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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

**NO<sub>x</sub> CONTROL IN  
FOREST PRODUCTS INDUSTRY  
BOILERS: A REVIEW OF  
TECHNOLOGIES, COSTS,  
AND INDUSTRY EXPERIENCE**

**SPECIAL REPORT NO. 03-04  
AUGUST 2003**

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## **Acknowledgments**

This report was prepared by Dr. Arun V. Someshwar, Principal Research Engineer at the NCASI Southern Regional Center. Dr. John E. Pinkerton, Vice President, Air Quality, provided valuable review of the report contents. Susan Kirkland was responsible for report preparation.

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National Council for Air and Stream Improvement, Inc. (NCASI). 2003. *NO<sub>x</sub> control in forest products industry boilers: A review of technologies, costs and industry experience*. Special Report No. 03-04. Research Triangle Park, N.C.: National Council for Air and Stream Improvement, Inc.



servicing the environmental research needs of the forest products industry since 1943

## PRESIDENT'S NOTE

The United States Environmental Protection Agency and many state agencies are attempting to lower ambient ozone concentrations by reducing emissions of precursor compounds, including NO<sub>x</sub>. The contribution of NO<sub>x</sub> to secondary fine particulate matter and regional haze is actively being studied by EPA as it develops strategies to reduce ambient PM<sub>2.5</sub> levels. As a result of these regulatory initiatives, it is not surprising to find an escalating interest in the investigation of NO<sub>x</sub> emissions and options for reduction. Although forest products manufacturing facilities represent only about 1% of the total U.S. NO<sub>x</sub> emissions, many regulatory agencies have been scrutinizing mill NO<sub>x</sub> emission sources for potential reductions.

Therefore, NCASI has devoted considerable efforts in recent years to studying NO<sub>x</sub> emissions from mill combustion sources, including kraft recovery furnaces, lime kilns, thermal oxidizers, and power boilers, particularly those burning wood residues. At most mills, boilers are the largest NO<sub>x</sub> emission source and are thus the most frequent target for reductions. To assist mills in responding to regulatory agency pressures for NO<sub>x</sub> reductions, NCASI issued a special report in 1999 (*A Review of NO<sub>x</sub> Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns*). Since there have been significant developments over the past five years in combustion modifications and add-on control technologies for boiler NO<sub>x</sub> reductions, NCASI reviewed the more recent information to update the 1999 report.

This special report is meant to serve as a background document to assist member companies in responding to NO<sub>x</sub> limitations that might be proposed by regulatory agencies as a result of uniform State Implementation Plan (SIP) requirements for industrial boilers or in permitting decisions for individual units. It reviews NO<sub>x</sub> control technologies that are available for direct application to forest products industry boilers, or that may be transferable from current utility boiler applications. Limitations identified by vendors and boiler operators that could preclude successful installation and operation of certain control technologies on particular boilers have been reviewed and summarized, especially with respect to technical feasibility. NO<sub>x</sub> control costs and removal cost-effectiveness estimates from a number of sources are provided.

NCASI appreciates the engineering, cost, and other information on boiler NO<sub>x</sub> reductions anonymously shared by several member companies for use in this report.

A handwritten signature in black ink, appearing to read "Ron Yeske", is positioned above the printed name.

Ronald A. Yeske

August 2003



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## MOT DU PRESIDENT

L'EPA et plusieurs agences d'état tentent de diminuer les concentrations d'ozone dans l'air ambiant par la réduction des émissions de composés précurseurs, tels que les NO<sub>x</sub>. La contribution des NO<sub>x</sub> aux particules secondaires et à la brume sèche en régions (*regional haze*) est actuellement à l'étude par l'EPA. L'EPA est en cours de développement de stratégies pour réduire les niveaux ambiants de PM<sub>2.5</sub>. Il n'est pas surprenant de voir apparaître, suite à ces initiatives réglementaires, un intérêt grandissant pour la recherche sur les émissions de NO<sub>x</sub> de même que sur les options de réduction de ces polluants. Malgré le fait que l'industrie des produits forestiers ne représente qu'environ 1% des émissions totales de NO<sub>x</sub> aux États-Unis, plusieurs agences de réglementation se sont penchées sur les sources d'émissions de NO<sub>x</sub> des fabriques afin de déceler des réductions potentielles.

Par conséquent, NCASI a déployé des efforts considérables depuis les dernières années afin d'étudier les émissions de NO<sub>x</sub> des sources de combustion des fabriques, incluant les fournaies de récupération kraft, les fours à chaux, les oxydateurs thermiques et les chaudières, plus particulièrement celles qui sont alimentées par de la biomasse. Dans la plupart des fabriques, les chaudières demeurent les principales sources d'émissions de NO<sub>x</sub> et elles représentent une cible de choix pour ce qui est des réductions potentielles. Afin de soutenir les fabriques qui doivent répondre aux pressions des agences de réglementation pour ce qui est des réductions d'émissions de NO<sub>x</sub>, NCASI a publié un rapport spécial en 1999 (*Une revue des stratégies de contrôle des émissions de NO<sub>x</sub> pour les chaudières, les fournaies de récupération kraft ainsi que les fours à chaux*). Depuis les cinq dernières années, d'importants développements ont vu le jour en matière de modifications de la combustion et de technologies de contrôle pour la réduction des émissions de NO<sub>x</sub> des chaudières. NCASI a brossé un tableau des informations les plus récentes afin de mettre à jour son rapport de 1999.

Ce rapport spécial se veut un document de référence afin d'aider les compagnies membres à répondre aux exigences de réductions des émissions de NO<sub>x</sub> qui peuvent être proposées par les agences de réglementation dans le cadre du Plan d'implantation de l'état (*State Implementation Plan*) pour les chaudières ou encore suite aux décisions reliées aux autorisations et permis pour les unités individuelles. Le rapport fait la revue des technologies de contrôle des NO<sub>x</sub> qui sont disponibles pour une application directe dans les chaudières de l'industrie forestière ou encore qui peuvent être transférées des expériences acquises sur les chaudières de centrales thermiques. Les limites identifiées par les fournisseurs et les opérateurs de chaudières et qui sont susceptibles de nuire au succès de l'installation et de l'opération de certaines technologies de contrôle des NO<sub>x</sub> sur des chaudières spécifiques ont fait l'objet d'une revue et d'une synthèse, principalement en ce qui concerne la faisabilité technique. On trouve également dans ce rapport les coûts de contrôle des NO<sub>x</sub> et les estimés d'efficacité d'enlèvement pour plusieurs sources.

NCASI tient à remercier les nombreuses compagnies membres qui ont bien voulu partager, dans l'anonymat, des données sur les travaux d'ingénierie, les coûts et d'autres informations en matière de réduction des NO<sub>x</sub> émis par les chaudières. Ces données ont été utilisées dans ce rapport.



Ronald A. Yeske

Août 2003



# **NO<sub>x</sub> CONTROL IN FOREST PRODUCTS INDUSTRY BOILERS: A REVIEW OF TECHNOLOGIES, COSTS AND INDUSTRY EXPERIENCE**

SPECIAL REPORT NO. 03-04  
AUGUST 2003

## **ABSTRACT**

Recent information on techniques for reducing NO<sub>x</sub> emissions from boilers burning fossil fuels and biomass fuels is reviewed. The applicability of both combustion modifications and flue gas treatment to industrial-sized boilers at forest products manufacturing facilities is discussed. Difficulties inherent in applying various technologies to boilers burning coal, gas, oil, wood, or combinations thereof are highlighted. Combustion modifications such as the use of low-NO<sub>x</sub> burners and overfire air appear suitable for most coal, oil and gas-fired boilers, although cost considerations in each individual instance should be evaluated. Selective non-catalytic reduction (SNCR) by urea injection appears to be a viable NO<sub>x</sub> reduction technology for base-loaded boilers. However, its applicability to boilers with swinging loads needs further research and development. Problems with ammonia slip and curtailed NO<sub>x</sub> removal efficiencies are key concerns. Installation and operation of selective catalytic reduction (SCR) on industrial boilers firing coal, oil, and gas is the most expensive add-on control option. There are numerous issues with using SCR on wood and combination wood-fired boilers, including catalyst plugging and soluble alkali poisoning as well as increased energy consumption. Emerging technologies such as gas reburning and low temperature oxidation followed by scrubbing, hold much promise as technologies that can fill the gap in NO<sub>x</sub> control efficiencies between the 30 to 50% expected from SNCR and 80 to 90% expected from the more expensive SCR. With regard to NO<sub>x</sub> removal costs, available mill-generated estimates of cost-effectiveness fall in the \$2,000 to \$6,000 per ton removed range. These estimates exceed EPA's benchmark figure of \$2,000 per ton removed, a figure EPA believes is a reasonable cost for retrofit industrial boiler NO<sub>x</sub> controls in ozone nonattainment areas.

## **KEYWORDS**

biomass, combustion modification, cost-effectiveness, costs, fuel NO<sub>x</sub>, LNB, OFA, SCR, SNCR, thermal NO<sub>x</sub>, staged combustion, wood residue

## **RELATED NCASI PUBLICATIONS**

Technical Bulletin No. 802 (March 2000). *Effect of stripper off-gas burning on NO<sub>x</sub> emissions.*

Special Report No. 99-01 (April 1999). *A review of NO<sub>x</sub> emission control strategies for industrial boilers, kraft recovery furnaces, and lime kilns.*

Technical Bulletin No. 646 (February 1993). *Emission factors for NO<sub>x</sub>, SO<sub>2</sub> and volatile organic compounds for boilers, kraft pulp mills, and bleach plants.*

Technical Bulletin No. 636 (July 1992). *An analysis of kraft recovery furnace NO<sub>x</sub> emissions and related parameters.*

Technical Bulletin No. 455 (April 1985). *Volatile organic carbon emissions from wood residue fired power boilers in the Southeast.*

Atmospheric Quality Improvement Technical Bulletin No. 111 (January 1981). *A study of nitrogen oxides emissions from large kraft recovery furnaces.*

Atmospheric Quality Improvement Technical Bulletin No. 109 (September 1980). *A study of wood-residue fired power boiler total gaseous non-methane organic emissions in the Pacific Northwest.*

Atmospheric Quality Improvement Technical Bulletin No. 107 (April 1980). *A study of nitrogen oxides emissions from lime kilns.*

Atmospheric Quality Improvement Technical Bulletin No. 105 (December 1979). *A study of nitrogen oxides emissions from kraft recovery furnaces.*

# CONTROLE DES NO<sub>x</sub> EMIS PAR LES CHAUDIERES DE L'INDUSTRIE DES PRODUITS DU BOIS - UNE REVUE DES TECHNOLOGIES, DES COUTS ET DE L'EXPERIENCE DE L'INDUSTRIE

RAPPORT SPECIAL NO. 03-04  
AOUT 2003

## RESUME

Les informations récentes portant sur les techniques de réduction des émissions de NO<sub>x</sub> générées par la combustion de combustibles fossiles et de biomasse dans les chaudières font l'objet d'une revue. On discute des modifications de combustion et du traitement des gaz de combustion appliqué aux chaudières utilisées dans les fabriques de l'industrie des produits du bois. On trouve également des informations sur les difficultés inhérentes à l'application de différentes technologies de contrôle sur des chaudières utilisant du charbon, du gaz, de l'huile, de la biomasse ou une combinaison de ces combustibles. Les modifications de combustion telles que l'utilisation de brûleurs à bas niveau de NO<sub>x</sub> (*low-NO<sub>x</sub>*) et l'optimisation de l'air de combustion secondaire et tertiaire (*overfire air*) semblent applicable pour la plupart des chaudières utilisant du charbon, de l'huile et du gaz, mais les considérations économiques doivent être évaluées au cas par cas. La réduction sélective non-catalytique (SNCR) à l'aide d'injection d'urée semble être une technologie de réduction des NO<sub>x</sub> viable pour les chaudières alimentées par la base; toutefois on se doit de poursuivre les efforts de recherche et développement en ce qui concerne l'application de cette technologie sur des chaudières dont les charges varient. Les problèmes reliés aux pertes d'ammoniac et à la diminution de l'efficacité d'enlèvement de NO<sub>x</sub> qui en découle demeurent des préoccupations majeures. L'installation et l'opération de la réduction catalytique sélective (SCR) sur des chaudières utilisant du charbon, de l'huile et du gaz représente l'option de contrôle la plus coûteuse. Il existe plusieurs enjeux associés à l'utilisation de la SCR dans les chaudières à biomasse et les chaudières à biomasse/combustibles multiples : obstruction du catalyseur, empoisonnement par des alcali solubles et augmentation de la consommation d'énergie. On mise beaucoup sur les nouvelles technologies telles que la combustion répétée des gaz et l'oxydation à basse température suivie de l'épuration pour combler l'écart existant en ce qui concerne l'efficacité de contrôle des NO<sub>x</sub>, entre 30 à 50% pour la SNCR et entre 80 à 90% pour la SCR, plus coûteuse. En ce qui concerne les coûts d'enlèvement des NO<sub>x</sub>, les estimés de rentabilité obtenus dans les fabriques varient de 2 000 \$ à 6 000 \$ par tonne enlevée. Ces estimés dépassent l'évaluation de référence de l'EPA de 2 000 \$ par tonne enlevée. L'EPA estime que ce montant représente un coût raisonnable pour modifier ou ajouter le contrôle des NO<sub>x</sub> émis par des unités situées dans les zones de non atteinte de la norme sur l'ozone.

## MOTS CLÉS

NO<sub>x</sub> combustible, NO<sub>x</sub> thermique, biomasse, combustion étagée, résidus de bois, SCR, SNCR, modification de combustion, NO<sub>x</sub> bas niveau, LNB, OFA, coûts, rentabilité

## AUTRES PUBLICATIONS DE NCASI DANS CE DOMAINE

Bulletin technique no. 802 (mars 2000). *Effect of stripper off-gas burning on NO<sub>x</sub> emissions.*

Rapport spécial no. 99-01 (avril 1999). *A review of NO<sub>x</sub> emission control strategies for industrial boilers, kraft recovery furnaces, and lime kilns.*

Bulletin technique no. 646 (février 1993). *Emission factors for NO<sub>x</sub>, SO<sub>2</sub> and volatile organic compounds for boilers, kraft pulp mills, and bleach plants.*

Bulletin technique no. 636 (juillet 1992). *An analysis of kraft recovery furnace NO<sub>x</sub> emissions and related parameters.*

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Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 111 (janvier 1981). *A study of nitrogen oxides emissions from large kraft recovery furnaces.*

Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 109 (septembre 1980). *A study of wood-residue fired power boiler total gaseous non-methane organic emissions in the Pacific Northwest.*

Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 107 (avril 1980). *A study of nitrogen oxides emissions from lime kilns.*

Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 105 (décembre 1979). *A study of nitrogen oxides emissions from kraft recovery furnaces.*

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# NO<sub>x</sub> CONTROL IN FOREST PRODUCTS INDUSTRY BOILERS: A REVIEW OF TECHNOLOGIES, COSTS, AND INDUSTRY EXPERIENCE

## 1.0 INTRODUCTION

As part of its strategy to reduce ground-level ozone concentrations, USEPA has become more focused on NO<sub>x</sub> emission reductions, especially in the eastern United States. In 1998, EPA issued the NO<sub>x</sub> SIP Call Rule. This rule, *NO<sub>x</sub> Trading Program for State Implementation Plans* (40 CFR Part 96), required 22 eastern states and the District of Columbia to submit State Implementation Plan (SIP) revisions to reduce emissions of NO<sub>x</sub>, one of the key precursors in the formation of ground-level ozone. Each of these states was assigned an NO<sub>x</sub> budget for the summer ozone season (May 1 through September 30). The statewide budget amounts were determined by photochemical modeling. NO<sub>x</sub> reductions could come from any type of NO<sub>x</sub>-emitting sources, but EPA felt the most cost-effective reductions would come from utility and large industrial boilers burning coal and residual oil. However, states could target additional sources such as smaller boilers, mobile sources, and industrial processes for NO<sub>x</sub> reductions.

States initially subject to the NO<sub>x</sub> reduction requirements were Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia and Wisconsin. For each of these states, EPA set a target reduction total amount of NO<sub>x</sub> (in tons) which would have to be achieved by May 31, 2004. NO<sub>x</sub> emission reductions are based on the May 1 through September 30 ozone season. In 2002, Wisconsin was removed from the list of states subject to the SIP Call, and the first compliance period for Georgia and Missouri was moved to May 1, 2005. Southern portions of Georgia and Alabama, northern portions of Michigan and western portions of Missouri were also excluded from geographic coverage of the NO<sub>x</sub> SIP call.

Emission reductions required by the states (except Georgia and Missouri) must be implemented by May 31, 2004. EPA suggested that a cost criterion of \$2,000 per ton of NO<sub>x</sub> reduction be used by the states to determine which types of stationary sources should be subject to control requirements. EPA concluded that electric utilities and fossil fuel-fired industrial boilers (>250 x 10<sup>6</sup> Btu/hr heat input capacity) should be the primary candidates for lowered NO<sub>x</sub> emissions, with average costs under \$2,000 per ton of NO<sub>x</sub> removed for units burning coal or residual oil. Other types of sources, including smaller industrial boilers, pulp mill recovery furnaces, and lime kilns, were determined to likely have NO<sub>x</sub> control costs exceeding \$2,000/ton. However, individual states must decide on the specific control requirements for each stationary NO<sub>x</sub> emission source.

In the 21 states, there are a large number of forest products manufacturing facilities, many of which operate combustion units, that are potential candidates for NO<sub>x</sub> controls. These facilities will need to ensure the technical feasibility and cost-reasonableness of any proposed new NO<sub>x</sub> emission restrictions. Mills with large coal and oil burning boilers have begun examining the costs and technical feasibility of various NO<sub>x</sub> control measures such as fuel switching, boiler combustion modifications, and add-on controls. In addition to coal and residual oil, pulp mills also use distillate oil, natural gas, and wood residues as boiler fuels. Most of these fuels are burned in conventional steam generating boilers. In addition to conventional boilers, fluidized bed combustors and gas turbines are being used for steam and power generation at an increasing number of mills. In 2000, natural gas and wood residues each accounted for 33% of the fuel use in paper mill steam generating units, followed by coal (26%), and residual oil (8%) (NCASI 2002a). Distillate oil and miscellaneous fuels accounted for the remainder. Miscellaneous fuels include tire chips, petroleum coke, anthracite

culm, fiber and paper-based fuels, wastewater treatment plant (WTP) residuals, rejects from old corrugated container processing, used oil, and refuse-derived fuel.

An earlier report (NCASI 1999) provided an overview of the mechanisms of NO<sub>x</sub> formation and explained how an understanding of these mechanisms was important in the context of applying NO<sub>x</sub> control technologies to many forest products industry (FPI) combustion units that are unique in their use of biomass fuels such as wood and black liquor. This report provides a review of the NO<sub>x</sub> control techniques that could be considered applicable to industrial boilers and highlights those technologies currently available for controlling industrial boiler NO<sub>x</sub> emissions. It also summarizes the various technological concerns raised in the literature or by individual companies and mills in their evaluations of potential NO<sub>x</sub> control technologies to particular boilers in the context of RACT (Reasonably Available Control Technology), BACT (Best Available Control Technology), LAER (Lowest Achievable Emission Rate), or other regulatory permitting requirements. Finally, cost estimates generated by individual FPI companies for implementing such technologies are provided and compared with those developed by EPA.

## **2.0 NO<sub>x</sub> LEVELS, CONTROL REQUIREMENTS, AND TYPES OF BOILERS**

The level of NO<sub>x</sub> control required for a boiler, along with the boiler design and operating conditions, will generally determine the technologies that are capable of achieving the requisite reduction. Some boilers are incapable of significant NO<sub>x</sub> control by combustion modifications because of the nature of their design and operation. Most boiler designs do not, however, directly influence post-combustion NO<sub>x</sub> control via flue gas treatment, such control being limited only by boiler operating considerations such as load swings and flue gas composition and other considerations such as space and geometry limitations, cost of control, etc. Gas and oil-fired boilers that need to achieve NO<sub>x</sub> removal efficiencies in excess of about 75% and solid fuel-fired boilers needing NO<sub>x</sub> removal efficiencies in excess of about 30% are generally forced to look at post-combustion NO<sub>x</sub> control. Boilers subject to lesser NO<sub>x</sub> removal requirements can resort to various combinations of combustion modifications.

### **2.1 NO<sub>x</sub> Levels and Control Requirements for Boilers**

Table 2.1 presents the uncontrolled NO<sub>x</sub> emission factors for typical industrial boilers with heat inputs >100 x 10<sup>6</sup> Btu/hr as given in EPA's AP-42 documents for bituminous coal, oil, gas (USEPA 1998a, 1998b, 1998c), and wood-fired boilers (USEPA 2001). In September 1998, EPA revised NO<sub>x</sub> emission limits contained in the Subpart Db NSPS (new source performance standards) which apply to new industrial boilers with heat input capacities of 100 x 10<sup>6</sup> Btu/hr or greater. Table 2.1 also shows the revised Subpart Db emission limits for various types of boilers. The Db limits are 30-day rolling averages and apply to all boilers for which construction started after July 9, 1997. Limits for natural gas and distillate oil-fired boilers were left essentially unchanged from the earlier NSPS Subpart Db standards promulgated on June 19, 1984, while limits for coal and residual oil were lowered significantly. The basis for the revised standards for coal- and residual oil-fired boilers is the application of combustion modifications and selective catalytic reduction (SCR) flue gas treatment, although EPA claims selective non-catalytic treatment (SNCR) may be sufficient for residual oil-fired units. While no specific limits were promulgated for boilers firing wood residues under Subpart Db, any boiler firing more than 10% of any fossil fuel on an annual basis is subject to the NO<sub>x</sub> emission limit for the fossil fuel. Thus, boilers firing coal or oil with wood would have a limit of 0.2 lb/10<sup>6</sup> Btu.

