United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

EPA-600/7-79-147
June 1979

EPA

# Environmental Assessment of Stationary Source $NO_x$ Control Technologies: Second Annual Report

## Interagency Energy/Environment R&D Program Report

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EPA-600/7-79-147

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# Environmental Assessment of Stationary Source $NO_x$ Control Technologies: Second Annual Report

by

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Program Element No. EHE624A

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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

# PREFACE

This report summarizes results of the second year of EPA Contract 68-02-2160: "Environmental Assessment of Stationary Source $NO_x$ Combustion Modification Technologies." The EPA Project Officer is J. S. Bowen and the Deputy Project Officer is R. E. Hall, both of the Combustion Research Branch, IERL-RTP. This report was prepared by the Energy and Environmental Division of Acurex Corporation. The Acurex Project Manager is H. B. Mason; L. R. Waterland is the Chief Project Engineer. Principal contributors to the effort, in addition to the report authors, were: L. B. Anderson, C. Castaldini, Z. Chiba, E. Chu, M. A. Herther, R. Ivani, R. J. Milligan, P. Overly, L. M. Schalit, A. B. Shimizu, D. Smith, and J. Steiner. C. B. Moyer and G. R. Offen provided technical review.

Additionally, subcontract support was provided by J. Thomasian of Energy and Environmental Analysis, Inc., who authored portions of Section 3 of this report; A. Eschenroeder and A. Lloyd of Environmental Research and Technology, who provided photochemical trajectory model calculations; and J. Gabrielson and P. Langsjeon of KVB, Inc., A. Crawford and I. Manny of Exxon Research and Engineering, and M. Hilt, L. B. Davis, and N. Fitzroy of General Electric Corporation, who provided field test support.

The contributions of the following individuals and organizations are also gratefully acknowledged: R. P. Hangebrauck, J. S. Bowen, R. E. Hall, D. G. Lachapelle, W. S. Lanier, G. B. Martin, J. H. Wasser, G. R. Gillis, and R. B. Perry of the Energy Assessment and Control Division, IERL-RTP, W. Axtman of the American Boiler Manufacturers' Association, J. Crooks of the Tennessee Valley Authority, R. Lippeatt and C. Jensen of Blueray Systems, Inc., E. Campobenedetto of the Babcock and Wilcox Company, J. Vatsky of the Foster Wheeler Energy Corporation, W. Barr, F. Strehlitz, and E. Marble of the Pacific Gas and Electric Company, R. Meinzer of the San Diego Gas and Electric Company, and L. Robinson of the Bay Area Air Pollution Control District.

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# SECTION 1

# INTRODUCTION

This report summarizes the results of the second year of the "Environmental Assessment of Stationary Source $NO_x$ Combustion Modification Technologies" ($NO_x$ EA). The $NO_x$ EA is a three year program to: (1) identify the multimedia environmental impact of stationary conventional combustion sources and $NO_x$ combustion modification controls applied to these sources; and (2) identify the most cost-effective, environmentally sound $NO_x$ combustion modification controls for attaining and maintaining current and projected $NO_2$ air quality standards to the year 2000.

During the first year of the program, efforts were concentrated in three areas:

- Compiling background data on combustion source process characteristics, multimedia pollutant emissions, and pollutant environmental impacts
- Developing methodologies for environmental assessment and process engineering studies
- Setting program priorities on sources, controls, pollutants, and impacts

Building upon this work, second year emphasis was placed on:

- Characterizing baseline (uncontrolled) combustion source impact
- Developing fuels usage and emissions projections
- Source testing to fill critical data gaps
- Performing process analysis and environmental assessment studies of $NO_x$ controls applied to utility boilers, industrial boilers, and stationary gas turbines
- Assembling and exercising reactive air quality models for systems analysis applications

- Developing source analysis models for environmental impact evaluation

This report summarizes the results of the second year activities and the plans for the third year.

## 1.1 BACKGROUND

The 1970 Clean Air Act Amendments designated oxides of nitrogen ($NO_x$) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. Accordingly, in 1971, EPA set a primary and secondary National Ambient Air Quality Standard (NAAQS) for $NO_2$ of 100 $\mu g/m^3$ (annual average). To attain and maintain the standard, the Clean Air Act mandated control of new mobile and stationary $NO_x$ sources, each of which emits approximately half of the manmade $NO_x$ nationwide. Emissions from mobile source, light duty vehicles were to be reduced by 90 percent to a level of 0.25 g $NO_2$/km (0.4 g/mile) by 1976. Stationary sources were to be regulated by EPA standards of performance for new stationary sources (NSPS), which are set as control technology becomes available. Additional standards required to attain air quality in the Air Quality Control Regions could be set for new or existing sources through the State Implementation Plans (SIP's).

Since the Clean Air Act, techniques have been developed and implemented that reduce $NO_x$ emissions by a moderate amount (30 to 50 percent) for a variety of source/fuel combinations. In 1971 EPA set NSPS for large steam generators burning gas, oil, and coal (except lignite). Currently, more stringent standards for coal-fired large utility steam generators have been proposed, based on technology developed since 1971. Standards have also been proposed for gas turbines and are being prepared for reciprocating internal combustion engines and intermediate sized steam generators. Local standards also have been set, primarily for new and existing large steam generators and gas turbines, as parts of the State Implementation Plans in several areas with $NO_x$ problems. This regulatory activity has resulted in reducing $NO_x$ emissions from many stationary sources by 30 to 50 percent. The number of controlled sources is increasing as new units are installed with factory equipped $NO_x$ controls.

Emissions have been reduced comparably for mobile source, light duty vehicles. Although the goal of 90 percent reduction (to 0.25 g $NO_2$/km) by 1976 has not been achieved, emissions were reduced by about 25 percent (1.9 g/km) for the 1974 to 1976 model years and now have been reduced by 50 percent to 1.25 g/km. Achieving the 0.25 g/km goal has been deferred indefinitely because of technical difficulties and fuel penalties. Initially the 1974 Energy Supply and Environmental Coordination Act deferred compliance to 1978. Recently, the Clean Air Act Amendments of 1977 abolished the 0.25 g/km goal and replaced it with an emission level of 0.62 g/km (1 g/mile) for 1981 and beyond. However, the EPA Administrator is required to review the 0.25 g/km standard in 1980 and report to Congress on the need for such a standard.

Because the mobile source emission regulations have been relaxed, stationary source $NO_x$ control has become more important for maintaining air quality. Several air quality planning studies have evaluated the need for stationary source $NO_x$ control in the 1980's and 1990's in view of recent developments (References 1-1 through 1-4). These studies all conclude that relaxing mobile standards, coupled with the continuing growth rate of stationary sources, will require more stringent stationary source controls than current NSPS provide. This conclusion has been reinforced by projected increases in the use of coal in stationary sources. The studies also conclude that the most cost-effective way to achieve these reductions is by using combustion modification $NO_x$ controls in new sources.

It is also possible that separate $NO_x$ control requirements will be needed to attain and/or maintain additional $NO_2$ related standards. Recent data on the health effects of $NO_2$ suggest that the current NAAQS should be supplemented by limiting short term exposure (References 1-4 through 1-8). In fact, the Clean Air Act Amendments of 1977 require EPA to set a short term $NO_2$ standard for a time period of less than three hours unless no need for such a standard can be verified.

EPA is also continuing to evaluate the long range need for additional $NO_x$ regulation as part of strategies to control oxidants or pollutants for which $NO_x$ is a precursor, e.g., nitrates and nitrosamines (References 1-4, 1-5, and 1-9 through 1-12). These regulations could be source emission controls or additional ambient air quality standards. In either case, additional stationary source control technology could be required to assure compliance.

In summary, since the Clean Air Act, near term trends in $NO_x$ control are toward reducing stationary source emissions by a moderate amount. Hardware modifications in existing units or new units of conventional design will be stressed. For the far term, air quality projections show that more stringent controls than originally anticipated will be needed. To meet these standards, the preferred approach is to control new sources by using low $NO_x$ redesigns.

## 1.2 PROGRAM OVERVIEW

Existing combustion modification techniques are increasingly being used on stationary conventional combustion sources, and the prospects for developing and using advanced techniques are good. Identifying combustion generated pollutant species from these sources and evaluating their potential environmental impacts have become increasing concerns. Thus, a critical need exists to not only evaluate the baseline environmental impact of conventional stationary source combustion, but also to evaluate the environmental, economic, energy, and engineering implications of combustion modification technology. The $NO_x$ EA was begun in June 1976 to provide such evaluations and specifically assess:

- The impacts and potential correction measures associated with using specific existing and advanced combustion modification techniques, such as:

- The change in gaseous, liquid, and solid emissions to the air, water, and land caused by $NO_x$ controls
- The capital and operating cost of $NO_x$ controls per unit reduction in $NO_x$
- The change in energy consumption efficiency
- The change in equipment operating performance

- The priorities and schedule for $NO_x$ control technology development considering:
  - The above impacts for each source/control combination
  - The need for controls to attain and maintain the current annual average $NO_2$ ambient air quality standard
  - The need for controls to attain and maintain a short term $NO_2$ standard or other $NO_x$ related standards such as a standard for oxidants
  - Alternate mobile source standards
  - Alternate energy and equipment use scenarios, to the year 2000, in the Air Quality Control Regions with potential $NO_x$ problems

The first assessment concerns evaluating the net impacts from specific combinations of stationary combustion source equipment and control techniques. The $NO_x$ EA addresses this goal through a series of coordinated efforts to evaluate the environmental impact and control potential of multimedia effluents from current and emerging energy and industrial processes. The assessment effort is focused in a major process engineering and environmental assessment task. This task is supported by additional tasks on emission characterization, pollutant impacts and standards, and experimental testing. Results from these tasks will be used to rank both current and emerging source/control combinations based on overall environmental, economic, and operational impact. This information is intended to help control developers and users select appropriate control techniques to meet regulatory standards now and in the future. It also will help define pollution control development needs and priorities, identify economic and environmental trade-offs among competitive processes, and ultimately guide regulatory policy. In this respect, the $NO_x$ EA will contribute to the broad program of assessments of energy systems and industrial processes being administered by EPA's Office of Research and Development.

The second assessment above deals with specifying the best mix of control techniques to meet air quality goals up to the year 2000. In the $NO_x$ EA, this is done in a systems analysis task which projects air quality in specific air quality control regions for various scenarios of $NO_x$ control, energy growth, and equipment use. These projections, together with the control cost and impact data discussed above will suggest the most cost-effective and environmentally sound controls. Results from the analysis are used in the $NO_x$ EA program to set priorities on both sources and controls. More importantly, this information will help R&D groups concerned with providing a sufficient range of environmentally sound techniques to meet the diverse control implementation requirements. It will also help environmental planners involved in formulating abatement strategies to meet current or projected air quality standards.

The interrelationships and technical content of each of the tasks in the $NO_x$ EA are shown in Figure 1-1. In this figure the arrows indicate the sequence of subtasks and major interactions among tasks, the boxes represent task efforts, and the ovals represent program outputs.

As noted above, second year efforts focused on characterizing baseline source impact; developing fuels usage and emissions projections; source testing; evaluating process, cost, and environmental impacts of $NO_x$ controls applied to utility boilers; assembling and exercising reactive air quality and systems analysis models; and source analysis modeling. In this report, results are presented in terms of these areas rather than on a task by task basis. This approach is consistent with general environmental assessment annual report formats developed within the IERL-RTP's Energy Assessment and Control Division. Thus, specific task efforts are discussed herein as follows:

| Task/Subtask | Report Section |
|---|---|
| • Emissions Characterization | |
| -- Combustion source process/emissions background | 2.1 |
| -- Stationary source fuel consumption | 2.2 |
| -- Equipment/fuels use projections | 2.3 |
| -- Multimedia emissions inventory | 5.1 |
| -- Baseline source impact ranking | 8.1 |
| • Impacts and Standards | |
| -- $NO_2$ and related standards projections | 3 |
| • Experimental Testing | |
| -- Sampling/analysis requirements; field test program | 5.2 |
| • Source Analysis Modeling | |
| -- Methodology development | 4.1 |
| • Process Engineering and Environmental Assessment | |
| -- $NO_x$ control process background | 6 |
| -- Process engineering methodology development | 4.2 |
| -- Detailed process studies (utility boilers) | 7 |
| • Systems Analysis | |
| -- Air quality model development | 4.3 |
| -- Control needs evaluation | 8.2 |

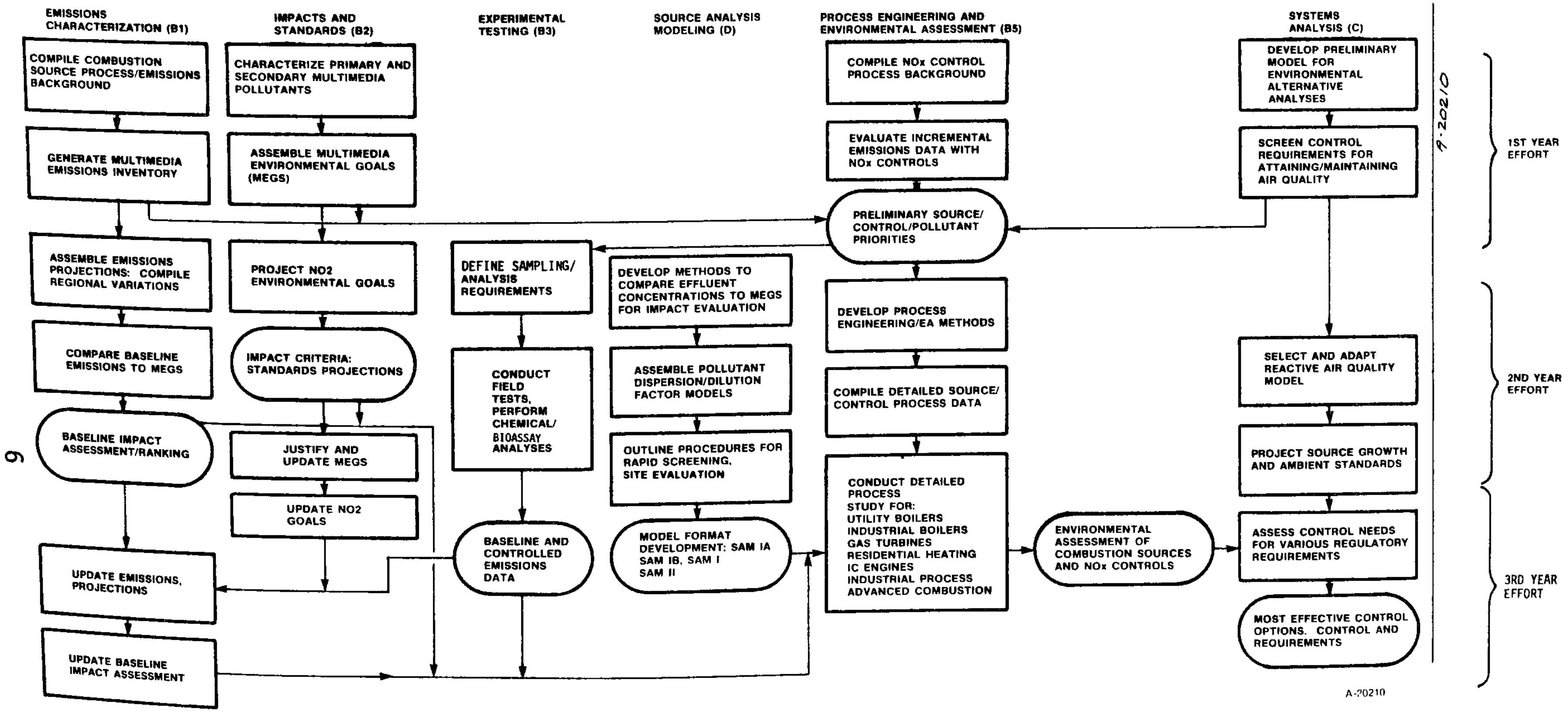


Figure 1-1. $NO_x$ EA approach.

In addition to the above, results from another support task not noted in Figure 1-1 are also summarized below. Updated conclusions from this task, to survey the potential for alternate clean fuels use in area sources, are reported in Section 2.4. Technology transfer activities performed as part the general $NO_x$ EA program support task are summarized in Section 9. Finally, third year plans are discussed in Section 10.

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1-4. "Air Program Strategy for Attainment and Maintenance of Ambient Air Quality Standards and Control of Other Pollutants," Draft Report, U.S. EPA, Washington, October 1976.

1-5. French, J. G., "Health Effects from Exposure to Oxides of Nitrogen," presented at the AIChE 69th Annual Meeting, Chicago, November 1976.

1-6. "Scientific and Technical Data Base for Criteria and Hazardous Pollutants -- 1975 EPA/RTP Review," EPA-600/1-76-023, NTIS PB-253 942, January 1976.

1-7. Shy, C. M., "The Health Implications of Non-Attainment Policy, Mandated Auto Emission Standards, and a Non-Significant Deterioration Policy," presented to Committee on Environment and Public Works, Serial 95-H7, February 1977.

1-8. "Health Effects for Short-term Exposure to Nitrogen Dioxide (Draft)," EPA, Office of Research and Development, December 1977.

1-9. "Control Strategy for Nitrogen Oxides," Memo from B. J. Steigerwald, Office of Air Quality Planning and Standards, September 1976.

1-10. "Report on Air Quality Criteria: General Comments and Recommendations," Report to the U.S. EPA by the National Air Quality Advisory Committee of the Science Advisory Board, June 1976.

1-11. Personal communication with M. Jones, Office of Air Quality Planning and Standards, Pollutant Strategies Branch, September 1976.

1-12. "Control of Photochemical Oxidants -- Technical Basis and Implications of Recent Findings," EPA-450/2-75-005, NTIS PB-242 428, July 1975.

# SECTION 2

# CURRENT PROCESS TECHNOLOGY BACKGROUND

During the second year of the $NO_x$ EA the equipment characterizations, fuels use compilations, and emissions inventories developed during initial program efforts and documented in References 2-1 and 2-2 were further defined and updated. Results from this continuing work are presented here in Section 2, and in Sections 5 and 8.

This section presents the combustion process technology background used to order and simplify the $NO_x$ EA process engineering and environmental assessment studies. The section characterizes equipment designs according to characteristics that affect the formation and control of multimedia pollutants. Although emphasis is on the stationary combustion sources of $NO_x$, other sources were also studied because the need for stationary source controls depends on how well these other sources can be controlled. The equipment categories described here are used as the basis for the emissions inventory in Section 5.1 and the source rankings discussed in Section 8. The source characterization considered the following steps:

- Identify significant sources of $NO_x$; group sources according to formative mechanism and nature of release into the atmosphere

- Categorize stationary combustion sources according to equipment and fuel characteristics that affect the generation and/or control of combustion generated pollution

- Qualify equipment/fuel categories on the basis of current and projected use and design trends; develop a list of equipment/fuel combinations to be carried through subsequent emission inventories, process studies, and environmental assessments

- Identify effluent streams from stationary combustion source equipment/fuel categories which may be affected by using $NO_x$ combustion modification controls

- Identify operating modes (transients, upsets, maintenance) in which emissions may be affected by $NO_x$ combustion modification controls

The significant sources of oxides of nitrogen emitted to the atmosphere are shown in Figure 2-1. On a global basis, natural emissions from biological decay and lightning make up about 90 percent of all $NO_x$ emissions. However, in urban areas, up to 90 percent of ambient $NO_x$ may be due to manmade sources, primarily combustion effluent streams. The primary emphasis of the $NO_x$ EA is on the fuel combustion sources bracketed at the top of the figure. Other sources are considered only to gauge the relative emissions and impacts due to stationary fuel combustion.

The major stationary fuel combustion source classes have been further categorized as shown in Table 2-1. This table lists the major equipment designs and corresponding fuels fired, and was compiled from a survey of installed sources, process characteristics, and emission data.

In the following, Section 2.1 discusses major stationary source equipment designs which have a significant impact on $NO_x$ emissions. The emphasis is on standard operating conditions for these sources, though nonstandard conditions are given cursory evaluation. Stationary source fuel consumption is characterized in Section 2.2. These data are important inputs for the emission inventories in Section 5. In addition, several energy scenarios through the year 2000, which bracket the uncertainty in future conditions, are discussed. Section 2.3 considers trends in equipment and fuels which are used to project energy use by sector through 2000.

In addition to the source characterization, fuels use, and energy projection efforts discussed in Sections 2.1 through 2.3, a related study to characterize the potential for alternate clean fuel usage in area sources continued during the second year of the $NO_x$ EA. Updated results from this task are discussed in Section 2.4.

## 2.1 STATIONARY COMBUSTION PROCESS BACKGROUND

Stationary combustion sources, noted above as having a significant impact on $NO_x$ emissions, are discussed in this section. Tables are provided which list the major designs in each sector and the variations in designs and fuels which are known to affect emissions. The primary design types are those projected for widespread use in the 1980's and thus are prime candidates for $NO_x$ control application. Secondary designs are defined as those either diminishing in use or unlikely candidates for $NO_x$ controls in the future. Secondary design types have not, and will not be given further consideration in subsequent $NO_x$ EA studies.

### 2.1.1 Utility and Large Industrial Boilers

Utility and large industrial boilers are defined as field erected watertube boilers with capacities greater than 73 MW heat input. These boilers generally burn pulverized coal, residual oil, and natural gas. Table 2-2 describes the variety of specific boiler designs and catalogs multimedia pollutant emissions from these sources. Further discussion of pollutant emissions from this source category under standard operation is given in Section 5.1.

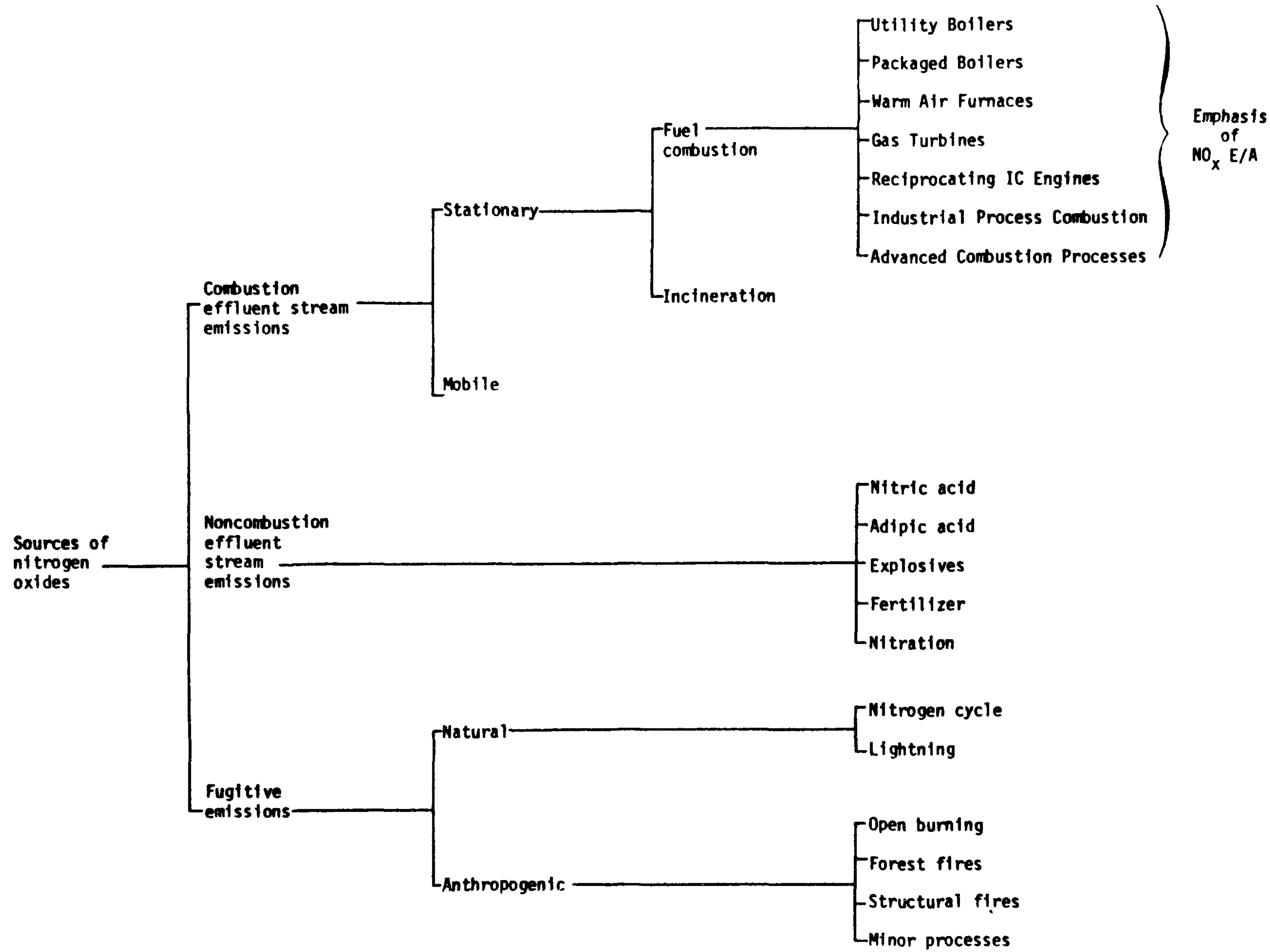


Figure 2-1. Sources of nitrogen oxide emissions.

