Status Report on NOx

Control Technologies and Cost Effectiveness for Utility Boilers
June 1998

Executive Summary

This effort addressed the technical and cost issues associated with using technologies that may be used to provide the NOx reduction required by the Ozone Transport Commission's (OTC's) September 27, 1994 Memorandum of Understanding (MOU) and the resulting state regulations. To understand the challenges of reducing NOx in the Ozone Transport Region (OTR), an analysis of the composition of utility boiler sources was performed. The results of this analysis are presented in Chapter One. Chapter Two provides a comprehensive technical review of the NOx reduction technologies that are expected to play a significant role in future NOx reductions by utility boilers in the OTR. Chapter Three provides a detailed cost analysis of the technologies of Chapter Two based upon the most up-to-date information. Finally, Chapter Four is a unique section. This final chapter presents fourteen case studies from companies that are users of NOx reduction technology. These case studies were prepared in cooperation with the users of the technology. The experience that these companies had in evaluating, procuring, implementing, and operating these technologies is discussed in depth. Hard data on capital cost, operating and maintenance costs, reliability, and cost effectiveness are presented where available. General experience, including operating problems and lessons learned, is presented as well. This information was incorporated into the cost models of Chapter Three to provide what is believed to be an extremely comprehensive and up-to-date analysis of cost of NOx reduction technology.

S.1 Summary - Chapter One: Inventory of NOx Emissions in the OTR
Throughout the OTR, the majority of utility boiler NOx - about 91% of the total in 1996 - is produced by coal-fired power plants. Figure S-1 is a chart of the 1996 NOx emissions by state and fuel in the OTR. It shows that emissions from coal plants dominate. Emissions from oil/gas-fired plants make up a significant amount of the total NOx generated from boilers in New York and some of the New England states. Nevertheless, emissions from coal plants dominate in many of these states as well. Therefore, understanding the technical and cost issues associated with reducing NOx from these coal-fired facilities is an important objective of this effort. It is important to note that this inventory of NOx emissions does not include emissions from plants in Virginia that are not part of the OTR. Hence, NOx emissions from most of the plants in Virginia are not included here.

According to Fig. S-2, in 1996 the majority of NOx from coal-fired boilers in the OTR was from units that were equipped with Low NOx Burners (LNBs, ~310,000 tons) or were uncontrolled (UNC, ~130,000 tons). Only a small portion of the total NOx was produced by units equipped with Flue Gas Treatment (FGT, ~20,000 tons) or Combustion Controls (CTR, ~20,000 tons). The majority of NOx from oil/gas units (see Fig. S-3) is from uncontrolled units (UNC, 28,000 tons) and, to a lesser extent, from units equipped with Low NOx Burners (LNB, 14,000 tons). It should be noted that many oil/gas units listed as uncontrolled in fact made some burner modifications short of an LNB retrofit. Units equipped with Combustion Controls contributed a relatively small amount (about 6,000 tons).

Since most of the Group 1 boilers in the OTR are equipped with LNBs for the purpose of compliance with Title I (RACT) or Title IV (Acid Rain) requirements, secondary NOx control measures - such as reburning, SNCR or SCR - are likely to provide most of the additional reductions from these units. Nevertheless, because the Group 2 boiler types (cyclone, wet-bottom, cell, and roof fired, in particular) produce a disproportionately high amount of NOx relative to their total generating capacity, significant reductions from Group 2 boilers may be appropriate. NOx reductions from Group 2 boilers are likely to be from application of secondary controls, because primary control options are more limited for these units.

Figure S-1. 1996 OTR Utility Boiler NOx Emissions by State

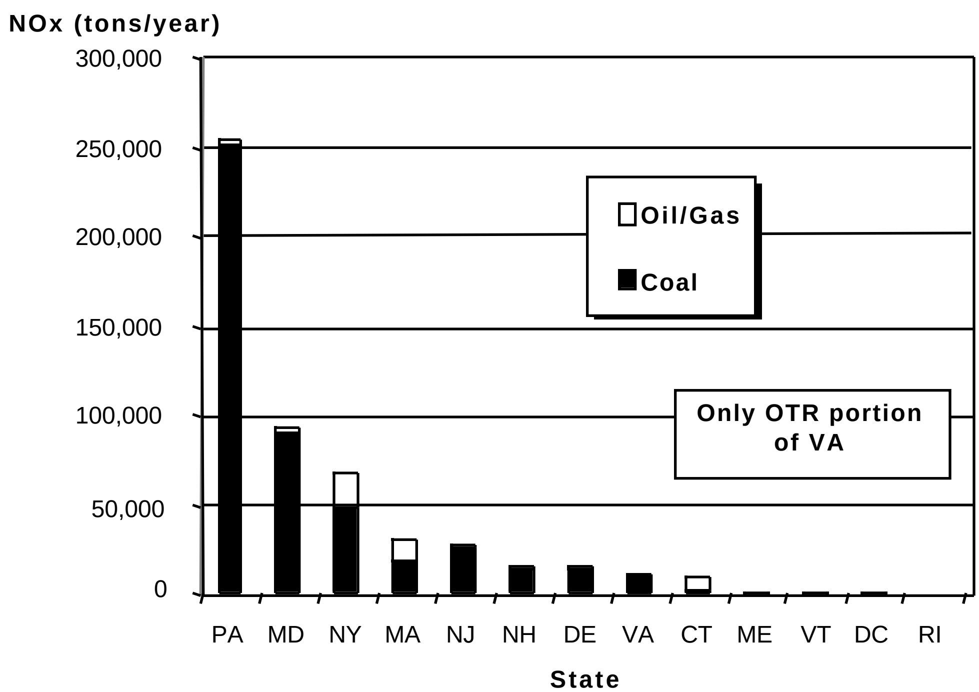


Figure S-2. 1996 OTR Utility Coal-Fired NOx Emissions by Applied Control Technology