Also shown in Table 2.1 are the corresponding percentage reductions in NO<sub>x</sub> emissions expected from the uncontrolled or baseline levels for boilers (as indicated by the AP-42 factors) that become subject to the revised NSPS. It should be noted that for large electric generating units (EGUs) in

states subject to the NO<sub>x</sub> SIP call, EPA has recommended that they be assigned NO<sub>x</sub> limits of about 0.15 lb NO<sub>x</sub>/10<sup>6</sup> Btu heat input, representing an average cost-effectiveness of \$1,720 per ozone season ton NO<sub>x</sub> removed in 1997 dollars. Very few, if any, boilers in the FPI are classified as EGUs. Large non-EGUs, i.e., industrial boilers with coal or residual oil heat input capacities over 250 x 10<sup>6</sup> Btu/hr, are recommended by EPA for a 60% reduction in NO<sub>x</sub> emissions from baseline levels.

**Table 2.1** AP-42 NO<sub>x</sub> Emission Factors (boilers with >100 x 10<sup>6</sup> Btu/hr heat input) and NSPS for Industrial Boilers (>100 x 10<sup>6</sup> Btu/hr heat input)<sup>a</sup>

Fuel Type	AP-42 <sup>b</sup> Uncontrolled Emission Factors lb/10 <sup>6</sup> Btu	Subpart Db Boilers Built After July 9, 1997 lb/10 <sup>6</sup> Btu	Reduction Required <sup>c</sup> to meet Subpart Db Limits Percent
Natural Gas	0.17 - 0.27 <sup>d</sup>	0.10 - 0.20 <sup>e</sup>	26 to 41
Residual Oil	0.21 - 0.31 <sup>d</sup>	0.20	5 to 35
Distillate Oil	0.16	0.10 - 0.20 <sup>e</sup>	0 to 38
Coal			
Pulverized	0.39 to 1.24 <sup>d</sup>	0.20	49 to 84
Stoker	0.30 to 0.44 <sup>f</sup>	0.20	33 to 55
Fluidized Bed	0.20 to 0.61 <sup>g</sup>	0.20	0 to 67
Wood <sup>h</sup>			
Bark/Wet Wood	0.22	none	NA
Dry Wood	0.49	none	NA

<sup>a</sup> 60% reduction from baseline expected for non-EGU boilers subject to SIP Call; <sup>b</sup> uncontrolled emission factors, converted using 1,020 Btu/ft<sup>3</sup> gas, 150,000 Btu/gal residual oil, 12,500 Btu/lb coal and 4,500 Btu/lb as-fired wood; <sup>c</sup> from uncontrolled AP-42 factor; <sup>d</sup> lower for tangential and higher for wall-fired boilers; <sup>e</sup> lower factor for low and higher factor for high heat release rates; <sup>f</sup> spreader, overfeed, and underfeed stokers; <sup>g</sup> circulating bed and bubbling bed; <sup>h</sup> note that wood-fired boilers firing >10% fossil fuel are subject to limits for fossil fuel

Besides boilers firing wood residues or fossil fuels, NO<sub>x</sub> emissions from kraft pulp mill boilers can also result from the burning of stripper off-gases (SOGs) containing ammonia. The burning of SOGs in five power boilers resulted in NH<sub>3</sub>-to-NO<sub>x</sub> conversion rates ranging from -11 to 34% with changes in baseline NO<sub>x</sub> levels ranging from -0.05 to 0.14 lb/10<sup>6</sup> Btu (NCASI 2002b).

## 2.2 Description of Boiler Types

Steam can be generated in many different types of combustion devices. The vast majority of pulp and paper mills and wood products plants use conventional boiler technology, where the fuel is combusted in a furnace chamber and the resulting heat is used to generate steam inside water tubes. The water tubes are located near the furnace walls and above the furnace. Water tube boilers are generally used in industrial applications to generate steam at rates of 20,000 lb/hr and greater. There are approximately 1,300 boilers at U.S. pulp and paper mills (about 2.5 boilers per mill), and most of these have steam generating capacities of 20,000 lb/hr and greater. Conventional boilers are often

characterized according to whether they are factory assembled (package) or assembled at the mill (field-erected). In addition, boilers can be categorized by their fuel burning capability (gas, liquid, solid), fuel firing mechanism (pulverized coal, cyclone, stoker, mass feed), grate type (vibrating, stationary, chain) and burner arrangement (tangential, wall-fired). These latter characteristics influence emission rates of  $\text{NO}_x$ .

Most paper mill boilers are equipped to burn more than one fuel to ensure steam availability and to provide it at the lowest possible cost. Package boilers frequently are equipped to burn either natural gas or oil. Boilers built primarily for coal firing often have the capability to burn either gas or oil, or both. Most of the boilers that burn wood have the capability to co-fire one or more fossil fuels. In fact, very few boilers at pulp and paper mills run exclusively on wood residues.

Besides conventional boilers, a few mills use fluidized bed combustors for steam generation. Fluidized bed units typically burn mixtures of solid fuels (coal, wood, wastewater treatment plant residuals), although gas or oil may serve as a back-up. The fuels are combusted in a moving bed of sand or other solid heat transfer media. Water tubes for steam generation are located in the moving bed and above the bed. These units are increasingly used for solid fuel combustion because of efficiency and environmental control considerations.

Gas turbines are used at about 25 mills for steam and electricity cogeneration. In these units, combustion air is compressed before introduction into a combustion chamber with the fuel, which is almost always natural gas (distillate oil is normally used only as a back-up fuel). Combustion takes place at very high temperatures, and the energy from the expanding combustion gases is converted to mechanical energy. About one-half of the energy is used to drive the compressor, and the remainder is used in the turbine to generate electricity. The hot gases are then passed into a heat recovery steam generator. The heat content of these gases can be increased to generate additional steam by burning fuel in duct burners prior to the steam generator.

### **3.0 REVIEW OF $\text{NO}_x$ CONTROL TECHNIQUES FOR INDUSTRIAL BOILERS**

There are two principal methods of industrial boiler  $\text{NO}_x$  emissions control: combustion modification and flue gas treatment. Combustion modifications are often associated with improving boiler performance. Flue gas treatment can occur both within the boiler and at several points along the path of the flue gas from the boiler to the stack. Other pre-combustion techniques such as fuel denitrogenation to reduce “fuel  $\text{NO}_x$ ” have shown little promise. Biomass fuel gasification could lead to lower  $\text{NO}_x$  emissions, but this technology is still in the early stages of development.

#### **3.1 Combustion Modifications**

Combustion modifications are the most common, commercially available means of controlling  $\text{NO}_x$  emissions from fossil fuel-fired boilers. These can be brought about either by effecting relatively simple modifications of operating conditions or by incorporating more elaborate modifications of the combustion facility. Retrofit applications of  $\text{NO}_x$  controls by combustion modification usually proceed in several stages. First, fine tuning of combustion conditions by lowering excess air and adjusting burner settings and air distribution may be attempted. Next, minor modifications such as biased burner firing or taking burners out of service may be implemented. Finally, if further reductions are desired, other retrofits such as installation of overfire air ports, flue gas recirculation systems, and/or low- $\text{NO}_x$  burners may be employed (USEPA 1992).

Combustion modifications can be divided into five categories: a) low excess air (LEA), b) staged combustion, c) temperature reduction technologies, d) low  $\text{NO}_x$  burners (LNB), and e) in-furnace destruction.

### 3.1.1 *Low Excess Air in the Flame Zone (LEA)*

By reducing the amount of excess air, and therefore excess oxygen, in the local flame zone, moderate reductions in NO<sub>x</sub> emissions may be possible. Operating the burners with low excess air (<5% for oil and gas-fired boilers) results in lower NO<sub>x</sub> emissions (both fuel and thermal NO<sub>x</sub>) and higher boiler efficiencies. Unfortunately, low excess air operation has proven to yield only moderate NO<sub>x</sub> reductions, if any (Wood 1994). Ten to 20% NO<sub>x</sub> reduction is believed feasible by LEA for every 1% reduction in furnace O<sub>2</sub> levels (Makanski 1988). However, this technique is limited by the production of smoke, high CO emissions and possibly other problems within the boiler itself such as increased fouling and corrosion due to the reducing atmosphere (Jones 1994). LEA is not in widespread use as an NO<sub>x</sub> control technique for industrial boilers, but it is used for energy conservation (Jones 1994).

### 3.1.2 *Staged Combustion or Off-Stoichiometric Combustion*

Staged combustion or off-stoichiometric combustion is one of the oldest modification techniques for NO<sub>x</sub> control. Diverting a portion of the total amount of air required through separate ports, generally located above the burners, creates a “fuel-rich” zone (also known as air staging). The fuel-rich conditions result in lower peak temperatures and thus, lower thermal as well as fuel nitrogen-generated NO<sub>x</sub>. Staged combustion can be accomplished by various in-furnace techniques such as a) overfire air (OFA), b) burners out of service (BOOS) and c) biased burner firing (BBF) or air/fuel mixing, each of which is described briefly below. These techniques are generally applicable to larger, multiple burner combustion devices (Wood 1994).

#### *Overfire Air (OFA)*

In OFA, about 10 to 20% of the combustion air flow is directed to separate air ports located downstream of the burners. OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and reducing NO<sub>x</sub> emissions. Residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is oxidized as the overfire air is admixed later. This modification is more attractive in original designs than in retrofit applications because of cost considerations, including cost of additional ductwork, furnace penetrations, extra fan capacity, and physical obstructions that make retrofit difficult in some installations (USEPA 1992). When implemented, 15 to 30% NO<sub>x</sub> reductions with OFA alone are expected (Makanski 1988). OFA is a very effective technique for NO<sub>x</sub> reduction, especially for tangentially-fired boilers (USEPA 1992), and may be used with all fuels and most combustion systems, including stoker/grate units (Jones 1994). Operational problems resulting from OFA can include decreased combustion efficiency and deterioration of final steam conditions.

#### *Burners Out of Service (BOOS)*

BOOS is a relatively simple technique used mostly in retrofit situations (suspension-fired coal and oil/gas-fired boilers) wherein multiple burners exist and fuel flow is blocked to an upper level of burners, allowing only air to pass through these. To avoid flame stability and vibration problems, the number of burners taken out of service should not exceed 25% (USEPA 1991). Operational problems resulting from BOOS can include corrosion and soot/slag formation (USEPA 1991).

#### *Biased Burner Firing*

In biased burner firing (BBF), also known as air/fuel mixing or fuel biasing, the furnace is divided into a lower, fuel-rich zone and an upper fuel-lean zone to complete the burnout. This technique has been proven only for oil/gas-fired utility boilers (Makanski 1988). A 20% reduction in NO<sub>x</sub> can be expected.

### 3.1.3 *Temperature Reduction Technologies*

Several NO<sub>x</sub> reduction technologies employ some method of reducing peak flame temperatures to minimize thermal NO<sub>x</sub> formation. These include a) flue gas recirculation (FGR), b) reduced air preheat, c) steam and water injection, and d) decreased load.

#### *Flue Gas Recirculation (FGR)*

In FGR, a portion of the combustion flue gas is brought into the combustion zone (up to 20% of the flue gas). This has typically been accomplished using a recirculation fan, but if there is already a forced-draft (FD) fan installed, some recirculation can be educted in the discharge or the suction of the FD fan. The flue gas acts as a heat sink, lowering the flame temperature. It also reduces the oxygen concentration. Both these effects result in lower thermal NO<sub>x</sub>. Reported flame temperatures (gas/oil) are 3,500°F with no recirculation and 2,900°F at 20% FGR. It should be noted that the onset of thermal NO<sub>x</sub> occurs around 2,800°F, and NO<sub>x</sub> generation increases exponentially with temperatures beyond 2,800°F.

High capital expenditures are necessary to install new ductwork, recirculation fans, devices to mix flue gas with combustion air, etc. Flue gas is typically taken from a stack breaching at about 300 to 400°F and mixed with the secondary combustion air (wind box). As only thermal NO<sub>x</sub> can be controlled by this technique, it is especially effective only in oil and gas-fired units. In fact, FGR is probably the most effective and least troublesome system for NO<sub>x</sub> reduction for gas-fired combustors (Wood 1994). A 20 to 30% reduction in NO<sub>x</sub> is expected (Makanski 1988). FGR is most effective when used in conjunction with air and/or fuel staging (Jones 1994). Once the favored method of industrial-boiler NO<sub>x</sub> control, today it has lost some of its favor due to a better understanding of the high capital costs and FGR fan and operation and maintenance costs involved, in addition to loss of boiler efficiency (Jones 1994). FGR is more adaptable to new designs than as a retrofit application (USEPA 1992).

#### *Reduced Air Preheat (RAP)*

Lowering the amount of combustion air preheat results in a lower primary combustion zone peak temperature, and thus lower thermal NO<sub>x</sub> emissions. The energy penalty usually makes this option unfavorable (Yaverbaum 1979). A rule of thumb is a 1% efficiency loss for each 40°F reduction in preheat (Wood 1994). As in FGR, RAP only lowers thermal NO<sub>x</sub>, and thus is economically attractive for only natural gas and distillate fuel oil combustion (USEPA 1992).

#### *Steam and Water Injection*

Flame quenching by the addition of steam or water in the combustion zone is an effective control technology for oil/gas-fired burners, although a significant energy penalty could ensue. Oil/water emulsions can realize a similar response as steam/water injection (Jones 1994). Up to 70% suppression of NO<sub>x</sub> formation in gas turbines is believed feasible (Makanski 1988).

#### *Decreased Load*

A reduction in the percentage of rated capacity leads to lower “volumetric heat release rates” in the boiler, and correspondingly lower flame temperatures and NO<sub>x</sub> formation. Wasted load capacity is a definite disadvantage. Reduced mass flow can also cause improper fuel-air mixing during combustion, creating carbon monoxide and soot emissions (USEPA 1992).

### 3.1.4 *Low NO<sub>x</sub> and Ultra Low NO<sub>x</sub> Burners (LNB & ULNB)*

Low NO<sub>x</sub> burners (LNBs) are designed to mix fuel and air in a controlled pattern that sustains local fuel-rich regions, keeps the temperatures down, and dissipates heat quickly. By controlling the

mixing of the fuel and air, the combustion process can be initiated at the burner throat and the zone of complete combustion can be varied in the furnace chamber, resulting in elongated flames as compared to short, intense flames. Virtually all of the boiler and burner vendors have developed LNBs for retrofit (Makanski 1988). Both staged air and staged fuel combustion principles are employed in LNBs. Combustion modification with LNBs is used in both gas/oil-fired and coal-fired units. A full LNB retrofit can be expected to reduce  $\text{NO}_x$  levels by about 50% (Makanski 1988). Flame containment, specifically sidewall and/or rear-wall flame impingement, is a challenge in the smaller boilers, particularly in a high-space-heat-release-rate package boiler. While LNBs use staged fuel to reduce  $\text{NO}_x$ , by contrast, ultra low  $\text{NO}_x$  burners or ULNBs reduce  $\text{NO}_x$  by inducing the internal circulation of fuel gas within the heater. ULNBs also tend to have large diameters, but shorter flame lengths and may be easier to retrofit.

Considered a modification of the low  $\text{NO}_x$  burner, slagging combustors involve high temperature combustion of coal in an air-deficient chamber. Ash is removed as a liquid slag and  $\text{NO}_x$  formation is suppressed. The gasified coal is then combusted in the existing furnace cavity. Because their combustion characteristics are similar to those of cyclone-fired coal boilers (coal ash removed as liquid slag), slagging combustors are thought to be particularly good for retrofitting the latter (Makanski 1988).

### **3.1.5 *In-Furnace Destruction***

Also known as “reburning,” “off-stoichiometric combustion” or “fuel staging”, in this technique from 15 to 25% of the total fuel input is diverted to a second combustion zone downstream of the primary zone (Makanski 1988). The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing  $\text{NO}$  formed in the primary zone to  $\text{N}_2$ . Low nitrogen-containing fuels such as natural gas and distillate oil are typically used for reburning to minimize further  $\text{NO}_x$  formation. For example, the METHANE de- $\text{NO}_x$  reburning process utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. Overfire air is then injected at a higher furnace elevation to burn out the combustibles (Loviska et al. 1998). This process is claimed to yield between 50 and 70%  $\text{NO}_x$  reduction and be suitable for all solid fuel-fired stoker boilers (coal, biomass, municipal solid waste, RDF, etc.). However, it has only been demonstrated on one pulp mill boiler (Rabovitser et al. 2000), one municipal waste combustor (Abbasi et al. 1998) and one 60 MWe stoker coal-fired unit (Loviska et al. 1998) in the U.S. The Gas Research Institute (GRI), which developed this process, has plans to apply METHANE de- $\text{NO}_x$  to several pulp and paper mill wood-fired stoker units (Schrecengost et al. 2002).

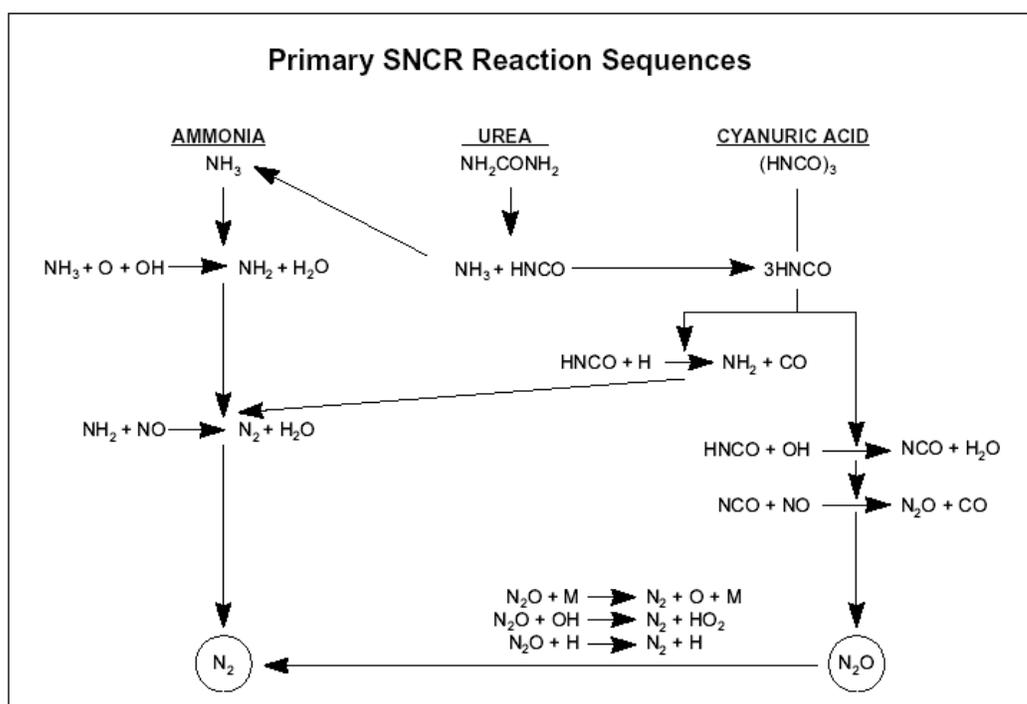
Fuel Lean Gas Reburn (FLGR) is GRI’s technology that offers operators of electric utility boilers a low cost approach for moderate levels of  $\text{NO}_x$  reduction (about 30% to 50%). Natural gas is injected into the upper furnace region in small quantities (under 10% of heat input, typically 5-7% of total heat input). Unlike conventional gas reburning technology, which requires overfire air (OFA) and 15% to 25% of the heat input from natural gas, with FLGR the furnace stays fuel-lean overall and does not require OFA. Therefore, furnaces that could not utilize conventional reburning due to the need for OFA and do not require the higher  $\text{NO}_x$  reductions of conventional reburning (over 60% in some cases), may be able to use FLGR.

### 3.2 Flue Gas Treatment

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), and to a lesser extent catalytic or non-catalytic oxidation with scrubbing, are among the only proven, viable, full-scale post-combustion flue gas treatment techniques for industrial boilers at the current time. Other advanced post-combustion treatment options are currently being developed, some awaiting results of pilot stage results, and others awaiting the enactment of more stringent  $\text{NO}_x$  control requirements before their full-scale use can be put to test.

#### 3.2.1 Selective Non-Catalytic Reduction (SNCR)

SNCR involves the injection of urea, ammonium hydroxide, anhydrous ammonia, or aqueous ammonia into the furnace exit region where the flue gas is in the range of 1,600 to 1,900°F (USEPA 1997).  $\text{NO}_x$  is reduced to  $\text{N}_2$  and  $\text{H}_2\text{O}$ . The primary reaction sequences for SNCR are shown in Figure 3.1 (ABB 1997). This figure does not show any of the potential side reactions and undesirable competing reactions which contribute to the complexity of the overall SNCR reaction mechanism.