TABLE 2-1. SIGNIFICANT STATIONARY FUEL COMBUSTION EQUIPMENT TYPES/MAJOR FUELS

| Utility Sector (Field Erected Watertubes) | Fuel |
|---|---|
| Tangential | PC, O, G |
| Wall Fired | PC, O, G |
| Horizontally Opposed and Turbo Furnace | PC, O, G |
| Cyclone | PC, O |
| Vertical and Stoker | C |
| **Packaged Boiler Sector** | |
| Watertube 29 to 73 MW[a] (100 to 250 MBtu/hr) | C, O, G, PG |
| Watertube <29 MW[a] (<100 MBtu/hr) | C, O, G, PG |
| Firetube Scotch | O, G, PG |
| Firetube HRT | C, O, G, PG |
| Firetube Firebox | C, O, G, PG |
| Cast Iron | O, G |
| Residential | C, O, G |
| **Warm Air Furnace Sector** | |
| Central Heaters | O, G |
| Space Heaters | O, G |
| Other Residential Combustion | O, G |

PC -- Pulverized coal
C -- Stoker coal or other coal
O -- Oil
G -- Gas
PG -- Process gas

[a]Heat input
[b]Heat output

TABLE 2-1. Continued

| Gas Turbines | Fuel |
|---|---|
| Large >15 MW[b] (>20,000 hp) | O, G |
| Medium 4 to 15 MW[b] (5,000 to 20,000 hp) | O, G |
| Small <4 MW[b] (<5,000 hp) | O, G |
| **Reciprocating IC Engines** | |
| Large Bore >75 kW/cyl[b] (>100 hp/cyl) | O, G |
| Medium 75 kW to 75 kW/cyl[b] (100 hp to 100 hp/cyl) | O, G |
| Small <75 kW[b] (<100 hp) | O, G |
| **Industrial Process Heating** | |
| Glass Melters | O, G |
| Glass Annealing Kilns | O, G |
| Cement Kilns | C, O, G |
| Petroleum Refinery | |
| Process Heaters | O, G, PG |
| Catalytic Crackers | O, G, PG |

PC -- Pulverized coal
C -- Stoker coal or other coal
O -- Oil
G -- Gas
PG -- Process gas

[a]Heat input
[b]Heat output

TABLE 2-1. Concluded

| | Fuel |
|---|---|
| Brick and Ceramic Kilns | O, G |
| Iron and Steel | |
| Coke Oven Underfire | G, PG |
| Sintering Machines | O, G, PG |
| Soaking Pits and Reheat Ovens | C, O, G, PG |

PC -- Pulverized coal
C -- Stoker coal or other coal
O -- Oil
G -- Gas
PG -- Process gas

## TABLE 2-2. SUMMARY OF UTILITY AND LARGE INDUSTRIAL BOILER CHARACTERIZATION

| Design Type | Design Characteristics | Process Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Tangential | Fuel and air nozzles in each corner of the combustion chamber are directed tangentially to a small firing circle in the chamber. Resulting spin of the flames mixes the fuel and air in the combustion zone. | Input Capacity:<br>73 MW to 3800 MW<br>Steam Pressure:<br>18.6 MPa (subcritical)<br>26.2 MPa (supercritical)<br>Steam Temperature:<br>755K to 840K<br>Furnace Volume:<br>Up to 38,000 m<br>Furnace Pressure:<br>50 Pa to 1000 Pa<br>Furnace Heat Release:<br>Coal -- 104 to 250 kW/m<br>Oil, gas -- 208 to 518 kW/m<br>Excess Air:<br>25% coal<br>10% oil<br>8% gas | 67% coal<br>18% oil<br>15% gas | Gaseous<br>Flue gas containing flyash, volatilized trace elements, $SO_2$, NO, other pollutants.<br>Liquid<br>Scrubber streams, ash sluicing streams, wet bottom slag streams.<br>Solid<br>Solid ash removal<br>Flyash removal | Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating. | During startup, NO emissions are low since flame temperatures not developed. During load reductions, emissions of $NO_x$ decrease because of lower flame temperatures. $NO_x$ should decrease following soot blow due to improved heat transfer. | Trend toward coal firing in new units; conversion to oil and coal in existing units.<br>19.4% of current installed units. | Primary |
| Single Wall | Burners mounted on single furnace wall -- up to 72 on single wall | Units typically limited in capacity to about 400 MW (electric) because of furnace area. | 43% coal<br>22% oil<br>35% gas | Gaseous<br>Flue gas containing flyash, volatilized trace elements, $SO_2$, NO, other pollutants.<br>Liquid<br>Scrubber streams, ash sluicing streams, wet bottom slag streams.<br>Solid<br>Solid ash removal<br>Flyash removal | Soot blowing, on-off transients load transients, upsets, fuel additives, rapping, vibrating. | During startup, NO emissions are low since flame temperatures not developed. During load reductions, emissions of NO decrease because of lower flame temperatures. $NO_x$ should decrease following soot blow due to improved heat transfer. | Trend toward coal firing in new units; wet bottom units no longer manufactured due to operational problems with low sulfur coals and high combustion temperatures promoting $NO_x$.<br>59% of current installed units. | Primary |

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TABLE 2-2. Continued

| Design Type | Design Characteristics | Process Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Horizontally Opposed Wall | Burners are mounted on opposite furnace walls -- up to 36 burners per wall. | Units typically designed in sizes greater than 400 MW (electric). | 32% coal<br>21% oil<br>47% gas<br>(includes Turbo-Furnace) | Gaseous<br>Flue gas containing flyash, volatilized trace elements, SO , NO, other pollutants.<br><br>Liquid<br>Scrubber streams, ash sluicing streams, wet bottom slag streams.<br><br>Solid<br>Solid ash removal<br><br>Flyash removal | Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating. | During startup, NO emissions are low since flame temperatures not developed. During load reductions, emissions of NO decrease because of lower flame temperatures. $NO_x$ should decrease following soot blow due to improved heat transfer. | Trend toward coal firing and conversions to oil and coal firing; again, wet bottoms being phased out.<br><br>8.2% of current installed units. | Primary |
| Turbo Furnace | Air and fuel fired down toward furnace bottom using burners spaced across opposed furnace walls. Flame propogates slowly passing vertically to the upper furnace. NO is usually low due to long combustion time and relatively low flame temperature. | Units typically designed in sizes greater than 400 MW (electric). | Included in horizontally opposed wall | Gaseous<br>Flue gas containing flyash, volatilized trace elements, SO , NO, other pollutants.<br><br>Liquid<br>Scrubber streams, ash sluicing streams, wet bottom slag streams. | Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating. | During startup, NO emissions are low since flame temperatures not developed. During load reductions, emissions of NO decrease because of lower flame temperatures. NO should decrease following soot blow due to improved heat transfer. | Trend toward coal firing -- (capacity included with opposed wall). | Primary |

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TABLE 2-2. Concluded

| Design Type | Design Characteristics | Process Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Cyclone | Fuel and air introduced circumferentially into cooled furnace to produce swirling, high temperature flame; cyclone chamber separate from main furnace; cyclone furnace must operate at high temperatures since it is a slagging furnace. | <u>Furnace Heat Release:</u><br><u>4.67 to 8.28 MW/m</u> | 92% coal<br>4% oil<br>4% gas | <u>Gaseous</u><br>Flue gas containing flyash, volatilized trace elements, SO , NO, and other pollutants.<br><br><u>Liquid</u><br>Scrubber streams<br><br><u>Solid</u><br>Solid ash removal<br><br>Flyash removal | Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating. | During startup, NO emissions are low since flame temperatures not developed. During load reductions, emissions of NO decrease because of lower flame temperatures. NO should decrease following soot blow due to improved heat transfer. | Two cyclone boilers sold since 1974 have not proven adaptable to emissions regulations. Must operate at high temperatures resulting in high thermal NO fixation; also operational problems with low sulfur coal.<br><br>3.3% of installed units. | Secondary |
| Vertical and Stoker | Vertical firing results from downward firing pattern. Used to a limited degree to fire anthracite coal.<br><br>Stoker projects fuel into the furnace over the fire permitting suspension burning of fine fuel particles. Spreader stokers are the primary design type. | <u>Furnace Heat Release:</u><br><u>1.1 to 1.9 MW/m$^2$</u> plan area | 100% coal | <u>Gaseous</u><br>Flue gas containing flyash, volatilized trace elements, SO , NO, and other pollutants.<br><br><u>Liquid</u><br>Scrubber streams<br><br><u>Solid</u><br>Solid ash removal<br><br>Flyash removal | Soot blowing, on-off transients load transients, upsets, fuel additives, rapping, vibrating. | During startup, NO emissions are low since flame temperatures not developed. During load reductions, emissions of NO decrease because of lower flame temperatures. NO should decrease following soot blow due to improved heat transfer. | Since anthracite usage has declined, vertical fired boilers are no longer sold.<br><br>Design capacity limitations and high cost have caused stoker usage to diminish.<br><br>9.9% of current installed units. | Secondary |

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Table 2-2 also lists the effects of nonstandard operating conditions on emissions. Unfortunately, emissions during nonstandard operation have not been extensively quantified. During startup $NO_x$ emissions are generally low because flame temperatures have not developed. However, particulate emissions may be high since precipitators are generally not energized during startup. Also, unburned carbon may be emitted due to poor mixing in the combustion region.

$NO_x$ emissions should decrease as furnace temperatures are lowered during load reductions. However, if excess air levels are increased to maintain steam temperatures, $NO_x$ emissions actually may increase.

Particulate emissions increase during soot blowing as the tube surfaces are cleaned. However, $NO_x$ emissions should decrease after soot blowing because of the lower gas temperatures caused by increased heat transfer through the tube walls. Failure of equipment such as air preheaters may also reduce $NO_x$ emissions by causing lower flame zone temperatures.

### 2.1.2 Packaged Boilers

The packaged boiler category includes all industrial, commercial, and residential packaged boilers. Generally, these boilers have capacities less than 73 MW thermal input. There are only a few packaged boilers with larger capacities and these are sufficiently similar to the smaller units to be included in this category. Table 2-3 describes the classes of packaged boilers and emissions from standard and nonstandard operation. Further discussion of multimedia pollutant emissions under standard operation is given in Section 5.1.

Since large packaged boilers (>29 MW or 100 MBtu/hr heat input) operate much like utility boilers, the effects of transients and nonstandard operations should be similar to those discussed in Section 2.1.1. For smaller packaged boilers, combustion characteristics are significantly different. Although quantitative data for nonstandard operating conditions are sparse, load changes are known to have a relatively small effect on $NO_x$ emissions (Reference 2-3). However, increasing the fuel preheat temperature of oil-fired boilers may increase $NO_x$ emissions. At low preheat temperatures, the atomizing pressure is not sufficient to properly atomize the colder, more viscous oil; this results in lower atomization efficiency.

### 2.1.3 Warm Air Furnaces and Other Commercial and Residential Combustion Equipment

This sector is made up of residential and commercial warm air furnaces used for comfort heating, and miscellaneous commercial and residential appliances used in cooking, refrigeration, air conditioning, clothes drying, and the like. $NO_x$ EA emphasis is on space heaters, where the unit is located in the room or area it heats, and central heaters, which use ducts to transport and discharge warm air into the heated space. Table 2-4 describes these equipment categories and the effects of operating conditions on multipollutant emission levels.

TABLE 2-3. SUMMARY OF PACKAGED BOILER CHARACTERIZATION

| Design Type | Design Characteristics | Typical Operational Values | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Watertube | Combustion gases circulate around boiler tubes that have water passing through them. Essentially the only type of boiler available above 29 MW (heat input). | Oil-Fired Watertube:<br>Capacity: 38 MW<br>Furnace volume: 123 m3<br>Heat release: 310 kW/m3<br>Burner type: steam atomization<br>Fuel preheat: 392K<br>Stack temperature: 422K<br>Excess oxygen: 5% | 41% coal<br>21% oil<br>38% gas | Gaseous<br>Flue gas<br>Particulate<br><br>Liquid<br>Ash sluicing water<br>Scrubber streams<br><br>Solids<br>Solid ash removal | Soot blowing, on-off transients, upsets, fuel additives. | During startup, low NOx emissions.<br><br>During load reductions NOx lowered.<br><br>Soot blowing should cause lower gas temperature due to improved heat transfer, thus lowering NOx. | Pulverized coal and stokers for large watertubes. | Primary |
| Scotch Firetube | Cylindrical shell with one or more furnaces in the lower portion. Combustion takes place in front section. Combustion products flow back to rear combustion chamber, flow through tubes to smoke box, then discharge. | Scotch Firetube-Oil:<br>Capacity: 2.9 MW<br>Furnace volume: 2.5 m3<br>Heat release: 1190 kW/m3<br><br>Operating pressure: 1030 Pa<br><br>Burners: Air atomizing (2)<br><br>Fuel preheat: 371K<br><br>Excess oxygen: 4.9% | 59% oil<br>41% gas | Flue gas<br>Bottom ash | On-off transients, load transients, upsets, fuel additives. | Changes in firing rate have little effect on NOx emissions from firetubes. Fuel oil temperature increases tend to decrease NOx emissions. | Scotch firetubes currently show growth over other firetube designs. | Primary |
| HRT Firetube | Hot gases pass to back of unit, enter horizontal tubes, returning to front of the boiler then exit through smoke box. | | 55% oil<br>35% gas | Flue gas<br>Bottom ash | On-off transients, load transients, upsets, fuel additives. | Changes in firing rate have little effect on NOx emissions from firetubes. Fuel oil temperature increases tend to decrease NOx emissions. | Trend toward decreasing use of HRT. | Secondary |

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TABLE 2-3. Concluded

| Design Type | Design Characteristics | Typical Operational Values | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Firebox Firetube | Combustion gases enter front of first tube pass, travel to rear smoke box, return through second pass to gas outlet at the boiler front. | | 53% oil<br>57% gas | Flue gas<br>Bottom ash | On-off transients, load transients, upsets, fuel additives. | Changes in firing rate have little effect on NOx emissions from firetubes. Fuel oil temperature increase tends to decrease NOx emissions. | Decreasing use of firebox firetubes | Secondary |
| Cast Iron Boilers | Gases rise through vertical section, and discharge through the exhaust duct. Water is heated as it passes upwards through the watertubes | Cast Iron:<br>Distillate oil<br>Capacity: 0.38 MW<br>Furnace volume: 0.57 m3<br>Heat release: 673 kW/m3<br>Operating pressure: 1030 Pa<br>Burner type: Pressure atomizing (1)<br>Fuel preheat: None<br>Excess oxygen: 4.4% | 59% oil<br>41% gas | Flue gas<br>Bottom ash | On-off cycling transients | | | Secondary |
| Steam and Hot Water Units | Besides small residential units, shell boilers, compact, locomotive, short firebox, vertical firetube, straight tube, and coal research designs are grouped here. | | 1.5% coal<br>56% oil<br>42.5% gas | Flue gas | On-off cycling, transients. | | | Secondary |

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## TABLE 2-4. SUMMARY OF WARM AIR FURNACES CHARACTERIZATION

| Design Type | Design Characteristics | Design Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Commercial and Residential Central Warm Air Furnaces | Furnaces in central heaters enclosed in steel casing; fuel burned in combustion space of heat exchangers. Heat exchangers have a single combustion chamber, either cylindrical or divided into individual sections; combustion gases pass through secondary gas passages of the heat exchanger and exit through flue. | Typical Gas-Fired Forced Air Furnace<br>Heat exchanger area: 2.8 to 3.3 m2<br>Draft system: natural<br>Excess combustion air: 20% to 50%<br>Overall heat transfer coefficient: 11.3 to 17 W/m2K<br>Combustion chamber pressure: + 49.8 Pa<br>Exit flue gas temperature: 506 to 617K<br>Overall efficiency: 75% to 80%<br>On-off operation | 31% distillate oil<br>69% gas<br>(Miscellaneous combustion fuels such as wood, LPG, etc. combined with natural gas) | Flue gas | On-off cycling transients | NOx emissions levels rise at a steady rate after initial jump due to ignition, drop off quickly after the burner is turned off.<br>NOx emissions increase with on time of burner. Improper burner adjustment, damaged components, increase NOx by as much as 50%. | Oil firing in new units, trend to high efficiency in new units.<br>General decline in natural gas usage; increase in electric heat, increased use of high efficiency burners. | Primary |
| Space Heaters | Room heaters self-contained; equipped with a flue. Heat by radiation, or naturalor forced air circulation. | | 23% distillate oil<br>73% gas<br>(Miscellaneous combustion fuels such as wood, LPG, etc., combined with natural gas) (includes other residential combustion). | Flue gas | On-off cycling transients | NOx emissions levels rise at a steady rate after initial jump due to ignition, drop off quickly after the burner is turned off.<br>NOx emissions increase with on time of burner. Improper burner adjustment, damaged components, increase NOx by as much as 50%. | Oil firing in new units, trend to high efficiency in new units.<br>General decline in natural gas usage; increase in electric heat, increased use of high efficiency burners. | Secondary |

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TABLE 2-4. Concluded

| Design Type | Design Characteristics | Design Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Other Residential Combustion | Miscellaneous equipment includes ranges and ovens, clothes dryers, fireplaces, swimming pool heaters, refrigerating and air-conditioning equipment. | | Included in space heaters | Flue gas | On-off cycling, transients | NOx emissions levels rise at a steady rate after initial jump due to ignition, drop off quickly after the burner is turned off.<br><br>NOx emissions increase with on time of burner. Improper burner adjustment, damaged components, increase NOx by as much as 50%. | Increased use of electric heat; high efficiency burners in new units. | Secondary |

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Emissions inventory data under standard operating conditions are given in Section 5.1.

The transient and nonstandard operations of warm air furnaces include on-off cycling and out of tune or worn burner operations (Reference 2-4).

The initial peak in emission levels at ignition is caused by the inability of the cold refractory to support complete combustion. This incomplete combustion produces peaks in the HC, CO, and particulate emissions. As the refractory warms up, more complete combustion occurs, thus decreasing combustible emissions. After shutdown, some fuel leaks from the nozzle, which produces another peak in both the CO and HC emissions (Reference 2-5). This can be controlled to some degree by using a solenoid.

The transient emissions of $NO_x$ generally correspond to the thermal history of the firebox. At startup, the emissions increase rapidly as the temperature rises above the thermal $NO_x$ threshold. During the cycle, the emissions continue to increase at a gradual rate as the refractory firebox is heated causing a corresponding increase in the temperature of the combustion gases. At shutdown, $NO_x$ emissions decrease rapidly as the gas temperature is quenched by incoming air.

Transient emissions characteristics of gas burners should be very similar to those of oil burners. However, the HC and CO emissions that occur after shutoff in gas burners are probably not as high as those from oil burners, since gas leaks are minimal after burner shutoff.

The duration of the "on" period within a cycle of a coal-fired warm air furnace does not significantly affect polycyclic organic matter (POM) and particulate emissions (Reference 2-6). However, particulate and POM loadings generated during the "off" transient are higher than those produced during the "on" transient for coals with volatile matter contents greater than 20 percent. This phenomenon is caused by incomplete combustion of tars emitted from the volatile coal. Data trends from two samples show that $NO_x$ emissions increase as the "on" time of a cycle is increased.

Improper burner adjustment, dirty burner cups or nozzles, or damaged components can significantly increase pollutant emissions. Extensive field testing of oil burners has been reported (References 2-7 and 2-8). This testing shows that, with proper maintenance, smoke, CO, HC, and $NO_x$ emissions can reduced by over 50 percent, while filterable particulate can be reduced by almost 25 percent.

For gas burners, tuning, cleaning, and replacement of worn burner components should not have as dramatic an effect. Gas burners provide much cleaner combustion, and can be expected to stay tuned for extended periods with few maintenance problems.

### 2.1.4 Gas Turbines

Gas turbines are rotary internal combustion engines fueled mainly by natural gas, diesel or distillate fuel oils, and occasionally by residual or crude oils. These units range in capacity from 30 kW to 100 MW power output and may be installed in groups for larger power output. Table 2-5 discusses the gas turbine categories and the effects of operating conditions on multimedia pollutant levels.

The transient and nonstandard operations of gas turbines can be separated into three groups: operational variations, startup/shutdown, and equipment failures. Operational variations include changes in load, speed, power, ambient conditions, and fuel quality.

Generally, gas turbines are designed to operate most efficiently at their rated capacity. However, deviations from these rated conditions are often necessary, and can cause the gas turbines to lose efficiency as well as change emissions characteristics. The most frequently changed operational variables are load and/or speed. Two studies (References 2-9 and 2-10) have indicated that, generally, CO, $NO_x$ and HC emissions vary with change in power or load. $NO_x$ emissions also increase with increased compressor inlet temperature, whereas CO and HC decrease.

Few data presently are available on emissions characteristics during startup/shutdown or equipment failures. However, CO, HC, smoke and particulate emissions should increase during these periods because of incomplete combustion. Under these conditions, air-to-fuel ratios are not stable and combustion temperatures are low. $NO_x$ emissions diminish, therefore, because of the lower combustor temperatures.

### 2.1.5 Reciprocating IC Engines

Reciprocating IC engines for stationary applications range in capacity from 750 W to 48 MW power output. These engines are either compression ignition (CI) units fueled by diesel oil or a dual fuel combination of natural gas and diesel oil, or spark ignition (SI) engines fueled by natural gas or gasoline. They are used for applications ranging from shaft power for large electrical generators and pipeline compressors to small air compressors and welders. Table 2-6 summarizes the characteristics of these unit designs.

Nonstandard operating conditions include load change, startup and shutdown transients, and upsets such as fuel or electrical system failure. Large IC engines used for power generation or pipeline compression applications are generally well maintained for economy. Moreover, they are run steadily for many hours at their most efficient operating condition. However, smaller engines are not maintained as well, and frequently are operated in transient modes. Transients affect emissions largely through their influence on air-to-fuel ratios. For example, $NO_x$ emissions peak near the air-to-fuel stoichiometric ratio.

# TABLE 2-5. SUMMARY OF GAS TURBINE CHARACTERIZATION

| Design Type | Design Characteristics | Typical Operational Values | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|---|
| Utility and Industrial Simple and Regenerative Cycles | Rotary internal combustion engines. Simple gas turbine consists of compressor, combustion chamber, and turbine. Fuel is burned before quenching. Hot gases quenched by secondary combustion air, expanded through a turbine providing shaft horsepower.<br><br>Regenerative cycles use hot gases to preheat inlet air. | <u>Utility Gas Turbine Simple Cycle</u><br><br>Capacity: 92.3 MW<br>Specific fuel consumption: 11.67 MJ/kWh<br>Compression ratio: 10:1<br>Exhaust flow: 345 kg/s<br>Exhaust temperature: 822K | 45% gas<br>55% oil | Flue gas | On-off transient, load following, idling at spinning reserve. | NOx emissions generally increase with increasing power<br><br>Increased turbine compressor inlet temperatures cause NOx to increase. Behavior of NOx is directly related to rpm when corrected to a constant percent $O_2$. | Trend to higher turbine inlet temperatures, larger capacity and oil firing in new units; rapid growth projected. | Primary |
| Combined Cycles, Repowering | Combined cycle is a basic simple cycle unit exhausting to a waste heat boiler to recover thermal energy. Repowering adds a combustion turbine to an existing steam plant, involving the mechanical or thermal integration of the combustion and steam cycles. | <u>Utility Gas Turbine Combined Cycle</u><br><br>Capacity: 364.5 MW (4 turbines)<br>Specific fuel consumption: 8.56 MJ/kWh<br>Compression ratio: 10:1<br>Exhaust flow: 256 kg/s (1 turbine)<br>Exhaust temperature: 811K | Negligible | Flue gas | On-off transient, load following, idling at spinning reserve. | NOx emissions generally increase with increasing power.<br><br>Increased turbine compressor inlet temperatures cause NOx to increase. Behavior of NOx is directly related to rpm when corrected to a constant percent $O_2$. | Use of combined cycles should increase because of improved heat rate and fuel flexibility of unit. | Secondary |

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TABLE 2-6. SUMMARY OF RECIPROCATING IC ENGINE CHARACTERIZATION

| Design Type | Design Characteristics | Fuel Consumption (%) | Effluent Streams | Operating Modes | Effects of Transient, Nonstandard Operation | Trends | Future Importance |
|---|---|---|---|---|---|---|---|
| Compression Ignition, Turbo-Charged, Naturally Aspirated | Air or an air and gas mixture is compression heated in cylinders. Diesel fuel is then injected into the hot gas, causing spontaneous ignition. | 67% gas<br>15% diesel<br>11% gasoline<br>7% dual (oil and gas)<br>(all IC engines) | Exhaust gas | On-off transients, idling, upsets | $NO_x$ emissions peak near stoichiometric air-to-fuel ratio. $NO_x$ emissions diminish with decreasing load, greater speed and timing retard. | IC engines finding use for compressor applications on pipelines; low growth rate of diesel units; IC engines increasingly being replaced by gas turbines for standby applications in buildings, hospitals, etc., because of space, weight, noise, vibration. | Primary |
| Spark Ignition, Turbo-Charged, Naturally Aspirated | Combustion is spark initiated. Natural gas or gasoline is either injected or premixed with the combustion air in a carbureted system. | 67% gas<br>15% diesel<br>11% gasoline<br>7% dual (oil and gas)<br>(all IC engines) | Exhaust gas | On-off transients, idling, upsets | $NO_x$ emissions peak near stoichiometric air-to-fuel ratio. $NO_x$ emissions diminish with decreasing load, greater speed and timing retard. | IC engines finding use for compressor applications on pipelines; low growth rate of diesel units; IC engines increasingly being replaced by gas turbines for standby applications in buildings, hospitals, etc., because of space, weight, noise, vibration. | Primary |
| Blower Scavenged | Air charging by means of a low pressure blower, which also helps purge exhaust gases. | 67% gas<br>15% diesel<br>11% gasoline<br>7% dual (oil and gas)<br>(all IC engines) | Exhaust gas | On-off transients, idling, upsets | $NO_x$ emissions peak near stoichiometric air-to-fuel ratio. $NO_x$ emissions diminish with decreasing load, greater speed and timing retard. | New large units tending toward turbocharging | Secondary |

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Other operational variations such as load, engine speed, and spark timing also affect pollutant emissions. In general, $NO_x$ emissions diminish with decreasing load, greater speed, and retarded timing. Variations in ambient temperature also affect emissions of pollutants. Recent experiments on automotive gasoline engines indicate that ambient temperature reductions increase HC and CO. However, $NO_x$ levels are not greatly affected by changes in ambient temperature.

Most stationary engines burn No. 2 diesel fuel or natural gas. The properties of pipeline quality natural gas are essentially constant, but field gas can vary in composition and sulfur content. These variations affect the emissions of all gaseous pollutants as well as the engine performance. For diesel oils, the most important properties are viscosity, cetane number, distillation point, and sulfur and ash content. In general, only the sulfur content varies significantly in commercial grade fuels, and hence only $SO_2$ emissions are affected noticeably by normal fuel variations.

### 2.1.6 Industrial Process Heating

Significant quantities of fuel are consumed by industrial process heating equipment in industries such as iron and steel production, glass manufacture, petroleum refining, and brick and ceramic manufacture. In addition, there are dozens of industrial processes such as coffee roasting, drum cleaning, paint curing ovens, and smelting of metal ores that burn smaller amounts of fuel. Fuels fired in these units include oil, natural gas, producer gas, refinery gas, and occasionally coal. Table 2-7 summarizes the industrial process heating characterization. Few data are available which quantify the effects of nonstandard operations on industrial process heating. Further testing of this equipment is necessary before nonstandard conditions can be understood.

## 2.2 STATIONARY SOURCE FUEL CONSUMPTION

This section characterizes fuel consumption for equipment and fuel combinations described in Section 2.1. These data are important input for both the emissions inventories discussed in Section 5 and the impact rankings discussed in Section 8.

### 2.2.1 Baseline Fuel Consumption

Since fossil fuels account for almost all of the energy consumed by stationary combustion sources nationally, the survey performed included only these fuels. Fuel consumption data were compiled for 1974, since this was the most recent year for which comprehensive and complete regional data were available. For comparative purposes it was important that both the national and regional fuel consumption data represented the same year. Table 2-8 summarizes total annual consumption for coal, petroleum, and gas. These totals do not reflect total energy consumed by stationary sources, because some of the process industries and nonfossil fuel uses have not been included.

