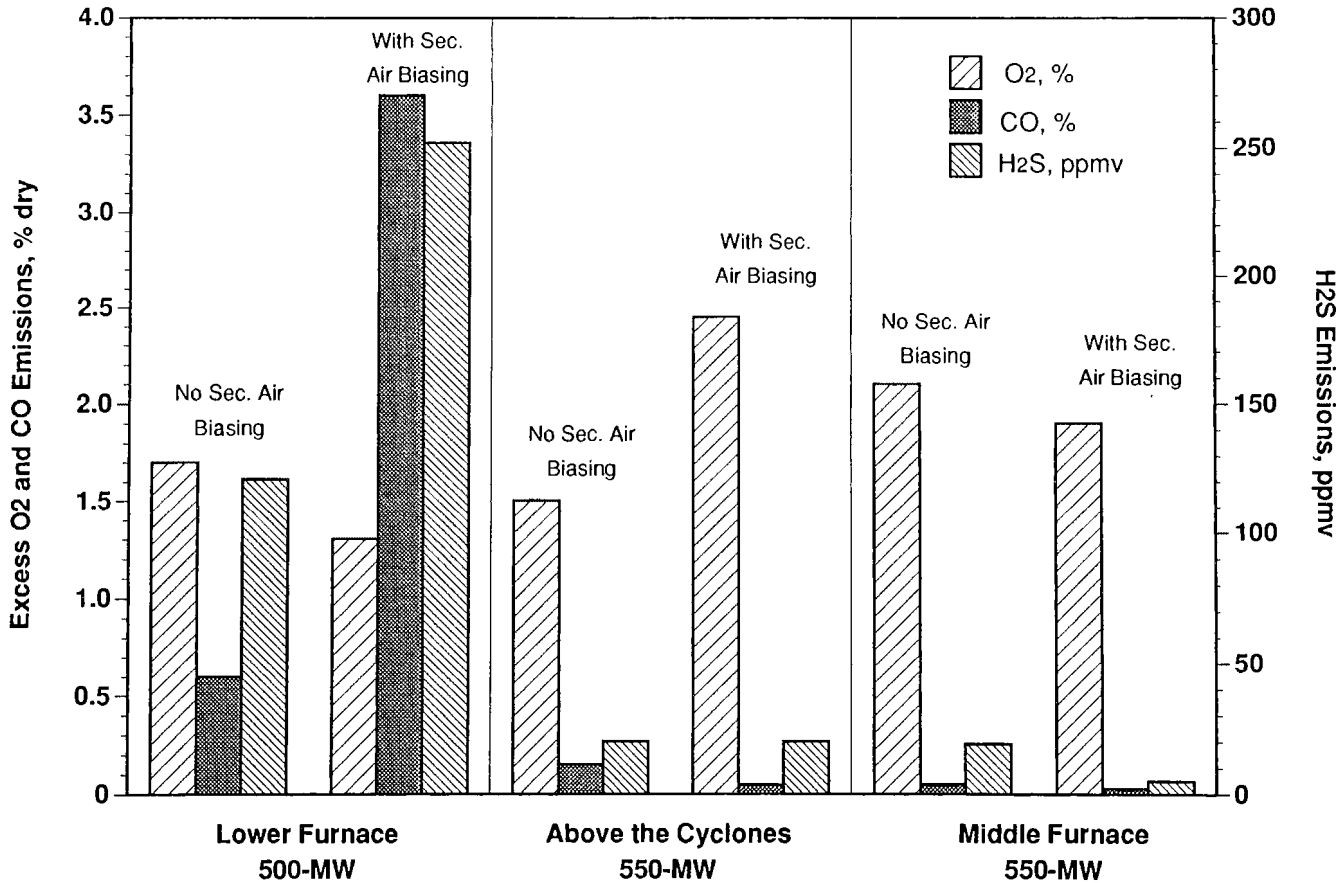

Figure 4. Oxygen (O_2), carbon monoxide (CO), and hydrogen sulfide (H_2S) data measured at three locations in the furnace at King Unit 1 with and without secondary air biasing. Data were collected with 12 cyclones in service and 2.5% excess O_2 at the furnace exit.

Middle Furnace Test Results. Flue gas sampling traverses were performed at four different elevations in the middle furnace starting above the upper cyclone position. In each case, flue gas samples were collected at multiple points along a short traverse into the furnace, starting as close to the waterwall as possible to minimize the effects of outside air infiltration. All of the testing in this furnace region was performed at a boiler load of 550-MW with all 12 cyclones in-service and with 2.5 percent excess O_2. With secondary air biasing, Figure 4 shows that in the furnace wall area immediately above the upper cyclone elevation the average O_2 increased from 1.55 to 2.5 percent, CO decreased from 0.15 to 0.05 percent (1,500 to 500 ppm), and H_2S decreased from 20 ppm to <20 ppm.

Flue gas sampling at a higher furnace wall elevation revealed a similar pattern in O_2, CO, and H_2S concentrations as observed at the lower elevations. Without air biasing, the average O_2 was measured at 2.1 percent, average CO was 500 ppm, and the H_2S concentration was 19 ppm. When secondary air flows were biased, the average O_2 decreased slightly to 1.9 percent, CO decreased to approximately 300 ppm, and H_2S levels were <20 ppm.

Summary

A test program was conducted at the King Unit 1 to evaluate the feasibility of utilizing air flow biasing as a cost-effective method to reduce NOx emissions on boilers with cyclone burners. The main concerns prior to the testing involved the degree of NOx emission reduction achievable, the amount of cyclone air biasing required, the potential of waterwall tube wastage due to the production of H_2S and reducing combustion conditions, and adverse effects on boiler operations and combustion, ash deposition, and opacity.

Two conditions were evaluated during the program. One testing period was conducted with a dirty furnace (pre outage) and the second was with a clean furnace (post outage). At 500-MW with a dirty furnace and balanced combustion air flow (i.e., no biasing), NOx emissions were 1.38 lb/MBtu. With a clean furnace without biasing, NOx emissions were 11 percent less at 1.23 lb/MBtu. Biasing the secondary air to decrease the stoichiometry of the cyclones in the lower elevations to 0.90 with a dirty furnace reduced NOx emissions by 17 percent to 1.14 lb/MBtu. For a clean furnace, biasing reduced NOx emissions by 24 percent to 0.94 lb/MBtu. The difference in NOx emissions for a clean and dirty furnace is significant and can be explained by increased heat transfer to the clean furnace walls, which lowers the gas temperature in the primary combustion zone. This would indicate that there is a thermal NOx component that takes place in the furnace outside of the cyclone combustion environment.

Data collected during the test program indicated that operating with secondary air biased from the lower cyclones presents no significant change in boiler operations.

Cyclone operations, evaluated by slag tapping characteristics, were not adversely affected in either the lower cyclones with reduced excess air, or the upper cyclones with higher excess air. Combustion conditions in both cyclone elevations, as evaluated by plant operations, appeared normal in regards to coal ignition and final coal combustion. Over the short-term of the testing period, there were no adverse effects on furnace and convection pass ash deposition.

Flue gas sampling from the furnace waterwall regions confirmed low concentrations of H_2S. As expected, the highest H_2S and CO concentrations, and lowest O_2 levels, were measured in the lower furnace immediately outside the fuel rich cyclone exits. Without secondary air biasing, the lowest O_2 measured was 0.3 percent, and the highest CO and H_2S were 1.5 percent and 214 ppm, respectively. With secondary air biasing, the lowest O_2 measured was 0.1 percent, and the highest CO and H_2S were 7.6 percent and 818 ppm, respectively. In the furnace region above the top cyclone elevation without biasing, the average O_2 was 1.55 percent, the average CO was 1,500 ppm, and the average H_2S was 20 ppm. With biasing, the average O_2 increased to 2.5 percent, the average CO decreased to 500 ppm, and the average H_2S was < 20 ppm. The H_2S levels measured along the furnace walls below the lower cyclone elevation and above the upper cyclone elevation do not pose a significant concern for increase tube wall wastage. The environment that is present in these regions is not highly reducing, having O_2 concentrations greater than 1 percent and CO levels lower than 1 percent. The low H_2S levels were primarily due the low overall sulfur and pyritic sulfur levels in the coal. At these conditions, a moderate tube metal loss less than 10 mils/yr would be expected.

Conclusions

The test program at King Unit 1 showed that significant reductions in NOx emissions can be realized with secondary air biasing air. There were no detrimental operating performance effects measured or observed. Based on the promising test results, NSP is planning to operate King Unit 1 with secondary air flow biased conditions for a period of six-months starting around September 1997. During this test period, long term effects on cyclone operation, furnace ash deposition, convection pass ash deposition, flyash loss on ignition (LOI), boiler operations and performance, ESP operation, and opacity trends will be monitored. Following this operating period, Unit 1 will be inspected and boiler wall UT tube thickness measurements will be performed.

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CYCLONE BOILER AIR STAGING DEMONSTRATION PROJECT
SIOUX UNIT 2

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Abstract

EPRI's Cyclone NO_x Control Interest Group (CNCIG) has been investigating a variety of issues related to finding low cost, innovative methods to lower NO_x emissions from cyclone-fired boilers. Alternative reduction techniques were desired in order to avoid high capital, O&M, and fuel costs associated with traditional technologies, such as coal or gas reburning, selective noncatalytic reduction, and selective catalytic reduction. CNCIG focused on exploring concepts pertaining to cyclone combustion modifications that have the potential to lower emissions to near the 0.86 lb/MMBtu limit proposed under Title IV of the Clean Air Act Amendments of 1990.

Computational fluid dynamics (CFD) modeling and corrosion studies of cyclone and furnace combustion processes indicated air staging had the potential to lower NO_x to the specified limit. Modeling indicated NO_x emissions could be lowered below the 0.86 limit through a combination of low stoichiometry cyclone operation and injection of secondary air above the top row of cyclones on a two-level, opposed-fired cyclone boiler, currently burning a blend of Powder River Basin and Illinois coals.

During April/May, 1997, Union Electric Company installed a temporary overfire air system (OFA) on Sioux Unit 2. The Sioux 2 boiler has ten cyclones, opposed-fired, arranged in two rows on the front and rear walls. The system was designed to inject combustion air into the furnace through existing gas recirculation ports located above the top row of cyclones. The demonstration was intended to validate predictions of NO_x emissions reductions and to demonstrate short-term operability with the OFA system.

This paper presents background CFD model results and design of the temporary OFA system. Testing is planned for July 1997 with short-term performance information becoming available in August, 1997. Preliminary data collected in July show reductions in NO_x of 50% from baseline are feasible and repeatable.

Background

Union Electric Company's Sioux Power Plant consists of two 500 MWe generating units located on the west bank of the Mississippi River in St. Charles County, approximately 20 miles north of St. Louis, Missouri. Unit 1 was commissioned in May-1967, and Unit 2 was commissioned in May-1968.

Turbine-generators on both units were supplied by General Electric, and were designed for 3500 psig 1000°F throttle steam, with 1000°F reheat. Condenser cooling is once through with water taken from the Mississippi River. The steam generators are supercritical, universal pressure, once through, cyclone-fired with balanced draft (originally supplied as pressurized steam generators). The steam generators were provided by Babcock & Wilcox as UP-19 and UP-20. Rated steam flow is 3,290,000 lb/hr at 3,625 psig and 1005°F at the superheater outlet with 575 psig and 1005°F at the reheater outlet. The cyclones are 10 feet diameter by 12 feet deep with five each on the front and rear boiler walls, arranged in two rows. All cyclones are equipped with radial burners and retractable oil ignitors. All cyclones utilize primary, secondary, and tertiary air. Secondary air is supplied to cyclones from a common windbox. Secondary air flows are controlled by control and shut off dampers for each cyclone. Primary and tertiary air is provided to each cyclone through common 24-inch diameter ducts from the windbox. Each steam generator incorporates a flue gas recirculation system for steam temperature control. The lower gas recirculation vestibules are equipped with ten ports with five each on front and rear walls. See Figure 1 for the arrangement of the steam generators.

The steam generators were designed for Illinois No. 6 high sulfur coal, but both Sioux units are currently fueled with a blend of 70% Powder River Basin (PRB) and 30% Illinois No. 6. The steam generators can typically achieve net outputs of roughly 430-440 MWe while burning the blend, but new fine grind crushers are expected to improve the ratio to 80 to 85% PRB. High percentages of Illinois coal can be burned in the event full unit capability is needed to meet system demands. A typical fuel analysis for the 70% PRB blend is provided below:

Table 1
Analysis of Fuel Blend

HHV	9,325 Btu/lb
Moisture	24%
Ash	6.2%
Sulfur	1.13%
SO_2	2.4 lb/MMBtu

Basis For The Air Staging Demonstration

Previously, Sioux Unit 2 was selected for a trial demonstration of the POWERMAX sequential process optimization (SPO) method as part of the EPRI CNCIG work. Computational fluid dynamics (CFD) modeling of the cyclones indicated that biasing or staging cyclones row to row could achieve substantial reductions in NO_x levels without impacting cyclone operability or

corrosion while burning specific western fuel blends. POWERMAX was used to aid operation of the boiler with the lower row of cyclones substoichiometric while the upper row had excess air. The short-term trial indicated reductions in NO_x of about 25% could be achieved at nominal unit output of 440 MW.

CFD modeling of the cyclone boiler furnace along with the cyclone barrel models indicated that a significant amount of NO_x was being produced in the furnace. Modeling results estimated that the Sioux cyclones produced 60 to 70% of NO_x measured in the stack with 30 to 40% being formed in the furnace. The cyclone biasing trial combined with the results from these models showed that measures employed in the furnace could have beneficial effects on NO_x. Coupling results of the barrel and furnace models showed the potential to achieve the greatest NO_x reductions was by lowering cyclone barrel stoichiometry and injecting the balance of the secondary air into the furnace as overfire air (OFA).

Furnace Model Background

The computer model used to simulate combustion in the Sioux boiler was developed by Reaction Engineering International and was used to model a series of furnace operating conditions as part of the EPRI CNCIG program. This furnace model was partnered with a model for the coal-fired cyclone barrel in order to predict combustion in the Sioux Unit 2 boiler under staged-air conditions. The model included mathematical descriptions for the controlling physics and chemistry in combustion, including turbulent gas flow, radiative and convective heat transfer, equilibrium gas species reactions, and finite-rate pollutant formation. The mathematical equations were applied over a computational grid or mesh, which represented the furnace geometry, in order to calculate approximately sixty different variables used to describe the combustion process. The model included coupling between the mathematical descriptions to more accurately represent the physical interdependencies in actual combustion processes. The refinement or resolution of the computational mesh determines the accuracy to which the simulated physics are resolved. The furnace model discussed here included more than 500,000 computational points in order to resolve furnace geometry, flow patterns, temperature profiles, and species concentrations.

Modeling Approach

Computational results from a single cyclone barrel model run at a stoichiometry of 0.90 were used as inputs for each of the ten cyclone inlets in the Sioux furnace. The mapping of results from the cyclone exit to the furnace inlets reproduced the flow velocities, temperature, and species concentration profiles while accounting for correct rotation of each cyclone. Each cyclone was assumed to be burning the 70/30 blend of PRB and Illinois coal at a firing rate of 413 MMBtu/hr. OFA was added to the furnace model through flue gas recirculation (FGR) ports located above the cyclones to bring total furnace stoichiometry to 1.15.

The major assumptions made during modeling of the furnace were: (1) All particles burned out before entering the furnace. Any volatiles not released in the barrel were distributed in the combustion products at the cyclone exit according to the off-gas profiles from the barrel model. (2) The furnace had nonuniform constant temperature walls which varied from the maximum slag

temperature in the lower furnace to near water wall temperatures in the upper furnace. (3) Cyclone flow (velocities, temperature, species concentrations) entering the furnace was identical at all cyclone exits except for differences due to cyclone rotations. (4) Reductions of NO_x concentrations through reburning of CO were allowed only at fuel-rich locations in the furnace. (5) All sulfur chemistry and resulting SO_2 and H_2S concentrations were based on equilibrium chemistry.

Results from the OFA modeling simulation were compared with predictions from a baseline furnace simulation without OFA. In the baseline, all cyclones were modeled at a stoichiometry of 1.15.

Modeling Results and Discussion

Figure 2 compares predicted NO_x levels at the center of the furnace for the baseline and OFA cases. The baseline case shows the higher NO_x concentrations observed during normal boiler operations whereas the OFA case shows significantly reduced NO_x. The primary reasons for this dramatic reduction in NO_x were reduced production of thermal NO due to lower temperatures in the bottom of the furnace and reburning of NO_x in the fuel-rich regions of the furnace.

Figure 3 compares predicted CO levels at the center of the furnace for the baseline and OFA cases. The OFA case has much higher CO concentrations throughout the furnace due to the lower part of the furnace being at a stoichiometry of 0.90, i.e., fuel-rich. Only after the air is added to the furnace through the OFA system do the CO levels decrease.

Figure 4 plots axial velocity contours at the OFA injection height indicating the nonuniform nature of the flow moving up the furnace. It is this nonuniformity of flow that contributes to the challenge of designing and implementing an effective OFA system that can provide sufficient mixing and coverage of overfire air with the fuel-rich combustion products moving up in the furnace.

Figure 5 shows CO concentrations for the OFA case at several heights in the furnace, ranging from the OFA ports to the gas tempering ports to a height just below the turn into the convection pass. The plots show that CO concentrations are reduced in the center of the furnace but remain relatively high along the furnace walls. As the graphs indicate, there are two high CO pockets, one each along the front and rear walls. These pockets are created from the flow patterns lower in the furnace around the flue gas recirculation ports. Basically, the OFA jets do not reach all the way across the furnace before being turned upward by combustion products leaving the lower furnace, and thus they are unable to mix with CO near the walls.

Corrosion

Corrosion issues were studied in conjunction with the CFD model work. Model outputs were used by EPRI to examine formation of corrosive species such as H_2S in the lower and upper furnace. The principal conclusion was that corrosion potential in the cyclones and lower furnace will be less with the 70% PRB blend than the potential for corrosion with design Illinois coal.

The corrosion study concluded that flamespray coatings employed above the stud line and maintenance of refractory in cyclones and the lower furnace should be adequate to protect against severe corrosion due to substoichiometric cyclone operation with OFA.

OFA System Design

The purpose of the OFA demonstration was twofold: (1) attempt to validate predictions of NO_x emissions reduction from the CFD modeling effort; and to (2) demonstrate short-term operability with the OFA system. The design of the OFA was kept as simple as possible to minimize impact on the Unit 2 planned overhaul outage schedule and to minimize costs.

The OFA air system was designed to stage approximately 20-25% of the normal unit air flow at 16% excess air. The fixed nozzles were initially sized based on previous EPRI research conducted on front-fired wall units; that research recommended a ratio of the overfire air velocity to the vertical component of furnace gas flow of 4:1 to 6:1 for adequate penetration (refer to EPRI TR-102906). Also, one of the early design constraints was not to perform any pressure part modifications. This resulted in having the overfire air injected into the furnace at angles other than normal to the furnace walls. Based on the furnace modeling of the preliminary OFA schemes, it was decided that modification to the FGR port tubes should be made to allow the overfire air to be injected normal to the walls for better coverage, and that higher velocities would be required to penetrate the furnace combustion gases. The modeling also confirmed that the location of the existing FGR ports, both in plan and elevation, provided good air distribution and mixing as well as sufficient residence time within the furnace. The final nozzle size was fixed to produce velocities approximately 300 ft/sec.

Figure 6 shows the final OFA system configuration as installed. Ten (10) each take-off ducts were installed in the top of the main windbox, five each on front and rear. The locations of the take-offs were selected to match the FGR ports as closely as possible while avoiding interferences with structural steel components. The 36-inch diameter ducts rise vertically and turn 90° to horizontal to penetrate the vertical walls of the flue gas recirculation vestibule. The ducts then run through the back of the FGR ports to inject secondary air into the furnace. Limited air flow instrumentation was provided. Each duct contains a manually operated butterfly damper to provide shut-off/isolation as well as a limited amount of air flow control. All duct sections that could be subject to furnace thermal radiation were fabricated from stainless steel. Puff blower piping and GR port tubing interferences were encountered during installation of the new ducts.

Because the installed OFA system design differed from the scheme included in the CFD furnace modeling, it has been recommended that the model be modified to replicate the final configuration. This would allow more direct comparison of the installed OFA system operating information to model results, and thus increase confidence in future model predictions.

The total installed cost of the OFA system was approximately $400,000. The cost breakdown is shown below. It should be noted that a system designed for permanent installation and environmental compliance purposes would likely be significantly more expensive, and costs will vary based on boiler type, e.g., opposed fired or single wall fired, single row, etc., and other site

specific factors. Design features and other considerations necessary for long-term continuous operation of the OFA were not included in the scope of this project, such as automation of the OFA air flow dampers, flamespray of tubes above the furnace stud line, etc.

Table 2
OFA Demonstration System Cost Estimate

Materials	$130,000
Labor	140,000
Engineering	60,000
Testing	70,000
Total	$400,000

Initial Operating Results

At the time this paper was written, testing with the OFA system was just beginning. NO_x, CO, and O_2 were measured with a 12-point grid installed in the economizer outlet ductwork. Flyash samples were taken from precipitator hoppers and tested for unburned carbon. Rather than adjusting the manual dampers during load reductions, the furnace oxygen control was changed to increase the O_2 setting to compensate for the additional air flow.

Preliminary operation indicated that reductions in NO_x of approximately 50% from baseline emissions were feasible and repeatable. Table 3 summarizes typical data obtained early in the trial operation period. Unit output was limited to 420 MWe due to induced draft fan vibrations even though 430 to 440 MW are achievable with the current fuel blend.

Table 3
Performance Indicators -- Preliminary Operation

	Baseline	Staged Data
Unit Load, MW	420	420
NO_x, ppm	990	492
SO_2, ppm	1060	1092
CO, ppm	26	29
O_2, %	3.0	3.0

This preliminary data suggest a reduction in NO_x emissions at the stack from a baseline of 1.22 lb/MMBtu to approximately 0.55 lb/MMBtu. Estimates of cyclone stoichiometries and other impacts on unit performance parameters were not available at the time this paper was written.

To further assess the potential of corrosion caused by operation of the unit under these staged conditions, furnace gas sampling and analysis of total reduced sulfurs (TRS), including the H_2S species, and CO will be performed by a testing contractor. Samples will be taken from the lower furnace and at the elevation of the OFA nozzles. Another contractor will be collecting molten

slag samples from the furnace floor just above the slag tank for analysis. The results of this sampling are not known at the time of this writing.

Conclusions

Preliminary operation of the OFA system appears to support the validity of the CFD modeling work and predictions of NO_x reductions. Additional testing is necessary to confirm these findings. The furnace model may be modified in the future with the final OFA system design to further increase confidence in future model predictions.

Long-term operation and testing for corrosion of water wall tubes was not addressed by this project.

Acknowledgments

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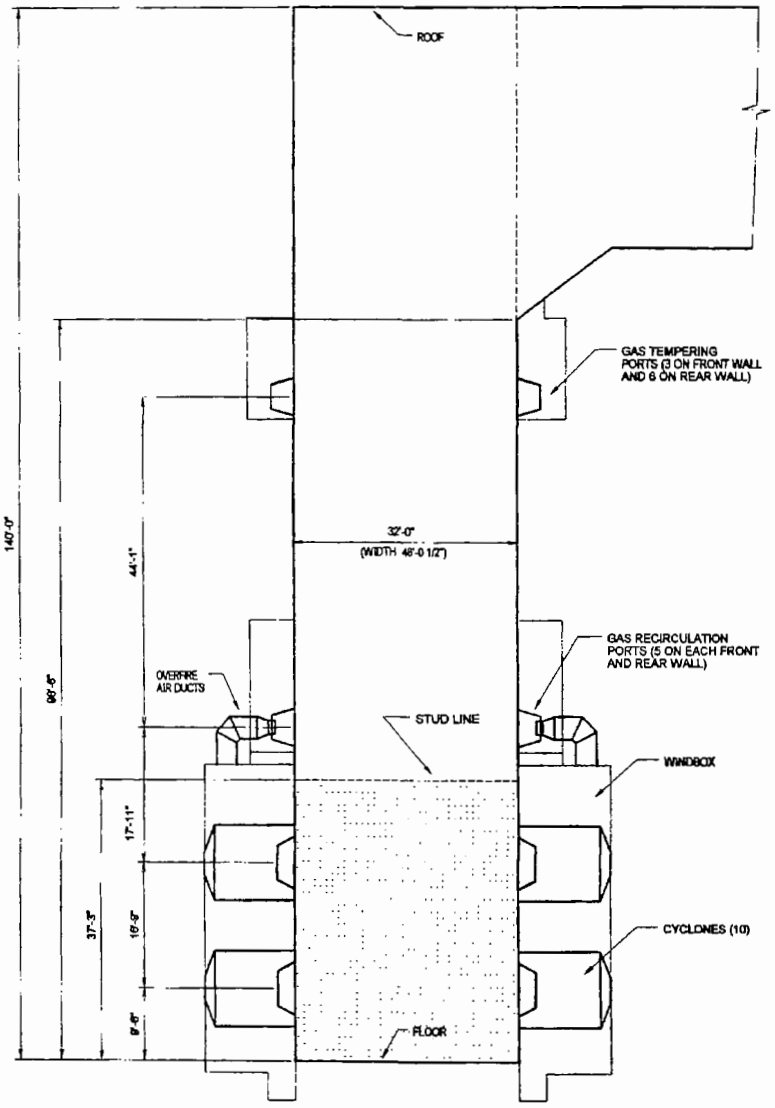


Figure 1. Sioux Steam Generator Arrangement with OFA System

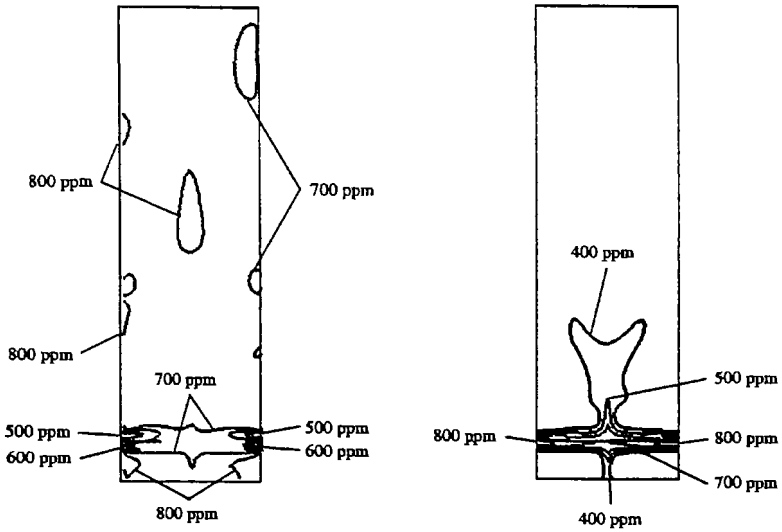


Figure 2. CFD Model Results
NO_x Concentration Profiles for the Baseline (left) and OFA (right) Cases.

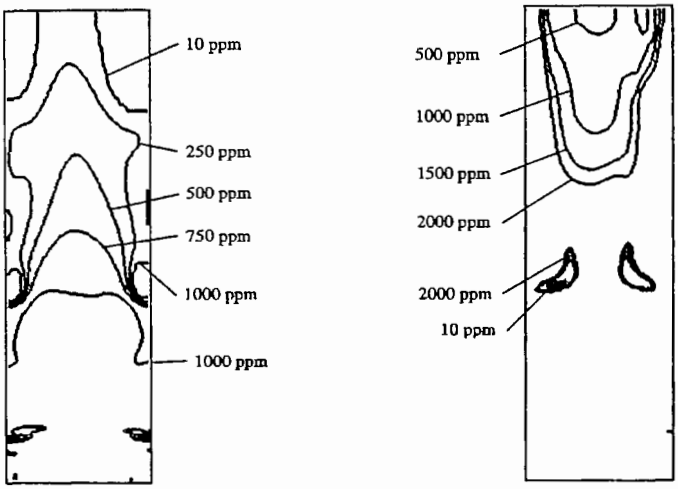


Figure 3. CFD Model Results
CO Concentration Profiles for the Baseline (left) and OFA (right) Cases.

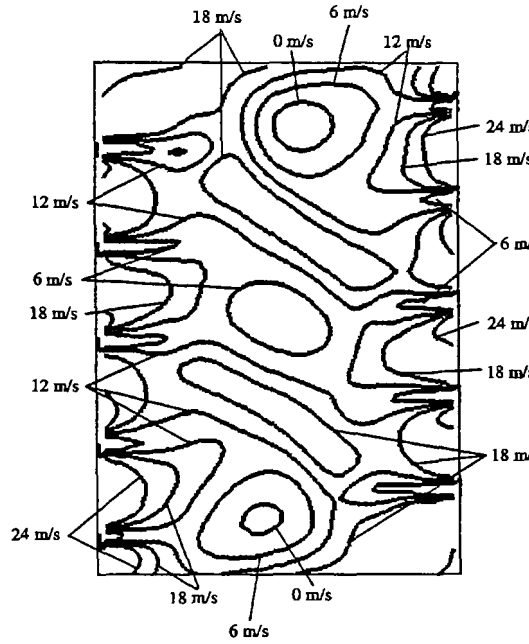


Figure 4. CFD Model Results
Axial (upward) Velocity Contours at FGR/OFA Injector Height.

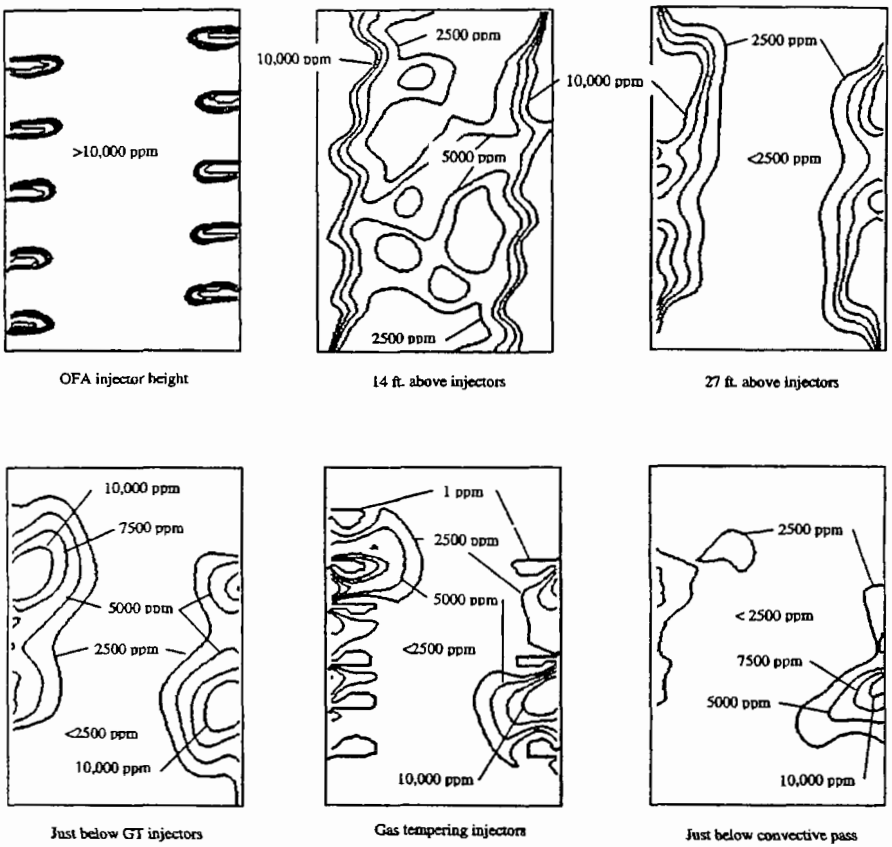
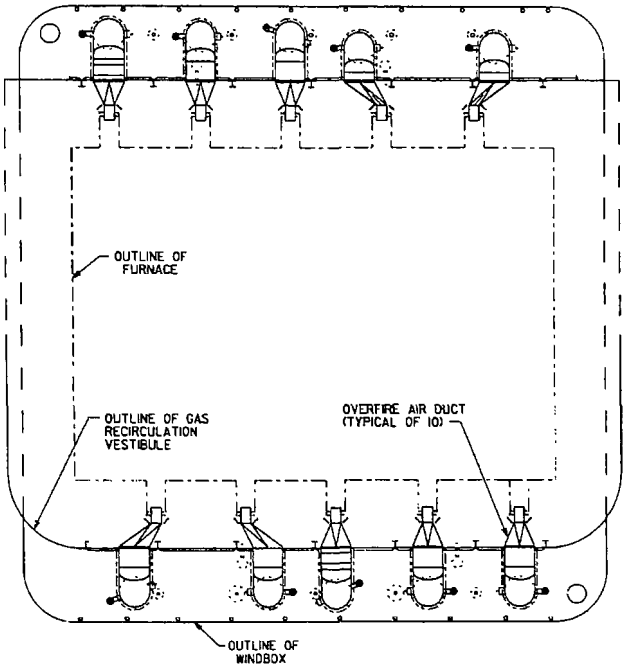


Figure 5. CFD Model Results
CO Concentration Profiles at Various Furnace Heights.



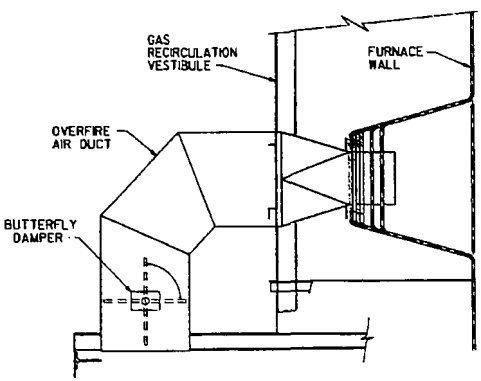


Figure 6. OFA System Arrangement - Plan (top) and Elevation (bottom)

NO_x CONTROL USING NATURAL GAS REBURN ON AN INDUSTRIAL CYCLONE BOILER

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Abstract

Eastman Kodak Company's cyclone boiler (Unit No. 43), located in Rochester, New York, has been retrofitted with the gas reburn technology developed by the Babcock & Wilcox (B&W) Company to reduce NO_x emissions in order to comply with the New York State regulations adopted in conformance with the Title I of the Clean Air Act Amendments (CAAA) of 1990. At the peak load, the ozone nonattainment required NO_x reduction from baseline levels necessary to meet the presumptive limit for cyclone boilers in this regulation is 56%.

Eastman Kodak Company and the Gas Research Institute (GRI) are cosponsoring this project. Chevron has supplied the natural gas. Equipment installation for the gas reburn system was performed in a September 1995 outage.

Boiler No. 43's maximum continuous rating (MCR) is 550,000 pounds per hour of steam flow (or approximately equivalent to 60 MW_e). Because of the compact boiler design, there is insufficient furnace residence time to use coal or oil as the reburn fuel, thus making it a prime candidate for gas reburn. Kodak currently has four cyclone boilers. Based upon successful completion of this gas reburn project, modification of Kodak's other cyclone boilers to include reburn technology is currently being considered.

The paper will describe gas reburn system design, manufacturing, installation, the test results, and commercial operation of the Kodak's Unit No. 43 boiler with the gas reburn system.

Introduction

The Clean Air Act Amendments of 1990 posed significant challenges to electric utilities to reduce both sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) emissions. The Act mandates an approximate 3.5 million ton-per-year reduction in SO_2 emissions from 111 selected existing utility boilers by January 1, 1995. An additional 5.3 million ton-per-year reduction is also mandated to occur by January 1, 2000, in order to reach a long-term SO_2 emissions cap of 8.9 million tons per year. Titles I and IV of the Act mandate NO_x reduction from stationary sources. Title IV (acid rain) requires the use of low-NO_x burner technology by utilities and Title I (ozone nonattainment) requires RACT (reasonable, available control technology) to reduce NO_x from utility and industry sources. The impact on utilities is that by the year 2000, more than 200,000 MW_e of electricity generating capacity, must be retrofitted with low-NO_x systems.

The limitations imposed by the act are particularly challenging, especially for NO_x emissions to cyclone-fired boilers. The cyclone furnace consists of a cyclone burner connected to a horizontal water-cooled cylinder, the cyclone barrel. Air and crushed coal are introduced through the cyclone burner into the cyclone barrel. The larger coal particles are thrust out to the barrel walls by the cyclonic motion of combustion air where they are captured and burned in the molten slag layer that is formed; the finer particles burn in suspension. The mineral matter melts and exits the cyclone via a tap at the cyclone throat that leads to a water-filled slag tank. The combustion gases and remaining ash leave the cyclone and enter the main furnace.

Cyclone-fired boilers represent approximately 26,000 MW_e of generating capacity in the U.S., which is approximately 15% of pre-New Source Performance Standards (NSPS) coal-fired generating capacity. These units contribute about 21% of NO_x emitted by pre-NSPS coal-fired units.

Typical low-NO_x burners and staged combustion techniques are not applicable to cyclones because these techniques rely on developing an oxygen deficient or reducing atmosphere to hamper NO_x formation. A reducing condition in the confines of a cyclone barrel is unacceptable due to the potential for tube corrosion and severe maintenance problems which could result. Cyclone operation must occur with excess oxygen in the cyclone barrel, and this condition coupled with high temperatures and severe turbulence within the cyclone barrel is the reason why cyclones are disproportionately high generators of NO_x.

The reburning technology offers cyclone boiler owners a promising alternative to expensive flue gas cleanup techniques for NO_x emission reduction. Reburning involves the injection of a supplemental fuel (natural gas, oil, or coal) into the main furnace in order to produce locally reducing conditions that convert NO_x produced in the main combustion zone to molecular nitrogen, thereby reducing overall NO_x emissions.

Eastman Kodak Company has four coal-burning cyclone boilers at their Rochester, NY facilities. These boilers are subject to Title I compliance (ozone nonattainment). To comply with New York State requirements, Kodak requested that B&W perform an engineering feasibility study to determine the best Reasonable Available Control Technology (RACT). B&W concluded that because of the compact boiler design, gas reburn technology is the most viable approach for these boilers. Because Kodak's boilers are relatively small, the average furnace residence time is

less than that available in larger cyclone units. Thus, coal or oil reburn technologies could result in major impact on unburned combustibles, fouling of convective pass tubes, and precipitator problems in Kodak's boilers. The final step to determine RACT is to demonstrate the gas reburn technology in one of these boilers (No. 43 Boiler) in order to determine specific NO_x reduction potential and cost of NO_x control for boilers designed with minimum available furnace resident times.

The uncontrolled NO_x level in No. 43 Boiler is 1.37 lb/MBtu at peak load. The required NO_x reduction from this baseline level necessary to meet the presumptive limit set by the New York State regulation, is about 56%. Based on successful completion of this gas reburn project, modification of the other cyclone boilers with reburn technology is anticipated.

Background / Reburning Process Description

To address the special needs of the cyclone boiler population with respect to NO_x reduction, B&W pursued the reburning technology. The B&W reburn technology development for cyclone boilers was performed via: 1) an initial engineering feasibility study (funded by EPRI Project RP-1402-30), 2) a pilot-scale evaluation co-funded by Electric Power Research Institute (EPRI RP-2154-11) and the Gas Research Institute (GRI 5087-254-1471), and B&W, and 3) a U.S. Department of Energy's Innovative Clean Coal Technology demonstration at Wisconsin Power and Light's Nelson Dewey station.[1-4]

The feasibility study suggested that the majority of cyclone- equipped boilers could potentially apply this technology in order to reduce NO_x emission levels by as much as 50-70%.[1] The major criterion that substantiated this potential was that of sufficient furnace residence within these boilers, allowing application of the technology. This residence time is required for both the NO_x reduction process in the reburn zone and subsequent combustion completion in the burnout zone to occur within the boiler. Based upon this conclusion, the next level of confirmation, pilot-scale evaluation, was justified. The pilot-scale tests evaluated the potential of natural gas, oil, and coal as the reburning fuel in reducing NO_x emissions.[2] The pilot-scale data confirmed the results of the feasibility study and showed that reburning is technically feasible and a potentially commercially viable technology for cyclone boiler owners. Coal was then selected as the reburn fuel to be used during the Clean Coal Project at Wisconsin Power & Light (WP&L) Company's Nelson Dewey station. The WP&L reburn demonstration validated the results of both the engineering feasibility and pilot-scale studies.[3,4]

Reburning is a process by which NO_x produced in the cyclone is reduced (decomposed to molecular nitrogen) in the main furnace by injection of a secondary fuel. The secondary (or reburning) fuel creates an oxygen-deficient (reducing) region that accomplishes decomposition of the NO_x. Since reburning is applied while the cyclone operates under normal oxidizing conditions, its effects on cyclone performance can be minimized.

The reburning process employs multiple combustion zones in the furnace, defined as the main combustion, reburn, and burnout zones as shown in Figure 1. The main combustion zone is operated at a stoichiometry of 1.1 (10% excess air) and combusts the majority of the fuel input (65 to 85% heat input). The balance of fuel (15 to 35%) is introduced above the main combustion

zone (cyclones) in the reburn zone through reburning burners. These burners are operated in a similar fashion to a standard wall-fired burner, except that they are fired at extremely low stoichiometries. The oxygen-deficient combustion gases from the reburn burners mix with combustion products from the cyclones to obtain a furnace reburning zone stoichiometry in the range of 0.85 to 0.95, which is needed to achieve maximum NO_x reduction based on laboratory pilot-scale results. A sufficient furnace residence time within the reburn zone is required for flue gas mixing and NO_x reduction kinetics to occur.

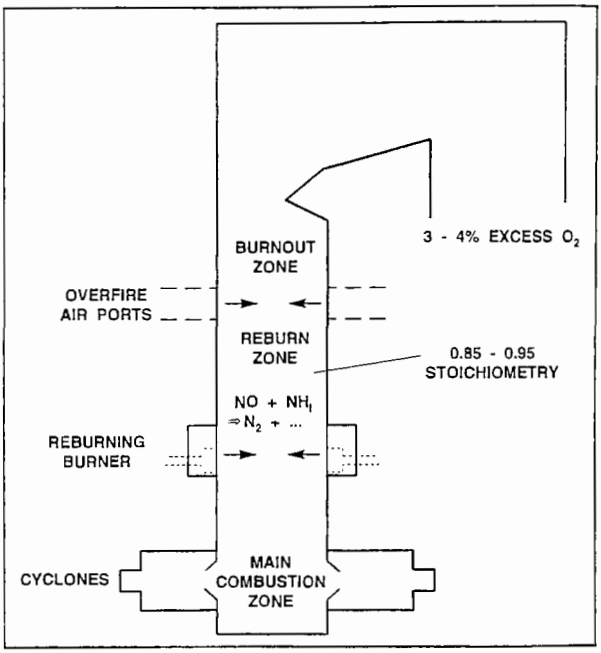

Figure 1 Reburning process

The balance of the required combustion air (totaling 15 to 25% excess air at the economizer outlet) is introduced through over-fire air (OFA) ports. B&W's Dual Air Zone Ports are designed with adjustable air velocity controls to enable optimization of mixing for complete fuel burnout prior to exiting the furnace. As with the reburn zone, a satisfactory residence time within this burnout zone is required for complete combustion.

Project Description

Project Objectives

The objective of this project at Eastman Kodak Company's No. 43 Boiler was to demonstrate the long-term application of gas reburning to reduce NO_x/SO_2 emissions from a coal-fired cyclone boiler, while maintaining acceptable cyclone boiler operating conditions.

Specific goals of this demonstration project were as follows:

- To maximize NO_x emission reduction at peak load. The project goal for NO_x emission is 0.6 lb/MBtu, while using 28% (or less) natural gas as a percentage of total heat input to the boiler. This corresponds to a 56% NO_x reduction from the baseline level of 1.37 lb/MBtu.

- To demonstrate boiler operational safety and acceptable turndown with reburn. The turndown at the baseline conditions (no reburn) for No. 43 Boiler is 55% of maximum continuous rating (MCR). At this load, boiler slag tap freezing occurs. With the introduction of reburn fuel into the boiler, the boiler turndown needed to be evaluated.

- Minimal impact on combustible losses (less than 0.1 percentage point change in combustion efficiency).

- CO levels of less than or equal to 200 ppm.

- No major impact on boiler tube losses. No. 43 Boiler has not experienced major tube losses within the main boiler in the past (no reburn). Reburning is not expected to increase the tube deterioration. The quantitative objective with reburn in service is to have no adverse impact on current expectations to continue No. 43 Boiler operation over the next 20 years.

- Obtain NO_x removal at a cost not to exceed $3000 per ton of NO_x removed.

- The capital cost of the reburn system should not exceed an installed cost of $75/KW for small cyclone boilers. The capital cost is high due to the small size of the boiler (economy of scale is not available here, e.g. at 100 MW_e the cost is $16 to $17 per KW without controls). Although the cost of instrumentation and controls is site-specific, it is included in this estimate.

Project Methodology

B&W's methodology for designing and operation of a reburn system at Eastman Kodak Company is identical to that used on the previous full-scale reburn application[3]. This includes using the previously acquired pilot-scale gas reburn data[2], reviewing past baseline characterization of No. 43 Boiler, a site-specific engineering study including scale-up of the results using proprietary B&W numerical models validated with baseline information, and finally full-scale design, installation, and commercial operation[5]. Once the system was in operation, a commercial evaluation, including revised cost information, was be developed. In order to accomplish these objectives, the gas reburn project consists of 7 tasks as shown in Figure 2.

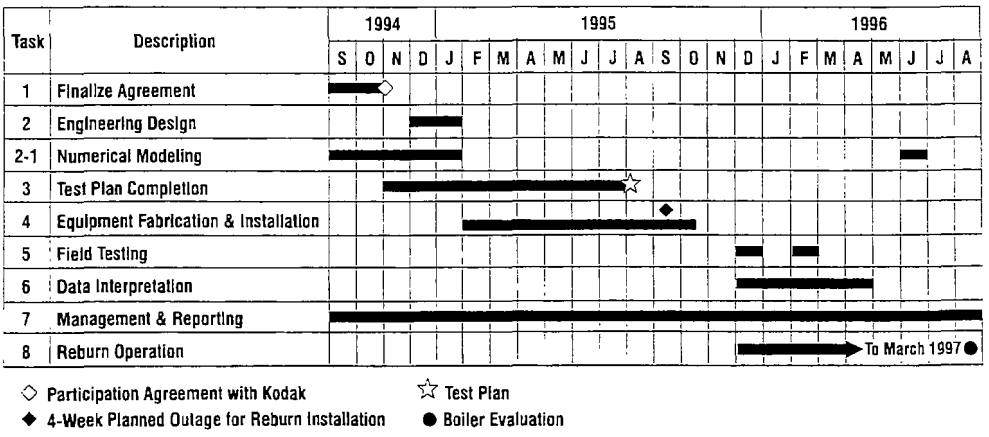

Figure 2 Project schedule

Project Organization

The project team is as follows:

- Eastman Kodak Company - Host site and co-sponsor
- Gas Research Institute - Co-sponsor
- B&W - Boiler manufacturer and prime contractor
- Chevron U.S.A. - Gas supplier
- Rochester Gas & Electric - Gas distributor
- Acurex - Field monitoring

Project Schedule

A schedule of 24 months was planned for this project, as shown in Figure 2. Equipment installation for the gas reburn system was scheduled for a September 1995 outage. At the conclusion testing, the reburn system was optimized and delivered to Kodak for day-to-day commercial operation to March 1997. The boiler went through an outage in March 1997 when the long-term performance of the reburn system and its effect on boiler tube life was assessed. Currently, Kodak is using the gas reburn technology as RACT for the Boiler No. 43.

Host Boiler Description and Conceptual Design of the Reburn System

Eastman Kodak Company's No. 43 Boiler was purchased from Babcock & Wilcox (B&W) in 1968. The unit is a two (2) drum Stirling Power Boiler designed for a Maximum Continuous Rating (MCR) of 550,000 lb/hr steam flow with a four (4) hour peak rating of 605,000 lb/hr steam flow. The boiler is designed with two (2) B&W nine-foot-diameter cyclone furnaces equipped with B&W radial burners. The cyclones are capable of firing either bituminous coal or heavy fuel oil. Operating steam pressure and temperature at full load are 1425 psig and 900°F, respectively, at the superheater outlet with a feedwater temperature of 400°F. The unit is also capable of 450,000 lb/hr steam flow, while maintaining full-load steam pressures and temperatures at a feedwater temperature of 238°F. Figure 3 shows the original boiler sectional side view.

B&W's reburning technology involves customizing the design to each specific site application in order to optimize performance. Depending on the boiler design and capacity, B&W evaluates the effectiveness of using natural gas, oil, or pulverized coal as the reburning fuel. One of the key parameters in this determination is defined as the available furnace residence time criteria. Smaller capacity boilers (less than about 650,000 lb/hr steam flow) typically have minimal furnace residence time and this dictates the use of natural gas reburning. Cyclone boilers of this size contain either one or two cyclone furnaces and make up approximately 18% of all cyclone firing capacity.

Eastman Kodak Company's No. 43 Boiler is one of these uniquely designed cyclone units. As is typical of the smaller size cyclone units, No. 43 Boiler contains heat transfer surface sections routed vertically up through the furnace region. These sections include the cyclone riser and wingwall tubes. This feature not only helps minimize furnace residence time, but it also creates reburning design problems with respect to space limitations for physically locating reburn system components and in-furnace mixing obstructions.

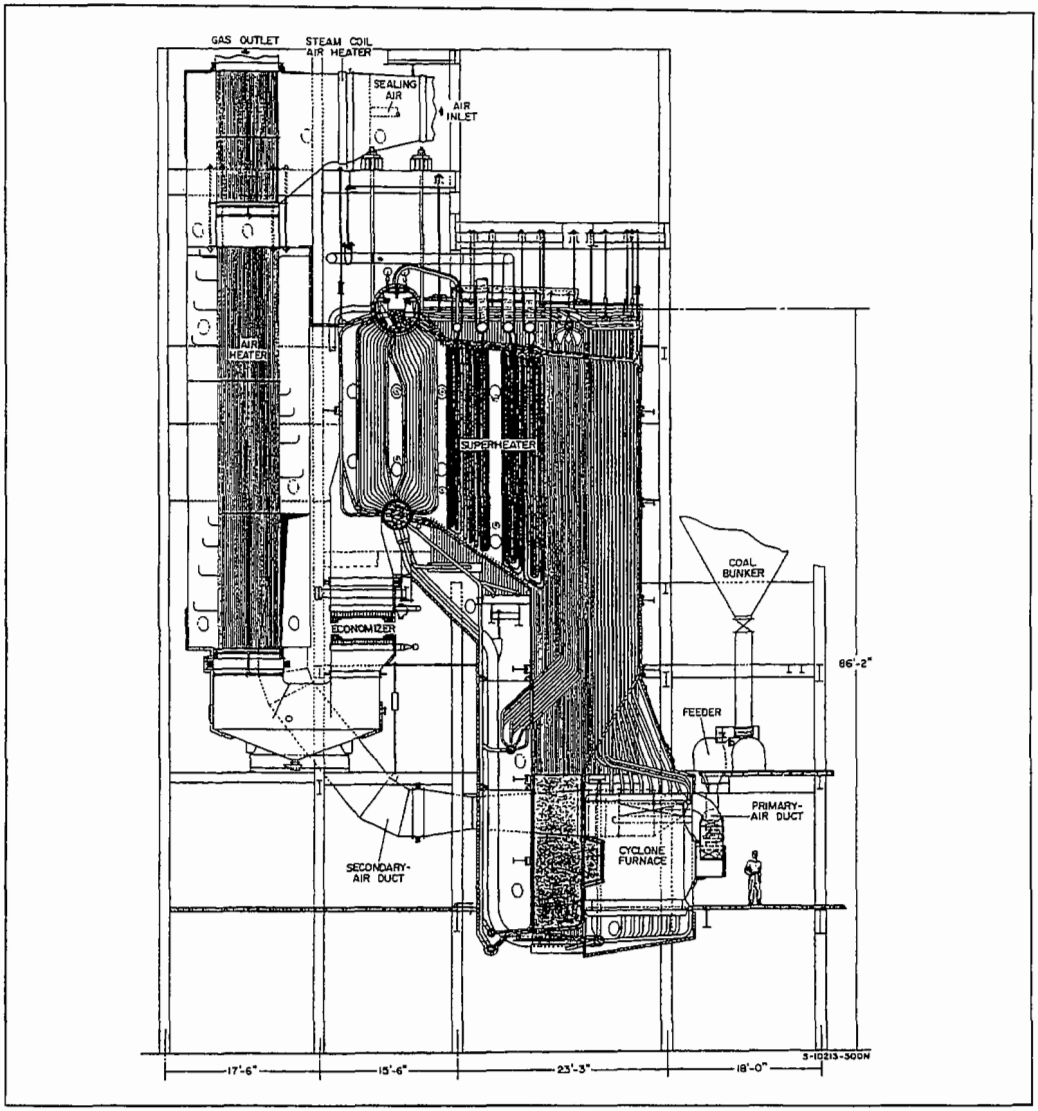

Figure 3 Eastman Kodak Company's No. 43 boiler

The major components of the B&W gas reburn system includes new reburn burners, overfire air (OFA) ports, ducts and flues to transport air and gas recirculation to the new system components, air monitors and dampers to control the flow rates, a gas recirculation fan, and controls. B&W S-type burners are used in the reburn system to provide a stable flame and good mixing characteristics. The burner is operated in a similar fashion to standard wall-fired burner applications (e.g.,

includes a standard flame scanner and gas lighter). Although optional, the reburn system at No. 43 Boiler includes gas recirculation to the burner to maintain maximum mixing flexibility within the reburn system and thus maximum NO_x reduction potential.