**Figure 3.1** Primary SNCR Reaction Sequences

One concern about this process is its ability to perform adequately under changing load and fuel conditions (Jones 1994), although the use of computational fluid dynamics (CFD) modeling and the design of multiple level injections in the boiler is reported to alleviate some of this concern (Sun 2002). The Exxon Thermal DeNO<sub>x</sub> process relies on the injection of ammonia, while Fuel Tech's NO<sub>x</sub>OUT process relies on the injection of urea into the boiler. Both ammonia and urea

bring about gas phase reduction of NO<sub>x</sub> to nitrogen. A portion of the NO reduction by SNCR systems, usually around 5%, is due to transformation of NO to N<sub>2</sub>O, which is a greenhouse gas (USEPA 1998d).

#### *Thermal DeNO<sub>x</sub>*

The thermal DeNO<sub>x</sub> process, developed and marketed by Exxon Research and Engineering Company (Hurst 1983), selectively reduces NO<sub>x</sub> to molecular nitrogen and water by using ammonia injection into the air-rich flue gas in the temperature range of 1600 to 2200°F, temperatures typically found in the upper portions of the furnace (superheater section or before air preheater). The actual chemical mechanism of the process is quite complex, involving 31 significant chemical reactions (Hurst 1983). NO<sub>x</sub> reductions as high as 60 to 70% have been achieved in some industrial applications. The reduction efficiency is affected by the NH<sub>3</sub> feed rate relative to NO<sub>x</sub> concentrations, by the degree of flue gas thermal stratification in the ammonia injection section, and by the flue gas residence time within the appropriate temperature window.

The reaction predominates around a temperature of 1740°F (USEPA 1981). For temperatures above 2000°F, the injected ammonia is oxidized to NO<sub>x</sub>, and for temperatures below about 1560°F the reaction proceeds slowly and the NO reduction falls off drastically, resulting in significant ammonia slippage (USEPA 1981). The oxidation of ammonia to NO, unreacted ammonia or ammonia slippage and reduction of NO in NH<sub>3</sub>-NO mixtures, is discussed further in NCASI Technical Bulletin No. 802 (NCASI 2000).

The ammonia injected must be diluted with air or steam to allow for good mixing. The injection is usually accomplished by using a multiport injection grid to allow for varying flue gas temperatures due to boiler load swings. Problems with NH<sub>3</sub> injection include ammonia slippage, fouling of air preheater surface by ammonium sulfate/bisulfate formation, and maintaining optimum reaction temperatures for the NH<sub>3</sub>-NO reaction (USEPA 1981).

#### *NO<sub>x</sub>OUT*

Research into the injection of urea (solid or aqueous solution) in a manner similar to ammonia was first carried out by the Electric Power Research Institute (DePriest, Jarvis, and Cichanowicz 1989). Known as the NO<sub>x</sub>OUT process, it has received increased attention on account of both the reduced cost and reduced danger of handling urea as compared with ammonia (Sun 2002). Also, it is believed that urea/water injection parameters can be more easily matched to furnace temperature, providing better load-following capability and resulting in reduced hardware requirements such as injection grids (Makanski 1988). The NO<sub>x</sub>OUT process is based upon the following chemical reaction that ideally occurs in the temperature range of 1700 to 2000°F (Muzio and Anand 1976), but could be operated at temperatures from as low as 1,600°F to as high as 2,200°F (Sun 2002).



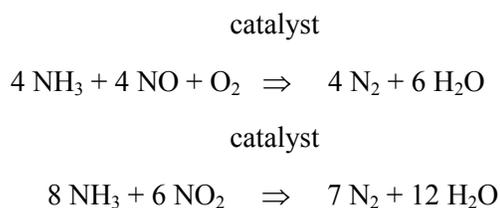
The problems of ammonia slippage and heat transfer surface fouling with byproduct formation also exist with the NO<sub>x</sub>OUT process.

Six factors directly affect the performance of urea- or NH<sub>3</sub>-based SNCR systems (USEPA 1997). These are a) inlet NO<sub>x</sub> level, b) temperature, c) mixing, d) residence time, e) reagent-to-NO<sub>x</sub> ratio, and f) fuel sulfur content. Lower inlet NO<sub>x</sub> concentrations reduce the reaction kinetics and hence the achievable NO<sub>x</sub> emissions reductions. As mentioned above, temperatures below the desired window result in ammonia emissions (slip), and temperatures above the desired window result in NH<sub>3</sub> being

oxidized to NO<sub>x</sub>. Mixing becomes an important consideration in regions distant from an injection nozzle where the level of turbulence is reduced and stratification of the reagent and flue gas will probably be a greater problem, especially at low boiler loads (USEPA 1997). Residence time becomes important to allow the desired reactions to go to completion. Small, packaged, water tube boilers and boilers with varying steam loads are therefore difficult applications for SNCR (USEPA 1997). As higher than the theoretical NH<sub>3</sub> to NO<sub>x</sub> ratios are generally required to achieve desired NO<sub>x</sub> emission reductions, a trade-off exists between NO<sub>x</sub> control and the presence of NH<sub>3</sub> in the flue gas. The main disadvantage of SNCR is the low NO<sub>x</sub> reduction that is experienced when the allowable ammonia slip is low (as in the Houston area, Southern California and Europe). Finally, in the case of high sulfur fuels, excess NH<sub>3</sub> can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit on downstream equipment leading to plugging and reduced heat transfer efficiencies.

### 3.2.2 *Selective Catalytic Reduction (SCR)*

The SCR process also uses ammonia injection, but the reduction reactions are carried out on the surface of a catalyst operating at temperatures between 450°F and 750°F. The following overall reactions are known to occur on the catalytic surface:



The active compound which promotes the NH<sub>3</sub>-NO<sub>x</sub> reaction may be composed of a precious metal (e.g., Pt, Pd), a base metal oxide, or a zeolite (USEPA 1997). Precious metal catalysts are used in clean fuel applications and at lower temperatures than the base metal oxide or zeolite catalyst. The most common base metal oxide catalysts are vanadium/titanium based, with V<sub>2</sub>O<sub>5</sub> as the active material and TiO<sub>2</sub> as the support material. The zeolite catalysts are stable over a wider temperature window than other types of catalysts. Optimum NO<sub>x</sub> reduction occurs at catalyst bed temperatures between 600 and 750°F for conventional (vanadium or titanium-based) catalyst types, and between 470 and 510°F for platinum-based catalysts (USEPA 1991). An ammonia to NO ratio of 1:1 has typically reduced NO<sub>x</sub> by 80 to 90%, with a leak rate of less than 20 ppm (USEPA 1981). The reactor is usually located between the boiler and air preheater. NO<sub>x</sub> control efficiencies are typically in the range of 70 to 90%, depending on the type of catalyst, amount of NH<sub>3</sub> injected, the initial NO level, and the age of the catalyst.

The performance of an SCR system is also affected by six factors (USEPA 1997). These are a) NO<sub>x</sub> level at SCR inlet, b) flue gas temperature, c) NH<sub>3</sub>-to-NO<sub>x</sub> ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO<sub>x</sub> concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO<sub>x</sub> concentrations (USEPA 1997). Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH<sub>3</sub> being oxidized to NO<sub>x</sub>. For up to about 80% NO<sub>x</sub> reduction efficiencies, a 1:1 NH<sub>3</sub>:NO<sub>x</sub> ratio is sufficient. For higher efficiencies, higher reagent to NO<sub>x</sub> ratios are required which may result in higher NH<sub>3</sub> slip. In the case of high sulfur fuels, excess NH<sub>3</sub> can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.

Catalysts degrade over time due to poisoning, fouling, thermal stress, erosion by particulate, etc. NO<sub>x</sub> removal decreases as the catalyst gets deactivated. Catalysts are a major component of the cost of SCR.

SCR is considered a high-efficiency removal device. Today, SCR has become a common feature of new gas-turbine cogeneration and combined cycle systems in the U.S. (Jones 1994). Several utility boilers have also been equipped with the SCR NO<sub>x</sub> control technology. By the year 2004, in excess of 100 GW of coal-fired capacity in the U.S. may be equipped with this technology in order to mitigate “seasonal” ozone production. As a result, in the 25 years since the first commercial installations in Japan, SCR technology has evolved in response to changing application conditions, with present day catalysts featuring thinner walls, improved mass transfer and activity, and better poison resistance than earlier generation catalysts (Cichanowicz and Muzio 2001).

Major problems with SCR processes include corrosion due to higher flue gas acid dew points, and formation of solid ammonium sulfate and ammonium bisulfate, particularly in high sulfur oil-fired or coal-fired boilers. These could deposit on the air preheater surface to reduce heat transfer efficiencies. Ammonia slippage is also a potential problem. Arsenic poisoning has been demonstrated as a major contributor to catalyst deactivation, requiring a minimum quantity of available calcium in the fly ash (which could be obtained by injecting or adding limestone or lime to coals) (Cichanowicz and Muzio 2001). Because of poisoning by trace metals or erosion by fly ash, catalysts lose activity over time. Although a proven technology for larger units (>20 MW), it is not in widespread use for smaller industrial boilers, primarily due to cost considerations. Catalyst regeneration rather than replacement, better reactor design and layout to promote contacting of reagent and flue gas, etc. may eventually improve performance at lower cost for industrial boilers.

### **3.2.3 *Scrubbing After Catalytic Oxidation or Ozone Injection***

Unlike NO, which is neutral, NO<sub>2</sub> can be scrubbed with caustic solutions. Several vendors have proprietary technologies for the catalytic oxidation of NO in scrubbing systems. Catalytic scrubbing is generally considered economical only if a caustic scrubber already exists. A scrubber with a long residence time and multiple scrubbing stages, such as a packed bed, is the main consideration in increasing efficiencies in most catalytic scrubbing processes (Bradford, Grover, and Paul 2002).

An alternative approach to catalytic scrubbing is the injection of ozone into the flue gas upstream of the scrubber. Ozone injection is said to achieve up to a 95% NO reduction, because ozone reportedly converts both the NO and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub>, which is more soluble in caustic solution than NO or NO<sub>2</sub>. Important design considerations for ozone injection include a) a large oxygen requirement since a 10% ozone stream is generated from oxygen using an electric arc, b) a low temperature (below 300°F) to prevent the ozone from decomposing, and c) a long enough residence time to allow the reaction to go to completion (Bradford, Grover, and Paul 2002). Cost considerations for the ozone generating equipment have been a major hindrance in the past.

## **4.0 NO<sub>x</sub> CONTROL TECHNOLOGIES TYPICALLY APPLICABLE TO FPI BOILERS**

This section discusses the various types of conventional fossil fuel and wood-fired boilers, turbines and fluidized bed combustion units operating in the FPI, the fuels fired in these units, and the type of NO<sub>x</sub> control technologies generally considered applicable.

## **4.1 Conventional Boilers Firing Fossil Fuels, Wood, or Both**

### **4.1.1 *Natural Gas***

Natural gas contains a high percentage (generally >85%) of methane and varying amounts of ethane, propane, butane, and inerts (typically N<sub>2</sub>, CO<sub>2</sub>, and helium). Natural gas is burned in package boilers (these units generally have heat input capacities under 100 x 10<sup>6</sup> Btu/hr) or in field-erected boilers (mainly over 100 x 10<sup>6</sup> Btu/hr). Field-erected boilers may be wall-fired (multiple burners on a wall) or tangential-fired (rows of fuel and air nozzles in each of the four corners).

The principal mechanism of NO<sub>x</sub> formation in natural gas combustion is by the “thermal” NO<sub>x</sub> mechanism (thermal fixation of atmospheric nitrogen). NO<sub>x</sub> emissions are dependent on the combustion temperature and the rate of cooling of the combustion products.

Several combustion modification techniques are available to reduce the amount of NO<sub>x</sub> formed in natural gas-fired boilers and turbines. The two most prevalent ones are flue gas recirculation (FGR) and low-NO<sub>x</sub> burners (LNB). FGR reduces formation of thermal NO<sub>x</sub> by reducing peak temperatures and limiting availability of oxygen. LNB reduces formation of thermal NO<sub>x</sub> by delayed combustion (staging), resulting in a cooler flame. In conjunction with FGR, the burners can achieve NO<sub>x</sub> emission reductions of 60-90%. Other techniques include staged combustion and gas reburning. In general, these techniques have been incorporated in newer boilers; thus their NO<sub>x</sub> emissions are lower than those of older units. There are also many add-on control technologies to reduce NO<sub>x</sub> emissions such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), although these are not commonly used because of cost considerations. The addition of NO<sub>x</sub> control systems such as low-NO<sub>x</sub> burners and flue gas recirculation may reduce combustion efficiencies and result in higher CO emissions (USEPA 1998c).

### **4.1.2 *Fuel Oil***

Two major types of oil are burned by combustion sources in the FPI: distillate and residual. Distillate oil is a relatively clean burning fuel that has negligible nitrogen. The heavier residual oils contain significantly higher levels of nitrogen. As for natural gas, distillate or residual oils are burned in either package boilers (generally having heat inputs less than 100 x 10<sup>6</sup> Btu/hr) or in field-erected boilers (heat inputs over 100 x 10<sup>6</sup> Btu/hr). Field-erected boilers may be normal-fired (wall) or tangential-fired.

NO<sub>x</sub> emissions from fuel-oil combustion depend on the grade and composition of the fuel oil, the type and size of the boiler, and the firing practices used. NO<sub>x</sub> emissions from burning distillate oil are similar to those from natural gas. Many paper mill boilers that mainly burn natural gas can also burn distillate oil during cold weather gas supply curtailments.

NO<sub>x</sub> emissions are formed from the nitrogen in the residual oil (“fuel” NO<sub>x</sub>) and from high temperature oxidation of nitrogen in the combustion air (“thermal” NO<sub>x</sub>). “Fuel” NO<sub>x</sub> can account for 60 to 80% of the total NO<sub>x</sub> formation, although the nitrogen levels in residual oil can vary from 0.1 to almost 1% and the percent conversion of fuel N to NO<sub>x</sub> can range from 20 to 90%. NO<sub>x</sub> emissions from tangentially-fired units are, on average, lower than those from horizontally opposed wall-fired units.

For fuel oil-fired boilers, NO<sub>x</sub> emissions can be controlled by fuel substitution/alteration, combustion modification, and post-combustion control. Fuel substitution reduces NO<sub>x</sub> by burning an oil with lower N content. For boilers burning residual oil, fuel NO<sub>x</sub> is the dominant mechanism for NO<sub>x</sub> formation, and thus the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. Several combustion

modification techniques are available to reduce the amount of NO<sub>x</sub> formed in fuel oil-fired boilers, including low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO<sub>x</sub> burners. NO<sub>x</sub> reductions from 5-60% may be expected from these techniques. Post-combustion controls include SNCR and SCR. NO<sub>x</sub> reductions from 25-40% and from 75-85% may be expected from use of SNCR and SCR systems on oil-fired boilers, respectively (Pakrasi 2000), although as shown later, the cost-effectiveness for these add-on controls could well exceed the threshold of \$2,000/ton NO<sub>x</sub> removed advocated by EPA.

#### 4.1.3 Coal

Bituminous and subbituminous coals are the main types of coal burned in paper industry boilers. No use of lignite or anthracite coal is known at the present time. Boiler types include pulverized coal, stoker, cyclone, fluidized bed, and mass feed units. The 2000 NCASI survey of pulp and paper industry boilers showed there were 105 pulverized coal, 67 spreader stoker, eight cyclone, eight fluidized bed, and 11 underfeed stoker coal-fired boilers operating during that year. Over half of these units were also capable of burning wood fuels and/or wastewater treatment plant residuals (NCASI 2002a).

Pulverized coal-fired boilers can be wall-fired (single or multiple burners on one or opposing walls) or tangential-fired (burners and air nozzles mounted in the corners of the furnace). In cyclone boilers, the coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. There are two main types of stokers. The underfeed stoker is either a horizontal-feed, side ash-discharge type or a gravity-feed, rear ash-discharge type. The spreader stoker uses mechanical or pneumatic feeders to distribute coal uniformly over the surface of a moving grate. Fluidized bed combustors (FBCs) can be atmospheric or pressurized. The atmospheric FBC can be of the bubbling bed design or the circulating bed design (USEPA 1998a).

NO<sub>x</sub> emissions from coal combustion are considerably higher than those from gas or oil. NO<sub>x</sub> formation results from thermal and fuel mechanisms. Fuel nitrogen can account for up to 80% of the total NO<sub>x</sub> formed. Coal nitrogen contents range from 0.5 to 2% (USEPA 1998a). Emissions of NO<sub>x</sub> are highest for cyclone boilers, followed by pulverized coal, stokers, and mass feed units.

Just as in fuel oil combustion, NO<sub>x</sub> emissions can be controlled by fuel substitution/alteration, combustion modification and post-combustion control. NO<sub>x</sub> reductions can be achieved by burning a coal with lower N content. NO<sub>x</sub> emissions from coal-fired boilers can be controlled by combustion controls and post-combustion controls. Combustion controls involve a) reducing peak temperatures in the combustion zone, b) reducing gas residence time in the high-temperature zone, and c) air or fuel staging by operating at an off-stoichiometric ratio by using a rich fuel-air ratio in the primary flame zone and lower overall excess air conditions (Pakrasi 2000). The use of combustion controls depends on the type of boiler and the method of coal firing. Low-NO<sub>x</sub> burners and overfire air (OFA) have been successfully applied to tangential- and wall-fired units, whereas reburning is the only current option for cyclone boilers. For large coal-fired boilers, the most developed and widely applied post-combustion NO<sub>x</sub> control technology is SCR. Catalyst deactivation and residual NH<sub>3</sub> slip are the two key operating considerations in an SCR system (Pakrasi 2000). The use of SNCR systems on coal-fired boilers is still in the development stage. NO<sub>x</sub> reductions from 30-70% and from 60-90% may be expected from use of SNCR and SCR systems on coal-fired boilers, respectively (Pakrasi 2000). The shortcomings of installing SCR systems on industrial coal-fired boilers are discussed later.

#### 4.1.4 *Wood Residues*

A majority of chemical wood pulp mills that debark logs on site burn the bark and other wood residues in boilers to generate steam and power. Although smaller boiler types such as the Dutch oven and fuel cell oven are sometimes utilized, the majority of boilers with steam generation rates exceeding 100,000 lb/hr are of the spreader stoker type. At pulp and paper mills in 2000, there were 9 Dutch ovens, 13 fluidized bed boilers, 38 pulverized coal-fired boilers, 1 gasifier and 141 spreader stokers that burned wood fuels (NCASI 2002a). Of the 202 boilers firing wood residues, 72 could co-fire coal, 93 could co-fire residual oil, 25 could co-fire distillate oil, 111 boilers co-fired natural gas, 76 burned waste treatment system residuals, and 25 burned tire-derived fuel. The wood products industry burns several types of wood residues including bark, sawdust, planer shavings, sander dust, and trim from lumber cutting and plywood manufacture in a variety of boilers including stokers, fuel cells, Dutch ovens, and suspension burners.

Using a 65 kW refractory-walled reactor to study biomass combustion under conditions typical of the suspension burning phase in a spreader-stoker-fired boiler, Winter et al. (1989) showed that wood-fired boiler NO<sub>x</sub> emissions were strongly dependent on combustion zone oxygen concentration and the nitrogen content of the biomass fuel. However, these emissions were relatively insensitive to both temperature and moisture content. In other words, NO<sub>x</sub> emissions from wood residue combustion are mainly the result of “fuel NO<sub>x</sub>.” This is consistent with the observation that “thermal NO<sub>x</sub>,” or NO<sub>x</sub> generated by the thermal fixation of atmospheric nitrogen, usually sets in only at temperatures exceeding about 2,800°F, and wood combustion in boilers seldom reaches such high temperatures. The dependence of NO<sub>x</sub> emissions on excess air levels was confirmed by Philo, Chapman, and Mirolli (1989) who conducted parametric tests on a 550,000 lb steam/hr wood-fired stoker unit varying the level of excess air. They found that the NO<sub>x</sub> emissions increased from 85 to 170 ppm when the flue gas O<sub>2</sub> content rose from 1.9 to 6.4%.

No systematic study has been conducted to examine the relationship between wood nitrogen content and emissions of NO<sub>x</sub>, although NCASI has begun a study to look at this relationship (NCASI 2003). Wood and bark nitrogen contents typically range from 0.1 to 0.2% (dry basis), lower than most coals and residual fuel oils. Thus, average NO<sub>x</sub> emissions from wood combustion in typical pulp mill boilers would be expected to be lower than those from coal or residual oil combustion, but slightly higher than those from natural gas combustion. However, if the wood fuel burned contains nitrogen from other sources (e.g., sander dust from wood products operations using urea formaldehyde resins), higher NO<sub>x</sub> emissions can be expected. Also, certain types of wood residues (e.g., juvenile woods) are known to contain somewhat higher levels of nitrogen (0.2 to 0.4% range).