TABLE 2-7. SUMMARY OF INDUSTRIAL PROCESS HEATING CHARACTERIZATION

| Process Type | Design Characteristics | Process Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Trends | Future Importance |
|---|---|---|---|---|---|---|---|
| Cement Kilns | Kilns are rotary cylindrical devices up to 230 m in length. Feedstock moves through kiln in opposite direction from products of combustion | Kiln product temperature: 1756K | 45% gas<br>40% coal<br>15% oil | Combustion products and entrained substances from feedstock | Charging operations, upsets, starting transients | Coal firing in new units; energy improvements due to grate preheaters and shorter, less energy intensive kilns. | Primary |
| Glass Melting Furnaces | Continuous reverbatory furnaces; end port or side port. Flame burns over glass surface; combustion gas exits through opposite end exhaust stack after heating the combustion air. | Furnace temperatures: 1528 to 1583K | Natural gas- and oil-fired; coal is unsuitable due to impurities. | Combustion products and entrained substances from feedstock | Charging operations, upsets, starting transients | Trend toward use of electric melters, or electrically assisted conventional melters; use of oil instead of gas in fossil fuel units. | Primary |
| Annealing Lehrs | Used to control the cooling of gas to prevent stains. Lehrs fired by atmospheric, premix, or excess air burners. | | Natural gas- and oil-fired; coal unsuitable | Combustion products | Upsets, transients | | Primary |
| Coke Oven Underfire | Produce metallurgical coke from coal from the distillation of volatile matter producing coke oven gas; done in long rows of slot type ovens; fuel gas supplies required heat. Spent combustion gas heats inlet air. | Flue temperature: 1500K | Blast furnace gas and coke oven gas are primary fuels | Combustion products | Charging operations, upsets, starting transients | Projected fuel consumption about 5% annual. | Primary |

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# TABLE 2-7. Continued

| Process Type | Design Characteristics | Process Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Trends | Future Importance |
|---|---|---|---|---|---|---|---|
| Steel Sintering Machines | Used to agglomerate ore fines, flue dust, and coke breeze for charging of a blast furnace. These products travel on a traveling grate sintering machine; after ignition is forced up through the mixture causing fusion and agglomeration. | | Low Btu gas | Combustion products and entrained substances from feedstock | Upsets, starting transients | Operation declining because of system incompatability; pelletizing replacing sintering lines | Primary |
| Open Hearth Furnaces | The charge is melted in a shallow hearth by heat from a flame passing over the charge and radiation from the heated dome. Spent combustion gases preheat the inlet combustion gases. | | Low Btu gas such as blast furnace gas | Combustion products and entrained substances from feedstock | Charging, upseting, starting transients. | Basic oxygen furnace in new units; fuel consumption decreasing by 8% per year | Primary |
| Brick and Ceramic Kilns | Tunnel or periodic kiln used most often. Periodic: hot gases drawn over bricks, down through them by underground flues, and out of the oven to the chimmey. Tunnel: cars carrying bricks travel by rail through kiln at about one car per hour. | Kiln product temperatures: 1367 K | Oil, gas, or coal (coal use less common) | Combustion products and entrained subtances from driers and feedstocks. | Charging, upsets, starting transients | Tunnel kilns in new units; continuous production with heat recovery | Primary |

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TABLE 2-7. Concluded

| Process Type | Design Characteristics | Process Ranges | Fuel Consumption (%) | Effluent Streams | Operating Modes | Trends | Future Importance |
|---|---|---|---|---|---|---|---|
| Catalytic Cracking | Preheated gas and oil is charged to a moving stream of hot regenerated catalyst. The gas and oil is cracked in the reactor; products pass through cylone for separation and are then cut into products in fractionator. | Process temperature: 840 to 922K<br>Fuel consumption: 829 kJ/ℓ feedstock. | Oil, gas, or electricity | Combustion products and volatilized products or catalysts | Starting transients, charging | Growth about 2% annually | Primary |
| Process Heaters | Two basic types -- natural draft and forced draft. Constructed as either horizontal box or vertical cylinderical | | 70% process gas | Combustion products | Upsets, start transients | New units are mechanical draft with combustion air preheater | Primary |
| Refinery and Iron Steel Flares | Used for the control of gaseous combustible emissions from stationary sources | | Waste gas | Combustion products | Upsets, transients | | Primary |

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TABLE 2-8. 1974 STATIONARY SOURCE FUEL CONSUMPTION (EJ)[a]

| Equipment Sector | Coal | Oil | Gas | Total Fuel |
|---|---|---|---|---|
| Utility Boilers | 10.833 | 3.483 | 4.906 | 19.222 |
| Packaged Boilers[c] | 3.470 | 5.780 | 6.323[b] | 15.573 |
| Warm Air Furnaces and Miscellaneous Combustion | -- | 2.132 | 5.542 | 7.674 |
| Gas Turbines | -- | 0.844 | 0.681 | 1.525 |
| Reciprocating IC Engines | -- | 0.328[d] | 0.914[e] | 1.242 |
| Total | 14.303 | 12.567 | 18.366 | 45.236 |

[a]EJ/yr = $10^{18}$ J/yr

[b]Includes process gas

[c]This sector includes steam and hot water units

[d]Includes gasoline and oil portion of dual fuel

[e]Includes natural gas portion of dual fuel

U.S. energy use in 1974 totaled about 77 EJ (72 x $10^{15}$ Btu) (Reference 2-11), of which 94 percent was supplied by the fossil fuels coal, petroleum, and natural gas. Approximately 57 percent of the total energy was used by stationary sources. Fossil fuels furnished 92 percent of the energy for these stationary sources; the remainder was supplied by nuclear, hydroelectric, and other miscellaneous sources such as waste fuels, wood, and geothermal. Of the total amount of fossil fuels burned in stationary sources, coal contributed 26 percent, natural gas 44 percent, and petroleum 30 percent. Unlike petroleum, which is also a major source of energy for transportation, coal and natural gas are used primarily in stationary applications.

### 2.2.2 Projected Fuel Consumption

Energy projections were next used to estimate the consumption trends and order-of-magnitude potential environmental problems from stationary source combustion. Since energy supply and demand can vary greatly, several projections for energy growth and equipment/fuel use were selected. These scenarios were selected to cover the range of probable developments in energy supply and consumption.

Five different energy scenarios were examined. The main factors considered in defining each alternative were: (1) the effect of government regulations and policies on the rate of growth in demand for energy resources; (2) the equipment additions, by fuel type, required to meet demand and source attrition; and (3) the effect of oil to coal, gas to coal, and gas to oil conversions on fuel consumption. The five energy alternatives are:

- Reference -- low nuclear
- Reference -- high nuclear
- Conservation
- Electrification
- Synthetics

Figure 2-2 shows the mix of fuels and equipment types for each scenario. These alternatives encompass a variety of contingencies in both total energy demand and demand for specific fuels which lead to important differences in the type and quantity of pollutants released.

In selecting energy alternatives, background information was obtained from the Department of Energy (DOE) and other sources (References 2-11 through 2-27). The DOE projections were used to take advantage of the technical expertise and the wide circulation of their results.

The reference case, high nuclear scenario assumes that current consumption patterns continue with no major design or efficiency improvements in the residential, commercial, or industrial sectors. The scenario assumes no new legislative mandates for energy conservation.

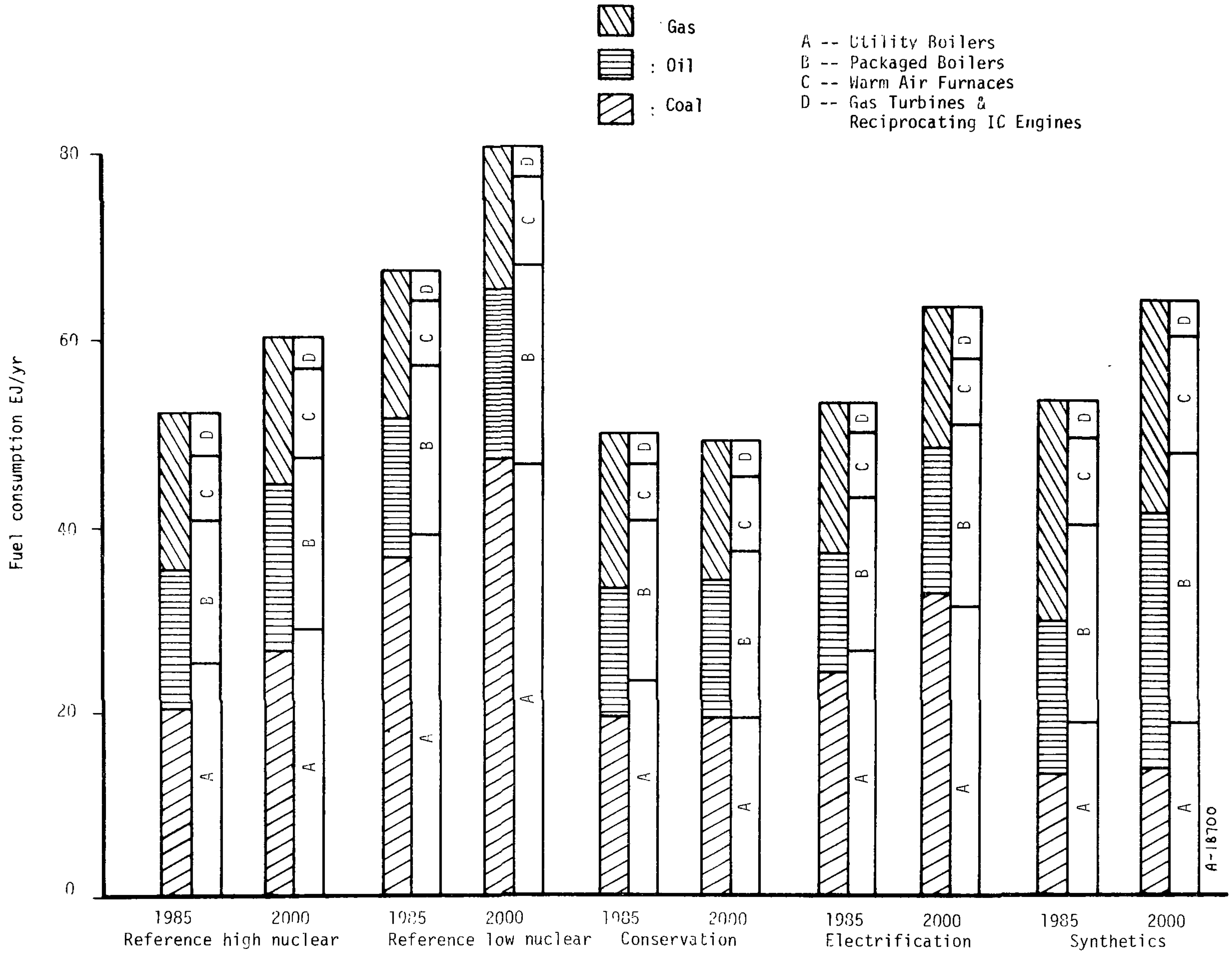


Figure 2-2. Energy scenarios.

However, the dependence of energy demand on energy cost is considered. Coal and nuclear powerplants continue to expand to meet electricity demand. Nuclear powerplants are projected to meet 65 percent of the demand for new power generation by the year 2000. Other energy sources such as geothermal, hydroelectric, and urban waste are projected to grow as required to meet energy demand, without pushing the development of the technology.

The reference case, low nuclear scenario also assumes that current consumption patterns continue. Coal and nuclear powerplants continue to meet new electricity capacity demand. However, this scenario assumes a lower use of nuclear power and a higher use of coal. Nuclear power accounts for 35 percent of new generating capacity through the year 2000, whereas coal accounts for 65 percent. This scenario would occur if there was increased pressure to use our coal resources to meet future energy demand, and if the use of nuclear powerplants continues to be low because of concerns about safety, waste disposal, safeguard costs, or uranium costs.

The conservation scenario was developed to examine energy conservation efforts such as improving energy conversion efficiency and increasing the use of energy resources presently available. This means increasing the recovery of gas and oil (secondary, tertiary recovery) and using waste materials from recycling and energy conversion. Thus, energy demand is effectively reduced, but the major sources of energy remain essentially the same.

The electrification scenario maximizes potential end uses of electricity and uses as much electric generating capacity as possible. In addition, existing oil- and gas-fired equipment is converted to coal where possible.

The synthetics scenario considers the effects of increased supply of synthetic liquids and gaseous fuels. It evaluates the impact of drawing on vast resources of coal and oil shale to produce liquid and gaseous fuels as direct substitutes for petroleum fuels. The total energy use projected is quite close to the reference scenario, although much less oil and natural gas are consumed. This scenario also assumes that growth in electric generating capacity is largely met by light water reactors, so that new coal production can be used for synthetics.

Energy projections by specific equipment/fuel type were generated for 1985 and 2000 for the five scenarios. The resulting projections were carried through the emission projections and the pollution impact evaluation. Summaries of energy consumption in the reference scenarios are given in Table 2-9. Results for the other scenarios are documented in Reference 2-28.

## 2.3 TRENDS IN EQUIPMENT/FUEL USE

From total energy consumption for 2000, energy consumption for specific sectors and equipment/fuel combinations were determined by

TABLE 2-9a. STATIONARY SOURCE FUEL CONSUMPTION FOR THE YEAR 2000: REFERENCE CASE -- LOW NUCLEAR (EJ)

| Equipment Sector | Coal | Oil | Gas | Total Fuel |
|---|---|---|---|---|
| Utility Boilers | 24.398 | 4.339 | -- | 28.737 |
| Packaged Boilers[b] | 2.763 | 8.802 | 6.949[a] | 18.514 |
| Warm Air Furnaces and Miscellaneous Combustion | -- | 2.800 | 6.634 | 9.434 |
| Gas Turbines | -- | 1.752 | 1.390 | 3.142 |
| Reciprocating IC Engines | -- | 0.472[c] | 0.240[d] | 0.712 |
| Total | 27.161 | 18.165 | 15.213 | 60.539 |

[a]Includes process gas

[b]This sector includes steam and hot water units

[c]Includes gasoline and oil portion of dual fuel

[d]Includes natural gas portion of dual fuel

TABLE 2-9b. STATIONARY SOURCE FUEL CONSUMPTION FOR THE YEAR 2000: REFERENCE CASE -- HIGH NUCLEAR (EJ)

| Equipment Sector | Coal | Oil | Gas | Total Fuel |
|---|---|---|---|---|
| Utility Boilers | 42.697 | 4.339 | -- | 47.036 |
| Packaged Boilers[b] | 4.835 | 8.802 | 6.949[a] | 20.586 |
| Warm Air Furnaces and Miscellaneous Combustion | -- | 2.800 | 6.634 | 9.434 |
| Gas Turbines | -- | 1.752 | 1.390 | 3.142 |
| Reciprocating IC Engines | -- | 0.472[c] | 0.240[d] | 0.712 |
| Total | 47.532 | 18.165 | 15.213 | 80.910 |

[a]Includes process gas

[b]This sector includes steam and hot water units

[c]Includes gasoline and oil portion of dual fuel

[d]Includes natural gas portion of dual fuel

evaluating trends in equipment sales and fuels usage. This section discusses these trends for each stationary source sector.

### 2.3.1 Utility Boilers

Tangential, single and horizontally opposed firing, and Turbofurnaces are the most common utility boiler designs. As shown in Figure 2-3 these primary designs will continue to be used extensively through the 1980's. Several recent design changes are being used on tangential and wall fired boilers. New units use reduced heat release rates to suppress slagging and tube wastage and modified combustion conditions to lower $NO_x$ emissions.

Secondary designs -- cyclone, vertical, and stoker firing -- will not be important equipment types because of inherent design limitations. Stokers are limited to about 40 MW electrical output and have high initial costs. Vertical furnaces were developed primarily for firing anthracite coal, which is no longer used as a utility fuel. Cyclone furnaces have not proved adaptable to emission reduction regulations. This slagging furnace must operate at high combustion temperatures, which cause high thermal $NO_x$. It is a desirable choice, however, for high sodium lignite applications.

Pressurized Fluidized Bed Combustion (PFBC) units are being designed for use in combined gas turbine/steam cycles in which the PFBC acts as both the external combustor for the gas turbine and a steam generator for the steam turbine. However, PFBC's will not be commercially developed until the late 1980's and are expected to have an insignificant impact on national fuel usage through 2000.

### 2.3.2 Packaged Boilers

Industrial boiler manufacturers are stressing design flexibility to adapt to changing fuels availability and impending emission limits. Additional emphasis is placed on combustion controls, boiler safeguards and heat recovery equipment for more efficient and reliable operation.

The trend toward fuel flexibility includes provisions for coal firing in most large industrial units. In general, pulverized coal firing is more efficient than stoker firing. In addition, combustion controls may be used effectively on pulverized units while maintaining high operating efficiency. However, as shown in Figure 2-4, stoker demand will grow rapidly because the cost of small pulverized coal units (<60 MW input) is higher for this industrial size category. In addition, stoker fired boilers are able to burn a wide variety of solid byproduct wastes, as well as residual refuse, with minimal preparation. Many solid wastes burned in a pulverized unit would require careful pretreatment, as well as an auxiliary burnout grate in the furnace.

For small applications (<30 MW), alternative steam sources such as firetube, electric, and heat recovery boilers are finding increasing use. Firebox firetube boilers can be designed to fire oil or gas now and coal at some future date by leaving room to add an underfeed stoker.

NOTE: Only coal consumption is shown by equipment types

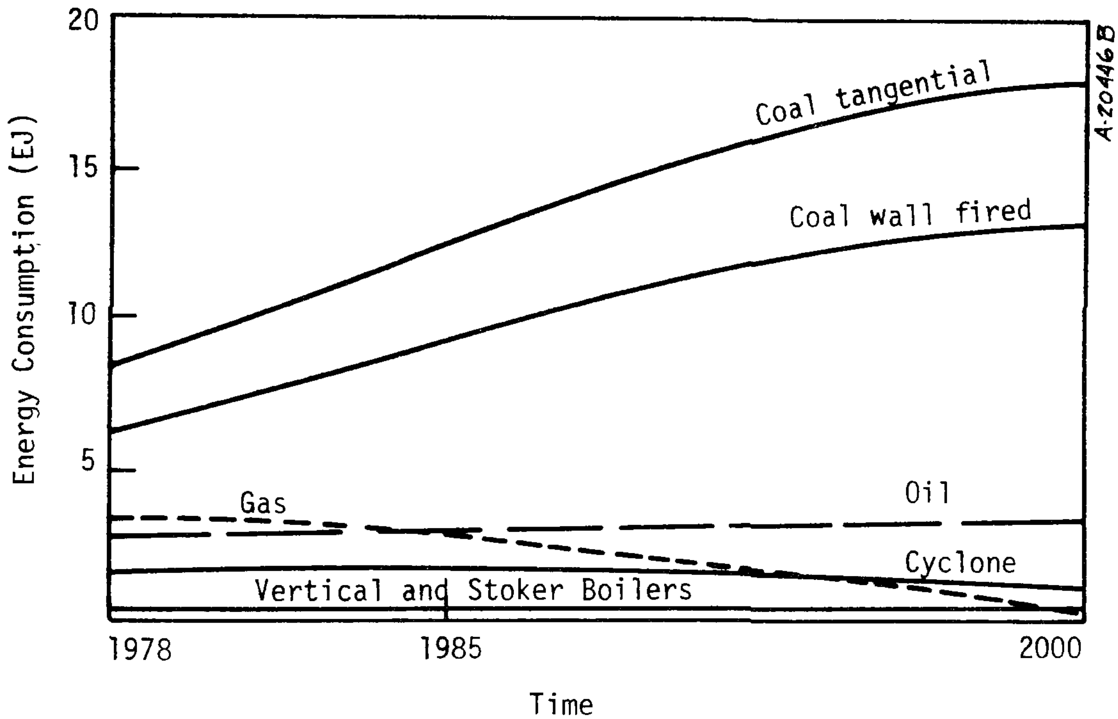


Figure 2-3. National energy consumption and equipment trends for utility boilers.

NOTE: Only coal consumption is shown by equipment types

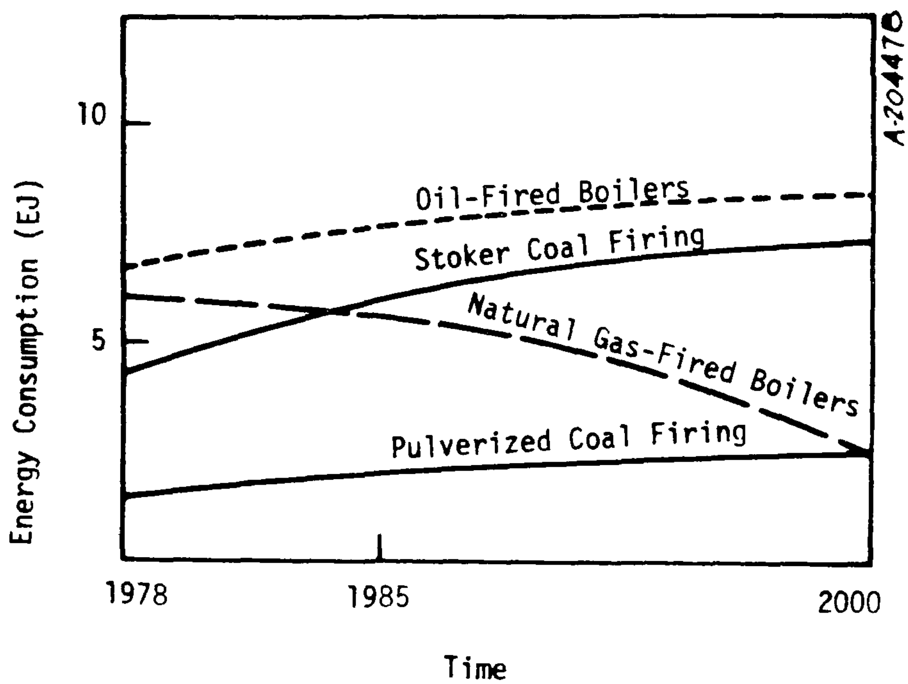


Figure 2-4. National energy consumption and equipment trends for packaged boilers.

Electric boilers have become economically attractive in some areas during the past few years because of environmental pressures and the increasing costs of petroleum fuels. Resistance type boilers are typically limited to about 3 MW whereas electrode boilers are cheaper and more practical at higher ratings.

### 2.3.3 Residential Heating Units

Trends in residential heating units are primarily toward optimized burners that reduce emissions and increase fuel efficiency. Units are presently being designed which use surface combustion of premixed fuel and air on the furnace refractory. Combustion occurs without a visible flame, and heat is transferred from the surface to an air cooled firebox wall by radiation. The surface combustion concept allows operation at low excess air, which improves the furnace efficiency. This unit design should be commercialized in the early 1980's.

An advanced distillate oil burner has also been developed by EPA which reduces $NO_x$ emissions and increases steady state furnace efficiency by up to 10 percent (Reference 2-29). Field demonstrations of a prototype burner installed in its integrated furnace have indicated $NO_x$ reductions of 65 percent compared to conventional residential burner/furnace systems. Furnace efficiencies of 83 to 84 percent were achieved.

Another approach uses a thermal aerosol burner to fire No. 1 and No. 2 fuel oils. This burner operates by heating the fuel and then flashing it in the burner nozzle to produce a mixture of vapor and fine droplets, and is commercially offered as part of the Blue Ray furnace system. The manufacturer claims that clean, efficient combustion can be achieved at low firing rates with excess air as low as 5 to 10 percent resulting in a furnace efficiency of 83 percent. However practical, safe home use may necessitate a much higher excess air level of 20 percent, thus the high furnace efficiency may not be realized.

Figure 2-5 shows fuel use trends for residential heating use. As the figure shows, natural gas is currently the major fuel. Distillate oil, however, is increasing its share of the market and should be the dominant fuel in the future. In addition, there is a continuing trend to electricity for space heating applications.

### 2.3.4 Gas Turbines

The growth in the use of gas turbines has been rapid since the mid-1960's because of their low initial cost, ease of maintenance, high power-to-weight ratio, reliability, and short delivery time. Gas turbines are now being built in larger capacities with improved heat rates. Moreover, combined cycle turbines are becoming the preferred future design for intermediate and baseline applications because of their improved heat rates and fuel flexibility. Present combined cycle plants are economically feasible only for intermediate range systems. Increasing the inlet temperatures to 2000K would improve unit efficiency to about 50 percent. However, these units will not be commercially available until

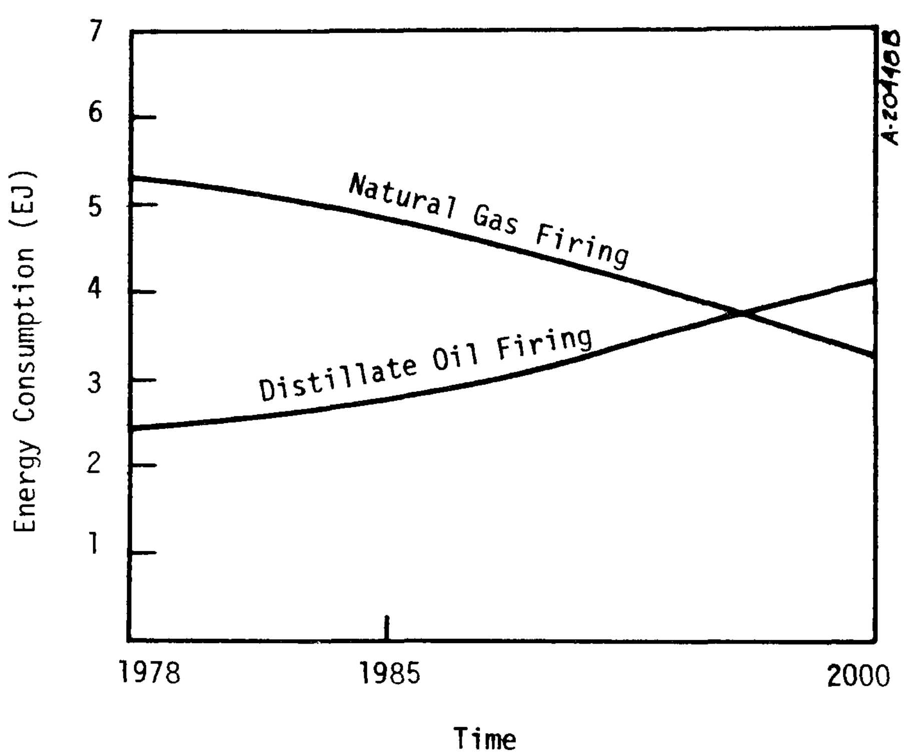


Figure 2-5. National energy consumption and equipment trends for residential and miscellaneous combustion sources.

the mid 1980's and will have negligible fuel use impact nationally through 2000. Users predict that gas turbines will continue to supply about 10 percent of new generating capacity through at least 1985.

The growth in gas turbine use, however, is highly dependent on their potential for burning coal derived fuels while maintaining a high heat rate and competitive initial cost. Since many different liquefaction, gasification, and other fuel cleanup processes are being developed, future turbines must be able to burn a broad spectrum of fuels, with a wide range of contaminant levels. Further, the energy loss in coal conversion creates strong incentives to design more efficient gas turbines and to use them in combined cycle systems for base and intermediate load service. Pressurized fluidized bed combustor (PFBC) development for coal and waste fuels firing is also proceeding. Combustors operating at high pressure offer high efficiency in a combined cycle application. However, substantial efforts are required before PFBC gas turbine combinations can be commercialized. Thus, pressurized fluidized bed combustion will probably not be commercialized until the late 1980's.

### 2.3.5 Reciprocating IC Engines

Reciprocating internal combustion (IC) engines are available in a wide range of sizes and configurations to serve an extremely varied set of applications. The use of large IC engines in baseload electric generation, oil and gas production and transportation, and other such uses should continue to remain strong. However, medium power engines face competition from substitute power sources in nearly all applications, particularly electricity generation. Direct purchase of electricity and use of electric motors require less maintenance and lower initial and operating costs for small general industrial and agricultural applications. Thus, markets for medium power engines are declining except where electricity is inaccessible or impractical. Low power engines are also largely being replaced by electric motors.

Modified designs are being developed for reciprocating IC engines to increase efficiency and reduce emissions. Combustion chamber modifications, and especially improvements to the fuel/air mixing process in the cylinder or the use of a precombustion chamber, are the most promising options. Some manufacturers, however, may elect to use exhaust gas recirculation or water induction. An improved design for large engines should be demonstrated by 1982. No other technology based developments are expected in the foreseeable future for this source category.

### 2.3.6 Process Furnaces

This source category is diverse, and trends in each segment are unique to that industry. Therefore, the following discussion is organized by industry.