Identification of the optimum number, size, and location of the reburn burners and OFA ports is a critical reburn system design issue. Since the burners and OFA ports require boiler pressure part openings, physical space limitations are a potential constraint. The design methodology of the gas reburn system is described in detail elsewhere[5].

Gas Reburning Retrofit at Kodak's Boiler No. 43

Retrofit of the gas reburning system to Boiler No. 43 at Kodak Park consisted of installation of the following items:

1. Two (2) B&W S-type gas reburn burners. The burners consist of an inner core zone that houses the natural gas spuds and an outer air zone that contains adjustable spin vanes. The core zone includes a manual sliding disk to control flow to this region. In addition to housing the manually adjustable spin vanes, the outer air zone includes the retractable B&W CFS gas lighter, the scanner sighting ports, and an observation port. The lighters contain a high-energy ignition probe and air cylinders for retracting purposes. The lighters are remotely operated by the Burner Management System or can be operated locally.

2. Four (4) OFA ports to introduce the balance of air flow for complete combustion. B&W's Dual Air Zone OFA ports were selected in order to control mixing capabilities from both a penetration and side-to-side mixing standpoint. The OFA ports contain two zones, an inner zone for penetration and an outer air zone with manually adjustable spin vanes for side-to-side mixing capability.

3. A mixture of secondary air and gas recirculation is introduced to the individual burner windbox. The air flow source is from the airheater outlet and is controlled/measured via an automatic control damper and air flow monitor. The gas recirculation source is from the economizer outlet and a booster fan is available to provide adequate conditions to mix the secondary air with the gas recirculation. Isolation dampers and a control damper are available around the fan to control flow, in addition to allowing fan maintenance to be performed while the boiler is operating. The air and gas recirculation flows were optimized during start-up activities and control curves for each of the parameters were incorporated into the control system.

4. Natural gas line.

5. Upgrade of the control system.

6. Various flues, ducts, flow control dampers, and monitors.

The isometric view of the system shown in Figure 4 gives the special relationships of each of the components in the system. Integration of the reburn system with the existing plant consisted of interfaces with the air heater outlet, flue gas recirculation system, hot air recirculation, penetration into the boiler, and the control system. The reburn equipment was fabricated at B&W's facilities and delivered to Kodak for installation. Prior to the boiler outage, all aspects of the system's erection that did not require a boiler outage were completed. This included installation of the FGR fan and all flues and ducts up to tie-in points. The remainder of construction, including burner and OFA installation, was completed in a four-week outage beginning September 11, 1995. In addition, Kodak had other boiler maintenance activities planned (e.g., rear-wall tube panels) and the overall outage lasted 9 1/2 weeks.

Results

The focus of this project's testing was to determine the maximum NO_x reduction capabilities while minimizing the gas heat input without adversely impacting plant performance, operation, and maintenance. In particular, the evaluation was designed to confirm and expand upon the results of the SBS pilot test program[2].

Test Plan Variables

Numerous variables are associated with the reburn system and a day-to-day test matrix was set up to proceed from one parameter to another during parametric optimization testing. The test variables included:

- Percent of boiler heat input by natural gas
- Reburn burner stoichiometry
- Reburn zone stoichiometry
- Reburn burner spin vanes adjustments
- OFA port spin vanes/sliding disk adjustment
- Boiler load
- Gas recirculation rates to the reburn burners

Information collected to evaluate performance of the technology are as follows:

- Impact on NO_x and CO emission levels by the itemized test variables
- Boiler temperature and cleanliness factor profiles
- Unburned combustibles loss
- Boiler thermal efficiency
- Operational experience

NO_x Emissions

Operation of the reburning system reduced NO_x emission levels by 35 to 71% from baseline conditions. Figure 5 shows the NO_x emission levels versus percent heat input from natural gas introduced through reburn burners at the peak load (605,000 lb/hr steam flow). NO_x is reduced from a preretrofit baseline value of 1.37 lb/MBtu to 0.6 lb/MBtu while using 20% natural gas. NO_x

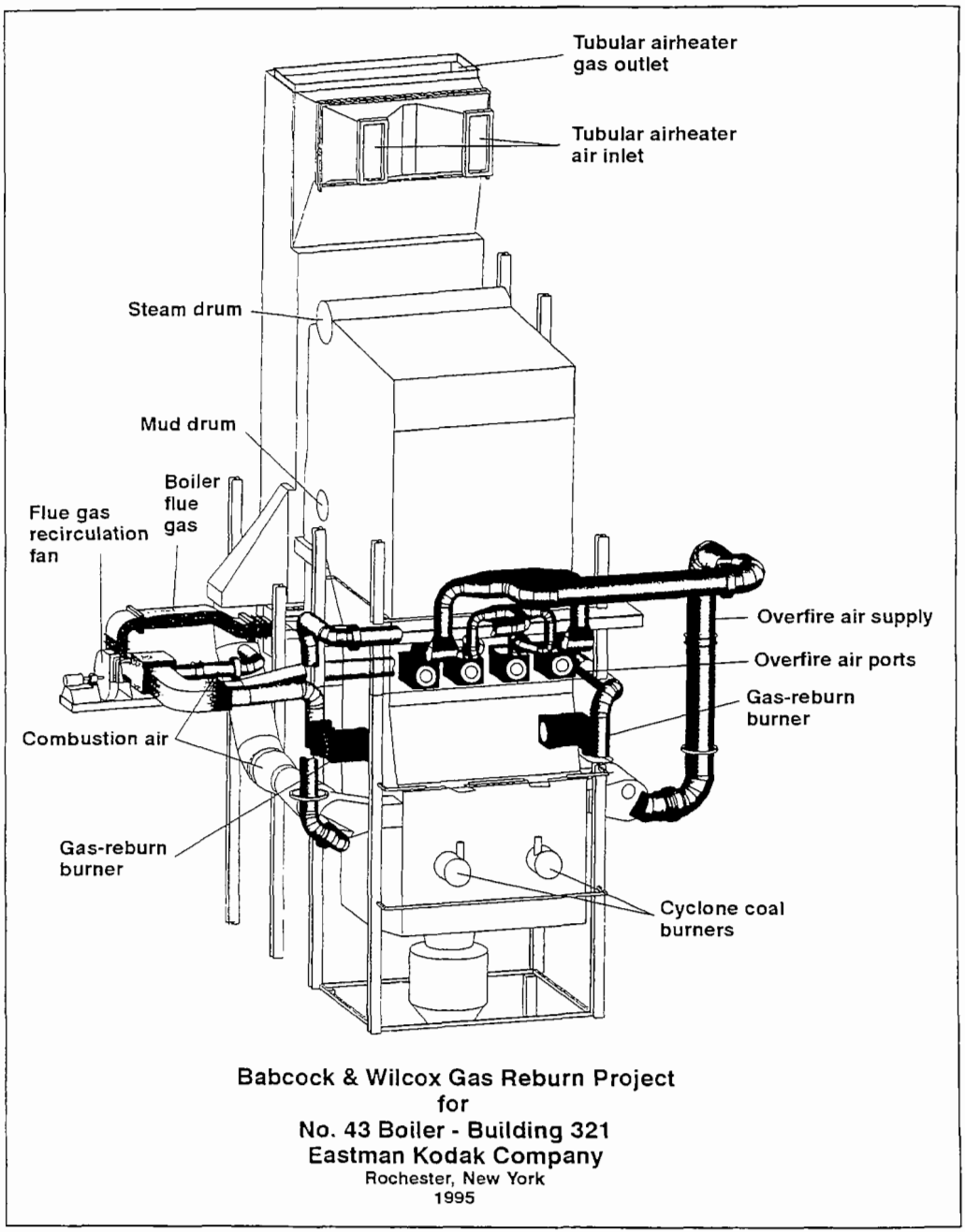

Figure 4 Isometric view of the reburn system

reduction ranged from 35 to 56% while varying 10 to 20% natural gas as reburning fuel. During these tests, cyclone stoichiometry is maintained as close to 1.1 (8 to 12% excess air) as possible to minimize potential cyclone operating concerns.

The maximum NO_x reduction of 71% was achieved at 27.5% natural gas heat input. Although lower NO_x emissions of 0.4 lb/MBtu can be achieved at 27.5% gas heat input, the recommended maximum heat input is 22%. Long- term operation at higher gas heat input requires additional testing / optimization prior to final acceptance.

Figure 6 shows the NO_x emission levels versus percentage of gas heat input at MCR (550,000 lb/hr steam flow). In addition, this figure identifies the effectiveness of FGR to the reburn burners for higher NO_x reduction. The normal preretrofit NO_x emission level at this load was 1.25 lb/MBtu. Varying the amount of the natural gas reburn from 10 to 20% of the total heat input decreased NO_x emissions from 0.82 to 0.56 lb/MBtu. Corresponding NO_x reduction from baseline levels are 34 to 55%. When FGR was introduced to the reburn burners while utilizing the same amount of the natural gas reburn fuel (10 to 20%), the NO_x emissions were 0.72 to 0.5 lb/MBtu (42 to 60% NO_x reduction). The improvement in NO_x reduction during FGR operation is greater at the lower natural gas heat input (e.g., 10%) and diminishes at higher gas heat input (e.g., 30%). This is expected because mixing between natural gas and cyclone combustion gases improves with increasing natural gas heat input.

Additionally, Figure 7 illustrates the effect of various FGR flow rates versus NO_x reduction potential. Increasing the FGR flow from 1 to 6% of total boiler flow resulted in improving NO_x emission levels from 4 to 82 ppm. It should be noted that the reburn system design was optimized based on using FGR via numerical modeling and varying FGR rates obviously changes the mixing potential within the reburn zone. As with any standard natural gas fired burner application, one practical limitation on the quantity of FGR that can be introduced is flame scanner indications. Based on total system optimization, the optimum FGR flow rate at Kodak's boiler 43 was determined at about 4%.

Boiler Turn Down

Based on all the parametric tests, optimized operating conditions were identified and incorporated into the control system. The optimized control curves include load versus gas heat input, reburn burner air and FGR flows, and OFA port flow. Figure 8 identifies the NO_x versus load data after these operating conditions were incorporated into the control system. The figure shows the effect of load on the required amount of natural gas to assure NO_x emissions below a targeted level of 0.6 lb/MBtu. Reducing load from 605,000 to 350,000 lb/hr of steam, requires less natural gas as a percentage of total heat input; 21 and 14%, respectively. The main reasons for lower gas requirement are the lower baseline NO_x levels and higher reburn zone residence time at 350,000 lb/hr of steam than at the 605,000 lb/hr of steam condition. The baseline NO_x level decreased from 1.37 lb/MBtu at the peak load to about 0.85 Lb/MBtu at 350,000 lb/hr of steam.

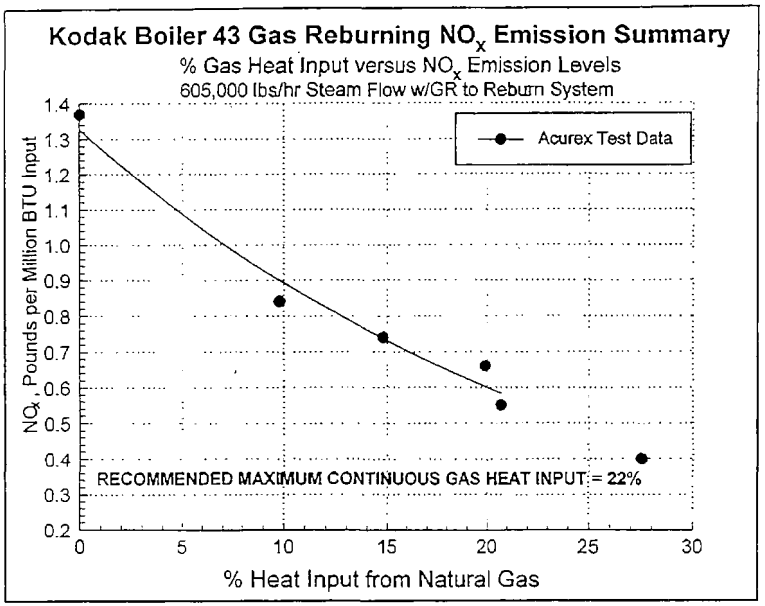

Figure 5 NO_x emissions at peak load with gas reburn

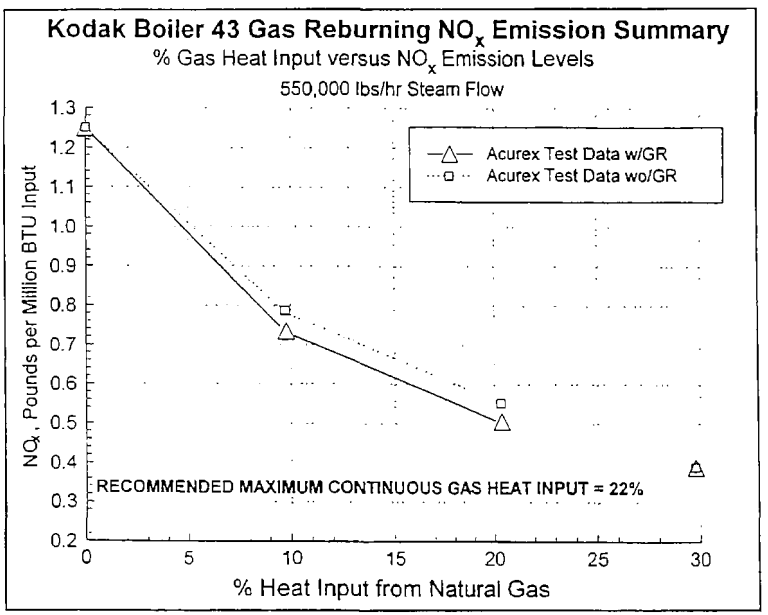

Figure 6 NO_x emissions at MCR with gas reburn

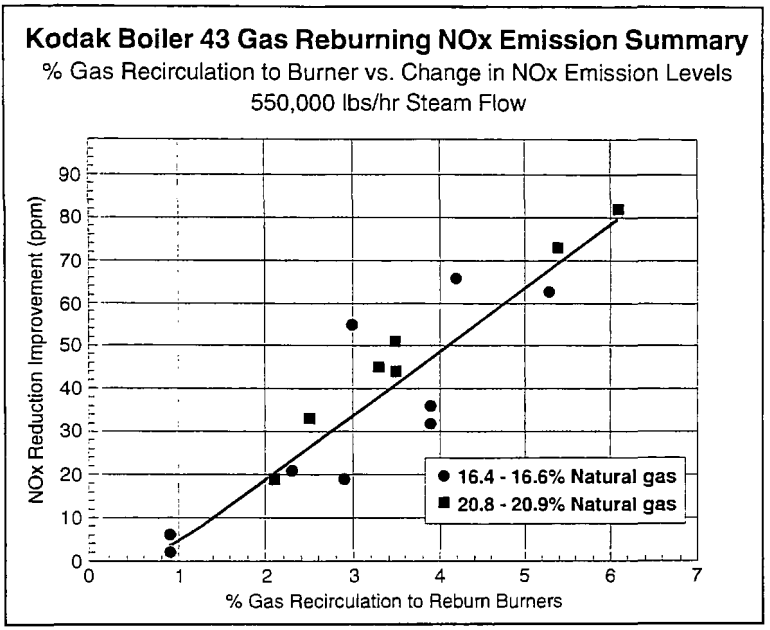

Figure 7 Effect of FGR on NO_x emissions

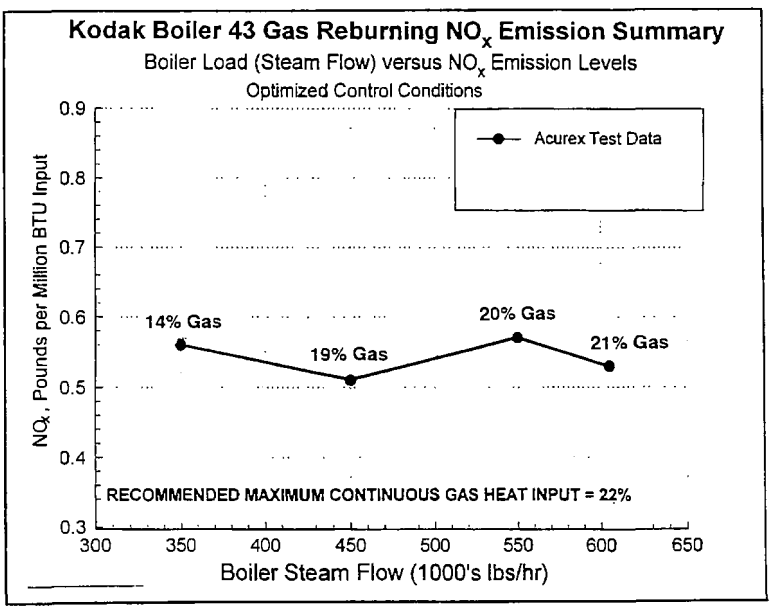

Figure 8 NO_x emissions at optimum conditions with gas reburn

Unburned Combustibles Losses

The effect of the gas reburn technology on unburned combustibles was explored by measuring carbon content of the fly ash as well as CO emission level. Typical average CO emission levels can be maintained below 200 ppm. Higher CO emissions have been observed when FGR flow to the reburn burners was turned off and when boiler economizer outlet oxygen concentrations are not balanced. During parametric tests several fly ash samples were isokenetically collected and analyzed for carbon content. Figure 9 shows the comparison of the combustible content in the fly ash from the baseline and gas reburn conditions over the range of boiler steam flow. The Baseline LOI levels varies between 6 to 11% over the boiler load range compared to 8 to 11% during gas reburning operation. These data indicate a minimal impact on unburned combustibles resulted during reburning operation.

Boiler Operations Experience

Smooth transition from baseline to reburn conditions has been Kodak's experience to date. The majority of the optimization tests were performed at approximately 20% gas in order to achieve the targeted 0.6 lb/MBtu of NO_x emissions. The boiler temperature profile, FEGT, and convection pass tube temperatures are within acceptable ranges. Under these optimized conditions, automatic boiler load control operates efficiently. One feature that was identified revealed that the boiler required additional oxygen probes at the economizer outlet to consistently measure/control the boiler oxygen concentrations accurately.

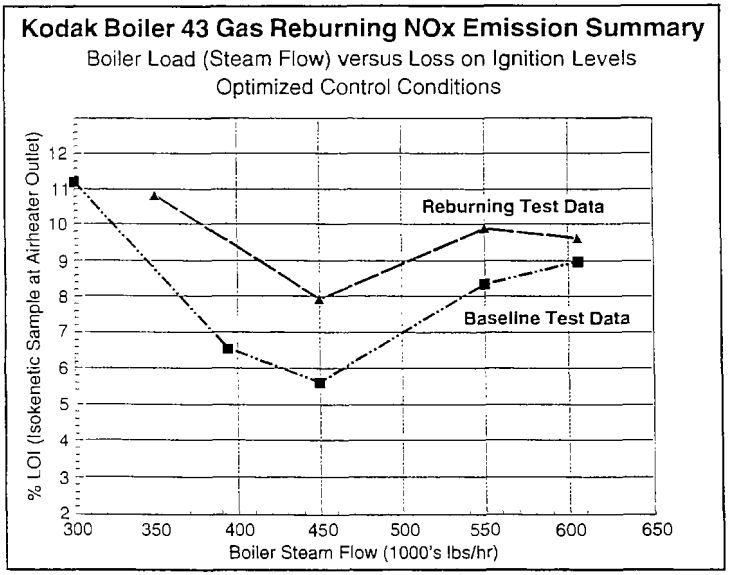

Figure 9 Effect of gas reburn on the unburned combustibles

Boiler Tube Corrosion Evaluation

Since gas reburn is accomplished by operating a portion of the furnace in a reducing atmosphere, potential corrosive conditions could exist. During the design of the reburn system, special attention was given to the design of reburn burners in order to provide sufficient penetration and distribute the gas in the boiler evenly; thereby reducing the potential for boiler tube wastage. In addition, to determine that the reburn system was not responsible for furnace corrosion, a furnace tube thickness study was performed during the outage when the reburn system was installed. The same study was performed again once the reburn system had been operating approximately 15 months.

Boiler tube thickness measurements were taken at four elevations in the furnace. Elevation 1: reburn burner centerline, elevation 2: approximate midpoint of the reburn zone, elevation 3: top of the reburn zone (center of the overfire air ports) and elevation 4: burnout zone (approximately eight feet above the overfire air ports). The elevations for the tube thickness measurements were identified by instrument survey and should be accurate plus or minus ½" The tubes were sandblasted and then ultrasonically tested for thickness on the crown of the tube as well as left and right of the crown. The accuracy of the instrumentation is plus or minus 0.005" and the readings indicate that the tube thicknesses are the same within the accuracy of the measuring equipment. Therefore, it is concluded that gas reburn has not contributed to any furnace tube wastage. Kodak will continue monitoring the boiler tubes for a potential long term effect, but no corrosion has been identified to date.

Economical Evaluation

An economical analysis was performed to evaluate the cost of the reburn technology for the small cyclone boilers. It should be mentioned that both capital and operating costs are site-specific. The capital cost depends on the size of the unit, ease of the retrofit, availability of natural gas at the plant and the control system upgrade requirements. The amount of the gas usage and the differential gas to coal price determines the operating cost.

The gas reburn system at Boiler 43 is more capital intensive due to the customer's need for a new control system for the entire boiler. For this first demonstration a FGR fan and associated equipment was installed to fully characterize the reburn technology potential. In addition, certain cost occurred due to the first-of-a-kind demonstration project. The total capital cost was approximately $5.9 million and it is high due to the small size of the boiler. The economy of scale is not available here, e.g. at 200 MW_e the cost of equipment is $16 to $17 per KW without controls.

Operating Cost & Levelized Cost

The differential cost of gas and coal is the main component of the operating cost. For the duration of this project, the gas/coal differential price was 1.74 $/MBtu. A maintenance cost of $ 25,000 per year is estimated for the Boiler 43 gas reburn system.

Using the above capital and operating cost, the levelized cost of NO_x reduction for Boiler 43 is $ 1335/ton of NO_x removed. This levelized cost is based on 85% capacity factor, and reducing NO_x from the baseline value of 1.37 to the post retrofit of 0.6 Lb/MBtu. The levelized cost was calculated over 20 years and a discount rate of 7.13%.

It should be mentioned that both capital and operating costs are site specific. The analysis does not include the additional advantage of the gas reburn in reducing SO_2 emissions. Also, larger units benefit from the economy of scale resulting in reduced capital cost per KW of capacity. The operating cost evaluation has a strong dependence on gas to coal cost differential and must be determined on a site specific basis.

Conclusions

Boiler No. 43 reburn system has been optimized and Kodak will continue day-to-day commercial operation. With the successful completion of the project, Kodak is considering the technology for implementation on its other cyclone-fired units. B&W's reburning technology is commercially available and is offered for turnkey retrofit projects. B&W also offers commercial guarantees for future installations.

Acknowledgments

The authors extend their appreciation to Joe Hallstrom, Jeff Rogers, Bruno Morabito, and Jim Riggs for leading the manufacturing of the reburn equipment, performing numerical modeling, field shakedown, and collecting/evaluating the test data for this project.

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Application Of Fuel Lean Gas Reburn Technology at Commonwealth Edison's Joliet Generating Station 9

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Abstract

This paper presents the preliminary results of the first full-scale application of Fuel Lean Gas Reburn (FLGR) in a cyclone fired boiler. Fuel Lean Reburn was installed on a 340 MW cyclone-fired utility boiler at ComEd's Joliet Generating Station Number 9. Fuel Lean Reburn involves the injection of 3-7% natural gas heat input via turbulent jets into the upper furnace of fossil-fueled boilers while maintaining an overall fuel lean furnace, thereby preventing excessive carbon monoxide emission and eliminating the need for downstream completion air as employed in conventional gas reburning technology. The controlled dispersion of natural gas into high NO_x regions downstream of the primary combustion zone is designed to create locally fuel rich zones or eddies in which NO_x reburning can take place while maintaining an overall fuel lean furnace environment. The Fuel Lean Reburn shows the potential to achieve better than a 40% reduction in NO_x emissions using 7% gas heat input or less. With the elimination of downstream completion air and the use of less gas heat input than with conventional gas reburning systems, Fuel Lean Reburn systems offer lower capital and operating costs than conventional reburn systems with a moderate decrease in the NO_x control potential. A Fuel Lean Reburn system was installed on Joliet Unit 6 in the Spring of 1997 with parametric and long-term performance testing taking place in the Summer of 1997. This project is sponsored by ComEd and the Gas Research Institute.

Introduction

The 1990 Clean Air Act Amendments (CAAA) are requiring utilities to make large reductions in nitric oxide (NO_x) emissions from their fossil-fired generating units. The conventional utility approach to reducing NO_x emissions has been through the installation of low NO_x burners with separated overfire air. However, cyclone fired boilers which are prevalent in the Midwest and within ComEd's generating system are a unique firing design for which conventional low NO_x burner technology can not be applied. Cyclone fired boilers represent about 9% of the US coal-fired generating capacity but account for about 14% of the NO_x produced by coal-fired utility boilers. This is due to the fact that the average uncontrolled NO_x emission rate from cyclone units is typically twice as high as comparative pulverized

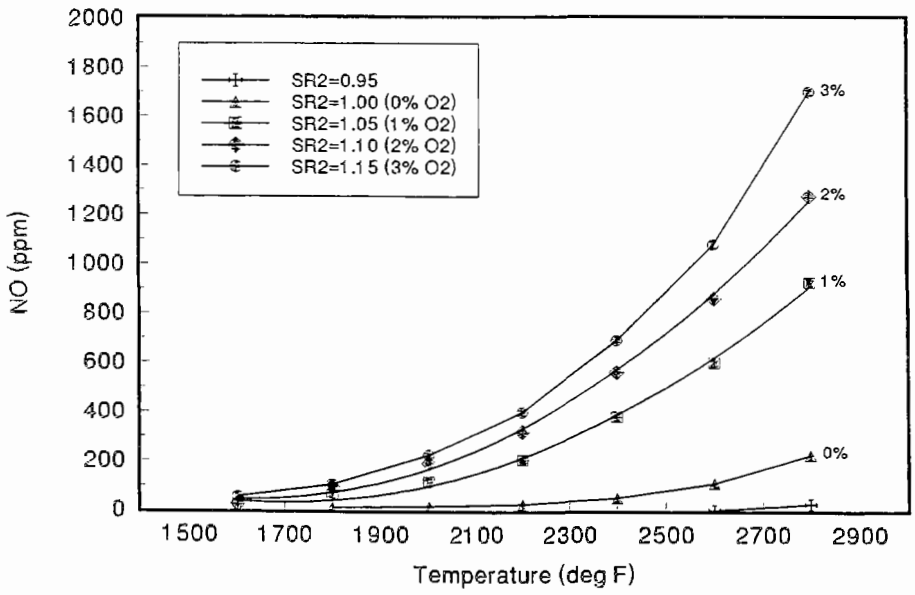
coal units based on the rapid fuel/air mixing characteristics inherent in the cyclone combustion design.

In response to the need for cost-effective NO_x emission control options the Gas Research Institute (GRI) and ComEd are jointly sponsoring a field evaluation of Fuel Lean Reburn Technology on ComEd's Joliet Generating Station 9, Unit 6. Energy Systems Associates has developed the process design for the Joliet Unit 6 system and is performing parametric and optimization testing.

Fuel Lean Reburning

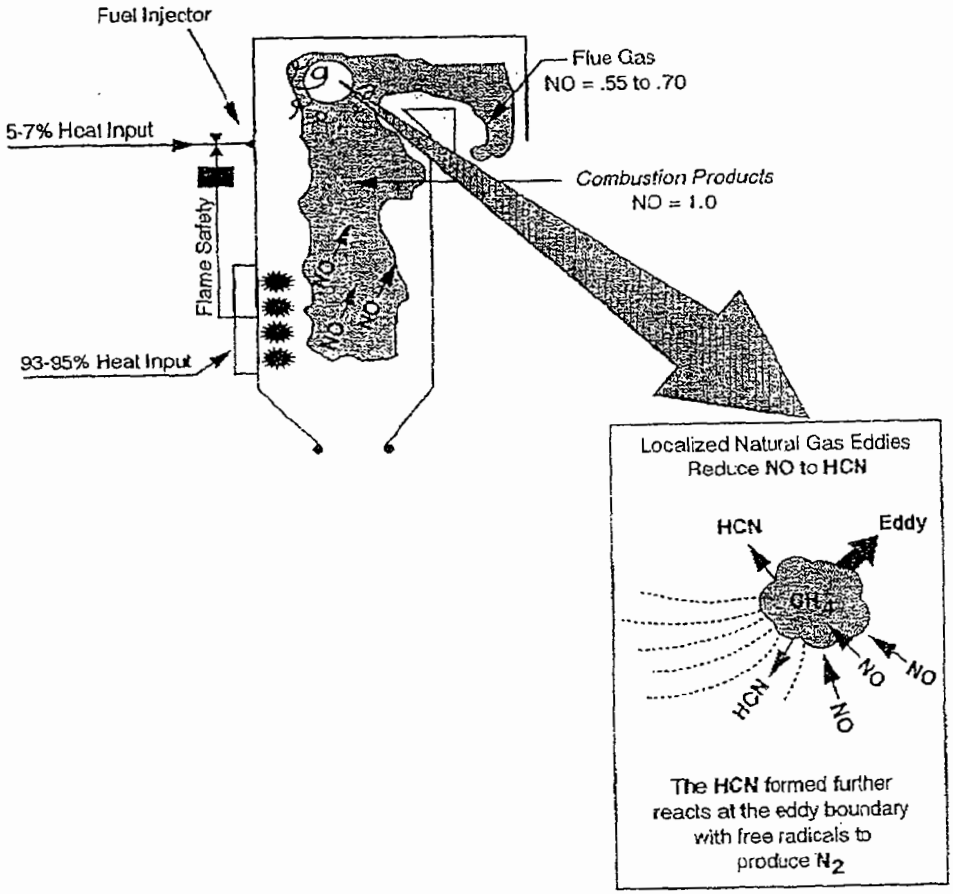
NO_x concentrations leaving boilers are a result of chemical kinetic and not thermodynamic limitations. Figure 1 shows the equilibrium concentration of NO in typical flue gas a function of temperature and the excess oxygen content. The equilibrium NO concentration is seen to decrease rapidly with decreasing flue gas temperature. Concentrations of NO under 100 ppm are predicted at flue gas temperatures of 1800 °F for excess oxygen concentrations of 3% and lower. So if the equilibrium NO concentration at 3% excess oxygen is 100 ppm, why do NO concentrations greatly exceed this level during normal practice? This is caused by the quenching of the NO equilibrating chemistry during normal boiler operation. In-furnace and post-combustion NO_x control technologies help to remove these chemical kinetic constraints to NO equilibration by injecting either natural gas or an amine (NH_i) based compound such as ammonia or urea into the furnace.[1]

Figure 1: Thermodynamic Equilibrium Nitric Oxide as a Function of Temperature and Stoichiometry



A schematic of the Fuel Gas Lean Reburn process retrofitted on a cyclone boiler is shown in Figure 2. The combustion of coal in the primary furnace creates a high temperature, low excess oxygen content flue gas containing 400 to 1000 ppm on nitric oxide. The injection of natural gas in the proper temperature window (~1800 to 2400 °F) results in chemical reactions which reduce NO to molecular nitrogen. The desired injection temperature is as low as possible consistent with the need to achieve natural gas ignition and burnout. The process uses high velocity turbulent jets for dispersing the gas into the furnace. The amount of natural gas is controlled to maintain an overall fuel lean stoichiometry in the upper furnace. Therefore, the gas is consumed in excess oxygen already present in the flue gas and no additional overfire air is injected above the gas injection zone for completing burnout. Conventional gas reburning typically requires 15% to 20% gas heat input injected at a higher temperature than Fuel Lean Gas Reburn to create a uniformly fuel rich reburning zone. In addition, conventional reburning employs the use of downstream overfire air to complete gas burnout.[2]

Figure 2. Conceptual Overview of Fuel Lean Gas Reburn Technology



Project Overview

A Fuel Lean Reburn demonstration program is currently underway at CoEd's Joliet Station 9 in Joliet, Illinois. This project is being supported by the Gas Research Institute (GRI) and by ComEd. The goal of this project is to achieve a 45% reduction from the baseline NO_x emissions at full load using a maximum of 7% natural gas heat input and to achieve a 50% to 60% NO_x reduction at low load using up to 12% gas heat input. Under all operating conditions it is necessary to maintain the average carbon monoxide concentration below 200 ppm when corrected to 50% excess air.

This demonstration program has been executed using two distinct project phases. Phase 1 involved proof-of-concept experiments conducted on a pilot scale combustor in combination with computational fluid dynamic (CFD) modelling of the simulator and full scale process. Phase 2 has involved the full-scale system engineering, the system retrofit and full-scale performance testing and optimization including validation of the CFD and advanced modelling practices.

Proof-of-Concept Experiments

The proof-of-concept experiments were conducted on the Small Boiler Simulator (SBS) test facility at Babcock and Wilcox Company's Alliance Research Center in Alliance, Ohio. The SBS is a 6 million Btu/hr capacity experimental boiler capable of simulating residence time and temperature profiles of a full scale utility boiler. The SBS was fired by a single cyclone combustor. The water-cooled SBS furnace measures 4.5 feet wide by 6.0 feet deep by 14.0 feet high. When operated at its design capacity, the calculated residence time from the cyclone exit to the furnace exit is about two seconds.

The experimental procedure involved the injection of natural gas into the upper furnace of the SBS using gas lances at a flue gas temperatures ranging from 1950 °F to 2300 °F. The natural gas heat input was varied between 3% and 11% while maintaining overall fuel lean conditions in the furnace. The pilot scale experiments documented NO_x reductions up to 40% at full load using 7% gas. At reduced loads, NO_x reductions up to 58% were measured using 11% gas. Figure 3 documents the percent NO_x reduction achieved at full and reduced load as a function of the percentage of gas heat input.

The amount of gas heat input and the degree of NO_x reduction attainable with the Fuel Lean Reburn process was found to ultimately be limited by the acceptable CO emission limit. Figure 4 shows the CO emissions measured as a function of the percentage of excess oxygen remaining in the stack gas. These results show that as the excess oxygen level was decreased below 1.5%, the CO threshold was reached and CO levels began to consistently exceed 100 ppm.

Figure 3. NO_x Reduction for Lance Injectors at Mid-Furnace and Upper Furnace at Full Load Reduced Load

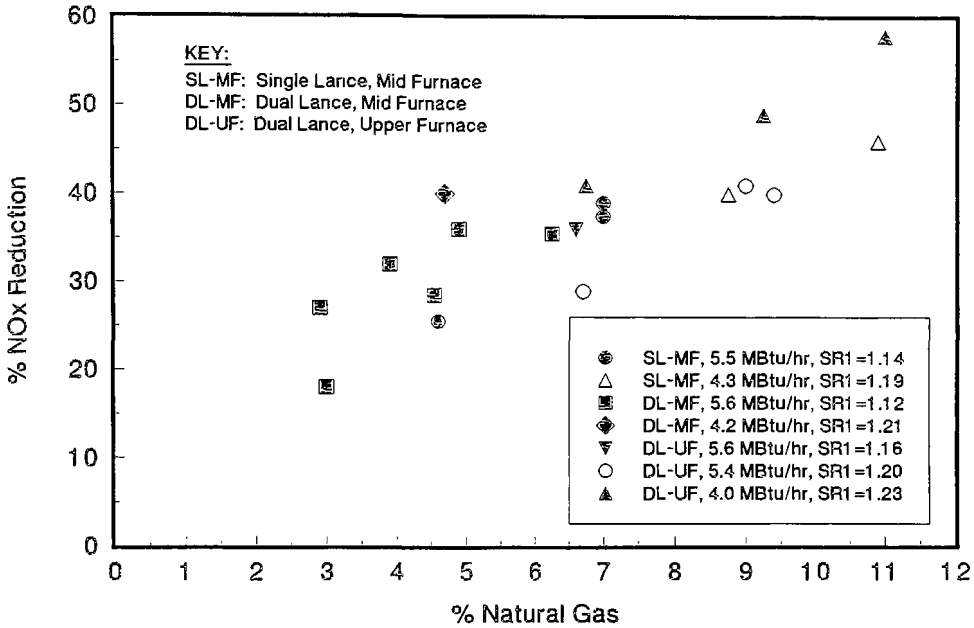
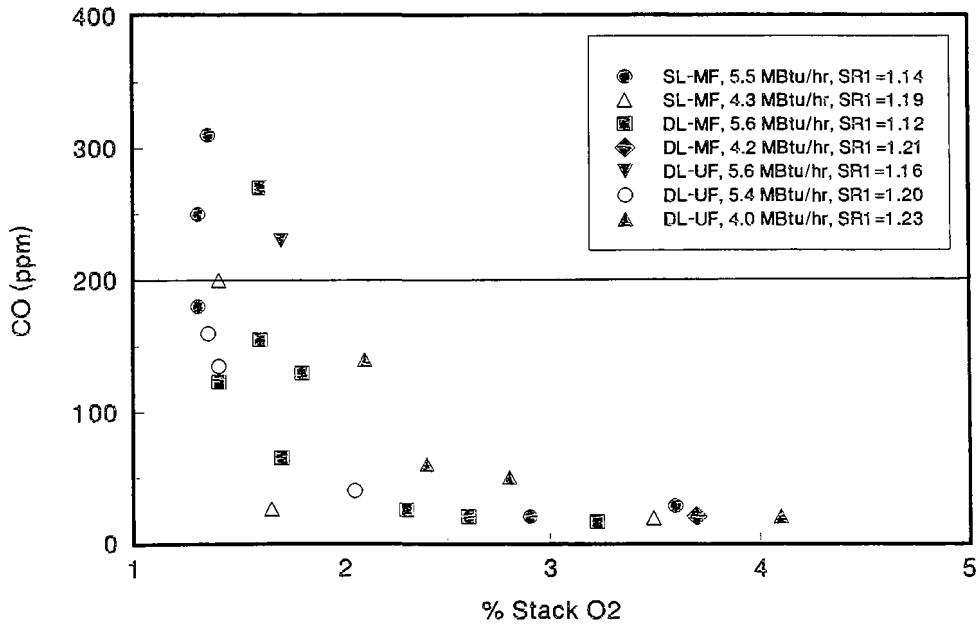


Figure 4. CO Emissions Versus Percent Oxygen at the Stack



Other major conclusions of the pilot scale testing and CFD modelling were that better NO_x reductions were predicted and measured at lower injection temperatures (approximately 2000 °F) than at higher injection temperatures, numerous low volume jets were determined to be more effective than fewer higher volume jets, natural gas must be introduced into regions containing the bulk flow for effective NO_x reductions but high velocities in the bulk flow region increased turbulent mixing and combustion rates of the gaseous fuel thereby limiting the exposure to CH_i radicals and working against the Fuel Lean Reburn Process and finally, that the Fuel Lean Reburn Process can produce strong NO_x reductions limited only by CO levels generated.[3]

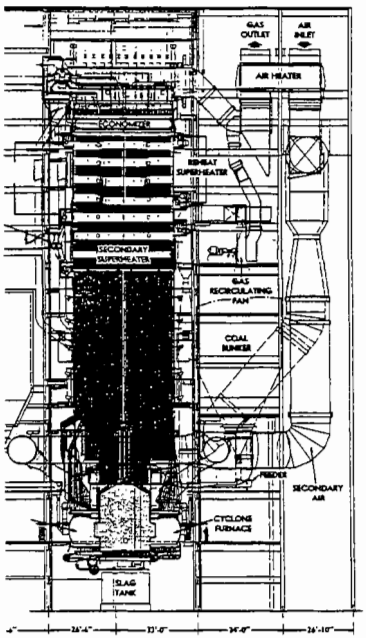
Based on the favorable results of the proof-of-concept experiments and CFD modelling, GRI and ComEd agreed to proceed with the full-scale installation and testing.

Unit Description

Joliet Unit 6 is a 327 MW B&W cyclone-fired boiler which was placed in-service in 1959. The unit currently fires a low-sulfur Western sub-bituminous coal. The boiler consists of a single divided furnace arranged with a water cooled slag tap furnace; a continuous tube, horizontal tube superheater interrupted for attemperators; a continuous tube, horizontal reheater with an economizer; and two regenerative Ljungstrom air heaters. The unit is fired with nine horizontal cyclone furnaces.

The primary furnace, secondary furnace, secondary superheater, primary superheater/reheater and economizer are arranged successively one above the other so that the gas flow is vertically upward through the unit as shown in Figure 5. The primary superheater and reheater are located on opposite sides of the divided furnace. A diversion air damper located at the exit from the economizer provides for the control of the reheat steam temperature by diverting flue gas either towards or away from the reheat side of the furnace. The boiler is capable of delivering a maximum of 2.2 million pounds of steam per hour at 2000 psi and 1015 °F superheat and 1005 °F reheat. The primary furnace is approximately 60 feet wide, 20 feet deep and 25 feet high. Four cyclones are located in the front wall or reheat side and five cyclones are located on the rear wall (superheat side).

Figure 5. Schematic of Joliet Unit 6



NO_x Regulation Affecting Joliet Unit 6

The acid rain provisions of Title IV of the 1990 CAAA will require Joliet 6 to meet an annual average NO_x emission rate of 0.86 lb/MMBtu beginning in the year 2000. For the first quarter of 1997, the NO_x emission rate for Joliet 6 averaged 0.96 lb/MMBtu. In addition to the current regulation enforceable under Title IV, ComEd must address additional NO_x regulations resulting from the ozone attainment provisions required by Title I. The Ozone Transport Advisory Group (OTAG) is currently working to establish required measures to reach ozone attainment in the eastern 37 states. The anticipated regulations from this process will likely be more stringent than current acid rain limits, particularly during the summer time ozone nonattainment months.

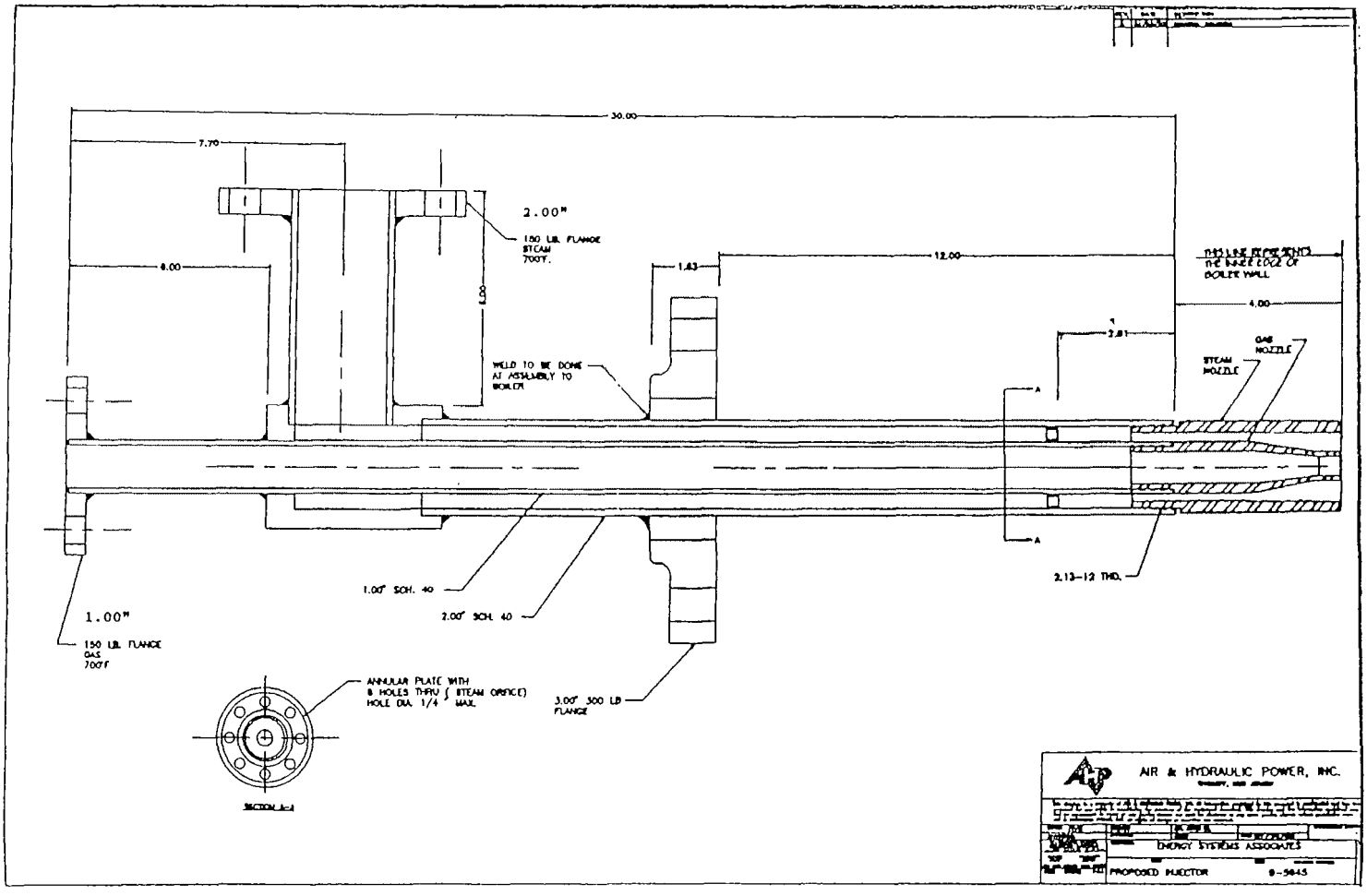
Overview of the FLGR System on Joliet Unit 6

The Fuel Lean Reburn system consists of a total of 36 gas injectors divided equally between the superheat and reheat side of the furnace. Low pressure steam is supplied to each gas injector to aide in the gas jet penetration. The steam was provided in this first large scale demonstration of Fuel Lean Gas Reburn has a hedge to ensure that adequate penetration of the gas into the bulk gas stream could be achieved. However, it is our expectation that adequate penetration may be achieved without steam, thereby limiting its necessary use in future deployments. There are 26 gas injectors located at 208 foot furnace elevation which is approximately 56 feet below the entrance to the convective section. The remaining 10 injectors are located at the 229 foot furnace elevation, or about 35 feet below the entrance to the convective section. The gas/steam injectors are designed to operate at about 35 psi and to maintain a design steam to gas mass ratio of 2:1. The gas system was sized to provide a maximum full load gas heat input of 12%. This is equivalent to about 350,000 SCF/hr of natural gas or about 15,000 lbs/hr of gas. The maximum steam flow is 30,000 lbs/hr but under normal operating condition will operate at about 17,500 lbs/hr. A schematic of the gas/steam injector is shown in Figure 6. The injectors are designed to provide high velocity jets of gas spatially into the furnace. The steam is intended to aide in gas penetration and to influence the gas mixing characteristics. Each injector is equipped with manual isolation and flow control valves for both the gas and the steam.

Results of Full-Scale Testing

At the time of this writing, full-scale performance testing of the Fuel Lean Gas Reburn process at Joliet Unit 6 is underway. The test plan calls for optimization of the Fuel Lean Reburn process at 320 MW which is currently full load, at 270 MW, 210 MW and 150 MW. To date all testing has been performed at 320 MW.

Figure 6


30.00
7.70
2.00"
150 LB. FLANGE
STEAM
700Y.
8.00
1.43
12.00
4.00
2.81
GAS
NOZZLE
STEAM
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WELD TO BE DONE
AT ASSEMBLY TO
BOILER
A
A
1.00" SCH. 40
2.00" SCH. 40
2.13-12 THD.
1.00"
150 LB. FLANGE
GAS
700F
ANNULAR PLATE WITH
8 HOLES THRU (STEAM ORFICE)
HOLE DIA. 1/4 MAX.
3.00" 300 LB
FLANGE
SECTION A-A
AIR & HYDRAULIC POWER, INC.
ENERGY SYSTEMS ASSOCIATES
PROPOSED INJECTOR
9-5845

The normal baseline operating condition at 320 MW is with all nine cyclones in-service and operating at roughly equivalent levels. Under normal operating conditions the baseline NO_x emission rate is in the range of 0.91 lbs/MMBtu to 0.98 lbs/MMBtu with this small variation being attributable to variability in fuel and operating conditions. The baseline CO level measured at the economizer outlet typically does not exceed 10 ppm corrected to 50% excess air (EA).

The parametric testing will included an evaluation of the following parameters on NO_x and CO emissions:

1. The impact of steam co-injection. The objective is to determine if the steam improves the gas penetration or mixing and adds value to NO_x or CO control.

2. The importance of the flue gas temperature at the gas injection location on the fuel lean reburning kinetics. The local injection temperature can be changed by using either the upper or lower elevation of injectors. Flue gas temperature measurements indicate that the lower (208 foot) elevation has an average gas temperature of about 2100 °F at full load whereas the upper elevation has an average gas temperature of about 2000 °F.

3. The impact of changes to the spatial distribution of gas within the furnace.

4. The impact of varying percentages of gas heat input up to about 12% heat input.

Figure 7 shows the percentage of NO_x reduced as a function of the percent gas heat input to the unit a full load with the results indicating either steam co-injection or no steam use. The results show NO_x reductions ranging from 8% to 43% using 1.5% to 7% gas heat input respectively. The preliminary results show no clear benefit to the use of steam co-injection. This result may mean that adequate jet penetration is achieved without the steam. The current gas/steam injector design will be evaluated to determine if it can be optimized to achieve greater NO_x reduction.

Figure 8 shows the same set of NO_x reduction data organized according to the location of the gas injector in-service. The lower elevation of injectors represents the hottest potential average injection temperature at full load while the upper injectors represent the coolest possible injection temperature at full load. The results show no clear indication that injection at the cooler elevation is consistent with improved fuel lean reburning kinetics. However, the known temperature difference between these elevations is only about 100 °F at this load. The effectiveness of cooler gas temperatures will become more pronounced at lower boiler loads when gas temperatures in these locations will decrease 100 to 200 °F.

Carbon monoxide emissions tend to become the limiting factor in achieving greater NO_x reductions. The CO results showed very poor correlation to the average excess oxygen level remaining in the flue gas as well as little correlation to steam co-injection characteristics or gas injection elevation. Figure 9 shows the CO level in parts-per-million at 50% EA as a function of the percent NO_x reduced. The results show it is possible to achieve up to a 20%

Figure 7

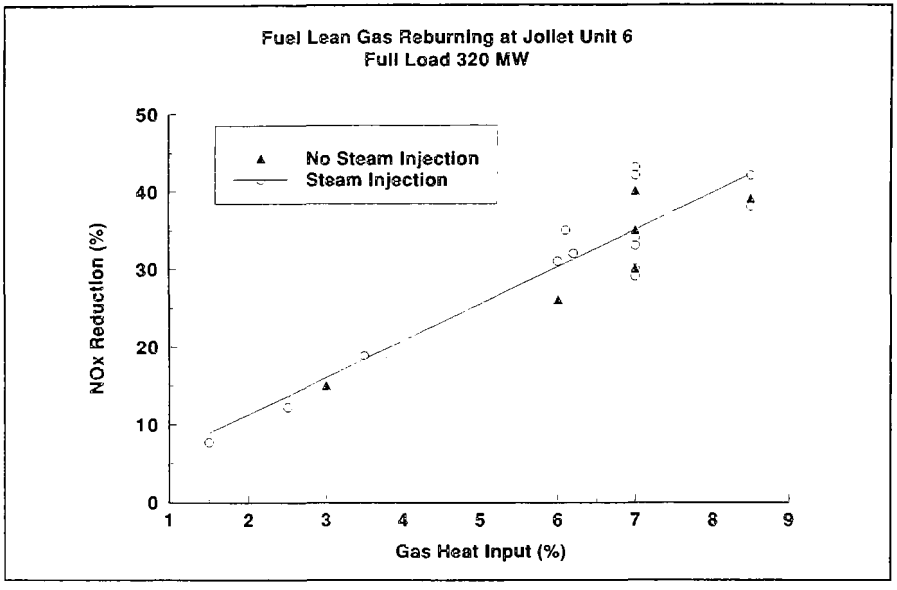
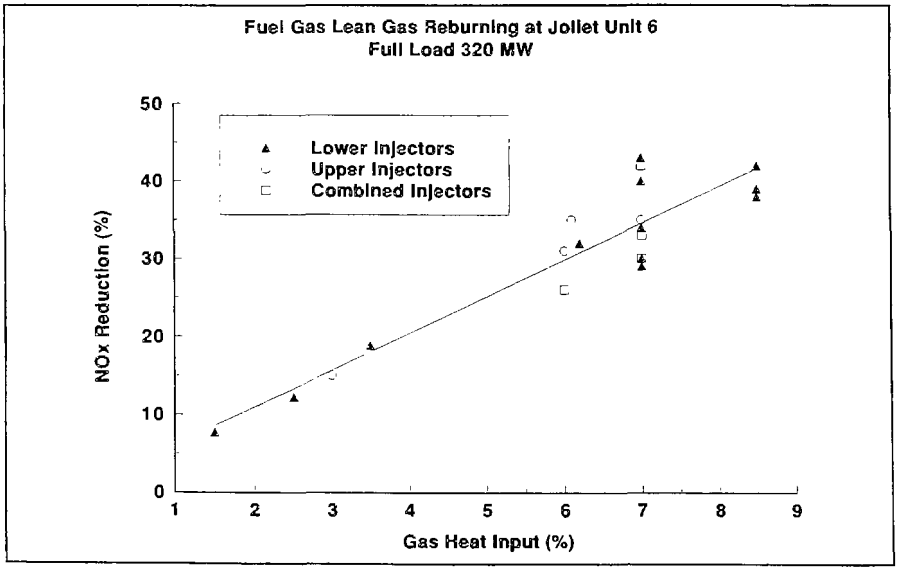
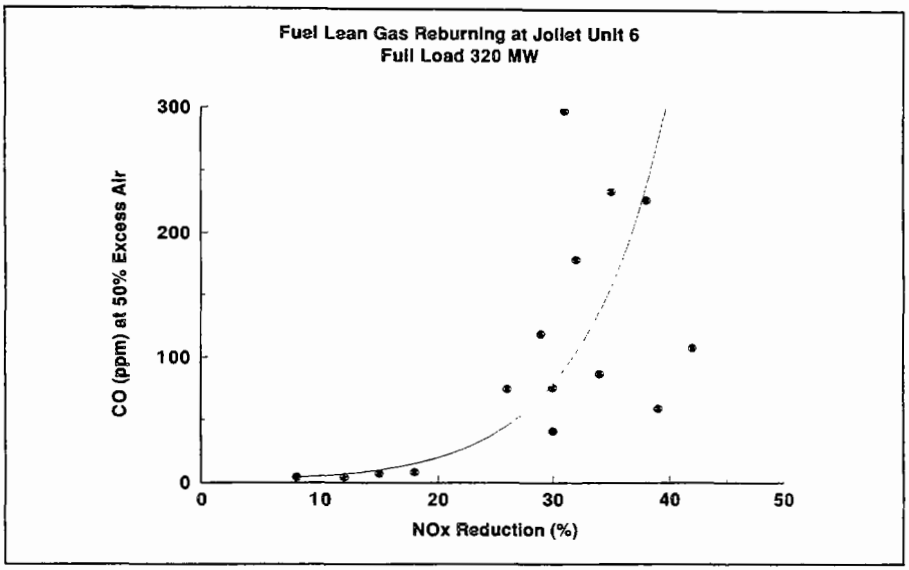


Figure 8



NO_x reduction with virtually no change in the boiler CO emission level. At 30% NO_x reduction the CO level begins to average about 100 ppm. Based on the need to remain below 200 ppm on average, the results to date indicate about a 38% NO_x reduction can be maintained with acceptable CO. Preliminary results also indicate that the unburned carbon levels measured in the fly ash have not changed as a result of the Fuel Lean Reburn process with baseline and reburning conditions both achieving loss-on-ignition (LOI) values of 2% and lower.