Common combustion modification techniques used to control fuel NO<sub>x</sub> by suppressing combustion air levels to below the theoretical amount required for complete combustion have not been demonstrated in full-scale wood-fired boilers. Overfire air ports are claimed to lower NO<sub>x</sub> emissions from wood-fired stoker and fluidized bed combustion units (USEPA 2001), although evidence that such installations exist is lacking. Tests conducted by Philo, Chapman, and Mirolli (1989) on a tangential wood-fired boiler (550 KPPH) with 0 and 20% OFA at a constant 30-35% excess air and over boiler loads ranging from 55 to 100% of rated capacity, showed NO<sub>x</sub> emissions actually increased (from 20 to 30%) with the 20% OFA operation at all three boiler loads evaluated. The authors stated, however, that this phenomenon was likely unit-specific, and that increasing OFA mass flow should typically lead to reduced NO<sub>x</sub> emissions as in situations with fossil fuel firing.

Certain biomass fuels such as sander dust from operations using urea formaldehyde (UF) resins or agricultural waste such as rice husks and wheat straw can contain high nitrogen levels ranging from 0.5 to 2.5% by weight. When combusted, these can lead to high levels of NO<sub>x</sub>. Webster and

Drennan (2003) discuss their experience with using air staging in reducing NO<sub>x</sub> emissions by over 50% when burning sander dust fuels in two boilers, one a “packaged” boiler at a medium density fiberboard plant, and the second a bark grate boiler with sander dust suspension-fired over the grate. A Dual Air Zone (DAZ) gas burner with an annular scroll to introduce the sander dust with sub-stoichiometric air flow through the burner was used in both cases. In the packaged boiler, a separate system of adjustable direction air ports in the boiler front wall was used to introduce the secondary combustion air, and NO<sub>x</sub> emissions were reduced by 43 to 51%. Tests in the bark grate boiler were reportedly under way. This boiler was to be equipped with overfire air ports above the suspension-fired sander dust burners, and computational fluid dynamics modeling techniques were to be used to bring about an NO<sub>x</sub> reduction of over 70% compared to unstaged combustion of the sander dust.

Gas reburning techniques have been demonstrated for a short duration in one wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with NO<sub>x</sub> reductions of 40 to 50% from baseline (untuned boiler) reported (Schrecengost et al. 2002). However, this reburn technology would require a 5 to 25% natural gas input. Other combustion modification techniques such as FGR would not be effective in wood combustion since FGR reduces formation of thermal NO<sub>x</sub> by reducing peak temperatures, and most of the NO<sub>x</sub> generated during wood combustion is from the “fuel NO<sub>x</sub>” pathway. FGR may also reduce the availability of O<sub>2</sub> in the combustion zone, but the impact of this on NO<sub>x</sub> generation during wood combustion has not been demonstrated.

As for fossil fuels, post-combustion control options for wood-fired boilers include SNCR and SCR. Other emerging technologies (see Section 6.0) such as catalytic or low temperature oxidation followed by scrubbing have not been applied on a full scale to FPI boilers at the present time.

SNCR has been applied to several base-loaded wood and combination wood-fired boilers ([www.fueltechnv.com](http://www.fueltechnv.com)). However, its efficacy on stoker wood-fired boilers, especially with changing loads, has not been adequately demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (Abrams 1998). While the manufacturer had guaranteed an NO<sub>x</sub> emission rate of 0.042 lb/10<sup>6</sup> Btu, the boiler was unable to meet this guarantee unless operated at less than half load. Even then, reducing NO<sub>x</sub> to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill. The fluidized bed combustor at the mill fired various fuels (bark, gas, recycled paperboard, and sawdust, ≈300 x 10<sup>6</sup> Btu/hr), and was equipped with a urea injection system (SNCR), which reduced NO<sub>x</sub> emissions under varying loads from about 250 lb/hr (uncontrolled) to between 25 and 40 lb/hr (84 to 90% removal) (NCASI File Information). However, a single measurement in the stack showed nearly 75 lb/hr of ammonia were being emitted, suggesting that nearly half the urea (on a molar basis) injected was being emitted as ammonia in order to bring about this level of NO<sub>x</sub> reduction.

The use of SNCR technology on most base-loaded wood-fired boilers could be considered a proven technology, although the suitability of the unique fuel mix, boiler design, and boiler operation (including ductwork, flue gas temperature profiles and desired residence times, flue gas chemistry, etc.) inherent in each boiler should be evaluated on a case-by-case basis. Typical maximum levels of NO<sub>x</sub> emissions control achievable are in the range of 30 to 60%. The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip (ammonia is an air toxic in many states) is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO<sub>x</sub> reduction reactions to go to completion. Also, when dry particulate matter (PM) emission control is utilized (such as an ESP), problems with plume opacity from ammonium chloride in the stack gases could arise, especially for combination boilers. For

boilers which produce high levels of SO<sub>2</sub>/SO<sub>3</sub> (combination wood-fired boilers), problems associated with ammonium sulfate/bisulfate deposition on heat transfer surfaces could also arise.

The impact of interference from higher CO levels present in many wood-fired boilers (compared to fossil fuel-fired boilers) with the SNCR chemical is currently unknown. Also, the possibility of appreciable SNCR chemical being absorbed on to the ash matrix in a wood-fired boiler should be examined. The extent and fate of ammonia in precipitated ash from boilers with dry PM control or scrubber purge streams for boilers with wet PM control also need to be adequately investigated.

The use of SCR on wood-fired boilers in the forest products industry has not been demonstrated. The use of SCR technology on wood- or combination wood-fired boilers would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application (450 to 750°F). Many wood- and combination wood-fired boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers (typical temperatures from 150 to 220°F) to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water soluble alkali (such as Mg, Na) in particulate-laden gas streams have been known to poison SCR catalysts (USEPA 1999). Space considerations for installing a catalyst section in an existing boiler's ductwork are also important.

In response to a request for information from a consultant and one of their FPI clients, Fuel Tech N. V. ([www.fueltechnv.com](http://www.fueltechnv.com)) reviewed the possibility of applying SCR to a certain circulating fluidized bed combination wood-fired boiler (T. Brown, personal communication, June 26, 2002). They found that the only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Archbold, Ohio. Fuel Tech contacted this facility (Sauder Corporation) to learn more about their process and the design of the SCR system. Although specific discussions on the fuel makeup were not held, it was assumed the wood fuel was sawdust and relatively high quality wood scraps from the furniture-making process. It was learned this SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550°F to 650°F. The only problem reported at this installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application.

Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters (Stultz and Kitto 1992). Thus, even when dry particulate control devices like an ESP are utilized, the flue gas exits such control devices at temperatures in the 350°F to 450°F range. Consequently, the installation of an SCR catalyst section after an ESP to treat gases in the range of 550°F and 650°F is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers are controlled for PM emissions by multiclones and wet scrubbers. The PM emissions from these would therefore

be higher than the Sauder situation. Third, it is unclear how the Sauder SCR system would have worked under a fluctuating boiler load characteristic of many FPI boilers. Finally, sawdust fired in the Sauder boiler is a low moisture fuel, and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.

In conclusion, the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the forest products industry, and the issues pertaining to severe energy penalties and space and logistical limitations, and potential catalyst poisoning from soluble alkali metals need to be addressed. The feasibility of achieving high levels of NO<sub>x</sub> removal (such as >60%) using SNCR technologies on wood-fired boilers is uncertain due to several limitations, including the key one of installing optimally placed injection points for the SNCR chemical in swinging load situations and dealing with potentially excessive NH<sub>3</sub> slip and plume opacity problems. Combustion modifications (with perhaps the exception of gas reburning where gas is available) are generally not effective for biomass-fired boilers since most of the NO<sub>x</sub> is generated by the fuel NO<sub>x</sub> pathway. Emerging post-combustion technologies and in-furnace technologies such as gas reburning are in the early stages of demonstration.

#### **4.1.5 *Combination Wood-Fossil Fuel***

As previously mentioned, nearly 40% of the wood-fired boilers in the pulp and paper industry are capable of firing coal. The Electric Power Research Institute (EPRI), with co-funding from the Department of Energy (DOE), and with utility cooperation and cost sharing, tested co-firing of biomass in ten coal-fired utility boilers (Hughes 1998). NO<sub>x</sub> emissions recorded at three of these boilers are summarized in Table 4.1. The biofuels fired included sawdust, dry shavings, and wood chips. Typically, the trend observed was lower NO<sub>x</sub> emissions with increased levels of biomass co-firing, at least up to the point where about 10% of the heat was supplied by the biomass. The recorded range of NO<sub>x</sub> reductions was typically between 0 and 15-20%. The authors conclude NO<sub>x</sub> reductions can be the result of several factors, including reduced total fuel nitrogen, lower firing temperatures because of increased fuel moisture, and increased staging of the combustion process due to early volatiles burnout in the biomass fraction. Preliminary results show that the co-firing of up to 7% biomass, on a heat-input basis, with crushed or pulverized coal can lower NO<sub>x</sub> emissions by as much as 15% depending on the firing configuration. These tests did not explore optimizing the firing configuration for biomass to maximize the NO<sub>x</sub> control potential for this renewable fuel. Some tests did not show any NO<sub>x</sub> reduction at all.

In an attempt to explain the outcomes of co-firing biomass in pulverized coal boilers, particularly the potential for simultaneous reduction of NO<sub>x</sub>, Tillman (2003) looked into the differences in combustion characteristics between various biomass fuels and coals using a drop tube reactor (DTR). An analysis of the NO<sub>x</sub> reduction data obtained from several EPRI demonstrations of the co-firing of biomass with coal showed that one could expect slightly above 1% NO<sub>x</sub> reduction from baseline levels for every 1% co-firing percentage of biomass (Btu basis). The DTR laboratory results with sawdust, urban wood waste, fresh switchgrass, and weathered switchgrass for biomass fuels and two reference coals led to the following conclusions: a) fuel reactivity is a key to NO<sub>x</sub> control using staged combustion; b) biomass fuels, in general, are highly reactive, although weathering reduces nitrogen reactivity in switchgrass; c) the relative reactivity of biomass and various coals can be used as a technique to evaluate potential in NO<sub>x</sub> management; and d) the DTR technique for analyzing fuels has significant benefits in evaluating initial combustion processes applied to NO<sub>x</sub> management.

**Table 4.1** NO<sub>x</sub> Emissions Results with Wood Waste Co-Firing with Coal (Hughes 1998)

Site	Biofuel	Baseline NO <sub>x</sub> lb/MMBtu	Percent Co-Fire (mass basis)	Percent Co-Fire (heat basis)	NO <sub>x</sub> Reductions (percent)
GPU Seward	Wood (FGS, DSS and OS) <sup>a</sup>	0.87 to 0.95	3.4 to 6.4	1.5 to 2.8	0 to 11
			8.2 to 9.4	3.1 to 4.3	2.3 to 13
			11.9 to 13.8	4.3 to 8.1	3.4 to 14
			16.1 to 17.9	7.6 to 10.3	5.7 to 18
TVA Allen	Wood (sawdust)	2.0 with E. Coal	8.5 to 10	4.5	0 to 11.6
			20	9.0	25
TVA Allen	Wood (sawdust & woodchips)	1.5 with W. Coal	4.3	1.9	-1.3 to 7.3
			10	4.7	-8.7 to 14
			15	6.9	-2.7
NIPSCO Mich. City	Wood	1.05 to 1.28 (1.17 avg)	10	6.5	0 to 20 (9.5 avg)

<sup>a</sup> FGS = Fresh Green Sawdust; DSS = Dry Shavings and Sawdust; OS = Old Sawdust

## 4.2 Gas Turbines

There are a variety of combustion modification techniques and add-on control technologies to reduce NO<sub>x</sub> emissions from combustion turbines (CT). These include a) wet controls, b) dry low NO<sub>x</sub> (DLN) combustion controls, c) catalytic combustors, and d) selective catalytic reduction (SCR). Wet controls involve injecting water or steam into the flame of a CT to provide a sink that limits thermal NO<sub>x</sub>. Suppression of NO<sub>x</sub> formation from 70 to 90% is believed feasible (USEPA 1996). Combustion controls consist of either the Lean Combustion or Lean Premixed System, which have been deployed on new CT units in recent years (USEPA 1996). These systems are generally used as alternatives to wet systems. One of the difficulties with lean premixed systems is maintaining flame stability in the narrow flame temperature range between high NO<sub>x</sub> production and lean flame extinction (Peltier 2003). Catalytic combustion promises to be an alternative for DLN technologies. Catalytic combustors burn lean fuel-air mixtures to achieve sub-5 ppm NO<sub>x</sub>. The maximum combustor exit temperature is 2,460°F or lower, which is well below the NO<sub>x</sub> formation temperature (Peltier 2003). SCR can be applied to CTs in a manner similar to that for steam boilers. Distillate oil is occasionally used in place of natural gas in gas turbines.

## 4.3 Fluidized Bed Combustors

Pulp mill boilers capable of firing coal or wood often have the option to burn other solid fuels such as tire chips, wastewater treatment plant residuals (sludge), rejected material from processing of old corrugated containers (OCC rejects), non-recyclable paper pellets, etc. The amount of these materials that can be burned in traditional spreader-stoker type boilers is relatively small, and co-firing them with wood and/or coal has only minimal effects on the emissions. Fluidized bed boilers, on the other hand, can accommodate much larger percentages of alternative solid fuels. In general, coal-fired fluidized bed combustors (FBCs) are capable of achieving relatively low levels

of  $\text{NO}_x$ ,  $\text{SO}_2$ ,  $\text{CO}$ , and particulates (Makanski 1991). The combustor operating temperatures are very low, in the  $1500^\circ$  to  $1600^\circ\text{F}$  range, thus limiting the formation of  $\text{NO}_x$ . Nearly all circulating fluid bed (CFB) designs employ staging to minimize  $\text{NO}_x$  emissions. Post-combustion  $\text{NO}_x$  control using the SCR or SNCR technologies is feasible, but SCR in particular has only been demonstrated on large utility FBCs.

One southeastern kraft pulp mill operates a bubbling fluidized bed boiler (BFB) equipped with an SNCR system. This 820 MMBtu/hr BFB burns various combinations of wood, waste treatment plant residuals, and tire-derived fuel and uses the  $\text{NO}_x\text{OUT}$  process to reduce  $\text{NO}_x$  levels by about 40% from a baseline level of about  $0.35 \text{ lb}/10^6 \text{ Btu}$  (NCASI file information). The  $\text{NO}_x\text{OUT}$  process was originally designed to reduce  $\text{NO}_x$  emissions by about 62%. A second southeastern mill operates a CFB boiler that burns coal, wood residue, non-recyclable and pulper rejects, and some synfuel gas (175 MMBtu/hr) in varying blends and has been equipped with a urea-based SNCR system since 1996. The SNCR system is designed to achieve a 50%  $\text{NO}_x$  reduction. However, the boiler is able to achieve its permit limit of  $0.3 \text{ lb/MMBtu}$  without the use of SNCR. The removal efficiency has never been guaranteed since the fuel blend varies all the time. A third (northwestern) pulp mill also operates a CFB boiler (165 MMBtu/hr) that burns wood residues, waste treatment plant (WTP) residuals and some gas, and since 1996 has also been equipped with an SNCR system designed to reduce  $\text{NO}_x$  by up to 60%. The WTP residuals at this mill contain high levels of nitrogen, resulting in higher levels of  $\text{NO}_x$  (uncontrolled) compared to wood alone.

Leckner and Karlsson (1993) studied emissions of  $\text{NO}$ ,  $\text{N}_2\text{O}$ ,  $\text{SO}_2$  and  $\text{CO}$  from fluidized bed combustion of mixtures of wood and coal in a 12 MW research circulating fluidized bed (CFB) boiler. Bituminous coal (1.5% N) was co-fired with sawdust (0.10% N) or fir chips (0.15% N) in amounts ranging from 0 to 100% coal. In spite of the much lower N content, 100% wood firing led to higher  $\text{NO}$  emissions than did 100% coal firing. Reduction of  $\text{NO}$  by char in the bed and ten times higher char concentrations in the bed during 100% coal burning compared to 100% wood burning were believed to explain this difference. Small additions of coal to wood initially yielded a higher  $\text{NO}$  emission than even 100% wood. The authors explained that at low coal contents, since the amount of char in the bed was small, the reduction of  $\text{NO}$  formed during coal burning by char was small and higher fractions of the coal N were converting to  $\text{NO}$ .  $\text{NO}$  reduction by char from coal burning increased with higher levels of coal burning, leading ultimately to lower  $\text{NO}$  emissions from 100% coal burning than from 100% wood burning. Emissions of  $\text{N}_2\text{O}$  were primarily from coal burning (negligible from wood burning).

One emission from circulating and bubbling bed combustors burning coal that could potentially be of concern is the greenhouse gas nitrous oxide ( $\text{N}_2\text{O}$ ). In CFB combustors, the  $\text{N}_2\text{O}$  levels could be as much as 70% of the corresponding  $\text{NO}_x$  ( $\text{NO} + \text{NO}_2$ ) levels (IPCC 1997). The formation of  $\text{N}_2\text{O}$  depends on the combustion temperature, with the highest  $\text{N}_2\text{O}$  emissions occurring at a temperature of about  $1,000^\circ\text{K}$  ( $1,340^\circ\text{F}$ ). For combustion temperatures below  $800^\circ\text{K}$  or above  $1,200^\circ\text{K}$ , the  $\text{N}_2\text{O}$  emissions are negligible (IPCC 1997). In pulverized coal and stoker-fired boilers, higher flame and post-flame temperatures in the presence of gas phase radicals preclude the formation of  $\text{N}_2\text{O}$  (Makanski 1991).

## 5.0 TECHNOLOGICAL ADVANCES IN $\text{NO}_x$ CONTROL FOR BOILERS

This section provides brief summaries of recent reports and reviews published in the literature on the current state of the art for  $\text{NO}_x$  emissions control, especially as applied to industrial boilers. Although much of the information pertains to utility boilers, some of it can be useful in understanding  $\text{NO}_x$  emissions control from industrial boilers.

### 5.1 Swanekamp (2002a)

In a special report titled *Emissions-Control Technologies Continue to Clear the Air*, Swanekamp described advances in combustion and post-combustion technologies that reduced stack emissions from utility boilers and gas turbines. He made the following observations relevant to NO<sub>x</sub> emissions control:

- Combustion modification is generally the lowest-cost option for NO<sub>x</sub> control.
  - At one utility, the John Zink Co. applied its COOLflow modeling technology to design baffles and turning vanes in the windbox and ductwork systems to correct air flow distribution problems; this in turn optimized combustion and also enabled existing (unused) OFA ports to be returned to service, resulting in a 22% reduction in NO<sub>x</sub> emissions.
  - The Rotating Opposed Fire Air (ROFA) system by Mobotec USA improved combustion by creating upper-boiler turbulence with high-velocity air injection through asymmetrically located nozzles in the boiler walls. The system was expected to reduce NO<sub>x</sub> emissions at two utilities by 50 to 75% using no chemicals or catalysts.
- LNB with OFA is the most popular combustion modification and is capable of achieving NO<sub>x</sub> reductions of up to 70% with gas and oil fuels.
- Sophisticated software known as a “process-optimization package” uses techniques like neural networks, Bayesian analysis, and internal heuristics to monitor critical process parameters, determine optimum setpoints and communicate them to control devices, and continuously reconfigure the control system based upon the software models. The software is used by many fossil-fueled utilities to limit NO<sub>x</sub> emissions. The use resulted in a 20% reduction in NO<sub>x</sub> at one utility.
- There are limitations to combustion modifications such as LNBS and optimization software.
  - LNBS are best applied to wall-fired units, not cyclones.
  - LNBS can cause performance problems, such as carbon loss and tube-wall wastage.
  - Most importantly, even in “layered” applications, they cannot meet levels dictated by the NO<sub>x</sub> SIP Call.
- SCR is the only commercially viable alternative for high levels of NO<sub>x</sub> reduction.
- Ammonia slip requirements are getting stricter in many states – typically 5 ppm in California; 2 ppm in Massachusetts; some NE states are pushing for “zero” slip.

### 5.2 Swanekamp (2002b)

In a brief excerpt titled “Connectiv plant cuts NO<sub>x</sub> emissions without SCR,” Swanekamp described RJM Corporation’s “layered approach” to achieve 90% NO<sub>x</sub> emissions reduction without an SCR at 60% of the cost of an SCR retrofit as applied to a 480 MW coal/oil-fired boiler in Beesley’s Point, New Jersey. The first four layers included:

- burner modifications
- installation of overfire air ports

- NO<sub>x</sub> tempering, which injects micronized water droplets into high-NO<sub>x</sub> production zones, and
- SNCR, which injects a urea-based reagent into the lean-fuel zone above the furnace.

The fifth layer, dubbed “absolute compliance” or “RJM-AC,” involved injection of an amine reagent in the primary combustion zone. RJM Corporation also described a “combustion tempering” technique applied to a natural gas-fired cyclone boiler, “burner optimizations” applied to three coal-fired front-fired utility boilers rated at 50MW each, and a rich reagent (amine-based) injection system followed by OFA applied to a 138 MW cyclone coal-fired boiler, all three in conjunction with SNCR systems, to achieve nearly 60%, over 70% and nearly 80% NO<sub>x</sub> reduction, respectively (<http://www.rjm.com/html/techinfo.htm>).

### 5.3 Swanekamp and Ellison (2001)

The use of ammonia- or urea-based additive treatments in de-NO<sub>x</sub> processes, either upstream or downstream of the boiler economizer, presented substantial problems. Technological advances to address these problems, including supplemental additive treatment techniques, were discussed in two conferences and summarized by Swanekamp and Ellison.