Combustion sources in the iron and steel industry include sintering lines, open hearth furnaces, soaking pits, reheat furnaces, and coke ovens. Use of sintering lines is declining at the rate of about 3.4

percent annually because they cannot accommodate rolling mill scale contaminated with rolling oil. Open hearth furnaces are also diminishing in importance, as old units are being replaced by basic oxygen furnaces. The need for soaking pits and reheat furnaces is diminishing, too, because continuous casting of molten metal is becoming the preferred method for making iron and steel.

Overall, the growth of process fuel consumption in the iron and steel industry is about 2.8 percent annually. This includes a projected 5.7 percent annual increase in fuel consumption for coke ovens.

The current trend in the glass industry is towards electric melters. In addition, fuel oil is increasingly being used in place of natural gas because of natural gas shortages and price increases. Coal, for the most part, is an unacceptable fuel for the glass industry because of its impurities. However, coal gasification may become a useful and economically viable fuel source for the glass industry in the late 1980's.

It is expected that many cement industries will convert to coal firing in the near future. According to current DOE statistics, 90 percent of all cement plants should be able to use coal by 1980, compared to 76 percent today. The cement industry has reduced energy consumption by using grate preheaters and quicker, less energy intensive kilns. One further improvement may be to replace traditional rotary kilns with fluidized bed kilns.

Cement industry figures show that the industry has grown at an average rate of about 1.9 percent annually over the past 20 years. Industry projections, however, predict a greater growth in the next few years of between 2.6 to 4.1 percent per year.

Current trends in the petroleum refining industry are toward mechanical draft process heaters with a combustion air preheater, primarily because they conserve more energy than natural draft heaters. Process heaters are fueled primarily (60 to 80 percent) by process gas, a byproduct of the refinery process. The auxiliary fuel is generally oil. However, oil consumption should decline as more process gas with a lower sulfur content is used. Thus, oil consumption should decline by as much as 28 percent. A 2.7 percent annual increase in process heating is projected for 1980, and a 2.9 percent annual increase for 1985.

## 2.4 AVAILABILITY OF ALTERNATE CLEAN FUELS FOR USE IN AREA SOURCES

To better understand the environmental and economic aspects and the near term potential for synthetic clean fuels use in area sources, a separate study on this subject was included as a support task of the $NO_x$ EA. The overall objectives of this study were to identify the scope and timing of current R&D projects aimed at commercializing alternate/synthetic fuels, to assess the potential for use of these fuels in area sources, to evaluate potential impacts on combustion generated air pollutant emissions deriving from their use, and thereby to anticipate control development needs.

The potential alternate fuels studied included low Btu, medium Btu, high Btu (synthetic natural gas), and hydrogen gases; methanol and coal or shale derived liquids; and solvent refined coal (SRC). The initial study was conducted in the first year of the program and documented in Reference 2-29. The conclusions and recommendations of this study were:

- Significant commercialization of any synthetic clean fuel process whose product would be used extensively for area sources will not be realized within the next 10 to 15 years

- Clean fuels use in area sources should be given only minor emphasis in subsequent $NO_x$ EA efforts since pollutant control development for candidate alternate fuels could be accomplished in less than the available 10 to 15 year lead time

- An annual update of the clean fuels study should be made to reevaluate the conclusions in view of the rapid state of flux of synthetic fuels technology and the implications of a national energy policy

The update to the original study discussed below is the result of a continuing survey of alternate fuels developments that occurred during the past year. In general, the conclusions of the original study have been further substantiated.

### 2.4.1 Alternate Liquid Fuels -- Coal Liquids

The primary product of the most promising coal liquefaction processes -- SRC II, H-Coal, and Exxon Donor Solvent -- is a synthetic crude or a heavy oil similar to residual oil. Utility and large industrial boilers are generally considered to be the prime candidate users of these fuels. This equipment sector currently uses a large portion of the petroleum based fuels that would be replaced by synthetic liquids. Area sources are typically not designed for heavy oil firing and, as such will probably not be capable of firing these coal derived liquids.

However, even though area sources cannot fire these synthetic liquids, widespread commercialization of these processes could indirectly affect the area source fuel distribution. The increased use of synthetic liquid fuels by large point sources will in turn increase the availability of petroleum based distillate oils to area sources. For the purposes of this study, combustion control evaluation activities for area sources fueled by petroleum based fuels are already underway.

Of the three most promising liquefaction technologies, SRC II will probably be first to reach the commercialization stage. A feasibility study is now underway, funded by the Department of Energy to build a 230 Mg/h (6000 tpd) demonstration plant. If the decision is made to build, this plant would be operating by 1985. If the demonstration is successful, the process module would be duplicated four times resulting in the first commercial scale plant with a 1.1 Gg/h (30,000 tpd) capacity. Completion of this plant would be in the 1995 to 2000 timeframe.

The H-Coal process is presently undergoing scaleup from a 110 Kg/h (3 tpd) process development unit to a 9.5 Mg/h (250 tpd) pilot plant expected to go online in late 1978. Completion of pilot plant evaluation is scheduled for late 1980 so a demonstration scale process is not expected prior to at least 1985. Consequently significant commercialization of H-Coal liquids cannot be expected before 1995 to 2000.

The Exxon Donor Solvent (EDS) process is in the design and procurement stage of a 9.5 Mg/h (250 tpd) pilot plant scheduled for startup in early 1980. Pilot plant evaluation is scheduled to continue through 1982. A demonstration plant would probably be operating prior to the 1985 to 1990 timeframe. Commercialization of the EDS process is therefore not expected to occur before about 2000.

Based on the above, the potential impact of coal derived liquids to supplant a substantial portion of petroleum derived fuels prior to the year 2000 is negligible. A recent study (Reference 2-30) estimates that by 1990, only 1.3 to 3.3 M ℓ/h (200,000 to 500,000 bbl/day) of coal derived liquids could be available from demonstration plants. This quantity represents less than 10 percent of the projected 1985 and 2000 distillate oil consumptions of residential space heaters (Reference 2-28). Accordingly, emission control research and development directed at area sources firing synthetic coal liquids is not recommended.

### 2.4.2 Alternate Liquid Fuels -- Methanol

An extensive methanol fuels program is presently under consideration by DOE. If the program is pursued, several use demonstrations will be undertaken on highway vehicles, peaking gas turbines, fuel cells, and utility boilers. Methanol is a particularly good substitute for gasoline since it is almost directly interchangeable in the internal combustion engine. As a result, high priority has been placed on developing alcohol as a fuel for highway vehicles. Still, even in stationary source applications, methanol and other alcohol fuels are preferred for the larger combustion equipment and as such will probably not see extensive use in area source equipment prior to 2000.

### 2.4.3 Alternate Gaseous Fuels -- Low Btu Gas

As stated in the original study (Reference 2-29), low Btu gas is currently being pursued as a fuel source for large utility and industrial combined cycle power plants and for utility boilers. The economics of distribution for low Btu gas are such that only short range distribution is feasible. As a result, low Btu gas use in area sources will probably occur only in close proximity to either utility or industrial installations.

Several low Btu gas generation installations are currently underway or planned. Among these are six projects sponsored by DOE (Reference 2-31) that will use the product gas for a variety of industrial and/or commercial applications. In one project the fuel gas will be used to produce hot water and steam for the heating and cooling needs of an entire planned community of housing and associated industry. These DOE demonstration projects are scheduled for startup and testing during the 1979 to 1980 timeframe.

A number of other privately sponsored ventures are also underway. These consist of either user demonstrations or equipment supplier pilot plants. All of these ventures, however, are directed at the large industrial user rather than the smaller commercial or residential combustion equipment.

In summary, it appears that the impact of low Btu gas on the fuel use patterns of area sources will be negligible. The only area source equipment that might be fueled by low Btu producer gas would be at the site or in the vicinity of the gasifier. Research and development work for emission control of low Btu gas combustion specifically for area sources is therefore not recommended.

### 2.4.4 Alternate Gaseous Fuels -- Medium Btu Gas

The obstacles confronting the widespread use of medium Btu gas in area sources are essentially the same as those that confront low Btu gas use in these sources. For medium Btu gases, the economics of distribution are less discouraging but remain sufficently questionable such that under current price and supply projections for petroleum fuels and natural gas, widespread area source use of medium Btu gas is not anticipated.

The marginal economics of distribution for medium Btu gas require that numerous district plants be built rather than a single central plant. Two distinct disadvantages exist with this concept. Oxygen is generally required for the gasification process thereby limiting plant location to one where oxygen is available. Furthermore, the flammability limits of medium Btu gas require that extensive safety precautions be exercised both in preparation and in even the shortest distribution.

At this time then, no emission control development directed at area sources firing medium Btu gas is recommended.

### 2.4.5 Alternate Gaseous Fuels -- High Btu Gas

High Btu gas, sometimes referred to as pipeline quality gas or synthetic natural gas (SNG) is essentially identical in composition to natural gas. Thus as stated in the original report (Reference 2-29) high Btu gas can use the same distribution and combustion systems now being used for natural gas. Control techniques for natural gas should therefore be directly applicable to this synthetic fuel.

### 2.4.6 Summary

The use of alternate clean fuels in area sources will be very limited prior to the 1990 to 2000 timeframe. Even though synthetic clean fuels will be available in increasing quantities after about 1985 to 1990, the majority of these fuels will be used to fire larger point sources. This displacement of conventional fuels in the utility and large industrial systems will provide continued availability of petroleum based liquids and natural gas to area source combustion equipment. Consequently technology development efforts directed at emissions control techniques for clean fuels in area sources are not appropriate at this time.

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# SECTION 3

## CURRENT ENVIRONMENTAL BACKGROUND

As noted in Section 1, one of the major goals of the $NO_x$ EA program is to identify the most cost-effective, environmentally sound $NO_x$ control techniques to attain and maintain ambient air quality standards to the year 2000, and, if adequate controls are unavailable, to recommend R&D priorities to develop needed technologies. A key aspect of satisfying this goal is to identify and incorporate into the analysis the potential effects of evolving regulatory strategies which could impact the need for $NO_x$ controls.

Thus, the primary purposes of this section are to summarize the current regulatory activities that will, or could potentially, affect the need for $NO_x$ controls, and to discuss the impacts of these activities. This will provide the necessary perspective for the evaluation of $NO_x$ control needs to be performed in the systems analysis activities of the $NO_x$ EA.

The passage of the Clean Air Act Amendments of 1977 likely will result in major changes in the strategy for controlling $NO_x$ emissions from stationary sources. The four most significant changes required by the act are the following:

- Requiring EPA to determine whether a short term standard for $NO_2$ ambient concentrations is necessary
- Requiring EPA to include $NO_2$ within the Prevention of Significant Deterioration provisions
- Requiring EPA to promulgate, within five years, NSPS for all major stationary sources, and fixed removal percentages for emissions from fossil fuel fired combustion facilities
- Establishing a 0.62 g/km $NO_x$ emission limit as the standard for light duty vehicles, and relegating the 0.25 g/km $NO_x$ emission limit to a research goal

The first three changes place increased regulatory emphasis on $NO_x$ control. The fourth change essentially shifts a greater portion of the burden of achieving any standard from mobile to stationary sources. The single most important change, however, is the requirement for EPA to make a determination as to the need for a short term standard.

Section 3.1 below describes the current $NO_2$ ambient standard, key $NO_x$ emission regulations, and the status of standard attainment throughout the country. Section 3.2 discusses the status of the $NO_2$ short term standard being developed, and its implications on AQCR attainment/nonattainment throughout the country. Section 3.3 briefly describes other regulatory provisions within the Clean Air Act that can exert significant emphasis on stationary source $NO_x$ control via mechanisms to ensure attainment or maintenance of ambient air quality. Other issues, such as HC control, acid rain, and increased use of coal, which relate to the need for $NO_x$ control are briefly discussed in Section 3.4. In Section 3.5 the status and weaknesses of the present $NO_2$ monitoring system in the U.S., primarily with regard to a short term $NO_2$ standard are discussed.

## 3.1 THE ANNUAL AVERAGE $NO_2$ STANDARD

In April 1971, EPA established $NO_2$ as one of the six criteria pollutants to be regulated under the new Clean Air Act. A primary ambient standard was set at 100 $\mu g/m^3$, annual average, to provide protection with an adequate margin of safety. The actual health effects for an annual period were determined to occur at 150 $\mu g/m^3$.

The existing $NO_x$ emission regulations designed to aid in attaining and maintaining the ambient $NO_2$ annual standard comprise the following: performance standards for mobile sources, New Source Performance Standards (NSPS) for boilers with a firing rate in excess of 73 MW (250 x $10^6$ Btu/hr) and nitric acid plants, and State Implementation Plan (SIP) provisions covering existing stationary sources. The promulgated standards are summarized in Table 3-1. In addition to these, NSPS for $NO_x$ emissions from gas turbines and IC engines and more stringent standards for large steam generators have been proposed or are in preparation. With the exception of motor vehicle standards, few of these regulations present significant compliance problems. Most of the regulations covering stationary combustion sources can be met with modification of combustion practices. For automobiles, the 1.2 g/km standard is being met through use of operational changes and exhaust gas recirculation (EGR), with a conventional oxidation catalyst to counteract resultant increases in HC and CO emissions. The 0.62 g/km standard is to be met through use of a three way catalyst and EGR.

Of the 247 air quality control regions (AQCR's) designated in this country, four are presently declared as nonattainment regions with respect to the 100 $\mu g/m^3$ annual average standard for $NO_2$: (1) Metropolitan Chicago, (067); (2) Metropolitan Denver (036); (3) San Diego (029); and (4) Metropolitan Los Angeles (024) (Reference 3-1). However, the actual number of AQCR's exceeding the standard could be greater, since many AQCR's do not have sufficient data on $NO_2$ ambient levels to determine a valid annual average (see Section 3.5). Table 3-2 shows 16 AQCR's which have been informally considered as potential candidates for designation as $NO_x$ Air Quality Maintenance Areas (Reference 3-2). Moreover, a recent

TABLE 3-1. SUMMARY OF CURRENT NSPS & MOBILE EMISSION STANDARDS FOR $NO_x$

| | Allowed Emission Levels | |
|---|---|---|
| Motor Vehicles | g/km | (g/mi) |
| Automobiles, 1978 | 1.2 | (2.0) |
| Automobiles, 1981 | 0.62 | (1.0) |
| Automobiles, (research goal) | 0.25 | (0.4) |
| Stationary Sources | | |
| Fossil Fuel Fired Steam Generators ($>$73 MW, 250 x $10^6$ Btu/hr) | ng/J | (lb/$10^6$ Btu) |
| Coal-fired (except lignite) | 301 | (0.7) |
| Oil-fired | 129 | (0.3) |
| Gas-fired | 86 | (0.2) |
| Nitric Acid Plants | 1.5 g/kg | (3 lb/ton) |

TABLE 3-2. AQCR'S RECOGNIZED AS POTENTIAL $NO_2$ PROBLEM AREAS[a]

| AQCR | AQCR Number |
|---|---|
| Phoenix | 15 |
| Los Angeles | 24 |
| San Diego | 29 |
| San Francisco | 30 |
| Denver | 36 |
| Springfield, MA | 42 |
| New York City | 43 |
| Philadelphia | 45 |
| Atlanta | 56 |
| Chicago | 67 |
| Baltimore | 115 |
| Boston | 119 |
| Detroit | 123 |
| Canton, OH | 174 |
| Salt Lake City | 220 |
| Richmond, VA | 225 |

[a]Reference 3-2

study concluded that a greater than 50 percent chance exists that 34 AQCR's would be judged in nonattainment if sufficient data were available (Reference 3-3).

Predictions of the number of AQCR's likely to be in violation of the annual average standard in the future are hindered not only by the lack of current data but also by inconsistent trends in monitored $NO_2$ concentrations for sites with several years of data (Reference 3-4). However, a generalized assessment of the change in the number of violators is possible by considering the contribution of point and area sources to annual $NO_2$ levels.

Recent work suggests that the major contributors to annual average $NO_2$ violations are area sources (both mobile and dispersed stationary sources, such as fossil fuel fired residential heating). Unlike point sources, area sources emit pollutants near the ground, allowing little effect from weather variations, and usually are concentrated within a given region. The effect of area sources on local $NO_2$ concentrations is fairly constant and, when a number of area sources are located close together, high annual average concentrations can result. On the other hand, point sources tend to emit $NO_x$ in concentrated form at higher altitudes and point source emissions are thus susceptible to a great deal of weather variations. Moreover, point sources often are more diffusely sited than area sources.

Thus, based on the reasonable assumption that annual average $NO_2$ concentrations are due primarily to area sources, changes in the number of violators can be approximated from changes in area source emission patterns. In fact, area source emissions should be less than the 1975 values in the near term for several reasons:

- Automobiles will be meeting more stringent emissions requirements*
- Fossil fuel fired residential heating units may be replaced by electric heating**
- Growth in area sources will probably not occur in already high emission areas***

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*Based on reasonable assumptions for vehicle populations and use, control deterioration factors, and source growth (~3 percent per year) the ratio of future mobile source emissions to 1975 emissions is projected to be 0.80, 0.82, 1.1 in 1985, 1990 and 2000, respectively.

**This will increase point source emissions which will, in turn, increase the point source contribution to the annual average.

***Based on space limitations for stationary sources and traffic density limitations for mobile sources in high emission areas.

If these trends occur, total reductions in area source $NO_x$ emissions should occur through 1985, even though the number of stationary sources may increase. Such conditions may improve or at least stabilize annual average $NO_2$ levels through 1985. However, beyond 1985, the growth in area sources (and point sources) may more than compensate for decreased mobile and stationary source emission factors, and aggravated $NO_2$ annual average levels may result. Without additional controls, it is estimated that a 25 percent increase in annual average $NO_2$ levels by the year 2000 will occur (see Section 8.2.1). Nevertheless, such predictions, although reasonable, remain conjectural considering the length of time over which emissions projections must be made and the absence of more specific modeling data on future ambient $NO_2$ annual levels.

## 3.2 SHORT TERM $NO_2$ STANDARDS

The existing ambient air quality standard for $NO_2$ was promulgated in April 1971. The primary basis for this standard was epidemiological evidence from 1968 to 1969 studies of school children and family groups residing downwind from an explosives plant in Chattanooga, Tennessee. These studies linked respiratory infection to annual $NO_2$ exposures of about 150 $\mu g/m^3$ (0.08 ppm) and higher. Based on later data, however, and a better understanding of the role of elevated short term exposures in the original Chattanooga study, it became evident that the annual standard of 100 $\mu g/m^3$ may not sufficiently protect public health.

Studies performed by the World Health Organization (WHO) and in Japan had demonstrated that harmful effects can result from short term exposures to $NO_2$. These studies in turn have led to the Japanese Government's adoption of a one hour $NO_2$ standard which is effectively six to seven times more stringent than the present EPA annual average for $NO_2$. Aware of these events, EPA reexamined the Chattanooga data to evaluate the study's validity as a basis for a short term $NO_2$ standard. If short term exposures could be correlated with respiratory or other health problems, a short term standard could be developed. Based on available health study data, EPA concluded that if concentrations exceeded 200 $\mu g/m^3$ no more than 10 percent of the time, then adverse effects on human health would be prevented. Using statistical techniques, EPA then concluded that if the 100 $\mu g/m^3$ annual average standard is maintained, the short term criterion (of no more than 10 percent of the measured one hour concentrations in excess of 200 $\mu g/m^3$) would be achieved in every AQCR except Chattanooga.

However, in light of continuing studies on short term $NO_2$ exposures, it became clear that the necessity for a short term $NO_2$ standard needed to be further assessed. Accordingly, the Clean Air Act Amendments of 1977 require EPA to promulgate, not later than August 1978, a national primary air quality standard for $NO_2$ concentrations over a period of not more than three hours, unless it is demonstrated that sufficient evidence for such a standard does not exist.

Since the enactment of the Clean Air Act Amendments, EPA has released a draft summary of the scientific basis for a short term $NO_2$ standard (Reference 3-5). A public meeting to receive comments from industry and the public was held in Washington, D.C. in April 1978. Based on these, a standard in the range of 250 to 1000 $\mu g/m^3$ for a one hour average is being considered. However, no recommendation has yet been submitted, and it now appears that proposal and promulgation will be delayed until 1979.

In the following subsections causes of high short term $NO_2$ levels are described, and the results of an analysis of predicted high short term $NO_2$ levels in Chicago are presented. The potential for violation of various short term standards is discussed. Potential point source dominated violations are examined using a modeling technique, and potential area source dominated violations are considered by evaluating monitoring data.

### 3.2.1 Causes of High Short Term $NO_2$ Levels

Recent studies performed by EPA have shown that high short term $NO_2$ concentrations come about through any one of several paths:

- Area source emissions (both mobile and dispersed stationary sources)
- Isolated point sources with multiple combustors impacting on a single site
- Multiple point sources impacting on the same receptor
- Both area and point sources with all sources contributing to high concentrations
- Terrain impaction by a plume from a large point source

The relative importance of these paths is highly dependent on both the level which is established as the short term standard and the relative contribution of each "source" to the short term $NO_2$ levels. Moreover, the $NO_x$ control requirements may be significantly different for each path.

An assessment of high short term $NO_2$ concentrations must therefore consider each type of source (point and area) and its respective contribution to ambient concentrations. Although studies have shown that either type can lead to relatively high concentrations, the nature of their impacts is different. Point sources tend to produce infrequent and spatially confined $NO_2$ peaks, although the slow formation rate of $NO_2$ smooths out these "hot spots" to some extent. Area sources, on the other hand, are less varied in their impact on peak $NO_2$ levels in both time and space.

Meteorological conditions can also determine the role of both point and area sources in the short term buildup of pollutants. High ground level concentrations from elevated point sources can be caused by surface inversion breakup, fumigation (plume trapping where the plume is confined beneath an elevated inversion), or plume downwash where the plume intersects the ground quickly. The meteorological parameters that frequently characterize these conditions are an unstable atmosphere (stability class of B or C) and moderate to high wind speeds. On the other hand, the greatest impacts of ground level sources, such as vehicles and other area sources (including point sources with short stacks), occur when the atmosphere is quite stable (stability class of D or E*), wind speeds are low, and mixing heights are small. The meteorological conditions that maximize the impact of either point sources or ground level area sources thus are at two opposite extremes, discouraging their individual maximum impact from occurring simultaneously. However, the difference in the impact of either source type at the maximum impact condition and that of the other source type may not be very large.

For these reasons, studies performed in support of a short term $NO_x$ standard have sought to model the $NO_x$ emissions of point and area sources together to determine what conditions maximize the contribution of one or the other, or both, to short term $NO_2$ concentrations. One such study employed a multiple point and area source model (RAM) to model $NO_x$ source contributions to the air quality in the Chicago AQCR (Reference 3-6).

The RAM model is a Gaussian steady-state model capable of predicting short term ambient concentrations of relatively stable pollutants from multiple point and/or area sources. However, $NO_2$ is primarily a secondary pollutant formed by oxidation of NO. The initial NO concentration present in exhaust gases, the plume diffusion and travel time, and the ambient concentration of photochemical oxidants and reactive hydrocarbons are some of the most important factors that affect conversion of NO in a plume to $NO_2$. Consequently, a dynamic model of $NO_2$ formation from point source $NO_x$ emissions has been used in conjunction with RAM to translate the predicted $NO_x$ concentrations at a receptor arising from point source contributions to $NO_2$ concentrations. For estimating area source contributions to the background concentrations in this study, a fixed $NO_2/NO_x$ ratio for each period of the day, based on observed data at continuous monitoring sites in Chicago, was used to translate ambient $NO_x$ concentrations derived from area sources into the corresponding $NO_2$ levels.**

The results from this Chicago study (Reference 3-6) are summarized in Table 3-3. Part (a) of the table shows the results for meteorological conditions which maximize the point source impact relative to the area source impact. The five highest $NO_2$ concentrations and the corresponding

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*All AQCR's listed in Table 3-2 have predominantly D and E stability classes

**An assumption used in the work of Reference 3-6 was that most monitors in urban areas are sited to reflect contributions primarily from area sources of $NO_x$ emissions. This assumption appears true based on available evidence.

TABLE 3-3. COMPARISON OF ESTIMATED $NO_2$ LEVELS FROM POINT AND AREA SOURCES UNDER DIFFERENT METEOROLOGICAL CONDITIONS IN CHICAGO* ($\mu g/m3$)(Reference 3-6)

| Five Highest Concentrations | (a) Meteorology for Maximum Relative Point Source Impact ($\mu g/m^3$) | | | (b) Meteorology for Maximum Relative Area Source Impact ($\mu g/m^3$) | | | (c) Maximum Total Impact ($\mu g/m^3$) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total | Point | Area | Total | Point | Area** | Total | Point | Area |
| 1 | 509 | 428 | 81 | 568 | 549 | 19 | 603 | 493 | 110 |
| 2 | 589 | 409 | 81 | 479 | 279 | 200 | 602 | 434 | 168 |
| 3 | 348 | 209 | 139 | 472 | 272 | 200 | 600 | 407 | 193 |
| 4 | 348 | 225 | 123 | 472 | 272 | 200 | 598 | 430 | 168 |
| 5 | 342 | 219 | 123 | 472 | 272 | 200 | 553 | 383 | 170 |
| Average concentration for all receptors above 200 $\mu g/m^3$ | 277 | 165 | 111 | 371 | 142 | 199 | 316 | 142 | 174 |
| Number of Receptors above 200 $\mu g/m^3$ | | 47 | | | 68 | | | 67 | |

*Cook, Dupage, and portions of Will, Lake and Porter Counties

**The receptors used in the analysis were selected to record maximum total concentration. Other receptors may reflect higher area source contributions, but lower total concentrations.

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area and point source contributions to these concentrations, the number of receptors reporting one hour levels above 200 μg/m$^3$, and the average concentration for these receptors are shown. Part (b) shows the results for meteorological conditions which maximize the relative area source impact. Results for meteorological conditions which lead to the maximum total concentrations are shown in part (c). A summary of the conclusions from this study is presented below:

- $NO_x$ emissions from either point or area sources can result in high short term $NO_2$ concentrations, although the point sources are the major contributors*

- Two distinct groups of point sources can be identified in terms of their response (dilution and $NO_2$ formation rate) to different meteorological conditions: (1) plants with tall stacks such as utilities, and (2) plants with a large number of short stacks such as steel mills and refineries

- The diffusion characteristics of the second point source group seem to be similar to those of the area sources

- The meteorological conditions that maximize the impact of sources with high effective stack heights are different from the conditions that result in high concentrations from both area sources or point sources with short effective stack heights

- A set of meteorological conditions closer to the area source maxima on the spectrum of diffusion conditions resulted in the highest short term $NO_2$ concentrations

These conclusions indicate that differing meteorological conditions can maximize contributions of point and area sources, separately or synergistically. For sources in urban areas, the multiple point and area source influence is overriding ("maximum impact case" in Table 3-3). In this case, point source influences are at a maximum simultaneously with high area source contributions.

### 3.2.2 Potential Extent of Short Term $NO_2$ Violations

Of major concern from the perspective of $NO_x$ control requirements is the extent (severity) of nonattainment on a nationwide basis for various levels of short term $NO_2$ standard. As noted above, ambient concentration levels of $NO_2$ are created by a mix of emissions from both types of sources. However, the two categories of sources may be evaluated separately to determine possible $NO_2$ short term concentrations under differing situations. Such a procedure has recently been employed to determine the nationwide impacts of meeting a possible short term $NO_2$

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*Note that discussion in the preceeding subsection attributed high <u>annual average</u> $NO_2$ concentrations primarily to area sources.

standard. Highlights of this work, reported in Reference 3-7, are described in the following paragraphs.