Figure 9



The test plan calls for additional testing over a wider boiler load range as well as better investigation of spatial gas distribution patterns at full load.

An additional benefit of the Fuel Lean Gas Reburn Process at Joliet Unit 6 has been the potential to extend the maximum generating capacity of the unit. Joliet 6 boiler is currently permitted to generate as much as 340 MW. However, the forced draft fans limit the summertime maximum reliable capacity to about 320 MW. Because the Fuel Lean Gas Reburn Process injects natural gas without combustion air, the displacement of coal heat input creates additional capacity on the forced draft fans. This has enabled the unit to increase maximum generating capacity about 10 MW to 330 MW using only 3% gas heat input and maintain NO_x emissions below 0.80 lbs/MMBtu.

Summary

The Fuel Lean Gas Reburning installation at Joliet Unit 6 offers a potential option to meet Title IV NO_x regulations for cyclone and wet bottom boilers and Title I regulations. The full load testing completed to-date has documented NO_x reductions of as much as 43% using 7% natural gas heat input. The full-scale results achieved are consistent with the pilot scale results and conclusions from CFD modelling of the process. To date the steam co-injection has not proven beneficial and the expected temperature dependency of Fuel Lean Gas Reburn kinetics has not been verified. As anticipated from the pilot scale and CFD modelling, CO emissions prove to be the limiting factor to achieve larger and sustained high levels of NO_x reductions. Additional testing at reduced loads as well as a long-term demonstration test remain to be completed in the summer/fall of 1997. Other tests of Fuel Lean Gas Reburn are underway or planned by GRI and ESA on boilers with different firing designs at other utilities.

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Tuesday, August 26; 1:00 p.m.
Parallel Session B:
Selective Catalytic Reduction

APPLICATIONS OF SELECTIVE CATALYTIC REDUCTION TECHNOLOGY ON COAL-FIRED ELECTRIC UTILITY BOILERS

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Abstract

In January 1996, the U.S. Environmental Protection Agency (EPA) initiated a study to examine the application and performance of SCR technology on coal-fired electric utility boilers. The findings of the study indicate that all of the SCR applications surveyed have achieved targeted NO_x emission rates. Many boilers reported average NO_x emission rates at or below 0.15 lbs/mmBtu. Those boilers reporting emission rates higher than 0.15 lbs/mmBtu are generally meeting emission limits set at these higher rates. In general, the operational histories of SCR installations indicate that NO_x reductions are being achieved in a reliable manner.

Introduction

Emissions of nitrogen oxides (NO_x) contribute to adverse health and environmental impacts resulting from formation of tropospheric ozone, acid rain, and fine particulates. In 1995, coal-fired electric utility boilers in the United States accounted for 5.5 million tons of NO_x (about 23 percent of the total national NO_x emissions).[1, 2]

Selective catalytic reduction is a NO_x control technology that utilizes a catalyst to reduce NO_x to nitrogen and water. Although SCR was developed in the United States, other countries, such as Japan and Germany, have aggressively implemented this technology on coal-fired utility boilers over the past fifteen years and have achieved substantially reduced NO_x emission rates. In general, more than 200 installations of SCR systems operating on coal-fired boilers worldwide have accumulated an experience base of more than 1700 years.[3]

In light of the broad international experience with use of SCR and the health and environmental concerns surrounding NO_x emissions, EPA initiated a study to assess the performance of SCR being achieved on coal-fired utility boilers. This paper summarizes the findings of this study; more detailed information can be found in the final report on the study.[4]

SCR Technology Description

Selective catalytic reduction is a post-combustion NO_x control technology capable of providing NO_x reductions in excess of 90 percent. This technology is widely used in commercial applications overseas and is experiencing expanded use in U.S. facilities. The SCR process uses a catalyst at approximately 300-450 °C to facilitate a heterogeneous reaction between NO_x and an injected reagent, ammonia (NH_3), to produce nitrogen and water.

A typical SCR system is comprised of: a storage, delivery, vaporization, and injection system for the reagent; an SCR reactor housing the catalyst; soot blowers; and additional instrumentation. Anhydrous or aqueous ammonia are used as reagents. The catalyst is a critical component of an SCR system and its NO_x reduction performance and resistance to deactivation affects the cost effectiveness of the SCR application.

Three SCR system configurations are available for use with coal-fired boilers. In a high dust configuration, the SCR reactor is located between the economizer and the air preheater. In this configuration, the catalyst is exposed to flyash and chemical compounds present in the flue gas that have the potential to degrade the catalyst mechanically and chemically. However, as evidenced by the extensive use of this configuration, appropriate design of a high-dust SCR system can mitigate the mechanical and chemical impacts on the catalyst. In a low dust configuration, the SCR reactor is located downstream of the electrostatic precipitator (ESP). In this configuration the potential for degrading effects of flyash on the catalyst is reduced. In a tail end configuration, the SCR reactor is located downstream of the flue gas desulfurization (FGD) unit. The tail end configuration is implicitly low dust. However, this configuration may be more expensive than the high dust configuration due to associated flue gas reheating requirements.

Assessment of SCR Performance on Coal-Fired Utility Boilers

To conduct a comprehensive assessment of SCR performance on coal-fired utility boilers, information on existing SCR installations and their operation was reviewed in the EPA study. This information was obtained from coal-fired plants in the U.S., Germany, Sweden, Austria, Denmark, and Finland. Since SCR systems are typically designed and operated to ensure compliance with applicable regulatory requirements, information on applicable NO_x emission limits was also obtained from these plants. Several of the European utilities requested that the names of their plants be kept confidential. To accommodate this request, each of the units in this paper is identified by a letter and a number. The letter identifiers relate to the countries in which plants are located and are: US (United States), A (Austria), D (Denmark), F (Finland), G (Germany), and S (Sweden). The number identifiers relate to the numerical order in which data was received from units in a country. The information received from SCR installations is discussed in the following sections.

Information on Units and Associated SCR Systems

Information on 33 units equipped with SCR systems at 21 coal-fired plants in the U.S. and Europe was acquired and reviewed in the EPA study. These units range in size from 40 MWe to 740 MWe. Thirteen units were constructed with SCR systems and are designated as "new", while 20 units were retrofitted with SCR systems. The SCR installations include 29 high dust, two low dust, and two tail-end configured systems. Of the plants reporting boiler information, thirteen units are tangentially fired, four are cyclone fired, and five are wall fired. Sixteen of the units are dry bottom boilers and 15 are wet bottom boilers; of the latter, six recirculate their flyash. As described above, the information collected on boilers and their associated SCR systems represents a broad variety of SCR applications. In addition, startup dates of these applications indicate that many of the SCR systems have been in operation for six or more years. Hence, these applications contribute a significant level of SCR-related operating experience to the EPA study.

Pertinent Regulations

Summarized in Table 1 are the applicable NO_x emission limits for the U.S. and the European units that provided data for the EPA study. In order to facilitate comparisons between the U.S. limits expressed in pounds of NO_x per million Btus of heat input (lbs/mmBtu) and European limits, lbs/mmBtu equivalents for the latter are also shown in Table 1. Note that in arriving at the lbs/mmBtu equivalents for the German and Austrian limits, the standard bituminous coal F-factor of 9870 dscf/mmBtu given in EPA Reference Method 19 (40 CFR Part 60, Appendix A) has been used.

As seen in Table 1, in general, coal-fired units in the U.S. and Europe are meeting emission limits set at or below 0.17 lbs/mmBtu. Notably, there are units in the U.S. and Germany that are complying with emission limits set at or below 0.10 lbs/mmBtu. An exception is a U.S. unit that is currently complying with a Reasonably Available Control Technology (RACT) limit of 1.4 lbs/mmBtu.

It is interesting to note that the plant in Sweden has an economic incentive to lower its NO_x emissions. In Sweden, all electric utility plants with more than 10 MWe capacity, that produce more than 50 GWe, pay a fee on NO_x emissions (on a per kg basis). After a one percent administrative fee is deducted, all remaining revenues are redistributed to the utilities based on the fraction of total national electrical power generated by each utility.

Analysis of NO_x Emissions

Emissions data were received from six units at five plants in the U.S., 18 units at 10 plants in Germany, three units at one plant in Sweden, four units at three plants in Austria, one unit in Denmark, and one unit in Finland. Many of these units provided continuous emissions data for a month or more of operation while other units provided summary data (e.g., annual averages, etc.)

As discussed before, these data represent a broad spectrum of SCR applications.

The NO_x emissions data were reported in various units (e.g., lbs/mmBtu, mg/m^3, mg/MJ, etc.). In order to compare SCR performance between data sets, it was necessary to normalize the emissions data to a standard basis. The basis chosen in this work was lbs/mmBtu since U.S. units report their NO_x emissions on this basis. Generally, F-factors were used to convert all concentration data to emission rates expressed in lbs/mmBtu. Several plants provided complete information for the coal(s) used on unit(s) during the period(s) for which emissions data were provided. For these plants, an F-factor was calculated for each emissions period. Other plants provided the characteristics for all coals used at the plant, without specifically identifying the unit(s) where the coal(s) were burned. For each of these plants, the coal data were used to determine a single plant-specific F-factor. Note that the higher the F-factor, the higher the calculated NO_x emission rate in lbs/mmBtu. Thus, to avoid underestimation of the controlled NO_x rates achieved with SCR, the highest of the computed F-factors (wherever possible) has been used in this study.

A few of the German plants did not provide sufficient coal data for determining F-factors but indicated that the coals used were either bituminous or "hard German coals." Such coals were considered to be equivalent to U.S. bituminous coals with the associated standard F-factor of 9780 dscf/mmBtu given in EPA Reference Method 19 (40 CFR Part 60, Appendix A). This standard F-factor was used in converting emissions data from these plants. The standard F-factor was also used in converting data from plants in Finland and Denmark.

Note that the continuous emissions data received from SCR applications may include exempt data (i.e., data related to startup, shutdown, or some other excusable event). These exempt data would have been excluded by plants in their compliance determinations. Because exempt events for most of the units were not specifically identified in the continuous emissions data that were received, all reported data were included in the calculations. The only plants providing continuous data that identified exempt emissions were US-4 (there were none for the reported period) and D-1 (three periods were identified). Data for the three exempt periods identified by D-1 were excluded from emissions analyses.

In contrast to exempt emissions, periods of no reported emissions could be identified in the continuous emissions data and were excluded from emissions analyses. In many cases it was possible to identify periods in which the unit was down because the corresponding load (Mwe) data were zero; data for these periods were also excluded from analyses. Additionally, data for the periods during which units (S-1:A and A-3) were burning a supplemental fuel (such as gas or oil) were also excluded from all analyses.

To assess SCR NO_x control performance, overall averages, daily averages, and 30-day rolling averages of emissions were examined. Presented are analyses related to continous emissions data received from SCR applications; analyses of summary data received can be found in the final report on the study. As noted previously, the emission averages were computed using data that may include exempt emissions and using the highest calculated F-factor, wherever possible. Hence, the averages presented in the following sections are considered to be conservative.

Overall Averages

Overall average emissions for units that provided continuous data are presented in Figure 1. The solid lines in this figure represent the regulatory emission limits for each of these units. For the German and Austrian units, a range of limits based on the applicable F-factors is shown. Note that the Swedish plant S-1:A provided continous emissions data for the months of October 1995 and January 1996. For this unit, the overall average emission for each of these months is shown separately in Figure 1.

As seen in Figure 1, in all cases the overall average emissions were lower than the applicable emission limits. Further, all of the units, except US-6, achieved 0.17 lbs/mmBtu or lower for their overall average emissions and 12 of the 19 units achieved 0.15 lbs/mmBtu or lower. Unit US-6 is regulated with an emission limit of 1.4 lbs/mmBtu and achieved an overall average emission rate of 0.91 lbs/mmBtu.

The German, Austrian, Danish, and Finnish units, achieved overall emission averages ranging from 0.08 to 0.17 lbs/mmBtu, and, therefore, are consistently able to achieve NO_x emissions rates at or below the applicable limits. The new German unit (G-4:A) operating under an emission limit of 100 mg/m^3, achieved an overall average of 0.08 lbs/mmBtu.

The Swedish unit achieved overall emission averages of 0.04 and 0.07 lbs/mmBtu during two separate months. The lower average was achieved during variable load conditions experienced in October 1995, and the higher during maximum load conditions experienced in January 1996. These emissions were dramatically below the Swedish standard of 80 mg/MJ (0.19 lbs/mmBtu).

Four United States units (US-1:A, US-1:B, US-2, and US-4) were able to achieve overall emission averages ranging from 0.13 lbs/mmBtu to 0.16 lbs/mmBtu. These averages were below the applicable 0.17 lbs/mmBtu emission limits in their Prevention of Significant Deterioration (PSD) permits.

Daily Averages

Daily emission averages were calculated for units that provided continuous emissions data. For each of these units, except US-6, the mean and the range of the daily averages experienced are shown in Figure 2. As noted before, unit US-6 is regulated with an emission limit of 1.4 lbs/mmBtu. This unit achieved daily averages below 1.13 lbs/mmBtu for the reported period. Note that for the Swedish Unit S-1:A, the averages for the months of October 1995 and January 1996 are shown separately in Figure 2.

The mean values shown in Figure 2 reflect that the SCR installations are consistently emitting NO_x at rates below the applicable emission limits. As explained before, the data shown in Figure 2 may include emissions generated during exempt periods (e.g., startup, shutdown, equipment malfunction, etc.). As emissions during such periods can be higher than those occurring during normal operation, inclusion of such emissions may explain those cases where maximum daily averages are much higher than the corresponding means.

As seen in Figure 2, the new German unit (G-4:A) complying with the limit of 100 mg/m^3, achieved relatively low daily averages. Further, the Swedish unit S-1:A was able to achieve NO_x emission rates that were substantially below the annual average emission limit of 80 mg/MJ. Also the four U.S. units achieved 24-hour averages consistently below 0.17 lbs/mmBtu; three of the four units consistently emitted at rates of 0.15 lbs/mmBtu or lower.

Thirty-Day Rolling Averages

Thirty-day rolling averages were calculated for all of the units for which at least 30 days of continuous data were provided. For each of these units, except US-6, the mean and the range of the 30-day rolling averages experienced are shown in Figure 3.

The 30-day rolling averages in Figure 3 range from 0.06 to 0.18 lbs/mmBtu. Note that nine of the 16 units experienced thirty-day rolling averages at or below 0.15 lbs/mmBtu. The average for the new German unit (G-4:A) was 0.08 lbs/mmBtu and the averages for the five new U.S. units (US-1: A and B, US-2, US-4, and US-5) ranged between 0.06 to 0.16 lbs/mmBtu. As noted previously, unit US-6 is regulated with an emission limit of 1.4 lbs/mmBtu that is much higher that the emission limits for the other units. Hence, this unit achieved 30-day rolling averages below 0.95 lbs/mmBtu for the reported period.

Emission Averages Using U.S. Bituminous Coal F-Factor

U.S. utilities can calculate emission rates using an F-factor based on their actual coal composition or on standard F-factors found in EPA Method 19 (40 CFR Part 60, Appendix A). In order to assess the impact of using calculated F-factors in the analysis of emission rates, a comparison of calculated versus standard F-factors was performed. Figure 4 depicts a comparison between the average NO_x emission rates determined using the calculated F-factors (for 20 units that provided sufficient coal data) and those determined using the Method 19 F-factor for bituminous coal.

As seen in Figure 4, the average NO_x emission rates determined using the calculated F-factors are higher than those determined using the Method 19 F-factor for bituminous coal. Thus by using calculated F-factors, wherever possible, EPA has been conservative in its conversion of NO_x concentration data to rates expressed in lbs/mmBtu.

NO_x Removal Efficiency

Some units provided continuous, contemporaneous pre- and post-SCR NO_x emissions data. Other plants provided pre-SCR NO_x averages. In calculating the NO_x removal efficiencies for the SCR applications, any data points where either pre- or post-SCR emissions were zero were discarded. Data points were also discarded where the pre-SCR emission rate was found to be lower than the contemporaneous post-SCR emission rate. All other emissions, including those occurring during possible exempt periods, were included in the SCR NO_x removal efficiency calculations. Where a range of pre-SCR values was provided, the mean value was used to calculate the corresponding NO_x removal efficiency.

Shown in Figure 5 are the NO_x removal efficiencies being achived at the SCR applications. These efficiencies ranged from 54 percent to 94 percent. The units with relatively lower removal efficiencies (54-79 percent) were the German and the U.S. units with relatively lower pre-SCR NO_x rates (0.32-0.8 lbs/mmBtu). Where pre-SCR rates were higher (greater than 0.8 lbs/mmBtu), the units achieved better than 80 percent removal efficiency.

Four units (G-4: A and the three units at Plant S-1) achieved relatively high NO_x removal efficiencies (85-89 percent) despite low pre-SCR rates (0.40-0.81 lbs/mmBtu). This demonstrates that SCR can reduce low levels of uncontrolled emissions effectively. As noted before, unit G-4: A is required to meet a lower emission limit than the other German units. Plant S-1 appears to be minimizing NO_x emissions below the applicable standard to take advantage of the economic incentive provided in the Swedish regulation. Also of interest is the unit G-9: A, which is characterized by a high pre-SCR NO_x level of 2.03 lbs/mmBtu. The retrofit SCR application at this unit reduces NO_x emissions by 93.6 percent to meet the applicable emission limit.

As seen in Figure 5, in general higher NO_x removal efficiencies need to be achieved by units with higher uncontrolled NO_x emissions. Further, the results suggest that SCR technology is capable of reducing a wide range of uncontrolled emissions (including NO_x emissions in excess of 2.00 lbs/mmBtu) to rates at 0.17 lbs/mmBtu or lower.

Operational Experience

SCR installations were requested to provide information on their SCR-related operational experience. Many of the SCR systems surveyed have been in operation for six or more years and have accumulated significant levels of operating experience. Although some plants experienced problems related to SCR, most have not, and all of the plants that reported problems have successfully resolved them. The following paragraphs discuss the information on operational experience received from SCR applications.

Ammonia Slip and Balance-of-Plant Impacts

At SCR installations, ammonia slip results from the reagent that does not participate in NO_x reduction and instead "slips by" the catalyst. Ammonia slip can react with the sulfur trioxide (SO_3) present in the flue gas to form ammonium salts. In high dust applications, these ammonium salts can increase the potential for air preheater pluggage. Further, excessive ammonia slip can cause flyash contamination and thereby have an adverse impact on flyash marketing. Generally, ammonia slip in an SCR application may be minimized by ensuring that adequate amount of catalyst is provided and that injected ammonia is adequately mixed with the flue gas.

Information on ammonia slip levels were provided by 17 plants for 26 units. Guaranteed slip levels (at the end of catalyst lifetime) are below 5 ppm for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range from

<0.1 ppm to 5 ppm and seven units reported levels of less than 1 ppm. Most of the units that reported ammonia slip information have been in operation for five years or more. These data reflect that ammonia slip levels are being controlled to levels below 5 ppm and that many installations are achieving much lower ammonia slip levels after significant periods of operation.

Air Preheater Impacts. Plants were requested to provide information on air preheater washings related to SCR operation. Many of the plants responded by providing historical information on air preheater washings. Of the 24 units reporting the impact of SCR on air preheaters, only those with high dust configurations reported the need to conduct washing. The frequency of air preheater washing varied from once in a six-to-seven-year period to once each year, except for unit US-6 which has reported many washings of its air preheater since SCR retrofit in 1995. However, unit US-6 noted that excessive ammonia slip occurring due to insufficient bypass damper closing was believed to have caused much of the air preheater fouling that required washing. Initially, Plant US-2 also conducted washings once or twice a month following the SCR operation. However, with the addition of a layer of catalyst in October 1996, the need to conduct frequent air preheater washings has been eliminated at this installation. Considering that annual washing of air preheaters at coal-fired plants is commonly conducted, the results suggest that all of the responding plants did not experience notable increases in air preheater washings resulting from normal SCR operation.

Flyash Contamination. Flyash absorption of any excess, unreacted ammonia (NH_3) released by an SCR system into the treated flue gas is a function of the ammonia slip rate, quantity of flyash, and specific ash characteristics (namely pH, alkali mineral content, and volatile sulfur and chlorine content). At an elevated pH, ammonia in the ash will be released, possibly leading to odorous emissions. Such an occurrence can impact the marketability of flyash. Flyash contamination with ammonia is avoided by designing and operating the SCR system to maintain low levels of ammonia slip.

Plants were requested to provide information related to flyash disposal at their SCR installations. The information received reflects that most of the responding plants sell their flyash and, therefore, flyash contamination is not an issue at these installations. In light of the low ammonia slip levels (less than 5 ppm) being maintained at the SCR installations, this result is not unexpected.

Catalyst Replacement

A need for catalyst replacement arises when catalyst becomes deactivated. Five primary causes of deactivation are: poisoning by arsenic and other chemical poisons, fouling of the surface by flyash or sulfur-related compounds, plugging of flow channels, erosion, and thermal degradation. In general, these deactivation mechanisms are countered by using poison-resistant catalysts, selecting proper catalyst pitches, using appropriate soot blowing cycles, and selecting thermally stable catalyst formulations.

Historical information received from SCR installations on their catalyst replacement cycles

reflects that, in general, a layer of catalyst was replaced/added after 15,000-56,000 hours (or approx. two to seven years) of operation. At Plant G-4B, no problems with catalyst performance were noted after 55,000 operating hours (or approximately six years). These results suggest that catalysts are performing satisfactorily over relatively long operating periods at all of the responding SCR installations.

Findings

The following general observations on NO_x emissions relate to all responding units with the exception of unit US-6 which had an unusually high uncontrolled NO_x emission rate (2.4 - 2.66 lbs/mmBtu) and is at an interim stage of NO_x emission reductions. Thus, when compared to emissions from all of the other units in this paper, the controlled NO_x emission rate for this unit is an outlier.

Many of the SCR systems surveyed have been in operation for six or more years and, thus, have accumulated a significant level of operating experience. In general, more than 200 installations of SCR systems operating on coal-fired boilers worldwide have accumulated an experience base of more than 1700 years.

Using SCR, coal-fired power plants in the U.S. and Europe are achieving average NO_x emission rates between 0.04 lbs/mmBtu and 0.17 lbs/mmBtu. Of the 19 units (including US-6) submitting continuous emissions data, 12 had overall averages at or below 0.15 lbs/mmBtu. Further, Germany, Sweden, and Austria have units that are achieving daily averages consistently below 0.10 lbs/mmBtu. The thirty-day rolling averages for the units surveyed ranged from 0.06 lbs/mmBtu to 0.18 lbs/mmBtu. Nine of the 16 units experienced thirty-day rolling averages at or below 0.15 lbs/mmBtu.

SCR NO_x removal efficiency for plants included in this study varied from 54 percent to 94 percent. As expected, this efficiency appears to depend on the pre-SCR NO_x level and the applicable emission limit. Results reflect that SCR is capable of reducing a wide range of pre-SCR NO_x emissions to rates at 0.17 lbs/mmBtu or lower.

The Swedish plants are emitting NO_x emission rates that are significantly below the applicable regulatory limit. This suggests that the economic incentive provided in the Swedish regulatory system has resulted in NO_x reductions in excess of those that would be available through compliance with the regulatory limit.

Guaranteed ammonia slip levels are below 5 ppm for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range from <0.1 ppm to <5 ppm and seven units reported levels of less than 1 ppm. Most of the units that reported ammonia slip information have been in operation for five years or more. These data show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels, even after significant periods of operation.

Of the 24 units reporting the impact of SCR on air preheaters, only those with high dust

configurations reported the need to conduct washing on a regular basis. At these units, the frequency of washing varied from once in a six-to-seven-year period to once each year. Considering that annual washing of air preheaters at coal-fired plants is commonly conducted, the results suggest that no notable impacts on air preheaters resulted from normal SCR operation.

Most of the SCR installations that provided information on flyash disposal reported that they sell their flyash. This indicates that flyash contamination with ammonia is not an issue at these SCR installations. In light of the low ammonia slip levels being maintained at SCR installations, this result is not unexpected.

Several plants provided historical information on their catalyst replacement cycles. This information indicates that in general a catalyst layer was replaced/added after 15,000-56,000 hours (or approximately two to seven years) of operation. At one plant no problems with catalyst performance were noted after 55,000 operating hours (or approximately seven years). These results suggest that catalysts are performing satisfactorily over relatively long periods of time at all of the responding SCR installations.

References

1. U.S. EPA. *Acid Rain Program Emissions Scorecard 1995.* EPA 430/R-97-009, March 1997.

2. U.S. EPA. *National Air Pollutant Emissions Trends 1900-1994.* EPA 454/R-95-011, October 1995.

3. "Coal Power 2," Worldwide Coal-Fired Power Stations and Their Pollution Control Systems, A Database by IEA Coal Research, 1997.

4. U.S. EPA, Acid Rain Division. *Final Report, Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units, June 25, 1997.*

Table 1

NO_x Emission Limits for the Units Examined in the Study

Country	**Size, MWt**	**NO_x Emission Limit**
United States		0.17 lbs/mmBtu, 0.10 lbs/mmBtu, 1.40 lbs/mmBtu
Austria	>500	200 mg/m^3 (~0.16 lbs/mmBtu)
Denmark	-	400 mg/MJ (0.93 lbs/mmBtu)
Finland	>150	70 mg/MJ (0.16 lbs/mmBtu)
Germany	>300	200 mg/m^3 (~0.16 lbs/mmBtu), 100 mg/m^3 (~0.08 lbs/mmBtu)
Sweden		80 mg/MJ (0.19 lbs/mmBtu) + Economic Incentive

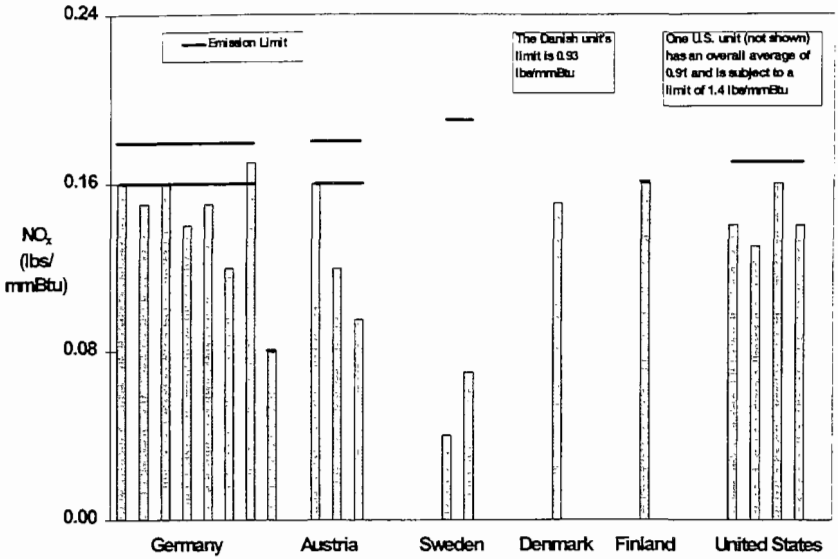

Figure 1. Overall averages of NO_x emissions being achieved at SCR applications.

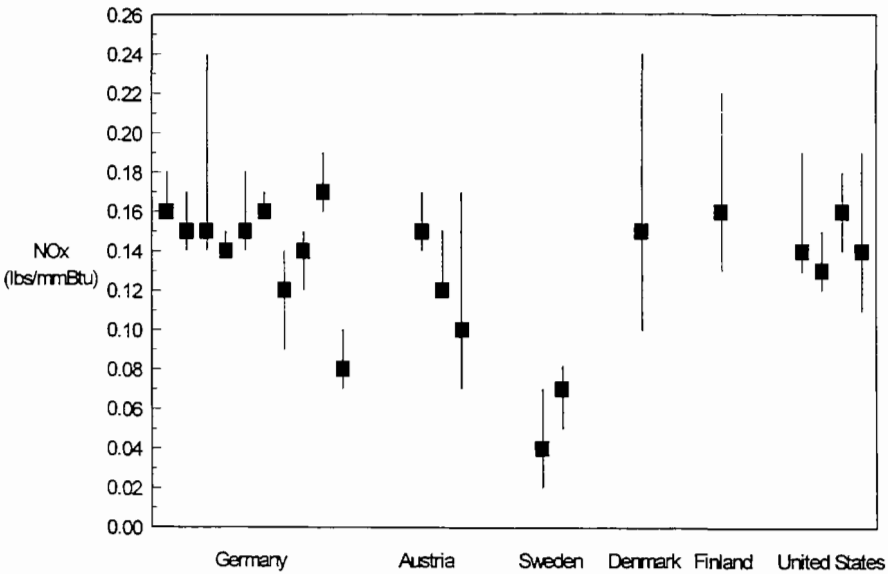

Figure 2. Daily averages of NO_x emissions being achieved at SCR applications.

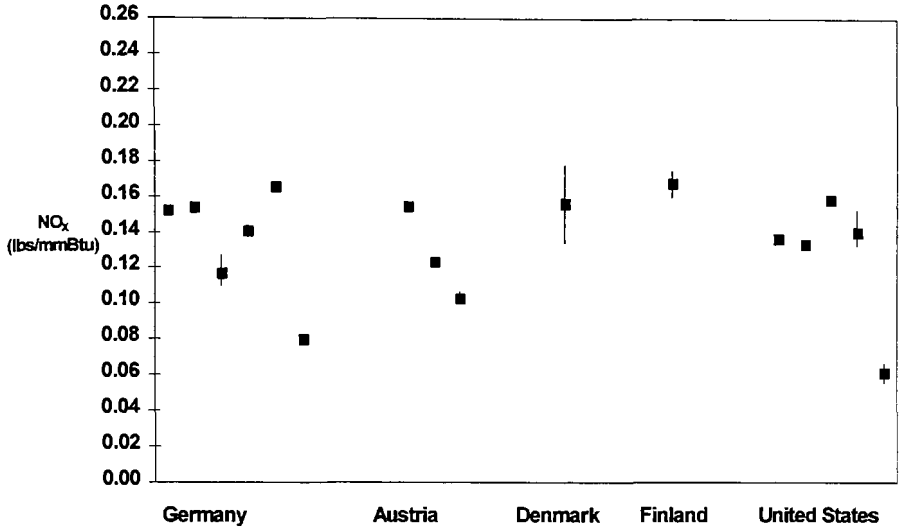

Figure 3. Thirty-day rolling averages of NO_x emissions being achieved at SCR applications.

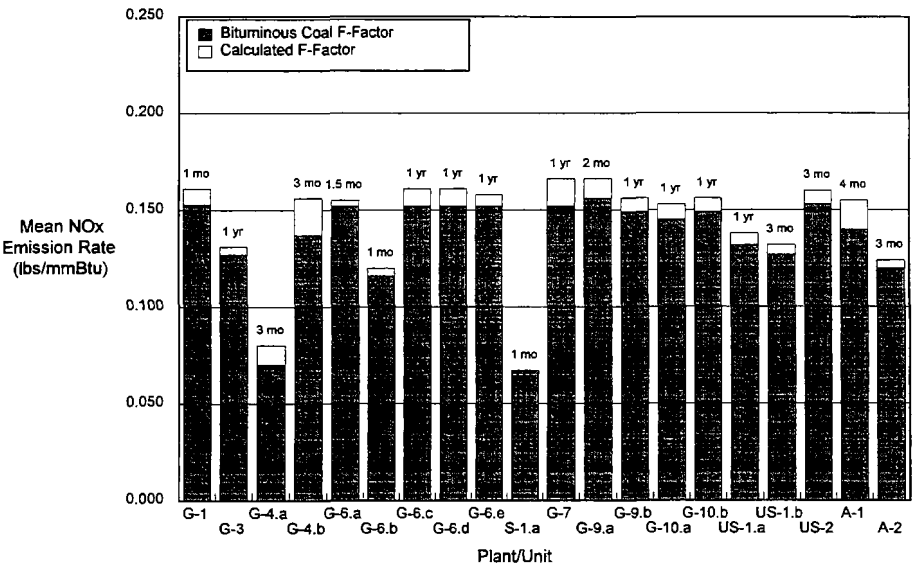

Figure 4. A Comparison of NO_x emissions calculated using alternative F-factors.

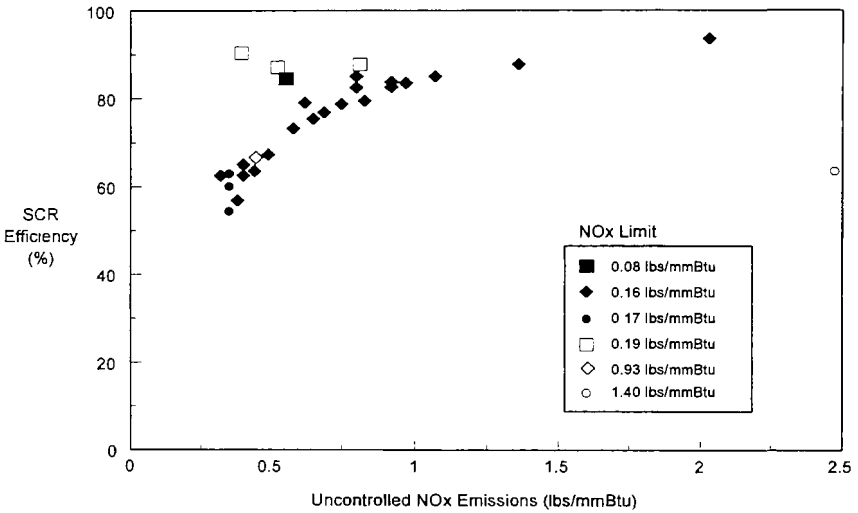

Figure 5. NO_x removal efficiency being achieved at SCR applications.

SCR APPLICATIONS: ADDRESSING COAL CHARACTERISTIC CONCERNS

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Abstract

Concerns exist within the U.S. power plant industry regarding the suitability of SCR application on power plants firing a variety of coals found in this country. Specifically, these concerns relate to impacts of coal characteristics, such as sulfur, alkali, trace elements, etc., on SCR system performance.

This paper presents the results of a study conducted by Bechtel (as a subcontractor to THE CADMUS GROUP, INC.) for the U.S. Environmental Protection Agency to examine the existing coal-fired SCR experience in light of the wide variability in the properties of coals fired in U.S. power plants. As compared to the U.S., considerable SCR experience exists abroad. This paper addresses the key question: Is SCR experience from abroad transferable to U.S. applications?

Introduction

Selective catalytic reduction (SCR) technology has been applied extensively worldwide for NO_x control on coal-fired installations. In the U.S., there now exist seven coal-fired installations utilizing SCR for NO_x control. Because this application base does not cover the wide variety of coals burned in U.S. plants, uncertainties seem to exist regarding SCR system design needs in accommodating the varying characteristics of U.S. coals. In particular, these uncertainties have been linked to coal characteristics, such as high sulfur and ash contents and high concentrations of some trace or toxic elements (e.g., arsenic, alkalis).

The subject of this paper is a study that was undertaken to evaluate the current state-of-the-art SCR technology and its suitability for NO_x reduction in domestic power plants firing a wide variety of U.S. coals[(1)]. The major areas investigated to meet the study objectives include the following:

Characteristics of worldwide SCR installations on coal-fired plants

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- Current SCR design practices and features available for coal-fired applications
- Characteristics of coals fired in the SCR-equipped, worldwide coal-fired plants and their comparison with the characteristics of coals fired in U.S. plants
- SCR experience with fuels other than coal that produce an operating environment comparable to those found in coal-fired installations

The purpose of the above investigations was to evaluate current SCR experience in relation to the concerns associated with the technology's capability to accommodate certain characteristics of coals in general and of U.S. coals in particular. The results of these investigations are summarized below.

Existing Coal-Fired Applications of SCR

The investigations for this study identified at least 212 worldwide SCR installations on coal-fired units. The majority of information on these installations was obtained from a database commercially available from the International Energy Agency[2]. Additional information was obtained from various other sources[1] Of the 212 installations, seven of them are located in the U.S. and the rest in other countries, notably Germany and Japan.

Tables 1 and 2 summarize the information on these 212 SCR-equipped units. While Table 1 covers all SCR units, Table 2 provides key data on the U.S. installations only. The information presented in these tables is analyzed below:

- The coals fired in the SCR installations include lignite and bituminous coals.
- The installations range in size from 13 to 1,050 MW. This range spans the broad range of boiler sizes used in the utility power plants.
- The design NO_x reduction efficiencies for the installations range from 35 to 90 percent. For a large number of these units, this efficiency is 80 percent or higher. Operating data available on some installations show that NO_x reduction has exceeded 90 percent[3,4]
- SCR has been applied to a variety of boilers, including cyclone-fired, pulverized dry-bottom (wall- and tangential-fired), pulverized wet-bottom, and vertical-fired type boilers. These installations span the spectrum of boiler types used in utility power plants.

  Since the above boilers use different combustion processes, coals with varying characteristics must be fired in these boilers. The coals selected for these boilers are based on different requirements associated with certain characteristics, especially the volatile content and ash fusion temperatures.
- Information available on the SCR units also shows that these installations are subjected to a variety of operating modes, which include base-load operation, cycling operation, and ash recycling (for cyclone-fired boilers)[5,6]
- The SCR installations span a variety of applications, including:

- Different SCR reactor arrangements, including high-dust, low-dust, and tail-end type arrangements
- Anhydrous and aqueous ammonia reagents
- Honeycomb and plate type catalysts (pellets used on three units)
- New and retrofit installations

- The seven SCR installations in the U.S. also cover a variety of applications, including:
  - Dry-bottom wall-fired, dry-bottom tangential-fired, cyclone-fired, and pulverized wet-bottom type boilers
  - Plate and honeycomb type catalysts
  - Anhydrous and aqueous ammonia as reagents
  - New and retrofit installations
  - NO_x reduction effectiveness ranging from 47 to 88 percent

In addition to the commercial U.S. SCR installations shown in Table 2, there have been test demonstrations of SCR on coal fired plants. In one of these demonstrations, tests were conducted over a period of two years at Plant Crist where SCR effectiveness was examined with coals containing up to 3 percent sulfur. These tests showed that firing of coals with high-sulfur content had no adverse impacts on catalysts with proper compositions[1]

The overall SCR experience discussed above covers a large number of installations with different types of boilers subjected to varying operating conditions and firing a variety of coals. Some of these installations were designed for and have achieved high NO_x reduction levels, exceeding 90 percent. In general, this experience strongly supports viability of SCR application on coal-fired boilers.

Advances in SCR Design Related to Coal-Fired Applications

Flue gas resulting from coal firing, offers a relatively harsh environment for SCR applications. Based on the extensive European and Japanese SCR experience, the following concerns have been associated with coal firing:

- Deposition of dust on catalyst surfaces resulting in masking of active sites and catalyst pluggage
- Erosion of catalyst due to fly ash impingement
- Deterioration and deactivation of catalyst active sites

The above effects and the mechanisms that cause them are now well understood. The coal properties that can contribute to these problems have been identified. This enhanced know how has resulted in many SCR technology improvements that address coal-related issues. The advances in technology include modifications in catalyst composition and physical properties as well as improved design techniques in other areas of the SCR system[1]

Table 3 summarizes the coal properties important to SCR, potential impacts of these properties, and countermeasures available to mitigate these impacts. The information presented in Table 3 is analyzed below:

- Coal ash, if present in high quantities, can potentially cause deposits on catalyst surfaces, pluggage of catalyst gas passages, and erosion of catalyst. The countermeasures that have been successfully used to combat such problems include use of a proper catalyst pitch (a measure of gas passage opening), use of sootblowers and screens above catalyst layers, use of devices to obtain a uniform flow distribution within the SCR reactor, and provision of a hardened leading edge on catalyst.

- During combustion of coal, the sulfur in coal forms SO_3, which can react with other flue gas components (e.g., CaO) and ammonia (SCR reagent) to form ammonium and calcium salts that have a variety of impacts. Within the reactor, these salts can cause masking of catalyst surface and pluggage of catalyst pores. Downstream of the reactor, SO_3 can react with residual ammonia (ammonia slip) to form sticky ammonium bisulfate that can cause pluggage in air heater surfaces or cause contamination of fly ash collected in particulate control devices, affecting marketability of this ash. SCR can exacerbate the effects of coal sulfur, since the catalyst causes additional SO_3 to be produced by oxidizing a portion of SO_2 present in flue gas.

  Two of the most effective countermeasures used to combat coal sulfur impacts include modifications in catalyst formulation to minimize oxidation of SO_2 to SO_3 and precise control of ammonia slip to low levels (2 to 5 ppm). In the new catalyst formulations, vanadium content is optimized and pore size distribution is designed to maximize small pores, both of which inhibit the SO_2 oxidation rate. A controlled ammonia slip restricts the maximum amount of ammonium bisulfate that can be formed downstream of the reactor (5 ppm of ammonia slip can convert to a maximum of 5 ppm of ammonium bisulfate), thus minimizing problems associated with this sticky substance.

  Other countermeasures against ammonium salts include maintenance of proper flue gas temperatures at the reactor inlet by utilization of an economizer bypass and use of sootblowers to remove any deposits formed on the catalyst surfaces. For high-sulfur coal applications, proper margins can also be added to catalyst volumes to account for the poisoning effects of ammonium salts over the catalyst's operating life.

- Alkaline metals present in coal, especially sodium and potassium, can react directly with the catalyst active sites to reduce the overall number of sites available for adsorption of ammonia and NO_x. However, such catalyst deactivation or poisoning is caused primarily by alkalis in the water-soluble form. Since the majority of alkalis present in coal are not water soluble, this poisoning effect is not a major concern with coal-fired SCR applications[7]

  A countermeasure applied against the above poisoning risk consists of adding proper margins in the catalyst volume to account for any potential catalyst deactivation. Research also shows that, addition of certain metal oxides (e.g., tungsten trioxide) to catalyst formulation, can actually enhance catalyst activity in the presence of alkaline metals[8,9]

- Certain heavy metals present in coal, such as arsenic, lead, and phosphorus, have been cited as catalyst poisons. These are present in coal in extremely small concentrations, and, therefore, are not a major concern. However, in certain German cyclone-fired boiler installations utilizing ash recycling, catalyst poisoning due to arsenic has been experienced. This arsenic poisoning has been traced to enhanced arsenic levels in flue gas, resulting from ash recycling used at these installations. It has been shown that ash recycling enriches the arsenic concentration in flue gas by a factor of 10 to 15[5, 8].

  Arsenic poisoning is caused by gaseous arsenic trioxide, which diffuses into the catalyst and solidifies on both active and non-active sites. Making provisions for an increased catalyst volume to account for the potential loss of catalyst activity with this poisoning is one of the countermeasures available. Arsenic content in flue gas can also be reduced by addition of lime or limestone (sources of CaO) to the coal[5] Another countermeasure is an optimized catalyst pore structure that limits arsenic diffusion into the catalyst. A more direct countermeasure available now is the use of an arsenic-resistant catalyst. In this catalyst, molybdenum oxide is added, which minimizes the loss of catalyst activity caused by the arsenic absorbed on the catalyst surface[5, 8].

- Chlorine is present in coal as organic and/or inorganic chlorides. Chlorides can have both poisoning and promoting effects on catalyst activity. Certain transitional metal chlorides (e.g., CuCl) actually act as strong catalysts. HCl and NH_4Cl can cause catalyst deactivation by removing NH_3 and/or by reacting with active vanadium oxide to form inactive vanadium chloride[9]. At low flue gas temperatures, NH_4Cl deposits may be formed on catalyst active sites.

  Catalyst deactivation from chlorides has not been reported as a significant problem in worldwide SCR installations. It has also been reported that U.S. coals generally carry lower chlorine concentrations as compared to foreign coals[10] The measures that can be used to combat chloride-related effects are the same as those described above for some of the other coal properties. This includes use of wider-pitch catalysts, sootblowers, and proper flue gas temperatures at all operating loads. Similarly, use of an increased catalyst volume to cover potential catalyst deactivation where high chlorides exist is an additional countermeasure.

- Fluorine, present in coal as metal fluorides or as a hydrofluoric acid, can have a potential impact on SCR similar to that associated with chlorine. However, concentrations of fluorine in coal are lower than those of chlorine. Fluorine is, therefore, not considered a significant factor in terms of catalyst poisoning. The countermeasures against possible fluorine impacts are the same as those described for chlorine.

The above analyses show that deactivating effects on SCR of contaminants in coal are well understood and countermeasures are now available to minimize these effects. The SCR suppliers contacted for this study indicated that an effective SCR design can be offered to match a given set of coal characteristics and other site specific conditions. These suppliers are offering SCR for commercial application on coal-fired plants with verifiable performance guarantees.

Applicability of Foreign SCR Experience to U.S. Coal-Fired Applications

A major task of this study was to identify the SCR-related characteristics of coals fired in utility power plants in the U.S. and compare these to the characteristics of coals fired in worldwide SCR installations. In addition, SCR experience with other fuels was reviewed to verify the applicability of this experience to U.S. coals. The information on U.S. coals was obtained from two databases: one available from Department of Energy, Energy Information Agency (DOE/EIA) and the other from U.S. Geological Survey (USGS)[11, 12]

The DOE/EIA database lists key information on coals fired in U.S. utility plants in 1995, including coal mine location, coal tonnage shipped, and coal sulfur, ash, and heat contents. The USGS database contains information on approximately 136 coal parameters from numerous coal mines. This database contains coal sources that fall outside of the range of the coals included in the DOE/EIA database. The coal sources in the USGS database were therefore reduced to match the key parameters in the DOE/EIA database, which included coal mine location and corresponding maximum sulfur and ash contents. While the DOE/EIA database provided the coal sulfur and ash content information, the modified USGS database was the basis for the information on remaining coal characteristics, pertinent to U.S. coals fired in utility power plants.

The information on the characteristics of fuels fired in the worldwide SCR installations was obtained from a variety of sources[2, 7, 13, 14] It should be noted that this information, especially on the coal trace element contents, was available only on a limited number of SCR-equipped units.

To facilitate comparisons between U.S. coals and coals fired in SCR installations, Figures 1 through 12 have been drawn to show the number of plants or coal tonnage fired with varying concentrations of coal constituents pertinent to SCR. Table 4 shows additional information on coals fired in SCR installations. In addition, Table 5 shows SCR installations on fuels containing high sulfur. The comparisons based on the information shown are discussed below:

- For U.S. coals, approximately 96 percent of the plants fire coals with ash content less than 15 percent (Figure 1). The remaining plants fire coals with ash between 15 and 30 percent. This experience is comparable to the coal ash in SCR installations (Figure 2). Approximately 73 percent of these installations fire coals with ash less than 15 percent. The remaining plants fire coals up to 30 percent ash.

- Approximately 58 percent of U.S. plants fire coals with less than 1.0 percent sulfur (Figure 3). An additional 24 percent fire coals with sulfur ranging between 1.0 and 2.0 percent. Only about 6 percent of the plants fire coals exceeding 3 percent. On a weight basis, approximately 85 percent of the coals fired in U.S. plants have sulfur content less than 2 percent (Figure 4). Only 6 percent of coal tonnage fired in U.S. plants has sulfur in excess of 3 percent.

  Of SCR installations, approximately 74 percent fire coals with up to 1.0 percent sulfur, 22 percent fire coals with sulfur between 1.0 and 2.0 percent, and 4 percent fire coals with sulfur between 2.0 and 3.0 percent (Figure 5). These data show that the majority of coals (94

percent) fired in U.S. plants (both on number of plants or weight basis) have less than 3.0 percent sulfur and that the existing SCR experience covers this range of coal sulfur.

SCR experience on high-sulfur applications is also evident from installations firing high-sulfur fuels other than coal (Table 5). One of these installations fires asphaltum with a 5.4 percent sulfur content, which is greater than the maximum sulfur content of U.S. coals. Such experience is considered applicable to coal firing, since ashphaltum contains relatively high amounts of vanadium (200 ppm), which promotes conversion of SO_2 to SO_3, resulting in a higher SO_3 concentration. This fuel, therefore, generates a harsher environment for SCR, compared to coal.

- The average arsenic content (89 percent) of the majority of U.S. coals on a weight basis falls below 20 ppm (Figure 6). The remaining coals have arsenic levels up to 30 ppm. In comparison, significantly higher arsenic levels of up to approximately 300 ppm have been reported for coals fired in SCR installations (Table 4).

- For U.S. coals, up to 1,000 ppm of chlorine concentrations have been reported (Figure 7). The maximum chlorine concentration reported for SCR installation coals is 1,900 ppm, which is higher than that for U.S. coals (Table 4).

- For U.S. coals, up to 305 ppm of fluorine concentration has been reported (Figure 8). However, for approximately 97 percent of these coals on a weight basis, fluorine is limited to 150 ppm. The fluorine concentration reported for SCR installation coals at 47 to 270 ppm is comparable to that for U.S. coals (Table 4).

- A major portion (89 percent) of U.S. coals on a weight basis contains ash with Na_2O ranging between 0 and 2.0 percent (Figure 9). Ash in the remaining coals (11 percent) has 2 to 5 percent of Na_2O. The maximum Na_2O reported in ash of coals fired in SCR installations is 1.6 percent, which is comparable to the concentration reported for the majority of U.S. coals (Table 4).

- U.S. coals have ash with K_2O ranging from 0 to 2.6 percent (Figure 10). In contrast, ash in SCR installation coals has higher K_2O concentrations, ranging between 0.1 to 5.0 percent (Table 4).

- For the majority (98 percent) of U.S. coals on a weight basis, P_2O_5 in ash varies between 0 and 1.0 percent (Figure 11). For less than 2.0 percent of these coals, the reported P_2O_5 level is 1.7 percent. Ash in the SCR installation coals is reported to contain between 0 and 1.3 percent of P_2O_5, which is comparable to the experience with U.S. coals (Table 4).

- The U.S. coals have ash containing between 0 and 25 percent of CaO (Figure 12). The maximum CaO in the ash of SCR installation coals is comparable at 26 percent (Table 4).

The above comparisons show that the characteristics of coals fired in SCR installations have properties that are comparable to the properties of coals fired in the U.S. power plants. Even in the case of Na_2O and P_2O_5 where the SCR installation coals have slightly lower concentrations, the difference is not significant. The experience from existing SCR installations is, therefore, directly applicable to applications firing U.S. coals.

Conclusions

Based on the investigations in this study, the conclusion reached is that SCR technology has been successfully applied to a large number of coal-fired boilers and that this experience supports the feasibility of this technology for application on boilers firing U.S. coals. In addition to this extensive experience with existing coal-fired applications, the following factors contributed to this conclusion:

- The issues involved with coal-firing impacts on SCR components, mainly catalyst, are well understood. The coal constituents, such as sulfur, ash, and arsenic, that can cause deactivation of catalyst, if present in large amounts, have been identified. The mechanisms of such deactivation are known and counteracting measures have been developed.