- Lime addition in a furnace can negate high SO<sub>3</sub> concentrations and lead to sludge buildup in the air preheater.
- Lime addition can also tie up catalyst poisoning arsenic in coal.
- Additives can counteract high lime content in some PRB coals, which can foul SCR catalysts.
- Replacing tubular air heaters with Ljungstrom-type helps catalyst plugging problems.
- Replacing soot blowers by on-line acoustic horns produces favorable results.

Additionally, the authors reported other technological advances including the following:

- a Fuel Lean Gas Reburn (FLGR) system (that used natural gas injection to replace 3-10% of heat input from coal) which can be integrated with SNCR
- a conversion system of urea, a stable non-volatile material that is safer to transport, store, and handle, to a gaseous mixture of ammonia on-site as and when needed for use in SCR systems.

### 5.4 NESCAUM (2001)

In a 2001 report entitled *Power Companies' Efforts to Comply with the NO<sub>x</sub> SIP Call and Section 126, Progress Report* the Northeast States for Coordinated Air Use Management (NESCAUM) made the following key points relative to NO<sub>x</sub> control:

- The NO<sub>x</sub> SIP Call region's total SCR commitment was at least 115 units, representing over 66,000 MWs of capacity.
- 0.15 lb/MMBtu represented an 85% reduction from uncontrolled NO<sub>x</sub> for most large coal-fired power plants; hence, SCR was the most suitable candidate for NO<sub>x</sub> control.
- Other emerging technologies in the mix included:

- a combustion technology called ThermalNO<sub>x</sub> that had been applied at American Electric Power's 375 MW Conesville facility (expected to achieve 80 to 90% NO<sub>x</sub> reduction)
- a combustion improvement technology called Rotating Overfire Air used at Carolina Power & Light's Cape Fear facility, and
- a reburn technology supplied by General Electric to the Southern Company's Scherer plant (50 to 70% reduction expected).

## 5.5 NESCAUM (2000)

In a 2000 report entitled *Status Report on NO<sub>x</sub> Control for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines – Technologies & Cost Effectiveness - Executive Summary*, NESCAUM evaluated various control technologies that had been commercially applied to four major source categories, including industrial boilers in the northeastern states and also their cost-effectiveness in reducing emissions of oxides of nitrogen. Case studies were taken up for actual installations of NO<sub>x</sub> reduction technologies on many sources, and detailed write-ups prepared in cooperation with the users of the technologies. The users provided all the information and approved the written descriptions of the case studies. Thus, the case studies represented the user's view of the performance, reliability, and cost of technologies (NESCAUM 2000). Relative to industrial boilers, the report noted the following significant findings:

- LNB, OFA, SCR, SNCR, and reburn technology have been used for NO<sub>x</sub> reduction.
- Decisions to use OFA should be made on a case-by-case basis.
- In year 2000, for pulverized coal boilers, a 30% NO<sub>x</sub> reduction could be achieved with LNB at a cost of <\$2,000/ton.
- LNBs were capable of controlling a majority of gas-fired industrial boilers to NO<sub>x</sub> levels below 0.15 lb/MMBtu.
- LNBs on boilers firing No. 6 oil achieved median NO<sub>x</sub> levels of 0.35 lb/MMBtu.
- SIP Call-dictated annual NO<sub>x</sub> reductions with LNB for oil & gas-fired industrial boilers can be achieved at <\$2,000/ton for moderate to high capacity factor (65 to 85%) units.
- SNCR was well suited for industrial boilers, achieving on average over 50% NO<sub>x</sub> reduction.
- SCR had seen only limited use in the U.S. on boilers firing solid fuel, but there was no technical reason to prevent its use on such boilers.
- Gas reburn technologies operating on some industrial boilers in the U.S. were providing NO<sub>x</sub> reductions of about 50%.

## 6.0 EMERGING TECHNOLOGIES FOR INDUSTRIAL BOILER NO<sub>x</sub> CONTROL

This section reviews some of the emerging NO<sub>x</sub> control technologies presented in the literature that may be applicable to industrial boilers. However, it should be emphasized that most (if not all) of these technologies are currently under development or in the "full-scale" evaluation stage. They involve both combustion modifications and post-combustion flue gas NO<sub>x</sub> emissions control.

## 6.1 Methane de-NOX Reburn Technology

Reburning involves the staged addition of fuel into two combustion zones: a) the primary combustion zone where the primary fuel is fired; and b) the reburn zone where additional fuel (the reburn fuel) is added to create a reducing (oxygen deficient) condition to convert the NO<sub>x</sub> produced in the primary zone to molecular nitrogen (N<sub>2</sub>) and water. In the reducing zone, the reburn fuel molecules break down to hydrocarbon fragments (CH, CH<sub>2</sub>, etc.) that react with NO<sub>x</sub>. Above the reburn zone is a burnout zone where OFA is added to complete the combustion.

Schrecengost et al. (2002) provided an overview of a gas reburn technology (Methane de-NOX ) using 5 to 25% natural gas heat input for combustion improvement and 50 to 70% NO<sub>x</sub> reduction in coal-, biomass-, and MSW-fired stoker boilers. The process features injection of gas near the grate with recirculated flue gas and injection of overfire air at a higher furnace elevation to burn out the combustibles. The oxygen-deficient atmosphere above the grate is expected to retard NO<sub>x</sub> formation. More recently, the Methane de-NOX technology (MdN) is being applied to kraft pulp mill stoker boilers by utilizing the VOC content of non-condensable gases (NCGs) to partially replace the natural gas (by up to 25%). This technology has been tested for over a year at one pulp mill boiler, and is being tested at several boilers within one FPI company. The MdN technology has also been applied to two MSW plants and a coal-fired utility. The authors claimed the following energy and environmental benefits when applying this technology to pulp and paper industry boilers:

- reduced operating costs and air emissions through advanced combustion with strategic use of natural gas
  - increased utilization of wood residues
  - improved boiler operability, reliability, and efficiency
  - improved boiler environmental performance
- increased effective, efficient, and reliable self-generated power capacity
- cost-effective and efficient destruction/utilization of NCGs.

## 6.2 Low Temperature Oxidation

Low temperature oxidation (LTO) is an NO<sub>x</sub> removal system that uses ozone, injected into the flue gas stream, to oxidize insoluble NO<sub>x</sub> to soluble oxidized compounds. Ozone is produced on site and on demand by passing oxygen through a conventional industrial ozone generator.

The BOC Group commercialized this technology under the trade name LoTOx. Barasso and Donovan (2002a, 2002b) presented the following key points relevant to the LTO technology for NO<sub>x</sub> control.

- NO and NO<sub>2</sub> in a gas stream were oxidized to highly soluble N<sub>2</sub>O<sub>5</sub> and HNO<sub>3</sub> by injecting ozone.
- A particulate and/or SO<sub>2</sub> scrubber was used to scrub out the oxidized compounds.
- Ozone was produced in response to the amount of NO<sub>x</sub> present in the flue gas.
- At the design retention time, ozone reacted selectively with NO<sub>x</sub> and not with SO<sub>x</sub> and CO.
- LTO operated optimally below 300°F.
- Performance was unaffected by “dirty” streams.

Tests conducted in 2002 on a slip stream from a pulp and paper industry bubbling fluidized bed boiler burning deink sludge, bark and TDF were reported to be successful in reducing NO<sub>x</sub> emissions by over 90% ([http://www.boc.com/news/article\\_detail.cfm?ID=334&bSegment=0](http://www.boc.com/news/article_detail.cfm?ID=334&bSegment=0)). A 25 MW coal-fired power plant at the Medical College of Ohio (MCO) is the only full-scale installation of LTO technology to date. It has been operating since October 2001. The MCO system involves a semi-dry rapid absorption process for SO<sub>x</sub> scrubbing (using lime slurry) and a bag house particulate control technology, followed by the LTO system for NO<sub>x</sub> removal. The LTO system consists of a reactor (72-inch diameter, one pass with 1.5 sec residence time), followed by a wet absorber and a wet stack, associated oxygen supply, an ozone generator, and a cooling water system. A six-month testing phase was planned in late 2001 to determine performance of the LTO system at a 45,000 lb/hr boiler steam load. Early operating results indicated 85 to 90% NO<sub>x</sub> removal from 50 to 70 ppm baseline levels. A 1,000 acfm slip stream at a 500 MW coal-fired boiler and a slip stream at a 400 MM Btu/hr bubbling fluidized boiler burning wood residues, deink residuals, tire-derived fuel, and natural gas at a deinking facility have also been reported to be tested successfully with over 90% NO<sub>x</sub> removal. Cost estimates are not available for comparison, although a cost analysis carried out using this technology on a 200 MW coal-fired power plant with an existing FGD scrubber showed that fixed costs were 50 to 55% of total annual cost, and operating costs (largely the power for ozone generation and oxygen) were 45 to 50%, with a cost-effectiveness estimated at about \$1,696 per ton of NO<sub>x</sub> removed from the baseline (0.4 lb/MM Btu).

### **6.3 Induced Flue Gas Recirculation Technology**

For modified flue gas recirculation technology (Broske 1998), a duct is added between the economizer outlet (or air preheater outlet) duct and the FD fan, thus eliminating the need for a separate FGR fan, where the boiler flue gas is recirculated to the combustion zone by induced flow through the FD fan(s) and a flue gas flow rate of 0 to 20% is controlled (manually or automatically) over the load range.

The following advantages were claimed for this technology.

- 40 to 50% NO<sub>x</sub> reduction at a low cost (\$0.25 to \$1.00/kW installed cost, about 30% of cost of LNB or FGR)
- easy to retrofit
- applicable to various boiler firing systems

The following disadvantages were also noted.

- may limit the boiler load (without modifications)
- involved a heat penalty (0.3 to 0.5%)
- reduced the rate of load change during transitions
- affected steam temperature (spray capacity)

### **6.4 The Pahlman Process**

Enviroscrub Technologies Corporation, a Minneapolis, Minnesota company, provided some information about a unique (but secretive) NO<sub>x</sub> scrubbing process at their website ([www.enviroscrub.com](http://www.enviroscrub.com)) that included the following:

- a one step, dry scrubbing process using a fine black powder dubbed Pahlmanite
- slip streams tested using this technology at the Huntsville Power station, Huntsville, Illinois, the Boswell Energy Center (Minnesota Power), Cohasset, Minnesota and Potlatch Corporation's Brainerd, Minnesota coal-fired boiler (mill since shut down)
- claimed between 75 and 96% NO<sub>x</sub> removal
- compounds of sulfur (sulfates) and nitrogen (nitrates) formed when Pahlmanite is regenerated for reuse could be resold for chemical or as fertilizer

## 6.5 Other Emerging Technologies

One emerging technology involves the injection of elemental phosphorus as an oxidant to convert NO to NO<sub>2</sub> which is then removed in a wet scrubber. The first full-scale application of Thermal Energy's THERMALONox technology on a power plant has been undergoing a commercial demonstration on a high sulfur coal-fired utility boiler in Ohio. Initial results of this demonstration at American Electric Power's (AEP) Conesville plant suggest a need for additional research. AEP stated that despite the promising nature of the technology, the data from the demonstration indicate the system did not appreciably reduce nitrogen oxide emission levels from the plant's 375-megawatt generating unit (<http://www.aep.com/environmental/performance>). The system was expected to remove as much as 75% of the NO<sub>x</sub> emissions from the exhaust gases of utility power plants and industrial boilers when used in combination with a flue-gas desulfurization system.

The Electric Power Research Institute (EPRI) stated in December 2002 it was involved with several emerging post-combustion NO<sub>x</sub> control technologies that were principally designed for utility coal-fired boilers ([http://www.epri.com/corporate/productservices/project\\_opps/gen/1007605.pdf](http://www.epri.com/corporate/productservices/project_opps/gen/1007605.pdf)). Some of these technologies may have application to industrial boilers. The projects included:

- boosted overfire air + SNCR (urea reagent)
- ecotube high pressure OFA system + ammonia injection
- Mobotec ROTAMIX™ (ammonia injection)
- SNCR Trim (single level of injectors)
- Selective Auto-Catalytic Reduction (SACR)
- rich reagent injection

Durr Environmental (<http://www.durrenvironmental.com/NOXCS.asp>) offered a Zero Ammonia Technology (ZAT) that did not require the injection of ammonia or urea. ZAT is a catalytic-based system that converts all of the NO<sub>x</sub> into NO<sub>2</sub> (i.e., it oxidizes the NO) and adsorbs the NO<sub>2</sub> onto the catalyst. Portions of the catalyst are isolated from the exhaust stream, and the adsorbed NO<sub>2</sub> is reduced to N<sub>2</sub> using diluted hydrogen, or some sort of hydrogen reagent gas, and desorbed from the catalyst.

The National Energy Technology Laboratory (NETL) stated that it was managing several NO<sub>x</sub> control technology R&D projects ranging from laboratory studies to modeling to full-scale demonstration. The technologies being addressed included ultra low NO<sub>x</sub> burners, advanced reburning, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), METHANE de-NO<sub>x</sub>, and oxygen-enhanced combustion. The project summaries may be found at <http://www.netl.doe.gov/publications/proceedings/02/ubc/lanisummary.pdf>.

### **6.5.1 *Ultra Low NO<sub>x</sub> Integrated Systems for NO<sub>x</sub> Emission Control***

Alstom Power reported developing an ultra low NO<sub>x</sub> integrated system for coal-fired power plants that will achieve furnace outlet emission levels at or below 0.15 lb/MMBtu. The reduced NO<sub>x</sub> emissions will be obtained without increasing the level of unburned carbon (UBC) in the fly ash through advances in control systems, combustion process modifications, and postcombustion carbon burnout technology. The target market would be tangentially fired (T-fired) coal boilers, which represent about 40% of the boilers currently listed in the State Implementation Plan (SIP) Call region.

### **6.5.2 *NO<sub>x</sub> Control Options and Integration for U.S. Coal-Fired Boilers***

Reaction Engineering International has reported optimizing the performance of the combined application of low NO<sub>x</sub> firing systems (LNFS) and post-combustion controls. The project will assess real-time monitoring equipment to evaluate waterwall wastage, soot formation, and burner stoichiometry. In addition, the impact of various coals on SCR catalyst activity will be investigated along with novel UBC/fly ash separation processes. The primary target of the research would be cyclone boilers, which represent about 20% of the U.S. generating capacity.

### **6.5.3 *Cost-Effective Control of NO<sub>x</sub> with Integrated Ultra Low NO<sub>x</sub>-PC Burners and SNCR***

In another advanced low NO<sub>x</sub> burner project, McDermott Technology and Fuel Tech have reported teaming up to develop an integrated system comprised of ultra LNBS, coupled with SNCR. The overall goal of this project is to develop a cost-effective control system capable of achieving NO<sub>x</sub> levels below 0.15 lb/MMBtu for a wide range of coals. The primary market for the ultra LNB/SNCR technology would be front- and opposed-wall-fired boilers within the NO<sub>x</sub> SIP Call region, with cell-fired, roof-fired, and arch-fired boilers also among the candidates.

### **6.5.4 *METHANE de-NO<sub>x</sub> for Utility Boilers***

The Gas Technology Institute (GTI; formerly the Institute of Gas Technology and Gas Research Institute) has reported developing a pulverized-coal combustion reburn system. The technology integrates natural gas-fired coal preheating, LNBS with internal combustion staging, and additional natural gas injection with overfire air. Preheating the coal promotes the conversion of fuel-bound nitrogen to molecular nitrogen rather than to NO<sub>x</sub>. GTI estimates the market for the technology would include more than 21,000 burners (over 260,600 MW) in the 37 eastern states encompassing wall-fired (wet- and dry-bottom), T-fired, roof-fired, and cell burners.

### **6.5.5 *Oxygen-Enhanced Combustion for NO<sub>x</sub> Control***

Praxair has reported developing oxygen-enhanced combustion and oxygen-enhanced reburning technologies for controlling NO<sub>x</sub>. Oxygen-enhanced combustion can be used to control both thermal and fuel NO<sub>x</sub>. The key to this project is the use of controlled conditions to take advantage of the combustion benefits of oxy-fuel firing to reduce NO<sub>x</sub> emissions below 0.15 lb/MMBtu.

## **7.0 TECHNICAL LIMITATIONS OF APPLYING AVAILABLE NO<sub>x</sub> CONTROL TECHNOLOGIES TO FPI BOILERS**

Much of the operating experience gained on fossil fuel-fired boiler NO<sub>x</sub> emissions control has involved utility boilers. A few gas and/or oil-fired FPI boilers have employed combustion modification NO<sub>x</sub> reduction techniques such as LNB, OFA and FGR. A few have even installed SNCR for post-combustion NO<sub>x</sub> emissions control. The SNCRs have typically been installed on base-loaded boilers or for marginal NO<sub>x</sub> removal purposes. None has SCR in place.

In November of 1998, the American Forest and Paper Association (AF&PA), along with several other organizations including the Council of Industrial Boilers (CIBO), submitted a petition to the DC Circuit Court challenging the revised Subpart Db standards of performance for NO<sub>x</sub> applicable to fossil-fuel fired steam-generating units (“boilers”) promulgated by EPA on September 16, 1998. The petition claimed EPA did not consider adequately the feasibility of installing SCR on coal-fired industrial boilers (or coal/wood and coal/oil boilers) which have different characteristics than utility boilers such as swinging loads. It highlighted several characteristics pertinent to pulp and paper industry boilers that differentiate them from utility boilers, thereby calling the applicability of a uniform technology-based NO<sub>x</sub> standard into question. EPA responded to this petition in a July 30, 1999 legal brief, arguing that it should be denied (USEPA 1999). Highlights of the AF&PA petition, EPA’s response, and an evaluation of EPA’s response can be found in Appendix A.

Appendix B summarizes the public comments relative to FPI boilers that were submitted to EPA in response to the July 9, 1997 proposal to revise the NO<sub>x</sub> emission limits in subparts Da and Db of 40 CFR Part 60. EPA’s responses to these comments (USEPA 1998d) are also included in Appendix B.

The following sections summarize the technical limitations identified in selected industry and non-industry publications on the application of various NO<sub>x</sub> control technologies to FPI boilers.

### **7.1 Applicability of Combustion Modifications**

Industrial boilers typically operate with widely varying steam loads, with an estimated mean capacity utilization factor of 45 to 55% (CIBO 1993). Even recently installed cogeneration and independent-power facilities with higher utilization factors operate on dispatch schedules dictated by the utility purchasing the power (Jones 1994). NO<sub>x</sub> reduction measures are particularly difficult to implement in small, low capacity facilities because a) residence time is limited and often inadequate for applying overfire air (OFA) without excessive loss of thermal efficiency or induced smoking; b) relatively small furnace dimensions limit combustion modifications that increase flame length and tend to cause the flame to impinge on tube walls’ c) peak boiler efficiency and minimized NO<sub>x</sub> emissions occur close to minimum flue-gas O<sub>2</sub> content, which is at the threshold of smoke or combustible-emissions formation; d) steam is used far more effectively in industrial applications than in conventional electric utility plants and, consequently, emission limits based on boiler heat input or volume of flue gas do not recognize such efficiency (Jones 1994).

The Council of Industrial Boiler Owners prepared an NO<sub>x</sub> RACT (Reasonably Available Control Technologies) guidance document (CIBO 1993) which identified numerous reasons why uniform RACT rules for industrial boilers would be inappropriate.

- The industrial boiler population is diverse – no specific type is prevalent.
- There are very little hard NO<sub>x</sub> emissions data for existing industrial systems.
- The variability of emissions from a unit, type system, or class of units, can be extreme.
- Projection of system trends is impractical; therefore, emissions may have to be considered on a unit-by-unit basis.
- Most industrial stoker fired units installed prior to 1987 were equipped with only one or two rows of overfire ports, and a maximum of 10 to 20% total air, an arrangement designed to optimize combustion efficiency, *not* to control NO<sub>x</sub> emissions.
- Bottom-supported stoker units are virtually impossible to retrofit with a new overfire air arrangement.

- Inherent system variability required that a 30-day rolling average be the standard for industrial boilers.

In written comments to the Maine Department of Environmental Protection, Sonnichsen (1994) of CARNOT listed several reservations about applying utility NO<sub>x</sub> control experience to industrial boilers.

- The greatest difference in utility and power boiler operations is the fluctuating steam demand characteristic of pulp and paper mill operations which requires that power boilers continuously adjust fuel firing rates and excess air levels. Even with the most sophisticated combustion controls, it is not practical or safe to maintain excess air continuously at minimum levels. Consequently, power boilers have characteristically and inherently higher NO<sub>x</sub> emissions.
- Fuel biasing on an industrial boiler subject to rapid and excessive load swings could result in too rich or lean firing conditions, which can lead to flame stability problems and explosive conditions.
- Windbox flue gas recirculation (FGR) could be considered for use on oil-fired boilers. Its application, however, can be limited by (1) the windbox and boiler fans' capacities, (2) increased boiler bank tube wall erosion, and (3) the potential for severe damage from changes in convection heat transfer and boiler water circulation patterns.
- The application of low NO<sub>x</sub> burners (LNB) is often limited by the longer flames produced as a consequence of improved air distribution control. While there is generally ample room for LNB flames in utility furnaces, their use on the smaller power boilers can result in flame impingement on furnace walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.
- Unlike utilities which can specify the nitrogen content of their large oil purchases, most mills cannot do this.