Point Source Impacts

Because detailed modeling of all point sources in each AQCR is far too ambitious for a nationwide study, a "model plant" technique was devised using National Emission Data System (NEDS) data. This analysis modeled a series of prototypic combustion plants which ranged in size and operating parameters corresponding to various source categories (e.g., utility boilers, industrial boilers, and furnaces). The plants were analyzed individually, using a simple Gaussian dispersion model and meteorological conditions associated with ground level maximum $NO_2$, to assess the air quality impacts of all respective $NO_x$ sources in the NEDS file. The ground level $NO_x$ concentrations around each point source characterized by the dispersion model were translated into $NO_2$ using the dynamic $NO_x$ to $NO_2$ conversion model referred to in the discussion of the RAM model.

Area source contributions to background $NO_2$ levels were determined from $NO_2$ monitoring information within individual AQCR's. Studies have shown that the annual average $NO_2$ concentrations in urban areas are mainly due to area source influence and are relatively less sensitive to point source impacts. Consequently, it is reasonable to use observed annual average concentrations to quantify the area source influence.*

The results of the point source analysis showed that a total of 4069 sources associated with 408 industries located in about 119 AQCR's would produce violations of a 250 $\mu g/m^3$ one hour standard. For a 500 $\mu g/m^3$ standard, the number of affected sources and AQCR's decreases significantly: 79 industries with about 1113 processes in about 30 AQCR's would produce violations. Table 3-4 shows the types of processes nationwide that are likely to be associated with violations of various standard levels. Table 3-5 lists the corresponding number of AQCR's projected to be in violation in 1975 and in 1982 for various short term $NO_2$ standards.

Area Source Impacts

As a means to capture the maximum impact of area source emissions directly, a simple modeling analysis (Reference 3-8) was used on monitored $NO_2$ concentrations (and current $NO_x$ emission levels for mobile and stationary sources) in those AQCR's which may experience future short term problems. As previously stated, the $NO_2$ monitoring networks in most

*Based on the Chicago study, 1.5 times the highest recorded annual average $NO_2$ was estimated as the area source background for the point source analysis.

TABLE 3-4. ESTIMATED POINT SOURCE RELATED VIOLATIONS OF VARIOUS ONE HOUR $NO_2$ STANDARDS (Reference 3-7)

| Source Category | Number of Sources Exceeding the Specified One Hour $NO_2$ Concentration ($\mu g/m^3$) | | | |
|---|---|---|---|---|
| | 250 | 500 | 750 | 1000 |
| Utility Boilers -- Coal | 350 | 42 | 15 | 0 |
| Utility Boilers -- Oil and Gas | 599 | 7 | 0 | 0 |
| Industrial Boilers -- Coal | 300 | 72 | 10 | 0 |
| Industrial Boilers -- Oil and Gas | 742 | 207 | 108 | 21 |
| Gas Turbines | 268 | 19 | 10 | 5 |
| Reciprocating IC Engines | 698 | 516 | 376 | 278 |
| Industrial Processes | | | | |
| • Combustion | 1045 | 235 | 114 | 17 |
| • Nitric Acid | 61 | 19 | 3 | 3 |
| Municipal and Industrial Incinerators | 11 | 1 | 0 | 0 |
| Total | 4074 | 1118 | 636 | 324 |

TABLE 3-5. ESTIMATED NUMBER OF AQCR's IN VIOLATION OF ONE HOUR $NO_2$ STANDARD BASED ON POINT SOURCE IMPACT (Reference 3-7)

| Standard ($\mu g/m^3$) | AQCR's in Violation | |
|---|---|---|
| | 1975 | 1982[a] |
| 1000 | 6 | 6 |
| 750 | 11 | 11 |
| 500 | 30 | 28 |
| 250 | 119 | 116 |

[a]In 1982, assumes 3 percent annual growth rate in VMT and expected 20 percent overall reduction in area source emissions due to mandatory mobile source emission reduction requirements

AQCR's are believed to reflect the impact of area, as opposed to point, source emissions. Thus, using ambient air quality data to analyze short term $NO_2$ pollution from area sources is justifiable.

The sample of AQCR's on which the area source analysis was based included all those estimated to have current one hour $NO_2$ concentrations above 200 $\mu g/m^3$ (Reference 3-8). Table 3-6 summarizes the results of the area source analysis in terms of two growth scenarios: 1) "low," assuming zero percent and one percent increases in stationary and mobile sources, respectively; and 2) "high," assuming one percent and three percent increases in stationary and mobile sources, respectively. Both scenarios assume mobile source emission standards will remain as currently mandated. Except for the 250 $\mu g/m^3$ standard, only a few AQCR's are estimated to be in nonattainment status due to area source emissions. The current Federal motor vehicle control program is seen to effect a considerable improvement in attainment status over time, although almost 70 AQCR's may still experience violations in 1990 for the 250 $\mu g/m^3$ standard. It is important to note the major impact of vehicle emission controls is realized in the late 1980's. This and the conservative growth rates are the primary reasons that air quality is shown to improve in this period. However, after 1990 air quality is projected to deteriorate (see Section 8.2.1).

In summary, violations of possible short term standards may be caused by either point or area source emissions and could occur for a variety of meteorological conditions. Based on the results given in Tables 3-5 and 3-6, it appears that at least 119 AQCR's, based only on point source analyses, would be in violation of a 250 $\mu g/m^3$ standard (in 1975) if sufficient monitors were available to record them (see Section 3.5). Moreover, it is unlikely that these 119 AQCR's include all 94 estimated in the area source analysis; therefore, the number in violation is estimated to be 158. However, less than 100 AQCR's currently would be in nonattainment based on $NO_2$ levels recorded at existing monitors, which are predominately located to reflect area source impacts (Table 3-6). By 1982, and without additional emission controls, the violating AQCR's could be as few as 68 (current monitor placement) or 116 (ideal monitor placement). Considering probable duplication in violating AQCR's in Tables 3-5 and 3-6, the number of nonattainment AQCR's in 1982 for a 250 $\mu g/m^3$ standard is estimated to be 145. Of course this estimate is again based on conservative growth rates and a successful mobile source task $NO_x$ control program. Thus, the number of violations is projected to continue to decrease until the mid to late 1980's and then start to increase.

## 3.3 OTHER CLEAN AIR ACT PROVISIONS

Overall, promulgation of the short term $NO_2$ ambient standard may be viewed as the most important immediate regulatory development relating to $NO_x$ controls needs. However, other significant Clean Air Act (CAA) provisions also govern (or will govern) the need for $NO_x$ controls. These include New Source Performance Standards (standards of performance for new stationary sources, NSPS) governing the emissions of $NO_x$ from specific sources; Prevention of Significant Deterioration (PSD) provisions

TABLE 3-6. ESTIMATED NUMBER OF AQCR's IN VIOLATION OF ONE HOUR $NO_2$ STANDARD BASED ON AREA SOURCE IMPACT[a] (Reference 3-7)

| Standard ($\mu g/m^3$) | Number of AQCR's in Violation | | | | |
|---|---|---|---|---|---|
| | 1975 | 1982 | | 1990 | |
| | | High Growth[b] | Low Growth[b] | High Growth | Low Growth |
| 1000 | 0 | 0 | 0 | 0 | 0 |
| 750 | 2 | 2 | 0 | 0 | 0 |
| 500 | 17 | 10 | 4 | 7 | 2 |
| 250 | 94 | 84 | 68 | 73 | 45 |

[a]Based on 150 AQCR's recording (or estimated to exhibit) second highest one hour $NO_2$ levels of 200 $\mu g/m^3$ or more in 1975

[b]"Low growth" assumes a one percent annual growth rate for VMT and a zero percent annual growth rate for stationary area sources. "High growth" assumes a three and one percent annual growth rate for VMT and stationary area sources, respectively. Statutory mobile source emission standards are also assumed.

governing both $NO_x$ emissions and ambient concentrations; and the nonattainment policy governing both $NO_x$ emissions and ambient concentrations.

New Source Performance Standards are technology based emission standards. Development of NSPS will affect specific technologies at different times; in general, however, the implications of NSPS will be straightforward, requiring available control of $NO_x$ emissions from individual source categories at a cost determined by EPA to be appropriate.

The implications of the PSD and nonattainment provisions, on the other hand, are not so straightforward. The nature and the stringency of either provision as applied to stationary sources will depend on the short term $NO_2$ standard promulgated. In essence, the short term $NO_2$ standard provides only a foundation for the establishment of appropriate PSD and nonattainment regulations, which actually impact sources of $NO_x$ through implementation of the individual SIP's.

In this section the PSD and nonattainment provisions of the CAA as they relate to a short term $NO_2$ standard are discussed. It is important to note that SIP regulations arising from either provision affect technology cost, through $NO_x$ emission control requirements, on a regional basis, depending on the short term $NO_2$ air quality of that region.

### 3.3.1 Prevention of Significant Deterioration

Prevention of Significant Deterioration provisions (Sections 160 through 169 of the CAA) are designed to protect air quality in areas now meeting all ambient standards. PSD regulations perform three interrelated functions: (1) they limit the degradation of air quality in "clean air" areas; (2) they provide a mechanism to regulate pollutant emissions from new sources; and (3) they allow the individual states to determine the degree of new source growth desired in clean air areas.

The PSD provisions outlined in the CAA allow for three area classification categories: Class I, where practically any air quality deterioration would be precluded; Class II, where deterioration in air quality arising from moderate growth would not be considered significant; and Class III, where intensive and concentrated industrial growth can occur while not departing from the intent of the PSD regulations. The area classification plans are to be executed and enforced through revised SIP's.

Specific ambient pollutant increment concentrations are assigned to each classification category which, when added to the determined "baseline" pollutant concentrations in a given area, prescribe the maximum allowable air quality degradation for that area. The number of new sources or expansions allowed in a given area are regulated through the preconstruction permitting process. This process requires a new source to demonstrate its strategy for compliance with the PSD increments and, among a number of specific stipulations, requires new sources to employ "best available control technology" (BACT). BACT, as defined by the Act, means an emission limitation based on the maximum degree of pollutant reduction available, taking into account energy, environmental, economic, and other costs. In no event can BACT mean an emission limitation less stringent than that allowed under the NSPS for a particular source. The most important aspect of BACT is that the States are empowered to determine it on a case by case basis.

The Clean Air Act stipulates that the pollutants sulfur dioxide ($SO_2$) and particulates presently be covered by PSD regulations within SIP's. By 1980 the EPA is to conduct a study to determine whether and how other pollutants also are to be covered by PSD. The pollutants to be studied include nitrogen oxides, hydrocarbons, carbon monoxide, and photochemical oxidants. The regulations, if and when the EPA does promulgate them, must provide specific measures at least as effective as the increments established for $SO_2$ and particulates. Such measures may include air quality increments and specific numerical measures against which permit applications may be evaluated.

Implications of PSD

If a short term $NO_2$ standard is promulgated, PSD provisions will affect the initial siting and/or the expansion (or addition) of major stationary sources with respect to $NO_x$. Depending on the level of the $NO_2$ ambient standard, $NO_2$ PSD provisions may establish lower levels of allowed $NO_2$ ambient degradation to protect the air quality in different PSD classification regions. In all cases, PSD provisions will enforce the use of BACT on stationary sources as a mechanism to ensure compliance with allowed short term ambient concentrations of $NO_2$.

The type and level of control established under BACT can vary according to different regions, since it is a case by case determination allowing states to choose the amount of new source growth desired. In essence then, the implications of any PSD $NO_2$ regulations are economic; they concern the cost of controlling new sources in a region so as to ensure compliance with an established level of $NO_2$ ambient degradation. Unfortunately, it is difficult to predict the regional impacts of a $NO_x$ PSD regulation since: (1) the level of $NO_2$ ambient degradation allowed under PSD is unknown, and (2) the nature of BACT and the amount of local growth desired cannot be assumed.

### 3.3.2 The Nonattainment Policy

The nonattainment provisions of the Clean Air Act Amendments of 1977 outline regulations governing the introduction of new sources in regions which have been shown by monitoring data (or calculated by air quality modeling) to exceed any national ambient air quality standard. Under the CAA, revised SIP's for these regions must assure attainment of primary air quality standards for $NO_x$ and the other criteria pollutants no later than December 31, 1982; with respect to especially severe oxidant and carbon monoxide problems, the deadline may be extended to December 31, 1987.

Before July 1, 1979, the interpretive EPA regulation published December 21, 1976, governing nonattainment regions shall apply to new sources wishing to enter such regions. The EPA regulations specify an emissions "trade-off" policy which requires:

> "emission reductions from existing sources in the area of a proposed source (whether or not under the same ownership) such that the total emissions from the existing and proposed sources are sufficiently less than the total allowable emissions from the existing sources under the SIP prior to the request to construct or modify, so as to represent reasonable progress toward attainment of the applicable NAAQS."

"Trade-off" may occur only if the state has an enforceable SIP which requires new sources to meet Lowest Achievable Emission Rate (LAER).*

After July 1, 1979, the state must have a revised and approved implementation plan, assuring attainment as a precondition for the construction or modification of any major stationary source. This plan must include a permitting process for construction or modification of major stationary sources in nonattainment areas. A permit may only be granted if the following conditions are met:

- Total emissions in the proposed modification/construction area must be significantly less after the modified or new facility is in operation than before

- The proposed source is in compliance with LAER

- The owner or operator of the proposed new or modified source has demonstrated that all major stationary sources owned or operated by such person in such state are in compliance, or on a schedule for compliance with all applicable emission limitations and standards under the Act

Implications of the Nonattainment Policy

The implications of the nonattainment policy, much like those arising from PSD, primarily concern the economics of facility siting and operation. Unlike PSD, which governs pollutants in areas now meeting ambient standards, the nonattainment provisions provide mechanisms designed to ensure attainment in those areas presently violating standards with regard to a particular pollutant. To progress toward attainment, the nonattainment provisions stipulate that emissions from existing sources be reduced accordingly. If new sources are to be added in the region, the

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*LAER is defined as the lowest applicable emission rate contained in any State Plan or the lowest emission rate achievable in practice by that category of source, whichever is lower.

nonattainment provisions require that emissions from existing sources be reduced so that resulting total emissions represent progress toward attainment, and that new sources meet very strict emission limitations, essentially regardless of the cost.

If a short term $NO_2$ standard is promulgated, the states must revise their SIP's within nine months. The SIP revisions must provide attainment of the standard within three years. In this regard, attainment of a one hour $NO_2$ standard may be required by mid-1982. Depending on the level of standard set, the number of regions placed in violation of the standard and the cost to attain the standard will vary.

A primary element of the studies supporting EPA's development of a short term $NO_2$ standard has been to estimate the cost of attainment/compliance with various standard levels being considered. In one such study (Reference 3-7), the cost to attain a 250 $\mu g/m^3$ ambient one hour $NO_2$ level in the Chicago AQCR was assessed for three different control approaches. The control strategies considered were:

- Least cost -- controls applied to specific sources only as necessary to reduce ambient concentrations below the required level for the meteorological conditions leading to maximum ambient levels*

- RACT with least cost -- all point sources initially are required to implement controls that have been demonstrated and are reasonably economical (Reasonable Available Control Technology). Additionally, incremental controls that are needed to meet the standard after RACT implementation are imposed in a cost minimizing manner.

- Maximum feasible control -- all sources implement the greatest degree of $NO_x$ control available. This is comparable to a situation in which all sources are required to reduce emissions by 90 percent, regardless of their impact on air quality

In all three cases, the control approaches were designed to achieve the standard at all receptors based on existing sources; they did not consider new sources and the associated cost of achieving LAER and purchasing offsets.

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*Under the least cost solution, at each receptor, each contributing source is controlled to the level at which its marginal cost of control per unit reduction in ambient $NO_2$ concentration is less than that for any other source contributing to the same receptor. Once the source with the lowest marginal cost is controlled to this level, other sources are controlled in sequence, starting with the source with the next lowest cost, until the standard has been achieved at all receptors.

TABLE 3-7. SIMULATION OF RESULTS FOR ATTAINMENT OF A 250 $\mu g/m^3$ ONE HOUR $NO_2$ STANDARD IN THE CHICAGO AQCR (Reference 3-7)

| | Sources Controlled[a] | Emissions Reduction (Mg/hr) | Annual Control Cost to Emitters ($10^6$ \$/yr) |
|---|---|---|---|
| Pure Least Cost | 94 | 2.3 | 21 |
| RACT w/Least Cost | 797 | 18.2 | 53 |
| Maximum Feasible Control | 797 | 48.1 | 588 |

[a]No new sources considered

The estimated costs of attainment for each of these cases are shown in Table 3-7. The pure, least cost solution provides attainment without necessarily requiring controls for all existing sources. The RACT with least cost option affords attainment through implementation of available control to all existing sources and any additional control thereafter required to attain the standard. The maximum feasible control option "penalizes" all point sources regardless of their contribution to ambient standard violations. This latter situation may depict a nonattainment AQCR implementing a control strategy that provides for the maximum growth allowance attainable. As expected, this strategy results in the greatest cost impact. It is also quite clear that the control approach to attainment will have a tremendous impact on the number of sources controlled, the amount of pollutant removed, and the technical requirements placed on the control technology itself.

## 3.4 RELATED ISSUES

In this section three additional issues associated with $NO_x$ control needs are briefly discussed: the interrelationship of $NO_x$ and HC control strategies on both $NO_2$ and oxidant, other secondary pollutants related to $NO_x$, and the increased utilization of coal.

### 3.4.1 The $NO_x$-HC Relationship

The interrelationship of $NO_x$ and HC emissions in affecting $NO_2$ and oxidant ambient concentrations is a well known fact; although the specific details are not that clearly understood. Smog chambers and analytical photochemical models have been used to study the chemistry of the $NO_x$-HC system. The necessity to consider this connection in the evaluation of control strategies has been recognized by EPA and is contained in the isopleth method for assessment of control needs for meeting ambient oxidant levels (Reference 3-9).

It is now clear that any control strategy for one of these pollutants must consider the consequent impact on ambient levels of both $NO_2$ and oxidant. This is made more complex because the impact depends on the existing ambient concentrations, the spatial scale of interest, and the time duration of interest. For example, control measures to maximize improvement in urban $NO_2$ may result in an increase in rural (downwind) oxidant levels. As another example, control strategies to reduce one hour peak concentrations may only shift the occurrence of the peak (in time or space) or may reduce the peak but have no effect on the annual average. Extensive study of the oxidant problem in the San Francisco AQCR (Reference 3-10) has shown the detrimental effects of $NO_x$ control on attainment of ambient oxidant goals. However, it is also recognized that current, or future, violations of $NO_2$ standards must be anticipated. Generally, it appears that the best approach will be simultaneous control of both $NO_x$ and HC with the particular mix being determined by AQCR specifics. (Results for such strategies for the San Francisco AQCR are presented in Section 8.2.2.)

### 3.4.2 Secondary Pollutants

Acid rain, nitrate aerosols, organic aerosols, sulfate aerosols, PAN (peroxyacetylnitrate), and nitrosamines are either known or thought to be secondary pollutants of $NO_x$. Presently, EPA does not regulate these pollutants. However, studies to determine the necessity for their regulation are being conducted.

Promulgation of a short term $NO_2$ standard could result in a reduction in the occurrence of these pollutants, although, in many cases, their link to $NO_x$ has not been verified. How a short term standard will affect possible regulation of these secondary pollutants is unknown. Of the pollutants mentioned, acid rain is the closest to being regulated. EPA is conducting continuing studies on acid rain and hopes to regulate it by 1981. Studies on sulfate aerosols also are being conducted; whether they will be regulated, however, is unclear. If sulfate aerosols are regulated, it may be to protect visibility, and not as a requisite to protecting public health. Presently, EPA cannot ascertain whether $NO_x$ is implicated in sulfate aerosol formation.

Nitrate aerosols, organic aerosols, and PAN most likely will not be regulated for 10 years or more. Presently, EPA has tremendous difficulty measuring nitrate and organic aerosols. These problems must be resolved to better understand the role of $NO_x$ in the formation of these pollutants. With regard to PAN, EPA will examine the role and formation of this pollutant when it next reassesses the existing annual $NO_2$ standard.

How these secondary pollutants will be regulated is not clear. It is possible that, in some cases, regulation would take the form of further restrictions on $NO_x$ emissions beyond those required to comply with a short term $NO_2$ standard for certain regions. However, until the role of

$NO_2/NO_x$ in the formation of these pollutants is better understood, the interaction of the short term $NO_2$ standard with the occurrence of and possible regulation of secondary pollutants cannot be evaluated.

### 3.4.3 Coal Utilization

In general, coal combustion results in higher emissions of $NO_x$ than comparable combustion processes utilizing oil or gas. Consequently, depending on the standard level chosen, attainment of a short term $NO_2$ standard may be difficult and/or costly for those areas having substantial numbers of coal based emission sources. In some respects, promulgation of a short term $NO_2$ standard may have the most significant policy implication on the role of coal in the National Energy Plan. Unfortunately, studies supporting EPA's development of a short term $NO_2$ standard have examined the standard's implication primarily with regard to the existing fuel use structure of industries and utilities and have not treated potential increased coal usage. Thus, any conclusion drawn here would be premature.

## 3.5 THE $NO_2$ MONITORING NETWORK

The discussion in the preceeding sections focused on the implications of various regulatory activities in driving the need to develop and implement stationary source $NO_x$ control techniques. Implicit in all this discussion is the fact that $NO_x$ control needs are really defined by the extent of the potential violation problems associated with any given regulation or standard. Of course, the number and extent of standards violations can only be determined from readings obtained through an air quality monitoring network. Thus, it seems appropriate here to briefly discuss the status, and potential shortcomings of the existing $NO_2$ monitoring network.

Two types of ambient $NO_2$ monitors are currently in use in the U.S.: 24 hour bubblers and continuous monitors. The 24 hour bubblers, most of which use the sodium arsenite method, can be used to determine annual average $NO_2$ concentrations. The continuous monitors, most of which use the chemiluminescence or the Saltzman method, are used to measure both one hour and annual average $NO_2$ levels. The sodium arsenite, chemiluminescence, and continuous Saltzman method all are considered acceptable monitoring methods by EPA.

In 1975 and 1976, approximately 1613 to 1740 $NO_2$ monitors operated in the U.S.; of these, only about 260 were continuous monitors (as shown in Table 3-8). EPA considers the existing 24 hour monitoring network, designed to record annual average $NO_2$ concentrations, as too extensive. Consequently, EPA is recommending that the number of 24 hour bubblers be reduced, as more continuous monitors come into use, since continuous monitors are capable of supplying both short term and annual average $NO_2$ concentration measurements.

Although most of the continuous monitors are placed in large cities, a number of cities with populations greater than 200,000 have no continuous monitors. Thus, if a one hour $NO_2$ standard is promulgated,

TABLE 3-8. THE U.S. $NO_2$ MONITORING NETWORK

| Monitors in Operation | | | | Monitors Recording Valid Annual Averages |
|---|---|---|---|---|
| Year | Continuous | 24 Hour | Total | |
| 1975 | 258 | 1355 | 1613 | 715 |
| 1976 | 260 | 1480 | 1740 | 1123 |

each state would have to assess the adequacy of its continuous monitoring network, and upgrade it, if necessary, as part of its State Implementation Plan revision in response to the new standard. The adequacy of the monitoring network will thus vary from region to region and will be evaluated by EPA on a regional basis in its review of SIP's.

In any event, if continuous $NO_2$ monitors were common in all AQCR's the likelihood of any AQCR violating the various suggested short term $NO_2$ standards could be determined with ease. Unfortunately, continuous monitors are not common. As a consequence, the potential for violation must be judged from 24 hour readings or annual averages. This can be done by establishing peak to mean ratios for representative continuous monitors and using these values to extend the annual average values determined from the 24 hour monitors.

Evidence now available suggests that the ratio of one hour peak readings to annual average levels for area source dominated monitors is less than six to one (References 3-3 and 3-8). Moreover, it has been reported that the average peak to mean ratio lies between six and seven for continuous monitors in central urban commercial and residential areas (Reference 3-11). Area sources are undoubtedly the major contributors to the $NO_2$ concentrations at these sites, although point sources in the region do have some impact. However, the ratio due to the area source impact alone should be below this six or seven peak to mean value. The peak to mean range of four to six, therefore, seems to be associated with sites impacted predominantly by area sources, and urban area monitors reporting peak to mean ratios of over six are believed to be significantly impacted by point sources.

As a general rule, annual average $NO_2$ values can be extended to peak one hour values by assuming a peak to mean ratio of six. It should be noted, however, that monitors intended to provide annual average data may not be properly located to record maximum one hour values and that locations heavily impacted by point sources may have peak-to-mean values as large as 12. Thus estimates of the impact of various short term standards using extensions of existing annual average data at a ratio of six to one should be considered as conservative.

## 3.6 SUMMARY

In this section, a variety of environmental issues related to assessing present and future $NO_x$ control requirements have been discussed. Many points were brought out which deserve summary and reiteration. Therefore, the main points of the discussion are summarized and the major conclusions are as follows:

- Promulgation of a short term $NO_2$ standard may have major impact on $NO_x$ control needs and $NO_x$ control strategies
- Area sources (mobile and dispersed stationary) appear to be the primary contributors to high annual average $NO_2$ levels

- Large point sources or concentrated smaller point sources appear to be the major contributors to high short term $NO_2$ levels, although, area sources may also be significant contributors

- Four AQCR's are presently in nonattainment with respect to the 100 $\mu g/m^3$ annual average, based on current monitoring data. It is estimated that 30 more would be in violation if sufficient monitoring data were available.

- Approximately 100 AQCR's would presently be in violation of a short term standard of 250 $\mu g/m^3$, based on estimates from current monitoring station data

- The number of AQCR's in violation of short term or annual average standards will probably decrease in the near term (1980 to 1990) but increase in the long term (2000) without additional stationary source control beyond current and projected NSPS

- PSD and nonattainment regulations in conjunction with a short term standard, will have major impacts on $NO_x$ control requirements, the number of sources controlled, and the cost of control

- Simultaneous control of $NO_x$ and HC must be considered if both $NO_2$ and oxidant ambient goals are to be met

- The current monitoring network reflects the impact of area sources and, even so, does not adequately measure the extent of violation of the annual average

- If a short term standard is promulgated, many more continuous monitors will be required to adequately measure short term $NO_2$ levels. It will be necessary to site these monitors to record the impact of point sources.

REFERENCES FOR SECTION 3

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3-6. "$NO_x$ Source Assessment of the Impacts of the Chicago AQCR - Volume III," Draft report prepared for EPA by Energy and Environmental Analysis, Inc., Arlington, VA, December 1978.

3-7. "Estimated Cost of Meeting Alternative Short-Term $NO_2$ Standards - Volume II," Draft report prepared for EPA by Energy and Environmental Analysis, Inc., Arlington, VA, December 1978.

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3-10. "Environmental Management Plan for the San Francisco Bay Region - Draft Air Quality Maintenance Plan," Prepared by the Association of Bay Area Governments, the Bay Area Air Pollution Control District, and the Metropolitan Transportation Commission, December 1977.