- The characteristics of coals fired in U.S. boilers do not differ significantly from the coals being burned in existing worldwide SCR installations. Based on a comparison with limited data available for the coals fired in SCR installations, the key constituents for the majority of U.S. coals are at levels similar to those for the coals from SCR installations.

- Only 6 percent of U.S. coals has a sulfur content greater than 3 percent. There are SCR installations firing coals with a sulfur content of 3 percent or slightly higher. In addition, SCR has been successfully applied to other high-sulfur fuels, one of them being an asphaltum-burning installation in Japan with a sulfur content of 5.4 percent (greater than that of any U.S. coal).

- Some of the important trace elements (arsenic, chlorine, fluorine, etc.) are present in higher concentrations in the coals being burned in the foreign SCR installations, as compared to U.S. coals. For some other trace elements (Na_2O and P_2O_5) , the concentrations in coals being burned in foreign SCR installations are somewhat smaller. However, these trace elements are considered weak poisons for SCR catalysts and the experience to date does not list them as significant considerations for SCR.

- The SCR suppliers are aggressively marketing this technology for coal-fired applications. The suppliers contacted for this study consider this technology to be fully commercial and have shown their willingness to offer guaranteeable performance for SCR systems on boilers firing any U.S. coals.

In summary, considerable experience has been gained to date from coal-fired SCR installations in the U.S. and abroad. This experience adequately covers the operating conditions that can be expected to be present when burning the coals fired in U.S. power plants.

Disclaimer

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Table 1
SCR System Characteristics for Worldwide Installations

SCR Characteristic	SCR Experience[2]
Coal type fired	Bituminous and lignite
Unit size range, MW	13 - 1,050
NO_x reduction efficiency, %	35 - 90
Number of SCR units:	
• With different boiler types[1]:	
Cyclone-fired	19
Pulverized-coal, dry bottom	130
Pulverized-coal, wet bottom	44
Vertical-fired	6
Pressurized, fluidized-bed	3
• In different countries:	
Germany	121
Other European countries	38
Japan	42
Taiwan	4
U.S.	7
• With different types of SCR:	
High dust	120
Low dust	30
Tail end	43
• With different reagents:	
Anhydrous	173
Aqueous	13
• With different types of catalyst:	
Honeycomb	106
Plate	54
Pellets	3
• With different types of installations:	
New	54
Retrofit	156

Notes:

1. The dry-bottom boilers include tangential-fired, front wall-fired, and opposed wall-fired boilers.
2. For some units, all of the information shown in this table was not available.

Table 2
SCR Installations in the U.S.

Description	Birchwood	Carneys Point	Indiantown	Logan	Mercer Unit 2	Merrimack Unit 2	Stanton Unit 2
Location	Virginia	New Jersey	Florida	New Jersey	New Jersey	New Hampshire	Florida
Boiler type	PC-TF	PC-WF	PC-WF	PC-WF	Wet-bottom	Cyclone-fired	PC-WF
Unit capacity, MW	240	2 x 140	330	200	321	375	465
Type of installation	New	New	New	New	Retrofit	Retrofit	New
SCR location	High-dust	High-dust	High-dust	High-dust	High-dust	High-dust	High-dust
Catalyst type	Plate	Honeycomb	Plate	Plate	Plate	Plate	Plate
Reagent: NH_3 type	Anhydrous	Aqueous	Aqueous	Aqueous	Aqueous	Anhydrous	Anhydrous
SCR supplier	ABB	FW	FW	FW	Wahlco	Noëll	Noell
NO_x reduction, %	50-70	63	60	63	88	65	47

Notes:

1. The legends used are as follows: PC-WF - Pulverized coal wall-fired; PC-TF - Pulverized Coal tangential-fired; FW - Foster Wheeler

2. At Mercer, the catalyst is an in-duct type. Tests were also conducted on a combination of the in-duct catalyst and catalyzed air heater baskets achieving a NO_x reduction efficiency of 95 percent.

Table 3
SCR-Related Fuel Properties, Their Impacts, And Solutions

Fuel Property	Potential Impacts	Solutions
Ash	• Catalyst pluggage • Surface deposits • Erosion	• Use proper catalyst pitch • Use sootblowers • Use screens above catalyst to collect popcorn ash • Design SCR reactor for a uniform flow distribution (use flow straightening devices) • Use catalyst with hardened leading edges
Sulfur (SO_3)[1]	• Catalyst surface masking • Catalyst pluggage • Oxidation of SO_2 to SO_3 • Air heater pluggage • Fly ash contamination	• Use optimized pore structure (maximize small pores) • Use sootblowers • Minimize catalyst's vanadium content to minimize SO_2 oxidation • Minimize ammonia slip • Provide proper catalyst volume • Use economizer bypass to maintain proper gas temperatures
Alkaline Metals (Na and K)[2]	Reduction in available catalyst active sites	• Provide proper catalyst volume • Modify catalyst composition (add tungsten)
Alkaline Earth Metal (Ca)[2]	Catalyst surface masking	• Provide proper catalyst volume • Use sootblowers
Heavy Metals (As)[2]	Catalyst surface masking	• Provide proper catalyst volume • Use optimized pore structure • Use arsenic-resistant catalyst
Chlorine/ Fluorine	Catalyst surface masking	• Provide proper catalyst volume • Use sootblowers • Use economizer bypass to maintain proper gas temperatures

Notes:

1. During combustion, sulfur in coal oxidizes to SO_2 and a small quantity of SO_3. The potential impacts listed for sulfur are caused by SO_3. The catalyst forms additional SO_3 within the SCR reactor by further oxidation of a small portion of SO_2.

2. Other potential catalyst poisons include magnesium, lead, and phosphorus. These are not considered important for SCR, since their concentrations in coal are small.

Table 4
Properties of Coals Fired in SCR Installations

Coal Analysis	Range
Trace metal, ppm:	
Arsenic	2 - <301
Chlorine	40 - 1,900
Fluorine	47 - 270
Ash analysis, wt. %:	
SiO_2	33.9 - 76.7
Al_2O_3	2.0 - 33.0
Fe_2O_3	0.83 - 15.4
TiO_2	0.55 - 1.8
CaO	0.11 - 26
MgO	0.07 - 49
Na_2O	.05 - 1.6
K_2O	0.1 - 5.0
P_2O_5	0 - 1.3

TABLE 5
SCR EXPERIENCE WITH 'HIGH SULFUR' FUEL-FIRED BOILERS

Facility	Size	% Sulfur	Fuel	Year of Ope	Comments
Herne IV (Germany)	500 MW	>3%	Coal	1989	No corrosion or plugging observed since 1989.
Walsum 9 (Germany)	450 MW	>3%	Coal	1988	New Plant: 70% NO_x removal. Only two air heater washings
Shimoneseki (Japan)	175 MW	3%	Coal and Oil	1980	The facility cofires coal and heavy oil.
Asahi Chemical Co. (Japan)	2x80 tph Steam	5.4%	Asphal-tum	1983	The fuel has about 200 ppm of vanadium; and 0.6% nitrogen.
Industrial Facility (Japan)		2.62%	Orimul-sion		The fuel has about 250 ppm of vanadium; and 28-29% H_2O.
Chubu Electric Power (Japan)	2x375	2.5%	Heavy Oil	1987	The fuel has about 36 ppm of vanadium.
Higashi Nippon Tetsudo (Japan)	125 MW	3.0%	Heavy Oil	1982	Contains vanadium.
Takehara (Japan)	250 MW	2.5%	Coal	1981	No corrosion, plugging or other problems reported.
Plant Crist, Gulf Power (DOE Demons.)	Slip Stream	3.0%	US Coals	1993	Two-year tests with coal containing up to 3.02% sulfur.

FIGURE 1
ASH IN COALS VERSUS NUMBER OF U.S. COAL-FIRED PLANTS

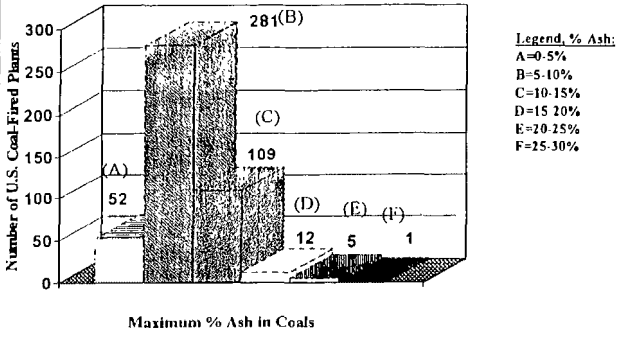


FIGURE 2
ASH IN COALS VERSUS NUMBER OF SCR-EQUIPPED COAL-FIRED UNITS

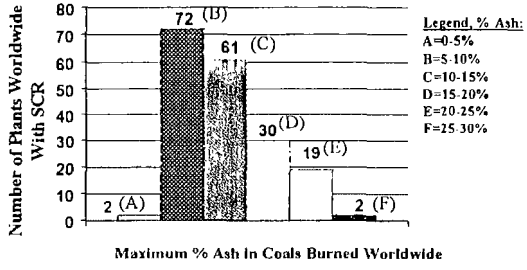


FIGURE 3
SULFUR IN COALS VERSUS NUMBER OF U.S. COAL-FIRED PLANTS

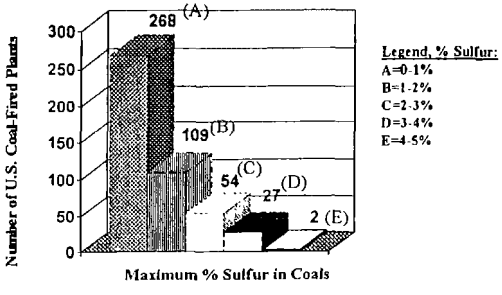


FIGURE 4
SULFUR IN COALS VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

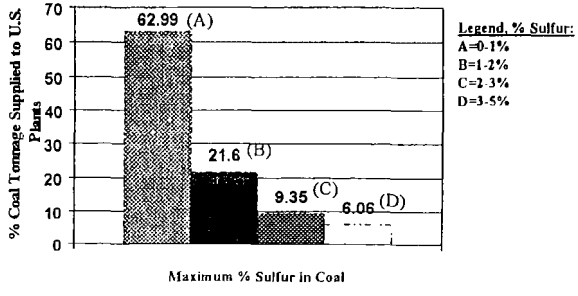


FIGURE 5
SULFUR IN COALS VERSUS NUMBER OF SCR-EQUIPPED COAL-FIRED UNITS

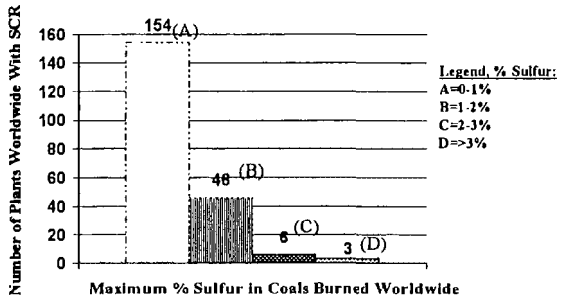


FIGURE 6
ARSENIC IN COALS VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

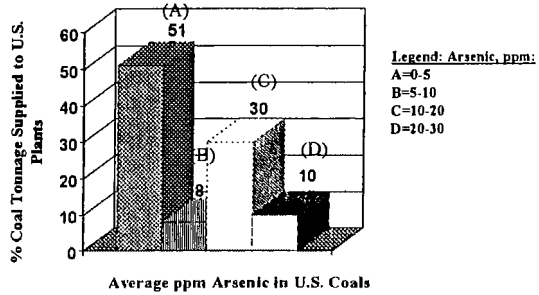


FIGURE 7
CHLORINE IN COALS VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

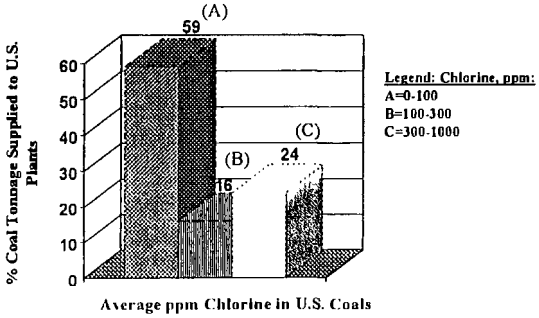


FIGURE 8
FLUORINE IN COAL VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

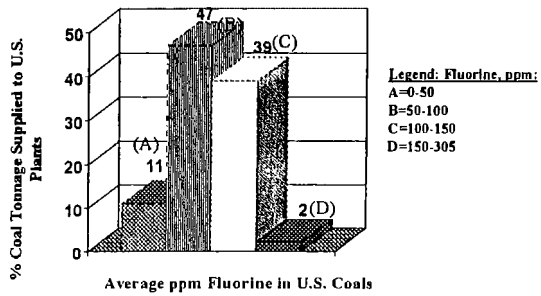


FIGURE 9
Na_2O IN ASH VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

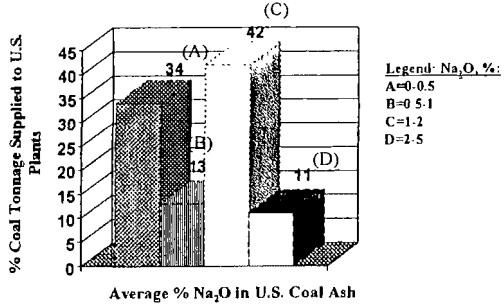


FIGURE 10
K_2O IN ASH VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

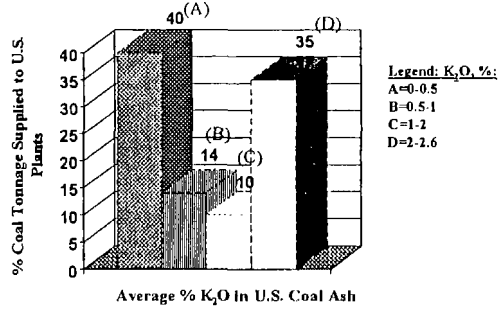


FIGURE 11
P_2O_5 IN ASH VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS

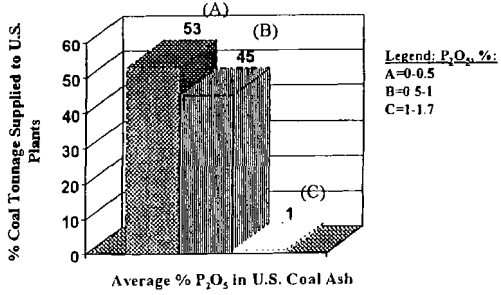
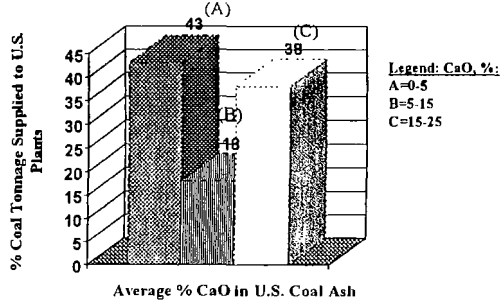


FIGURE 12
% CaO IN ASH VERSUS COAL TONNAGE SUPPLIED TO U.S. PLANTS



SELECTIVE CATALYTIC REDUCTION (SCR) RETROFIT AT SAN DIEGO GAS & ELECTRIC COMPANY SOUTH BAY GENERATING STATION

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Abstract

San Diego Gas & Electric (SDG&E) retrofitted South Bay Generating Station Unit 1 with selective catalytic reduction (SCR) technology to comply with San Diego County Air Pollution Control District (SDCAPCD) Rule 69 which regulates NO_x emissions. South Bay Unit 1 is a 154 MW gas/oil fired B&W radiant boiler of late 1950s vintage. The SCR project also included an aqueous ammonia storage and delivery system and SCR controls integrated in a recently installed Distributed Control System (DCS). This paper discusses significant aspects of the technical and economic evaluation, design, installation, and operational characteristics of this NO_x compliance project. A preview of SDG&E's compliance programs for South Bay and Encina Generating Station is also presented.

Compliance With Rule 69

NO_x emissions reduction Rule 69 was adopted by the San Diego County Air Pollution Control District (SDCAPCD) Board in January 1994 to meet California Clean Air Act requirements for Best Available Retrofit Control Technology (BARCT) for electrical generating steam boilers. A Compliance Plan was submitted to the SDCAPCD in July 1994, and updated in July, 1995 and July, 1996.

On December 12, 1995, SDCAPCD adopted amendments to Rule 69. The amendments eliminated the individual unit emission rate limits, retained the two aggregate annual NO_x emission caps and added a third cap. The current Rule 69 NO_x aggregate annual cap for all SDG&E units is:

January 1, 1997 to December 31, 2000..... 2100 tons/year

January 1, 2001 to December 31, 2004..... 800 tons/year

January 1, 2005 ..... 650 tons/year

Rule 69 also requires each unit to be operated at its maximum performance for NO_x reduction. For South Bay Unit 1 with the new SCR, SDCAPCD requires a NO_x limit of 20 ppmv when firing natural gas and 40 ppmv when firing No. 6 fuel oil averaged over each 24 hour calendar day of operation or portion thereof, excluding startup and shutdown.

Prior to Rule 69, NO_x emission limits were governed by SDCAPCD Rule 68 limits that represented Reasonable Available Control Technology (RACT). Rule 68 NO_x limits are as follows:

Natural Gas Fuel ..... 125 ppm

Oil Fuel ..... 225 ppm

NO_x Compliance Strategy

Compliance with San Diego County Air Pollution Control District (SDCAPCD) Rule 69 required an overall systems analysis of the operating units within SDG&E's generation system. The systems analysis was comprised of the following steps:

Design Basis Development - For each unit, an emissions data base was developed and target emission levels were established based on unit capacity factor, availability, and contribution to the overall system emissions cap.

Screening of NO_x Control Technologies - Identify candidate NO_x control/removal technologies and their current status in the industry. NO_x control technologies considered included the following:

a. Combustion Modification, Low NO_x Burners, Over Fire Air (OFA), Flue Gas Recirculation (FGR)

b. Selective Non-Catalytic Reduction

c. Partial Selective Catalytic Reduction

d. Combinations of Above

e. Selective Catalytic Reduction

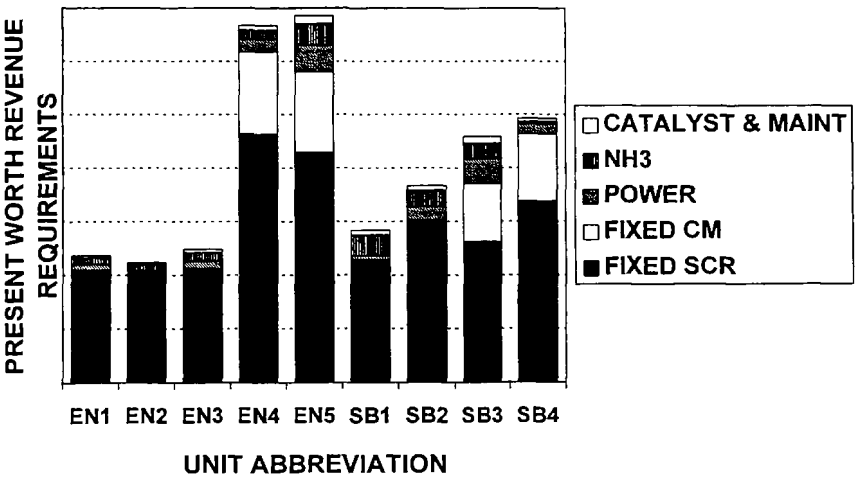
Technologies were then screened based on performance, constructibility, schedule, and economics.

Determine Performance and Plant Impacts - For each unit and the selected technology, the emission performance and boiler performance impacts were determined. Process flow diagrams and layout drawings for selected technologies were also developed to assist in evaluating these impacts and in development of total installed costs.

Economic Comparison - The economic analysis performed was based on the present worth of revenue requirements (PWRR) methodology. PWRR requires a projection of all costs associated with each technology over the service life, including capital costs, operating and maintenance costs (reagent, catalyst replacement, labor, and power) which are then converted to present worth over the selected life of the installation. The PWRR of the selected technologies for each unit are shown on Figure 1. Cost effectiveness was then evaluated on the basis of cost per ton of NO_x removed, as shown on Figure 2. This measure represents the PWRR divided by the tons of NO_x removed over the service life and is designed to show which projects have the most removal at the lowest evaluated cost. The results are strongly influenced by the capacity factor (CF); the units with the highest CF generally have the lower control costs.

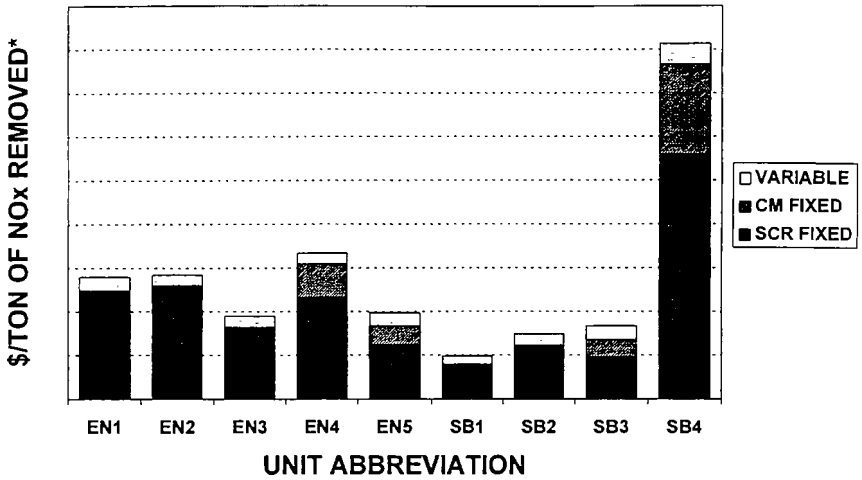
Risk Analysis - This analysis considered certain intangibles, such as capability for higher NO_x removal and ease of permitting; cost sensitivities such as catalyst cost fluctuations, space velocity and projected catalyst life; and risk evaluations with respect to performance, initial capital cost and levelized cost.

Based on the system-wide analysis, economic evaluation, and an assessment of risk and cost sensitivities, the decision was made to proceed with SCR on Units 1 and 2 at South Bay. Unit 1 was targeted for an in-service date of February 1997, with Unit 2 to follow in 2000.



* SCR ONLY AT EN 1-3; SB 1,2 // SCR & LNB AT EN 4,5 // SCR & LNB & OFA & FGR AT SB 3,4

FIGURE 1 PWRR COMPARISON BY UNIT (MINIMUM REQUIRED EQUIPMENT*)



*ALL UNITS ON A CONSISTENT TIME BASIS: 20 YEAR SERVICE LIFE.
= PRESENT WORTH OF REV REQ DIVIDED BY TOTAL TONS OF NOx REMOVED OVER LIFE

FIGURE 2 PRESENT WORTH CONTROL COST COMPARISON*

Project Organization

The organization of the project is illustrated in Figure 3. SDG&E acted as the overall project coordinator, including taking the lead on licensing/permitting issues and interfacing with station operating and maintenance personnel.

Raytheon Engineers and Constructors (Raytheon) in Denver, Colorado, provided support in the development of the NO_x compliance strategy and economic evaluations, design and engineering services, administration of contracts, and construction management services.

Babcock & Wilcox (B&W) in Barberton, Ohio had turnkey responsibility for the SCR and Ammonia Systems. Other separate contracts included 1) asbestos abatement, 2) DCS modifications (Duke Engineering Services), 3) CEMS upgrades (Control Technology, Inc.), and 4) balance of plant electrical work (Davies Electric).

SCR Process Overview

Selective catalytic reduction (SCR) is a highly effective method of post-combustion NO_x control when high levels of NO_x reduction are required or when low NO_x emission levels at the stack must be attained. SCR is a dry process in which ammonia (NH_3) in vapor form is injected into the flue gas stream upstream of the SCR catalyst layer as shown in Figure 4.

The ammonia acts as a reducing agent, and the NO_x contained in the flue gas decomposes into nitrogen and water vapor in the presence of the SCR catalyst. The catalyst is typically

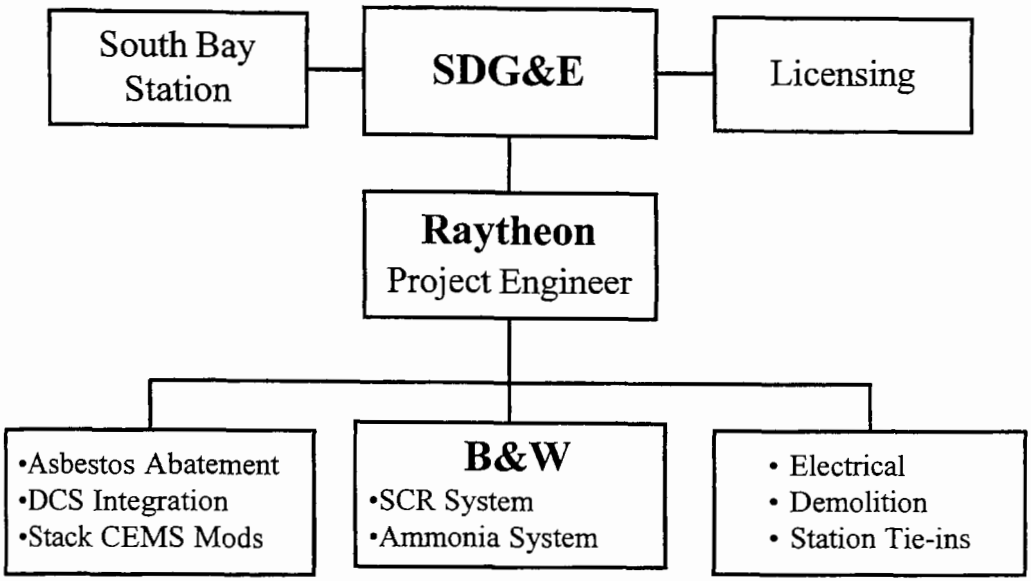


FIGURE 3 SCR IMPLEMENTATION

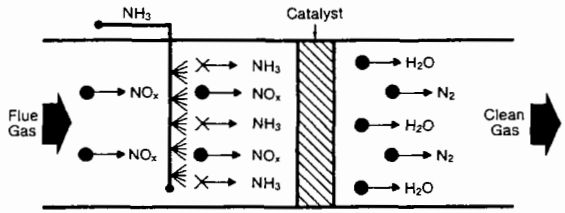


FIGURE 4 PRINCIPLES OF NO_X REMOVAL PROCESS FOR SCR

a titanium-based material with a micropore surface which provides many active sites for the NO_x reduction to occur. Several reactions between the ammonia and NO and NO_2 compounds can occur in the SCR process:

$$4NO + 4NH_3 + O_2 \text{----->} 4N_2 + 6H_2O$$

$$6NO_2 + 8NH_3 \text{----->} 7N_2 + 12H_2O$$

$$NO + NO_2 + 2NH_3 \text{---->} 2N_2 + 3H_2O$$

Most SCRs operate within a temperature range of 450 to 840°F (232 to 449°C), with optimum performance for natural gas firing occurring in the range of 650 to 750°F (343 to 399°C). Minimum SCR operating temperature varies based upon fuel type, flue gas compo-

sition (including SO_2) and catalyst formulation, and is key to SCR system performance. The catalyst layer must be located strategically in the boiler gas train for proper temperature exposure and minimum pressure drop.

South Bay Unit 1

South Bay Unit 1 is a 154 MWe gross, pressure fired, B&W El Paso design, radiant boiler with natural circulation. The primary fuel is natural gas with No. 6 fuel oil as backup. There are eight (8) front wall mounted burners arranged in two (2) rows of four (4) burners each. Flue gas recirculation is taken from the economizer hopper. The back-end arrangement is parallel flow upward to two (2) vertical shaft, Ljungstrom type, regenerative air preheaters. Rated steam flow is 980,000 lb/hr at 2,150 psig and 1005° F / 1005° F steam temperatures.

SCR Design Basis

Specifications for design of the SCR system required meeting performance criteria while firing either natural gas or No. 6 fuel oil. Key conditions for the SCR design basis and performance are shown in Table 1.

Table 1

SCR System Design Basis/Performance Conditions

Item		Design Conditions	
Fuel		Natural Gas	No. 6 Oil
Flue Gas Parameters			
Flow Rate	acfm[1]	646,924	627,406
Temperature	°F	709	701
Composition at SCR Inlet			
NO_x	ppmdv[2]	150	225
O_2	% Volume[1]	1.80	2.30
SO_2	ppmwv[1]	—	200
SO_3 Increase	%	—	3.5
H_2O	% Volume[1]	18.52	11.81
Composition at SCR Outlet			
NO_x	ppmdv[2]	15	33
NH_3	ppmdv[2]	10	2
$DeNO_x$ Efficiency	%	90	85.3
Maximum Allowable			
Pressure Drop Increase	in.wg	3	3
Minimum Flue Gas Temp.	°F.	500	570

[1] Wet basis. [2] Dry volume basis corrected to 3% O_2.

Flow Model Testing

SCR performance can be significantly affected by nonuniform flow into the catalyst. Therefore, catalyst manufacturers normally specify a maximum allowable nonuniformity of flue gas velocity as a condition of guarantee. Additionally, the project specification limited the allowable increase in system resistance to 3 in. wg. To satisfy these requirements a 1/10 scale cold flow model study was performed. The ammonia injection grids are immediately downstream of the gas recirculation (GR) fan take-off and possible recirculation of flue gas back to the GR fan was a concern. The study simulated four different boiler loads for each fuel and considered the effects of a possible 60/40 side-to-side maldistribution of flue gas flow from the boiler. Iterative testing determined the optimum number and location of flow correction devices necessary for the required uniformity of velocity and also confirmed that recirculation from the injection grids back to the GR fan would not be a problem. After an acceptable uniform model flow was established, a tracer gas was used to confirm that the ammonia injection grid design would provide satisfactory uniform distribution of ammonia into the flue gas stream. As a result of the model test, flow corrective devices consisting of splitter plates and perforated plates were added to the SCR inlet duct design as shown in Figure 5.

SCR System Arrangement and Components

The SCR system consists of several subsystems including the SCR reactor and ducting, catalyst, ammonia vaporization / flow control skid, ammonia distribution manifolds and injection grids, an aqueous ammonia storage system, flue gas analyzers and a control module in the DCS. Auxiliary equipment includes atomizing air compressors, dilution air fans, interconnecting piping, system instrumentation, electrical power distribution equipment and a tie to the existing plant uninterruptable power supply.

From parallel economizer outlets, the flue gas flows through parallel ducts into two low pressure ammonia injection grids which are designed for optimal mixing of ammonia and flue gas with minimal system resistance. The ammonia laden flue gas continues on into a single reactor where it passes through a bed of parallel plate-type catalyst. Within the catalyst bed the NO_x reacts with the ammonia to form nitrogen and water vapor. After exiting the reactor, the flue gas splits to pass through the parallel regenerative air heaters before being discharged up the stack.

A simplified arrangement is shown in Figure 5.

SCR Reactor and Catalyst

A single reactor, arranged within the existing boiler structure, houses a single-stage, parallel passage, horizontal flow bed of Babcock-Hitachi, titanium-based, plate-type catalyst. Other catalysts were also considered. For this arrangement, pressure drop and cross-section were critical and the plate-type catalyst offered the best solution for meeting performance

requirements in a compact setting while minimizing pressure drop. The catalyst is contained in 28 blocks in a 4 high by 7 wide by 1 deep arrangement that measures approximately 12 feet high by 44 feet wide by 6 feet deep.

The reactor is self-supporting and is constructed of structurally reinforced carbon steel casing which is externally insulated. Personnel access doors and a removable catalyst maintenance panel provide access to the interior. One monorail mounted, 3-ton electric hoist is used to move catalyst blocks in and out of the reactor, while a second hoist is used to position blocks within the catalyst bed. Seals are installed around the perimeter of the catalyst bed to prevent flue gas from by-passing the catalyst.

Ammonia Vaporization and Flow Control

Aqueous ammonia, at 29.4% concentration, is supplied at high pressure to the skid mounted flow control system by a common plant header. A pressure regulating valve provides ammonia flow at constant pressure to a pneumatically actuated flow control

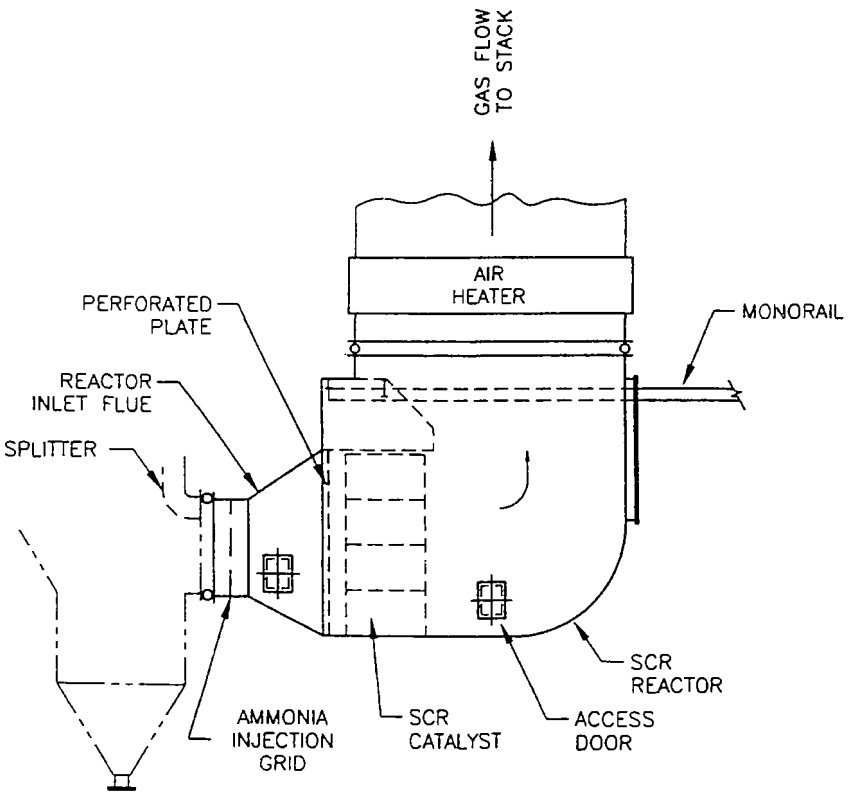


FIGURE 5 SCR SYSTEM SIDE VIEW

valve which is controlled by a signal from the DCS. Downstream of the flow control valve, the ammonia is injected into the vaporizer through a dual-fluid atomizer utilizing compressed air for atomization. Due to a shortage of plant compressed air, atomizing air is provided by stand-alone compressors dedicated to SCR service. In the vaporizer the liquid ammonia is mixed with a hot air stream and is thereby vaporized and diluted to a safe concentration. The hot air used for vaporization and dilution is extracted from the boiler's hot secondary air ducts and pressure is boosted by one of two skid mounted fans. The vaporization system is designed to maintain a minimum ammonia / air temperature of 180°F (82°C) to avoid condensation prior to injection into the flue gas. From the vaporizer, the dilute ammonia/air mixture is conveyed through insulated ducting to the ammonia / air injection system.

Ammonia/Air Injection System

The ammonia / air injection system is comprised of an external manifold / valve station and four internal injection grids. The ammonia / air mixture is ducted from the vaporizer to the manifold / valve station where the total flow is apportioned to 14 independently controlled branches. Two grids, one horizontal and one vertical, are located in each of the parallel ducts exiting the economizer hopper. Each of the grids is divided into separate branches which sub-divide the flue gas duct into separately controllable zones. In this manner, the total flow of ammonia may be distributed across the flue gas ducts to ensure optimum SCR performance. A simplified arrangement of the internal grids is shown in Figure 6.

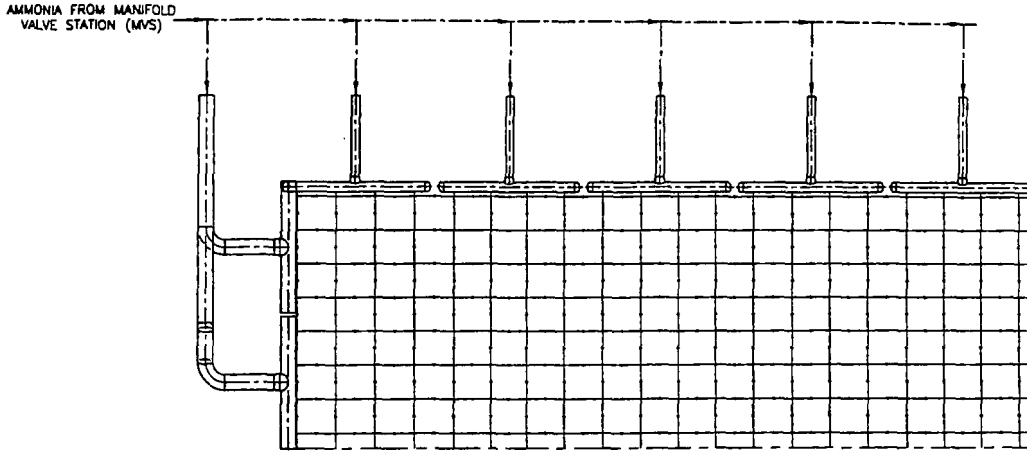


FIGURE 6 SIMPLIFIED INTER INJECTION GRIDS

Aqueous Ammonia Storage System

The selected reagent for the SCR is industrial grade aqueous ammonia at 29.4 % concentration. The aqueous ammonia storage and delivery system was designed to handle current requirements for Unit 1 along with future requirements for Units 2 and 3. The arrangement provides for a total of three (3) carbon steel storage tanks (two current and one future) at 22,500 gallons each. Total storage capacity is approximately 30 days usage for all three units. The storage tanks are above ground and are surrounded by a concrete berm. All ammonia deliveries are by truck. The truck unloading area is outside of, and adjacent to the tank area. The truck unloading pad is equipped with a catch basin and drain line which would divert any leakage from a truck into a large sump located within the berm. All interconnecting piping and the supply pumps are located inside the berm while controls are located outside. Emergency showers are located both inside and outside the berm. An ammonia detector is centrally located within the tank area for both local and remote alarm to the control room.

Two 100% capacity supply pumps in the tank area maintain a constant recirculation feed loop through the storage tanks. This loop supplies a flow to a single supply line which feeds a common plant header. The single supply line is equipped with its own electronic leak detection system. In turn, the common plant header supplies aqueous ammonia to Units 1, 2 and 3. Flow to each unit is independently controlled from this common header.

In an emergency situation, the ammonia supply system can be remotely shut down from the control room. Otherwise, essentially all controls are local to the storage tank area.

A schematic of the ammonia storage and supply system is depicted in Figure 7.

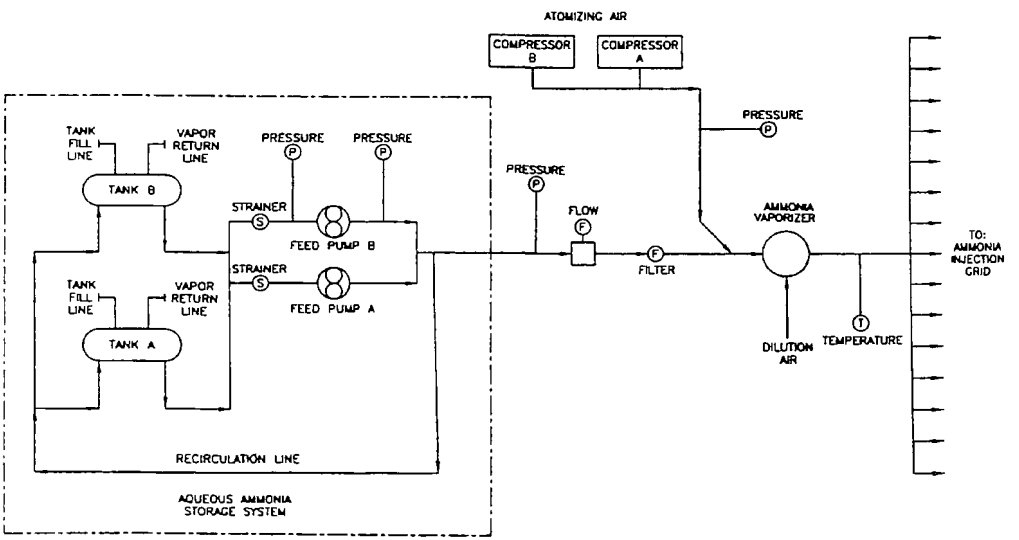


FIGURE 7 AMMONIA STORAGE AND SUPPLY SYSTEM SCHEMATIC

Control Systems

Figure 8 illustrates the basic controls setup and the coordination required to integrate the SCR and Ammonia Systems into the Unit 1 & 2 Distributed Control System (DCS), which is a Bailey Infi 90, as well as tie-ins to other control systems at the station.

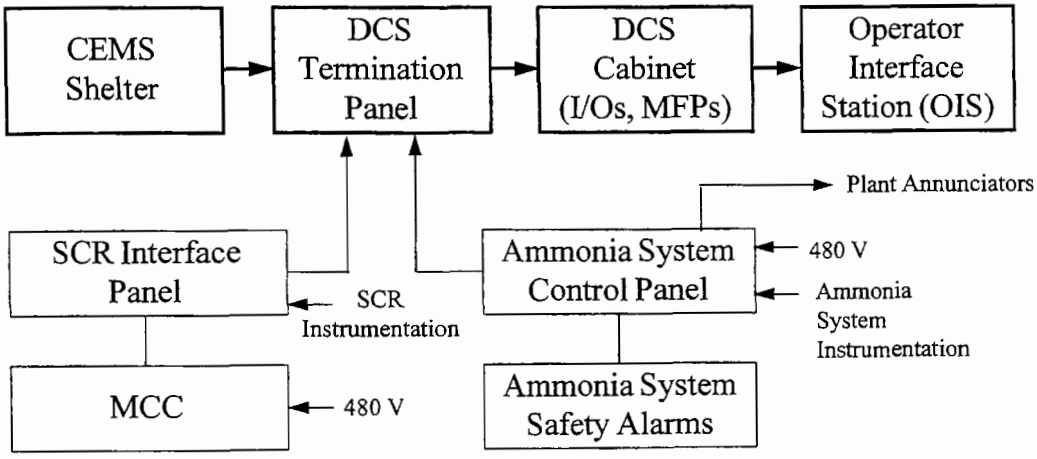


FIGURE 8 CONTROLS INTERFACE/COORDINATION

SCR System - In general, the controls of the SCR System have been established to provide ammonia flow for a constant NO_x reduction with an outlet NO_x feedback. The amount of ammonia introduced is controlled by two loops: 1) a feed forward loop which estimates ammonia demand based on NO_x removal stoichiometric relationships, and 2) a feedback loop which compares the outlet NO_x reading against the desired outlet NO_x and trims or adds ammonia accordingly. The feed forward and feedback loops are programmed in the DCS and will automatically control the ammonia flow control valve which is located on the vaporization skid. This valve can also be controlled directly by the operator.

Logics programmed into the DCS for SCR control include:

- Ammonia/Air Mixture Temperature and Ratio Limits
- Ammonia Flow Control
- Operating Permissives
- Dilution Air Fan Control
- System Shutdown Logic
- Atomizing Air Control

As part of the overall SCR retrofit, the stack Continuous Emissions Monitoring Systems (CEMS) was modified to accommodate the lower NO_x emissions at the stack.

Ammonia Storage and Feed System - Instrumentation and controls are provided for the safe operation of the system. System layout allows for normal operation without requiring personnel to enter the storage tank containment area. All controls are accessible from outside the berm and all indicators are visible from the berm wall. Controls were integrated into the station in the following areas:

- Local Control Panel - pump control, local annunciation, and ammonia pipe leak detection panel.
- DCS - equipment monitoring and remote trip.
- Unit Control Room - annunciation of safety related alarms.
- Unit 1 Auxiliary Operator Panel - system trouble alarms.

In summary, by coordinating the controls for the SCR and Ammonia Systems into the DCS and other local panels, the system monitoring and control functions were assimilated into the responsibilities of the existing station operating and maintenance personnel.

Installation and Startup

Similar to most retrofits at operating power plants, the approach was to complete as much work as possible prior to the outage and carefully plan the outage work to ensure: 1) the demolition and subsequent installation work can be performed within the time allotted, and 2) the boiler can be returned to service successfully with minimal impacts to the operation of the existing boiler system. Careful coordination between all participants in the project was needed. This required installation of the ammonia storage and feed system as well as portions of the SCR electrical and control work prior to the outage. The SCR system could only be installed during the outage. In summary, the major activities associated with this approach are as follows:

Pre-Outage: Ammonia Storage and Feed System

- Earthwork/Foundations/Relocation of Buried Utilities
- Install Ammonia Storage Tanks, Pumps and Ammonia Feed Piping
- Process Electrical and I&C Including Tie-ins to Existing Items
- Verify System Integrity on Condensate
- Verify System Integrity on Aqueous Ammonia
- DCS Modifications for Ammonia and SCR System

Outage: SCR System

- Asbestos Removal and Abatement
- Demolition of Ductwork and Steel
- Install New Ductwork and Steel

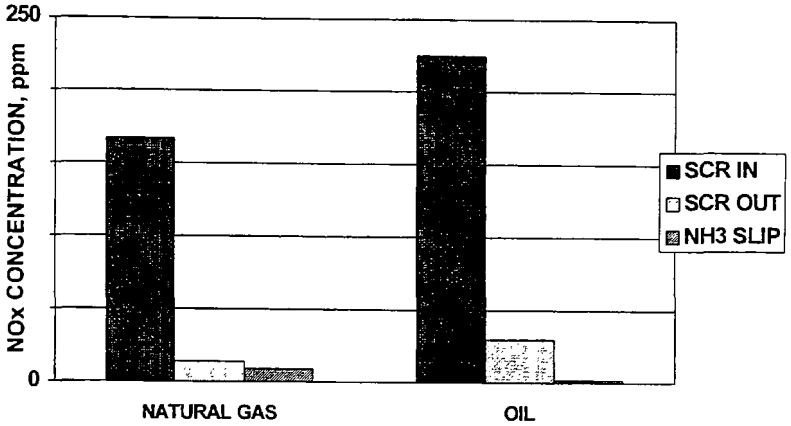


FIGURE 9 SCR PERFORMANCE TEST RESULTS

Next Step for Rule 69 Compliance

SDG&E is preparing for the competitive utility marketplace which begins in 1998. NO_x removal technologies will continue to be reviewed and evaluated to determine which are most cost effective in meeting the requirements of Rule 69. In 1998, the Rule 69 SDCAPCD Compliance Plan will be revised based on the evaluated NO_x control technologies, competitive environment influences and economics. SDG&E is committed to installing NO_x reduction technology on a yearly basis to ensure meeting the SDCAPCD yearly system NO_x emissions cap.

In order to meet the Rule 69 compliance schedule, SDG&E has developed the preliminary schedule in Table 2. Compliance activities have started with SCR installation at South Bay Generating Station Unit 1. Afterwards, Encina Generating Station Units 4 & 5, South Bay Units 2 & 3 and Encina Units 1, 2, and 3 will follow.

Table 2

Year	Unit	Control
1997	South Bay 1	SCR
1998	Encina 4 & 5	FGRW
1999	Encina 4 & 5	LNB/FGRW
2000	South Bay 2	SCR
2001	South Bay 3	SCR
2002	Encina 1	SNCR
2003	Encina 2	SNCR
2004	Encina 3	SNCR

- Install Catalyst (Using Catalyst Hoist)
- Install all Process Equipment
- Electrical Tie-ins Including I&C Tie-ins to DCS and CEMS Upgrades/Modifications
- Inspect Furnace and all Flue Gas Passage Items

Startup and Testing: Operational Unit

- Startup on Condensate
- Initial Operation on Aqueous Ammonia
- System Check Out and Troubleshooting
- Adjustment of the Ammonia Injection Grid (AIG)
- Boiler Tuning for SCR and Overall NO_x Removal Program
- Pre-Test in Preparation for First SCR Performance Test

SCR Performance Tests

The first performance test on the SCR System was concluded in early May, roughly three months after initial operation of the SCR system. This test was performed while firing natural gas and fuel oil.

An independent testing agency was contracted to perform the tests which measured the performance of the following process guarantees:

- NO_x Outlet
- Ammonia Slip
- PM_{10} Increase
- CO Increase
- Ammonia Consumption
- VOC Increase
- Opacity
- Flue Gas Pressure Drop
- SO_2 Increase
- Auxiliary Power
- SCR Minimum Inlet Temperatures

A comparison of inlet/outlet NO_x values including ammonia slip is shown on Figure 9.

Summary

In summary, the project was completed within schedule and budget and after nearly six months of operation, the emission requirements in Rule 69 are being met. Additionally, the SCR System has been integrated into the plant DCS with minimal impact on operating and maintenance personnel.

ENGINEERING AND PILOT SCALE ASSESSMENTS OF A LOW COST COMBINED LOW-NO_x BURNER-SCR SYSTEM

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Abstract

To date, compliance with strict NO_x requirements has often dictated the use of large—and expensive—SCR technology to achieve the necessary NO_x levels. An alternative to these expensive SCR reactors is the use of a technology strategy which combines several low cost systems to achieve the necessary degree of control.

This paper describes one attractive combined system which, when applied to a large utility boiler, has the potential for low overall installed cost. This system consists of low-NO_x burners, in conjunction with a "true in-duct SCR" The design concept minimizes or avoids structural modifications, earthwork foundations, draft system alterations, and ductwork changes to minimize the cost of the retrofit.

An engineering assessment of the true in-duct SCR concept was conducted utilizing a new methodology which integrates physical cold flow modeling and SCR process modeling. The engineering study addressed catalyst location as well as the location and design of the ammonia injection system.

The EPRI/PG&E ASCR pilot plant at Morro Bay, California was then converted to a "true in-duct" configuration, including a catalytic air preheater. The pilot tests provided a direct validation of the engineering calculations.

Introduction

Faced with more stringent NO_x emission regulations, the utility industry is moving in a direction of utilizing Selective Catalytic Reduction (SCR), in addition to combustion modifications, as a

way of achieving compliance. At the same time, efforts are being made to reduce costs by exploring in-duct SCR arrangements. In-duct SCR arrangements incorporate the SCR reactor basically along the existing flue gas path from the economizer to the air preheater.

In many cases, in-duct arrangements will involve enlarging the ductwork to lower velocities in order to accommodate a larger volume of catalyst and reduce pressure drop. This in-duct concept is contrasted to a more traditional retrofit approach associated with Japanese or German SCR installations, where a large separate SCR reactor is built with fairly extensive ductwork changes to route the flue gas to and from the SCR reactor. In the true in-duct SCR, there would be no changes to the ductwork and a smaller amount of catalyst is inserted into existing ducts. The avoidance of extensive structural modifications, foundations/earthwork, separate reactor vessels, etc., and the smaller catalyst volume greatly reduce the cost of such SCRs.

True in-duct catalysts would experience relatively high velocities and somewhat poor distribution of ammonia, therefore constraining NO_x removal efficiency to about 60 to 80 %. However, when used in conjunction with other NO_x control techniques, such as FGR, low-NO_x burners (LNB), catalytic air preheaters, etc., the desired overall NO_x removal can still be achieved and at a significantly lower cost than a conventional SCR system.

While the in-duct arrangement can reduce retrofit costs, it also poses greater challenges to the designer. In addition to the type and amount of catalyst, the process designer must also address velocity and NH_3/NO_x uniformity across the catalyst face. In the traditional separate SCR reactor approach, there is usually sufficient ductwork to allow uniform velocity to be generated at the ammonia injection grid. A uniform velocity profile at the ammonia injection grid greatly simplifies the ammonia/NO_x mixing process. Likewise, with the separate SCR reactor, there will be sufficient space to design ductwork expansions and turning vanes to meet velocity uniformity requirements at the catalyst face. As a consequence, previous design approaches specified criteria such as the standard deviation in the velocity profile, or NH_3/NO_x profile at the catalyst face. If these criteria are met, then the SCR system will perform as designed.

With an in-duct arrangement, it may not be possible to: (1) provide a uniform velocity at the ammonia injection grid, or (2) accommodate traditional design guidelines in terms of duct expansion angles, etc. As a consequence, it will be more difficult, if not impossible in some instances, to meet traditional criteria in terms of a velocity uniformity and/or NH_3/NO_x uniformity at the catalyst face. However, this does not mean that an in-duct arrangement should be discarded as a viable approach. Rather, it points to the need to develop better engineering design tools to assess the performance of these systems.

This presentation describes a new methodology to support the design of SCR systems. The method integrates cold flow modeling with an SCR process model to quantitatively account for site-specific conditions. The paper will describe the methodology and a case study where the methodology was used to design a true in-duct SCR. Pilot scale tests were then conducted in conjunction with LNBs and a catalytic air preheater.

SCR Process Design Methodology

Physical cold flow modeling has been used previously during the design of SCR systems. In most cases, the cold flow modeling has focused on developing uniform velocities at the catalyst face and/or at the plane of the ammonia injection grid, and reducing pressure drop. In some instances, tracer gas techniques have been used to simulate the ammonia injection process. To provide more input to the SCR design process, a methodology has been developed that integrates cold flow modeling results along with a mathematical model of the SCR process to predict performance for a given specific configuration.