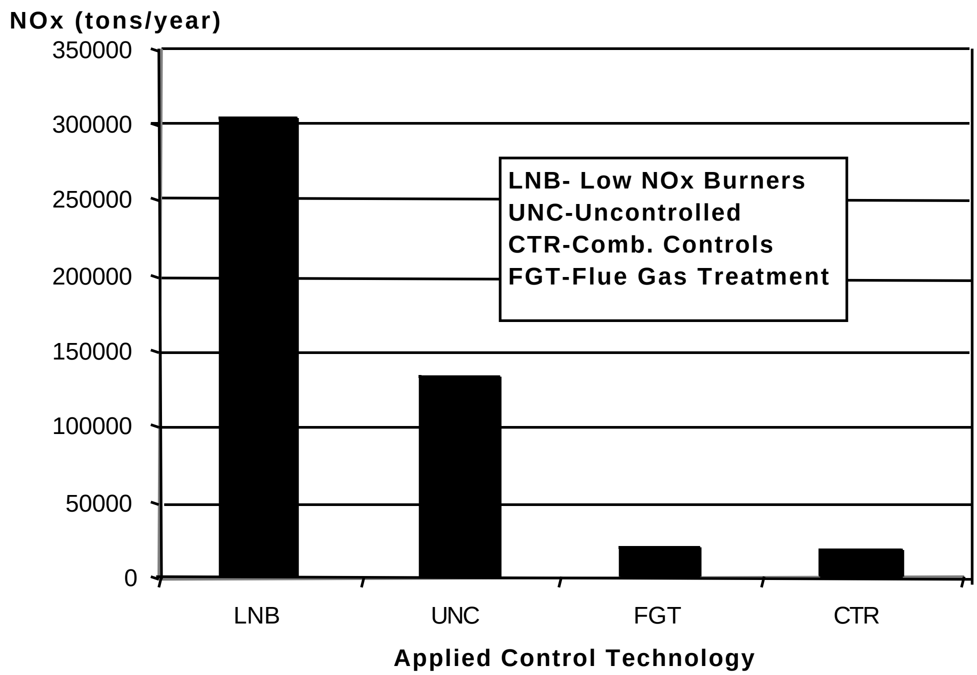
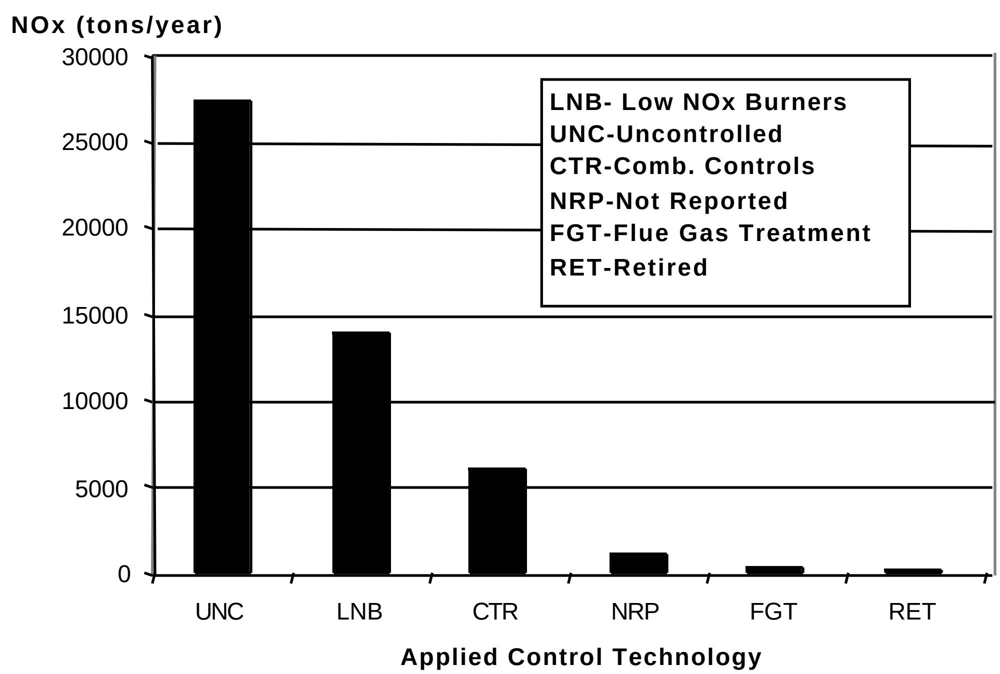


Figure S-3. 1996 OTR Utility Oil/Gas-Fired NOx Emissions by Applied Control Technology



S.2 Summary - Chapter Two: NOx Control Technologies

Thus far, NOx reduction in the OTR has largely been achieved through the application of primary controls - Low NOx Burners (LNBs), Combustion Controls (CTR), and other approaches that reduce the amount of NOx originally formed in the primary combustion zone of the furnace. In fact, the Title IV requirements on Group 1 boilers and RACT were both explicitly formulated with primary controls as a basis of cost. On the other hand, achieving future reductions in the OTR will rely much more heavily on the use of secondary controls - methods of reducing the NOx concentration of the exhaust gas from the primary combustion zone.