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# SECTION 4

# ENVIRONMENTAL OBJECTIVES DEVELOPMENT

Addressing the goals of the $NO_x$ EA program, as stated in Section 1, requires performing impact assessments of $NO_x$ sources and source/control combinations of three general types:

- Multimedia environmental impact assessments of individual sources under both baseline and controlled operation
- Operational and cost impact evaluations of applying $NO_x$ combustion modification controls to individual sources
- Air quality impact assessments of applying different $NO_x$ control strategies to the accumulation of sources on a regional basis

Thus, at the individual combustion source category level, evaluations are needed of the environmental impact of the multimedia pollutant emissions from a given source under both uncontrolled (or baseline) and controlled (for $NO_x$) operation. Such evaluations are needed not only to guide the setting of priorities for control development recommendations. They are also needed to allow overall impact comparisons between baseline operation and the application of various $NO_x$ control options to ensure that the $NO_x$ control techniques are environmentally sound, and to provide a basis for identifying preferred means of control.

Impact assessments of this type require the development of Source Analysis Models (SAM's) which translate multimedia pollutant emissions data into measures of potential hazard to health and welfare. Thus, such SAM's will take emissions data, compare these to health or ecological effects indicators, and output quantitative indicators of potential for environmental harm.

Also needed at the individual source level are procedures for assessing the effects of $NO_x$ control application on source efficiency, operation, and costs of operation. These evaluations are needed to flag potential adverse operational impacts of $NO_x$ control and to evaluate their cost effectiveness and economic soundness. To perform this kind of assessment requires detailed process and cost analysis methods.

Finally, evaluations are needed of the effects on ambient air quality of applying various $NO_x$ control strategies on a regional basis. These are required so that the preferred, environmentally sound, and cost-effective control strategies can be identified and, if found insufficient, control R&D needs and recommendations can be formulated. These assessments require the development of ambient air quality models which translate source emissions data to ambient pollutant levels on a regional basis.

The development of methodologies to address each of the above assessment needs is described in this section. Thus, Section 4.1 describes the form of several Source Analysis Models developed for pollutant impact assessments; Section 4.2 describes the process and cost analysis methods used to evaluate the operational and cost impacts of applying $NO_x$ controls to a given source; and Section 4.3 discusses the systems analysis models used to evaluate the effects of various control strategies on regional ambient $NO_2$ and $O_3$ levels.

## 4.1 SOURCE ANALYSIS MODELS

As noted above, Source Analysis Models (SAM's) are required in environmental assessment activities to treat source emissions data by comparing them to health/ecological effects indicators and thereby translate them into quantitative measures of potential environmental hazard. In the $NO_x$ EA, SAM's have been, or are being, developed for performing these comparisons in three levels of mathematical detail. These SAM's are intended for use not only within the $NO_x$ EA, but in other IERL environmental assessments as well. The three levels of SAM's currently defined are:

- SAM IA -- designed for rapid screening
- SAM I -- designed for intermediate screening
- SAM II -- designed for regional site evaluation

All SAM's developed will use, as the requisite health/ecological effects indicators, the set of Multimedia Environmental Goals (MEG's) developed elsewhere (Reference 4-1). These MEG values represent either defined maximum allowable effluent stream pollutant concentrations based on acute toxicity considerations, or maximum allowable ambient pollutant levels based on chronic exposure considerations. MEG's of the first type (allowable effluent concentrations) are termed Minimum Acute Toxicity Effluent (MATE) values. MEG's of the second type (allowable ambient levels) are termed Estimated Permissible Concentrations (EPC's) or Ambient Level Goals (ALG's).

Thus, each SAM developed will provide structured comparisons between source pollutant emissions levels and a given set of MEG's to produce the desired measures of multimedia environmental impact of a pollutant source. To date procedures for SAM IA and SAM I have been developed. In addition, an extended form of SAM I representing a projected approach to SAM II has been defined. An overview of each of these methodologies follows. The detailed formulation of the SAM II model will be performed in future efforts; thus it is not discussed below.

### 4.1.1 SAM IA

SAM IA was the first of the models developed and was designed for rapid screening applications. In this relatively simple model, comparisons between discharge stream pollutant concentrations are made directly to corresponding MATE values. Individual pollutant Potential Degrees of Hazard (PDOH) are defined as the ratio of an undiluted pollutant concentration to its MATE value. A further impact indicator, the Potential Toxic Unit Discharge Rate (PTUDR), is defined as the product of the PDOH with discharge stream flow rate. PDOH's and PTUDR's are then summed over all pollutants emitted in a given stream to yield the desired measures of potential environmental impact. Details of the model are explained more fully in Reference 4-2.

It should be noted here that efforts are currently underway to incorporate the results of bioassay testing (Reference 4-3) into SAM IA so that chemical analysis results from emissions testing can be qualitatively compared to corresponding bioassay results. These efforts are not yet complete.

### 4.1.2 SAM I

The next most sophisticated model developed was the SAM I model, developed for intermediate screening purposes. SAM I comparisons incorporate ambient level MEG's. Thus, in SAM I ambient MEG values are translated to pollutant emission level concentration goals through the use of dilution factors. Dilution factors were thus defined for a set of discharge stream/receiving medium combinations (e.g., gaseous stream discharge to the atmosphere, liquid stream discharge to a river, solid stream discharge to a waste pile, etc.) based on the application of dilution models.

A given pollutant emission level concentration goal is defined as the product of an appropriate dilution factor with the pollutant ambient MEG value. From this the pollutant species Potential Degree of Hazard is defined as the ratio of the effluent stream pollutant concentration and its emission level concentration goal. The corresponding PTUDR is defined as the product of this PDOH with the given pollutant species mass discharge rate.

As in SAM IA, PDOH's and PTUDR's are summed for each discharge stream to provide the desired overall measures of potential environmental impact. Further details of this model are given in Reference 4-4.

### 4.1.3 Extended SAM I

An extended form of SAM I was also developed to form a more fundamental basis for the baseline combustion source impact rankings discussed in Section 8.1. In this model a more detailed treatment is given to gaseous stream emissions to the atmosphere, while the SAM IA methodology is retained for liquid and solid effluent streams.

In the treatment of gaseous effluents, the extended SAM I model explicitly applies mathematical dispersion models in a continuous fashion in contrast to the discrete treatment adopted in SAM I. Point source emissions are treated using the Gaussian dispersion model tabulations of Turner (Reference 4-5). Area sources are treated using the dispersion model of Holzworth (Reference 4-6).

The environmental impact indicator defined in this extended SAM I model is termed a potential impact factor and represents the ratio of resultant ground level ambient pollutant concentration to the corresponding MEG value integrated over exposed population. The model also incorporates differing urban and rural population densities, and installed pollutant source densities, and factors in corrections for ambient background pollutant concentrations. Details of this model are documented in Reference 4-7.

## 4.2 PROCESS IMPACTS EVALUATION

Evaluating the effectiveness and impacts of $NO_x$ combustion controls applied to stationary sources requires assessing their effects on both controlled source performance, (especially as translated into changes in operational limitations, operating costs, and energy consumption) and on incremental emissions of pollutants other than $NO_x$. In this section, the methods developed for use in the $NO_x$ EA to evaluate process impacts -- correlation of $NO_x$ emissions with boiler/fuel variables, detailed process analysis procedures, and cost analysis of controls -- are discussed. The discussion centers on utility and large industrial boilers, the largest source of stationary combustion source $NO_x$, and the source category treated in detail in second year efforts. The results from applying the methodologies presented below to data assembled for utility boilers are discussed in Section 7.

### 4.2.1 $NO_x$ Emissions Correlation

The key boiler/burner design and operating variables and fuel properties affecting $NO_x$ formation were identified by performing statistical correlations of $NO_x$ emissions data with these parameters. Thus, the basis and effectiveness of control techniques which modify these parameters were assessed. A second order regression model was used to fit uncontrolled and controlled $NO_x$ emission data from field tests on a total of 61 boiler firing type/fuel combinations. These combinations, the controls applied, and the individual test points correlated are summarized in Tables 4-1 and 4-2. The correlation parameters considered in the analysis were:

- Boiler operating variables:
  - -- Overall furnace fuel/air stoichiometry
  - -- Stoichiometry at active burners

TABLE 4-1. FIELD TEST PROGRAM DATA COMPILED

| Fuel | Firing Type | | | Total |
|---|---|---|---|---|
| | Tangential | Opposed Wall | Single Wall | |
| Coal | 13 | 6 | 10[a] | 29 |
| Oil | 2 | 7 | 7 | 16 |
| Natural Gas | 1 | 8 | 7[b] | 16 |
| Total | 16 | 21 | 24 | 61 |

[a]Includes two wet bottom furnaces
[b]Includes one unit originally designed for coal firing with a wet bottom furnace

## TABLE 4-2. INDIVIDUAL TEST POINTS CORRELATED

| Firing Type | Fuel | Baseline[b] | Single Controls | | | | Combined Controls[a] | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | LEA[c] | OSC[d] | FGR[e] | Low Load[f] | Low load + OSC | Low Load + FGR | OSC + FGR | Low Load + OSC + FGR | |
| Tangential | Coal | 21 | 29 | 46 | -- | 24 | 27 | -- | -- | -- | 147 |
| Opposed Wall | Coal | 8 | 11 | 11 | 7 | 7 | 5 | 1 | 2 | -- | 52 |
| Single Wall | Coal | 18 | 23 | 29 | -- | 19 | 19 | -- | -- | -- | 108 |
| Tangential | Oil | 1 | -- | 1 | -- | 1 | 1 | 1 | -- | 1 | 6 |
| Opposed Wall | Oil | 6 | 5 | 11 | 2 | 7 | 7 | 5 | 2 | 11 | 56 |
| Single Wall | Oil | 4 | 6 | 5 | 4 | 8 | 6 | 10 | 10 | 8 | 61 |
| Tangential | Nat gas | 1 | 1 | -- | 2 | 2 | 1 | 5 | 1 | -- | 13 |
| Opposed Wall | Nat gas | 7 | 9 | 18 | -- | 13 | 13 | 3 | 3 | 8 | 74 |
| Single Wall | Nat gas | 5 | 4 | 9 | 2 | 7 | 7 | 3 | 4 | 5 | 46 |
| All Boilers | All fuels | 71 | 88 | 130 | 17 | 88 | 86 | 28 | 22 | 33 | 563 |

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[a]Low excess air also generally employed

[b]Baseline = no controls applied; boiler load near or at maximum rating; excess air at normal or above normal settings

[c]LEA = low excess air setting

[d]OSC = off stoichiometric combustion (includes: biased burner firing, burners out of service, overfire air)

[e]FGR = flue gas recirculation; generally includes low excess air setting

[f]Load less than 80 percent of maximum continuous rating (MCR)

- -- Percent flue gas recirculated
- -- Firing rate
- -- Percent burners firing
- -- Heat input per active burner

- Boiler design variables:
  - -- Maximum continuous rating
  - -- Volumetric heat release rate
  - -- Surface heat release rate
  - -- Heat input per active burner
  - -- Number of burners
  - -- Number of furnaces
  - -- Number of division walls

- Fuel properties:
  - -- Fuel type (coal, oil, and natural gas)
  - -- Fuel nitrogen
  - -- Fuel moisture
  - -- Heating value

A multiple regression procedure was developed which statistically correlated $NO_x$ emissions with the key parameters. This regression model served as a predictive tool in estimating the emissions impact of $NO_x$ controls, as well as identifying the important design and operating parameters affecting $NO_x$ formation.

Results from applying this correlation model to utility boiler field test data are discussed in Section 7.1.

### 4.2.2 Process Analysis Procedures

To evaluate the impact of controls on process operation, detailed process variable data compiled for baseline and for low $NO_x$ operation were analyzed and compared. Significant changes in the process variables were noted, and these were highlighted as real or potential problems. A summary of field test programs used as sources of process data is given in Table 4-3. Specific test report references can be found in Reference 4-8. Process variables investigated are itemized in Table 4-4.

TABLE 4-3. SUMMARY OF PROCESS DATA SOURCES

| Furnace Type | Fuel | Boiler | Manufacturer | Utility Company | $NO_x$ Control Technique | New or Retrofit |
|---|---|---|---|---|---|---|
| Tangential | Coal | Barry No. 2 | CE | Alabama Power | BOOS, OFA | Retrofit |
| | | Barry No. 4 | CE | Alabama Power | LEA, BOOS | -- |
| | | Huntington Canyon No. 2 | CE | Utah Power and Light | OFA | New, NSPS |
| | | Columbia No. 1 | CE | Wisconsin Power & Light | OFA | New, NSPS |
| | | Navajo No. 2 | CE | Salt River Project | LEA, BOOS, OFA | New, NSPS |
| | | Comanche No. 1 | CE | Public Service of Colorado | OFA | New |
| | | Kingston No. 6[a] | CE | Tennessee Valley Authority | LEA, BBF, BOOS | -- |
| Opposed Wall | Coal | Harllee Branch No. 3 | B&W | Georgia Power | LEA, BOOS | -- |
| | | Four Corners No. 4 | B&W | Arizona Public Service | BOOS, WI | -- |
| | | Hatfield No. 3 | B&W | Allegheny Power Service | BOOS, FGR | New |
| | | E.C. Gaston No. 1 | B&W | Southern Electric Generating | LNB, LEA, BOOS | Retrofit |
| | | "B&W Units Nos. 1 & 2"[a] | B&W | -- | LNB | New, NSPS |
| | | "FW Unit No. 1"[a] | FW | -- | LEA, OFA, LNB | Retrofit |
| Single Wall | Coal | Widows Creek No. 5 | B&W | Tennessee Valley Authority | LEA, BOOS | -- |
| | | Widows Creek No. 6 | B&W | Tennessee Valley Authority | LEA, BOOS | -- |
| | | Crist Station No. 6 | FW | Gulf Power | LEA, BOOS | -- |
| | | Mercer No. 1 | FW | Public Service Electric & Gas | LEA, BBF | -- |
| | | "FW Unit No. 2"[a] | FW | -- | LEA, OFA, LNB | Retrofit |
| | | "FW Unit No. 3"[a] | FW | -- | LEA, OFA, LNB | New, NSPS |
| Tangential | Oil | South Bay No. 4[a] | CE | San Diego Gas & Electric | LEA, BOOS, RAP | -- |
| | | Pittsburg No. 7 | CE | Pacific Gas & Electric | OFA, FGR | Retrofit |
| | | -- | CE | Southern California Edison | FGR, BOOS | New |
| Opposed Wall | Oil | Moss Landing Nos. 6 & 7[a] | BW | Pacific Gas & Electric | OFA, FGR | Retrofit |
| | | Ormond Beach Nos. 1 & 2 | FW | Southern California Edison | FGR, OFA, BOOS, WI | OFA New<br>FGR Retrofit |
| | | -- | B&W | Southern California Edison | FGR, OFA, BOOS | OFA New<br>FGR Retrofit |
| | | Sewaren Station No. 5 | B&W | Public Service Electric & Gas | LEA, BOOS | -- |
| Single Wall | Oil | Encina Nos. 1, 2 & 3[a] | B&W | San Diego Gas & Electric | LEA, BOOS | -- |
| Turbo Furnace | Oil | South Bay No. 3[a] | RS | San Diego Gas & Electric | Air adjustment, WI, RAP | Retrofit |
| | | Potrero No. 3-1 | RS | Pacific Gas & Electric | OFA, FGR | Retrofit |

[a]Denotes new results or previously unreported data

TABLE 4-3. Concluded

| Furnace Type | Fuel | Boiler | Manufacturer | Utility Company | $NO_x$ Control Technique | New or Retrofit |
|---|---|---|---|---|---|---|
| Tangential | Gas | South Bay No. 4[a] | CE | San Diego Gas & Electric | LEA, BOOS | -- |
| | | Pittsburg No. 7 | CE | Pacific Gas & Electric | OFA, FGR | Retrofit |
| Opposed Wall | Gas | Moss Landing Nos. 6 & 7[a] | B&W | Pacific Gas & Electric | OFA, FGR | Retrofit |
| | | Pittsburg Nos. 5 & 6 | B&W | Pacific Gas & Electric | OFA, FGR | Retrofit |
| | | Contra Costa Nos. 9 & 10 | B&W | Pacific Gas & Electric | OFA, FGR | Retrofit |
| Single Wall | Gas | Encina Nos. 1, 2 & 3[a] | B&W | San Diego Gas & Electric | BOOS | -- |
| Turbo Furnace | Gas | South Bay No. 3[a] | RS | San Diego Gas & Electric | Air adjustment WI, RAP | Retrofit |
| | | Potrero No. 3-1 | RS | Pacific Gas & Electric | OFA, FGR | Retrofit |

[a]Denotes new results or previously unreported data

TABLE 4-4. PROCESS VARIABLES INVESTIGATED

| Process Variables |
| --- |
| Boiler Load |
| Furnace Excess Air |
| Excess Air at Firing Zone |
| Percent Oxygen in Flue Gas |
| Percent Oxygen in Windbox |
| Furnace Cleanliness Condition |
| Percent Overfire Air |
| Percent Flue Gas Recirculation |
| Burners Out of Service |
| Damper Positions |
| Burner Tilt |
| Flowrates: |
| Superheater Steam |
| Reheater Steam |
| SH Attemperator Spray |
| RH Attemperator Spray |
| Airflow |
| Fuel Flow |
| Pressures: |
| Steam Drum |
| SH Steam Outlet |
| RH Steam Outlet |
| Furnace |
| Windbox |
| Fan Inlet |
| Fan Discharge |
| Temperatures: |
| Superheater Steam |
| Reheater Steam |
| Air Heater Air In/Out |
| Air Heater Gas In/Out |
| Furnace Gas Outlet |
| Stack Gas Inlet |
| Heat Absorption: |
| Furnace |
| Superheater |
| Reheater |
| Economizer |

TABLE 4-4. Concluded

| |
|---|
| Fan Power Consumption |
| Gas Emissions: |
| $NO_x$ |
| $SO_x$ |
| Carbon Monoxide |
| Hydrocarbons |
| Polycyclic Organic Matter |
| Particulate Loading |
| Particulate Size Distribution |
| Ringleman Smoke Density |
| Carbon/Unburned Fuel Loss |
| Additional Factors Considered: |
| Corrosion Rates |
| Slagging and Fouling |
| Flame Instability |
| Furnace Vibration |
| Fan and Duct Vibrations |

Wherever possible, comparisons of baseline and controlled operation were made on tests which were similar in the general operating characteristics tested. Steam flow and load conditions, overall excess air levels, furnace conditions, etc., were matched for the baseline and controlled tests selected for comparison.

In certain tests, where process data were sufficiently detailed, overall mass and energy balances were conducted. The mass balances were used to determine the amount of gaseous pollutants and particulate and solid matter emitted by the boiler under baseline and low $NO_x$ conditions. Overall energy balances were used to check boiler efficiencies. Energy balances on individual boiler components established the distribution of heat absorption in the boiler. Attemperator spray flowrates were checked by heat and mass balances on superheater and reheater sections. Air and gas volume flowrates were calculated to determine the effect of changed operating conditions on fan draft and power requirements.

For coal-fired tests, data were collected on carbon loss in flyash, furnace slagging, and water wall tube corrosion. Data were also obtained from some tests on coal- and oil-fired boilers on particle loading and size distribution. Some data, mainly for oil and gas fuels, were also available on flame stability, furnace vibrations, superheater tube temperatures, and flame carryover to the convective section.

Comparisons of the process data were made for baseline and low $NO_x$ modes of operation. Significant changes in the process variables were noted and evaluated for their impact on emissions and boiler operation and maintenance. The results from applying this analysis to the utility boiler data on units noted in Table 4-3 are discussed in Section 7-2.

### 4.2.3 Cost Analysis Procedures

Representative control costs were generated for typical boiler/control combinations using regulated utility economics. First, typical boilers were identified using the EPA's Energy Data System (Reference 4-9). The cases selected were a tangential coal-fired unit to power a 225 MW turbine generator, a 540 MW opposed wall coal-fired unit, and a 90 MW front wall oil- and gas-fired unit. Primary considerations in making these selections included:

- The trend toward coal firing, particularly in larger size units, emphasizes tangential and opposed wall firing designs
- Many units are capable of burning both oil and gas, especially in the smaller size ranges. Single wall (front or rear) fired units are common in this application.
- The average control cost on a per unit output basis is not a strong function of unit size. Hence a representative unit size was judged adequate.

Preliminary engineering designs of the $NO_x$ controls that would be required for the selected boilers were prepared. This design work provided an estimate of the hardware and installation requirements for applying retrofit controls. Up to date vendor quotations were obtained. In addition, the design effort permitted estimating the actual engineering time required for implementing controls.

The cost analysis was based on the annualized revenue approach, adapted from that used by the Tennessee Valley Authority in evaluating the cost of powerplant projects for EPA (Reference 4-10) and EPRI (Reference 4-11). Details of the cost analysis algorithm adopted are given in Reference 4-8.

The use of accepted estimation procedures for costing $NO_x$ control implementation in current dollars was employed, with heavy reliance on discussions with boiler manufacturers, equipment vendors, and utilities. Use of the annualized cost methodology then permitted a systematic, well documented, up to date cost analysis of typical controls for representative boiler design/fuel classifications. In this manner, the cost effectiveness of controls was compared from boiler to boiler on a consistent basis.

Results from applying this procedure to costing $NO_x$ controls for the aforementioned utility boiler cases are given in Section 7.3.

## 4.3 SYSTEMS ANALYSIS METHODS

The purpose of the systems analysis is to provide a quantitative basis for identifying the future needs (when, where, how much, and what kind) for $NO_x$ controls to satisfy the requirements of the Clean Air Act. This information will be used in the program to recommend R&D directions and schedules for developing necessary controls.

In the systems analysis, uncontrolled emissions projections, controls cost and effectiveness data, fuel costs, and ambient air quality goals are combined to evaluate the control needs for a particular Air Quality Control Region (AQCR). The elements of the systems analysis model developed are shown in Figure 4-1. The specific air quality issues which must be assessed were discussed in Section 3. In this section, the methods used for the systems analysis are briefly described. Results of applying the analysis are presented in Section 8.2.

### 4.3.1 Preliminary Model

The most critical element in the systems analysis is the air quality model. Candidate models differ not only in their degrees of sophistication, but also in their resolution and versatility. Usually, the sophisticated models require more elaborate input data than the simpler models, a significant amount of calibration, and considerable experience to use them intelligently. On the other hand, the simpler models, which try to model the atmospheric processes in an integral manner, are based on many correlations of the available data and lack the resolution of the sophisticated models.

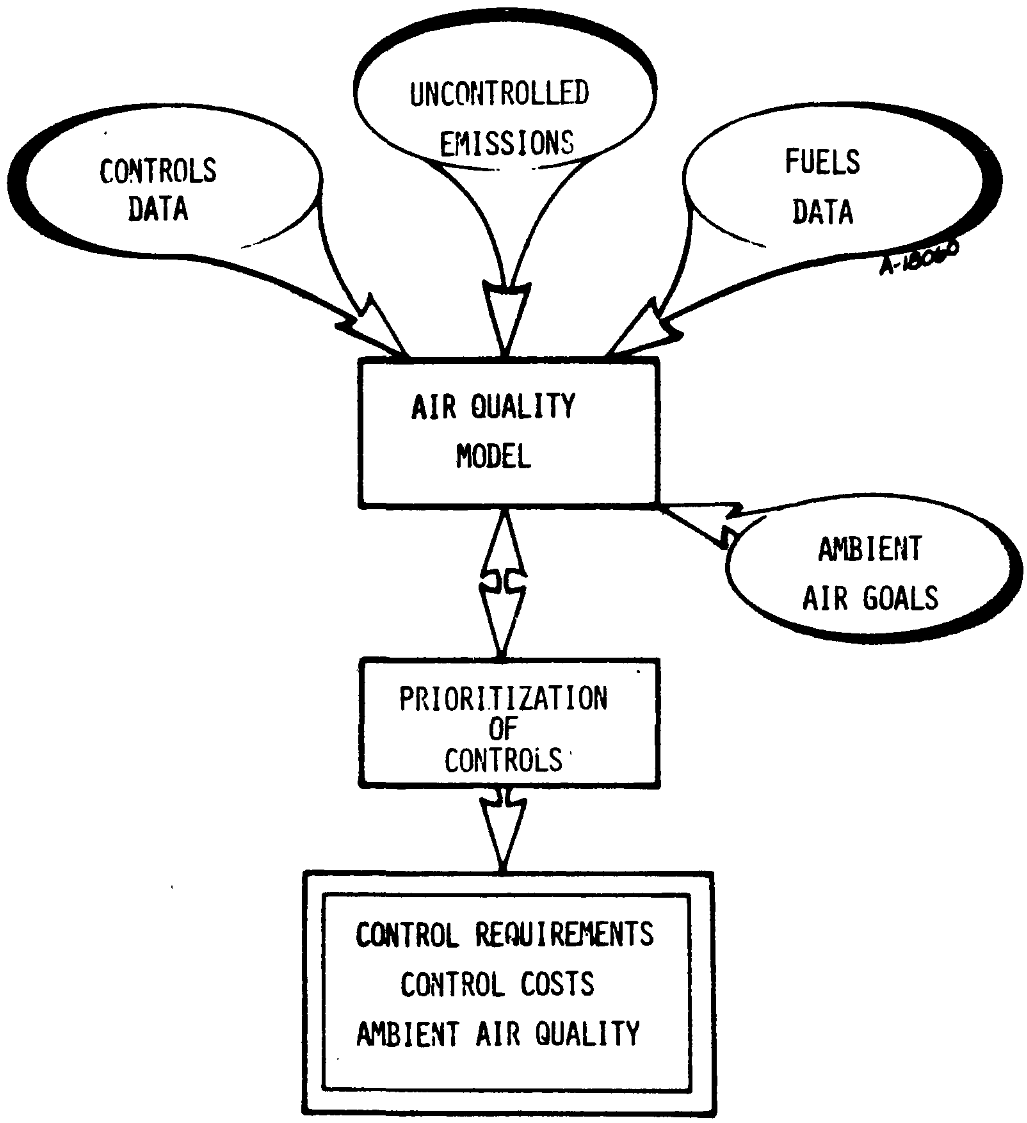


Figure 4-1. Elements of the systems analysis model.

During the first year of the $NO_x$ EA, a systems analysis model was needed to provide a preliminary priority ranking of control methods. A modified form of rollback was selected to reduce the amount of emission data needed, minimize computational costs, and provide maximum flexibility in the initial phases of the analysis. Furthermore, only the $NO_x/NO_2$ relationship was considered, and thus, HC emissions data did not need to be collected.

This same model has also been used during the past year as a screening method applied to a wide variety of AQCR's. Approximately 30 AQCR's have been identified (Reference 4-12) as exceeding or possibly exceeding the annual average $NO_2$ standard between now and 1985 (see Section 3.1). The flexibility and minimum data requirements of the preliminary model allowed us to examine 8 representative AQCR's for each of over 20 different emissions/control scenarios.

The rollback model used is given by:

$$AC = k \left( \sum_i (1 - R_i) E_i W_i \right) + BG$$

where AC = ambient concentration ($NO_2$)
$E_i$ = uncontrolled emissions from source i
$R_i$ = fractional emissions reduction by control of source i
$W_i$ = weighting factor for source i
BG = background concentration (the background concentration has been assumed to be 10 $\mu g/m^3$ for all cases)

The calibration constant, k, is determined by evaluating the equation at some "base year" for which the ambient concentration and emissions are known ($R_i$ = 0).