As depicted in Figure 1, the process model integrates:

1. The cold flow velocity distributions, which define local variations in space velocity.

2. Tracer gas results which define local variations in NH_3/NO_x ratio, and

3. Ideal catalyst performance data (i.e., NO_x removal and NH_3 slip versus NH_3/NO_x and space velocity with uniform velocity and NH_3/NO_x profiles) to calculate overall NO_x removal and NH_3 slip for a given catalyst and NH_3 injection configuration.

This integration of physical flow modeling with an SCR process model gives performance predictions that are unique to a specific application. The model also estimates the pressure drop across the catalyst. The basic methodology was validated at the PG&E/EPRI ASCR Pilot Plant[1] in 1994.

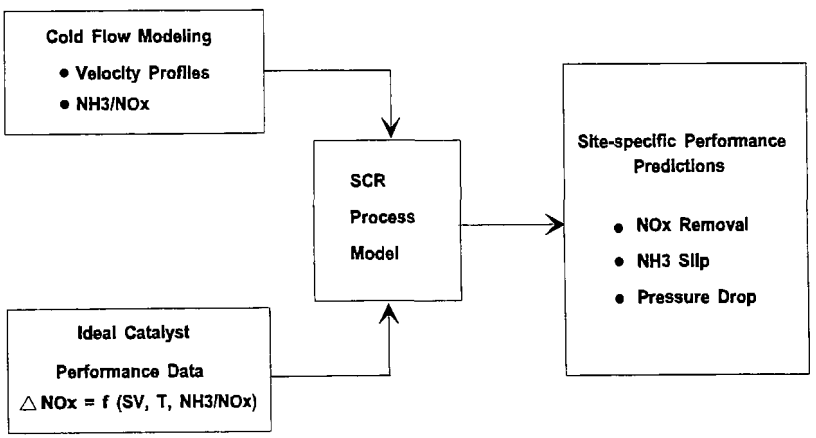


Figure 1. SCR Process Model Methodology

Case Study: PG&E Morro Bay SCR Design

The methodology was used to perform a preliminary design for a true in-duct SCR for PG&E's Morro Bay Unit 3. Morro Bay Unit 3 is a 345 MW gas-fired load-following unit with 24 burners in an opposed wall-fired configuration. Figure 2 is a side elevation drawing of Morro Bay Unit 3. For NO_x control, the unit was previously retrofitted with FGR, overfire air (not shown), and LNBs. The LNBs in Morro Bay Unit 3 are Babcock & Wilcox S-Burners, and their optimization with FGR and OFA's currently provides NO_x emission levels of below 40 ppm (dry @ 3% O_2) across the entire load range. The performance target for the true in-duct SCR was a further reduction to 10 ppm NO_x and NH_3 slip.

The experimental approach for this case study was to use the PG&E/EPRI ASCR pilot plant as a test bed for the Morro Bay Unit 3 true in-duct SCR design. This was possible because the ASCR pilot plant is a 5000 scfm slip stream of Unit 3 (1% at full load), and the pilot SCR can be evaluated directly with the existing combustion NO_x controls on Unit 3.

Figure 3 shows two simplified views of Morro Bay Unit 3, with the potential ammonia injection grid (AIG) and catalyst locations. Note that space between the economizer and the APH is limited with a tight 90° turn, the FGR extraction opening, and a short length of duct. The logical location for the catalyst was at the current location of a damper just upstream of the air preheater (Catalyst Location 1). Similarly, the logical location for the AIG was either just downstream of the 90° turn, or just downstream of the FGR take-off duct.

A 1/12 scale plexiglass model of the Morro Bay Unit 3 boiler was used for the cold flow modeling phase of the design. The important issues addressed during the cold flow modeling study included:

1. optimum location for the catalyst and AIG,
2. the velocity uniformity at the catalyst,
3. NH_3/NO_x uniformity at the catalyst, and
4. minimizing NH_3 entrainment into the FGR stream.

Because the AIG is potentially located near the FGR intake (see Figure 3), a key design consideration for this SCR arrangement was how to minimize ammonia entrainment into the FGR flow. Such ammonia would return to the furnace and increase NO_x production, which would then increase NH_3 demand. An engineering calculation showed that with uniform distribution of ammonia at the FGR intake and full conversion of NH_3 into NO_x in the boiler, the furnace NO_x can increase by as much as 7 ppm.

Three approaches were considered for restricting ammonia entrainment by the FGR:

1. locating the AIG downstream of the FGR duct (i.e., Location 2 in Figure 3),
2. biasing the individual AIG injectors (i.e., turn off injectors near the FGR intake), and
3. using a baffle to separate the AIG from the FGR flow.

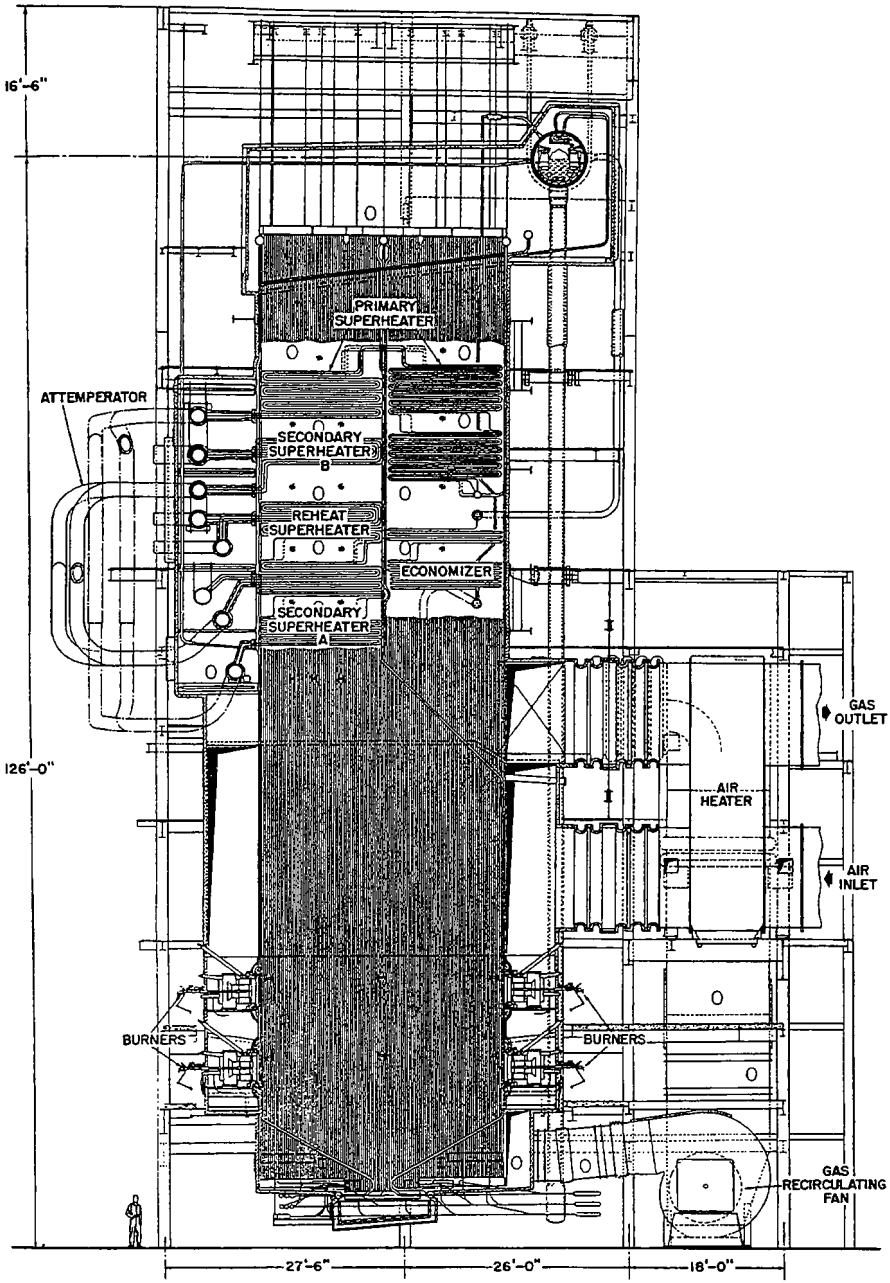


Figure 2. Morro Bay Unit 3

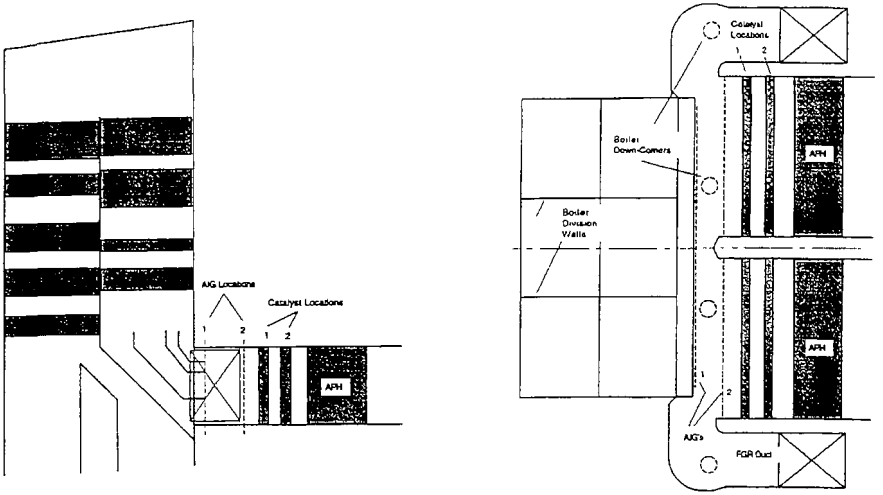


Figure 3. Potential Locations for the AIG and In-Duct Catalyst for Morro Bay Unit 3

Tracer gas studies eliminated approach one as there was a large recirculation zone that carried NH_3 from Location 2 back into the FGR duct. Further, approaches two and three would only be feasible if the flue gas that entered the FGR duct was localized to the outer portions of the duct. To assess the origin of the flue gas that enters the FGR duct, a point source of tracer gas was added at various points across the exit of the 90° turn (AIG Plane 1). With tracer gas measurements in the FGR duct, the fraction of main flue gas that enters the FGR duct from each specific point could be calculated. The results of two such tracer gas tests are shown in Figures 4(a) and (b). Figure 4(a) is without turning vanes and surprisingly shows that combustion products entering the FGR duct are drawn from essentially the entire width of the flue gas duct. This would preclude approaches 2 and 3 to limit NH_3 entrainment into the FGR duct. However, with the installation of the turning vanes (both vertical and horizontal vanes), the FGR is localized to the outer edges of the duct.

With the turning vanes installed, further cold flow tests showed that Location 1 was the preferred location for the AIG and catalyst. Also, biasing the AIG injectors was preferred over the flow baffle to minimize NH_3 entrainment into the FGR duct while maximizing NH_3 at the catalyst face.

Table 1 shows the results of the AIG bias tests. Note the tradeoff between minimizing NH_3 entering the FGR with NH_3/NO_x uniformity at the catalyst. Two lances turned off at the outer edges of the duct was the best case based on cold flow model results (Case 2). Subsequent pilot-scale data showed a similar trend, but that additional throttling of injectors were needed at the pilot plant to obtain similar NH_3 entrainment fractions (Case 3).

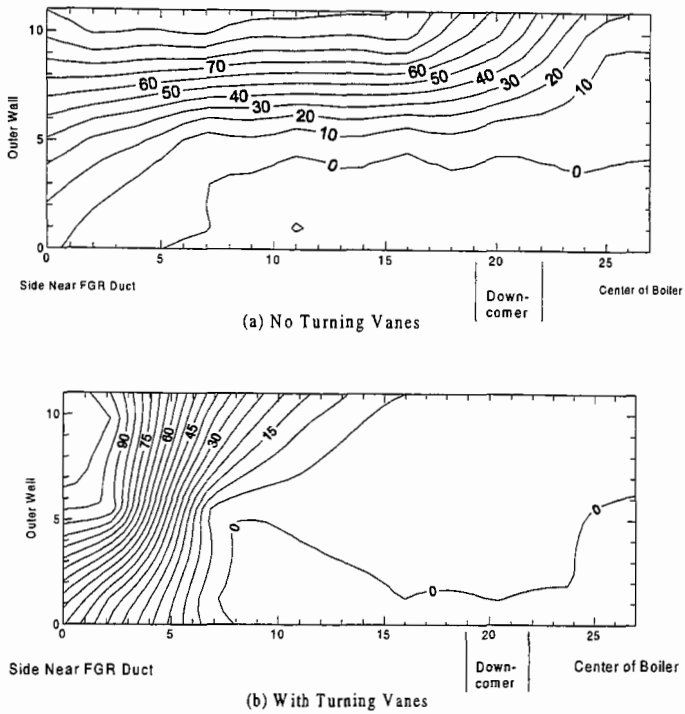


Figure 4. Origin of the FGR, View of Economizer Exit Elbow from APH

Table 1
AIG Optimization in Both the Cold Flow Model and the Pilot Plant

		Physical Cold Flow Model		Pilot Plant Results	
Case	**AIG Bias**	**NH_3/NO_x Uniformity Std. Dev. %**	**Fraction of NH_3 in FGR**	**NH_3/NO_x Uniformity Std. Dev. %**	**Fraction of NH_3 in FGR**
1	None, all lances in service	14%	40%	14%	66%
2	Two lances turned off	18%	9%	N/A	27%
3	Two lances off, two throttled	N/A	N/A	23%	11%

Following the cold flow study, the SCR process model was used to predict catalyst performance for the Morro Bay system. Based on a 2.5 inches H_2O pressure drop limit and a SV of 35,000 hr^{-1}, the model found that a 3.9 mm pitch catalyst (3.3 mm hydraulic diameter) could achieve 10 ppm NO_x and NH_3 if the initial NO_x level is below 35 ppm. With the encouraging results from the assessment study, the project proceeded to the pilot scale tests.

Case Study: Pilot-Scale Performance Tests

The PG&E/EPRI ASCR pilot plant was modified according to the true in-duct SCR design from the cold flow process modeling study. Shown in Figure 5, the modified ASCR reactor is at nominally 1/8 scale to Morro Bay Unit 3. Note that the pilot reactor models just one half of the full-scale boiler, and incorporates all major components, including the FGR extraction duct, turning vanes, and downcomer pipe.

It is also important to point out that the pilot plant featured a catalytic air preheater downstream of the in-duct catalyst. The catalytic air preheater consisted of a small-scale, size 8HK Ljungstrom® air preheater with catalyst-coated hot end elements. Figures 6 and 7 show performance of the APH catalyst alone. As can be seen, load or space velocity has a larger impact on performance than temperature.

Table 2 shows the test conditions for both the in-duct and APH catalysts for the true in-duct tests.

Overall True In-Duct Performance

The true in-duct catalyst performance was tested for two configurations of the AIG. One configuration was Case 1 in Table 1 which had all of the injectors flowing equally (14% standard deviation in NH_3/NO_x). The second configuration was the optimized AIG (Case 3 in Table 1) which had the two injectors near the FGR take-off duct turned off and the next two throttled down (23% standard deviation in NH_3/NO_x).

Figures 8(a) and (b) show that the in-duct catalyst alone and the combined in-duct and catalytic air preheater elements both performed quite well. During these tests, the inlet NO_x levels varied from 26 to 38 ppm. The target outlet NO_x level of 10 ppm was achieved by the in-duct catalyst at NH_3/NO_x ratios of 0.72 - 0.95 with resulting NH_3 slip levels of 3 ppm to 9 ppm. With the combined in-duct and APH catalyst system, the target NO_x reductions were achieved at NH_3/NO_x ratios of 0.65 - 0.85 with corresponding NH_3 slip levels of 1.3 to 3 ppm.

An interesting observation in Figure 8 is the effect that NH_3/NO_x uniformity had on the performance of the in-duct catalyst. Despite the rather large difference in NH_3/NO_x uniformity, (14% versus 23% standard deviation) there is a very small impact on performance in terms of either NO_x reduction or NH_3 slip. In fact, these differences appear to be within experimental uncertainty. While a general statement can be made that NH_3/NO_x uniformity has a greater impact than velocity uniformity, the actual magnitude will depend on the site-specific situation.

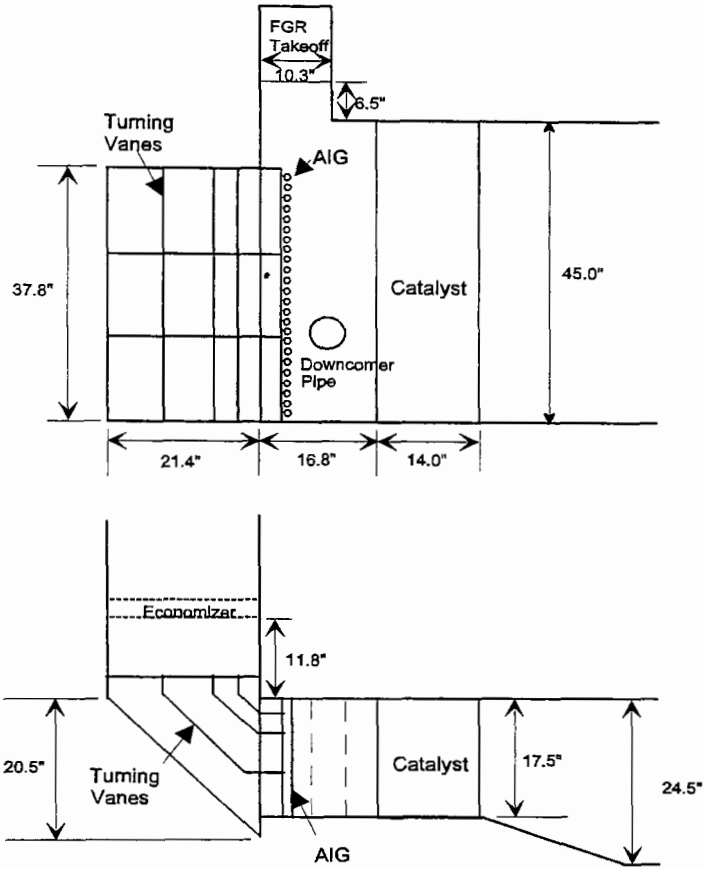


Figure 5. Modified Pilot In-Duct Reactor

The process model discussed previously was used to assess whether the results shown in Figure 8 are indeed realistic. The velocity profiles and the NH_3/NO_x profiles measured at the in-duct catalyst face for the two AIG cases tested were input into the process model using the catalyst conditions shown in Table 2. The results of the calculations are shown in Figure 9. In this figure, the predicted NO_x removal and NH_3 slip for the two AIG configurations are shown along with the line drawn through the experimental points plotted in Figure 8(a). Figure 9 supports the pilot plant performance measurements in that changing the NH_3/NO_x uniformity by biasing the injectors (i.e., increasing NH_3/NO_x nonuniformities from a standard deviation of 14% to 23%) has little impact on NO_x reduction for this particular application. The model predicts that at an NH_3/NO_x ratio of 0.9 biasing, the injectors should only result in a one percentage point drop in NO_x removal (from 75% to 74%) and a one ppm increase in NH_3/NO_x slip (from 5 ppm to 6 ppm). For reference, if the NH_3/NO_x ratio and velocity were perfectly uniform across the catalyst, the model predicts that at an NH_3/NO_x ratio of 0.9, the NO_x removal would be 81% and the NH_3 slip 3 ppm.

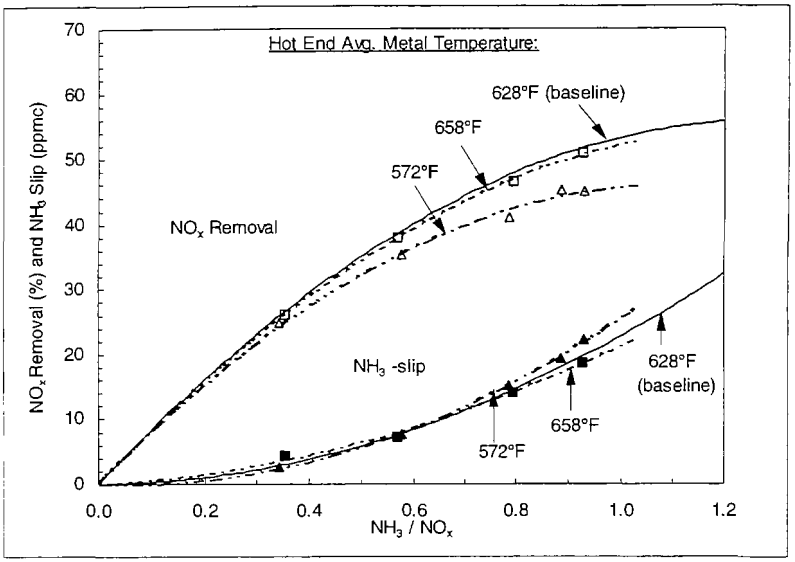


Figure 6. APH Catalyst Performance as a Function of Temperature

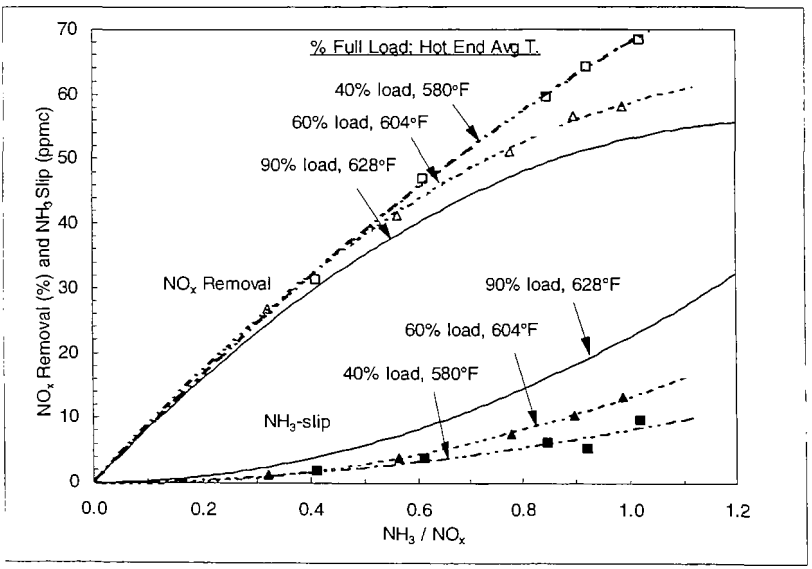


Figure 7. APH Catalyst Performance as a Function of Load

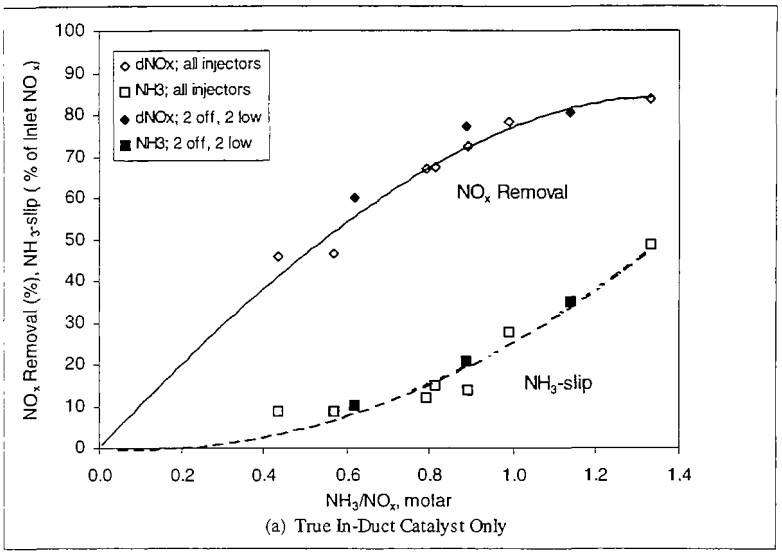
Table 2
Pilot In-Duct and APH SCR Specification and Conditions

	In-Duct	**APH**
Manufacturer	Haldor Topsøe A/S	ABB/Engelhard
Catalyst Type	DNX-930	FNC® Coating
Flue Gas Flow	4200 scfm	4200 scfm
Flue Gas Temperature	680°F	660°F
Inlet Velocity	27.6 ft/sec	23.5 ft/sec
ΔP Limit	2.5" H_2O	
Hydraulic Diameter	3.3 mm	8 mm
Pitch	3.9 mm	
Wall Thickness	0.6 mm	0.7 mm
Catalyst Dimensions	27.5" x 45" x 19"	12" inner rad, 28" outer rad, 16" L
Space Velocity (SV)	29,100 1/hr	29,300 1/hr [1]

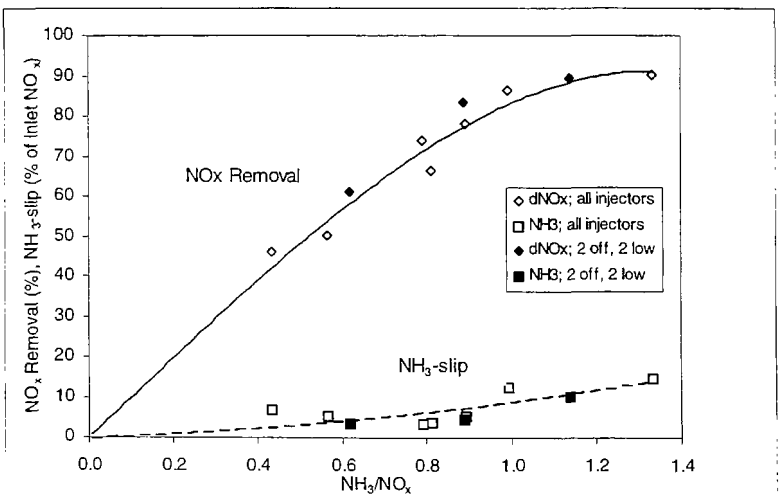
1. Based on the fraction of the air preheater catalytic elements actually exposed to the flue gas flow (46%).

The pilot plant performance measurements and the model predictions show that for this specific SCR arrangement, a fairly large change in NH_3 nonuniformity had little impact on performance. This clearly illustrates the potential shortcomings of using rule of thumb criteria for either velocity or NH_3/NO_x uniformities. By employing the current methodology, actual performance predictions can be made for site-specific SCR arrangements.

Figure 9 also represents a comparison of pilot plant measurements to model predictions on an absolute basis. The solid line in Figure 9 is the line drawn through the data points in Figure 8 (Note: the NH_3 slip levels in Figure 9 have been normalized to an initial NO_x level of 35 ppm). As can be seen, the model predictions, and the actual pilot plant measurements, are in good agreement. Also, the measured pressure drop across the in-duct catalyst at a flow rate of 4200 scfm (SV=29,100 hr^{-1}) was 2.02 inches H_2O, the model predictions were 2.1 inches H_2O.



(a) True In-Duct Catalyst Only



(b) Combined In-Duct and APH Catalysts

Figure 8. Pilot Scale Performance Results with Two Injection Bias Conditions

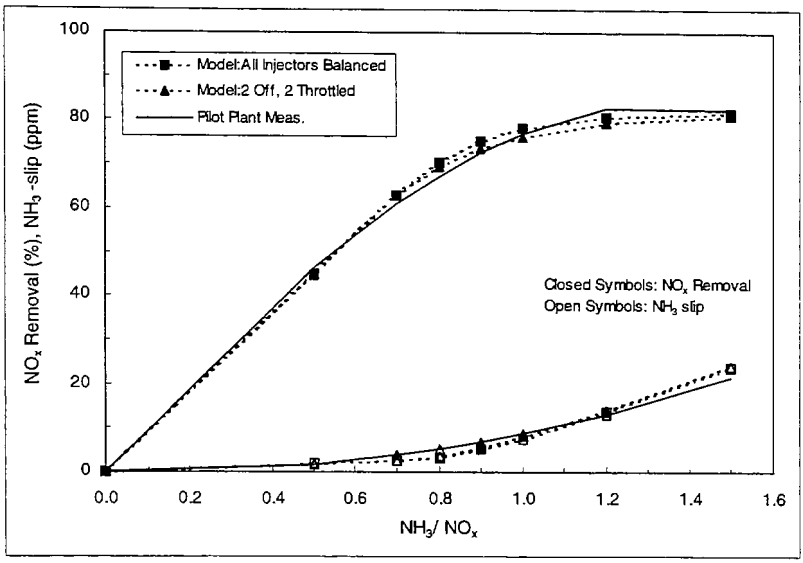
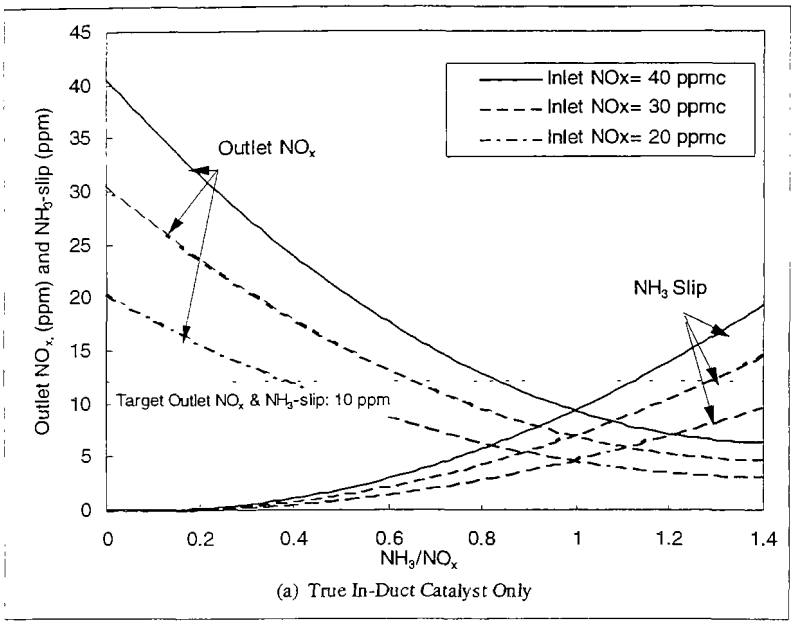
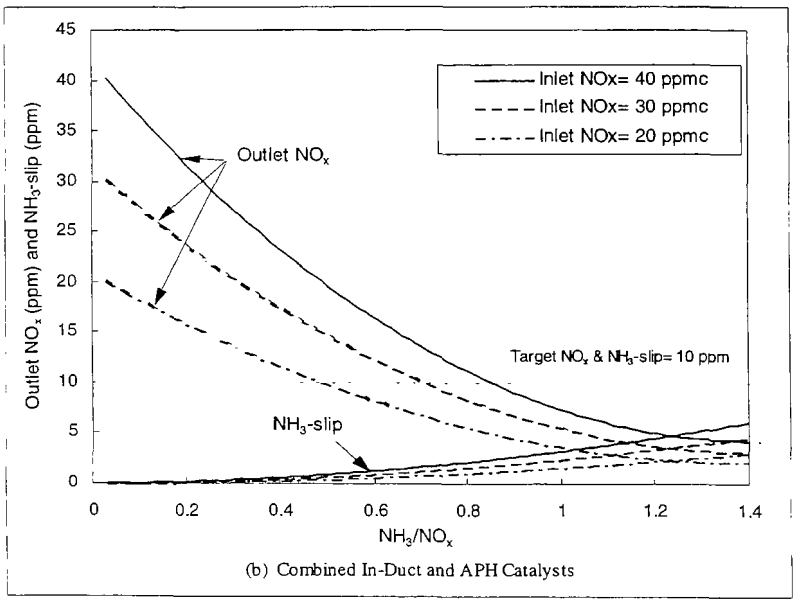


Figure 9. Comparison of Model Predictions with Pilot Plant Catalyst Measurements (NH_3 Slip Based on an Initial NO_x Level of 35 ppm)

The results discussed above showed the performance of the true in-duct SCR and combined true in-duct plus catalytic air preheater elements in terms of NO_x reduction and NH_3 slip. The next step is to interpret these results in terms of the applicability of a true in-duct SCR in helping to meet future NO_x regulations. Since a true in-duct SCR will generally be used with other combustion NO_x controls, the basic question is, "How low must the NO_x entering the SCR be reduced?" To illustrate this interaction, the pilot plant performance results presented in Figure 8 have been generalized and replotted in Figure 10. In Figures 10(a) and (b), the outlet NO_x and NH_3 slip levels have been plotted for various inlet NO_x levels. With the results generalized in this way, it is easy to assess the applicability of a true in-duct SCR. For instance, a future NO_x regulation may require 10 ppm outlet NO_x with less than 10 ppm NH_3 slip. As seen in Figure 10(a), with the in-duct catalyst alone, outlet NO_x and NH_3 slip levels of 10 ppm can be attained, provided the inlet NO_x levels are less than 40 ppm. For the combined in-duct/APH catalyst system, the 10 ppm outlet NO_x level can be easily achieved with a 40 ppm inlet NO_x. In fact, based on Figures 8(b) and 10(b), the 10 ppm outlet NO_x and NH_3 slip targets can be achieved with inlet NO_x levels of nominally 80 ppm with the combined in-duct catalyst and APH catalyst system. It should be noted that the test results shown in Figure 8 represent catalyst performance with nominally 1700 - 2100 hours of operation. Some margin would need to be included in a full scale system to accommodate further catalyst aging. Also, the results are based on an allowed pressure drop of 2 inches H_2O across the in-duct SCR. With higher allowed pressure drop, more catalyst could be utilized resulting in higher performance.



(a) True In-Duct Catalyst Only



(b) Combined In-Duct and APH Catalysts

Figure 10. Generalized Pilot Scale Performance Results

Summary and Conclusions

This paper has described a successful design and pilot-scale application of a low cost combined LNB-SCR system. A design methodology was used which incorporates cold flow modeling as a means to obtain site-specific velocity and ammonia uniformity information as well as resolve complicated issues such as catalyst and AIG placement and minimizing NH_3 entrainment into the FGR stream. A process model predicted the NO_x removal and NH_3 slip as well as catalyst pressure drop, and the predictions were verified at the Morro Bay ASCR pilot plant.

The case study of the design and application of a true in-duct SCR to Morro Bay Unit 3 showed that:

1. ammonia entrainment into the FGR can be controlled by using turning vanes and biasing the NH_3 injection away from the FGR intakes,

2. increased ammonia non-uniformity due to injector biasing (Std. Dev. 14% to 23%) had little impact on performance for this particular SCR system,

3. sub-10 ppm NO_x and NH_3 slip were possible with the Morro Bay Unit 3 true in-duct SCR design if the inlet NO_x remain at 40 ppm or lower,

4. combining a catalytic air preheater with the true in-duct catalyst gives extra operating margin and allows for higher inlet NO_x levels while maintaining sub-10 ppm outlet NO_x and NH_3.

In conclusion, this study has demonstrated the feasibility of a low-cost LNB-SCR system and the utility of a methodology as a predictive design tool for cost-effective, high performance SCRs.

References

1. L. J. Muzio, et al., *A New Design Tool for SCR Systems*, 1995 Joint EPRI/EPA Symposium on Stationary Combustion NO_x Control, Kansas City, May 1995.

FEASIBILITY OF APPLYING SELECTIVE CATALYTIC REDUCTION (SCR) TO OIL-FIRED, SIMPLE- AND COMBINED-CYCLE COMBUSTION TURBINES

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Abstract

This paper contains the results of an EPRI Tailored Collaboration project to determine the technical feasibility and cost of selective catalytic reduction (SCR) as applied to 0.4%-sulfur, 100% oil-fired combustion turbines. SCR has been widely applied on natural gas-fired turbines; however, there is comparatively little commercial operating experience on oil-fired combustion turbines, particularly when firing fuel oil containing up to 0.4% sulfur.

The project included two years of pilot testing on an exhaust gas slipstream from the Unit 14 LM2500 combustion turbine at the Maui Electric Company's Maalaea generating station. The pilot unit included the SCR reactor and a heat-pipe heat exchanger designed to simulate the operation of a full-scale heat recovery steam generator (HRSG). Two different types of catalyst were tested. These included a low-temperature conventional SCR catalyst which would be employed within the HRSG, and a high-temperature zeolite catalyst which would be employed on simple-cycle units, or alternatively, upstream of the HRSG on combined-cycle units.

The test results show that the key issues affecting the technical feasibility and cost of SCR include catalyst performance and life in the combustion turbine exhaust gas environment and HRSG pressure drop increases resulting from the deposition of ammonium sulfate and bisulfate salts on heat transfer surfaces. This paper presents these test results and discusses their influence on SCR costs.

Introduction

New combustion turbine generating capacity has recently been added to the Hawaiian Electric Company (HECO) generating system, and additional capacity will be needed in the near future. In accordance with State and Federal regulations, the Prevention of Significant Deterioration (PSD) permit applications and subsequent permits for these units addressed the environmental control equipment which has or will be installed to control air pollutant emissions. An unresolved issue associated with this permitting process was the control of NO_x emissions.

Recent permit decisions covering control of NO_x emissions from U.S. mainland natural gas-fired combustion turbines have been based on the use of dry low-NO_x combustion technologies and/or selective catalytic reduction (SCR). These permit decisions have resulted in the widespread application of SCR - mostly within the heat recovery steam generators (HRSG's) of natural gas-fired, combined-cycle units.

Despite the widespread application of combustion turbine SCR, there is comparatively little commercial operating experience on oil-fired combustion turbines. Over the past few years, dual-fuel units with SCR have generally utilized oil-backup for only limited periods of time - on the order of 400 hours per year or less. In addition, this oil-backup is usually very low-sulfur fuel oil (less than 0.05% sulfur), which is widely available on the mainland.

The situation in the State of Hawaii is different in several respects. First, large quantities of natural gas are not available in Hawaii, and all generating equipment in the HECO generating system is fired exclusively on oil. Second, it is not cost-effective to burn very low-sulfur fuel, and the fuel that is burned, as authorized by recent air permits, contains up to 0.4% sulfur. This combination of factors raises concerns about the technical feasibility of SCR since SCR on 0.4%-sulfur, oil-fired combustion turbines has not been demonstrated on the mainland or elsewhere. Third, there is limited excess generating capacity in Hawaii, and there is no grid to provide power when demand exceeds the available generating capacity. Thus, HECO is concerned about the reliability of SCR on 0.4%-sulfur, oil-fired combustion turbines.

Recently installed combustion turbines in the HECO generating system were permitted on the basis of water injection for NO_x control. However, the Hawaii Department of Health included a permit condition which requires a demonstration program to determine the technical and economic feasibility of SCR. The outcome of the demonstration program will assist in NO_x BACT determinations for a total of seven existing and planned HECO-system combustion turbines.

To meet the state permit requirement, a two-year demonstration program was conducted using an SCR pilot unit located adjacent to Unit 14 at the Maui Electric Company's Maalaea

generating station. The first year of the demonstration program consisted of an evaluation of a conventional vanadium-based catalyst which would be installed within a relatively low-temperature region of a combined-cycle unit HRSG. The pilot unit equipment configuration used during this portion of the demonstration program included a "surrogate HRSG" heat-pipe heat exchanger designed to simulate the HRSG operating environment downstream of the SCR reactor. The second year of the demonstration program consisted of an evaluation of a high-temperature zeolite catalyst which would be employed on simple-cycle turbines, or alternatively, on combined-cycle units upstream of the HRSG. Both catalysts were selected based on the results of a bench-scale catalyst evaluation conducted prior to pilot testing.

The remainder of this paper presents an overview of the demonstration program results. First, descriptions of the host combustion turbine unit and the SCR pilot unit are presented. Then, a summary of key demonstration program results is presented which addresses the major factors found to affect the technical and economic feasibility of SCR for HECO-system, oil-fired combustion turbines. Finally, supplemental information is presented which supports the key demonstration program conclusions. This information includes the results of an engineering evaluation to predict full-scale HRSG operating impacts from the pilot-scale test results and operating data quantifying the performance of an oil-fired, combined-cycle combustion turbine with SCR located at Tekniska Verken's Garstad generating station in Linkoping, Sweden. Even though the Garstad unit fires oil with a lower sulfur content than is fired in HECO-system combustion turbines, it is the only unit in the world with comparable operating conditions. Recent operating experience at this facility supports several of the key conclusions from the demonstration program.

Description of the Host Unit and the SCR Pilot Unit

The pilot unit used to collect demonstration program data was located adjacent to Unit 14 at Maui Electric Company's Maalaea generating station. Unit 14 includes a General Electric LM2500 combustion turbine which typically operates at full-load (about 20 MW), although unit output decreases to between 12 and 15 MW at night. Unit 14 is fired with No. 2 fuel oil containing up to 0.4% sulfur. The exhaust gas SO_2 concentration at the maximum fuel sulfur level is about 79 ppm; however, the SO_2 concentration during the pilot test program ranged from 20 to 70 ppm, and averaged 40 ppm and 30 ppm during the low- and high-temperature test periods, respectively.

Unit 14 is equipped with a Zurn heat recovery steam generator (HRSG) that feeds a 16-MW steam turbine. Steam produced from Unit 14 generates about 8 MW while steam from an identical, parallel combustion turbine and HRSG (Unit 16) generates the remaining power. HRSG's generally contains multiple tube banks of closely spaced, finned heat transfer tubes. For the Unit 14 HRSG design, these tube banks include a high-pressure superheater, a split high-pressure evaporator, a high-pressure economizer, and a low-pressure evaporator. Unit 14 was designed to allow the retrofit installation of SCR, and the split high-pressure evaporator

contains a spool piece at a location where the exhaust gas temperature is appropriate for a low-temperature SCR catalyst. A diagram of the Unit 14 HRSG is shown in Figure 1.

A diagram of the SCR pilot unit is shown in Figure 2. The pilot unit was designed to accept a slipstream of turbine exhaust gas from two locations. During the first year of low-temperature testing, exhaust gas was withdrawn using an isokinetic scope located within the split high-pressure evaporator. The exhaust gas temperature at this location is typically about 650°F. During the second year of high-temperature testing, exhaust gas was taken from upstream of the HRSG where the exhaust gas temperature is typically between 950 and 1,000°F, depending on unit load.

As shown in Figure 2, the turbine exhaust gas passed through a venturi flow meter, a duct expansion, and a perforated plate. The exhaust gas then passed through trim heating and cooling equipment, and an ammonia injection grid. After a 90° turn, the exhaust gas passed through a second perforated plate, an SCR reactor, and a heat-pipe heat exchanger. Finally, the exhaust gas passed through an induced-draft fan and was returned to the Unit 14 stack. The purpose of the two perforated plates was to straighten the gas flow after a flow disturbance. The second plate also served to mix the ammonia and exhaust gas.

The SCR reactor contained two layers of catalyst. Engelhard's VNX catalyst was installed in the reactor during low-temperature testing. The VNX catalyst is a conventional vanadium pentoxide catalyst supported on titanium dioxide, and is suitable for use at temperatures between 600 and 750°F. This "washcoat" catalyst is supported on a ceramic honeycomb substrate which, for this application, had a 3.175 mm pitch. Engelhard's ZNX catalyst was installed during high-temperature testing. This catalyst is a zeolite which, according to Engelhard, can be used at temperature up to 1,100°F. This catalyst is also a washcoat catalyst, and the catalyst installed in the pilot unit also had a 3.175 mm pitch.

During low-temperature testing, gas exiting the SCR reactor passed through a pilot-scale, heat-pipe heat exchanger. This "surrogate HRSG" was designed to simulate the conditions in a full-scale HRSG downstream of the SCR catalyst where ammonium salts are expected to deposit as the exhaust gas cools. During high-temperature testing, the surrogate HRSG was removed and replaced with a spool piece (this unit was not designed to handle the high-temperature exhaust gas).

Summary of Results and Conclusions: Low-Temperature SCR Evaluation

Low-temperature testing was conducted using Engelhard Corporation's VNX catalyst. The performance characteristics of the low-temperature catalyst over the one-year demonstration period are presented in Figure 3. This figure shows NO_x removal efficiency versus ammonia slip as a function of time for data collected at baseline operating conditions (650°F and a space velocity of 10,300 hr^{-1}). The ammonia slip data in Figure 3 are presented as percentages of the

nominally 35 ppm inlet NO_x concentration to normalize the data for variability in the inlet NO_x concentration.

The results in Figure 3 show that high NO_x removal rates were achieved with the VNX catalyst. The ammonia slip concentrations were initially very low, but increased slightly over the one-year test period due to deactivation of the catalyst. Catalyst activity projections based on these test results, including results obtained at the reactor midpoint, indicate that it should be possible to obtain 65% NO_x removal with a maximum of 10 ppm ammonia slip over an operating period (catalyst life) of about four years.

The results of SO_2 oxidation measurements showed that SO_2 oxidation over the catalyst averaged about 2% of the SO_2 present in the exhaust gas. At the average SO_2 concentration of 40 ppm measured during low-temperature testing, 2% SO_2 oxidation would increase the exhaust gas SO_3 concentration from about 1 ppm (in the turbine exhaust) to about 1.8 ppm downstream of the SCR reactor.

Overall, the results show that reasonably good NO_x removal and SO_2 oxidation performance would be expected for the VNX catalyst. Even so, there would be sufficient ammonia slip and SO_3 in the exhaust gas to result in the deposition of ammonium salts such as ammonium sulfate and bisulfate on heat transfer surfaces within the HRSG, particularly as the catalyst ages and the ammonia slip begins to rise. Operating impacts associated with ammonium salt deposition include an increase in the HRSG pressure drop, decreased heat transfer efficiency, and corrosion of carbon steel heat transfer surfaces. An engineering evaluation based on the demonstration program results indicates that increased HRSG pressure drop is the most important of these impacts and has the greatest influence on the operation of the combustion turbine and SCR-related costs. Specifically, HRSG pressure drop increases of about 3.3 inches of water per month would be experienced on existing HECO-system units beginning in the second year of a four-year catalyst life-cycle.

An ammonium salt management strategy would be required to prevent equipment damage and/or a unit derate associated with an excessive HRSG pressure drop. Strategies evaluated as part of the demonstration program included periodic water washing of the HRSG, more frequent catalyst replacement, and HRSG sootblowing. Each of these strategies is discussed below.

Water washing could be conducted to remove deposited ammonium salts when the HRSG pressure drop reaches unacceptable levels (dictated by HRSG casing pressure limitations and/or turbine backpressure limitations). Demonstration program results show that water washing should remove the soluble ammonium salt deposits, although the effectiveness may vary depending on the HRSG design and access to affected tube banks. Even if washing is effective, however, frequent unit outages would be necessary to perform the washing operation. For existing HECO-system units, calculations based on the demonstration program results show that HRSG washing would be required at two-month intervals beginning in the

second year of a four-year catalyst life-cycle. Forced outages associated with the need for periodic water washing increase the cost to implement SCR on the higher-sulfur, oil-fired combustion turbines in the HECO generating system.

More frequent catalyst replacement could also be employed to reduce the impacts of ammonium salt deposition. To implement this strategy, the catalyst would be replaced while the ammonia slip was still relatively low. This minimizes the deposition rate of ammonium salts in the HRSG. For existing HECO-system units, annual catalyst replacement would reduce the need for HRSG washing to once per year (i.e., during an annual outage). However, relative to the water washing strategy, higher catalyst procurement and disposal costs would largely offset savings associated with the reduced number of forced outages.

Sootblowers were also considered as a means of preventing the buildup of ammonium salt deposits and minimizing the frequency of unit outages. However, there is limited operating data quantifying the effectiveness of sootblowers for removing these types of deposits from HRSG heat transfer surfaces, and the data which are available indicate that sootblowers are not effective. Specifically, sootblowers were installed and operated on an oil-fired, combined-cycle combustion turbine with SCR located at Tekniska Verken's Garstad generating station in Linkoping, Sweden. Even though this unit fires a lower-sulfur fuel oil than is used in HECO-system units, rapid increases in HRSG pressure drop have been experienced at Garstad, and sootblowers have not been effective in removing these deposits or limiting the rate of pressure drop increase.

Operating problems associated with ammonium salt deposition increase the cost of SCR. Table 1 summarizes cost estimates developed as part of the demonstration program for the various ammonium salt management strategies. For existing HECO-system units, costs associated with the water washing and annual catalyst replacement strategies more than double the annualized cost of SCR relative to a hypothetical, similarly-sized natural gas-fired combustion turbine.

Costs associated with the sootblowing strategy could be somewhat lower if sootblowing effectively removed ammonium salt deposits (the cost estimates in Table 1 are based on the premise that sootblowers will completely prevent the deposition and accumulation of ammonium salts). However, the operating experience at Garstad demonstrates that sootblowers are not effective. Therefore, the costs listed in Table 1 for the sootblower management strategy underpredict actual costs, and the costs listed for the water washing and annual catalyst replacement strategies more accurately represent the actual costs to implement SCR on HECO-system combustion turbines.

Summary of Results and Conclusions: High-Temperature SCR Evaluation

High-temperature testing was conducted using Engelhard Corporation's ZNX catalyst. The performance characteristics of the high-temperature catalyst over the one-year demonstration

period are shown in Figure 4. Again, the figure shows NO_x removal efficiency versus ammonia slip (as a percentage of the inlet NO_x) as a function of time for data collected at 1,000°F, and space velocities of 20,600 and 10,300 hr^{-1} (these space velocities correspond to the reactor midpoint and outlet, respectively).

Relative to the low-temperature VNX catalyst, the high-temperature ZNX catalyst performance shows lower NO_x removal capability with significantly higher ammonia slip. Calculations show that the activity of this catalyst is only about one-third of that for the conventional low-temperature catalyst, and the catalyst deactivation rate is somewhat greater. The results show that this catalyst could be used to remove up to 65% of the NO_x in the exhaust gas with less than 10 ppm ammonia slip. However, the required catalyst volume would be greater than for a low-temperature application with the same performance requirements, and the catalyst life would be only about one year.

In addition to poor NO_x removal performance, the high-temperature ZNX catalyst oxidized excessive amounts of the SO_2 in the exhaust gas to SO_3. At a typical exhaust gas SO_2 concentration of 40 ppm, and an ammonia injection rate giving 65% NO_x removal, about 20% of the inlet SO_2 was oxidized to SO_3 (this corresponds to the production of about 8 ppm SO_3). When the ammonia injection system was turned off, about 50% of the inlet SO_2 was converted to SO_3 (this corresponds to the production of about 20 ppm SO_3).

The demonstration program results indicate that the use of the high-temperature ZNX catalyst on a simple-cycle combustion turbine would generate environmental issues associated with sulfuric acid emissions or emissions of ammonium salt particulate. In addition, the cost would be high due to the large catalyst volume and short catalyst life (costs for a simple-cycle application are included in Table 1). Further, a combined-cycle application is considered technically infeasible because of the excessive deposition of ammonium salts in the HRSG downstream of the SCR catalyst. It is apparent from the test results that further advances in catalyst technology would be required before high-temperature SCR could be applied to higher-sulfur, combined-cycle combustion turbines.

Engineering Evaluation of HRSG Operating Impacts

In a full-scale, combined-cycle combustion turbine SCR application, ammonium salts will condense on the HRSG's finned heat transfer tubes if ammonia and sulfur trioxide (SO_3) are present in the cooling exhaust gas (ammonium salts will begin to condense from the exhaust gas when the temperature falls below approximately 450°F). Condensed ammonium salts deposit on the fins and foul the area between the fins. This restricts gas flow over the tubes and results in an increase in the HRSG pressure drop and a decrease in heat transfer efficiency. HRSG pressure drop increases appear to be the more important of these two effects, and will eventually force a shutdown of the combustion turbine to avoid equipment damage and/or a unit derate. Figures 5 and 6 show clean and fouled heat transfer tubes, respectively, from the surrogate HRSG used during the demonstration program.

Ammonia is present in the exhaust gas due to unreacted ammonia (ammonia slip) exiting the catalyst, and the ammonia concentration would increase over time as the catalyst ages. Thus, catalyst performance and life will directly influence the deposition rate of ammonium salts in the HRSG. The SO_3 concentration in the exhaust gas also affects the ammonium salt deposition rate. SO_3 is present in the exhaust gases of sulfur-bearing fuels, and additional SO_3 is produced via SO_2 oxidation as the exhaust gas passes through the catalyst.

Surrogate HRSG performance changes were quantified by monitoring pressure drop increases and heat transfer decreases over time. These performance characteristics changed over time due to deposition of ammonium salts such as ammonium bisulfate and ammonium sulfate on the finned heat transfer tubes. The mass deposition rates of ammonium salts were also quantified during pilot testing by periodically washing the surrogate HRSG and measuring the concentrations of ammonia and sulfate in the wash solution. Over the one-year, low-temperature test program, the ammonium salt deposition rate and corresponding impacts on surrogate HRSG performance were measured at ammonia slip concentrations ranging from 1.0 to 8.4 ppm.

Mass transfer, heat transfer, and pressure drop models were developed to evaluate the demonstration program data and to allow projections of full-scale operating impacts. The specific objective of this evaluation was to determine the required washing frequency and forced outage schedule for the Unit 14 HRSG over a four-year catalyst life-cycle. To begin this analysis, a mass transfer model was developed to predict the mass deposition rate of ammonium salts as a function of temperature and the concentrations of ammonia and SO_3. The model was based on the assumption that the gas phase is at equilibrium with respect to ammonium bisulfate such that the deposition rate is controlled by diffusion of ammonia and SO_3 to the tube surface. Reasonably good agreement was obtained between the modeling results and the mass deposition rates measured in the surrogate HRSG.

In addition to the mass transfer model, heat transfer models were developed to provide exhaust gas and tube temperatures throughout the surrogate HRSG, and pressure drop models were developed to predict pressure drop changes as a function of gas velocity and the mass of deposited ammonium salts. Good agreement was obtained between the model predictions and the surrogate HRSG performance data.