Even within the family of industrial boilers there are considerable differences in the design of various types of boilers and therefore the applicability of certain NO<sub>x</sub> control technologies. For example, considerable differences exist in the heat removal rates between a grate-fired boiler for wood residue or coal combustion and a packaged boiler for oil or gas combustion. The grate boiler is designed for staged combustion since a large amount of the combustion air is introduced above the grate fire. Also, the size of the grate furnace is two to three times greater than a similar packaged boiler. The net result is that there is more heat absorption in a grate-fired boiler resulting in lower thermal NO<sub>x</sub> formation. Both air staging and flue gas recirculation, recommended NO<sub>x</sub> control techniques for oil and gas combustion, when applied to packaged boilers will increase the burner flame length and require added furnace length to avoid flame impingement on the furnace walls.

## **7.2 Applicability of SNCR NO<sub>x</sub> Control Technology**

As previously mentioned, the use of the SNCR process in a packaged boiler would require access to a temperature window between about 1700 and 2000°F in which to inject the ammonia or urea. Controlling flue gas temperatures in the convective section of a package or even grate boiler over the entire range of operating loads the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection

nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.

### **7.3 Applicability of SCR NO<sub>x</sub> Control Technology**

An important factor restricting the use of the SCR process on most industrial boilers is the loss in energy efficiency that would result from the need to reheat the exhaust gases. Exhaust gases exiting the economizer sections of most FPI boilers are typically in the range of 250 to 400°F, while the desired temperature range for the SCR process is between 450 and 750°F. At part load, a boiler economizer bypass will probably be required, especially in high sulfur applications, as most boilers feature flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point (Cichanowicz 1999). Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO<sub>3</sub> produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO<sub>2</sub> to SO<sub>3</sub> conversion could cause accelerated corrosion or higher SO<sub>3</sub>-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposing or marketing fly ash or scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning (Cichanowicz 1999).

## **8.0 PERMITTING INFORMATION**

NO<sub>x</sub> emission limits for boilers are often set on a case-by-case basis as part of an air quality permitting process. For new boilers, or existing boilers undergoing a major modification, obtaining a construction permit generally involves a determination of Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). For existing boilers located in or near ozone non-attainment areas, NO<sub>x</sub> emission limits may be based on facility-specific determinations of Reasonably Available Control Technology (RACT). EPA guidance indicates LAER limits should be the most stringent, followed by BACT and RACT limits.

Permitting decisions are usually made by states and reviewed by EPA regional offices. Information submitted by the permit applicant is considered in the decision-making process. Factors such as technical feasibility, cost-effectiveness, ambient air quality impact, and non-air quality impacts are evaluated on a facility-specific basis.

Appendix C contains information submitted to permitting agencies by forest products companies as part of their evaluation of alternative RACT, BACT, and/or LAER NO<sub>x</sub> control options for boilers. Appendix D tabulates permitting decisions and NO<sub>x</sub> emission limits in EPA's RACT/BACT/LAER Clearinghouse database for boilers at forest products industry manufacturing facilities for the period between 1992 and 2001.

## **9.0 NO<sub>x</sub> EMISSIONS CONTROL COST ESTIMATES FOR INDUSTRIAL BOILERS**

This section deals with costs for implementing NO<sub>x</sub> emissions control on industrial boilers. Cost plays a critical role in making permitting decisions and in development of nationwide emission regulations such as the NSPS. First, EPA's summary analysis on NO<sub>x</sub> control costs for fossil fuel-fired boilers presented during the promulgation of the revised Subpart Db NO<sub>x</sub> emission standards for boilers is discussed. Cost estimates published by NESCAUM are then briefly summarized.

Finally, cost estimates and comments provided in permitting analyses of boiler NO<sub>x</sub> control options performed by individual forest products industry companies are summarized.

### **9.1 EPA Estimates for New Industrial Fossil Fuel-Fired Boilers**

In the background technical document for the revised Subpart Db NO<sub>x</sub> emissions standards, EPA estimated control technology costs for installing various types of NO<sub>x</sub> emissions control on new fossil fuel-fired industrial boilers (USEPA 1997). Annualized costs and incremental cost-effectiveness ranges from this document are reproduced for various model boilers in Tables 9.1 and 9.2, respectively. Table 9.1 shows the cost of installing combustion controls for NO<sub>x</sub> emissions on industrial fossil fuel-fired boilers ranges from 0 to 2% of the net cost of generating steam in the boiler. It should be noted that the requisite combustion controls for fluidized bed combustors and spreader stokers burning coal and field-erected water tube boilers burning distillate oil or natural gas are already assumed to exist and thus represent the baseline for these boilers. When combustion controls are augmented by SNCR, the total cost rises to between 4% and 16% of the steam cost. Finally, when SCR is used along with combustion controls, the total cost increases appreciably to between 10% and 48% of the steam cost. Table 9.2 gives estimates for incremental cost-effectiveness in \$/ton NO<sub>x</sub> removed. When applying SCR to industrial boilers after combustion controls have been implemented, the incremental cost-effectiveness estimates range from \$5,900 to \$49,800 per ton of NO<sub>x</sub> removed. Incremental cost-effectiveness estimates for applying SNCR to boilers after combustion control implementation are also high, ranging from \$1,720 to \$32,140 per ton of NO<sub>x</sub> removed. In the July 1997 *Federal Register* proposal ([FR 62 (131) 36948-36963]), EPA explained the wide range in the cost and cost-effectiveness estimates as follows: “The main differences between industrial steam generating units and utility steam generating units are that industrial steam generating units tend to be smaller and tend to operate at lower capacity factors. The differences between industrial and utility steam generating units would be reflected in the cost impacts of the various NO<sub>x</sub> control technologies. Smaller sized and lower capacity factor units tend to have a higher cost on a per unit output basis.”

**Table 9.1** Summary of Annualized Costs for Model Boilers<sup>a</sup> (USEPA 1997)

Fuel Type	Furnace Type <sup>b</sup>	Size (MM Btu/hr)	CC <sup>c</sup>		CC + SNCR <sup>c</sup>		CC + SCR <sup>c</sup>	
			\$/yr	%	\$/yr	%	\$/yr	%
Coal	PC	250	40,040	1	286,530	9	997,740	33
		500	59,020	1	384,460	6	1,605,070	27
	FBC	1,000	87,010	1	538,850	4	2,756,820	23
		100	0	0	173,170	14	NA	NA
		250	0	0	227,480	8	NA	NA
		500	0	0	287,410	5	NA	NA
Residual Oil	Spreader Stoker	1,000	0	0	375,780	3	NA	NA
		100	0	0	184,580	15	583,440	48
		250	0	0	256,000	8	960,920	32
	Field-Erected Water Tube	500	0	0	344,540	6	1,551,210	26
		100	23,970	2	197,060	16	461,860	38
		250	40,040	1	265,600	9	668,940	22
Distillate Oil/ Natural Gas	Packaged Water Tube	500	59,020	1	341,770	6	972,550	16
		1,000	87,010	1	453,320	4	1,522,790	13
	Field-Erected Water Tube	100	23,970	2	197,060	16	461,860	38
		250	40,040	1	265,600	9	668,940	22
		100	0	0	168,910	14	418,880	35
		250	0	0	215,110	7	581,250	19
Packaged Water Tube	500	0	0	261,830	4	818,200	14	
	1,000	0	0	324,470	3	1,245,120	10	
Packaged Water Tube	100	23,970	2	194,400	16	443,210	37	
	250	40,040	1	258,940	9	622,310	21	

<sup>a</sup> Annualized costs are for a capacity factor of 0.30. Annualized cost expressed as a percentage of steam cost; steam cost based on \$6 per 1000 lb steam; and 1,300 Btu of heat input per lb of steam generated

<sup>b</sup> PC = Pulverized Coal; FBC = Fluidized Bed Combustion;

<sup>c</sup> CC = Combustion Control; SCR = Selective Catalytic Reduction; SNCR = Selective Non-Catalytic Reduction

**Table 9.2** Model Boiler Incremental Cost-Effectiveness Ranges<sup>a</sup> (USEPA 1997)

Fuel Type	Furnace Type <sup>b</sup>	Control Technology Comparisons <sup>c</sup>	Incremental Cost Effectiveness (\$/ton)		
Coal	PC	CC vs. Baseline	240 - 440		
		CC + SNCR vs. CC	1,720 - 3,375		
		CC + SCR vs. CC	6,350 - 9,110		
		CC + SCR vs. CC + SNCR	14,070 - 18,040		
	FBC	CC vs. Baseline	0		
		CC + SNCR vs. CC	2,860 - 13,180		
		CC + SCR vs. CC	NA <sup>d</sup>		
		CC + SCR vs. CC + SNCR	NA		
	Spreader Stoker	CC vs. Baseline	0		
		CC + SNCR vs. CC	2,100 - 5,620		
		CC + SCR vs. CC	5,900 - 11,100		
		CC + SCR vs. CC + SNCR	12,250 - 20,240		
Residual Oil	Field-Erected Water Tube	CC vs. Baseline	740 - 2,030		
		CC + SNCR vs. CC	2,930 - 13,870		
		CC + SCR vs. CC	7,190 - 21,920		
		CC + SCR vs. CC + SNCR	14,280 - 35,350		
	Packaged Water Tube	CC vs. Baseline	640 - 960		
		CC + SNCR vs. CC	7,230 - 13,870		
		CC + SCR vs. CC	12,600 - 21,920		
		CC + SCR vs. CC + SNCR	21,540 - 35,350		
		Distillate Oil/ Natural Gas	Field-Erected Water Tube	CC vs. Baseline	0
				CC + SNCR vs. CC	6,170 - 32,140
CC + SCR vs. CC	14,180 - 49,800				
CC + SCR vs. CC + SNCR	29,190 - 79,250				
Packaged Water Tube	CC vs. Baseline		2,030 - 3,040		
	CC + SNCR vs. CC		11,110 - 21,620		
		CC + SCR vs. CC	18,460 - 33,240		
		CC + SCR vs. CC + SNCR	30,730 - 52,600		

<sup>a</sup> Incremental cost-effectiveness at a capacity factor of 0.30 for the range of boiler sizes 250, 500 and 1,000 MMBtu/hr for PC boilers; 100, 250, 500 and 1,000 MMBtu/hr for FBC and field-erected boilers; 100, 250 and 500 MMBtu/hr for spreader stoker boilers; and 100 and 250 MMBtu/hr for packaged boilers

<sup>b</sup> PC = Pulverized Coal; FBC = Fluidized Bed Combustion

<sup>c</sup> CC = Combustion Control; SNCR = Selective Noncatalytic Reduction; SCR = Selective Catalytic Reduction

<sup>d</sup> NA = Not Applicable

## 9.2 NESCAUM

The NESCAUM report (2000) also evaluated cost-effectiveness of reducing NO<sub>x</sub> emissions from existing industrial boilers. Table 9.3 summarizes the type of NO<sub>x</sub> control, percent NO<sub>x</sub> removal expected, and cost-effectiveness for oil, gas- and coal-fired industrial boilers in the NESCAUM area (retrofit situations).

**Table 9.3** Cost Estimates of NO<sub>x</sub> Control for Industrial Boilers (NESCAUM 2000)

Boiler Type, Size & Fuel Fired	Type of NO <sub>x</sub> Control	Percent NO <sub>x</sub> Control	Cost-Effectiveness, \$/ton NO <sub>x</sub> removed
Oil- & Gas-Fired Industrial Boilers	LNB		<\$2,000
	Gas Reburn	>50	<\$2,000
	Gas Reburn + SNCR	>60	<\$2,000
Coal-Fired Industrial Boiler	LNB	30	<\$2,000
	SNCR	35	\$1,300 to \$1,800
	SCR	90	\$2,000

## 9.3 FPI Cost Estimates for Industrial Boiler NO<sub>x</sub> Control

Table 9.4 was compiled from studies done by pulp and paper companies, and lists the type of NO<sub>x</sub> control, percent NO<sub>x</sub> removal expected, and cost-effectiveness for various boilers at several mills. The date for each analysis is shown in the first column. All the situations except that for Mill F (greenfield mill) correspond to retrofit applications.

### 9.3.1 Detailed NO<sub>x</sub> Estimates for Mill H Pulverized Coal-Fired Boiler

In October of 2001, Mill H developed detailed cost estimates for various NO<sub>x</sub> reduction technologies potentially applicable to its 360 MM Btu/hr pulverized coal-fired boiler. Table 10.1 provides a summary of costs for this pulverized coal-fired boiler for four different NO<sub>x</sub> control options considered [Option 1: Low NO<sub>x</sub> Burners + Overfire Air + NO<sub>x</sub> Monitor; Option 2: Low NO<sub>x</sub> Burners + Overfire Air + Urea System (SNCR) + NO<sub>x</sub> Monitor; Option 3: Ammonia Addition + SCR Catalyst + NO<sub>x</sub> Monitor; and Option 4: Low NO<sub>x</sub> Burners + Overfire Air + Ammonia Addition + SCR Catalyst + NO<sub>x</sub> Monitor]. The summary costs include the annualized capital cost, annual operating and maintenance cost, and total annualized cost. The details of the cost analysis for each NO<sub>x</sub> control option are included in Appendix E.

## 9.4 Comparison of Cost Estimates

It is clear from comparing the mill-generated and EPA-generated cost estimates that the actual costs for installing and operating most NO<sub>x</sub> control technologies on FPI boilers will be boiler-specific. The costs can easily exceed the cost-effectiveness threshold of \$2,000/ton NO<sub>x</sub> removed, a figure EPA believes is reasonable for retrofit NO<sub>x</sub> controls in ozone nonattainment areas. In addition to the typical costs associated with the nature of the boiler whose emissions are to be controlled, other factors would also appear to cause the cost-effectiveness estimates to become significantly higher than \$2,000/ton NO<sub>x</sub> removed, principal among them being the extent of NO<sub>x</sub> control desired from the baseline level and the cost of installation of each boiler.

**Table 9.4** Cost Estimates of NO<sub>x</sub> Control in Forest Products Industry Boilers

Boiler Type, Size & Fuel Fired	Type of NO <sub>x</sub> Control	Percent NO <sub>x</sub> Control	Cost-Effectiveness, \$/ton NO <sub>x</sub> removed
Mill A (July 1994) Baseline = 0.4 lb/MMBtu; coal-fired, traveling grate, 225 KPPH	FBC (new)	62.5	\$11,244
	SNCR	30.0	\$1,041
	OFA	10.0	\$2,300
	FGR	5.0	\$4,600
Mill B (Oct. 1994) Baseline = 0.37 lb/MMBtu; oil-fired, 855 MM Btu/hr	Fuel Switching	45.0	\$20,158
	FGR	5.0	\$5,840
	LNB	5.0	\$3,239
	LNB + OFA	25.0	\$2,023
	LNB + OFA + FGR	32.0	\$2,476
Mill C1 (Feb. 1996) Coal, PC - 500 MM Btu/hr	LNB	30.0	\$3,286
	SNCR	50.0	\$4,826
	SCR	80.0	\$6,755
Mill C2 (Feb. 1996) Gas - 150 MM Btu/hr	LNB	40.0	\$3,422
	LNB + FGR	60.0	\$3,666
	SNCR	50.0	\$6,766
	SCR	90.0	\$5,563
Mill D (Jan. 1996) Sludge, FBC, 90 MMBtu/hr	SNCR	--	\$3,400
Mill E (Dec. 1996) Baseline - 0.25 lb/MMBtu; wood-fired boiler, stoker	SNCR	40.0	\$3,400
Mill F1 (March 1997) <sup>a</sup> Oil/Gas, Package Boiler, 365 MM Btu/hr, baseline = 0.10 lb/MMBtu	O/R <sup>b</sup>	90.0	\$8,580
	SCR	75.0	\$6,276

(Continued on next page. See notes at end of table.)

**Table 9.4** Continued

Boiler Type, Size & Fuel Fired	Type of NO <sub>x</sub> Control	Percent NO <sub>x</sub> Control	Cost-Effectiveness, \$/ton NO <sub>x</sub> removed
Mill F2 (March 1997) <sup>a</sup>	O/R <sup>b</sup>	90.0	\$7,142
Oil/Gas, Power Boiler, 781 MM Btu/hr, baseline = 0.10 lb/MMBtu	SCR	75.0	\$5,816
Mill G1 (June 1998) Solid Fuels <sup>c</sup>	Staged Comb/LNB/GR <sup>d</sup>	5 to 30	\$1,000 to \$2,500
Mill G2 (June 1998) Oil/Gas/low fuel bound N	FGR/LNB	30 to 80	\$1,000 to \$3,000
Mill G3 (June 1998) All Fuels (solid, liquid, gas)	SNCR SNCR/Hybrid <sup>e</sup> SCR O/R <sup>2</sup>	33 to 50 50 to 85 90.0 90.0	>\$1,700 \$3,000 \$6,000 to \$7,500 \$7,500 to \$9,000
Mill H (Oct. 2001) <sup>f</sup> Baseline – 0.83 lb/MMBtu – Coal, PC – 360 MMBtu/hr	LNB + OFA <sup>g</sup> LNB + OFA + SNCR <sup>g</sup> NH <sub>3</sub> Addition + SCR <sup>g</sup> LNB/OFA/NH <sub>3</sub> SCR <sup>g</sup>	30.0 60.0 60.0 85.0	\$1,989 (\$4,746 <sup>h</sup> ) \$1,645 (\$3,925 <sup>h</sup> ) \$2,440 (\$5,821 <sup>h</sup> ) \$2,342 (\$5,588 <sup>h</sup> )

<sup>a</sup> greenfield mill, never built; <sup>b</sup>O/R=Oxidation/Reduction Scrubbing; <sup>c</sup>stokers: wood, coal, TDF; burners: oil; pulverized coal; fuels w/high fuel-bound N; <sup>d</sup>GR=gas reburn; <sup>e</sup>urea injection followed by small catalyst; <sup>f</sup>details provided in Appendix E; <sup>g</sup>including NO<sub>x</sub> monitor (LNB & OFA total capital cost=\$2,910,934; NO<sub>x</sub> monitor & flow monitor total capital cost=\$628,878; SNCR total capital cost=\$1,468,719; SCR total capital cost=\$5,348,505); <sup>h</sup>if based on ozone season only, May 1–Sept. 30

**Table 9.5** Summary of Estimated Costs and NO<sub>x</sub> Control Options for Mill H Pulverized Coal-Fired Boiler

Capital Amount Total Invested <sup>a</sup>	Annualized Capital Cost <sup>b</sup>	Annual Operating & Maintenance Cost <sup>c</sup>	Total Annualized Cost	Estimated Percent NO <sub>x</sub> Removal	Annual NO <sub>x</sub> Reduction (tons)	Annualized Cost (\$/ Ton of NO <sub>x</sub> Reduction	Annualized Cost (\$/ Ton of NO <sub>x</sub> Reduction <sup>d</sup>	Capital Cost (\$)/Ton for NO <sub>x</sub> Reduction <sup>d</sup>
Option 1: 3,500,000	569,450	215,000	784,450	30%	395	1,989	4,746 <sup>d</sup>	21,174 <sup>d</sup>
Option 2: 4,900,000	797,230	500,300	1,297,530	60%	789	1,645	3,925 <sup>d</sup>	14,822 <sup>d</sup>
Option 3: 5,977,000	972,458	954,350	1,926,808	60%	789	2,440	5,821 <sup>d</sup>	18,057 <sup>d</sup>
Option 4: 8,900,000	1,448,030	1,169,175	2,617,205	85%	1,118	2,342	5,588 <sup>d</sup>	19,003 <sup>d</sup>

Boiler NO<sub>x</sub> Control Options (see details in Appendix C)

Option 1: Low NO<sub>x</sub> Burners + Overfire Air + NO<sub>x</sub> Monitor; Option 2: Low NO<sub>x</sub> Burners + Overfire Air + Urea System (SNCR) + NO<sub>x</sub> Monitor  
 Option 3: Ammonia Addition + SCR Catalyst + NO<sub>x</sub> Monitor; Option 4: Low NO<sub>x</sub> Burners + Overfire Air + Ammonia Addition + SCR Catalyst + NO<sub>x</sub> Monitor

<sup>a</sup>Incorporates \$600,000 of capital for NO<sub>x</sub> monitor as boiler is not subject to Subpart D (see Tables 8 to 11 for detailed cost summary)

<sup>b</sup>Annualized Capital Recovery Factor of 0.1627 (at 10% interest) calculated using EPA-OAQPS Costing Manual EPA-453/R95

<sup>c</sup>Using the following estimated annual operating cost factors:

Monitor: \$40,000/year for consultants, certification, testing, cal gas (does not include maintenance)

Services: \$50,000/year for service based on a southeastern mill's NALCO SNCR system

Maintenance: 5% of capital investment (Includes operating, maintenance, and supervisory labor, and power, materials, taxes, and misc.)