Although factors such as stack height and relative position of source and receptor are not explicitly included in this model, they are implicitly included because the model is essentially a correlation between existing emission patterns and the resulting ambient air quality conditions. Moreover, in the formulation employed it is possible to specify the relative importance of each source type by using the weighting factors. For example, in an AQCR characterized by large mixing heights, emissions from elevated sources are widely dispersed and, therefore, do not have the same impact on ground level concentration as the same amount of ground level emissions. Thus, a source weighting factor less than 1.0 could be assigned to the elevated sources (e.g., powerplants) to account for the effects of stack height. (Each choice of weighting factors is equivalent to choosing a different model for the AQCR. In all cases the model must be calibrated for the base year before future year projections are made.)

The utility of the preliminary model has been further increased by testing the sensitivity of the results to the input values. This ensured that the predicted control requirements would be responsive to the majority of $NO_x$ critical situations which might develop. Control strategies were developed for numerous combinations of stationary and mobile source growth, base year calibration, and source weighting factors for each AQCR.

Growth scenarios that represented reasonable bounds for both mobile and stationary sources were selected. Generally, growth rates apply to an end use sector such as industrial or residential; however, in this analysis they have been extended to each source within the sector. Whenever possible, growth rates specific to an AQCR were used. If specific AQCR rates were not available, state, regional, or national rates were used. In addition, the influence of population growth and any local limitation on new source growth were considered. Two basic scenarios were selected for stationary sources. One case represented a moderately conservative growth influenced by conservation measures and rising energy costs. The other represented a higher growth rate closer to historical patterns. This case represented a reasonable upper boundary on stationary source growth.

The growth rates of emissions from mobile sources were treated differently, since a detailed investigation of mobile source control options was not of direct interest to this study. However, the emissions contributions of the mobile sources were needed; therefore, two representative scenarios were used. One scenario (the nominal case) was selected to reflect historical growth in vehicle population and miles traveled, as well as the current mobile emission standards* (0.62 g/km for light duty vehicles in 1981). The alternate, or low, case was for a reduced growth rate (closer to the population growth rate) and an emission standard reflecting the research goal of 0.25 g/km in 1985 for light duty vehicles. This case was selected to represent the most optimistic mobile emissions scenario, which is least demanding of stationary source control.

Two values of the $NO_2$ annual average ambient concentration were selected for each AQCR for the base year calibration. These reflected the high and low of the AQCR maximum annual average recorded from 1972 to 1975, or, in some cases, a reasonable variation in the recorded or estimated maximum annual average over the same time period.

The preliminary model has proven to be very useful for its intended purpose -- preliminary priority ranking of $NO_x$ control needs based only on consideration of $NO_2$ air quality. Several conclusions derived from model calculations are discussed in Section 8.2. However, more sophisticated models, as outlined in the next section, are needed to explore the many complexities of the $NO_2$ air quality problem.

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*For California AQCR's the current California schedule for mobile source emission standards was used.

### 4.3.2 Advanced Models

As the preliminary modeling efforts progressed it became increasingly apparent that there were many questions regarding the $NO_2$ air quality problem that could not be answered by the simple air quality models such as modified rollback. This was further accented by increased interest in the impact of a one hour $NO_2$ standard on the need for $NO_x$ controls. (Most of the issues of interest concerning a one hour standard were discussed in Section 3.) To meet the needs of a more sophisticated analysis in a variety of AQCR's at a realistic cost it was decided to use or extend the results of previous analyses.

Nonreacting dispersion modeling had been done for the Chicago and Baltimore AQCR's. In addition, detailed photochemical modeling had been done for Los Angeles, San Francisco and Denver, and was planned for St. Louis. In all cases, this meant that emissions and meteorology data bases had already been created, and appropriate computer models were operational. The results of these air quality modeling efforts were thus used to verify the assumptions of the rollback model, to guide the modification of the air quality model in the systems analysis, and to examine specific emission/air quality issues. Major advantages of this approach are the ability to include specific source/receptor relationships, meteorology, mixing, kinetic reactions, and the $HC/NO_x/NO_2/O_3$ interactions.

Efforts to date have concentrated on two models and two AQCR's. The LIRAQ model, developed by the Lawrence Livermore Laboratory, has been applied to the San Francisco AQCR and an advanced version of the DIFKIN model, developed by ERT, to Los Angeles. These two models are briefly described below.

#### 4.3.2.1 ERT Model

The ERT model, a successor to DIFKIN, is a photochemical, Lagrangian trajectory model which tracks an air mass throughout the region of interest based on a prescribed wind field. The model considers advection of pollutants (motion relative to the air mass being tracked) and assumes horizontal diffusion of pollutants to be negligible. These assumptions reduce the species continuity equations to a vertical diffusion equation similar to the heat equation. Embedded sources in the vertical cells represent both emissions (from elevated sources) and chemical transformations. Sources at the lower boundary represent emissions from area emitters as expressed by time and space varying flux schedule boundary conditions. In the detailed chemical mechanism a distinction is made among the effects of five classes of reactive hydrocarbon substances: paraffins, olefins, aromatics, formaldehyde, and higher aldehydes. Although a high degree of lumping of parameters occurs within each class, distinguishing five separate categories permits relatively specific treatment of different levels of reactivity.

Several trajectory analysis simulations were performed using this model to address questions appropriate to the systems analysis effort.

Model simulations performed, and their results, are briefly discussed in Section 8.2.

#### 4.3.2.2 LIRAQ Model

The LIRAQ model was developed by the Lawrence Livermore Laboratory with the support of the National Science Foundation and in cooperation with the Bay Area Air Pollution Control District (BAAPCD) (Reference 4-13). This model is a photochemical Eulerian model designed to treat most of the important factors of interest in the San Francisco Bay Area. The complex topography and changing meteorology are treated on one of several available grid scales. Mass consistent windfields, based on real or hypothetical meterological situations, are provided by an auxiliary program. Reactive hydrocarbons are divided into three characteristic types: alkenes, alkanes and aromatics, and aldehydes. The model computes pollutant concentrations at all grid points in the region at each time interval and gives resultant concentration contours for each hour.

Computational scenarios and results of calculations obtained using this model are also discussed in Section 8.2.

#### 4.3.2.3 Short Term - Annual Average Correlation

Both of the models described above provide results in the form of one hour concentrations. To extrapolate such results to an impact on an annual average $NO_2$ level, some relationship between annual average and one hour values is necessary. This is usually provided by the concentration frequency data from monitoring stations in the region of interest. In both San Francisco and Los Angeles the concentration frequency data were found to be approximately log-normal. The implication of this is that the same percentage change calculated for one hour values can also be applied to an annual average. This assumes that the slope (on a log probability scale) does not change as a result of the control strategy.

There are no direct data to support the above assumption; however, comparison of data from several monitoring stations in Los Angeles for the period 1970 to 1973 indicated a relatively constant slope. This is slightly misleading since only minor changes in the emissions patterns occurred during this time period. Furthermore, as will be shown in Section 8.2, the response of the $NO_2$ one hour peak and the 24 hour average (a better measure of the long term average response) may be very different depending on both the $NO_x$ and HC emissions changes. It does appear that for those cases where the ratio of HC to $NO_x$ emissions remains relatively constant (i.e., simultaneous control of $NO_x$ and HC) the one hour and 24 hour average values change by approximately the same percentage. Therefore, a constant relationship between the $NO_2$ one hour and annual average, subject to simultaneous $NO_x$ and HC control was assumed.

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# SECTION 5

# ENVIRONMENTAL DATA ACQUISITION

This section describes the updated multimedia emissions inventory compiled to support the source impact ranking and environmental impact assessment efforts in the $NO_x$ EA. Emissions data available as of 1976 were previously discussed in the Preliminary Environmental Assessment report (Reference 5-1) and summarized in the $NO_x$ EA first annual report (Reference 5-2). The results presented herein incorporate additional data and augment the earlier work with projections. These updated results are discussed more fully in Reference 5-3. Updating of the inventories assembled will continue in the third year.

Based on the emission inventory work, together with preliminary process analysis and environmental assessment efforts, numerous emissions data gaps were identified in the inventories. To address these a field test program was defined and is now underway. This test program, developed with emphasis on clarifying the incremental effects of $NO_x$ control application on pollutant emissions other than $NO_x$, is also described in the following.

## 5.1 BASELINE EMISSIONS

The national and regional multimedia emissions inventories are presented below for the stationary $NO_x$ sources and fuels identified in Section 2.

### 5.1.1 National Baseline Emissions Inventory

A baseline multimedia emissions inventory was produced for all significant stationary $NO_x$ sources. This inventory was then extended to include all other sources of $NO_x$ (mobile, noncombustion, fugitive) to compare emissions from stationary combustion sources with those from other sources. Multimedia pollutants inventoried included the criteria pollutants ($NO_x$, $SO_x$, CO, HC, particulates), sulfates, polycyclic organic matter (POM), trace metals, and liquid and solid effluents.

This inventory was compiled to provide the basis for weighing the incremental emissions impact of using $NO_x$ controls. In addition, the inventory also serves as a reference for projections to the year 2000 for anticipated trends in fuels, equipment, and stationary source emissions.

Data gaps identified in compiling the emission factors highlight areas where further testing is needed.

The emissions inventory was performed in the following sequence:

- Compile fuel consumption data for the categories of combustion sources specified in Section 2. Subdivide fuel consumption data based on fuel bound pollutant precursor composition.

- Compile multimedia emission data

  -- Base fuel dependent pollutant emission factors on the trace composition of fuels

  -- Base combustion dependent pollutant emission factors on unit fuel consumption for specific equipment designs

- Survey the degree to which $NO_x$, $SO_x$, particulates are controlled

- Produce emissions inventory

- Rank sources according to emission rates

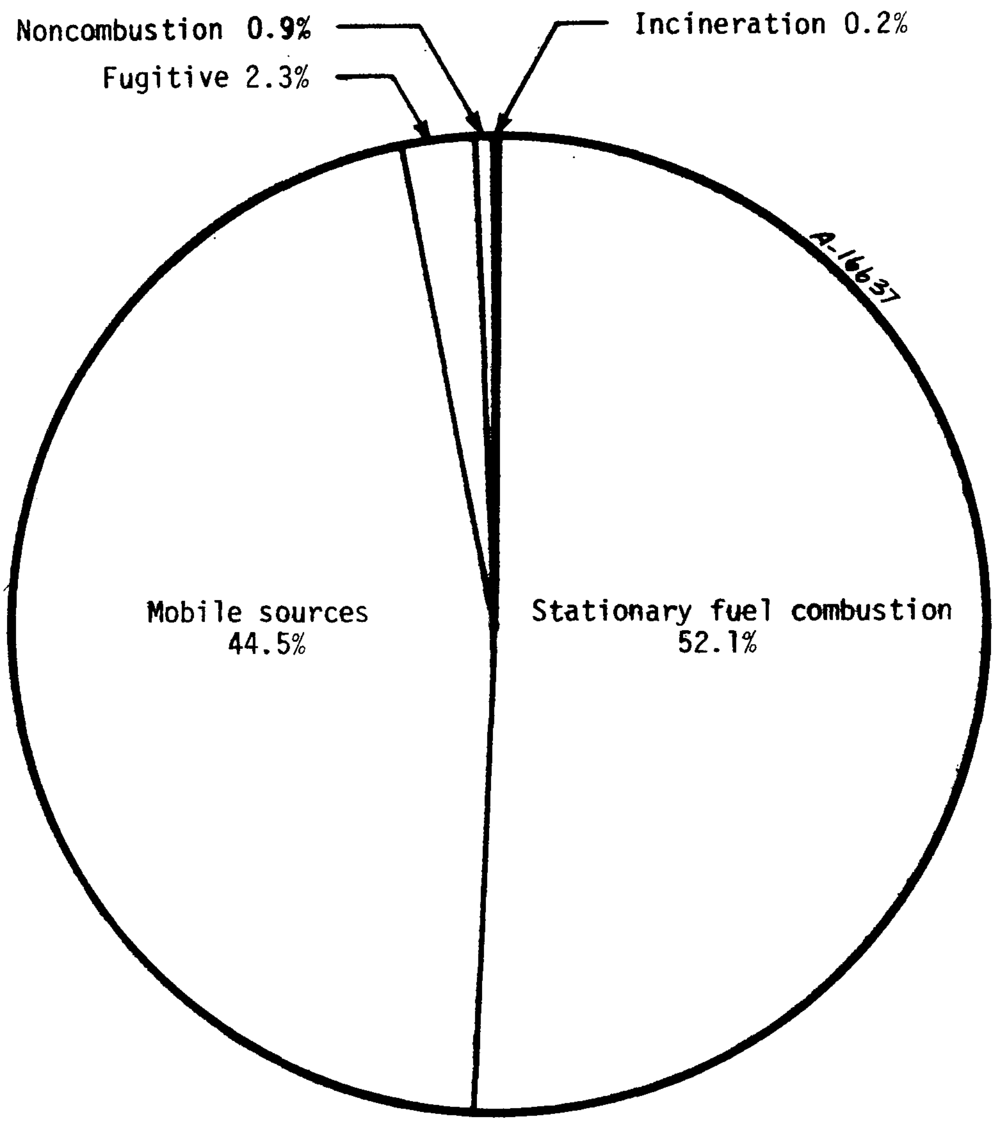
Although detailed breakdowns of fuel consumption, emission factors, and total emissions for each equipment/fuel combination were developed, only emission totals for each sector are summarized here.

The distribution of anthropogenic $NO_x$ emissions is shown in Figure 5-1 for the year 1974. The estimates of utility boiler emissions account for the reduction resulting from using $NO_x$ controls. From a survey of boilers in areas with $NO_x$ emission regulations, it was estimated that using $NO_x$ controls in 1974 resulted in a 3.0 percent reduction in nationwide utility boiler emissions. This corresponds to a 1.6 percent reduction in stationary fuel combustion emissions. Reductions from using controls on other sources were negligible in 1974.

Stationary source $NO_x$ emissions are subdivided by sector and fuel type in Table 5-1. The emission inventory summaries for other pollutants are shown in Table 5-2.

Data for the criteria pollutants were generally good and the results of these current inventories are in reasonable agreement with other recent inventories. Data for the noncriteria pollutants and liquid or solid effluent streams, however, were sparse and scattered. For example, emission factors for POM varied by as much as two orders of magnitude; thus, Table 5-2 shows a range for total POM emissions.

Table 5-3 ranks equipment/fuel combinations by annual, nationwide $NO_x$ emissions, and lists corresponding rankings for these combinations by fuel consumption and emissions of criteria pollutants. Although there were over 70 equipment/fuel combinations inventoried, the 30 most significant combinations account for over 80 percent of $NO_x$ emissions. The ranking of a specific equipment/fuel type depends both on total




| | Gg | 1,000 Ton | Percent Total |
|---|---|---|---|
| Stationary Fuel Combustion | 11,297 | 12,437 | (52.1) |
| Fugitive Emissions | 498 | 548 | (2.3) |
| Noncombustion | 193 | 212 | (0.9) |
| Incineration | 40 | 44 | (0.2) |
| Mobile Sources | 9,630 | 10,600 | (44.5) |
| Total | 21,658 | 23,841 | 100 |

Figure 5-1. Distribution of anthropogenic $NO_x$ emissions for the year 1974.

TABLE 5-1. SUMMARY OF 1974 STATIONARY SOURCE $NO_x^a$ EMISSIONS BY FUEL TYPE

| Sector | $NO_x$ Production Gg/yr (% of total) | | | Total by Sector | Cumulative (%) |
|---|---|---|---|---|---|
| | Coal | Oil | Gas | (% of total) | |
| Utility Boilers | 3808 (31.7) | 848 (7.0) | 1152 (9.6) | 5808 (48.3) | 48.3 |
| Packaged Boilers[b] | 781 (6.5) | 886 (7.4) | 779 (6.5) | 2446 (20.3) | 68.6 |
| Warm Air Furnaces | -- | 130 (1.1) | 190 (1.6) | 320 (2.7) | 71.3 |
| Gas Turbines | -- | 308 (2.6) | 132 (1.1) | 440 (3.7) | 75.0 |
| Reciprocating IC Engines | -- | 457[c] (3.8) | 1400[d] (11.6) | 1857 (15.4) | 90.4 |
| Industrial Process Heating | -- | -- | -- | 426 (3.5) | 93.9 |
| Noncombustion | -- | -- | -- | 193 (1.6) | 95.5 |
| Incineration | -- | -- | -- | 40 (0.3) | 95.8 |
| Fugitive | -- | -- | -- | 498 (4.2) | 100.0 |
| Total | 4589 (38.2) | 2629 (21.8) | 3653 (30.4) | 12,028 (100.0) | |

[a] $NO_2$ basis
[b] Includes steam and hot water commercial and residential heating units
[c] Includes gasoline
[d] Includes dual fuels (oil and gas)

TABLE 5-2. SUMMARY OF AIR AND SOLID POLLUTANT EMISSIONS FROM STATIONARY FUEL BURNING EQUIPMENT (Gg/yr)

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| Sector | $NO_x$ [b] | $SO_x$ | HC | CO | Part. | Sulfates | POM | Dry[c] Ash Removal | Sluiced[c] Ash Removal |
|---|---|---|---|---|---|---|---|---|---|
| Utility Boilers | 5808 | 16,768 | 29.5 | 270 | 5,965 | 231 | 0.01 – 1.2 | 6.2 | 24.8 |
| Packaged Boilers | 2446 | 6,405 | 72.1 | 175 | 4,930 | 146 | 0.2 – 67.8 | 1.1 | 4.4 |
| Warm Air Furnaces & Misc. Comb. | 320 | 232 | 29.7 | 132.6 | 39.3 | 6.4 | 0.06 | -- | -- |
| Gas Turbines | 440 | 10.5 | 13.7 | 73.4 | 17.3 | a | a | -- | -- |
| Recip. IC Engines | 1857 | 19.6 | 578 | 1,824 | 21.5 | a | a | -- | -- |
| Process Heating | 426 | 622 | 166 | 9,079 | 4,766 | a | a | -- | -- |
| TOTAL | 11,297 | 24,057 | 889 | 11,554 | 15,739 | 383 | 69 | 7.3 | 29.2 |

[a]No emission factor available

[b]Controlled $NO_x$, $NO_2$ basis

[c]Based on 80 percent hopper and flyash removal by sluicing methods; 20 percent dry solid removal

TABLE 5-3. $NO_x$[a] MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT AND FUEL USE CROSS RANKING

| Rank | Sector | Equipment Type | Fuel | Annual $NO_x$ Emissions (Mg) | Cumulative (Mg) | Cumulative (Percent) | Fuel Rank | $SO_x$ Rank | CO Rank | HC Rank | Part. Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Utility Boilers | Tangential | Coal | 1,410,000 | 1,410,000 | 11.7 | 1 | 1 | 7 | 16 | 2 |
| 2 | Reciprocating IC Engines | >75 kW/cyl[c] | Gas | 1,262,000 | 2,672,000 | 22.2 | 21 | >30 | 4 | 1 | >30 |
| 3 | Utility Boilers | Wall Firing | Coal | 1,137,000 | 3,809,000 | 31.7 | 3 | 2 | 6 | 23 | 5 |
| 4 | Utility Boilers | Cyclone | Coal | 848,300 | 4,657,300 | 38.7 | 6 | 3 | 12 | 9 | 13 |
| 5 | Utility Boilers | Wall Firing | Gas | 646,800 | 5,304,100 | 44.1 | 4 | >30 | 13 | 28 | >30 |
| 6 | Utility Boilers | Wall Firing | Oil | 458,300 | 5,762,400 | 47.9 | 8 | 9 | 17 | 27 | 18 |
| 7 | Utility Boilers | Horizontally Opposed | Gas | 352,200 | 6,114,600 | 50.8 | 14 | >30 | 24 | >30 | >30 |
| 8 | Reciprocating IC Engines | 75 kW to 75 kW/cyl[c] | Oil | 325,000 | 6,439,600 | 53.5 | >30 | >30 | 3 | 3 | 26 |
| 9 | Utility Boilers | Horizontally Opposed | Coal | 324,500 | 6,764,100 | 56.2 | 23 | 5 | >30 | >30 | 7 |
| 10 | Packaged Boilers | Wall Firing WT[d] >29 MW[b] | Gas | 318,500 | 7,082,600 | 58.9 | 16 | >30 | 29 | 19 | >30 |
| 11 | Packaged Boilers | Stoker Firing WT[d] <29 MW[b] | Coal | 278,170 | 7,360,770 | 61.2 | 7 | 4 | 11 | 4 | 1 |
| 12 | Packaged Boilers | Wall Firing WT[d] >29 MW[b] | Oil | 232,480 | 7,593,250 | 63.1 | 26 | 16 | >30 | 26 | 22 |
| 13 | Utility Boilers | Tangential | Oil | 205,100 | 7,798,350 | 64.8 | 12 | 10 | 27 | >30 | 19 |
| 14 | Packaged Boilers | Scotch FT[e] | Oil | 203,990 | 8,002,250 | 66.5 | 11 | 11 | >30 | >30 | 16 |
| 15 | Packaged Boilers | Single Burner WT[d] <29 MW[b] | Gas | 180,000 | 8,182,250 | 68.0 | 5 | >30 | >30 | 22 | >30 |
| 16 | Utility Boilers | Horizontally Opposed | Oil | 168,900 | 8,351,150 | 69.4 | >30 | 17 | >30 | >30 | 27 |
| 17 | Packaged Boilers | Single Burner WT[d] <29 MW[b] | Coal | 164,220 | 8,515,370 | 70.8 | >30 | 8 | >30 | >30 | 9 |

[a] $NO_2$ basis
[b] Heat input
[c] Heat output
[d] Watertube
[e] Firetube

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TABLE 5-3. (Concluded)

| Rank | Sector | Equipment Type | Fuel | Annual $NO_x$ Emissions (Mg) | Cumulative (Mg) | Cumulative (Percent) | Fuel Rank | $SO_x$ Rank | CO Rank | HC Rank | Part. Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | Industrial Process Comb. | Refinery Heaters Forced & Natural Draft | Oil | 147,350 | 8,662,720 | 72.0 | >30 | 29 | >30 | 18 | 21 |
| 19 | Packaged Boilers | Firebox FT[e] | Oil | 139,260 | 8,801,980 | 73.1 | 17 | 13 | >30 | >30 | 20 |
| 20 | Utility Boilers | Tangential | Gas | 137,900 | 8,939,880 | 74.3 | 13 | >30 | >30 | >30 | >30 |
| 21 | Packaged Boilers | Stoker Firing WT[d] | Coal | 125,350 | 9,065,230 | 75.3 | >30 | 7 | 28 | 29 | 8 |
| 22 | Gas Turbines | 4 to 15 MW[c] | Oil | 118,500 | 9,183,730 | 76.3 | 30 | >30 | 15 | 14 | >30 |
| 23 | Packaged Boilers | Single Burner WT[d] <29 MW[b] | Oil | 116,430 | 9,300,160 | 77.3 | 27 | 15 | >30 | >30 | 23 |
| 24 | Warm Air Furnaces | Central | Gas | 106,300 | 9,406,460 | 78.2 | 2 | >30 | 10 | 8 | 25 |
| 25 | Packaged Boilers | Stoker Firing FT[e] <29 MW[b] | Coal | 102,040 | 9,508,500 | 79.0 | 29 | 6 | >30 | 10 | 6 |
| 26 | Packaged Boilers | Scotch FT[e] | Gas | 98,010 | 9,606,510 | 79.8 | 19 | >30 | >30 | >30 | >30 |
| 27 | Gas Turbines | >15 MW[c] | Oil | 97,400 | 9,703,910 | 80.6 | >30 | >30 | >30 | 30 | >30 |
| 28 | Reciprocating IC Engines | >75 kW/cyl[c] | Oil | 94,000 | 9,797,910 | 81.4 | >30 | >30 | 22 | 13 | >30 |
| 29 | Industrial Process Comb. | Refinery Heaters Forced & Natural Draft | Gas | 92,608 | 9,890,518 | 82.2 | 15 | >30 | >30 | 7 | 30 |
| 30 | Utility Boilers | Vertical and Stoker | Coal | 88,500 | 9,979,018 | 82.9 | >30 | 12 | >20 | >30 | 10 |

[a] $NO_2$ basis
[b] Heat input
[c] Heat output
[d] Watertube
[e] Firetube

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installed capacity and emission factors. A high ranking, therefore, does not necessarily imply that a given source is a high emitter; large installed capacity may offset a low emission factor to give the high ranking. In general, coal-fired sources rank high in $SO_x$ and particulate emissions, while IC engines rank high in emissions of CO and hydrocarbons.

As noted above, inventory results presented are for 1974 data, the most recent when the effort was initiated. However, future $NO_x$ EA efforts will update this national emissions inventory to 1977 using improved emission factors, 1977 utility boiler fuel consumption, and updated fuel projection data for other equipment.

### 5.1.2 Projected National Emissions Inventories

Emissions inventories assembled for the year 2000 for $NO_x$ are presented here for the two reference scenarios described in Section 2.2. These emissions inventories are a culmination of the projected fuel consumption data presented in Section 2.2 and control projections.

Tables 5-4 and 5-5 summarize total $NO_x$ emissions from fuel user sources for the year 2000 for the reference scenarios. The $NO_x$ mass emissions ranking of stationary combustion equipment is presented in Table 5-6 for the year 2000 high nuclear reference scenario. Tangential boilers appear to be the most significant $NO_x$ source through 2000 if projected trends are realized. Coal-fired sources should increase their share of $NO_x$ emissions and dominate the highest rankings. Natural gas-fired sources show lower $NO_x$ emissions rankings due to decreased fuel consumption and implementation of controls. In 2000, the highest natural gas source is tenth on the ranking, compared to second in 1974. Oil-fired sources also show a gradual decrease in $NO_x$ emissions due to their attrition and replacement with coal-fired sources.

### 5.1.3 Regional Emissions Inventories

This section presents regional emissions inventories for combustion related pollutants from stationary sources. Figure 5-2 shows the distribution of fuels by region in 1974. This distribution formed the basis for the regional emissions inventory generated. The figure shows that oil is the major fuel used in the East Coast region. The West Coast and Southwest are supplied largely by natural gas, and the Midwest relies primarily on coal for its fossil fuel requirements. Table 5-7 summarizes $NO_x$ emissions for the nine regions shown in Figure 5-2. These estimates are for uncontrolled $NO_x$ only since the impact of $NO_x$ control implementation on a regional basis was small in 1974.