At some facilities primary controls were found to be uneconomical or impractical for complying with Title IV (Acid Rain), Title I (RACT) or other state or federal regulations. These facilities chose to retrofit some form of secondary control technology to reduce NOx. Newer facilities have generally been required to comply with more stringent New Source Review NOx requirements (BACT or LAER) and for the most part are gas-fired and equipped with primary and secondary control technologies. New, U.S. pulverized-coal units, although few in number, have all required primary and secondary controls. As a result, over the last few years there has been an increased level of experience in the U.S. with secondary NOx control technologies. This experience was reviewed in this report. It is acknowledged that there is extensive experience with some secondary control technologies overseas. This experience, although not reviewed in detail in this effort, provides a substantial experience base that will be useful for application of NOx controls to U.S. facilities.

The technologies that were reviewed in this report are listed in Table S-1 along with boiler types where they are most applicable. Although Table S-1 breaks down the boiler population into three broad categories, it is acknowledged that there is a wide variety of combustion system types within these broad categories. Not every technology listed under a boiler type category is practical for every boiler of that category. The report briefly reviews the status of primary controls for oil and gas -fired boilers and reviews the use of secondary controls in more detail. It is expected that secondary controls will play an important role in the future reduction of NOx from coal-fired facilities in the OTR. The secondary controls that were reviewed included Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR), Conventional Reburning Technology (Gas and Coal Reburning), Fuel-Lean Gas Reburnô (FLGRô), and combinations of these: hybrid SNCR/SCR, Amine Enhanced Gas Injection (AEGI), Advanced Gas Reburn (AGR) and Reburning + SNCR.

Table S-1. Technologies Reviewed in this Report		
Coal-Fired Boilers		**Oil/Gas**
Group 1	Group 2	all types
Flue Gas Treatment • SNCR • SCR • hybrid SNCR/SCR	Flue Gas Treatment • SNCR • SCR • hybrid SNCR/SCR	Flue Gas Treatment • SNCR • SCR • hybrid SNCR/SCR
Reburning • Gas • AGR, FLGR, AEGI • GR+SNCR	Reburning • Gas • AGR, FLGR, AEGI • GR+SNCR • Coal	• Ultra Low NOx Burners • Combustion Controls & Optimizaton

It should be noted that for the purpose of technical and cost analysis in this report, Group 2 boilers include cyclone, wet bottom, cell, and other slagging combustors. These boiler types comprise the majority of the Group 2 population and they pose similar technical challenges to the use of flue-gas treatment NOx-reduction technology.

There is more commercial experience with SNCR on coal-fired facilities in the U.S. than with SCR or Reburning on U.S. facilities. SNCR is generally capable of moderate levels of NOx reduction. It is expected to take a major role in future reductions of NOx from coal-fired plants in the OTR, either alone or in combination with another primary or secondary control technology. The actual performance achievable with SNCR on a particular facility is determined by the site-specific characteristics of the facility, and NOx reductions on commercial systems have ranged from 15% to over 60% with ammonia slip generally below 5 ppm. A principal advantage of SNCR is its low capital cost relative to most other secondary control approaches, which also makes it very attractive as a seasonal control strategy. Most utility boilers that are equipped with SNCR use urea-based technology (NOxOUT), indicating a general market preference for urea reagent over ammonia. Nevertheless, ammonia can be used as an SNCR reagent, as it is in one commercial utility application.

Natural Gas and oil -fired facilities are, for the most part, expected to find primary controls most effective in reducing NOx. In general, SNCR is not very cost effective on natural gas applications because of the low baseline NOx value, and Natural Gas Reburn will be limited primarily by the design of these boilers - which normally don't have the space in the upper furnace region to accommodate reburning equipment. However, a small number of oil and gas-fired facilities may use SCR for compliance with proposed 2003 NOx emission levels. SCR may be useful at some gas or oil -fired facilities for providing extremely low NOx levels and creating excess NOx reduction credits. This, however, is expected to be economically viable at very few oil and gas facilities because these units are normally used for peaking and reserve that results in extremely low capacity factors.

There have been several successful commercial SCR systems installed on Group 1 and Group 2 boiler types in the U.S. It should be noted that for the purpose of technical and cost analysis in this report, Group 2 boilers include cyclone, wet bottom, cell, and other slagging combustors. These boiler types comprise the majority of the Group 2 population and they pose similar technical challenges to the use of flue-gas treatment NOx-reduction technology. Combined with extensive experience from U.S. demonstration programs and from overseas commercial installations, SCR has the largest utility boiler experience base of any secondary control technology. SCR, which is expected to play a key role in future NOx reductions from coal-fired facilities, was found to be technically viable for all U.S. coal-fired facilities. However, the economic viability of using SCR at any given site can only be determined after a careful analysis is performed. SCR, used in combination with SNCR, may prove to be a cost effective alternative to full SCR for some applications, particularly those facilities that have congested sites and would benefit from a smaller catalyst reactor. SCR might also be used in conjunction with or in lieu of primary controls.

The widespread technical viability of SCR does not mean that it is necessarily the most economical approach for any given facility. There are technical challenges associated with each facility that will make the use of SCR technology somewhat more or less expensive, and this needs to be considered in the context of detailed resource planning. There are other factors of project lifetime, financing options and the future needs for generation capacity that need to be considered as part of this planning. The most economical NOx compliance approach will depend upon many technical, economic and regulatory factors.