Urea: \$500/ton NO<sub>x</sub> removed (\$250/ton of 50% urea delivered and used)

Catalyst: \$800,000 replacement cost every 2 years

<sup>d</sup>Assuming control applied during ozone season only (153 days/year; May 1 - September 30);

Operating Assumptions

(1) Riley Boiler operates at 360 MMBtu/hr burning pulverized coal only; (2) 2000 Coal shipments averaged 13,191 Btu/lb; (3) Average tons of coal burned per hour = 13.65; (4) 2000 MAERS emission factor for NO<sub>x</sub> equaled 22 lbs NO<sub>x</sub>/ton coal (0.8339 lbs NO<sub>x</sub>/MMBtu); (5) Average NO<sub>x</sub> generation by Riley Boiler = 300.3 lbs./hr; (6) Current emissions of NO<sub>x</sub> from the Riley are about 300.3 lbs./hr, 3.6 Tons/day, and 1,315.3 tons/yr

## 10.0 SUMMARY

There is growing regulatory pressure for NO<sub>x</sub> emission reductions, particularly in and near ozone nonattainment areas. Although utility boilers have been the major target for these reductions, industrial boilers are under increasing scrutiny. As a result, NO<sub>x</sub> control measures are being installed at a rapid pace on both utility and industrial boilers.

NO<sub>x</sub> control measures can be categorized as either combustion modification or flue gas treatment. The applicability of a particular control measure to a given boiler will depend upon the boiler type, design parameters, fuel type, and operating conditions.

In this report, currently available NO<sub>x</sub> control measures are described and their applicability to boilers operated by the forest products industry is discussed. Emerging technologies with potential applicability are also reviewed. Differences between utility and industrial boilers that influence the applicability or effectiveness of certain NO<sub>x</sub> control measures are enumerated. Estimates of the capital and operating costs for NO<sub>x</sub> control measures developed by EPA, NESCAUM, and individual companies are presented.

Relative to combustion modifications, the following observations may be made.

- Combustion modifications such as low-NO<sub>x</sub> burners with overfire air and flue gas recirculation work well with oil- and gas-fired boilers.
- For coal-fired boilers, low-NO<sub>x</sub> burners and overfire air have been successfully applied to tangential- and wall-fired units, whereas reburning is the only current option for cyclone boilers. Among emerging technologies worth consideration are the gas reburn technology (when gas is available), the low temperature oxidation technique using ozone injection, and layered technologies such as LNB with OFA combined with SNCR.

Relative to flue gas treatment, the following observations may be made.

- Considering reasonably available and proven NO<sub>x</sub> control technologies applicable to solid fuel-fired industrial boilers, only SNCR and SCR would be deemed applicable when control efficiencies exceeding about 40% are desired.
- Outstanding issues for applying SNCR and SCR technologies to boilers with swinging loads remain, especially with respect to ammonia slip, and reliable removal efficiencies.
- Base-loaded oil-, coal- and gas-fired boilers can perhaps be controlled by SNCR or SCR technologies, but site-specific factors must be considered.
- The use of SCR for biomass boilers or combination boilers firing biomass of all configurations, even when base-loaded, needs further investigation since the ash concentrations in the uncontrolled flue gas are quite high and the wood ash is known to be rich in alkali metals that could potential act as catalyst poisons.
- SNCR for stoker-type biomass boilers or combination boilers firing biomass, even when base-loaded, also needs to be further investigated since insufficient dispersion of the ammonia or urea injected could lead to significant ammonia slip or low control efficiencies.
- The performance of SNCR and SCR on swing-loaded industrial boilers has not been demonstrated to deliver consistently high levels of NO<sub>x</sub> reduction efficiencies.

The most cost-effective strategy for installing NO<sub>x</sub> control on an industrial boiler could involve the following steps (in succession) for higher levels of NO<sub>x</sub> control.

- Step 1 – Fine-tune the boiler (e.g., burner modification or replacement, process modification and/or energy efficiency improvements).
- Step 2 – Improve or replace the convective section to preheat process fluid, improve heater's efficiency and decrease firing rate.
- Step 3 – Install low NO<sub>x</sub> and/or ultra low NO<sub>x</sub> burners.
- Step 4 – Investigate other combustion modifications such as OFA, FGR and NO<sub>x</sub> tempering.
- Step 5 – Investigate use of SNCR.
- Step 6 – Investigate use of one of the emerging NO<sub>x</sub> control technologies such as gas reburn and catalytic or ozone oxidation/scrubbing.
- Step 7 – For boilers with relatively clean flue gases (gas-, oil-, or coal-fired) that also have access to the required temperature windows without severe energy penalty, investigate installing SCR.

Relative to NO<sub>x</sub> control costs, the following observations may be made.

- Cost-effectiveness estimates vary considerably from one application to another, depending on factors such as baseline and final NO<sub>x</sub> emission levels, specific site installation costs, age and condition of the boiler, type of boiler, fuel types, and capacity utilization.
- Estimates developed by individual mills showed NO<sub>x</sub> control cost-effectiveness for mill boilers ranged from \$2,000 to over \$6,000 per ton NO<sub>x</sub> removed. The estimates generally exceeded generic estimates prepared by EPA and NESCAUM for similar control measures.

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## APPENDIX A

### THE 0.2 lb NO<sub>x</sub>/10<sup>6</sup> Btu EMISSION STANDARD FOR INDUSTRIAL BOILERS – AF&PA PETITION CHALLENGING AND EPA LEGAL BRIEF DEFENDING THIS STANDARD AND NCASI COMMENTS ON EPA'S LEGAL BRIEF

In November of 1998, AF&PA, along with several other organizations, including the Council of Industrial Boilers (CIBO), submitted a petition to the DC Circuit Court challenging the revised Subpart Db standards of performance for NO<sub>x</sub> applicable to fossil-fuel fired steam-generating units (“boilers”) promulgated by EPA on September 16, 1998. The petition claimed EPA did not consider adequately the feasibility of installing SCR on coal-fired industrial boilers (or coal/wood and coal/oil boilers) which have different characteristics than utility boilers, such as swinging loads. This petition highlighted the following characteristics pertinent to pulp and paper industry boilers that differentiate them from utility boilers, thereby calling the applicability of a uniform technology-based NO<sub>x</sub> standard into question:

- **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO<sub>x</sub> control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO<sub>x</sub> reduction to fluctuate, making it more difficult to know where to inject the reactants.
- **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window for SCR (550 to 750°F), the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly. Downstream of the PM control device, the temperature is too low for the catalyst to be effective.
- **Burning of Sulfur-Containing Gases** - Many kraft mills use their boilers to combust pulp mill gases containing reduced sulfur compounds. This process may constrain combustion patterns in that it requires high temperatures to be maintained to ensure complete oxidation.
- **Adverse Trade-Offs** - There are very few NO<sub>x</sub> reduction options available for most large non-utility combustion sources, but even these options (e.g., low NO<sub>x</sub> burners, overfire air, and flue gas recirculation systems) often have adverse trade-offs.
- **Unproven Technologies for High Levels of NO<sub>x</sub> Control** - Even these options likely would not achieve the levels of NO<sub>x</sub> reduction outlined in any of EPA's ozone transport rule makings, including the Subpart Db revisions. The 60% reductions proposed as part of the Section 126 rulemaking likely would require the use of SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.
- **SCRs Unproven for Biomass Applications** – Many of the FPI boilers are fired to a large degree by biomass. SCRs are not a proven NO<sub>x</sub> reduction technology for biomass applications. There is test evidence of catalyst poisoning in sludge-burning applications and

accelerated deterioration in bark-burning applications. Furthermore, carryover of burning embers from the furnace to the desired temperature zone for SCRs is expected in varying degrees unless the catalyst is installed after a “hot” dust collector.

- **Space Limitations For Installing SCRs** - SCRs and the associated reagent systems require considerable space, which would present problems for many pulp and paper mill applications.
- **Lack of Guarantee for SCRs on FPI Boilers** – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in the EPA proposal.
- **EPA Claims of Transferability of SCR Experience on One Boiler Type to Other Boiler Types** – Industry experience conflicts with this, both on a technical basis and on a cost basis.

On July 30, 1999 EPA submitted a legal brief to the DC court outlining its arguments why certain consolidated petitions challenging the revised Subpart Db standards of performance for NO<sub>x</sub> applicable to fossil-fuel fired steam-generating units (“boilers”) promulgated by EPA on September 16, 1998 (viz., 0.2 lb NO<sub>x</sub> /10<sup>6</sup> Btu for utility and industrial boilers firing more than 10% gas, coal, or oil on an annual basis) should be denied (USEPA 1999). According to EPA, the petitions addressed three main issues:

1. whether in revising the standards of performance for NO<sub>x</sub> emissions applicable to new boilers, EPA properly chose selective catalytic reduction in combination with combustion controls as the best system of emission reduction, taking into account environmental impacts, costs and energy requirements
2. whether EPA reasonably established uniform emission standards for newly constructed boilers based on the record before it
3. whether EPA properly assigned a 50% credit for the steam exported from cogeneration units for purposes of determining compliance with the revised output-based standard for new utility boilers

In its brief, EPA mentioned it chose “selective catalytic reduction in combination with combustion control technologies as the best system of emission reduction because those technologies could obtain significant NO<sub>x</sub> reductions at reasonable costs with minimal energy requirements.” The revised limit for coal-fired industrial boilers was 0.20 lb/MMBtu heat input, 30-day rolling average. The brief contained the following points relevant to NO<sub>x</sub> emissions control.

- For industrial boilers, data on SCR were available for gas-fired units only.
- Results of SCR coal-fired utility boiler data analyses were used to assess appropriateness of SCR for industrial boilers.
- EPA considered similarities and differences between utility and industrial boilers.
- EPA obtained cost data from utility questionnaires, vendor information, and published literature and combined these with performance data and theoretical constructs of 38 utility and 22 industrial boilers to arrive at control costs.
- For a boiler operating at 65% capacity, average cost-effectiveness for SCR was about \$1,500 and \$2,000 per ton NO<sub>x</sub> removed for utility and industrial boilers, respectively, over the cost required to meet the regulatory baseline.

- Since combustion controls prevent NO<sub>x</sub> formation during combustion, their effectiveness depends, in part, on the fuel used (e.g., the nitrogen content of the fuel) and the boiler design.
- The effectiveness of flue gas technologies, like SCR, however, does not depend on these factors - they are applied after the combustion phase and destroy NO<sub>x</sub> regardless of how it was formed.
- To avoid plugging and corrosion of catalyst during use of SCR on high S coal applications, vendors have modified catalyst composition, including pore size; also, they have reduced the temperature range for the NO<sub>x</sub> chemical reduction in new catalysts.
- Poisoning of SCR catalysts by alkaline metals—poisoning caused by alkalis in water soluble form—most alkaline metals in coal-fired flue gas are not water soluble.
- Alkaline metals in oil-fired boiler emissions are water soluble—thus greater poisoning potential—Mg (fuel oil additive) and Na (sea water contamination).
- EPA recognized differences between industrial and utility boilers and focused extensively on the one main difference viz., more fluctuating loads.
- EPA evaluated CEM data on two utility boilers with cycling loads—32 to 100% and 28 to 84%—0.15 lb/MMBtu met on a 30-day rolling average.
- Issue of overcoming effect of flue gas temperatures while operating at low loads can be addressed by including an economizer bypass duct.
- Other issues arising from operating at low loads such as lower gas flow rates and catalyst poisoning were discounted by EPA.
- EPA claimed “Because SCR responds to NO<sub>x</sub> levels in the flue gas, adding wood should not affect results, particularly given that coal represents the worst case scenario in terms of NO emissions.”
- Wood-fired boilers using SNCR, which operates similarly to SCR, can achieve limits of 0.06 to 0.07 lb/MMBtu, far below the revised NSPS limits, at reasonable costs.
- EPA’s regulations do not require use of specific fuels or technologies—not favoring natural gas—fluidized bed units using combustion controls alone, industrial boilers using SNCR, or gas reburn alone can achieve the limit.

NCASI performed a technical review for AF&PA of the July 30, 1999 legal brief submitted by EPA to the DC court in which it included the following comments.

- EPA cites two domestic gas-fired boilers with SCR with <0.01 lb NO<sub>x</sub> /10<sup>6</sup> Btu. If these were base-loaded, gas-fired boilers equipped with SCR, it is easy to understand how the flue gases could be controlled for NO<sub>x</sub> to such low levels; however, it is unclear whether these levels could be achieved for swing-loaded boilers. Also, since no emissions data were available for the two foreign coal-fired boilers, it is not clear why these were identified.
- EPA’s assertion that utility and industrial forest products industry boilers burn the same fuels is untrue. Also, EPA states “boiler type is irrelevant for SCR because the technology is applied downstream of the combustion process.” This is correct except, as shown later, the type of boiler fuels could impact the particulate and/or SO<sub>2</sub> loading in the gases entering the SCR system, which may have an impact.

- EPA cites data from “two utility boilers with cycling loads analogous to industrial boilers.” How was this determination of *analogous* made? For example, were these cycling on a day-to-day basis or more slowly over a 30-day period?
- While operating at low loads, the lowered flue gas temperature that results is no doubt the most important factor that could affect SCR performance. EPA recommends “adding an economizer bypass duct.” First, this recommendation is not a “catalyst design” as mentioned, but rather a design change of the ductwork. SCR requires a certain fixed temperature window before the flue gases enter the catalyst section. Bypassing the economizer section will no doubt raise the gas temperature, but this rise will depend on the boiler load at any given time. Does EPA have data to show that achieving the desired temperature range before the catalyst section can be met at various boiler loads by just bypassing the economizer section?
- On page 45, EPA states “Because SCR responds to NO<sub>x</sub> levels in the flue gas, 63 Fed. Reg. 49, 444/3, adding wood, as Petitioners suggest, should not affect the results, particularly given that coal represents the worst case scenario in terms of NO<sub>x</sub> emissions.” There is, however, a major difference between wood- and coal-fired boilers. EPA’s AP-42 document gives an uncontrolled particulate matter emission factor for pulverized, bituminous coal, dry bottom boiler operations of 10 lb/ton or about 0.38 lb/10<sup>6</sup> Btu. The same AP-42 document gives an uncontrolled PM emission factor for bark firing in a spreader-stoker of 48 lb/ton or about 5.33 lb/10<sup>6</sup> Btu, i.e., about a 14 times higher particulate loading on a heat input basis is expected from wood residue-firing than coal-firing. It is not clear EPA has considered the impact upon SCR performance from increased PM loading in combination bark/coal boilers. Note that the use of SNCR is likely not affected by PM loading.
- It is not clear whether the 0.06 to 0.07 lb NO<sub>x</sub>/10<sup>6</sup> Btu quoted as having been achieved by wood-fired boilers with SNCR are for base-loaded or swing-loaded wood-fired units.

## APPENDIX B

### NEW SOURCE PERFORMANCE STANDARDS, SUBPARTS Da AND Db – SUMMARY OF PUBLIC COMMENTS AND EPA RESPONSES

EPA summarized the public comments it received with respect to its proposed amendments on July 9, 1997 to subparts Da and Db of 40 CFR Part 60 and the responses to such comments in September of 1998 (USEPA 1998d). Several comments pertinent to FPI boilers and EPA responses to such comments are summarized below.

#### a) **Selective Catalytic Reduction as Best Demonstrated Technology**

##### *Comments on coal-fired industrial boilers*

- SCR is not the best demonstrated technology for coal-fired industrial boilers.
- EPA should consider the potential problems associated with SCR, including costs, catalyst poisoning, and oil ash coating catalyst.
- Deactivation of catalyst from alkali sulfates and excess SO<sub>3</sub> in the flue gas.

##### *Comments on appropriateness at pulp and paper mills*

- SCR not appropriate for combination boilers at pulp and paper mills
- Boilers subject to wide, sudden changes in load that complicate use of SCR
- Other problems – high particulate loadings, sulfur poisoning, difficulty in maintaining temperatures to minimize NO<sub>x</sub> and HAP generation

##### *Comments on oil-fired boilers*

- SCR is not the best demonstrated technology for oil-fired industrial boilers.
- Annual averaging period preferred if 0.20 lb/10<sup>6</sup> Btu is set as standard.

##### *EPA Response*

- Additional U.S. experience - EPA obtained new data from three U.S. utility boilers with SCRs that suggested all three could meet the input-based NO<sub>x</sub> standard of 0.15 lb/MM Btu and output-based standard of 1.6 lb/MWh on a 30-day rolling average (one if facility “improves” SCR performance).
- 30-day averaging period accommodates fluctuations in performance due to changing loads - Data from two U.S. utilities showed that SCR can meet the proposed standard over a 30-day averaging period under cycling conditions (one cycled from 32 to 100% load, the second from 28 to 84%).
- Expected temperature range at economizer exit is factored into selection of SCR catalyst formulation.
- In cases of low load with low gas velocity to keep ash in suspension, an ash hopper can be added to divert the ash from reactor and catalyst surface.

- An economizer bypass can be added to avoid low boiler exit temperatures at low loads.
- Developments in catalyst technology minimize the impact of poisoning.
- A 1997 study identified 212 worldwide SCR installations on coal-fired units covering different types of boilers subject to varying operating conditions and firing a variety of coals.
- Issues such as burning high sulfur coals, catalyst poisoning, SCR use in high dust vs. low dust environments, etc. are more cost-based issues dealing with catalyst life.

**b) Selective Non-Catalytic Reduction**

*Comments on Fluidized Bed Combustion Boilers (FBCs)*

- SNCR not demonstrated on circulating FBCs which have inherently low combustion temperatures - three of five CFBCs that use SNCR stated SNCR did not work when units were operated at less than maximum capacity.

*EPA Response*

- Subpart Db background information document (BID) states that flue gas temperatures exiting the furnace range from  $2,200 \pm 200^\circ\text{F}$  at full load to  $1,900 \pm 125^\circ\text{F}$  at half load.
- Addition of hydrogen or other hydrocarbon reducing agent while injecting  $\text{NH}_3$  or urea lowers effective  $\text{NO}_x$  reduction temperature range.

**c) Control Technology Costs**

*Comments on Estimated Costs Being Too Low*

- EPA cost estimates for SCR are much too low since they were extrapolated from an earlier study that focused on retrofit costs for existing plants, and did not consider site layout, with boiler conditions not typical of new units. EPA estimates are only 65% of values estimated in a recent EPA/DOE/EPRI technical conference.
- SCR systems require more energy to operate due to a pressure drop across the catalyst bed.
- Costs associated with fouling of air heater surfaces by ammonium salts, and waste disposal costs for the spent catalyst need to be considered.
- Additional costs associated with (a) lower catalyst life than 5 years due to catalyst poisoning, (b) disposal of ash with higher nitrogen content, (c) plugging of air heaters by ammonium bisulfate and fouling of catalyst by calcium and ammonium salts, (d) storing large quantities of ammonia, (e) requiring open space for the catalyst bed, and (f) handling and disposal of spent ammonia catalyst were not considered.
- Unplanned shutdown due to control device malfunction for utility boilers can be managed differently than for industrial boilers that need the steam for the manufacturing operation. A considerable economic penalty follows a shutdown in the case of the latter.
- Cost-effectiveness values for coal units using SCR are calculated using a baseline  $\text{NO}_x$  emission rate of 0.45 lb/MM Btu when low  $\text{NO}_x$  burners can easily meet a 0.30 lb/MM Btu emission rate.

***EPA Response***

- Cost estimates were made using actual baseline emissions from planned, new units in the country and using more recent information obtained by the Acid Rain Division.
- Energy impact of SCR amounts to only about 0.4% of boiler output, which is justified.
- EPA used a three-year catalyst life for coal-fired units; the agency did account for different types of coals, with varying ash contents in the costing analysis; indirect costs from downstream effects from SCR have been included; additional storage costs for ammonia were considered in indirect costs for SCR and SNCR; retrofit costs were included in EPA's analysis; spent catalyst costs were also included in indirect costs of SCR.
- In the case of a malfunction, the NSPS provisions do not apply for the period of the malfunction, assuming the source acted to repair the malfunction soon thereafter.
- Model plants used a higher emission rate (0.45 lb/MM Btu), but the impacts analysis used emission rates based on projected permit limits, which are lower.

***Comments on Fuel Switching Costs***

- Natural gas can cost more than twice as much as coal (Btu basis) when purchased on a "curtailment basis."

***EPA Response***

- The proposed standards are written in a "fuel-neutral" format that would allow use of natural gas but would not require it when fuel costs exceed the costs of meeting the standard using alternative means such as the use of SCR.