The models developed to evaluate the demonstration program data were modified for application to a full-scale HRSG and used to predict performance changes in the Unit 14 HRSG over a four-year catalyst life-cycle. An example of the results of this modeling process are described below for a case in which the unit is operating at full-load, the NO_x removal requirement is 65%, and the fuel sulfur content is 0.2% (this fuel sulfur content is representative of the fuel used during the demonstration program, but is only half of the maximum possible 0.4% fuel sulfur content which could be supplied to HECO-system combustion turbines).

To begin this analysis, ammonia slip over the four-year catalyst life-cycle was estimated from the demonstration program data and from information provided by the catalyst vendor. The results of this analysis are shown in Figure 7. As shown in this figure, ammonia slip is initially very low and rises with time as the catalyst ages. After four years, the ammonia slip reaches 10 ppm (consistent with the projected four-year catalyst life). Next, the mass transfer, heat transfer, and pressure drop models were applied to estimate the ammonium salt deposition rate, and the corresponding changes in heat transfer efficiency and HRSG pressure drop, on a month-by-month basis.

The Unit 14 HRSG has a maximum casing pressure rating of 20 inches of water. The "clean" HRSG pressure drop is about 7 inches of water, and the estimated catalyst pressure drop for the baseline reactor design is about 5.8 inches of water. Thus, the incremental pressure drop increase resulting from ammonium salt deposition cannot exceed 7.2 inches of water (i.e., 20 - 7 - 5.8 = 7.2 inches of water). To provide a safety margin, it was assumed that the unit would be shut down to remove deposits via water washing when the incremental pressure drop approached or exceeded a 5.2-inch threshold (i.e., 2 inches of water below the maximum allowable increase). It was further assumed that the washing process would reduce the incremental pressure drop to zero by removing all accumulated ammonium salt deposits.

The results of this analysis are shown in Figure 8. This figure shows the incremental HRSG pressure drop due to ammonium salt deposition for the first 24 months of the four-year catalyst life-cycle. During the first year, the incremental pressure drop increases slowly because the ammonia slip from the catalyst is low (the ammonia slip concentration is lower than the SO_3 concentration and thus controls the ammonium salt deposition rate). As a result, the first HRSG wash is not required until after 12 months of operation, and washing reduces the incremental pressure drop to zero. Subsequent pressure drop increases occur more rapidly as the ammonia slip reaches and then exceeds the SO_3 concentration, and the required washing frequency increases. By the end of the second year, HRSG washing is required at two-month intervals, and the pressure drop is increasing at a predicted rate of 3.3 inches of water per month. The pattern at the end of the second year continues through the third and fourth years of the four-year catalyst life-cycle. The predicted washing frequency does not increase in these later years because the ammonia slip concentration has risen above the SO_3 concentration, and the ammonium salt deposition rate is now controlled by the SO_3 concentration in the exhaust gas.

A forced outage lasting approximately three days would be required to clean the HRSG. For the HECO generating system, this affects operating costs in two ways. First, less efficient units would be employed to make up for lost power production during forced combustion turbine outages. Second, the need for frequent cleaning effectively derates these units, and the installation of future generating capacity would be required at an accelerated rate.

SCR Operating Experience at the Garstad Generating Station

Tekniska Verken operates an oil-fired, combined-cycle combustion turbine with SCR in their Garstad generating station in Linkoping, Sweden. Even though this unit is fired with oil containing less sulfur than is used in HECO-system units, it is the only unit in the world with comparable operating conditions (i.e., 100% oil-fired with an appreciable fuel sulfur content). Operating problems have recently been experienced in this unit which are consistent with predictions developed from the demonstration program results.

The unit at Garstad began operations in October, 1994. During the first two years of operation, the unit was fired with oil containing an average sulfur content of 0.07%. Ammonium salt deposits were found in the HRSG after about 1.5 years of operation, but these deposits had not caused significant operating problems.

During the third year of operation, the unit was fired with oil containing 0.13% sulfur due to the unavailability of lower-sulfur fuel oil. During a 2.5-month period in the fall of 1996, rapid increases in the HRSG pressure drop were experienced which forced a reduction in unit load followed by a forced outage to clean the HRSG.

Operating data covering the third year of operation at Garstad are shown in Figure 9. This figure shows the average daily unit load and the HRSG pressure drop (HRSG, catalyst, and ammonium salt deposits) versus time. Higher-sulfur oil firing began in early October. Over the next 2.5 months, the HRSG pressure drop increased at a rate of about 4.8 inches of water per month. In December of 1996, unit load was reduced due to the excessive HRSG pressure drop, and the HRSG was washed in early January, 1997.

The operating experience at Garstad validates the demonstration program methodology used to predict HRSG operating impacts. The delayed onset of operating problems and the magnitude of the pressure drop increases observed at Garstad are consistent with the predictions developed from the demonstration program results.

The HRSG at the Garstad unit is equipped with five sets of steam-fired sootblowers. During the first two years of operation, these sootblowers were fired at a frequency of once per week. When the increases in HRSG pressure drop became apparent, the sootblower operating frequency was increased to once per day. According to Tekniska Verken, the sootblowers had no apparent effect on HRSG pressure drop or the rate of pressure drop increase. Since the sootblowers were ineffective, and their use resulted in reduced unit generating capacity, the sootblower operating frequency was subsequently reduced to once every three days.

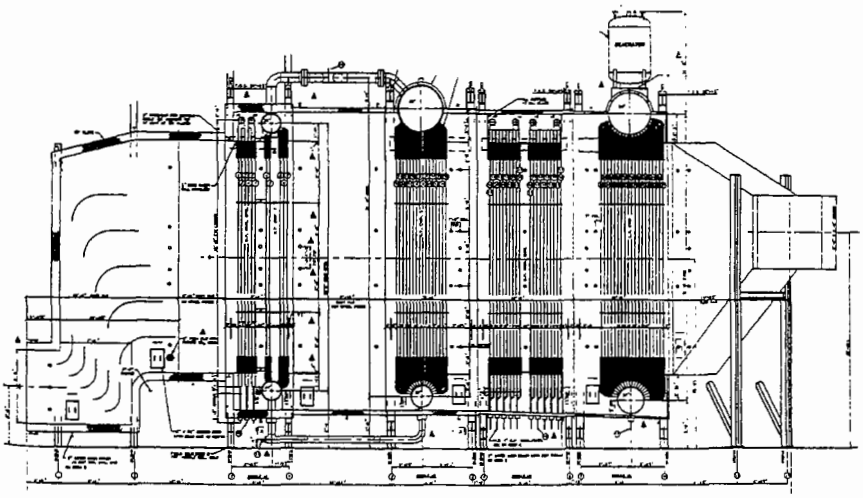

Figure 1
Diagram of the Maalaea Unit 14 HRSG

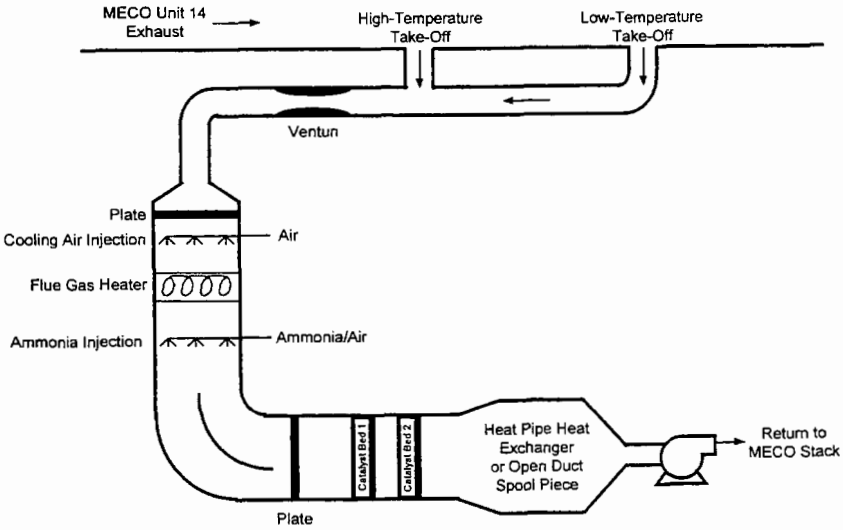

Figure 2
SCR Pilot Unit System Configuration

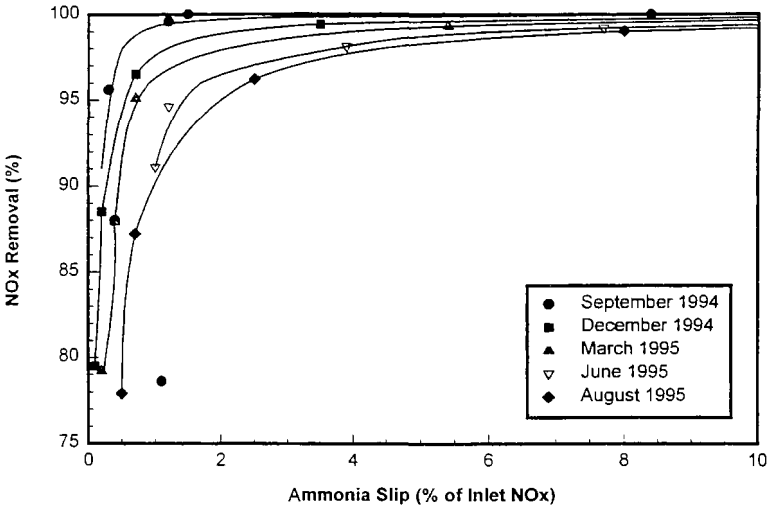

Figure 3
Low-Temperature Catalyst Performance at Reactor Outlet (3100 scfm, 650°F)

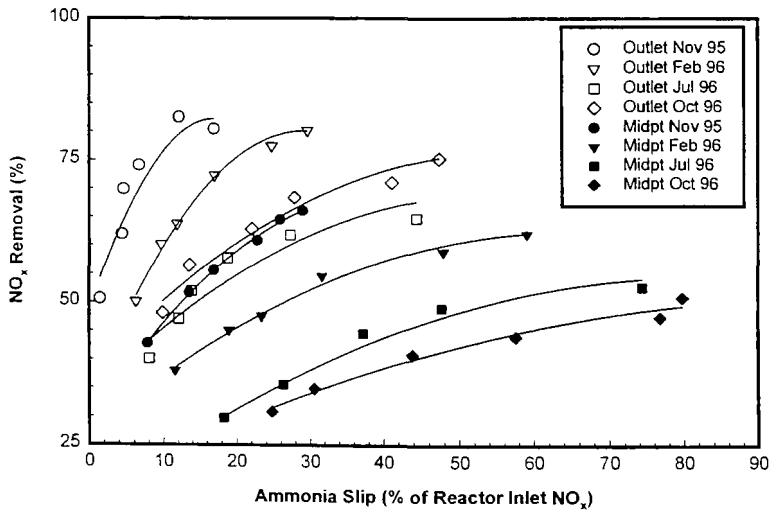

Figure 4
High-Temperature Catalyst Performance (3100 scfm, 1000°F)

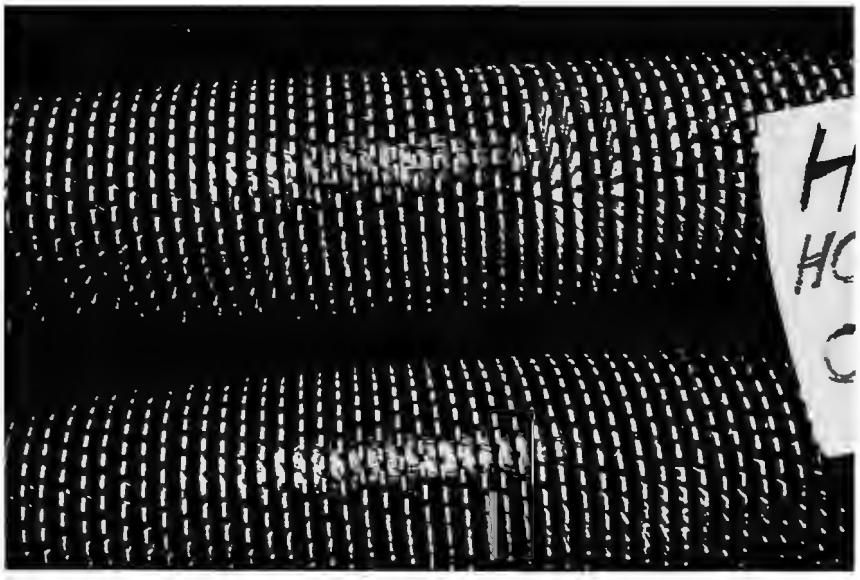

Figure 5
"Clean" Hot-End Tubes (taken after cleaning the tubes for the first time)

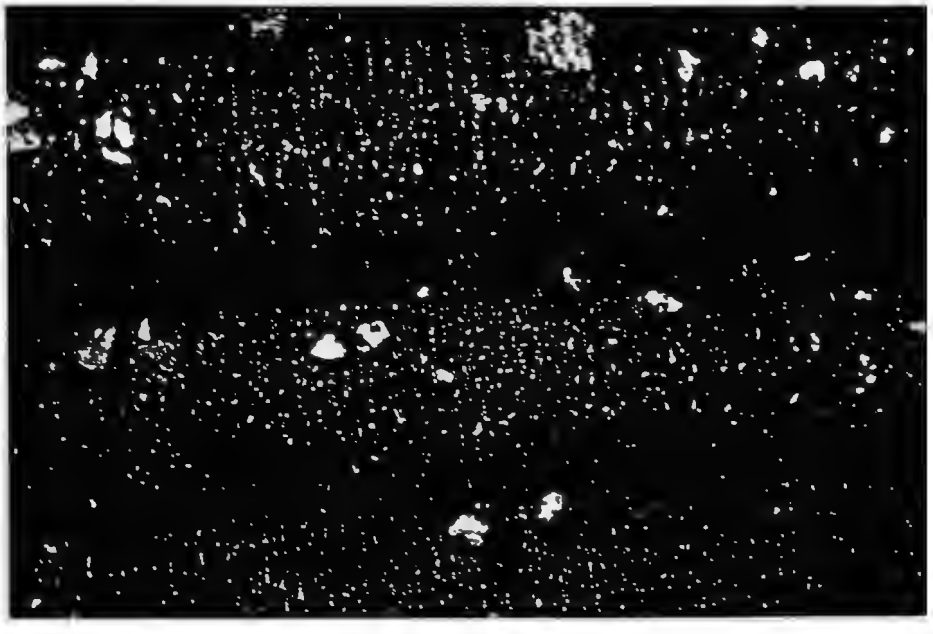

Figure 6
First Cold-End Tubes After Third Long-Term Test)

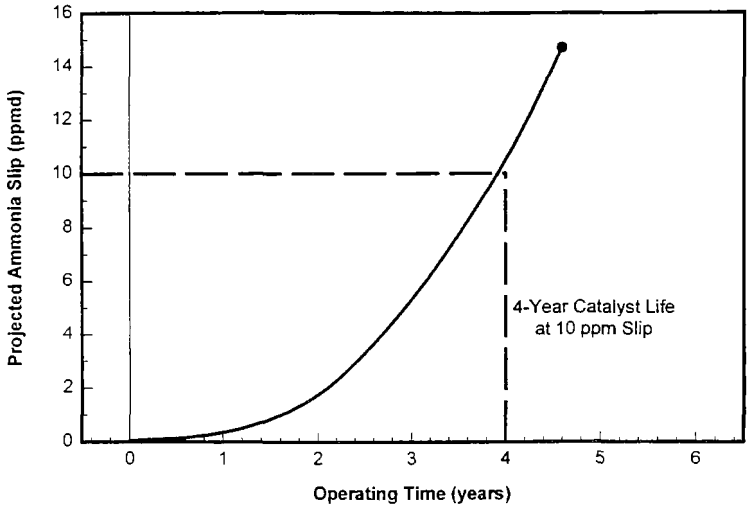

Figure 7
Projected Effect of Low-Temperature Catalyst Deactivation on Ammonia Slip

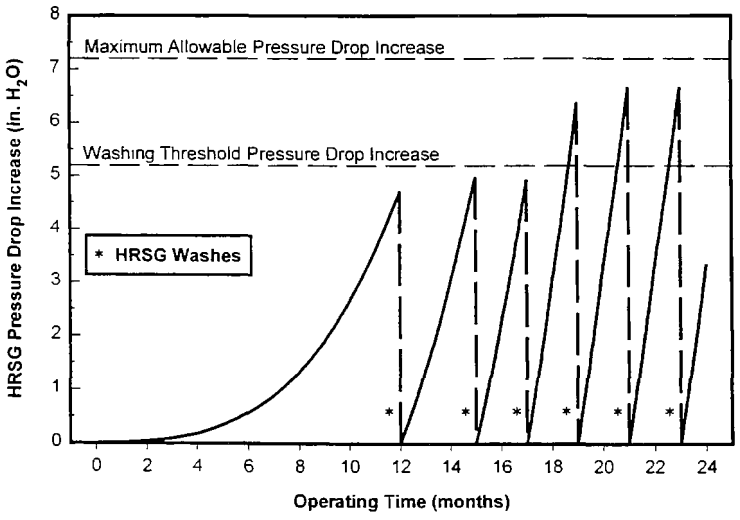

Figure 8
Predicted HRSG Pressure Drop Profile vs. Time

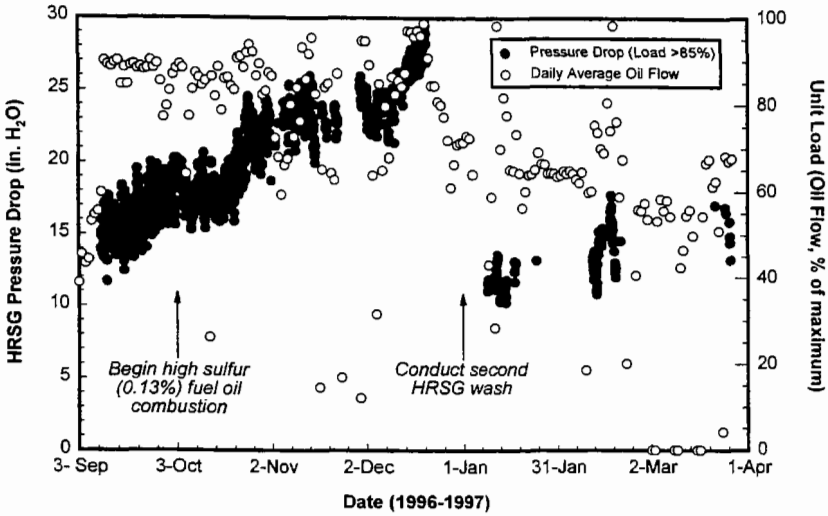

Figure 9
Garstad HRSG Pressure Drop and Unit Load (Oil Flow) Data

Table 1

Demonstration Program SCR Cost Estimates

Cost Case	Capital Cost	Annualized Cost
Low Temperature SCR		
Hypothetical natural gas-fired, 4-year catalyst life.	$1,456,000	$482,000
Oil-fired, 4-year catalyst life:		
- Sootblower management strategy	$2,996,000	$969,000
Water washing management strategy	$2,719,000	$1,212,000
Oil-fired, annual catalyst replacement	$2,719,000	$1,253,000
High-Temperature SCR		
Oil-fired, simple-cycle, 1-year catalyst life	$3,491,000	$1,652,000
Oil-fired, combined-cycle	Not feasible	Not feasible

ECONOMIC ANALYSIS OF SELECTIVE CATALYTIC REDUCTION APPLIED TO COAL-FIRED BOILERS

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Abstract

This report presents the results of an economic evaluation produced as part of an Innovative Clean Coal Technology project, which demonstrated selective catalytic reduction (SCR) technology for reduction of NO_X emissions from utility boilers burning U.S. high-sulfur coal. The project was sponsored by the U.S. Department of Energy (DOE), managed and cofunded by Southern Company Services, Inc. (SCS), on behalf of Southern Company, and also cofunded by the Electric Power Research Institute (EPRI) and Ontario Hydro. Six worldwide catalyst suppliers and major equipment suppliers also participated with technical and financial contributions to the project. The project was located at Gulf Power Company's Plant Crist Unit 5 (75-MW tangentially fired boiler) near Pensacola, Florida. The test program was conducted for approximately two years to evaluate catalyst deactivation and to quantify operational impacts of SCR technology employed in a high-sulfur flue gas environment. The SCR test facility included nine parallel reactors equipped with commercially available catalysts ranging in size from 400 scfm (680 Nm^3/hr) to 5000 scfm (8500 Nm^3/hr). Results of the economic evaluation indicate that total capital requirements ($/kW) decrease with increasing unit size for both new and retrofit SCR applications. However, capital costs are approximately 50 percent higher for retrofit installations when compared with new plant applications. Lower levelized costs ($/ton) are achieved when SCR is applied to larger, higher utilized units due to economies of scale and the fact that a greater amount of tons are removed on larger units. In all SCR applications, higher inlet NO_X levels significantly decrease the levelized cost.

Introduction

There are several regulatory and environmental drivers in various stages of consideration that may increase the likelihood of employing SCR technology in the future. Recent experience of

applying SCR to new coal-fired installations has created regulatory precedent under New Source Review, which will affect future best available control technology (BACT) and lowest achievable emission rate (LAER) determinations for other new units. With one exception, these new installations are owned and/or operated by independent power producers (IPPs) who report that adopting SCR technology was necessary to obtain construction and/or operating permits quickly.

The 1990 Clean Air Act Amendments (CAAA) mandated several NO_X control requirements and regulatory reviews to reduce NO_X emissions from utility boilers. Application of SCR to existing boilers is being considered for units located in areas designated under Title I (nonattainment provisions) for attainment of the ambient ozone standard. Recent efforts by the Ozone Transport Assessment Group (OTAG) have focused on NO_X reduction strategies on a broader scale, encompassing 37 states east of and bordering the Mississippi River. Results of the OTAG review may increase the likelihood for retrofits of SCR technology, particularly if emission averaging and NO_X trading are allowed. Additionally, nationwide reductions in NO_X mandated under Phase II of Title IV (acid rain provisions) may be required. In order to meet these additional NO_X reduction requirements, utilities are given flexibility to select the most suitable and cost-effective NO_X control technologies for their situation.

Application of SCR Technology for a New Unit

The economic evaluation presented in this section is based on the application of a high-dust, hot-side SCR (located between the boiler economizer outlet and the air preheater inlet) at a new coal-fired facility. The technical design premises used to prepare the economic analysis were selected to be representative of actual or anticipated plant configurations and NO_X control requirements currently being permitted or likely to be permitted on new coal-fired boilers in the U. S. Therefore, defining assumptions were selected in an effort to have broad utility applicability.

250-MW Base Case Unit Description

The base case represents a new, base-loaded 250-MW pulverized coal power plant typical of the majority of new coal-fired projects currently under development, construction, or recently declared in commercial operation. The 250-MW plant size is consistent with current and future capacity trends of new domestic power plants. The plant is located in a rural area with minimal space limitations. The fuel is a high-sulfur bituminous Illinois No. 6 coal having an analysis shown in Table 1.

Table 1: Coal Analysis Used for Economic Evaluation

Proximate Analysis	Dry Basis	As Received
Ash	9.30 %	8.39 %
Volatile Matter	37.88 %	34.16 %
Fixed Carbon	52.82 %	47.65 %
Moisture		9.80 %
Total	100.00 %	100.00 %
Ultimate Analysis	**Dry Basis**	**As Received**
Carbon	74.82 %	67.48 %
Hydrogen	5.00 %	4.51 %
Nitrogen	1.58 %	1.43 %
Sulfur	2.58 %	2.33 %
Chlorine	0.16 %	0.14 %
Oxygen	6.56 %	5.92 %
Ash	9.30 %	8.39 %
Water		9.80 %
Total	100.00 %	100.00 %
Higher Heating Value	13,265 Btu/lb	12,500 Btu/lb

Utilizing current generation low-NO_X combustion systems, the boiler is assumed to

produce NO_X at an emission rate of 0.35 lb/MBtu. For purposes of this study, it is assumed that tangentially fired boilers and wall-fired boilers are interchangeable with respect to thermal performance and flue gas constituents. The flue gas exits the boiler and enters a single, hot-side SCR reactor. Flue gas flow is vertically downward through the reactor to the air preheater. The air preheater is typical of what is commercially offered as a "deNO_X" air preheater. The SCR is designed as a universal reactor capable of accepting either, or both, plate- or honeycomb-type catalysts. Anhydrous ammonia is used as the reagent. Assumptions used to prepare the material balance for the base case are shown in Table 2. General design criteria for the SCR are shown in Table 3. Where applicable, the design criteria reflect operational lessons learned from the test facility and/or current utility industry trends in post combustion NO_X control.

Table 2: 250-MW Base Case Material Balance and Combustion Calculation Assumptions

Unit capacity (gross)	250 MW
Capacity factor	65%
Type of installation	New facility
Boiler type	Wall-fired or tangentially fired
Heat input	2,375 MBtu/hr
Coal feed	190,000 lb/hr
Gross plant heat rate	9,500 Btu/kW-hr
Type of air preheaters	Vertical shaft, Ljungstrom
Number of air preheaters	One
Air preheater outlet temperature	300°F
Air preheater leakage	13%
Excess air @ boiler outlet	18%

Table 3: SCR Design Criteria

Type of SCR	Hot-side
Number of SCR reactors	One
Reactor configuration	3 catalyst support layers + 1 dummy layer
Initial catalyst load	2 of 3 layers loaded, 1 spare layer
Required range of operation	35% to 100% boiler load
NO_X concentration @ SCR inlet	0.35 lb/MBtu
Design NO_X reduction	60%
Flue gas temp @ SCR inlet	700°F
Flue gas pressure @ SCR inlet	-5 in. W.G.
Design ammonia slip	5 ppm
Guaranteed catalyst life	2 years (16,000 hours)
SO_2 to SO_3 oxidation	0.75% (initial catalyst load)
Maximum pressure drop	6 in. W.G. (fully loaded reactor)
Velocity distribution	$\Delta V / V_{mean} < 10\%$ over 90% of reactor area
	$\Delta V / V_{mean} < 20\%$ over remaining 10% area
Ammonia distribution	$\Delta C / C_{mean} < 10\%$
Temperature distribution	$\Delta T < 10°C$ max deviation from mean

Initial Space Velocity and Catalyst Volume

Space velocity is a process variable that is used in determining the quantity of catalyst required for a given NO_X removal requirement. Space velocity is defined as the volume of flue gas

treated per unit volume of catalyst. The standard convention for expressing flue gas flow rate is in ft^3/hr (m^3/hr) corrected to conditions of 32°F (O°C) and 1 atmosphere (1 bar). Catalyst volume is expressed in corresponding units of ft^3 or m^3 Thus, space velocity can be expressed:

$$SV = \frac{\text{Flue Gas Flow, } ft^3/hr\ (m^3/hr)}{\text{Catalyst Volume, } ft^3\ (m^3)}$$

For this analysis, a relationship between space velocity and NO_X removal has been determined for both new and retrofit units. The relationship for new units is represented by a least squares curve fit of space velocities taken from five new coal-fired SCR installations in the U.S. Design information was assembled from commercial bid evaluations, project specific design criteria, and publicly available sources. The relationship for retrofit units was developed using a least squares curve fit of test facility data measured during parametric testing and each catalyst supplier's proposed space velocity based on the test facility steady state design criteria. The relationship does not represent a single catalyst supplier's offering, but rather a composite of all catalyst space velocities. This approach was selected to provide a reasonable method for estimating space velocity, which is independent of catalyst geometry.

Catalyst Life and Catalyst Management Plan

The term "catalyst life guarantee" is often misinterpreted to mean the performance of the SCR sharply decreases and the entire volume of catalyst must be replaced after the guarantee period. This interpretation is not correct. In general, catalyst performance during early project years (or months) normally exceeds the guarantee values. Over time, the catalyst performance will deteriorate gradually until the SCR is unable to maintain the required NO_X removal while simultaneously achieving the required ammonia slip. (Most SCR installations operate on a constant NO_X removal to allow continued operation with permitted NO_X emissions at the expense of increased ammonia slip.) Even though the SCR cannot meet guaranteed ammonia slip versus NO_X performance, the catalyst still has considerable activity remaining.

The SCR reactor for this evaluation includes space for three catalyst layers plus a flow straightener. Initially, only two of the three catalyst layers are loaded. The third empty layer allows catalyst suppliers to develop optimized management plans to improve catalyst utilization. A fresh catalyst layer can be added to the reactor after the guarantee period when ammonia slip begins to exceed the guaranteed limit. The activity of the new catalyst combined with the residual activity of the existing catalyst restores the performance of the SCR and extends the next addition or replacement outage beyond the original guarantee interval.

During the demonstration at Plant Crist, catalyst deactivation data were periodically measured by taking catalyst samples from the test facility reactors and returning the samples to the respective catalyst supplier. The catalyst suppliers performed a standard protocol of laboratory and bench scale tests to develop an activity versus time relationship. The base case catalyst management plan (Figure 1) was derived using these data. A least squares curve fit of catalyst relative activity (k/ko - ratio of activity to initial activity) over time resulted in a value of approximately 0.80 after 16,000 hours of service.

The catalyst management plan is based on a 16,000-hour (2-year) catalyst life guarantee period. After the initial guarantee period of 2 years, a new layer of catalyst is added to the reactor spare layer, taking advantage of the residual activity in the initial layers to boost the performance of the SCR. The next addition of catalyst is required in project year 6, when one of the initial layers is replaced. After project year 6, staged replacement of catalyst layers occurs approximately every three years.

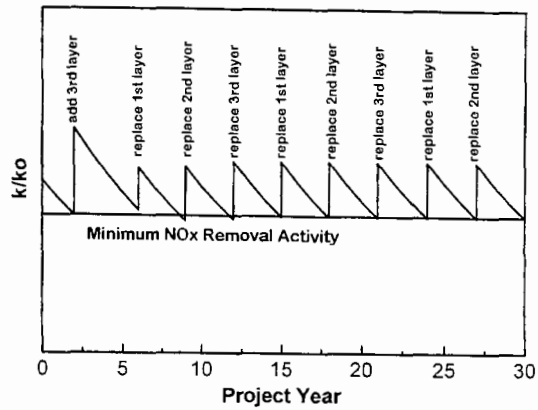

Figure 1: Catalyst Management Plan

Economic Premises

The base case economic evaluation includes total capital requirement, fixed and variable operating costs, and levelized costs for a new 250-MW pulverized coal utility boiler. The economics are presented on both a current dollar basis, which includes the effect of inflation, and a constant dollar basis, which ignores inflation.

The methodology used to calculate the economic factors is consistent with guidelines established by EPRI in their Technical Assessment Guide (TAG). The economic parameters assumed for this evaluation are representative of typical domestic utility financing (Table 4).

Table 4: Economic Evaluation Factors

Current Dollar Analysis:	
Capital Charge Factor	0.150
O&M Cost Levelization Factor	1.362
Constant Dollar Analysis:	
Capital Charge Factor	0.116
O&M Cost Levelization Factor	1.000

Cost Methodology

The capital cost methodology must reflect all utility costs incurred (including incremental costs) and address a complete scope of supply for a commercial SCR system. For example, the differential cost of an ID fan for a unit without SCR compared to a unit with SCR is seldom assessed against the SCR scope of the project. This differential cost, while real to the utility, is more commonly assessed to either a fan or draft system account that does not fully capture the incremental economic impact to balance-of-plant systems due to the SCR. The capital cost estimates prepared for this economic evaluation include incremental cost adders applicable to new facilities brought about by the addition of SCR.

Fixed O&M costs include estimates of operating labor, maintenance labor, administration or support labor, and maintenance material. Variable O&M captures the cost of all commodities as well as costs of expendables such as anhydrous ammonia, catalyst addition/replacement, and utilities. Variable O&M also includes the boiler efficiency penalty incurred due to increased APH outlet gas temperature. Because variable O&M costs are dominated by catalyst replacement, the catalyst management plan is one of the most significant factors affecting overall

costs of SCR technology. Table 5 presents the assumptions used to calculate the fixed and variable O&M costs for the base case evaluation.

Table 5: Fixed and Variable O&M Assumptions

Anhydrous ammonia cost	$250/ton
SCR catalyst cost	$400/ft^3
SCR catalyst escalation	3.0%
Power cost	30 mills/kWh
ID fan efficiency	75%
SCR draft loss (fully loaded reactor)	3.0 in. W.G.
Ductwork draft loss	0.75 in. W.G.
Ammonia injection grid draft loss	0.75 in. W.G.
Unrecoverable air preheater draft loss	1.0 in. W.G.
Operating labor man-hour rate	$23.00/hr
Maintenance factor (% of total process capital)	2.0%

250-MW New Unit Base Case

The 250-MW base case (60 percent NO_X removal efficiency) results are summarized in Table 6. The total capital requirement for a new SCR installation was estimated at $54/kW or $13,415,000 in 1996 dollars. Total first year O&M is $1,045,000 in 1996 dollars. The initial catalyst charge accounts for approximately 21 percent of the total process capital for the SCR installation. From an O&M perspective, the total catalyst added over the project life is approximately 61 percent of the variable O&M and 43 percent of the total annual O&M cost, reiterating the fact that O&M costs are dominated by catalysts.

Compared with other NO_X reduction alternatives, the higher capital costs of SCR dominate the levelized cost. For the 250-MW base case, the capital cost is 59 percent of the current dollar total levelized cost, indicating a major portion of the levelized cost goes toward debt service (revenue requirement) of the capital investment rather than operating costs.

Table 6: Capital, O&M, and Levelized Cost for New SCR vs. Unit Size
(60 Percent NO_X Removal Efficiency)

	Unit Size (MW)	Base Case	
	125-MW	250-MW	700-MW
Total Capital Requirement	$7,602,000	$13,415,000	$31,327,000
Total Capital Requirement	$ 61/kW	$54/kW	$45/kW
First Year Fixed Operating Cost	$ 213,000	$312,000	$614,000
First Year Variable Operating Cost	$ 367,000	$ 733,000	$2,053,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.89	2.57	2.22
Levelized Cost ($/ton)	$2,811	$2,500	$2,165
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	2.09	1.85	1.59
Levelized Cost ($/ton)	$2,037	$1,802	$1,547

Sensitivity Analyses for New Unit Applications (Effect of Variables on Economics)

Sensitivity analyses were performed to examine the impact of major process variables on the capital, O&M, and levelized cost of SCR technology applied to a new unit. Results from sensitivity cases examined as part of this evaluation are discussed in the following sections.

Capital, O&M, and Levelized Cost for New SCR vs. Unit Size

In order to examine the variation in SCR costs with unit size, capital and O&M estimates were calculated for a 125-MW unit and 700-MW unit (Table 6). To maintain consistency with the base case unit, an SCR removal efficiency of 60 percent NO_X reduction was assumed for each scenario. Where possible, consistent or identical assumptions were made with regard to the 125-MW and 700-MW units.

When plotted in $/kW vs. unit size, the total capital requirement of the SCR system decreases unit cost with increasing unit size, indicating significant economy of scale. Total capital requirement ranges from $61/kW for the 125-MW unit to $45/kW for the 700-MW unit (Figure 2). The levelized cost decreases with increasing unit size due to larger NO_X tonnages removed; however, the trend is not overly sensitive to unit size (Figure 3).

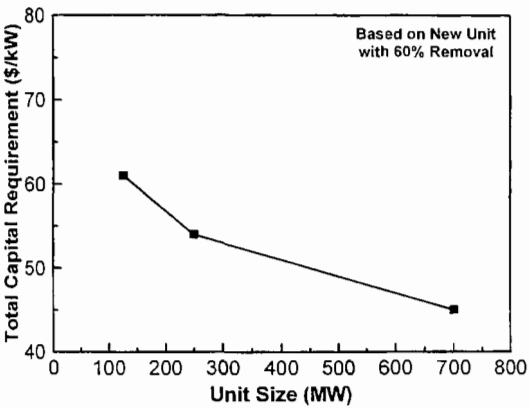

Figure 2: Total Capital Requirement vs. Unit Size

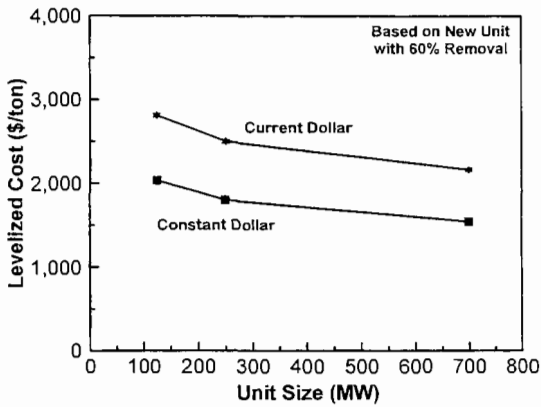

Figure 3: Levelized Cost vs. Unit Size

Capital, O&M, and Levelized Cost for New SCR vs. Capacity Factor

In many instances SCR costs are determined assuming a capacity factor of 65 percent. Frequently, however, the capacity factor of the SCR may be less than that of the overall unit, or the unit may be dispatched at a level lower than anticipated. In practice units equipped with SCR may only utilize ammonia injection at or above certain loads. At lower loads, many units emit very low levels of NO_X eliminating the need to utilize the SCR. For those units that must meet daily emissions limits, it may be possible to turn off the ammonia injection once the daily limit has been achieved. Therefore, in effect, these practices may decrease the SCR capacity factor.

With this in mind, the variation of SCR costs with capacity factor was determined (Figure 4). O&M and levelized cost estimates for capacity factors of 30 and 90 percent are compared with the base case (65 percent) in Table 7. Results indicate increasing the capacity factor beyond 65 percent has a relatively small impact on levelized cost; however, as the capacity factor drops below 60 percent, costs increase rapidly. For example, a 20 percent reduction in capacity factor from the base case increases the current dollar levelized cost from $2500/ton to $3451/ton (a 38 percent increase).

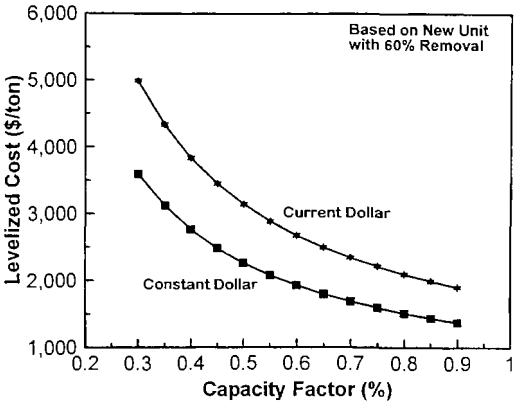

Figure 4: Levelized Cost vs. Capacity Factor

Table 7: O&M, and Levelized Cost for New SCR vs. Capacity Factor (250-MW Plant and 60 Percent NO_X Removal)

	Capacity Factor (%)	Base Case	
	30	65	90
First Year Fixed Operating Cost	$ 266,000	$312,000	$346,000
First Year Variable Operating Cost	$ 581,000	$ 733,000	$842,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	5.13	2.57	1.96
Levelized Cost ($/ton)	$4,994	$2,500	$1,907
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	3.69	1.85	1.41
Levelized Cost ($/ton)	$3,593	$1,802	$1,377

Capital, O&M, and Levelized Cost for New SCR vs. NO_X Removal Efficiency

NO_X removal cases for 40 percent and 80 percent were calculated to examine the impact of NO_X removal efficiency on levelized cost. For these cases, capital, O&M, and levelized costs versus NO_X removal efficiency for a 250-MW plant size were determined (Table 8 and Figure 5). The levelized cost decreases with increasing NO_X removal percentages and is fairly sensitive to the percentage removal. Thus, once committed to an SCR, significant levelized cost savings ($/ton) can be realized for an incremental increase in capital cost. The difference in capital cost between 40 percent and 80 percent removal is $1,168,000 or approximately a 9 percent increase in capital cost over the 40 percent design. However, the corresponding difference in current dollar levelized cost is $1466/ton, a 42 percent decrease from the 40 percent case. This difference is primarily due to doubling the number of tons removed by increasing NO_X removal from 40 to 80 percent. This trend in lower levelized cost is also very evident in high NO_X emitting boilers where similar NO_X removal designs (as a percentage) yield lower $/ton due to a larger number of tons removed.

Table 8: Capital, O&M, and Levelized Cost for New SCR vs. NO_X Removal Efficiency (250-MW Plant Size)

	NO_X Removal Efficiency Base Case		
	40%	60%	80%
Total Capital Requirement	$12,974,000	$13,415,000	$14,142,000
Total Capital Requirement	$52/kW	$54/kW	$57/kW
First Year Fixed Operating Cost	$305,000	$312,000	$324,000
First Year Variable Operating Cost	$621,000	$733,000	$857,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.39	2.57	2.79
Levelized Cost ($/ton)	$3,502	$2,500	2,036
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	1.74	1.85	2.00
Levelized Cost ($/ton)	$2,536	$1,802	$1,460

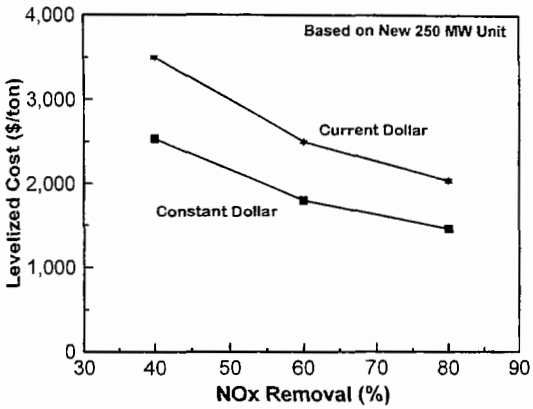

Figure 5: Levelized Cost vs. NO_X Removal Efficiency

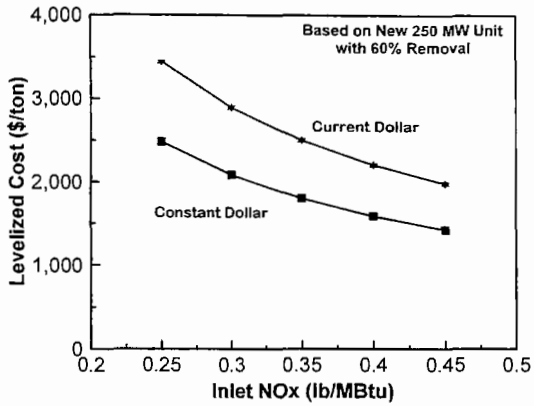

Figure 6: Levelized Cost vs. Inlet NO_X

Levelized Cost for New SCR vs. Inlet NO_X Concentration

At many new boiler installations, difficult decisions are made on how to best optimize overall NO_X reduction requirements using a combination of a low-NO_X combustion system and SCR. While maximizing combustion NO_X reductions can allow lower SCR variable O&M, it may have a negative impact on thermal cycle efficiency due to increased unburned carbon in the flyash. Increased carbon monoxide production may also be a limiting factor during deep staged combustion. Optimizing the combustion system to minimize unburned carbon can lead to higher NO_X concentrations entering the SCR and, therefore, higher variable O&M costs to achieve a permitted outlet NO_X emission limit. The relationship between levelized cost ($/ton) and SCR inlet NO_X concentration indicates a significant trend of increasing levelized cost with decreasing inlet NO_X concentration (Figure 6 and Table 9). In this case, fewer tons of NO_X are removed by the SCR, highlighting one of the key differences in levelized cost between a controlled new unit application and an uncontrolled (or higher NO_X emitting) retrofit application.

Table 9: Levelized Cost for New SCR vs. Inlet NO_X Concentration
(250-MW Plant Size and 60 Percent NO_X Removal Efficiency)

	Inlet NO_X Concentration (lb/MBtu)				
	0.25	0.30	0.35	0.40	0.45
Current Dollar Analysis					
Levelized Cost (mills/kWh)	2.53	2.55	2.57	2.59	2.61
Levelized Cost ($/ton)	$3,446	$2,894	$2,500	$2,205	$1,977
Constant Dollar Analysis					
Levelized Cost (mills/kWh)	1.82	1.84	1.85	1.87	1.88
Levelized Cost ($/ton)	$2,483	$2,086	$1,802	$1,590	$1,425

Levelized Cost for New SCR vs. Catalyst Relative Activity

For this evaluation, three catalyst management plans were formulated based on a 16,000-hour (2-year) catalyst life guarantee period by correlating deactivation data from the Plant Crist demonstration. Because the relative activity data indicate a wide variation in values as well as the fact that each catalyst supplier extracted an unequal number of catalyst samples at different time intervals over the test period, three sets of individual catalyst data were identified for further evaluation. From the demonstration data, catalyst management plans were developed for sensitivity evaluation based on relative activity (k/ko) data having values of 0.90, 0.80, and 0.70 after 16,000 hours. This range sets the limit for the upper and lower bounds of the relative activity variation and appears reasonably plausible and equally likely to occur given the scarce amount of data beyond 8,000 hours and the differences in catalysts.

Using the relative activity data, catalyst management plans were developed which define the catalyst replacement schedule over the project life. From the management plan, the total number of catalyst layers installed or replaced in each year over the life of the project was determined (Figure 7).

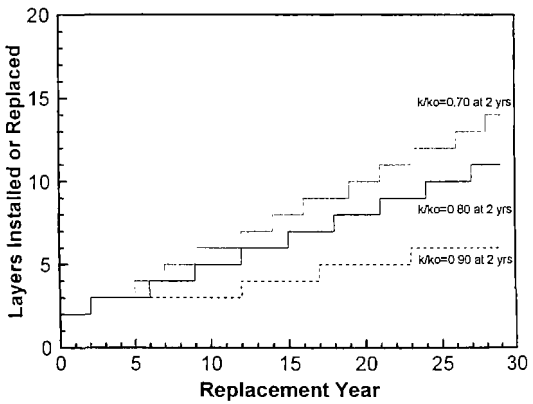

Figure 7: Number of Catalyst Layers Installed or Replaced

Knowing the volume of catalyst, as well as the time which it is added, project cash flows were developed for each scenario. The total catalyst volume installed between the most optimistic (k/ko = 0.90) and most pessimistic (k/ko = 0.70) management plans varies by 21,664 ft^3 (a factor of three times). This translates to a catalyst cost difference of $377,000 per year, representing a 64-percent difference in annual O&M dollars (Figure 8). Additionally, if catalyst disposal costs were included, the cost difference would be more pronounced since the k/ko = 0.70 plan would require the disposal of three times as much catalyst. The current dollar levelized cost varies only $373/ton or a

difference of only 14 percent between the two extreme cases (Figure 9 and Table 10). Even though the k/ko = 0.70 plan adds three times as much catalyst, the catalyst is added in later project years, which has less effect when performing a present value analysis and levelizing to calculate the equivalent annual catalyst cost.

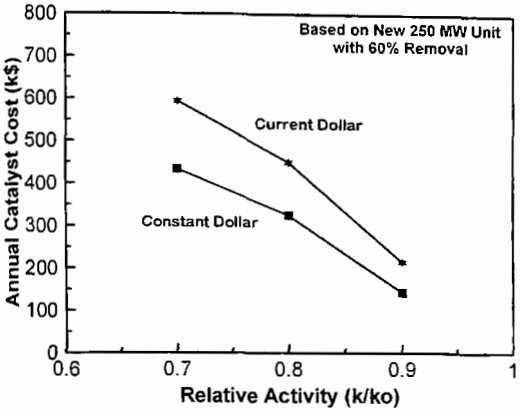

Figure 8: Catalyst Cost vs. Relative Activity

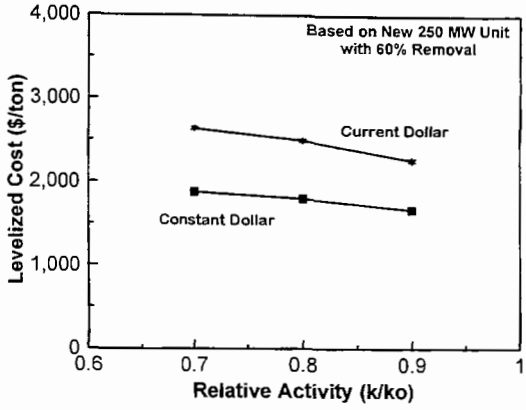

Figure 9: Levelized Cost vs. Relative Activity

Table 10: Levelized Cost for New SCR vs. Catalyst Relative Activity (Catalyst Management Plan) (250-MW Plant Size and 60 Percent NO_X Removal Efficiency)

	k/ko = .90	k/ko = .80	k/ko = .70
Total Catalyst Volume Added or Replaced Over the Life of the Plant (ft^3)	10,832	24,372	32,496
Equivalent Annual Current Dollar Catalyst Cost	$216,000	$450,000	$593,000
Equivalent Annual Constant Dollar Catalyst Cost	$144,000	$325,000	$433,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.33	2.57	2.71
Levelized Cost ($/ton)	$2,269	$2,500	$2,642
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	1.72	1.85	1.93
Levelized Cost ($/ton)	$1,671	$1,802	$1,881

Levelized Cost for New SCR vs. Catalyst Life

In addition to the previous scenarios, three additional catalyst management plans were developed by varying the year in which the third layer of catalyst is initially added. These plans represent better than expected (add 3rd layer at year 3) and worse than expected (add 3rd layer at year 1) results and assume a relative activity of k/ko = 0.80 after 1, 2, and 3 years. Total catalyst volume and levelized cost for the three different management plans are summarized in Table 11. In the worst-case scenario (3rd layer added at year 1), 22 layers of catalyst were installed or replaced over the project life (Figure 10). In contrast, only 8 layers were installed or replaced in the best-case scenario (3rd layer added at year 3). In terms of levelized cost on a current dollar basis, the two extreme cases vary by $674/ton (Figure 11).

Table 11: Levelized Cost for New SCR vs. Year to Add 3rd Catalyst Layer
(Catalyst Management Plan)
(250-MW Plant Size and 60 Percent NO_X Removal Efficiency)

	k/ko = .80 after 1 yr	k/ko = .80 after 2 yrs	k/ko = .80 after 3 yrs
Total Catalyst Volume Added or Replaced Over the Life of the Plant (ft^3)	51,452	24,372	16,248
Equivalent Annual Current Dollar Catalyst Cost	$965,000	$450,000	$285,000
Equivalent Annual Constant Dollar Catalyst Cost	$686,000	$325,000	$217,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	3.09	2.57	2.40
Levelized Cost ($/ton)	$3,011	$2,500	$2,337
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	2.12	1.85	1.77
Levelized Cost ($/ton)	$2,065	$1,802	$1,724

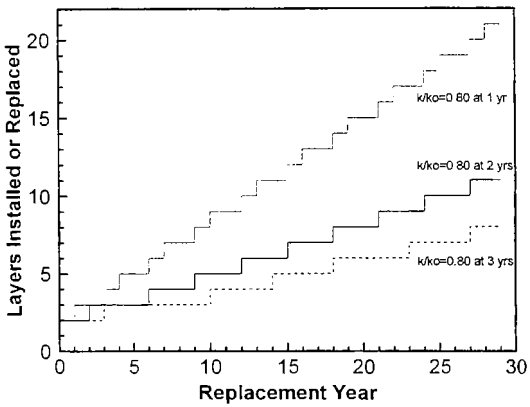

Figure 10: Number of Catalyst Layers Installed or Replaced

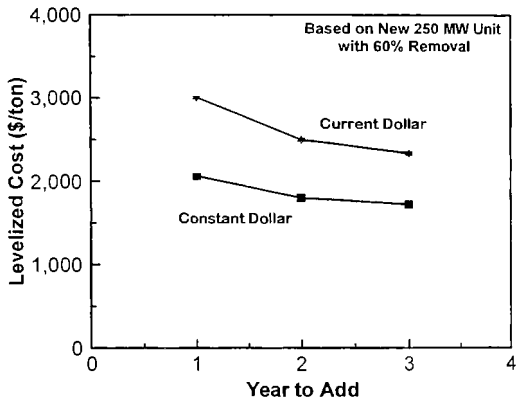

Figure 11: Levelized Cost vs. Year to Add 3rd Layer

Capital, O&M, and Levelized Cost for New SCR vs. Catalyst Price

To address the sensitivity of capital, O&M, and levelized costs to changes in the market price of catalyst, the catalyst price was varied between $350/ft^3 and $450/ft^3 for a new 250-MW plant with 60 percent NO_X removal efficiency (Table 12). It is recognized that dynamic market forces may cause wider variation in prices than those assumed for this analysis. Varying the catalyst price +/- 12.5 percent (+/- $50/ft^3) results in a change in levelized cost of only +/- 4 percent. Variable O&M is the most sensitive to changes in catalyst price since catalyst cost dominates this annual expense. Capital cost changed approximately 2 percent as the catalyst represents only 20 to 25 percent of the total process capital.

Table 12: Capital, O&M, and Levelized Cost for New SCR vs. Catalyst Price (250-MW Plant Size and 60 Percent NO_X Removal Efficiency)

	Catalyst Price ($/ft^3)		
	$350	$400	$450
Total Capital Requirement	$13,040,000	$13,415,000	$13,777,000
Total Capital Requirement	$52/kW	$54/kW	$55/kW
First Year Fixed Operating Cost	$306,000	$312,000	$319,000
First Year Variable Operating Cost	$677,000	$733,000	$789,000
Current Dollar Analysis			
Levelized Cost (mills/kWh)	2.46	2.57	2.67
Levelized Cost ($/ton)	$2,398	$2,500	$2,602
Constant Dollar Analysis			
Levelized Cost (mills/kWh)	1.78	1.85	1.92
Levelized Cost ($/ton)	$1,737	$1,802	$1,867

Application of SCR Technology for a Retrofit Unit

The economic evaluations reported in prior sections of this paper focused on an SCR reactor installed on a new coal-fired facility. However, the majority of the near-term U.S. SCR market may be in retrofit applications. The cost of implementing SCR technology is a topic of considerable debate in the present deliberations by OTAG and in defining the U.S. Environmental Protection Agency's (EPA) proposed CAAA Title IV NO_X emission limits for Group 2 boilers.