Natural Gas Reburn also has a significant amount of experience, especially when demonstration programs are included. Experience at numerous demonstration programs and a few commercial installations has proven that the technology vendors have addressed the major issues of concern. Conventional Gas Reburn is capable of moderate levels of reduction of up to about 60-65%, but typically achieves 50%-60% reduction. It is expected that Natural Gas Reburn will play a significant role in reducing NOx from coal-fired boilers alone or in combination with another technology, such as SNCR. Gas Reburn is especially cost effective on units with high uncontrolled NOx levels. However, conventional Gas Reburn may not prove suitable for all coal-fired facilities because of the need for burn-out air (also referred to as Over Fire Air - OFA) above the reburn zone and the availability of gas. Fuel Lean Gas Reburnô (FLGRô), which does not require burn out air, has been demonstrated to provide about 35%-45% NOx reduction with relatively low natural gas consumption. Natural Gas Reburn is not expected to take a major role in NOx reductions at natural gas and oil fired facilities. These boilers usually have a lower baseline NOx and often cannot provide NOx reductions as cost effectively as coal units. Moreover, experience in California has shown that primary controls are extremely effective for NOx reduction at Oil or Gas facilities.

Gas Reburn technology can be classified as Conventional Gas Reburn and Fuel Lean Gas Reburn (FLGR). FLGR, which uses less natural-gas reburning fuel than Conventional Gas Reburn (4%-7% versus 15%-over 20% heat input from reburn fuel) and does not require the use of burn-out air, produces somewhat lower reductions than Conventional Gas Reburn (typically 35%-45% reduction versus typically 50% to 60% reduction). Gas Reburn may also be operated with injection of amine-based agents with natural gas in order to provide enhanced reduction. Depending upon the method of amine introduction and the use of burn out air (sometimes called OFA), the technology may be Amine Enhanced Gas Injection, Advanced Gas Reburn, or simply Gas Reburn + SNCR. These combinations of reburning with injection of ammonia or urea may offer the potential for higher reductions at low cost, and demonstration programs are in progress to explore the commercial viability of this approach.

Experience at the two facilities where Coal Reburn has been demonstrated suggests that the capital cost exceeds that of SCR for small units (~100MW). Projections for larger units (~500 MW) suggest that Coal Reburn becomes much more economical for large boilers. While demonstration of Coal Reburn has proven its technical viability for applicable units, there is insufficient experience with Coal Reburn technology to generate meaningful cost information or to indicate that it will be practical for more than a few specialized situations. Nevertheless, for those cases where Coal Reburn is practical, it may provide NOx reduction at costs competitive with other technologies.
As mentioned earlier, it is expected that gas or oil fired facilities will, for the large part, utilize primary controls to comply with the state regulations that are expected to be implemented for Phase III of the OTC's MOU. Ultra Low NOx Burners and Combustion Modifications (FGR, etc.) have demonstrated an ability to maintain NOx below 0.15 lb / MMBTU on gas-fired units in California and the Northeast U.S. Combustion optimization software, which can be applied to any boiler or fuel type, has demonstrated an ability to provide some modest reductions; however, the ability of this technology to maintain low NOx operation in a consistent manner is what is most valuable about this technology. Oil-fired facilities that have access to gas may use gas during the control period when gas is less costly. Some gas units with sufficiently high capacity factors for economic operation may utilize SCR to provide very low NOx levels and a supply of surplus NOx reduction credits for other units.

S.3 Summary - Chapter Three: Cost of NOx Control Technologies

The costs of the various NOx control technologies were evaluated on a Constant Dollar basis using a project lifetime of 15 years and real cost of capital rate of 6.55% (nominal rate of 9.75% with inflation at 3%). As will be discussed in Chapter One, the average age of boilers in the OTR is about 30 years with the average age of boilers (on a capacity-weighted average basis) in NESCAUM being 33 years. The median age is even higher because of the many older, smaller units in the Northeast. *Note that some other studies have used an average project lifetime of 20 years to evaluate the costs of NOx control, which was* *appropriate for those studies. However, the unusually high age of boilers in the OTR, especially in the NESCAUM states, makes a shorter lifetime more appropriate for this study.* Cost information was based upon publicly available information and the case study information of Chapter Four. The case studies provided useful information on operating costs for these technologies that does not appear to have been available in the public literature. Cost of controlling NOx was evaluated on the basis of $/ton of NOx removed and $/MWhr. While $/ton of NOx removed is a parameter that is useful to policy-makers as a measure of the cost effectiveness of reducing NOx, $/MWhr is of most interest to operators of electric power plants. Indicating cost in $/MWhr (or mills/KWhr or mills/MWhr) relates cost directly to the unit cost of operations that can be used to determine impact on revenue and on unit profitability. Both measures become important, particularly when considering trading and seasonal controls. With an efficient trading system in place for NOx surplus reduction credits, the cost of control in $/ton becomes a critical parameter because it establishes a market price for NOx reduction. Also, when an efficient trading system is in place, the lowest $/ton option, which may include purchasing credits, is also the lowest $/MW option. Until such a trading system is in place and running efficiently, there will be some imbalances in value and some risk that will need to be considered. In a seasonal control scenario, the cost of NOx control measured in $/ton will be somewhat higher, although the total cost of NOx reduction is lower. On the other hand, in the case of seasonal controls the cost measured in $/MWhr will be less than in the case of annual controls because the total variable operating cost over the year will be lower.

Because facilities have the option of averaging, trading or reducing NOx, some cases were evaluated where initial NOx levels were higher than those typically expected for Group 1 boilers with low NOx burners. This may be surprising for a report on Post-RACT NOx control. However, not every Group 1 boiler in the OTR is equipped with low NOx burners, and some operators may choose another technology for future compliance. Also, there are Group 2 boilers in the OTR that have baselines of over 1.0 lb/MMBTU. It is possible that operators of these facilities may elect to use a technology such as SNCR or Gas Reburn for moderate reductions while over controlling on another unit.