## APPENDIX C

### RACT/BACT/LAER NO<sub>x</sub> CONTROL OPTIONS FOR BOILERS – INFORMATION SUBMITTED BY FOREST PRODUCTS COMPANIES

#### Mill A - RACT Proposal – July 1994

Two coal-fired spreader stokers – Alternatives for NO<sub>x</sub> Control

- Conversion to Fluidized Bed Combustion – technically feasible, but economically infeasible – estimated cost-effectiveness was about \$11,200/ton NO<sub>x</sub> removed
- SNCR – economically feasible, but unproven technology for the type of boilers – specifically, not proven for stokers over a wide range of load levels on a potentially rapidly varying basis – rejected based on technical grounds
- Modification of Grate and Overfire Air System – small reductions in NO<sub>x</sub> – technically infeasible – control of temperature to ensure effectiveness was found to be beyond the capability of existing technology – costs were too high - \$2,300/ton NO<sub>x</sub> reduction
- FGR – small reduction feasible – technically infeasible – flue gas temperature cannot be controlled for proper combustion at all loads - \$4,600/ton NO<sub>x</sub> reduction

#### Mill B, RACT Proposal – Aug. 1994

Two pulverized coal-fired boilers - separated OFA was considered not technically feasible due to the following reasons:

- insufficient space in the furnace zone to accommodate installation of system
- unknown if boiler wall tubes could be relocated to accommodate the OFA ports
- boiler materials inadequate to accommodate corrosive conditions created in the reduction zone
- risk of flame stability problems and, potentially, the creation of explosive conditions
- adverse effect on boiler energy efficiency from improperly functioning OFA system
- no prior installation of OFA system as retrofit on similar PC boilers

One wood-coal combination boiler (spreader stoker) - FGR was considered not technically feasible due to:

- feasibility and effectiveness of FGR was questionable because of uncontrollable effects associated with the temperature of the flue gas – if gas is too hot, the grate may overheat – if too cold, this may lead to higher PM, CO, and VOC emissions
- PM entrained in recirculated flue gas could cause localized pluggage of grate
- no prior installation of FGR as retrofit on a similar mixed fuel stoker boiler

**Mill C – BACT Analysis – October 1994**

Power boiler, 855 MMBtu/hr (85% from No. 6 fuel oil, rest wood), oil burned through burners, wood burned on grate - NO<sub>x</sub> control technologies considered – LNB, FGR, LNB w/OFA, LNB with OFA and FGR, and fuel switching

LNB - technologically feasible

FGR - technologically feasible, especially in combination with LNB and OFA

OFA - technologically feasible

Staged Combustion – considered technologically infeasible for this boiler

BOOS – not applicable to this boiler since only 6 burners available

Gas Reburning – not applicable, since gas not available

**Mill D – BACT Proposal – January 1997**

Bark Boiler – 622 MMBtu/hr

- FGR - not applied to wood-fired boilers
- Low excess air - generally not applicable to low N, high-moisture fuels that require more excess air to assure flame stability and effective combustion to control formation of CO, VOC, and PM emissions
- SCR
  - Not demonstrated on wood solid fuel boilers
  - Use of solid fuels can result in catalyst contamination even with efficient PM control system
  - High moisture levels in exhaust air would result in inefficient SCR operation
  - Exhaust gases need to be reheated by at least 150°F, representing about 40 MMBtu/hr or about 6.5% of the boiler heat rate
- SNCR
  - technically feasible
  - economic analysis results in a cost-effectiveness of \$3,400/ton NO<sub>x</sub> removed - considered cost-prohibitive
  - adverse environmental impacts due to ammonia slip of 10 to 25 ppmv
  - storage of ammonia or urea poses potential for accidental releases
- Enhanced staged combustion with OFA – proposed as BACT – 0.25 lb/MMBtu

### **Mill E – Greenfield Mill - BACT Analysis - March 1997**

#### ***Combination Boiler (wood, sludge, OCC rejects, oil, gas) – 500 MMBtu/hr***

- FGR – technically infeasible – would have to withstand high temperature and particulate matter (PM) loading in the flue gas stream – does not affect fuel NO<sub>x</sub> from wood combustion – not demonstrated on wood waste-fired boilers in pulp and paper industry
- SCR – technically infeasible – catalyst would be poisoned by sulfur compounds present - PM would plug catalyst – reheat necessary if installed downstream of ESP – not demonstrated on wood waste-fired boilers in pulp and paper industry
- SNCR – technically infeasible – temperature would be above the required temperature window, and residence time would be less than the 1 second required
- Oxidation/Reduction Scrubbing – technically infeasible – high moisture content would result in dew point exceeding max temperature required for effective scrubbing
- LNB – applies to fuel oil and gas – selected as BACT – 0.30 lb/MMBtu

#### ***Package Boiler (oil, gas) – 365 MMBtu/hr***

- SNCR – technically infeasible – temperature would be above the required window and residence time would be less than the 1 second required
- Oxidation/Reduction Scrubbing – economically infeasible – \$8,580/ton NO<sub>x</sub> removed
- SCR – economically infeasible – \$6,276/ton NO<sub>x</sub> removed
- LNB & FGR – selected as BACT – 0.10 lb/MMBtu

#### ***Power Boiler (oil, gas) – 781 MMBtu/hr***

- SNCR – technically infeasible – temperature would be above the required window and residence time would be less than the 1 second required
- Oxidation/Reduction Scrubbing – economically infeasible – \$7,142/ton NO<sub>x</sub> removed
- SCR – economically infeasible – \$5,816/ton NO<sub>x</sub> removed
- LNB & FGR – selected as BACT – 0.10 lb/MMBtu

### **BACT/LAER Study of NO<sub>x</sub> Reduction Technologies Study, June 1998**

A consulting company carried out a comprehensive study evaluating several NO<sub>x</sub> reduction technologies for various boilers within a company. The following summarizes their major findings:

- Load Reduction, Excess Air Reduction, Fuel Switching, Fuel Biasing, Air Staging, BOOS, Water Injection - all these techniques are limited to applications where they can be effectively implemented without sacrificing steam load - percent reductions in NO<sub>x</sub> of between 5 and 10% feasible where applicable - cost-effectiveness = < \$500/ton NO<sub>x</sub> reduced
- Staged Combustion/Low NO<sub>x</sub> Burners – feasible on the stoker-fired boilers – cost per ton NO<sub>x</sub> removed = \$1,000 to \$2,500 - percent reduction in NO<sub>x</sub> 5 to 30 (maximum)
- Flue Gas Recirculation/LNB – LNB extends the flame and FGR limits flame temperature more than OFA – up to 30% of flue gases recirculated to dilute amount of O<sub>2</sub> present in

combustion air, thereby delaying combustion process – also stages air within the burner itself to reduce thermal NO<sub>x</sub> – only thermal NO<sub>x</sub> reduced – good for gas and low fuel-bound N oils only - cost per ton NO<sub>x</sub> removed = \$1,000 to \$3,000 - percent reduction in NO<sub>x</sub> 30 to 80 (maximum)

- SNCR – due to the narrow temperature window, applicable to base-loaded boilers only - cost per ton NO<sub>x</sub> removed = >\$1,700 - percent reduction in NO<sub>x</sub> 33 to 50
- SNCR Hybrid Systems – rely on SNCR followed by a small catalyst grid in a lower temperature zone – allows for increasing the temperature window between 1500°F and 1900°F and possibly allows for some variations on boiler load – problems with particulate plugging unless hot-side ESP used – cost per ton NO<sub>x</sub> removed = \$3,000 – percent reduction in NO<sub>x</sub> 50 to 85 (maximum)
- SCR – large catalyst bed – prone to plugging from PM – not suitable for PC units or other solid fuel-firing methods like stokers – equipment size often quite large leading to space limitations for retrofitting – cost per ton NO<sub>x</sub> removed = \$6,000 to \$7,500 – percent reduction in NO<sub>x</sub> up to 90 (maximum)
- Oxidation/Reduction Scrubbing – 2-stage process involves oxidation of NO to NO<sub>2</sub>, using ozone or sodium hypochlorite – 2<sup>nd</sup> stage uses caustic to remove NO<sub>2</sub> – capital intensive, with two scrubbing towers, recirculation tank, pre-mix tank, blowers, heat exchanger, and a waste handling system – limited to maximum temperature of 200°F which makes it very prone to corrosion – cost per ton NO<sub>x</sub> removed = \$7,500 to \$9,000 – percent reduction in NO<sub>x</sub> up to 90 (maximum)

## **APPENDIX D**

### **PERMITTING DECISIONS AND NO<sub>x</sub> EMISSION LIMITS IN EPA'S RACT/BACT/LAER CLEARINGHOUSE DATABASE FOR FPI BOILERS**

#### **RACT/BACT/LAER Clearinghouse**

Table D1 provides a summary of relevant information on FPI boiler NO<sub>x</sub> control extracted from reports in the RACT-BACT-LAER Clearinghouse for the period between 1992 and 2001. This information provides a look at the type of NO<sub>x</sub> limits and pollution prevention/add-on descriptions outlined in these reports. It is clear from the information presented here that during the past decade, LNBs with FGR and LNB were the most commonly recommended NO<sub>x</sub> control technologies for oil/gas and coal-fired boilers, respectively, while good combustion control was typically the only recommendation for wood waste-fired boilers.



**Table D1** Summary of RACT-BACT-LAER Clearinghouse (RBLC) Information on NO<sub>x</sub> for FPI Boilers - 1992 to 2001

Permit Date	Boiler Description	Primary Fuel	MM Btu/hr <sup>1</sup>	NO <sub>x</sub> Limit, lb/10 <sup>6</sup> Btu	Basis	P2/Add-on Description	Process Notes	Company
7/7/93	Coal-fired	Coal	174.7	0.20	BACT -PSD	Good Combustion Control	Not built	Seminole Kraft, Jacksonville, FL
12/21/94	Coal-fired	Coal	214	0.51	RACT	LNB, 30% eff.; some nat. gas	Pulverized Coal	IP, Erie. PA
9/10/96	Power Boiler	Wood/Coal	1600	0.50	BACT -PSD	Contd. Efficient Operation w/LNB	other fuels <sup>4</sup>	Weyerhaeuser, Columbus, MS
1/25/96	Fluidized Bed	Sludge	90	100 ppm	Other	SNCR		Fort James, Green Bay, WI
3/10/97	Combination	Wood/Sludge	494	0.30	BACT	LNB (applies to oil & gas)	Not built	Mid-South Project
12/17/98	Oil-fired	No. 6 Oil	212	0.425	BACT -PSD	LNB w/FGR - 20% control	Stack Tests	Rayonier, Fernandina Bch, FL
3/10/97	Package	No. 2 Oil/ Gas	365	0.10	BACT	LNB w/FGR	Not built	Mid-South Project
3/10/97	Power Boiler	No. 2 Oil/ Gas	781	0.10	BACT	LNB w/FGR	Not built	Mid-South Project
8/15/94	Oil-fired	No. 6 Oil	223	0.30	BACT -PSD			Mead, Stevenson, AL
7/1/93	Oil-fired	No. 2 Oil	240	0.10	BACT -PSD	LNB w/FGR	75% efficiency	Appleton Papers, Combined Lock, WI

**Table D1 (Cont'd).** Summary of RACT-BACT-LAER Clearinghouse (RBLC) Information on NOx for FPI Boilers, etc. – 1992 to 2001

Permit Date	Boiler Description	Primary Fuel	MM Btu/hr <sup>1</sup>	NO <sub>x</sub> Limit, lb/10 <sup>6</sup> Btu	Basis	P2/Add-on Description	Process Notes	Company
7/1/93	Wood-fired	Wood Waste	718	150 ppm <sup>1</sup>	BACT-Other	Good Combustion Control	SNCR rejected <sup>3</sup>	Scott Paper Co., Everett, WA
10/28/94	Wood-fired	Wood Waste	91	0.23	BACT-PSD			Weyerhaeuser, Millport, AL
12/19/94	Wood-fired	Wood Waste	275	0.23	BACT-Other	No Controls		Kes Chateaugay Project, NY
12/21/94	Wood-fired	Bark/Wood	326	0.54	RACT	None		IP, Erie, PA
4/11/95	Wood-fired	Wood Waste	244	0.30	BACT-PSD	None		Georgia Pacific, Gloster, MS
4/17/96	Wood-fired	Bark/Wood	470	0.30	BACT	Good Combustion	also natural gas	Willamette, Bennettsville, SC
1/15/97	Wood-fired	Bark/Wood	622	0.25	BACT-PSD	Combustion Control	other fuels <sup>5</sup>	Mead, Stevenson, AL
12/9/97	Wood-fired	Wood Waste	710	0.25	BACT-PSD	Addition of tertiary air system; 30% η	other fuels <sup>6</sup>	Champion Interntl, Courtland, AL
12/10/97	Wood-fired	Bark	775	0.3	BACT-PSD	LNB for gas/oil burners; 50% eff.	includes sludge	Gulf States, Demopolis, AL
5/13/98	Wood-fired	Wood	245.3	115 ppm <sup>2</sup>	GACT	SNCR	Stack Tests	Sierra Pacific Ind., Redding, CA
10/14/98	Wood-fired	Wood	98	0.3	BACT-PSD	None		Gulf States, Moundville, AL

<sup>1</sup>@ 7%O<sub>2</sub> or about 0.25 lb/MM Btu; <sup>2</sup>@12%CO<sub>2</sub> or about 0.23 lb/MM Btu; <sup>3</sup>NH<sub>3</sub> injection led to visible plume; <sup>4</sup>sludge/gas/ oil/NCG;

<sup>5</sup>NRP/rejects/sludge/NCG; <sup>6</sup>sludge/NRP/TDF/gas/NCG

## APPENDIX E

### DETAILED COST ANALYSIS FOR MILL H COAL-FIRED BOILER

**Table E1** Low NO<sub>x</sub> Burners and Overfire Air Installation Costs at Mill H

	Quantity	Price	Cost
<b>Direct Costs</b>			
<i>Purchased Equipment Costs*</i>			
Low NO <sub>x</sub> Burner Assemblies	4	\$75,000	\$300,000
Replace Burner Management System	1	\$150,000	\$150,000
Replace Forced Draft Fan	1	\$125,000	\$125,000
Replace Forced Draft Fan Motor	1	\$40,000	\$40,000
Lot Windbox Modification Materials	1	\$75,000	\$75,000
Lot OFA Nozzles & Pressure Part Openings	1	\$180,000	\$180,000
Lot New Instrumentation & PLC Controller	1	\$316,000	\$316,000
Lot Misc. Boiler Repairs/Modifications**	1	\$250,000	\$250,000
<i>Sales and Construction Taxes (10%)</i>			\$118,600
<i>Freight (7.5%)</i>			\$88,950
<i>Purchased Equipment Costs, Subtotal</i>			<i>\$1,554,600</i>
 <i>Installation Costs</i>			
Lot Foundation/Demolition	1	\$10,000	\$10,000
Structural, tons	2	\$5,000	\$10,000
Lot Equipment (Incl. port installation)	1	\$500,000	\$500,000
Lot Instrumentation/Electrical	1	\$200,000	\$200,000
<i>Installation Costs, Subtotal</i>			<i>\$720,000</i>
		<b>Total Direct Costs</b>	<b>\$2,274,600</b>
 <b>Indirect Costs</b>			
Engineering, @ 7% of Direct Cost			\$159,222
Construction & Field Expenses			--
Contractor			--
Owner's Cost, @ 5% of Direct Cost			\$113,730
Consultant Services/Testing (Boiler Model)			120,000
Contingency, @ 10% of Direct Cost and Engineering			\$243,382
		<b>Total Indirect Costs</b>	<b>\$636,334</b>
		<b>Total Capital Costs</b>	<b>\$2,910,934</b>

\*operating and maintenance (OM) equipment estimates from Alstom Power

\*\*One of the vendors indicated there may be a problem with flame impingement due to the extended flame from the burner and the small width of the furnace (19'). The cost to install shields or additional refractory can be quantified only after selection of vendor and burner.

**Notes:**

1. Principal vendors are Alstom Power and ABB-Ahlstrom
2. Guarantees:
  - (a) All willing to guarantee greater than 30% reduction (Alstom insistent on 50%—but no bond)
  - (b) Alstom willing to guarantee 50% for base-loaded boiler at 100% MCR
  - (c) All unwilling to guarantee any reduction when boiler operates below 70% MCR

**Table E2** NO<sub>x</sub> Monitor and Flow Monitor Installation Costs at Mill H

	Quantity	Price	Cost
<b>Direct Costs</b>			
<i>Purchased Equipment Costs*</i>			
NO <sub>x</sub> Monitor	1	\$175,000	\$175,000
Flow Monitor	1	\$25,000	\$25,000
Lot Stack Platform Materials	1	\$55,000	\$55,000
<i>Sales and Construction Taxes (10%)</i>			\$25,500
<i>Freight (7.5%)**</i>			\$19,125
<i>Purchased Equipment Costs, Subtotal</i>			<i>\$280,500</i>
<i>Installation Costs</i>			
Lot Foundation/Demolition	0	\$0	\$0
Structural, tons	4	\$5,000	\$20,000
Lot Equipment (Includes Stack Platform)	1	\$55,000	\$55,000
Lot Instrumentation/Electrical*	1	\$120,000	\$120,000
<i>Installation Costs, Subtotal</i>			<i>\$195,000</i>
Total Direct Costs			\$475,500
<b>Indirect Costs</b>			
Engineering, @ 7% of Direct Cost			\$33,285
Construction & Field Expenses***			
Contractor			
Owner's Cost, @ 5% of Direct Cost			23,775
Testing****			20,000
Contingency, @ 15% of Direct Cost and Engineering			\$76,318
Total Indirect Costs			\$153,378
Total Capital Costs			\$628,878

\*includes programming for NO<sub>x</sub> Monitor (\$50,000) and Flow Monitor (\$15,000) from Thermo Environmental Instruments (formerly STI)

\*\*not included in purchased equipment cost

\*\*\*crane rental included in Stack Platform installation costs

\*\*\*\*includes RATA, Compliance test, QA/QC Manual, and cal-gas

**Notes:**

1. Principal vendors are Automated Control Systems and Thermo Environmental.
2. Guarantees: all willing to guarantee satisfactory RATA and 95% uptime
3. Cost for Compliance test and RATA is \$12,000 per Weston - assume 3.5 /year (\$40,000).

**Table E3** SNCR NO<sub>x</sub> Control Installation Costs at Mill H

	Quantity	Price	Cost
<b>Direct Costs</b>			
<i>Purchased Equipment Costs</i>			
One Lot - (Urea) SNCR System	1	\$515,000	\$515,000
Structural Materials (Building)	1	\$65,000	\$65,000
Misc. Materials	1	\$25,000	\$25,000
<i>Sales and Construction Taxes (10%)</i>			\$60,500
<i>Freight*</i>			\$23,000
<i>Purchased Equipment Costs, Subtotal</i>			\$665,500
<i>Installation Costs</i>			
Lot Foundation/Demolition	1	\$105,000	\$105,000
Structural, tons	0	\$5,000	\$0
Lot Equipment Installation	1	\$240,000	\$240,000
Lot Instrumentation/Electrical	1	\$105,000	\$105,000
<i>Installation Costs, Subtotal</i>			\$450,000
		<b>Total Direct Costs</b>	<b>\$1,115,500</b>
<b>Indirect Costs</b>			
Engineering, @ 7% of Direct Cost			\$78,085
Construction & Field Expenses			--
Contractor			--
Owner;s Cost, @ 5% of Direct Cost			\$55,775
Consultant, Boiler Model			\$100,000
Contingency, @ 10% of Direct Cost and Engineering			\$119,359
		<b>Total Indirect Costs</b>	<b>\$353,219</b>
		<b>Total Capital Costs</b>	<b>\$1,468,719</b>

\*Not included in purchased equipment cost

**Notes:**

1. Principal vendors are Nalco and Wheelabrator Fuel Tech
2. Guarantees:
  - (a) all willing to guarantee greater than 30% reduction in addition to LNB & OFA
  - (b) all willing to guarantee >50% for base loaded boiler at 100% MCR
  - (c) all unwilling to guarantee any reduction when boiler operates below 70% MCR
  - (d) none willing to guarantee ammonia slip

**Table E4** SCR NO<sub>x</sub> Control Installation Costs for Mill H

	Quantity	Price	Cost
<b>Direct Costs</b>			
<i>Purchased Equipment Costs*</i>			
One Lot - SCR System	1	\$2,000,000	\$2,000,000
Misc. Materials (Includes CRI-Shell catalyst)	1	\$900,000	\$900,000
<i>Sales and Construction Taxes (10%)</i>			\$290,000
<i>Freight**</i>			\$88,000
<i>Purchased Equipment Costs, Subtotal</i>			<i>\$3,190,000</i>
<i>Installation Costs***</i>			
Lot Foundation/Demolition	1	\$205,000	\$205,000
Structural, tons	55	\$5,000	\$275,000
Lot Equipment Installation	1	\$440,000	\$440,000
Lot Instrumentation/Electrical	1	\$205,000	\$205,000
<i>Installation Costs, Subtotal</i>			<i>\$1,125,000</i>
Total Direct Costs			\$4,315,000
<b>Indirect Costs</b>			
Engineering, @ 7% of Direct Cost			\$302,050
Construction & Field Expenses			54,000
Contractor			--
Owner's Cost, @ 5% of Direct Cost			\$215,750
Contingency, @ 10% of Direct Cost and Engineering			\$461,705
Total Indirect Costs			\$1,033,505
Total Capital Costs			\$5,348,505

\*not included in purchased equipment cost

\*\*Assume that cost for ammonia feed system will be same as estimated for urea feed and complete assembly supplied except building for liquid ammonia feed.

\*\*\*Assume that it is possible to install modular SNR system and duct from ESP and from SCR back to use the existing stack. This project could require stack replacement, and the location could be affected by Boiler MACT which is not included in cost estimate.

**Notes:**

1. Principal vendors are Durr' and Pearlless - Both offer fabricated modular systems that include ammonia feed, fan, ducting, SCR, and complete control systems.
2. Guarantees:
  - (a) All are willing to guarantee greater than 60% reduction, regardless of boiler load, but both recommend LNB and OFA installation for dependable benefit.
  - (b) Both will guarantee <3 ppm ammonia slip with additional (20%) catalyst.