Because of the considerable uncertainty and debate involving SCR retrofit cost for existing plants, the cost and technical feasibility of retrofitting SCR technology to existing coal-fired generating units was determined. The results of this study reflect the wide range of retrofit costs typically encountered due to site-specific issues. It is recognized that the costs summarized are applicable to dry-bottom, pulverized coal boilers and may or may not be indicative of other installations due to boiler type, site constraints, and/or inlet NO_x levels to the SCR.

Summary of Capital and O&M Costs for Retrofit Units

For a 250-MW plant, the capital cost difference between a new SCR installation and retrofit SCR installation were evaluated (Table 13). Results of this evaluation indicate capital costs to be approximately 50 percent higher for retrofit installations when compared with new plant applications.

Of the units evaluated, capital costs for installing a retrofit SCR range from $59/kW for an 880-MW unit to $87/kW for a 100-MW unit assuming no balanced draft conversions. For a similar 880-MW unit requiring a balanced draft conversion, the capital requirement is estimated to be $130/kW. This comparison is highly site specific, however, and actual retrofit costs may be higher or lower than those presented here.

Current dollar levelized costs for an SCR retrofit vary from $1,541/ton to $7419/ton depending on NO_x removal percentage, unit size, inlet NO_x concentration, utilization (capacity factor), and capital and O&M costs. Lower levelized costs are achieved when SCR is applied to larger, higher utilized units due to economies of scale and the fact that greater amounts of tons are removed on larger units. All of the units included in the study are equipped with some type of combustion modifications to lower the NO_x concentration prior to the SCR. While some capital cost savings can be achieved in the SCR by lowering the inlet NO_x, the resulting levelized cost is higher due to reduced tons removed when compared to an SCR retrofit on an uncontrolled unit.

Figure 12 shows a comparison of levelized cost versus NO_x removal efficiency for a new and retrofit SCR installation applied to a 250-MW unit designed for 60 percent NO_x removal. The difference in cost is primarily due to higher capital cost of the retrofit installation, since the inlet NO_x concentration for the retrofit (0.40 lb/MBtu) and the new unit (0.35 lb/MBtu) are similar and approximately the same number of tons of NO_x are removed. Compared to the difference in capital costs, the levelized cost differences between the new SCR installation and the retrofit SCR installations are much less significant. Nevertheless, technical and economic assessment of SCR must be based on both the levelized cost and the first cost (capital cost cash flow) of the proposed installation.

In addition to the low inlet NO_X conditions, specific retrofit cost data were extrapolated to high inlet NO_X conditions in an effort to represent many of the boilers in the OTAG region

Table 13: Capital Cost Differences for New and Retrofit SCR Installations (250-MW Plant Size)

	NO_X Removal Efficiency		
	40%	60%	80%
New SCR Installation			
Total Capital Requirement	$12,974,000	$13,415,000	$14,142,000
Total Capital Requirement	$52/kW	$54/kW	$57/kW
Retrofit SCR Installation			
Total Capital Requirement	$18,800,000	$20,281,000	$21,403,000
Total Capital Requirement	$75/kW	$81/kW	$86/kW

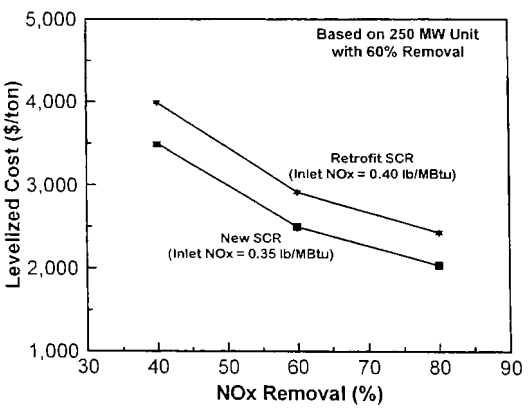

Figure 12: Levelized Cost vs. NO_X Removal

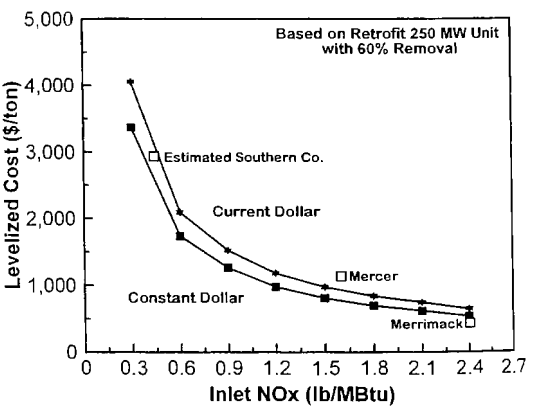

Figure 13: Levelized Cost vs. High Inlet NO_X

(Figure 13). The extrapolated data indicate a significant trend of decreasing levelized cost with increasing inlet NO_X concentration, highlighting a key difference in cost effectiveness between lower emitting boilers (or boilers which have been controlled with combustion modifications prior to the SCR) and higher emitting, uncontrolled boilers.

Conclusions

The economic analysis of applying SCR to a new 250-MW unit with a 60 percent NO_X removal efficiency resulted in capital and first year O&M costs (in 1996 dollars) of $13,415,000 ($54/kW) and $1,045,000, respectively. Levelized costs are $2,500/ton on a current dollar basis and $1,802/ton on a constant dollar basis.

Once the base case was established, sensitivity analyses were performed to examine the impact of major process variables on the capital, O&M, and levelized cost of applying SCR technology to a new unit. Those factors affecting capital costs include unit size, NO_X removal efficiency, and catalyst price with unit size having the greatest impact. For new plant applications, total capital requirements for a 60 percent NO_X removal design range from $45/kW for a 700-MW unit to $61/kW for a 125-MW unit.

With respect to current dollar levelized costs, several additional factors were examined including capacity factor, inlet NO_X concentration, catalyst relative activity, and catalyst life. Of these, levelized costs are most sensitive to capacity factor and inlet NO_X. The relationship between levelized cost and SCR inlet NO_X concentration demonstrates that SCR installations become much more costly as the inlet NO_X is reduced. Capacity factor shows a similar trend. For example, a 20 percent reduction in capacity factor from the base case (65 percent) increases the current dollar levelized cost by 38 percent.

An evaluation of retrofit SCR applications was performed as well. The retrofit applications evaluated show a range of capital requirements from $59/kW for an 880-MW unit size to $87/kW for a 100-MW unit size. For units that require a balanced draft conversion, capital requirements range from $112/kW to $130/kW. In retrofit applications, lower levelized costs are achieved when SCR is applied to larger, higher utilized units due to economies of scale and the fact that a greater amount of tons are removed on larger units. Similar to the new unit cases, higher inlet levels significantly decrease the levelized cost.

Acknowledgments

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SCR FOR COAL-FIRED BOILERS: A SURVEY OF RECENT UTILITY COST ESTIMATES

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Abstract

Accurate projections of SCR capital cost are critical both for prudent NOx control rulemaking by federal and local environmental regulators, and to establish realistic utility compliance plans. Within the last few years, many utilities have engaged architect/engineers and/or SCR vendors to project SCR cost for selected units in their system, employing detailed site-specific assessments. This paper reports results of SCR cost studies conducted by eleven utility companies, addressing 24 dry-bottom boilers, and 27 Group 2 boilers. The results show significant uncertainty characterizes SCR capital cost estimates, as a wide range of values is projected for both boiler types. This paper discusses and evaluates cost trends, demonstrates the impact of capital cost uncertainty on the cost per ton of NOx removed, and compares capital cost results with those from a computer algorithm widely used in NOx control rulemaking.

Introduction

The availability of selective catalytic reduction (SCR) NOx control technology at reasonable cost is a key consideration in the promulgation of NOx emission limits by federal and local environmental agencies. The cost of SCR is a topic of considerable disagreement among the various "stakeholders" participating in the NOx emissions debate - most significantly the utility industry, federal and local environmental regulatory agencies, and vendors of SCR technology. This disagreement is capital cost translates into equal uncertainty regarding projections for cost per ton of NOx reduced. Specific concerns have been summarized in written comments submitted by the utility industry (UARG, 1997) to the Environmental Protection Agency's Acid Rain Division (ARD), and in technical reports submitted by industry for use by the Ozone Transport Assessment Group (OTAG, 1996a). Rebuttal positions have been formally issued by the EPA ARD (EPA, 1996a), and OTAG stakeholders that support SCR-based NOx limits (OTAG, 1996b).

In December 1996, the EPA ARD issued NOx emissions for Group 2 boilers based on an evaluated cost per ton of NOx removed, which required EPA to project SCR capital cost for the national boiler population. In June of 1997, the OTAG Policy Committee issued general recommendations for the control of NOx emissions, which may require broad application of SCR from generating units in the 38 states that comprise OTAG's interest. Both the EPA ARD and the OTAG Policy Committee base their understanding of SCR cost on discussions with equipment suppliers, and experience from Europe. EPA ARD developed a cost algorithm to project SCR capital cost as a function of generating capacity, and used this algorithm to select the NOx levels proposed in December 1996 (EPA, 1996b), as well as support OTAG analysis.

During approximately the same time period, many utilities sponsored detailed studies by architect/engineering firms and/or SCR vendors to estimate SCR capital and operating cost. Given the significant cost implications of NOx policy decisions, it is prudent to summarize cost results derived from these utility-sponsored engineering studies, for discussion and comparison with other cost sources.

Objective

The objective of this paper is to report the range of SCR capital cost determined by site-specific engineering studies, estimated by either architect/engineering firms and/or SCR technology vendors.

Subsequently, the impact of capital cost on the cost per ton of NOx removed is calculated. The influence of two economic parameters that strongly dictate SCR cost - capacity factor and capital recovery factor - is also demonstrated.

Approach

Utilities known to have sponsored major NOx planning studies that employed detailed site assessments were requested to volunteer cost results for summary and comparison.

Given the competitive climate within the utility industry, disclosure of factors that affect the cost of generation has become extremely sensitive. With the exception of two studies entered into the public record as part of CAAA Section 407 rulemaking (OVEC, 1997, and TECO, 1996), utility companies only shared cost information on the basis that specific units remain anonymous.

This evaluation considered only engineering studies that employed a site assessment by the architect/engineer, or SCR vendor. Cost estimates were required to be developed from specific equipment lists, derived after considering plant layout, design specifications of the plant and components, and condition of existing equipment (e.g. flue gas handling components). In

most cases, the studies employed a general arrangement drawing to identify the location of the reactor and ancillary equipment, as well as flue gas routing.

Eleven utility companies provided engineering studies for review that addressed SCR capital cost for selected units in their system. These utilities are located in the midwest, portions of the northeast, and the mid-Atlantic states. The data set consists of a total of 24 dry-bottom boilers (e.g. wall- and tangential-fired), and 27 Group 2 boilers (cyclone, wet-bottom, and cell-fired).

The number of boilers represented is a small fraction of the national inventory. Within the 38 state OTAG region alone, approximately 700 dry-bottom boilers exist. The total number of cyclone, wet-bottom, and cell-fired boilers nationally number approximately 140. No rigorous statistical analysis is possible with this data set, as the details of sites are unknown.

Description Of Cost Methodology

This section summarizes the cost methodology followed by most studies.

Cost Methodology

A detailed description of SCR cost methodology has been presented in an earlier paper (Cichanowicz, 1993). This discussion highlights the following cost elements that are of particular interest in this evaluation: Process Capital, Installation Charge, Process/Project Contingency, Utility Indirect Charge, and Allowance for Funds During Construction (AFDC)

Process Capital. Process Capital reflects acquisition cost for equipment required for both the SCR process, and modifications to the balance-of-plant or ancillary components. The Process Capital reflects the sum of expenditures for equipment delivered to the site, but not an installation charge.

Table 1 summarizes the major Process Capital components. The first three items (SCR catalyst, reactor, reagent storage, and reagent vaporization) are direct SCR capital requirements, with remaining items denoted as balance-of-plant components or installation expenditures. A subsequent section of this paper addresses how costs partition between these two categories.

Installation Charge. The Installation Charge reflects primarily the labor charge and lease of special equipment required for installation/erection, as well the upgrade of balance-of-plant equipment or ancillary components.

Process/Project Contingency. These cost elements comprise a "reserve" fund for unanticipated expenses due to either project-specific or process-specific issues. Most of the engineering studies used 15-20% (of Process Capital and Installation Charge) for the sum of both contingency funds.

Utility Indirect Charge. Utility-incurred costs are comprised of staff engineering, project management, and facilities such as access roads, buildings, etc., and is usually 5-10% of Process Capital and Installation Charge.

Allowance for Funds During Construction (AFDC). AFDC is a finance charge, incurred for time periods when equipment is not employed in power production. Although not necessarily a significant cost component compared to the sum of all other components, AFDC represents a real incurred cost, and is included for completeness. All planning studies reviewed included a modest charge of nominally 4-5% annually, for a period of usually 1-2 years.

Most results were derived for a 1995-1997 dollar basis, and for generally similar process conditions (major exceptions are noted). These similarities, and the desire to observe only gross trends, allow the use of results as directly reported, thus not corrected for cost year basis and process conditions.

Capital Cost Components

Two cost indices are proposed to further characterize capital cost: (a) the Process Capital/Installation Charge ratio, and (b) the sum of the catalyst, reactor, and reagent storage/vaporization components to the Process Capital. These cost ratios are further described as follows:

Ratio of Process Capital/Installation. Process Capital/Installation Cost ratio, determined before application of Process/Project Contingencies, Utility Indirect Costs, and AFDC indicates whether the bulk of direct costs are driven by capital procurement (ratio >1) or manpower for installation (ratio <1).

It is anticipated a difficult retrofit site with significant obstacles that complicate access of construction equipment would be characterized by a relatively low Process Capital/Installation Cost ratio; a site with relatively unrestricted access would be characterized by Process Capital/Installation Cost ratio of >1.

Ratio of SCR Process/Process Capital. SCR Process/Process Capital ratio, determined before application of Process/Project Contingencies, Utility Indirect Costs, and AFDC indicates whether the bulk of process equipment acquisition costs are for SCR components, or balance-of-plant equipment to allow the boiler/plant to accommodate SCR process impacts.

It is anticipated that sites requiring few modifications would be characterized by a relatively high SCR Process/Process Capital ratio; retrofit sites that require boiler modifications and upgrades to accommodate the SCR process would be characterized by a relatively low SCR Process/Process Cost ratio.

Results

Results from this survey are presented according to two major boiler categories: dry bottom and Group 2 (cyclone, wet-bottom, and cell-fired). Ideally, separate cost comparisons would be developed for each of the five major boiler categories. However, the relatively small number of units and the desire to observe only general trends allows this simplification. Results are discussed according to (a) capital cost, and (b) components of capital cost.

Capital Cost

Dry-Bottom Boilers. Figure 1 summarizes SCR capital cost for dry-bottom boilers, presented as a function of generating capacity. The NOx reduction efficiency for all units is 80-90%, with residual NH3 a maximum of 5 ppm (2 ppm for selected sites). With the exception of two units, boiler initial NOx production rates are approximately equivalent to the Phase 1, Group 1 limits of 0.45-0.50 lbs/MBtu, depending on boiler type (e.g. tangential- or wall-fired). Note several of the data represent multiple units at the same station.

Group 2 Boilers. Figure 2 summarizes SCR capital cost for cyclone, wet-bottom, and cell-fired boilers, presented as a function of generating capacity. The wet-bottom boilers, all which feature SCR designed for 50% NOx removal from approximately 1.1-1.3 lbs/MBtu, are identified separate from the cyclone and cell-fired boilers. The SCR NOx reduction efficiency for the cyclone and cell-fired boilers is 80%, with one case at 50% noted. Except as indicated, all cyclone/cell-fired boiler NOx production rates are 1.2-1.5 lbs/MBtu. All costs reflect sufficient catalyst to maintain a residual NH3 level of at most 5 ppm, throughout the entire operating period.

Capital Cost Components

Figure 3 presents trends in both the Process Capital/Installation Cost and SCR Process/Process Capital cost ratios, as a function of projected capital cost, for dry-bottom boilers. As suggested, the highest capital cost sites are characterized by a Process Capital/Installation Cost ratio of 1-1.25; the lowest capital cost sites can have values exceeding 2. The SCR Process/Process Capital ratio ranges from 0.50 for high cost sites, to 0.75 for low cost sites.

Results Discussion

Results presented in this paper are based upon an extremely small sample of the boilers, compared to the candidates considered to deploy SCR NOx control. Clearly, caution should be exercised in extrapolating any results or observations in cost trends from this sample to the national or the OTAG regional population.

Average Capital Cost

Dry-Bottom Boilers. The average of capital cost for dry-bottom boilers for all 24 boilers presented in Figure 1 is $86/kW. The average for units greater than 175 MW capacity is $75/kW.

Figure 1 demonstrates the wide variation in capital cost depending on site-specific conditions. If only generating capacity is considered as an indicator of "average" SCR capital cost, significant variations from the $75/kW average for units >175 MW are witnessed. Specifically, within the cluster of units at approximately 550 and 625 MW, any unit can vary in cost by $30-50/kW.

Group 2 Boilers. The average of capital cost for Group 2 boilers for all units presented in Figure 2, calculated with four different averaging techniques, ranges from $79-86/kW. The lowest cost ($79/kW) was determined by eliminating boilers of less than 200 MW capacity, using only 2 boilers at each of the Kyger and Clifty Creek sites in the average, and eliminating balance-of-plant upgrades necessary to accommodate SCR at three large cyclones. The highest cost was determined by employing all boilers in Figure 2 in the average (all 11 Kyger and Clifty Creek units, and not eliminating small boilers), and including balance-of-plant costs for the large cyclones.

For units above 200 MW capacity, if generating capacity alone is used to project SCR capital cost, significant variations from the nominal $83/kW average are witnessed. These variations appear to be $15-50/kW.

Economies of Scale

SCR is generally recognized by most observers to exhibit economies of scale with respect to capital cost. This trend is dependent upon the assumption that all other plant and SCR process design factors are maintained equivalent, as generating capacity increases.

Figure 1 shows that cost per unit capacity decreases as generating capacity increases from 100 to 200 MW. The average SCR cost for the units at approximately 600 MW suggests continued cost reduction at larger capacities. For the Group 2 boilers, the different boiler designs prevent identifying any trend between cost and generating capacity.

For both boiler categories, the reduction in SCR unit cost with increasing generating capacity is most pronounced for increases from lowest (~100 MW) to intermediate capacities (~175-200 MW). SCR capital cost may not exhibit economies-of-scale anticipated at larger capacities, as the design basis for the SCR process and host unit changes significantly with increased capacity. An example is the utilization of two reactors (each of 50% treating capacity) in place of one reactor (at 100% capacity), to maintain turndown for larger units.

Cost Per Ton Evaluation

The cost of NOx control per ton of NOx removed - sometimes referred to as cost-effectiveness - is an important cost index. The EPA ARD has issued NOx regulations for Group 2 boilers based on the "cost-effectiveness" of low NOx burners on Group 1 boilers compared to the "cost-effectiveness" of candidate NOx control technologies on Group 2 boilers. Essentially all NOx trading programs proposed or presently in place employ this cost index. Also, several states have proposed definitions of Reasonably Available Control Technology (RACT) depending on the "cost-effectiveness" of NOx reduction achieved by any given technology. It is instructive to examine the significance of the uncertainty in capital cost observed in Figures 1 and 2 on the evaluated cost per ton of NOx removed. Also, the impact on cost-effectiveness of two economic factors of particular significance for SCR - the capital recovery factor and generation capacity factor - is addressed.

Capital Cost

Table 2 summarizes NOx control cost per ton provided by SCR, as applied to (a) dry bottom boilers in a "post-RACT" mode, and (b) Group 2 (cyclone) boilers. Table 2 also presents the sensitivity of cost per ton to uncertainties in capital cost, capacity factor (CF), and capital recovery factor (CRF).

Dry-Bottom Boilers. Cost results apply only to the specified conditions of 80% NOx reduction, initial NOx production rates of 0.45-0.50 lbs/MBtu, 4 year mean catalyst life, and a final space velocity of 3200 1/h. The generation capacity factor and annual capital recovery factor are 65% and 0.15, respectively. For the average SCR cost (as approximated from Figure 1) of $75/kW, Table 2 shows that SCR NOx control cost is $1600-1768/ton, for boiler NOx production rates of 0.50 and 0.45 lbs/MBtu, respectively.

Table 2 also shows the impact of $15/kW variations in capital cost. Increasing capital cost by $15/kW to $90/kW would increase the $1600-1768/ton cost range by $220-250/ton. Similarly, decreasing capital cost by $15/kW to $60/kW would decrease the $1600-1768/ton range by approximately the same.

Group 2 Boilers. Cost results apply only to the specified conditions of 80% NOx reduction, 4 year average catalyst life, initial NOx production rate of 1.3 lbs/MBtu, and a final space velocity of 2000 1/h.

For the average SCR cost (as approximated from Figure 1) of $79/kW, Table 2 shows that SCR NOx control cost is $696/ton, for NOx production rates of 1.3 lbs/MBtu. Adjustments to capital cost by $15/kW impact cost by $80/ton.

Sensitivity Analysis: Additional Factors

Although the focus of this paper is SCR capital cost, it is prudent to briefly consider two other factors that can dominate the evaluated cost per ton of NOx reduced by SCR. The ability to recover capital cost, as determined by unit capacity factor and financing conditions, is particularly important with SCR, due to the high capital requirement compared to alternatives. This section demonstrates how the range of capacity factor and capital recovery factor impact the evaluated cost per ton.

Capacity Factor. Future projections of capacity factor for the deregulated industry have received considerable attention recently. Projections for system capacity factor averages range from 65% to as high as 85%, depending on the economic conditions presumed for the relevant time period. This differential of 20 percentage points translates into a considerable difference in cost per ton of NOx. As shown in Table 2, simply increasing capacity factor from historical norms of 65% to 85% lowers SCR cost per ton for dry-bottom boilers by $340 to $380/ton, for boiler NOx productions rates of 0.50 and 0.45 lbs/MBtu. For Group 2 boilers, the same increase in capacity factor lowers evaluated cost by approximately $120/ton.

Capital Recovery Factor. Utility planning studies reviewed documented the range in capital recovery factor employed for cost evaluations. This factor depends not only on the details of financing capital, but also the secondary cost of equipment ownership, such as property taxes, insurance, etc. Most significantly, the term over which the utility intends to operate the facility - either 10, 15, or 20 years exerts a dominant role in determining the capital recovery factor. The studies reviewed for this paper show the range in capital recovery factor to be 0.14- 0.167. Within the NOx policy debates, stakeholders supporting the application of SCR have proposed a capital recovery factor of 0.115, for a 20 year plant life. Accordingly, a sensitivity analysis was conducted to determine the impact of capital recovery factor to levels as low as 0.115.

Table 2 shows for dry bottom boilers reducing capital recovery factor to 0.115 lowers evaluated cost by $650/ton, for a boiler NOx production rate of 0.50 lbs/MBtu. For Group 2 boilers, the same variation in capital recovery factor lowers evaluated cost by $90/ton. Accordingly, the role of capital recovery factor is significant, and is equal to or greater than the impact of reasonable changes in capacity factor or capital cost.

Observation

Results from this evaluation highlight how uncertainty in capital cost, capacity factor, and capital recovery factor impact cost per ton of NOx.

Depending on the value of capital cost, capacity factor, and capital recovery factor, the evaluated cost per ton of NOx can vary by almost 50%. Specifically, Table 2 reports cost per ton for both dry-bottom and cyclone boilers, employing inputs that based on the studies reviewed for this paper, discussions with utilities, and economic projections, appear extreme. These values are $60/kW capital cost, 85% capacity factor, and 0.115 capital recovery factor. Employing these values for dry-bottom boilers produces a cost of $935-1029/ton, approximately 55% of that estimated for the "baseline" case. For cyclone boilers, cost is $424/ton, or 60% of the "baseline"

The cost per ton is further reduced, when employing capital cost estimates based on the computer algorithm describing capital cost versus generating capacity, that was derived by EPA ARD. For dry-bottom boilers, using 550 MW as a reference case, this correlation used in OTAG rulemaking projects a capital requirement of $47/kW, for an SCR process designed for 80% NOx removal from Phase 1/Group 1 boiler NOx production rates. A generating capacity of 650 MW is anticipated to require SCR capital cost of $44/kW, according to this correlation.

These algorithm-derived estimates are 60-65% of the average capital cost at 550 and 650 MW presented in Figure 1. Using these algorithm-derived capital costs results in estimates of cost per ton of $791-818/ton, half of the baseline case. Similar trends were noted with Group 2 boilers, where the algorithm also significantly underpredicted cost for 50% NOx reduction cases.

Summary

Engineering studies submitted by 11 utility companies revealed trends in SCR capital cost, based on detailed site-specific assessments. For dry bottom boilers, the projected cost for SCR was $86/kW, and reduced to $75/kW when boilers less than 175 MW were eliminated. For cyclone boilers, the average cost was $79-86/kW, depending on how the average was calculated.

This significant capital cost uncertainty translates into equivalent uncertainty in cost per ton. Economic and technical premises selected from this survey suggest deploying SCR delivers NOx reduction for $1600-1768/ton, in a post-LNB application. For cyclone boilers, the cost per ton anticipated for these conditions is $674/ton.

Both capacity factor and capital recovery factor exert significant impact on cost per ton. By using values for these inputs that based on the utility site-specific studies appear to be extreme, evaluated cost can be reduced to 55-62% of the previously cited values. Further complicating the matter is the apparent tendency of the SCR capital cost algorithm developed for NOx rulemaking by EPA ARD to underpredict SCR capital cost, producing estimates approximately 60-65%% of those inferred from Figure 1. In summary,

estimates of SCR cost that do not employ a detailed site-specific analysis could be significantly in error, and generating capacity and capital recovery factor should be carefully considered to reflect authentic industry experience.

References

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EPA, 1996b — Distributions Of NOx Emission Control Cost-Effectiveness By Technology, prepared by ICF Incorporated, October 31, 1996, EPA Contract No. 68-D3-0005, Work Assignment No. 5F-01.

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TABLE 1

SUMMARY OF PROCESS CAPITAL COMPONENTS
FOR SCR RETROFIT

Cost Component	Comment
SCR Catalyst, Reactor	usually the largest cost components
Reagent Storage	facilities for the unloading, transfer, and storage for aqueous or anhydrous ammonia reagent
Reagent Vaporization/Injection	equipment to vaporize reagent, and monitor and control injection rate
Sootblowers	included in almost all SCR designs and cost estimates; sometimes not seperately identified
Foundations	re-inforcing of existing foundations, or construction of new foundations depending on reactor location
Structural Steel	re-inforcing of existing structures, or construction of new structures depending on reactor location
Ductwork Modifications	modifications to existing ductwork to accommodate SCR equipment
New Ductwork	new ductwork for process bypass, reactor access, etc.
Process I&C	control systems for process operation
Fan Modifications	improvements to existing fans to increase flow rate rating, or replacement with new fans
Balanced Draft Conversion	reinforcement of ductwork structure, and addition of fans as necessary to convert from forced to balanced draft.
Electrical	additional auxiliary power supply for reagent, blowers, etc. can require an increase in power delivery capabilities on-site
Boiler Modifications	installation of economizer bypass, removal or addition of heat absorbing surface area as necessary to provide correct flue gas temperature vs. load
Other (BOP)	modifications to the air heater to improve tolerance to increased SO3; improvements to particulate control equipment to tolerate residual NH3, SO3; etc.
Duct Burner, Gas/Gas Heater	heat exchange equipment necessary for post-FGD applications
Misc/General	flow modeling, construction management, demolition charge, etc.

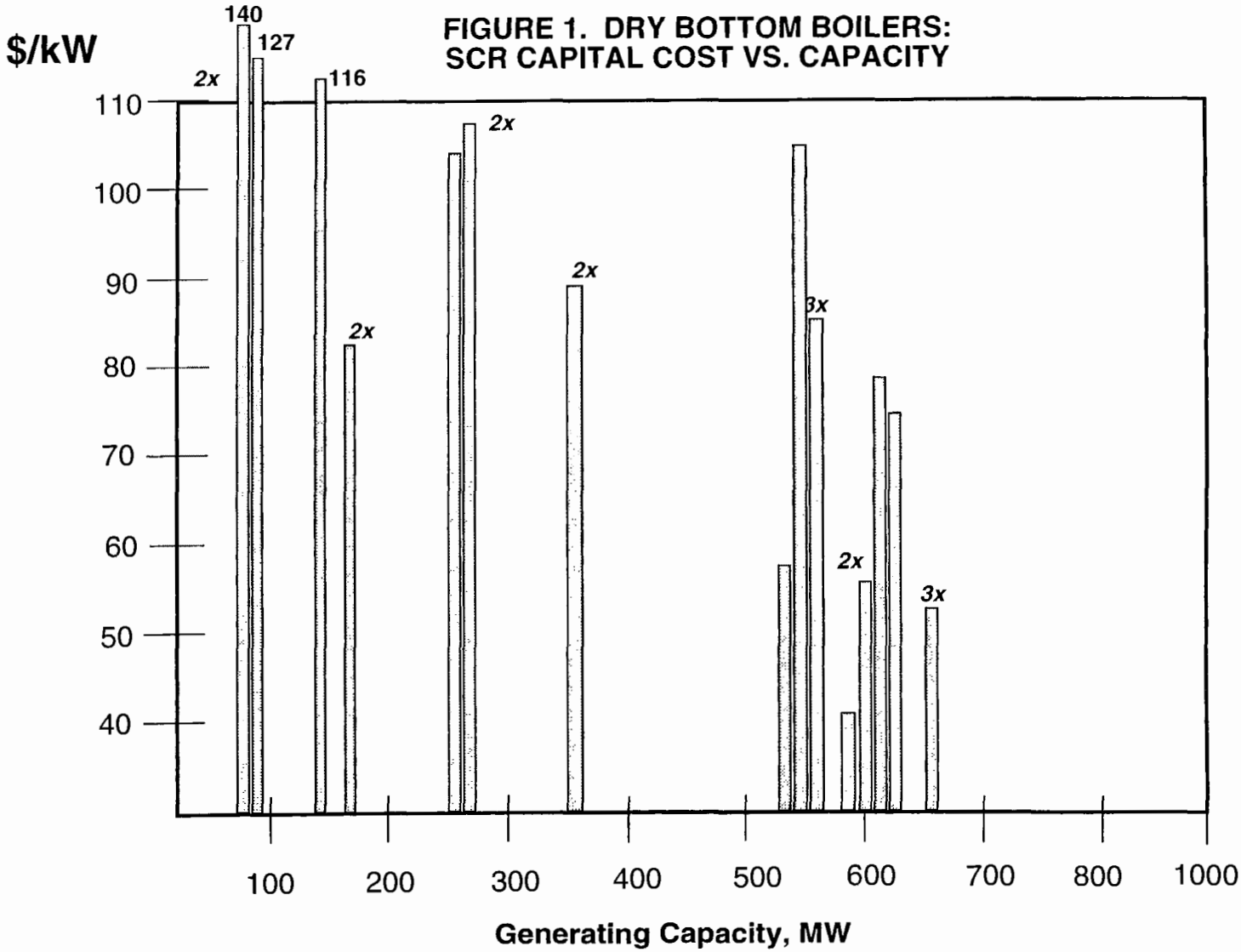

FIGURE 1. DRY BOTTOM BOILERS: SCR CAPITAL COST VS. CAPACITY

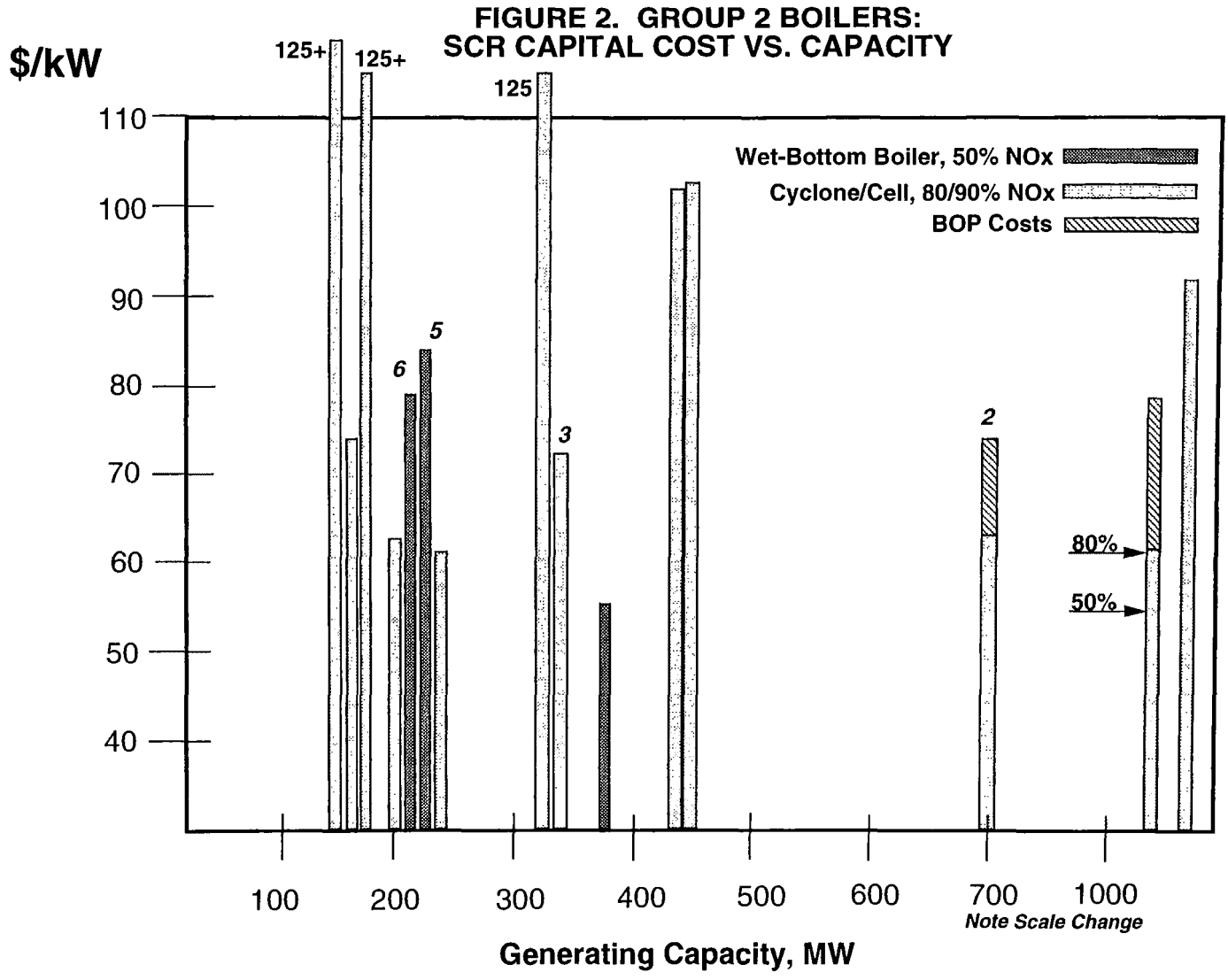
FIGURE 2. GROUP 2 BOILERS:
SCR CAPITAL COST VS. CAPACITY
$/kW
110
100
90
80
70
60
50
40
125+
125+
125
6
5
3
2
80%
50%
Wet-Bottom Boiler, 50% NOx
Cyclone/Cell, 80/90% NOx
BOP Costs
100
200
300
400
500
600
700
1000
Note Scale Change
Generating Capacity, MW

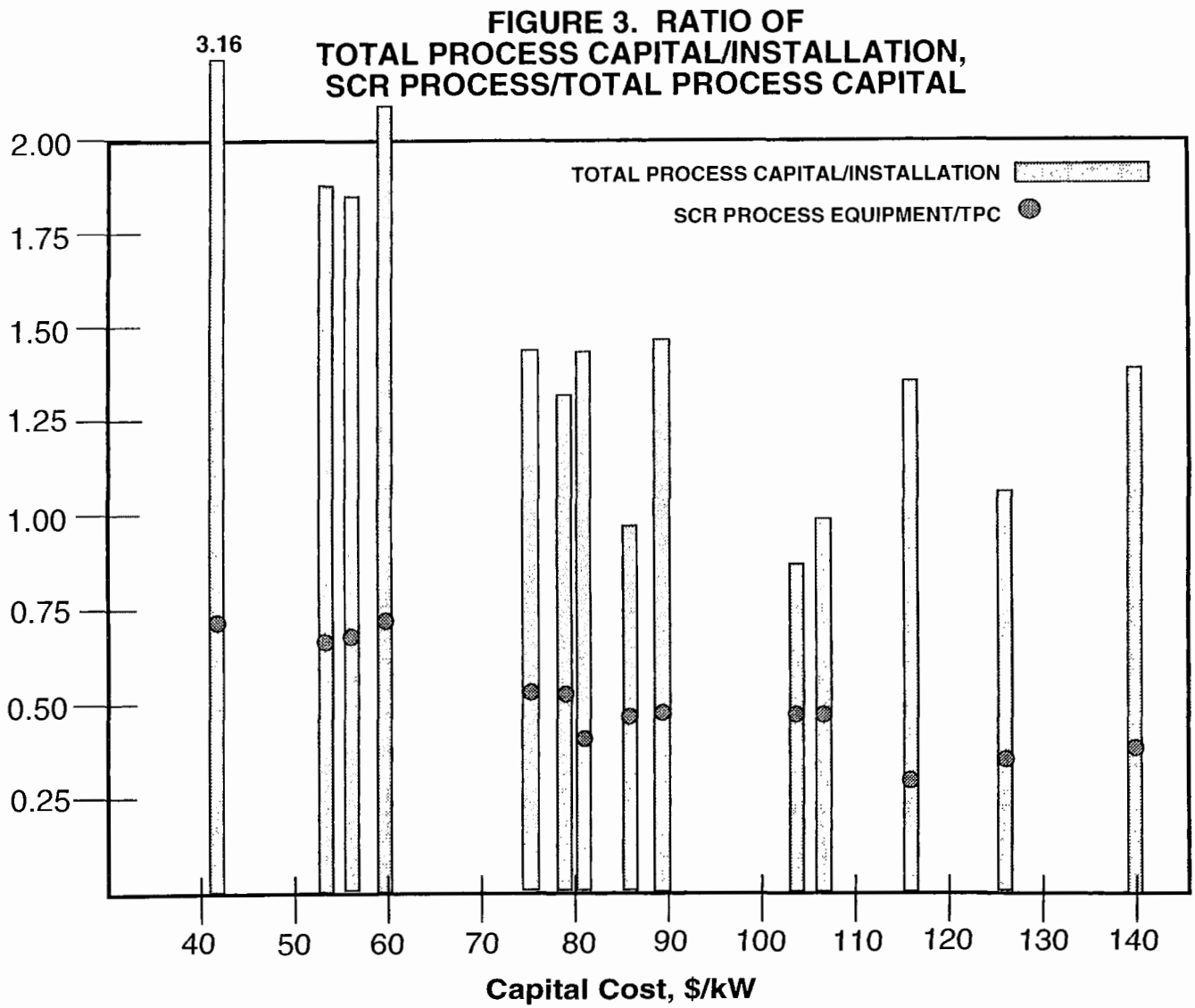
FIGURE 3. RATIO OF
TOTAL PROCESS CAPITAL/INSTALLATION,
SCR PROCESS/TOTAL PROCESS CAPITAL
3.16
TOTAL PROCESS CAPITAL/INSTALLATION
SCR PROCESS EQUIPMENT/TPC
2.00
1.75
1.50
1.25
1.00
0.75
0.50
0.25
40
50
60
70
80
90
100
110
120
130
140
Capital Cost, $/kW

TABLE 2

COST PER TON EVALUATION
SCR ON POST-LNB DRY-BOTTOM, AND GROUP 2 BOILER
(Baseline Case And Sensitivity Analysis)

Evaluation	Process Conditions	Economic Factors	Cost Per Ton $/Ton (NOx)
Baseline: SCR Applied to Post-LNB, Dry-bottom Boiler	80% NOx reduction/ 5 ppm slip, 3200 1/h SV, 4 yr catalyst life *(Baseline)*	$75/kW, 65% CF, 0.15 CRF	**1600 (0.50)** **1768 (0.45)**
Baseline: SCR Applied to Group 2 (Cyclone) Boiler	80% NOx reduction/ 5 ppm slip, 2000 1/h SV, 4 yr catalyst life, *(Baseline)*	$79/kW, 65% CF, 0.15 CRF	**696 (1.3)**
Sensitivity: Incremental Capital (+/- $15/kW)	Dry-Bottom Baseline Boiler Case	same	**Δ 220 (0.50)** **Δ 250 (0.45)**
	Group 2 Boiler Baseline Case	same	**Δ 80 (1.3)**
Sensitivity: Capacity Factor (65% to 85% increase)	Dry-Bottom Baseline Boiler Case	same, except CF	**Δ 340 (0.50)** **Δ 380 (0.45)**
	Group 2 Boiler Baseline Case	same, except CF	**Δ 120 (1.3)**
Sensitivity: Capital Recovery Factor (0.15 to 0.115 decrease)	Dry-Bottom Boiler Baseline Case	same, except CRF	**Δ 650 (0.50)**
	Group 2 Boiler Baseline Case	same, except CRF	**Δ 90 (1.3)**
SCR/Dry-Bottom ($60/kW, 85% CF, 0.115 CRF	Dry-Bottom Case, except as noted	as noted	**935 (0.50)** **1029 (0.45)**
SCR/Group 2 ($60/kW, 85% CF, 0.115 CRF	Group 2 Baseline Case, except as noted	as noted	**424 (1.3)**

SCR FOR A 460 MW COAL FUELED UNIT: STANTON UNIT 2 DESIGN, STARTUP, AND OPERATION

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Abstract

Orlando Utilities Commission's (OUC) Stanton Energy Center consists of two 460 MW (gross) pulverized coal fueled units each burning eastern bituminous coal. Unit 1 began operation in 1986 and controlled NO_x emissions only by low NO_x burners to meet an emission limit of 0.60 lb/MBtu. Unit 2 was intended to be a virtual replication of Unit 1, but with more advanced Babcock & Wilcox XCL burners to achieve an emission rate of 0.32 lb/MBtu. However, the Best Available Control Technology (BACT) determination for Unit 2 required the use of a post combustion NO_x emission reduction system to meet an emission limit of 0.17 lb/MBtu. Comprehensive technical and economic analyses indicated that a high dust, selective catalytic reduction (SCR) system should be installed on Unit 2. Unit 2 began commercial operation on June 1, 1996.

This paper describes Unit 2's SCR system design basis, configuration, startup, testing, initial operation, and annual inspection. In addition, SCR system cost effectiveness values are presented.

Licensing Background

Prevention of Significant Deterioration (PSD) permitting for Unit 2 began in 1991. The original BACT analysis recommended the use of combustion controls to achieve an uncontrolled NO_x emission rate of 0.32 lb/MBtu. This was recommended on the basis of incremental NO_x emission reduction costs estimated as exceeding $6,000/ton when using either selective non-catalytic reduction (SNCR) or SCR technologies. Despite these high estimated costs and a number of technical concerns, EPA Region IV and the Florida Department of Environmental Regulation required using a post combustion NO_x emission reduction system to achieve emissions of 0.17 lb/MBtu (30-day rolling average). This system also had to achieve a one-time demonstration of the capability to achieve 0.10 lb/MBtu during initial performance testing. In addition, Unit 2 was also

required to limit ammonia slip emissions to less than 5 ppm (volumetric). The permit for Unit 2 did not dictate a NO_x emissions control technology.

Technology Selection

Given the flexibility to select the optimum control technology for Unit 2, OUC directed Black & Veatch to perform technical and economic analyses to select between SCR and SNCR technologies. Subsequently, comprehensive experience investigations and detailed capital and annual cost estimates regarding both technologies were performed. Economic and technical analyses both supported the use of an SCR system for Unit 2. SCR had a differential levelized annual cost of $2.4 million per year less than SNCR. Because of compelling technical and economic results, OUC proceeded with a decision to install a high dust SCR system on Unit 2. [1]

Plant Description and SCR Design Basis

Unit 2 is equipped with the following components.

- A single Babcock & Wilcox sub-critical, pulverized coal steam generator.
- One vertical shaft Ljungstrom air heater.
- Two cold-side electrostatic precipitators.
- A three, 50 percent module wet limestone flue gas desulfurization system.

The unit burns eastern bituminous coal with maximum design sulfur and ash contents of 2.5 percent and 11 percent, respectively. Table 1 lists typical and range fuel qualities for the Unit 2 design. Table 2 lists pertinent steam generator performance parameters (full and minimum loads) that had to be considered in the SCR system design.

The following summarizes the SCR system guarantee requirements:

- Initial performance test (new catalyst) -- NO_x reduction equal to or greater than 70 percent while maintaining outlet NO_x emissions equal to or less than 0.10 lb/MBtu.
- Post initial performance test -- NO_x reduction equal to or greater than 47 percent while maintaining outlet NO_x emissions equal to or less than 0.17 lb/MBtu (30-day rolling average basis).
- Maximum ammonia slip of 2 ppm (corrected to 3 percent oxygen).
- SO_2 oxidation rate less than 1.0 percent.
- Total system pressure drop of less than 3.42 in wg at full load.
- Ammonia usage rate of less than 232 lb/h at full load.
- Power consumption of less than 68.5 kW (dilution fans and soot blowers).
- Minimum catalyst life of 24,000 hours of boiler operation to achieve above guaranteed performance (exclusive of 1).

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[1] A more detailed description of the technology selection analysis is presented in the technical paper "Selective Catalytic Reduction for a 460 MW Coal Fueled Unit: Overview of a NO_x Reduction System Selection", J.R. Cochran, et al, Black & Veatch, presented at the 1993 EPRI/EPA Joint Symposium on Stationary NO_x Control.

SCR System Configuration

Figures 1 and 2 illustrate the process flow diagram for Unit 2's SCR system. Anhydrous ammonia was selected as the reagent for the SCR system to minimize NO_x reduction costs.[2] The SCR system consists of ammonia receiving and storage; ammonia vaporization and injection; reactor, ductwork, and sootblowing; catalyst; and controls subsystems.

Ammonia Receiving and Storage

Anhydrous ammonia is received at the plant by truck. Ammonia is directed to one of two 12 foot diameter, 30,000 gallon tanks. This storage is adequate to meet plant requirements for 30 days. The tanks are designed for a working pressure of 250 psig. A concrete containment area surrounds the tanks. In addition, a sun shield and emergency deluge system is located directly above the storage tanks.

Ammonia Vaporization and Injection

The ammonia vaporization system consists of two, 100 percent capacity electric heated vaporizers. The vaporizers are located directly adjacent to the ammonia storage tanks in an enclosure. Vaporized ammonia pressurizes the ammonia storage tanks. Vaporized ammonia is taken from the top of the tanks and directed through piping to the ammonia mixer. A motorized control valve modulates the flow of ammonia to the mixer based on NO_x emission monitor measurements and set points.

Ammonia is diluted with air in a stainless steel mixer to a concentration of approximately 6 percent. Two 20,000 cfm (100 percent capacity) fans provide the dilution air to the mixer. This dilution air is taken from the secondary air supply. Diluted ammonia is directed from the mixer to a 12 zone injection grid located in the SCR reactor inlet duct. All piping from the mixer to the point of ammonia injection is constructed of stainless steel.

Reactor, Ductwork, and Sootblowing

A single reactor treats all flue gas exiting the boiler. The reactor and ductwork are constructed of 1/4 inch plate A36 carbon steel. The reactor is 65 feet wide, 35 feet deep, and 53 feet high. The reactor is totally enclosed in the boiler building.

Single louver isolation dampers are installed at the inlet and outlet of the reactor. A partial bypass duct and dampers are installed for use during startup, and shutdown.

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[2] For a more detailed description of this selection refer to "Aqueous or Anhydrous? What Stanton and Other SCR Experience Tell Us About Ammonia Selection", M.G. Gregory, et al, Black & Veatch, presented at the 1996 ICAC NO_x Forum.

Flue gas exiting the economizer turns upward 90° The flue gas flows through two stages of static mixers and the ammonia injection grid in this vertical ductwork. The static mixers are utilized to mix flue gas and ammonia. Flue gas with ammonia then crosses over to the reactor. A dummy catalyst layer is utilized to ensure gas flow vectors are vertical prior to entering the first layer of catalyst, as well as absorbing the energy of initial impact of particulate/fly ash. A physical flow model study was performed to configure flow distribution devices and to minimize pressure drop.

The initial catalyst charge consists of two layers of catalyst. However, the reactor is configured to accept two additional catalyst layers for future use as part of the catalyst management plan described in this paper. A hoist and monorail system was used to load catalyst into the reactor. The hoist lifts catalyst from grade through a hoistway within the SCR reactor enclosure building to the appropriate reactor level. The catalyst is then transferred from the hoist to a monorail. Catalyst is moved into the reactor through a single door per level using a monorail system. Once the catalyst was placed, seals were installed to minimize leakage around the catalyst.

The reactor is equipped with steam sootblowers. Sootblowers, of a retractable, rake design, are located directly above each catalyst layer. Sootblowing steam has a pressure of approximately 150 psig. The sootblowers are oriented to blow debris downward through the catalyst.

Catalyst

Siemens' SINOx™ plate type catalyst was selected for Unit 2. This catalyst had been used in numerous US and European high dust SCR applications. The catalyst has a high durability with respect to erosion and corrosion. In addition, this catalyst has a low pressure drop as compared to ceramic honeycomb catalysts.

Two levels of catalyst are currently installed in the reactor. Each of these levels has a 10 x 11 arrangement of catalyst module frames. Carbon steel, catalyst module frames contain a 2 wide by 4 long by 2 deep arrangement of catalyst elements. Each of these catalyst module frames are fully loaded with two 500 mm element layers.

The initial two levels of catalyst totals 13,100 ft^3 (370 m^3) with a space velocity of 3,945 h^{-1} The plate type catalyst has a relatively conventional composition of vanadia, titania, and tungsten supported on a stainless steel expanded mesh. The catalyst has a specific surface area of 328 m^2/m^3 and an SO_2 to SO_3 oxidation rate less than 1 percent.

Ultimately the reactor could accept another two levels of catalyst module frames. Future catalyst increments can be added in single element increments. Therefore, the current four element layers in the reactor could be increased to a total of eight element layers as catalyst additions become necessary. The additional module layers will act as spares to give OUC considerable flexibility in managing future catalyst additions.

Controls

The control system for the Unit 2 SCR system mainly consists of inlet and outlet, NO_x and O_2 monitors, as well as logic programmed into the plant's DCIS. Ammonia injection was designed to be controlled by a feedforward signal of reactor NO_x inlet concentration and unit load, and a feedback trim signal from reactor NO_x outlet monitoring.

Startup and Initial Performance

Catalyst was loaded into the reactor in March 1996. Startup of the system occurred during April and May 1996. No substantial difficulties were encountered with startup or commissioning activities. The ammonia injection rates were tuned based on monitoring CEM data and sampling over a 50-point SCR outlet fixed grid matrix. The plant began commercial operation on June 1, 1996.

SCR system performance tests were performed at low-, mid-, and full-load points from June 21 through June 23, 1996. Table 3 summarizes the results of these tests. All guarantee values were met with the exception of ammonia consumption.

SCR operations have continued to date (July 1997) in full compliance with NO_x emission limits without any interference with normal unit operations. No air heater pluggage or degradation have occurred. Existing fly ash sales and disposal practices of fixated scrubber solids with flyash have continued without any effect by the SCR system. Opacity from Unit 2 generally ranges from 1 to 3 percent, with no visible plume. As compared to Unit 1, OUC has not realized any additional O&M staffing requirements as a result of the SCR system on Unit 2. The most persistent problem encountered to date with SCR system operation has been with the emissions monitoring system.

As previously described, the control system for the SCR consists of feedforward signal based on measured NO_x and O_2 at the reactor inlet, as well as unit load as the primary control signals for ammonia feed modulation. Secondary modulation is designed based on feedback of reactor outlet NO_x concentrations to meet setpoint values. This control system setup minimizes the potential for overinjection of ammonia and the resultant ammonia slip. Any ammonia slip present in the flue gas exiting the catalyst can ultimately react with SO_3 in the flue gas to form ammonium bisulfate and sulfate salts which may potentially foul the air heater.

To date, OUC has only encountered persistent problems with the Lear Siegler monitoring system located at the inlet and outlet of the SCR system. The probes have plugged in this high dust environment. In addition, the monitors have had periodic calibration problems. Efforts continue to resolve these probe pluggage and calibration difficulties. Until monitoring system problems are resolved, the SCR system is being controlled based on a feedback signal of stack NO_x only. The long lag time between ammonia injection point and NO_x measurement results in not only a sluggish control system, but also risks overinjection of ammonia. Fortunately, the relatively large amount of fresh catalyst installed in the reactor will allow primary feedback control for now. However, as the catalyst deactivates, this practice will become increasingly risky. OUC expects to return to feedforward control in the next 2 months.