Also, much of the cost analysis was based on boilers of specific sizes: 200 MW for SNCR and Gas Reburn and 330 MW for SCR. SNCR and Gas Reburn are expected to play a greater role in controlling NOx on small boilers and SCR is expected to play a greater role in controlling NOx on larger boilers. Hence, considering different sized units is appropriate. Nevertheless, for the cost-effectiveness information that is provided in the tables of this chapter and in the tables of Chapter Three, this data addresses the full range of boiler sizes encountered in the OTR that are likely to use the particular technology.

Tables S-2a, b, and c, which also appear in Chapter Three, show a summary of approximate control costs for SCR, SNCR and reburning. It is very important to note that the data presented in Tables S-2a, S-2b and S-2c are estimated to be representative for the majority of situations. The following notes and the notes below the tables should be considered when using the tables:

- The ranges shown for SCR costs include the effect of capacity factor variations from 50% to 80% (15% from 65%, about the average for coal boilers in the OTR), as well as the effect of variation in capital costs shown. The lowest costs reflect the highest capacity factor shown with the lowest capital cost. The highest costs reflect the lowest capacity factor with the highest capital cost. For SCR on Gas and Gas/Oil facilities, it is assumed that the catalyst lifetime varies from a low of 32,000 hours to as much as 48,000 hours to address the uncertainties associated with oil operation.

- Since all commercial utility SNCR systems but one are urea-based, the SNCR analysis is based on using urea as the reagent. Furthermore, SNCR is extremely process dependent. A 40% NOx reduction was considered because it is in the range of reduction that is typically possible with this technology. In some cases NOx reduction may be higher or lower. It was assumed that capacity factor equals 0.65 (the average for coal fired boilers in the OTR - SNCR economics have a relatively low sensitivity to capacity factor) and chemical utilization (a measure of how efficiently a unit of reagent reduces NOx) was in the range of 35%-60%, which is typical for about 40% reduction with this technology. For lower reduction, chemical utilization will often be higher, resulting in lower cost.

- Because of the important role baseline, fuel premium and level of NOx reduction play on Gas Reburn economics, the impact of each of these factors is shown in the table. Gas Reburn economics, like SNCR, are less sensitive to variations in capacity factor than other technologies. Also, the costs shown are based upon analysis at the reburn fuel flows of Figure 2-13 and a capacity factor of 0.65. Because of the shape of this curve, the fuel flows at 60% NOx reduction could vary such that cost might vary by as much as about 20%. For 40% NOx reduction, the costs could vary by about ± 10% from those shown.

- The values presented for Coal Reburning technology assume a 500 MW plant with a capital cost of $45/KW, which is DOE's estimate of the capital cost of a 500 MW plant. It should be kept in mind that there is virtually no commercial experience with this technology, and the technology has not been demonstrated on units larger than ~100MW. Demonstration had capital costs in excess of $100/KW. This is expected to drop rapidly with boiler size. Therefore, these costs and application are highly uncertain.

- The seasonal cost analysis values are based upon a 5-month ozone season control period and no operation at all outside of the ozone season.

- The results shown in this table should be regarded as typical values, and representative of facilities that have similar characteristics and circumstances as those included in the analysis. Each facility owner should evaluate his or her facilities individually.

In many cases the cost of NOx control can be reduced through combination of two or more technologies rather than using one for the same overall level of reduction. Hybrid SCR/SNCR is one technology that has been demonstrated at some facilities to provide high levels of NOx reduction at congested sites where a full SCR system may be very expensive. Other technology combinations are possible. Combination of Gas Reburning and SNCR are addressed in Chapter Three. The results of the analysis, shown in Table S-3, demonstrate that these two technologies can be very cost effective when used together. SNCR and/or Gas Reburn can be combined with primary control measures as well to provide highly cost effective control.

Table S-2a. Summary of Approximate Retrofit NOx Control Costs - SCR									
Technology	**Reduction**			**Cap. Cost**	**Capacity Factor**	**Annual Control**		**Seasonal Control**	
	From: lb/MMBTU	**To: lb/MMBTU**	**% Red'n**	**$/KW**	**%**	**$/ton**	**$/MWhr**	**$/ton**	**$/MWhr**
SCR Coal-Grp 1	0.45	0.15	67%	50-70	50-80	825-1,525	1.25-2.30	1,750-3,430	1.10-2.15
SCR Coal-Grp 1	0.45	0.07	85%	70-90	50-80	900-1,550	1.65-2.80	1,890-3,350	1.50-2.65
SCR Coal-Grp 2	1.50	0.35	75%	50-70	50-80	390-560	2.23-3.20	760-1,165	1.80-2.80
SCR Coal-Grp 2	1.50	0.15	90%	70-90	50-80	400-570	2.70-3.85	790-1,200	2.20-3.40
SCR Gas	*0.20*	*0.03*	*85%*	*~35*	*50-80**	*1,200-1,500*	*1.00-1.40*	*2,500-3,800*	*0.90-1.30*
SCR Gas	0.20	0.03	85%	~35	10-20	2,950-5,450	2.50-4.64	6,700-12,750	2.37-4.51

In 1996 only 8 of the 123 oil/gas fired units (~4% of the total capacity) in the OTR had a Capacity Factor (CF) of 50% or more

Notes on Table S-2a:

- For example, a Group 1 boiler that annually controls from 0.45 to 0.15 lb/MMBTU will cost in the range of $50-$70/KW in capital and reduce NOx in the range of $825-$1525/ton and $1.25-$2.30/MWhr, depending upon capacity factor. Greater reduction (85%) can be achieved at a higher cost of about $70-$90/KW in capital, $900-$1550/ton and about $1.65-$2.80/Mwhr.
- The lowest costs reflect the highest capacity factor shown with the lowest capital cost. The highest costs reflect the lowest capacity factor with the highest cost.
- The ranges shown for SCR costs include the effect of capacity factor variations from 50% to 80% and the range of capital costs shown, regardless of MW.
- Group 2 boiler results are based on a unit with fly ash reinjection and arsenic-resistant catalyst with a catalyst replacement period of 14,000 hours. For Group 2 units that do not reinject fly ash, costs should be lower due to longer catalyst replacement periods. For Group 1 boilers, the catalyst replacement period was assumed to be 24,000 hours. With regard to catalyst deterioration, it is assumed that flue gas is applied to the catalyst year round, even when seasonal controls are in place.
- Capital cost of Group 2 boilers equipped with SCR is expected to be somewhat higher than that of similar MW Group 1 boilers. This difference was generally found to be within the ranges shown.
- For SCR on Gas and Gas/Oil facilities, it is assumed that the catalyst lifetime varies from a low of 32,000 hours to as much as 48,000 hours to address the uncertainties associated with oil operation.
- The seasonal cost analysis values are based upon a 5-month ozone season and no ammonia injection outside of the ozone season. Any costs associated with shutting down the SCR during the non-ozone season are not included because it is assumed that the reactor will not be bypassed for this period. If the reactor were to be shut down, there would be savings in catalyst cost that are not reflected in this analysis.
- The results shown in this table should be regarded as typical values, and representative of the majority of facilities - most having similar characteristics and circumstances as those included in the analysis. In practice, each facility should be evaluated individually.
- In 1996 the capacity-weighted average capacity factor of oil and gas fired units in the OTR was 12.5%
- In 1996 the capacity-weighted average capacity factor of coal fired units in the OTR was about ~65%

Table S-2b Summary of Approximate Retrofit NOx Control Costs - SNCR								
Technology	**Reduction (40% - see notes)**		**Capital Cost**	**Chemical Utilization**	**Annual Control**		**Seasonal Control**	
	From: lb/MMBTU	**To: lb/MMBTU**	**$/KW**	**Utilization %**	**$/ton**	**$/MWhr**	**$/ton**	**$/MWhr**
SNCR Coal	0.45	0.27	15	35-60	860-1,160	0.78-1.05	1,370-1,670	0.51-0.63
SNCR Coal	1.00	0.60	15	35-60	620-920	1.24-1.84	845-1,145	0.71-0.95
SNCR Coal	1.50	0.90	15	35-60	550-850	1.66-2.55	705-1,005	0.88-1.25

Notes on Table S-2b:

- The actual level of reduction by SNCR must be determined on a case by case basis. Some facilities will not be able to achieve 40% NOx reduction. Others may be capable of greater reductions by SNCR.
- For example, an SNCR system on a Group 1 boiler might provide 40% reduction from 0.45 to 0.27 lb/MMBTU at a cost of $15/KW in capital, $860-$1160/ton of NOx reduced, and $0.78-1.05/MWhr.
- Costs shown include capital and O&M.
- Capital costs are assumed for a ~200 MW or smaller boiler. $/KW for capital is expected to be lower for larger boilers.
- Since all commercial utility SNCR systems but one are urea-based, the SNCR analysis is based upon using urea as the reagent. Furthermore, SNCR is extremely process dependent; therefore, 40% reduction was considered because it is in the range of reduction that is typically possible with this technology. Chemical utilization was in the range of 0.35-0.60, which is typical for about 40% reduction with this technology. In some cases reduction may be higher or lower. It was assumed that capacity factor equals 0.65 (SNCR economics have a relatively low sensitivity to capacity factor). For lower reduction, utilization will often be higher, resulting in lower cost.
- The seasonal cost analysis values are based upon a 5-month ozone season and no operation outside of the ozone season.
- The results shown in this table should be regarded as typical values, and representative of facilities that have similar characteristics and circumstances as those included in the analysis. Each facility should be evaluated individually by the owner.

Table S-2c. Summary of Approximate Retrofit NOx Control Costs- Reburn							
Technology	Reduction			Annual Control		Seasonal Control	
	From: lb/MMBTU	To: lb/MMBTU	% Red'n	$/ton	$/MWhr	$/ton	$/MWhr
Fuel-Lean Gas Reburn $1.00/MMBTU* $1.50/MMBTU*	1.00	0.60	40%	 489 648	 0.98 1.30	 657 795	 0.55 0.66
Conventional Gas Reburn $1.00/MMBTU* $1.50/MMBTU*	1.00	0.40	60%	 790 1,114	 2.37 3.34	 946 1,255	 1.18 1.57
Fuel Lean Gas Reburn $1.00/MMBTU* $1.50/MMBTU*	0.45	0.27	40%	 1,086 1441	 0.98 1.30	 1,460 1,767	 0.55 0.66
Conventional Gas Reburn $1.00/MMBTU* $1.50/MMBTU*	0.45	0.18	60%	 1,756 2,274	 2.37 3.34	 2,100 2790	 1.18 1.57
Coal Reburn	1.00	0.50	50%	315-485	0.78-1.20	710-1,115	0.75-1.15
Coal Reburn	1.50	0.75	50%	210-320	0.78-1.20	475-745	0.75-1.15