In an effort to minimize the risk associated with purely feedback control, OUC has changed their NO_x set point practices. Initially, because of uncertainty regarding the SCR system's capability of meeting a 0.17 lb/MBtu limit on a 30-day rolling average, OUC set outlet NO_x emissions at 0.13 lb/MBtu. However, the reliability of the system to date has caused OUC to change this set point to 0.16 lb/MBtu.

Annual Inspection Results

During the annual outage in April 1997, the reactor and catalyst were inspected. At this point, the catalyst had been in operation (exposed to flue gas) for approximately 7,500 hours. The purpose of the inspection was to assess fly ash deposits and the effectiveness of sootblowing and to determine the mechanical condition of the catalyst. The inspection indicated that there were no significant areas of maldistribution of gas or dust flow. There were no significant deposits on, or pluggage of, the catalyst (see Figures 3 and 4), which indicated proper sootblowing operation. In addition, no unusual erosion of the catalyst was evident.

Eight pairs of plate catalyst elements were pulled randomly from the first module layer. Siemens is in the process of testing the activity (k/k_o) of these elements. The expected activity after 7,500 hours of operation is a k/k_o value of 0.9. However, based on inspection and operational results to date, it is expected that remaining activity will be equivalent or higher than this value.

Prior to inspection, sootblowing had been performed once per day. The results of the inspection prompted OUC to change operating procedures to a once per week SCR reactor sootblowing cycle. Until the next annual inspection, the effects of this operational change will be assessed by differential pressure measurements across the catalyst and air heater.

Catalyst Management Plan

Catalyst additions and replacements represent the most significant O&M cost for an SCR system. Catalyst additions and replacements can have a cost as high as \$310 to \$340/ft^3 (\$11,000 to \$12,000/m^3). Accordingly, each element layer addition to the Unit 2 reactor will cost approximately \$1.1 million. Therefore, a major objective of OUC is to minimize future catalyst additions.

Figure 5 presents the original catalyst management plan for Unit 2 developed on the original design conditions for the unit. The management plan reflects the operation of the unit at a constant NO_x outlet from the SCR reactor. The graph illustrates that the relative activity of the catalyst will decrease over the initial guarantee period, resulting in a predicted increase in ammonia slip. Periodic addition of catalyst increases the total activity of the system and lowers ammonia slip to the initial low levels.

As previously described, the reactor is configured for up to four catalyst module levels (eight element layers). Currently, four element layers (2 full catalyst module levels) are installed. Guaranteed deactivation rates require that an additional element layer be added to the reactor after about 24,000 hours (about 3 years of unit operation). This catalyst will be added to catalyst module level 3. After about 47,000 hours the second element layer will be added to catalyst module level3. After about 69,000 hours an element layer will be added to catalyst module level 4, and after about 90,000 hours (more than 11 years of unit operation will have elapsed) another element layer will be

added completely filling the reactor with catalyst. Subsequent catalyst additions will replace existing catalyst element layers.

Cost Effectiveness

The cost effectiveness of an SCR system (generally reported in $/ton values) is predominately dependent on the inlet NO_x concentration and SCR removal requirements. The higher the inlet NO_x concentration and SCR removal rate the better the cost effectiveness. Therefore, considering low inlet NO_x concentrations (0.32 lb/MBtu) and relatively low removal rates required (50 percent), Unit2 $/ton NO_x removal costs will be higher than coal fueled units not using low NO_x burners.

Table 4 lists the costs associated with the Unit 2 SCR system with an inlet NO_x concentration of 0.32 lb/MBtu and an outlet NO_x concentration of 0.16 lb/MBtu (50 percent removal).

The all-in capital cost of the Unit 2 SCR system was $21.4 million ($47/kW). This cost includes all direct and indirect costs associated with the project's SCR system including the following equipment, labor, materials, and services:

- Ammonia receiving and transfer.
- Ammonia storage tanks, detection, and deluge equipment.
- Ammonia vaporization and transport.
- Dilution air fans and ammonia mixer.
- Ammonia injection.
- Static mixers.
- Interconnecting ductwork, expansion joints, and turning vanes.
- Louver bypass dampers.
- Reactor, internal supports, and access doors.
- Catalyst loading system including all associated hoists and monorails.
- Catalyst, module frames, and seals.
- Steam sootblowers.
- Inlet and outlet NO_x and O_2 monitoring.
- Instrumentation and distributed control system.
- Fire protection and safety equipment.
- Foundations and support steel.
- Insulation and lagging.
- Complete enclosures for the ammonia vaporizers and reactors.
- Piping and valves.
- Construction labor, materials, and equipment.
- Scale model study.
- Engineering, construction management, and owner indirects.
- Startup, tuning, and performance testing.

Unit 2's projected levelized annual O&M costs total $1.2 million (0.41 mills/kWh). These costs were levelized by multiplying first year costs by a factor of 1.36 (20-year basis). These costs include ammonia, catalyst additions and replacements, energy (vaporizers, dilution air fans, sootblowers, and differential ID fan power), and annual testing and tuning. No increase in staffing requirements have resulted from the use of SCR. The cost listed for catalyst additions and

replacements is based on the projected guarantee basis catalyst management plan. Intermittent catalyst addition costs at approximately 3 year intervals were individually escalated and discounted. As such, no catalyst additions are expected for the first 3 to 4 years of unit operation.

Fixed charges on capital were added to annual O&M costs resulting in a total projected levelized annual cost of $2.9 million (0.98 mills/kWh). This is equivalent to an emission reduction cost effectiveness of $1,200/ton of NO_x removed. This value is relatively high as compared to higher NO_x emitting sources. SCR cost effectiveness values of as low as $400/ton are possible for high NO_x emitting wet bottom boilers (uncontrolled emissions greater than 1.5 lb/MBtu).[3]

Summary

The SCR system installed at Stanton Unit 2 has operated for over 8,500 hours without significant difficulty. The system has provided abundant operational flexibility while reliably meeting a NO_x emission limitation of 0.17 lb/MBtu. The SCR system has not impacted plant operations or availability. Off-line SCR system inspection did not indicate any fouling or erosion of the catalyst. In addition, catalyst reactivity testing indicates a high probability for the catalyst to exceed the guaranteed 24,000 hour life.

Although costs to date have been much lower, the projected life cycle cost for the SCR system is equivalent to a levelized cost effectiveness of $1,200/ton of NO_x removed and an all-in (capital and operating) busbar increment of 0.98 mills/kWh.

[3] "The Cost of Compliance for Group 2 Boilers", J.R. Cochran, et al, Black & Veatch, 1997 EPRI-DOE-EPA Mega Symposium, August 25, 1997.

Table 1
Unit 2 Design Coal Quality

	Coal Supply A		Coal Supply B	
Parameter	**Typical, %**	**Range, %**	**Typical, %**	**Range, %**
Ultimate Analysis:				
Carbon	74.09	73 78	68.73	66 - 70
Hydrogen	4.71	4.65 4.90	4.86	4.5 - 5.1
Sulfur	0.77	0.71 0.82	2.50	2.2 - 2.5
Oxygen	4.04	2.38 - 4.04	6.81	6.0 - 7.0
Ash	10.00	8.3 11.0	7.8	7.0 8.5
Nitrogen	1.26	1.24 - 1.49	1.14	1.0 1.3
Chlorine	0.13	0.02 - 0.15	0.16	0.12 0.20
Higher Heating Value, Btu/lb	13,000	12,900 13,150	12,400	12,200 - 12,600

Table 2
Steam Generator Performance Parameters
(Economizer Outlet)

Parameter	**100% Load**	**25% Load**
Uncontrolled NO_x, lb/MBtu	0.32	0.32
Design Flue Gas Flow Rate, lb/h	4,273,000	1,749,000
Flue Gas Temperature, °F	706	601
Design Economizer Outlet Volumetric Flow Rate, acfm	2,079,000	780,000
Corrected Flow Rate, dscfm (3% O_2)	784,000	240,000
Oxygen Concentration, %	3.9	8.3

Table 3
SCR System Performance Test Results

Parameter	100% Load	Mid Load	Low Load
Boiler Load, MW	453	281	187
NO_x Inlet, lb/MBtu	0.35	0.32	0.35
NO_x Outlet Emission, lb/MBtu	0.10	0.16	0.14
NO_x Reduction, %	71	54	62
NH_3 Consumption, lb/h	330	141	112
NH_3 Slip, ppm at 35 O_2	<0.1	<0.1	0.3
Power Consumption, kW	41	41	41

Table 4
Stanton Unit 2 SCR System Costs

Parameter	Cost	
Total All-In 1996 Capital Cost*	$21,400,000	$47/kW
Levelized Annual Costs**:		mills/kWh
Ammonia	$280,000	0.09
Catalyst Additions and Replacements	$590,000	0.20
Energy	$260,000	0.09
Annual Testing and Tuning	$70,000	0.02
Levelized Annual O&M Cost	$1,200,000	0.41
Fixed Charges on Capital	$1,690,000	0.57
Total Levelized Annual Cost	$2,890,000	0.98
Cost Effectiveness	$1,200/ton	

* Includes all related SCR equipment and construction; including foundations, full SCR and vaporizer enclosures, electrical, engineering, construction management, and owner indirects.

** Levelized costs reflect the escalation and present worth discounting of future expenditures. A levelization factor of 1.36 times first year costs was used.

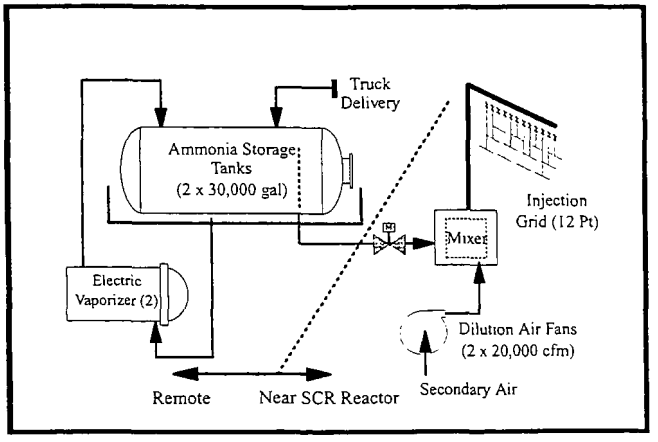


Figure 1
Stanton Unit 2 Ammonia Storage and Vaporization System

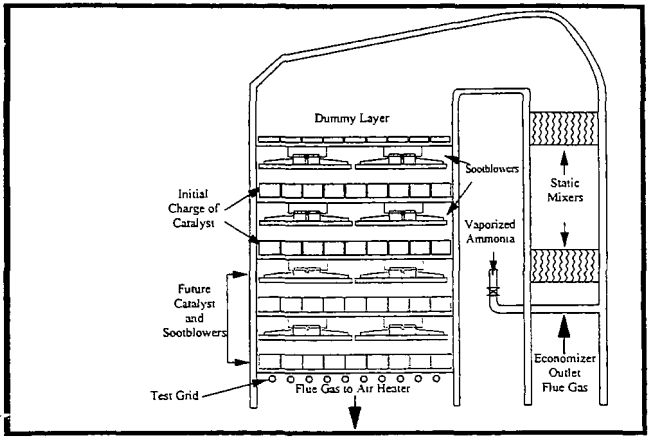


Figure 2
Stanton Unit 2 Catalyst Reactor System

Figure 3
Unit 2 Catalyst (Level 1) After 7,500 Hours of Operation
(Note that the debris on the catalyst protective screens
sloughed off of dummy layer support beams.)

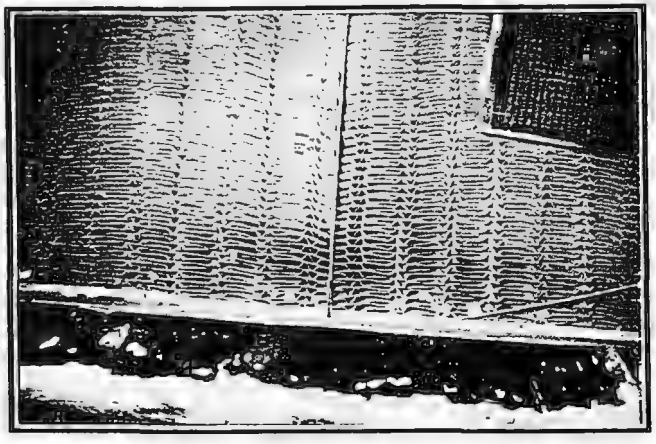
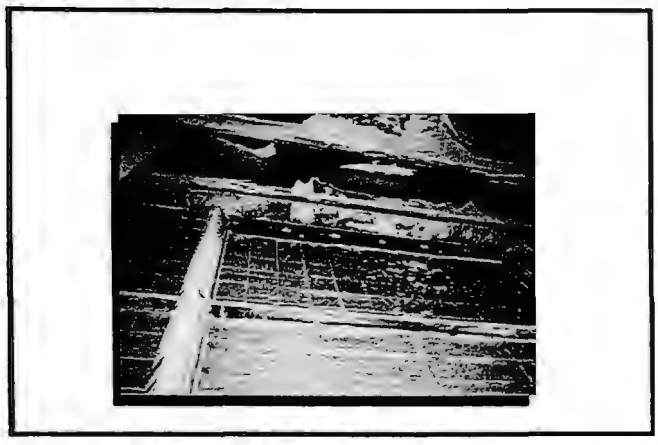


Figure 4
Unit 2 Catalyst Element (level 1) After 7,500 Hours of Operation
and With Protective Screen Removed



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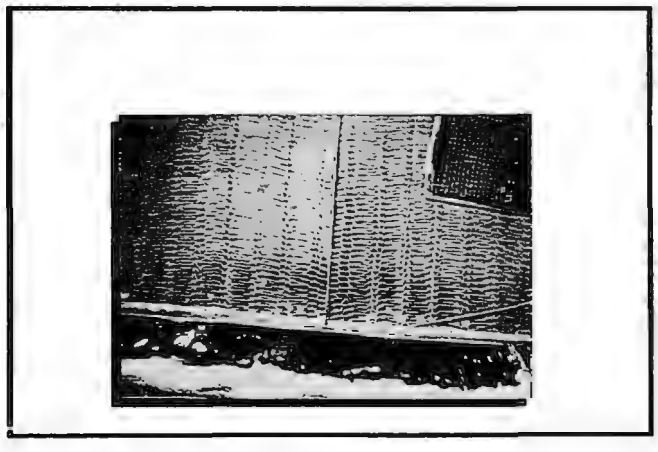

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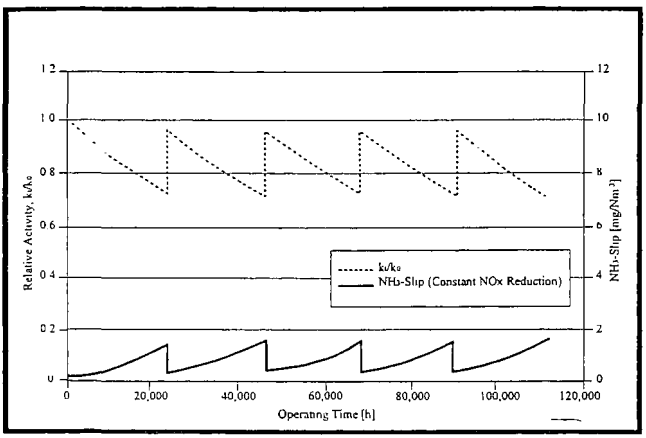

Figure 5
Relative Catalyst Activity and Ammonia Slip vs. Catalyst Loading Requirements

SELECTIVE CATALYTIC REDUCTION: SUCCESSFUL COMMERCIAL PERFORMANCE ON TWO U.S. COAL-FIRED BOILERS

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Abstract

There is valuable operating experience in the United States with Selective Catalytic Reduction NOx emission control on coal-fired boilers. Several systems have started up within the last couple of years. Experience on two of these systems will be examined in this paper.

The authors will present and discuss the following relevant topics:

- full-scale SCR system design considerations in context with expected boiler operation;
- SCR system start-up and performance over the first several years of operation;
- how SCR catalyst management and recent catalyst addition are currently providing operating flexibility for these boilers;

- how SCR system and catalyst enable economic and more efficient boiler operation with reduced LOI levels;
- life-cycle costs analysis of SCR operation and catalyst management.

Background

The Logan Generating Plant and the Indiantown Generating Plant are managed and operated by U. S. Generating Company (US Gen). Each plant uses selective catalytic reduction (SCR) technology to reduce NOx emissions. They, along with the Carney's Point Generating Plant, are the first coal burning plants to utilize full-scale SCR technology in the United States.

USGen is a wholly owned subsidiary of Pacific Gas and Electric Corporation. USGen currently owns, operates and manages seventeen plants generating up to 3,400 MWe. These plants sell electricity and process steam to various customers and industrial firms across the United States.

Logan Generating Plant

The Logan Plant is a 218 MWe net cogeneration plant located in Logan Township, Gloucester County, New Jersey. The plant provides electricity to Atlantic Electric. For cogeneration, the plant provides up to 50,000 lbs. per hour of process steam and 2 MWe to the Monsanto Delaware River Plant. Excess electricity is sold to the energy market through wheeling agreements. The plant (Figure 1) includes a 2,660 psig pulverized coal-fired steam generator with the SCR system, a dry scrubber using quick lime and recycled flyash reagents for sulfur dioxide control, and a reverse air fabric filter for particulate control. The plant is a zero-discharge facility in which all process and waste waters are recycled through a lime/soda ash softener and reverse osmosis technologies. Construction began in April, 1992 and the unit started commercial operation in September, 1994.

Logan Generating Plant received one of the 1995 "Projects of the Year" award from *Power Engineering/Power Engineering International* magazines.

Indiantown Generating Plant

The Indiantown Generating Plant (Figure 2) is a 330 MWe net coal-fired, co-generation plant located in Indiantown, Florida. The plant sells electricity to Florida Power and Light and provides up to 125,000 lbs. per hour of steam to Caulkins Citrus. The steam generator is rated at 2,400 psig, and the unit includes the SCR system, as well as a dry scrubber and reverse air fabric filter. The plant uses agricultural runoff for makeup water and is a zero liquid discharge facility. Softeners and evaporation equipment is installed to recycle and reuse water internally. Indiantown began commercial operation in December, 1995.

SCR System Design

The initial design for Logan Plant included a Selective Non-Catalytic Reduction system for NOx emission control. In the final design review stages, the decision was made by USGen to eliminate the SNCR system and to install Selective Catalytic Reduction for post-combustion NOx control. This decision was made for several technical and commercial reasons. USGen and the boiler manufacturer became increasingly concerned with the applicability of SNCR for the Logan plant due to the complexity of the system and the requirements for load cycling. There was a higher degree of confidence with the SCR system from an operational viewpoint. Combined with commercial benefits such as improved debt service coverage, shortened construction schedule, and improved heat rate, USGen concluded that SCR would be a more effective , and more economical, operating system for controlling NOx emissions. USGen decided to standardize on SCR technology for the three coal-fired plants at Logan, Indiantown and Carneys Point. No changes in the air permits were required as a result of this design change.

Logan Plant

The SCR system at Logan Plant was designed to control boiler NOx emissions to 0.17 lb/MMBtu, from a NOx loading of 0.27 lb/MMBtu. Ammonia slip was limited to 5 ppmvd, corrected to 7% oxygen in the flue gas, at the end of 24,000 operating hours. 141.3 m^3 of Siemens' SINOx plate catalyst was installed initially in three element layers. Three element layers were reserved for spares to accommodate future catalyst management plans.

Indiantown Plant

The SCR reactor at Indiantown is similarly arranged, except that the initial loading of Siemens plate catalyst (161.4 m^3) was installed in 2 element layers. A 40% NOx emission reduction was the initial design requirement. Ammonia slip was also limited to 5 ppmvd, corrected to 7% oxygen. The primary difference, pertaining to the SCR systems, in the two plants lies in the air permits.

Siemens' SINOx plate catalyst was chosen by the SCR system supplier for installation at the Logan and Indiantown SCR plants. Siemens has furnished SCR catalyst in over 100 SCR systems on coal and oil-fired boilers in Europe and the United States, and has compiled over 1,000,000 operating hours of service since 1988. The plate catalyst is preferred for coal-fired applications. Due to the greater open area compared to honeycomb structured catalyst, the plate catalyst provides excellent NOx emission control with a lower pressure drop impact on the unit. It also is extremely resistant to both fly ash deposition and erosion. Additionally the mechanical design of the plate catalyst affords greater resistance to thermal and mechanical stresses that are normal for power boiler operation. The Siemens plate catalyst is very resistant to arsenic poisoning and can be designed to minimize sulfur oxidation rates. Operating

experience with plate catalyst on a variety of boiler types has demonstrated the ability to provide consistent performance over varying load conditions.

The following table presents the SCR catalyst design information for the Logan and Indiantown plants.

PLANT	LOGAN	INDIANTOWN
NOx inlet loading (lb/MMBtu)	0.27	0.25
NOx reduction efficiency (%)	63	40
Ammonia slip (ppmvd@ 7% O2)	5	5
Ammonia slip (ppmvd @ act. O2)	6.2	6.2
Initial Operating period (hr)	24,000	24,000

Operation to date

The SCR systems have performed well over the first few years of commercial operation. NOx and ammonia emissions have been maintained under normal parameters. Other subsystem deficiencies have affected the overall reliability of the SCR, but USGen and Siemens have implemented a number of solutions that will improve long-term operation.

Low-NOx Burners

The low-NOx burners coupled with overfire air systems were designed to minimize NOx emissions from the boilers, ranging from 0.27 lbs/MMBtu at Logan to 0.30 lbs/MMBtu at Indiantown. To date, furnace NOx emissions have generally exceeded 0.30 lbs/MMBtu at both plants. These higher than design levels have forced the SCR system to control the excess NOx in order to maintain compliance with permit requirements. As a result, more ammonia has been needed, and this has resulted in higher levels of unreacted ammonia.

High loss on ignition (LOI) levels in the fly ash have been experienced in both plants, as a result of the non-performance of the burners. As boiler NOx was lowered by reducing excess oxygen, the LOI and carbon monoxide (CO) levels increased. The Logan boiler is quite sensitive to changes in excess oxygen, so the boiler has experienced fluctuations in both NOx and CO emissions.

The situation at Indiantown has been very similar. The plant has tried tuning the burners, with the supplier, numerous times in attempts to optimize NOx emissions with load swings and dispatch requirements. The optimization program was started by Bechtel Startup and Foster Wheeler Energy, the company that furnished the plant. Due to contractual requirements, the entire program was conducted outside of USGen's scope. USGen was not happy with the results of this program, due to poor boiler stability, ramping capabilities and overall combustion. Due to schedule slippage, this optimization program was condensed into a 2-3 week period. The results, confirmed by additional tests, indicated that combustion, and furnace NOx levels, could not be improved without changes and modifications to other boiler auxiliaries.

At the Logan Plant, a combustion optimization program was implemented to improve emissions and reduce fly ash LOI. Over forty different tests were conducted to determine the best settings of register dampers, adjustable tips and overfire air quantities. USGen was able to determine the following from these series of tests:

1. Minimization of CO spikes was achieved by closing the two lower fire air ports on the front wall.
2. Biased overfire air flow to the rear wall had the most improvement in flyash LOI, approximately 3%. However, LOI levels fluctuated between 18 and 28%.
3. Achieved balanced NOx and oxygen emissions at the economizer outlet test grid. At full load, NOx was in the range of 0.35 to 0.39 lb/MMBtu.
4. SO_2 to SO_3 conversion in the SCR was well below design levels.
5. Ammonia slip above 5 ppmvdc at the air preheater gas inlet was not detected at the stack. The high levels of slip and the frequency of air preheater washes prompted the addition of another half-layer of fresh catalyst.

USGen discontinued the program due to loss of support from the boiler manufacturer, but continued to experience both high boiler outlet NOx and high fly ash LOI. Unfortunately, the Logan boiler was designed with a short distance from the overfire air ports to the furnace nose arch, approximately 15 feet. This has resulted in minimal residence time to completely burn out carbon char. The end result is high fly ash LOI. Additional test programs are being planned to optimize combustion by concentrating efforts on fuel and air management.

Impacts of SCR system performance

The SCR system at either plant was not designed to provide the NOx removal efficiency required with these new operating conditions. While the system controlled NOx emissions to the required levels at each plant, higher ammonia consumption rates were needed to maintain the appropriate NH3 : NOx stoichiometry. These higher rates, and the resultant ammonia slip through the catalyst caused some balance of impacts that were unacceptable to USGen.

Figure 3 illustrates the projected ammonia slip, and associated catalyst management plan, for the Logan Plant under design conditions. Separately plotted are several data points representing measured ammonia slip data at approximately 8,000 hours of service. It is clear that the measured data is significantly different from the projected. This is indicative of a critical imbalance among catalyst volume, NOx loadings, ammonia consumption and ammonia slip control.

The increased slip led to accelerated rates of air preheater fouling due to ammonium bisulfate formation. Both plants began to monitor air heater differential pressure to determine boiler operating time between air heater washes, and as an indirect ammonia slip measure. This information was useful for providing some guidance in understanding the operation of the SCR system, but clearly it was unsatisfactory for

identifying the primary problem related to the higher than design furnace NOx emissions.

Ammonia slip in the gas stream is very difficult to measure accurately on a frequent basis. It is common practice in European installations to assess ammonia slip from the SCR process by quantifying ammonia by weight in the unit's fly ash. Trends established by this process are very similar to those presented in the catalyst management plans. The comparative ease of measuring ammonia in this fashion make it a low-cost alternative to costly testing and monitoring, and it provides a very predictable indication of ammonia slip. Both Logan and Indiantown began to use this measurement in 1996 as a tool for improving system diagnostic capabilities. It is Siemens' experience that 200 ppm of ammonia by weight in the fly ash is a threshold for most units, in terms of balance of plant impacts.

Indiantown decided to install additional catalyst because it was unacceptable to shut the unit down every ten weeks to wash the air heater. During outages to wash the air heaters so that pressure drop could be lowered, ash sample analyses confirmed that ammonium bisulfates were the cause of the pluggage. This formation was the result of excessive ammonia slip through the SCR. Indiantown personnel believed the answer was in the addition of SCR catalyst, but they were uncertain of the reasons. Support from the SCR system supplier was lacking, so USGen turned to Siemens for an understanding of the problem. It was through these discussions that USGen learned that the design basis for the SCR system was founded on unrealistic low-NOx burner expectations. Working together, USGen and Siemens have resolved the operating problems. There has been no need to wash the air heaters in the last nine months of operation.

Based on the high frequency of air preheater washes, high levels of ammonia in the fly ash samples and greater than 5 ppmvdc slip while operating near the NOx permit limit, USGen exercised their option to install fresh catalyst under warranty agreements with the boiler manufacturer. A half layer of catalyst was procured and installed during the September, 1996 annual plant outage. The half layer was installed beneath an existing layer. Following the installation of fresh catalyst, an immediate drop in ammonia in fly ash levels was noted. Long term improvements were achieved in reducing air preheater fouling rates due to slip while slowly reducing NOx emissions below permit levels.

Figure 4 illustrates the relationships among ammonia slip and catalyst volume as functions of operating temperature and required NOx reduction efficiency. The lines are iso-ammonia slip and would be specific only for a given unit. Each unit, in other words, would have a curve appropriate for specific design conditions. This particular figure was developed for the Logan Plant and shows the ammonia slip design point at the 24,000 operating hour point. To maintain a 5 ppm ammonia slip with an increased NOx reduction efficiency requirement, either a reduced operating period must be accepted or additional catalyst must be installed to maintain the 24,000 hour period.

USGen decided to increase SCR catalyst volume at both plants to restore an operating balance between efficiency and ammonia slip. The immediate benefits to unit performance can be seen in Figure 5. Prior to the installation of the new catalyst, ammonia concentrations in the Logan fly ash were approximately 180 to 210 ppm by weight. These dramatically dropped to 60 ppm upon startup with the additional volume of catalyst.

Impacts on long-term performance

USGen is currently evaluating a number of operating options for the Logan and Indiantown plants, as a result of these changes in SCR operation. At both plants, the long term catalyst management plans have been altered by the need for higher reduction efficiencies. This alone has impacted the financial strategies for the plants by increasing the projected operating costs over a thirty year life cycle. As can be seen in Figure 6, the frequency of catalyst replacement is higher compared to the original design. These costs are also affected by higher ammonia consumption rates.

It is also known that the design ammonia slip limit of 5 ppmvd at 7% oxygen is probably too high for consistent boiler operation. Past performance indicates that the slip should be limited to 2 or 3 ppmvd to avoid the balance of plant impacts that both Logan and Indiantown plants have experienced. Of course this magnifies the projected increase in long-term operating costs by shortening the intervals between catalyst addition or exchange. USGen and Siemens are evaluating several options to determine the most cost effective ammonia slip and management plan for each plant.

Benefits of the SCR system

However, USGen has also recognized that the SCR system affords a number of benefits in terms of overall boiler performance.

There is relatively little impact on operations, in that maintenance requirements are minimal. USGen has concluded that the cost of SCR is insignificant to the cost of producing electricity.

Knowing that the SCR system can handle higher NOx loadings than design, USGen has realized that future operating costs can be mitigated by improvements in boiler efficiency. In tuning unit burners to reduce NOx emissions from the furnace, USGen has accepted loss on ignition levels in excess of 30%, and a corresponding boiler efficiency of approximately 86%. The benefit of the SCR systems is the ability to accept a higher NOx loading and to allow the boiler to operate at higher efficiencies with a much lower LOI level. USGen is currently testing the boilers at Logan and Indiantown in order to determine the optimal operating points, while letting the SCR system absorb the fluctuations in NOx loadings.

It is expected that long-term costs can be improved by a reduction in maintenance associated with burner operation and parts, and boiler corrosion.

USGen has concluded that the SCR systems will maintain compliance while controlling ammonia slip to optimal levels at each of the plants. Proper planning will also help US Generating choose a catalyst management plan according to the current and future operating conditions at each plant, and in conjunction with future unit outages.

References

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D Beckham, "Horses and Carts: The Roadmap to Productive Electric Competition," presented at the Cost-Effective Reduction Strategies for Power Companies conference, Washington, D. C. (November, 1996)

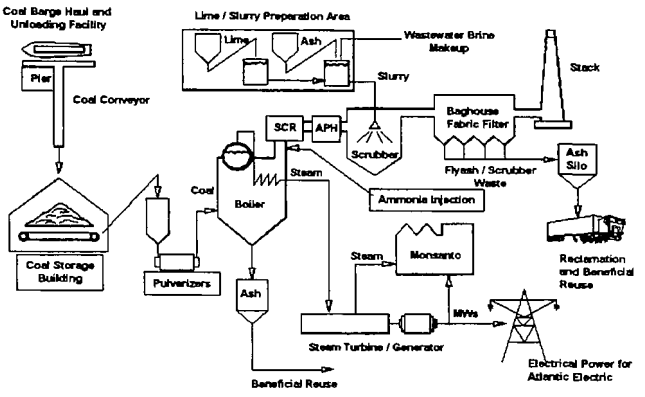

Figure 1. Logan Generating Plant

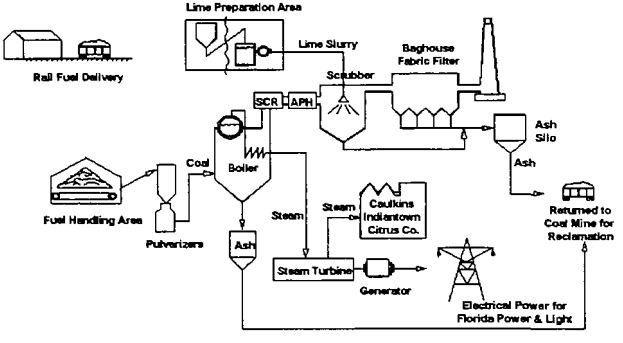

Figure 2. Indiantown Generating Plant

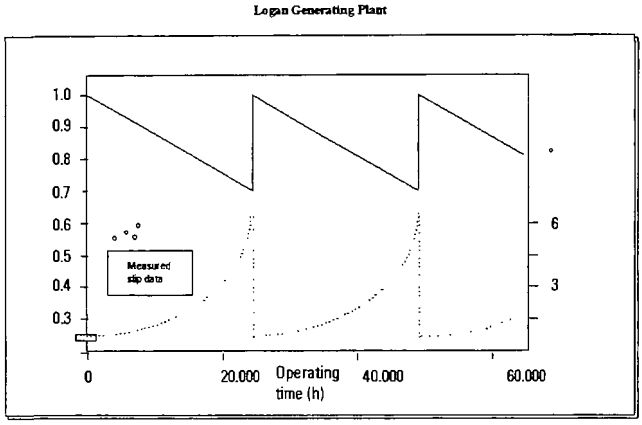

Figure 3. Relative Activity (k/k_o), Ammonia Slip (ppmvdc) vs. Operating Time

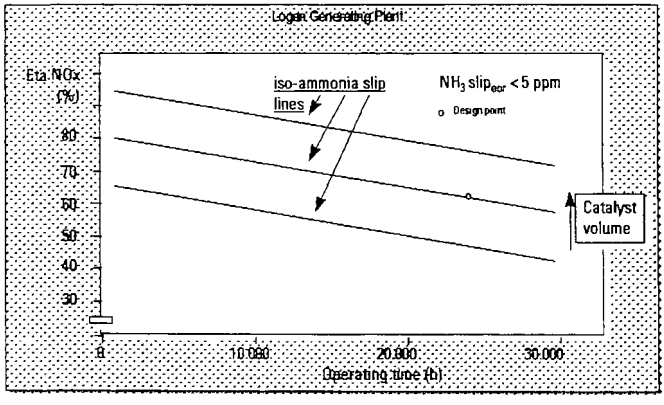

Figure 4. Ammonia Slip and Catalyst Volume vs. Operating Time

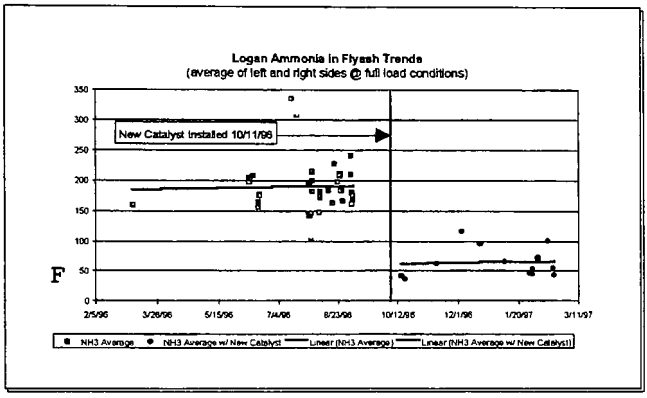

Figure 5. Ammonia in fly ash trends

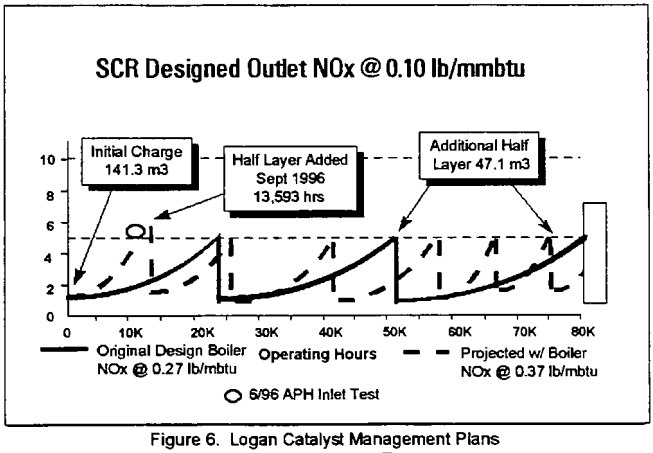

Figure 6. Logan Catalyst Management Plans
Ammonia Slip (ppmv) Trends

Successful Implementation of Cormetech Catalyst

in High Sulfur Coal-Fired SCR Demonstration Project

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Abstract

The U.S. Department of Energy (DOE), Electric Power Research Institute (EPRI), Ontario Hydro, and Southern Company Services (SCS) jointly funded a project under the Innovative Clean Coal Technologies (ICCT) Program to demonstrate the capabilities of Selective Catalytic Reduction (SCR) technology on high sulfur U.S. coal. The demonstration site was at Gulf Power Company's Plant Crist Unit No. 5 (75 MW capacity) near Pensacola, Florida. The demonstration was completed in July 1995.

Cormetech was one of a number of catalyst manufacturers that participated in the program. Cormetech supplied catalyst for two (2) small-scale SCR reactors, one high dust and one low dust. The high dust catalyst was in operation for 10,600 hours and the low dust catalyst was in operation for 5,800 hours. Required performances, including NOx removal and SO2 oxidation, were maintained during the demonstration for both reactors. Moreover, the catalysts are projected to have met required performances well beyond the duration of the demonstration.

The report included herein details the primary field test results performed by SCS and catalyst test results performed by Cormetech during the test period for the reactors containing Cormetech catalyst. Specific results and their impact are discussed, including changes in catalyst performance and properties over time.

I. BACKGROUND

The U.S. Department of Energy (DOE), Electric Power Research Institute (EPRI), Ontario Hydro, and Southern Company Services (SCS) jointly funded a project under the Innovative Clean Coal Technologies (ICCT) Program to demonstrate the capabilities of Selective Catalytic Reduction (SCR) technology on high sulfur U.S. coal. The results of the project are summarized in Topical Report Number 9, Clean Coal Technology - Control of Nitrogen Oxide Emissions: Selective Catalytic reduction (SCR) by The U.S. Department of Energy and Southern Company Services, Inc, May 1997.

The demonstration site was at Gulf Power Company's Plant Crist Unit No. 5 (75 MW capacity) near Pensacola, Florida. The demonstration facility includes a total of nine (9) SCR reactors which were run in parallel. Three (3) 2.5 MWe reactors and six (6) 0.2 MWe. All reactors represent high dust applications (upstream of hot-side ESP) except one 0.2 MWe reactor which was configured as a low dust application (downstream of hot-side ESP).

The two year demonstration project began in June 1993 and concluded in July 1995.

Cormetech was one of a number of catalyst manufacturers that participated in the program. Cormetech designs and manufactures honeycomb catalyst of homogeneous composition for SCR based on licensed technology of Mitsubishi Chemical Corporation and Mitsubishi Heavy Industries. Developmental catalyst was not employed on this project. The specific licensed catalyst technology used has been employed world-wide on a total of 400 units including 75 coal-fired boilers.

Cormetech supplied catalyst for two (2) 0.2 MWe SCR reactors, one high dust and one low dust. The 0.2 MWe reactors were approximately one (1) square foot in cross-section and consisted of three (3) and two (2) layers of catalyst respectively. The catalyst for the low dust reactor was installed in April 1994 as a substitute for another catalyst vendor that withdrew from the test. Therefore, the total number of operating hours was somewhat less for the low dust catalyst versus the high dust.

SCS managed the project from permitting to engineering and construction, as well as, all field operation and testing.

Sootblowing was used regularly on all reactors. The 2.5 MWe reactors were equipped with automatic rake type sootblowers, while the remaining reactors were manually air blown.

In addition to field tests on each reactor, catalyst samples were pulled and returned to each respective catalyst manufacturer. Each manufacturer was responsible for testing and reporting on the state of their catalyst to the project funders.

This paper presents specific field and laboratory data for Cormetech's catalyst. The data is compared to requirements showing that the demonstration was successful. Key flue gas and ash data for Plant Crist are provided in the Appendix to define the conditions under which the SCR was operated.

II. DESIGN CONDITIONS

Performance Design Conditions

Temperature, ^{O}F	700
Superficial Velocity, ft/s	18.1
O_2, vol % wet	3
Inlet NOx, ppmv	400
Inlet SOx, ppmv	~ 2000 (~3% S in fuel)
Molar Ratio, NH3/NOx	0.8
NOx Conversion Target, %	80
Maximum Allowable NH3 slip, ppmv	5
Maximum Allowable Pressure Drop, in H_2O	4
Maximum Allowable SO2 Oxidation, %	0.75
Number of Full Size Layers	3 (High dust) 2 (Low dust)
Catalyst Pitch, mm	7.1 (High dust) 3.7 (Low dust)
Catalyst Length, mm	1000 (High dust) 600 (Low dust)
Space Velocity (SV), Hr^{-1} @ $32^{O}F$, 1 atm	2776 (High dust) 7033 (Low dust)

III. PERFORMANCE RESULTS

A. High Dust (10,600 hours in operation)

Field Results

Ammonia slip remained ≤ 1 ppmv for the duration of the demonstration. This was well below the 5 ppmv maximum allowable slip. No change in ammonia slip over time was detectable (Figure 1).

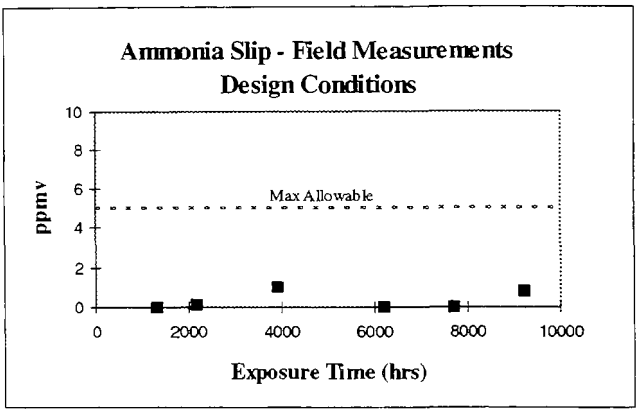

Figure 1

SO_2 oxidation rate remained well below the 0.75% maximum allowable rate for the duration of the demonstration. Average SO_2 oxidation rate was below 0.4%. No change in SO_2 oxidation rate over time was detectable (Figure 2).

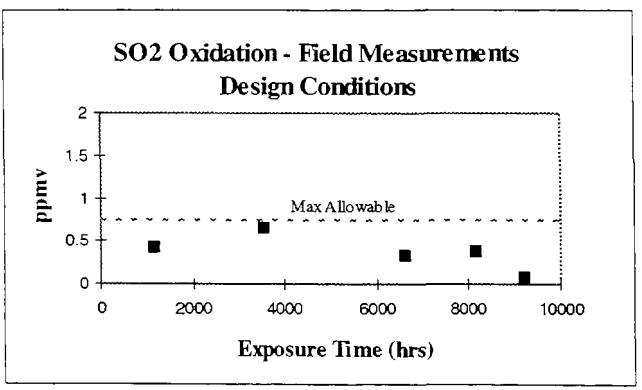

Figure 2

Pressure drop remained below the 4 inches H2O maximum for the duration of the demonstration.

Lab Performance Results

Field measurements were subject to more inaccuracies than measurements from a pilot scale laboratory reactor. The scatter in the field data makes it difficult to detect changes in catalyst performance. In order to more accurately measure the change in catalyst performance over time, full-sized catalyst samples were tested fresh and at the end of the demonstration in a pilot scale laboratory reactor. Such periodic testing is typical for SCR systems in order to assure proper operation and manage catalyst life. For a description of the pilot scale test, refer to "Quality Assurance of SCR Catalysts for the Southern California Edison 480 MW Power Generating Plants Through Laboratory and Field Performance Testing", Chris DiFrancesco, et. al., ICAC Forum '94.

The tests were performed at the design conditions. The catalyst pulled from the reactor was tested "as is" without any cleaning. Only the first two layers of catalyst were evaluated so that ammonia slip would be detectable (SV = 4164 hr-1). Ammonia slip increased over time from 0.7 - 1.4 ppmv, well below the 5 ppmv maximum, even with only two catalyst layers. (Figure 3)

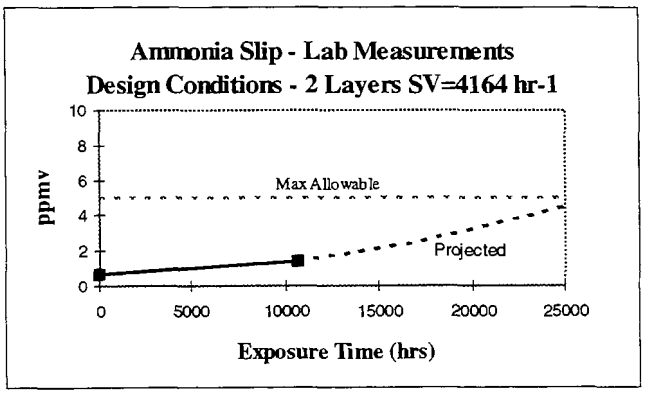

Figure 3

Based on this rate of change in performance, we predict that the ammonia slip for two layers of catalyst would remain below the 5 ppmv maximum for approximately an additional 15,000 hours.

Lab Chemical Analysis Results

Chemical analyses of field sample pulled at 10,600 hours was conducted by X-ray Fluorescence. It was determined that the decrease in performance over the duration of the demonstration was mainly due to a combination of arsenic (As) accumulation, surface masking by fly ash components (Ca, Fe), and alkaline metal accumulation (K). The graph below illustrates the observed increases in the X-ray intensities of these elements relative to the total X-ray intensities of the titanium catalyst base. (Figure 4)

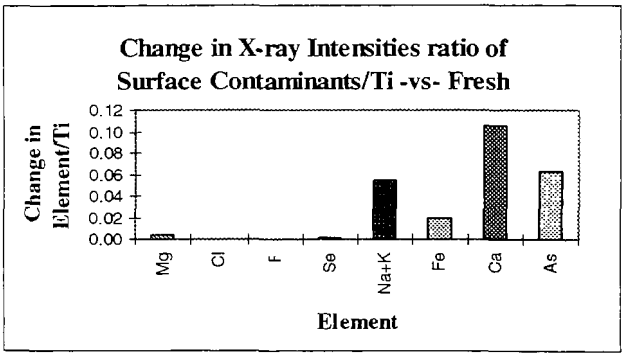

Figure 4

These performance deterioration factors are typical for coal fired applications and is consistent with the coal analysis in the appendix and the experience of Cormetech and its licensors. For a description of the deterioration mechanisms, refer to "Optimizing SCR Catalyst Design and performance for Coal-Fired Boilers", by Scot Pritchard, et. al., EPRI/EPA 1995 Joint Symposium on Stationary Combustion NOx Control.

B. Low Dust Summary (5,800 hours in operation)

Field Results

Operation time was limited on this reactor. Pressure drop was somewhat erratic (4 - 8 in H_2O) caused by plugging of the small pitched catalyst due to unexpected carry-over of large particulate to the "low" dust reactor. More than 30% of the catalyst was plugged with fly ash. This carry-over was due to the long duct runs of the test facility and a less than optimum flue gas take-off scoop. This situation would not be expected in a full scale unit.

Despite these operational issues, ammonia slip remained below 1 ppmv for the duration of the demonstration, well below the 5 ppmv maximum allowable slip. Similar to the high dust case, no change in ammonia slip over time was detectable in the field.

SO_2 oxidation rate remained well below the 0.75% maximum allowable rate for the duration of the demonstration. Similar to the high dust case, average SO_2 oxidation rate remained below 0.4% and no change in SO_2 oxidation rate over time was detectable.

Lab Results

As with the high dust reactor, fresh samples and samples removed at the end of the demonstration run were tested in the laboratory reactor. Although the reactor as a whole was 30% plugged, the particular samples tested were only 3% plugged. Ammonia slip increased over time from 0.6 - 1.0 ppmv, well below the 5 ppmv max. Based on this rate of change in performance, we predict that the ammonia slip would remain below the 5 ppmv maximum for more than 15,000 hours, excluding impact of the overall severe plugging.

Through chemical and physical property analyses, it was determined that the very slight decrease in performance over time was due mainly to a small amount of arsenic accumulation.

VI. CONCLUSIONS

For the high dust application, deNOx performance (catalyst deactivation), SO_2 oxidation, and pressure drop remained within design limits. Performance is expected to have lasted much longer than the duration of the demonstration even with only two-thirds of the reactor charge. Deterioration mechanisms and impact were consistent with expectations based on the coal composition fired.

Also, note that the low ammonia slip values achieved are consistent with current design practices (limit < 2-3 ppmv) to avoid fly ash contamination and excess air pre-heater maintenance. Design ammonia slip limits are unit specific depending on ash disposal method, sulfur content, and air pre-heater design.

For the low dust application, deNOx performance (catalyst deactivation) and SO_2 oxidation remained within design limits even with 30% of the catalyst plugged. Pressure drop increased significantly due to the plugging but was a result not realizing a truly low dust situation. If a truly low dust situation was realized, the catalyst performance, as in the high dust case, is expected to have lasted much longer than the duration of the demonstration.

APPENDIX

Boiler Type: Tangentially-Fired, Dry-bottom

Particulate Control: Hot and Cold-side Electrostatic Precipitator

Design Fuel Analysis:

C, wt %	67.80
H, wt %	4.60
S, wt %	2.90
N, wt %	1.40
Cl, wt %	0.25
Ash, wt %	9.50
Moisture, wt %	7.90
Oxygen, wt% (by diff.)	5.65

Actual Fuel Analysis from March 1993 to July 1995 Based on Monthly As-Burned Composites. Alabama Power Company Results, Dry Basis

Test	Method	Units	Ave.	Std. Dev.
Moisture, Total	ASTM D 3302	% by Wt	10.87	0.97
Ash	ASTM D 3180	% by Wt	9.30	0.63
Gross Caloric Value	ASTM D 3180	Btu/lb	13268	130
Sulfur, Total	ASTM D 3180	% by Wt	2.58	0.04
Sulfur, lb/MMBtu	ASTM D 3180	lb/MMBtu	1.95	0.31
Carbon	ASTM D 3180	% by Wt	74.82	0.81
Hydrogen	ASTM D 3180	% by Wt	5.00	0.07
Nitrogen	ASTM D 3180	% by Wt	1.25	0.03
Oxygen	ASTM D 3180	% by Wt	6.73	0.66
Carbon, Fixed	ASTM D 3180	% by Wt	52.83	1.31
Volatile Matter	ASTM D 3180	% by Wt	37.88	1.17
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Test	Method	Units	Ave.	Std. Dev.
Aluminum	ASTM D 3682	% by Wt	1.09	0.11
Antimony	ASTM D 3683	mg/kg	< 1.0	
Arsenic	Sec. Chem. Acta. 44B	mg/kg	3.2	1.9
Barium	ASTM D 3683	mg/kg	40	18
Beryllium	ASTM D 3683	mg/kg	3	1
Cadmium	ASTM D 3683	mg/kg	< 1.0	-
Calcium	ASTM D 3682	% by Wt	0.24	0.03
Chlorine	ASTM D 4208	mg/kg	1767	812
Chromium	ASTM D 3683	mg/kg	19	4
Cobalt	ASTM D 3683	mg/kg	7	2
Copper	ASTM D 3683	mg/kg	9	2
Flourine	ASTM D 3761	mg/kg	56	27
Iron	ASTM D 3682	% by Wt	1.08	0.17
Lead	Sec. Chem. Acta. 44B	mg/kg	11.7	4.5
Lithium	ASTM D 3683	mg/kg	9	5
Magnesium	ASTM D 3682	% by Wt	0.06	0.02
Manganese	ASTM D 3683	mg/kg	24	4
Mercury	ASTM D 3684	mg/kg	0.07	0.04
Molybdenum	ASTM D 3683	mg/kg	7.78	4.33
Nickel	ASTM D 3683	mg/kg	15	2
Phosphorous	ASTM D 3682	% by Wt	0.02	0.02
Potassium	ASTM D 3682	% by Wt	0.20	0.06
Selenium	Sec. Chem. Acta. 44B	mg/kg	< 2	-
Silica	ASTM D 3682	% by Wt	2.27	0.19
Sodium	ASTM D 3682	% by Wt	0.06	0.02
Titanium	ASTM D 3682	% by Wt	0.06	0.01
Vanadium	ASTM D 3683	mg/kg	41	10
Zinc	ASTM D 3683	mg/kg	39	29

Design Flue Gas Composition:

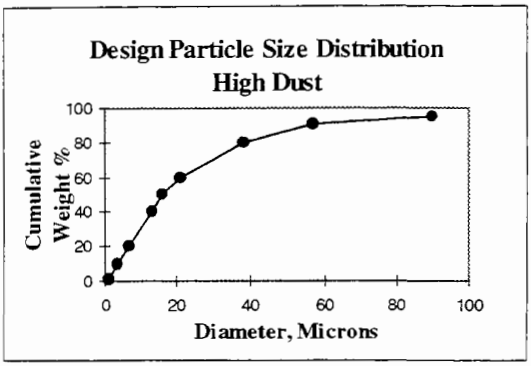
N_2, vol %	73.29
O_2, vol %	3.01
CO_2, vol %	13.82
H_2O, vol %	9.61
SO_2, ppmv	2210
SO_3, ppmv	20
NOx, ppmv	400
Hcl, ppmv	104

Design Flyash Composition:

SiO_2, wt %	50.4
Al_2O_3, wt %	19.9
Fe_2O_3, wt %	18.1
TiO_2, wt %	1.0
CaO, wt %	4.2
MgO, wt %	1.0
K_2O, wt %	2.6
Na_2O, wt %	0.7
SO_3, wt %	1.4
P_2O_5, wt%	0.3
LOI, % (typ represents UC)	6.5

Design Particulate Loading: Average: High Dust - 8000 mg/Nm^3
Range: 6000 - 11,000

Average: Low Dust 30 mg/Nm^3 Avg.



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