** reburn fuel premium: cost of natural gas minus cost of coal*

Notes on Table S-2c:

- Gas Reburn economics is extremely sensitive to the incremental cost of natural gas over coal. Gas Reburn economics, like SNCR, are less sensitive to variations in capacity factor than other technologies, and a capacity factor of 0.65 is assumed. Also, the costs shown are based upon analysis at the reburn fuel flows of figure 2-13. Because of the shape of this curve, the fuel flows at 60% reduction could vary such that cost might vary by as much as 20%. For 40% NOx reduction, the costs may vary by about ± 10% from those shown.
- No credit is taken for impact on SO_2 emissions, reduced ash handling, or similar beneficial effects of firing natural gas.
- It is assumed that a Conventional Gas Reburn System cost is $15/KW. The cost of a Fuel Lean System is assumed to be $10/KW or less.
- Costs shown include capital and production costs (O&M plus fuel).
- The seasonal cost analysis values are based upon a 5-month ozone season and no operation outside of the ozone season.
- The results shown in this table should be regarded as typical values, and representative of facilities that have similar characteristics and circumstances as those included in the analysis. Each facility should be evaluated individually by the owner.
- *The Coal Reburn example is based on a 500 MW plant and capital cost of $45/KW (based on DOE estimate of capital cost) and capacity factor of 65%. It should be kept in mind that there is very little experience with this technology. Two demonstration systems <~100MW cost well in excess of $100/KW in capital cost. Hence, the cost values for Coal Reburn should be regarded as very uncertain.*

Table S-3: Combination of Urea SNCR and Gas Reburn (200 MW boiler)			
	urea SNCR: 1.0 to 0.40	**Conventional Gas Reburn: 1.0 to 0.40**	**Fuel Lean Gas Reburn: 1.0 to 0.60 + urea SNCR: 0.60 to 0.36**
Reburn Annual Costs **Ann. NOx Removed** **$/MWhr**		$3.84 million 3,416 tons $3.37 / MWhr	$1.51 million 2,280 tons $1.33 / MWhr
SNCR Annual Costs **Ann. NOx Removed** **$/MWhr**	$3.90 million 3,416 tons $3.42 / MWhr	- - -	$1.15 million 1,367 tons $1.01 / MWhr
Total Annual Costs ***Ann. NOx Removed*** ***$/MWhr*** ***$/ton NOx removed***	***$3.90 million*** ***3,416 tons*** ***$3.42/MWhr*** ***$1,142/ton***	***$3.84 million*** ***3,416 tons*** ***$3.37/MWhr*** ***$1,124/ton***	***$2.66 million*** ***3,647 tons of NOx*** ***$2.34/MWhr*** ***$729/ton***

- *In reading this table add the cost of Gas Reburn and tons reduced by Gas Reburn to the cost of SNCR and tons reduced by SNCR. For example, it would cost approximately $3.90 million per year to reduce NOx from 1.0 lb/MMBTU to 0.4 lb/MMBTU or less by urea SNCR alone. Alternatively, it would cost about $3.84million per year by Gas Reburn alone. As an alternative to using either technology alone, it would cost about $2.66million by combining the two technologies such that each provides 40% reduction for an outlet NOx of about 0.36 lb/MMBTU.*
- Annual costs include levelized cost of capital and the operating and maintenance costs (including fuel).
- No credit is taken for impact on SO_2 emissions, reduced ash handling, or similar beneficial effects of firing natural gas.
- *Both SNCR and Gas Reburn are highly process specific, and each facility should be evaluated individually. This data should be considered indicative of possible scenarios. The analysis assumes 45% urea chemical utilization for 40% reduction and 25% urea chemical utilization for 60% reduction. In any particular SNCR application, these estimates could be significantly different; but, the same trends should exist. For many utility boilers 60% NOx reduction is not practical with SNCR or reburning alone. Figure 2-13 was used to estimate reburn fuel heat input.*
- *It was assumed that the cost of gas is $1.50/MMBTU greater than that of coal and capacity factor is 65%.*

S.4 Summary - Chapter Four: Case Studies

The fourteen case studies in Chapter Four include SNCR, SCR, Gas Reburn and gas-fired Low NOx Combustion technology applications. A total of roughly 30 boilers are addressed. Each of these case studies was prepared in cooperation with facility operators. The case studies provided detailed information on project cost, operating cost, and operating experience. The cost information - capital and operating - gathered in the case studies was used in the cost analysis (Chapter 3). This cost information enabled more representative cost estimates to be made since some cost information was not readily available in the literature, and having information provided directly by users assures that the cost analysis of Chapter Three is anchored in reality. For example, information on catalyst disposal cost, maintenance, impacts on heat rate, etc. from the actual facilities was incorporated into the cost analysis of Chapter Three. We are not aware of another study that incorporates such up-to-date and representative operating data in such a direct manner.

Some technology users were contacted that chose not to participate in the case studies. In some cases these users were reluctant to provide cost information; but, in most cases the users did not have enough operating experience to provide meaningful information.

While specifics on performance levels, experience, and costs for each of the technology applications addressed in the case studies can be found in Chapter Four, in Table S-4 a list of facility types, technologies, and measures of experience and reliability is presented. In all of these applications, a total of six forced outage incidents were reported at two facilities (three at each facility - see case studies SNCR-1 and SCR-1). At both of these facilities changes in O&M practices or replacement of auxiliary hardware have already or will in the future eliminate the problem that caused the forced outages. It is notable that in no case did NOx Control process failure result in a forced outage. In two cases the technology cannot be operated continuously to provide intended NOx reductions (see SNCR-4 and SNCR-5). Both of these cases these are very challenging SNCR applications that required sophisticated injection methods that generally have not been necessary in other commercial SNCR systems. Nevertheless, these SNCR systems are operated regularly to provide some NOx reduction. All of the other SNCR systems are operated continuously at the intended NOx reductions.

Table S-5 breaks down the information of Table S-4 by experience with the various technologies for coal-fired plants. As shown, SNCR has provided over 24 total boiler-years of service on these U.S. installations with a total of 3 outage incidents (3 days of lost service) that all occurred in the initial months of operation at the first electric utility boiler SNCR system (see case study SNCR-1). Since that time there have been no forced outage incidents. There have been a total of about 15 boiler-years of SCR service at these U.S. facilities with only 3 forced outages (see case study SCR-1). And, in both cases, the problems that caused the outages have been corrected (in the case of the SNCR application) or will be corrected over time (in the case of the SCR application) - assuring higher reliability in the future. In the case of Gas Reburn, while the total commercial experience level is considerably less, the lack of any outages after about 3 total boiler-years of service is a very promising trend.

The experience with these technologies has been extremely positive. While each project had its challenges, the overall reliability and performance of the secondary control technologies has been extremely good. Technology suppliers appear to have addressed the concerns that have been expressed by the utility industry regarding difficulties in applying these technologies to commercial U.S. facilities and any impact to facility reliability.

Table S-4 Summary of Case Study Results

Boiler Type	Technology[1]	# Boilers		Performance Achieved? [2]	Tot. Boiler-Months in Service [3]	# Forced Outage Incidents
Gas	LNB	5		yes	na	0
	SNCR	18		yes	na	0
	SCR	9		yes	na	0
Oil	SNCR	1		yes	30	0
Coal, Grp 1	SNCR	4		yes	158	3 [4]
	SNCR	1		yes [5]	30	0 [5]
	SCR	5		yes	142	0
	Gas Reburn	1		yes	12	0
Coal, Grp 2	SNCR	3		yes	72	0
	SNCR, NH_3	1		no [6]	30	0
	SCR	1		yes	30	3 [7]
	SCR, demo	1		yes	5 [8]	0
	Hybrid demo	1		yes	2	0
	Gas Reburn	1		yes	22	0
Totals		**Gas/Oil** **33**	**Coal** **19**		**533**	**6**

Notes:

1 - SNCR is urea-SNCR, except where noted as ammonia-SNCR (NH_3)

2 - Yes for Performance Achieved means that design reduction, ammonia slip, CO emissions, etc. have been met and catalyst activity has - thus far - met expectations

3 - Months in service as of Nov / Dec 1997. Gas-fired unit data not available, but generally longer

4 - Forced outage incidents were in initial months of operation. Improved O&M practices - more frequent inspection of urea injectors - have corrected problem

5 - System meets design reduction and ammonia slip; however, unexpected high air preheater deposit formation rates cause system to be operated at lower reduction. Since modified operation, no forced outages

6 - At design reduction, ammonia slip is high and causes rapid air heater deposit formation. System is operated at lower reduction levels

7 - Forced outages resulted from failure of auxiliary mechanical equipment (expansion joints). Operator will replace / upgrade all expansion joints over time, reducing these failures. SCR catalyst and controls operate as intended

8 - Catalyst is still in duct after 30 months of operation and continues to be tested. Catalyst has met or exceeded expected activity levels over this time

Table S-5. Summary of Case Study Experience by Technology Coal Fired Boilers Only				
Technology	**# of Boilers**	**MW**	**Total Boiler-Months in Service (Nov '97)**	**Total Forced Outage Incidents**
SNCR (urea & NH_3)	9	1,664	290	3
SCR	7	1,845*	177	3
Gas Reburning	2	169	34	0
Total	**18**	**3,678***	**501**	**6**

S.5 Concluding Remarks

Coal-fired utility boilers emitted 91% of the total utility boiler NOx emissions in 1996. Therefore it is important to understand what methods may be available to reduce NOx from these coal-fired facilities. Because many of these facilities are already equipped with primary controls, secondary controls will be necessary to achieve further reductions.

The experience with secondary controls demonstrates that the application of available, commercially-proven, secondary control technologies can potentially provide significant NOx reduction capability for every coal-fired boiler in the OTR. The actual approach any particular facility chooses to reduce NOx will be site specific. There are several technical and economic issues that require careful consideration. For nearly all boiler types, NOx reduction is possible for less than $1,500/ton (based on annual controls). The OTC's MOU provides for substantial flexibility in how compliance may be achieved, such as trading and averaging. Because many facilities can reduce NOx for well below $1,000/ton, it is expected that the actual cost of controls for the region will average well below $1,500/ton for even high levels of reduction. For seasonal controls, the $/ton value will be higher; however, the total cost to the utility industry will be less.

Experience in the U.S. with secondary control technologies has been extremely good. These technologies have demonstrated a high degree of reliability and a high degree of process effectiveness, as attested to by the users of these technologies in Chapter Four. Although each case study of Chapter Four had unique challenges, in very few cases did these challenges ultimately create any operating difficulty for the user. And, in each of the few cases where a difficulty was encountered, the facilities were able to find ways to address the issue of concern. In these cases, the problem was usually a result of failure of auxiliary equipment or boiler hardware, not the NOx-reduction process hardware.