Over 40 percent of all $NO_x$ emissions from utility boilers are from the East-North-Central and the South Atlantic regions. The New England region accounts for less than 5 percent of utility boiler $NO_x$ emissions. However, areas such as New England and the Far West may be most strongly affected by fuel switching to coal since they are heavily

TABLE 5-4. SUMMARY OF ANNUAL $NO_x$[a] EMISSIONS FROM FUEL USER SOURCES (2000): REFERENCE SCENARIO -- LOW NUCLEAR

| Sector | $NO_x$ Production -- Gg (% of Total) | | | Total By Sector -- Gg (% of Total) | Cumulative (%) |
|---|---|---|---|---|---|
| | Gas | Coal | Oil | | |
| Utility Boilers | -- | 7,951.9 (58.51) | 763.5 (5.62) | 8,715.3 (64.13) | 64.13 |
| Packaged Boilers | 657.2 (4.84) | 898.2 (6.61) | 1,064.4 (7.83) | 2,619.8 (19.28) | 83.40 |
| Warm Air Furnaces | 178.8 (1.32) | -- | 124.4 (0.92) | 303.1 (2.23) | 85.63 |
| Gas Turbines | 156.9 (1.15) | -- | 249.7 (1.84) | 406.5 (2.99) | 88.62 |
| Reciprocating IC Engines | 248.3 (1.83) | -- | 610.3 (4.49) | 858.6 (6.32) | 94.94 |
| Process Heating | -- | -- | -- | 289.5 (2.13) | 97.07 |
| Noncombustion | -- | -- | -- | 322.0 (2.37) | 99.44 |
| Incineration | -- | -- | -- | 76.0 (0.56) | 100.0 |
| Total by Fuels | 1,241.2 (9.13) | 8,850.1 (65.12) | 2,812.2 (20.69) | 13,590.8 | |

[a]$NO_2$ basis

TABLE 5-5. SUMMARY OF ANNUAL $NO_x$[a] EMISSIONS FROM FUEL USER SOURCES (2000): REFERENCE SCENARIO -- HIGH NUCLEAR

| Sector | $NO_x$ Production -- Gg (% of Total) | | | Total By Sector -- Gg (% of Total) | Cumulative (%) |
|---|---|---|---|---|---|
| | Gas | Coal | Oil | | |
| Utility Boilers | -- | 5,197.0 (49.21) | 763.5 (7.23) | 5,960.5 (56.44) | 56.44 |
| Packaged Boilers | 657.2 (6.22) | 622.1 (5.89) | 1,064.4 (10.08) | 2,343.7 (22.19) | 78.64 |
| Warm Air Furnaces | 178.8 (1.69) | -- | 124.4 (1.18) | 303.1 (2.87) | 81.51 |
| Gas Turbines | 156.9 (1.49) | -- | 249.7 (2.36) | 406.5 (3.85) | 85.36 |
| Reciprocating IC Engines | 248.3 (2.35) | -- | 610.3 (5.78) | 858.6 (8.13) | 93.49 |
| Process Heating | -- | -- | -- | 289.5 (2.74) | 96.23 |
| Noncombustion | -- | -- | -- | 322.0 (3.05) | 99.28 |
| Incineration | -- | -- | -- | 76.0 (0.72) | 100.0 |
| Total by Fuels | 1,241.2 (11.75) | 5,819.0 (55.10) | 2,812.2 (26.63) | 10,599.9 | |

[a] $NO_2$ basis

TABLE 5-6. YEAR 2000 -- $NO_x$ MASS EMISSIONS RANKING FOR STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT CROSS RANKING

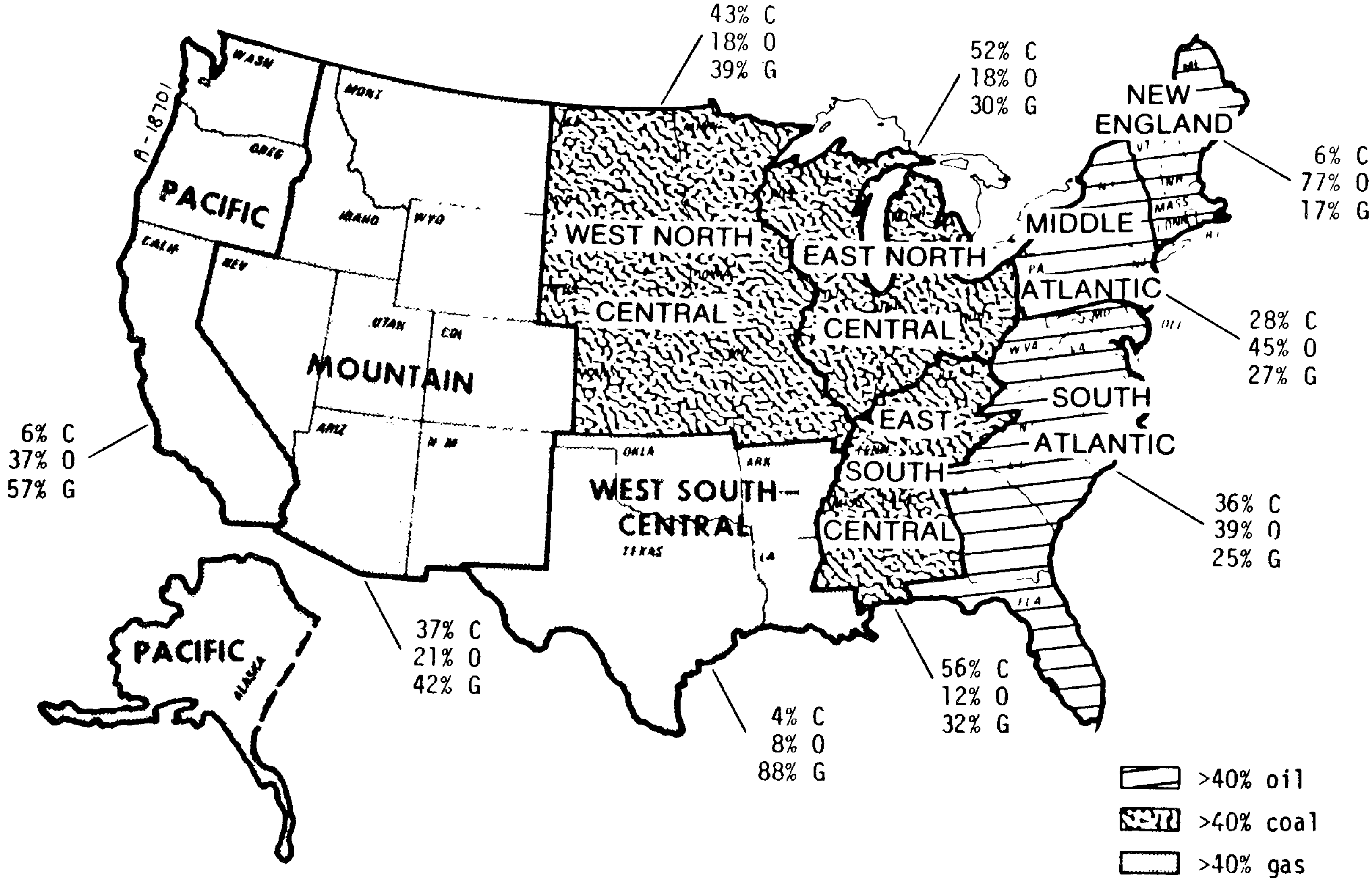
| Rank | Sector | Equipment Type | Fuel | Annual $NO_x$ Emissions (Mg) |
|---|---|---|---|---|
| 1 | Utility Boilers | Tangential | Coal | 2,586,100 |
| 2 | Utility Boilers | Wall Firing | Coal | 1,634,800 |
| 3 | Utility Boilers | Horizontally Opposed | Coal | 472,400 |
| 4 | Utility Boilers | Cyclone | Coal | 450,300 |
| 5 | Utility Boilers | Wall Firing | Oil | 378,100 |
| 6 | Packaged Boilers | Scotch FT[d] <29 MW[a] | Oil | 267,500 |
| 7 | Utility Boilers | Tangential | Oil | 236,200 |
| 8 | Packaged Boilers | Stoker Firing WT[c] <29 MW[a] | Coal | 221,600 |
| 9 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Oil | 212,700 |
| 10 | Reciprocating IC Engines | CI[f] 75 kW to 75 kW/cyl[b] | Oil | 202,600 |
| 11 | Reciprocating IC Engines | SI[e] >75 kW/cyl[b] | Gas | 201,800 |
| 12 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Gas | 189,300 |
| 13 | Packaged Boilers | Single Burner WT <29 MW[a] | Gas | 184,700 |
| 14 | Packaged Boilers | Firebox FT[d] <29 MW[a] | Oil | 184,300 |
| 15 | Reciprocating IC Engines | CI[f] >75 kW/cyl[b] | Oil | 161,200 |
| 16 | Packaged Boilers | Single Burner WT[c] <29 MW[a] | Oil | 150,200 |

[a]Heat input
[b]Heat output
[c]Watertube
[d]Firetube
[e]Spark ignition
[f]Compression ignition

TABLE 5-6. Concluded

| Rank | Sector | Equipment Type | Fuel | Annual $NO_x$ Emissions (Mg) |
|---|---|---|---|---|
| 17 | Utility Boilers | Horizontally Opposed | Oil | 139,400 |
| 18 | Gas Turbines | Simple Cycle >15 MW[b] | Oil | 137,700 |
| 19 | Reciprocating IC Engines | SI[e] 75 kW to 75 kW/cyl[b] | Gas | 136.900 |
| 20 | Packaged Boilers | Wall Firing WT[c] > 29 MW[a] | Coal | 130,700 |
| 21 | Gas Turbines | Simple Cycle 4 MW to 15 MW[b] | Oil | 114,600 |
| 22 | Packaged Boilers | HRT Boiler | Oil | 113,900 |
| 23 | Reciprocating IC Engines | CI[f] > 75 kW/cyl[b] | Dual (Oil and Gas) | 110,500 |
| 24 | Packaged Boilers | Scotch FT[d] < 29 MW[a] | Gas | 100,500 |
| 25 | Packaged Boilers | Stoker WT[c] > 29 MW[a] | Coal | 99,800 |
| 26 | Warm Air Furnaces | Warm Air Central Furnace | Gas | 95,600 |
| 27 | Packaged Boilers | Firebox FT[b] < 29 MW[a] | Gas | 93,100 |
| 28 | Gas Turbines | Simple Cycle > 15 MW[b] | Gas | 99,800 |
| 29 | Packaged Boilers | Single Burner WT < 29 MW[a] | Coal | 85,200 |
| 30 | Warm Air Furnaces | Warm Air Central Furnace | Oil | 81,900 |

[a]Heat input
[b]Heat output
[c]Watertube
[d]Firetube
[e]Spark ignition
[f]Compression ignition




(Except South Atlantic, where oil represents 39% total fuel consumption.)

Figure 5-2. Regional fuel distributions.

TABLE 5-7. DISTRIBUTION OF REGIONAL UNCONTROLLED $NO_x$[a] EMISSIONS (Gg/yr) -- 1974

| Sector and Equipment Type | Fuel | New England | Middle Atlantic | E-N-Central | W-N-Central | South Atlantic | E-S-Central | W-S-Central | Mountain | Pacific | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Utility Boilers | | | | | | | | | | | |
| Tangential | Coal | 7.5 | 161.7 | 477.6 | 132.8 | 281.5 | 220.3 | 18.6 | 97.8 | 11.4 | 1409.2 |
| | Oil | 30.1 | 54.8 | 10.2 | 1.4 | 60.2 | 3.8 | 8.9 | 4.4 | 31.3 | 205.1 |
| | Gas | 0.4 | 1.8 | 4.8 | 14.1 | 8.9 | 2.1 | 85.3 | 8.2 | 12.3 | 137.9 |
| Wall Fired | Coal | 6.0 | 130.1 | 385.7 | 107.3 | 227.4 | 178.0 | 15.0 | 78.9 | 9.3 | 1137.7 |
| | Oil | 67.5 | 122.6 | 22.8 | 3.0 | 134.6 | 8.3 | 19.8 | 9.8 | 69.9 | 458.3 |
| | Gas | 1.8 | 8.4 | 22.8 | 66.4 | 41.4 | 9.5 | 400.0 | 38.4 | 58.1 | 646.8 |
| Horizontally Opposed | Coal | 1.7 | 37.1 | 110.0 | 30.5 | 64.8 | 50.8 | 4.3 | 22.5 | 2.6 | 324.3 |
| | Oil | 58.5 | 35.7 | 8.4 | 1.1 | 35.2 | 3.0 | 7.3 | 3.6 | 16.1 | 168.9 |
| | Gas | 2.0 | 4.5 | 12.3 | 36.2 | 22.5 | 5.2 | 217.1 | 20.9 | 31.5 | 352.2 |
| Cyclone | Coal | 1.5 | 97.4 | 288.7 | 80.2 | 170.1 | 133.1 | 11.3 | 59.1 | 6.9 | 848.3 |
| | Oil | 2.4 | 4.3 | 0.7 | 0.1 | 4.8 | 0.3 | 0.7 | 0.4 | 2.5 | 16.2 |
| | Gas | 0.1 | 0.2 | 0.5 | 1.4 | 0.9 | 0.2 | 9.2 | 0.9 | 1.3 | 14.7 |
| Vertical and Stoker | Coal | 0.5 | 10.1 | 30.0 | 8.4 | 17.6 | 13.8 | 1.2 | 6.1 | 0.8 | 88.5 |
| Subtotal | All | 180.0 | 668.7 | 1374.5 | 482.9 | 1069.9 | 628.4 | 798.7 | 351.0 | 254.0 | 5808.1 |
| Packaged Boilers | All | 146.3 | 372.2 | 621.3 | 180.4 | 412.6 | 171.5 | 250.6 | 96.1 | 195.6 | 2446.6 |
| Commercial and Residential Furnaces | All | 9.5 | 31.2 | 65.5 | 22.7 | 56.5 | 22.9 | 42.6 | 25.4 | 44.4 | 320.7 |
| Gas Turbines | All | 131.0 | 66.8 | 19.3 | 36.7 | 33.8 | 9.4 | 83.9 | 52.3 | 7.3 | 440.5 |
| IC Engines | All | 11.7 | 60.7 | 248.5 | 360.6 | 79.7 | 130.0 | 684.2 | 206.9 | 74.7 | 1857.0 |
| Process Heating | All | 0.5 | 63.8 | 87.6 | 25.4 | 18.2 | 27.3 | 149.9 | 2.9 | 50.0 | 425.6 |
| Subtotal | | 299.0 | 594.7 | 1042.2 | 625.8 | 600.8 | 361.1 | 1211.2 | 383.6 | 372.0 | 5490.4 |
| Total | All | 479.0 | 1263.4 | 2416.7 | 1108.7 | 1670.7 | 989.5 | 2009.9 | 734.6 | 626.0 | 11298.5 |

[a] $NO_2$ basis

T-861(a)

dominated by oil and gas firing. The East-North-Central and South Atlantic regions also account for over 40 percent of the $NO_x$ emissions from packaged boilers. But, considering all stationary sources, the East-North-Central and the West-South-Central regions of the nation generate the highest levels of $NO_x$ representing about 40 percent of the total emissions.

The regional inventories developed here show significant localized variations of $NO_x$ emissions by fuel/equipment type. These variations result from both the regional fuel mix variations and the distribution of stationary source types. Thus, a national policy of $NO_x$ control must be broad enough to encompass these regional variations in developing strategies for future $NO_x$ emissions reductions.

## 5.2 EXPERIMENTAL TESTING

During compilation of the baseline emissions inventory discussed in Section 5.1 and in the preliminary evaluation of the incremental effects of $NO_x$ controls on pollutant emissions other than $NO_x$ (Reference 5-1), it became apparent that data were lacking in several key areas. Most noteworthy was the virtual absence of data on the effects of $NO_x$ combustion controls on emission levels of noncriteria flue gas pollutants and liquid and solid effluents. To address these data needs a field test program was defined and is currently underway.

Based on the results of the preliminary source impact ranking performed in the first year of the $NO_x$ EA (Reference 5-2) a series of 19 candidate field tests were identified. From this set of 19 potential tests, 7 were selected and scheduled. A summary of these seven tests is given in Table 5-8.

A prerequisite for selecting a test to be performed was that, whenever possible, field testing was to be performed as a subcontracted addition to planned or ongoing tests. This represented the most cost-effective manner to obtain needed data. Thus, collaborating test contractors are also listed in Table 5-8. Of course where add-on testing was not feasible, new tests were initiated as indicated for two tests.

As noted in Table 5-8 the sampling program followed for each test incorporated:

- Continuous monitoring of flue gas $NO_x$, $SO_2$, CO, $CO_2$, and $O_2$

- Flue gas Source Assessment Sampling System (SASS), EPA Method 5 particulate load, and EPA Method 8 (or equivalent) sulfur species sampling; both upstream and downstream of the particulate collector, if applicable

- Flue gas grab sampling and onsite gas chromatographic analysis for $C_1$-$C_6$ hydrocarbons; both upstream and downstream of the particulate collector, if applicable

TABLE 5-8. $NO_x$ EA FIELD TEST PROGRAM

| Source Category | Description | Test Points (Unit Operation) | Sampling Protocol | Test Collaborator | Status |
|---|---|---|---|---|---|
| Coal-fired Utility Boiler | Kingston #6; 180 MW tangential; twin furnace, 12 burners/ furnace, 3 elevations; cyclone, 2 ESP's for particulate control | Baseline<br>Biased Firing (2)<br>BOOS (2) | Continuous $NO_x$, $SO_2$, CO, $CO_2$, $O_2$<br>Inlet to 1st ESP:<br>-- SASS<br>-- Method 5<br>-- Method 8<br>-- Gas grab ($C_1$-$C_6$ HC)<br>Outlet of 1st ESP:<br>-- SASS<br>-- Method 5<br>-- Method 8<br>-- Gas grab ($C_1$-$C_6$ HC)<br>Bottom ash<br>Hopper ash (1st ESP, cyclone)<br>Fuel<br>Operating data | TVA | Complete, August 1977 |
| Coal-fired Utility Boiler | Crist #7, 500 MW opposed wall fired; 24 burners, 3 elevations; ESP for particulate control | Baseline<br>BOOS (2) | Continuous $NO_x$, $SO_2$, CO $CO_2$, $O_2$<br>ESP inlet<br>-- SASS<br>-- Method 5<br>-- Method 8<br>-- Gas grab ($C_1$-$C_6$ HC)<br>ESP outlet<br>-- SASS<br>-- Method 5<br>-- Method 8<br>-- Gas grab ($C_1$-$C_6$ HC)<br>Bottom ash<br>ESP hopper ash<br>Fuel<br>Operating data<br>Bioassay | Exxon | Complete, June 1978 |

TABLE 5-8. Continued

| Source Category | Description | Test Points (Unit Operation) | Sampling Protocol | Test Collaborator | Status |
|---|---|---|---|---|---|
| Oil-fired Utility Boiler | Moss Landing #6; 740 MW opposed wall fired; 48 burners, 4 elevations | Baseline<br>FGR<br>FGR + OFA | Continuous $NO_x$, $SO_2$, CO, $CO_2$, $O_2$<br>SASS<br>Method 5<br>Method 8<br>Gas grab ($C_1$-$C_6$ HC)<br>Fuel<br>Operating data<br>Bioassay | New test start | Complete, September 1978 |
| Coal-fired Industrial Boiler | Traveling grate spreader stoker, 38 kg/s (300,000 lb/hr); ESP for particulate control; wet scrubber for $SO_x$ control | Baseline<br>LEA + high OFA | Continuous $NO_x$, $SO_2$, CO, $CO_2$, $O_2$<br>Boiler exit:<br>-- SASS<br>-- Method 5<br>-- Shell-Emeryville<br>-- Gas grab ($C_1$-$C_6$ HC)<br>ESP outlet<br>-- SASS<br>-- Method 5<br>-- Shell-Emeryville<br>-- Gas grab ($C_1$-$C_6$ HC)<br>Bottom ash<br>Cyclone hopper ash<br>Fuel<br>Operating data | KVB | Complete, October 1977 |
| Coal-fired Industrial Boiler | Traveling grate spreader stoker, 25 kg/s (200,000 lb/hr) ESP for particulate control | Baseline<br>LEA + High OFA | Continuous $NO_x$, $SO_2$, CO, $CO_2$, $O_2$<br>Boiler exit:<br>-- SASS<br>-- Method 5<br>-- Shell-Emeryville<br>-- Gas grab ($C_1$-$C_6$ HC)<br>ESP Outlet<br>-- SASS<br>-- Method 5<br>-- Shell-Emeryville<br>-- Gas grab ($C_1$-$C_6$ HC)<br>Bottom ash<br>ESP hopper ash<br>Fuel<br>Operating data<br>Bioassay | KVB | Complete, February 1978 |

TABLE 5-8. Concluded

| Source Category | Description | Test Points (Unit Operation) | Sampling Protocol | Test Collaborator | Status |
|---|---|---|---|---|---|
| Oil-fired Gas Turbine | T.H. Wharton Station, 60 MW GE MS 7001 C machine | Baseline<br>Maximum water injection | Continuous $NO_x$, $SO_2$, CO $CO_2$, $O_2$<br>SASS<br>Method 5<br>Method 8<br>Fuel<br>Water<br>Operating data<br>Bioassay | General Electric | Complete, April 1978 |
| Oil-fired Residential Heating Unit | Blue Ray low $NO_x$ furnace, Medford, New York | Continuous Cycling | Continuous $NO_x$, $SO_2$, CO $CO_2$, $O_2$<br>SASS<br>Method 5<br>Method 8<br>Fuel | New test start with EPA-RTP | Complete, November 1977 |

- Bottom ash slurry sampling
- Particulate collector hopper ash (slurry) sampling
- Fuel and fuel additive, if applicable, sample collection
- Operating data collection

Also, as noted in Table 5-8, the test program was conducted, as a minimum, for at least two conditions of source operation: baseline (uncontrolled) and low $NO_x$ operation. In several instances, operation at intermediate levels of $NO_x$ control was tested. In addition, replicate testing was performed in selected cases.

A key part of the test program involved close monitoring of source operating data. This was done not only to ensure that test conditions remained constant and representative of acceptable source operation over the duration of sample collection, but also to provide the necessary input to further process analysis efforts analogous to those described in Section 6.

Subsequent laboratory chemical analyses of samples collected generally followed IERL-RTP defined Level 1 procedures (References 5-4, 5-5). A specific exception dealt with liquid and solid sample trace element analysis. Here, instead of assaying for trace elements by spark source mass spectroscopy, atomic absorption spectroscopy was employed to determine the 23 more commonly occurring elements listed in Table 5-9. Another exception dealt with organic analyses of flue gas (XAD-2 extract), particulate and liquid/solid samples. Here the analyses were extended, when feasible, to the determination of the 11 polycyclic organic compounds (POM) listed in Table 5-10. Other minor exceptions were:

- The SASS particulate combining scheme shown in Figure 5-3 was employed to maximize the usefulness of analysis results
- Analyses for the ionic species listed in Table 5-11 were performed using specific ion electrodes instead of test kits

The specific analysis procedures followed are indicated schematically in Figures 5-3 through 5-6. Following these procedures the Level 1 analysis data listed below can be obtained for each test point:

- Continuous flue gas $NO_x$, $SO_2$, CO, $CO_2$, and $O_2$
- Flue gas $SO_2$, $SO_3$, and speciated $C_1$-$C_6$ hydrocarbon
- Flue gas particulate load and size distribution
- Flue gas vapor phase trace element composition for the 23 elements listed in Table 5-9

TABLE 5-9. ELEMENTAL ANALYSIS: SPECIES DETERMINED

| | |
|---|---|
| Antimony (Sb) | Manganese (Mn) |
| Arsenic (As) | Mercury (Hg) |
| Barium (Ba) | Molybdenum (Mo) |
| Beryllium (Be) | Nickel (Ni) |
| Bismuth (Bi) | Selenium (Se) |
| Boron (B) | Tellurium (Te) |
| Cadmium (Cd) | Thallium (Ti) |
| Chromium (Cr) | Tin (Sn) |
| Cobalt (Co) | Titanium (Ti) |
| Copper (Cu) | Vanadium (V) |
| Iron (Fe) | Zinc (Zn) |
| Lead (Pb) | |

TABLE 5-10. POM ANALYSIS: SPECIES DETERMINED

| | |
|---|---|
| Anthracene | Coronene |
| Anthanthrene | Fluoranthene |
| Benz(a)anthracene | Phenanthrene |
| Benzo(g,h,i)perylene | Perylene |
| Benzo(a)pyrene | Pyrene |
| Benzo(e)pyrene | |

TABLE 5-11. ANION ANALYSIS: SPECIES DETERMINED

Chloride ($Cl^-$)
Fluoride ($F^-$)
Nitrate ($NO_3^-$)
Cyanide ($CN^-$)
Sulfate ($SO_4^{2-}$)
Ammonia ($NH_4^+$)

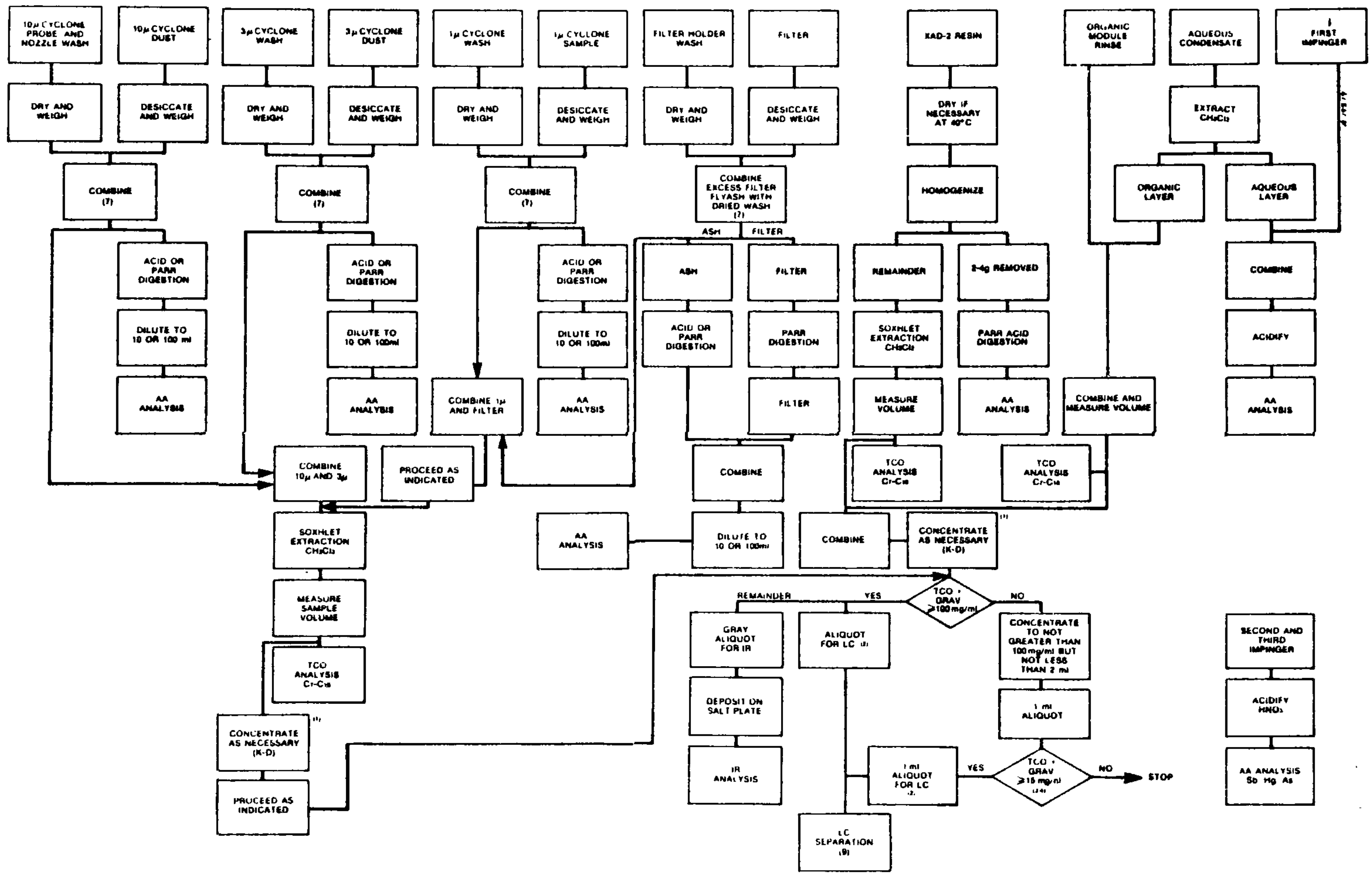



Figure 5-3. Analysis scheme for SASS train samples.

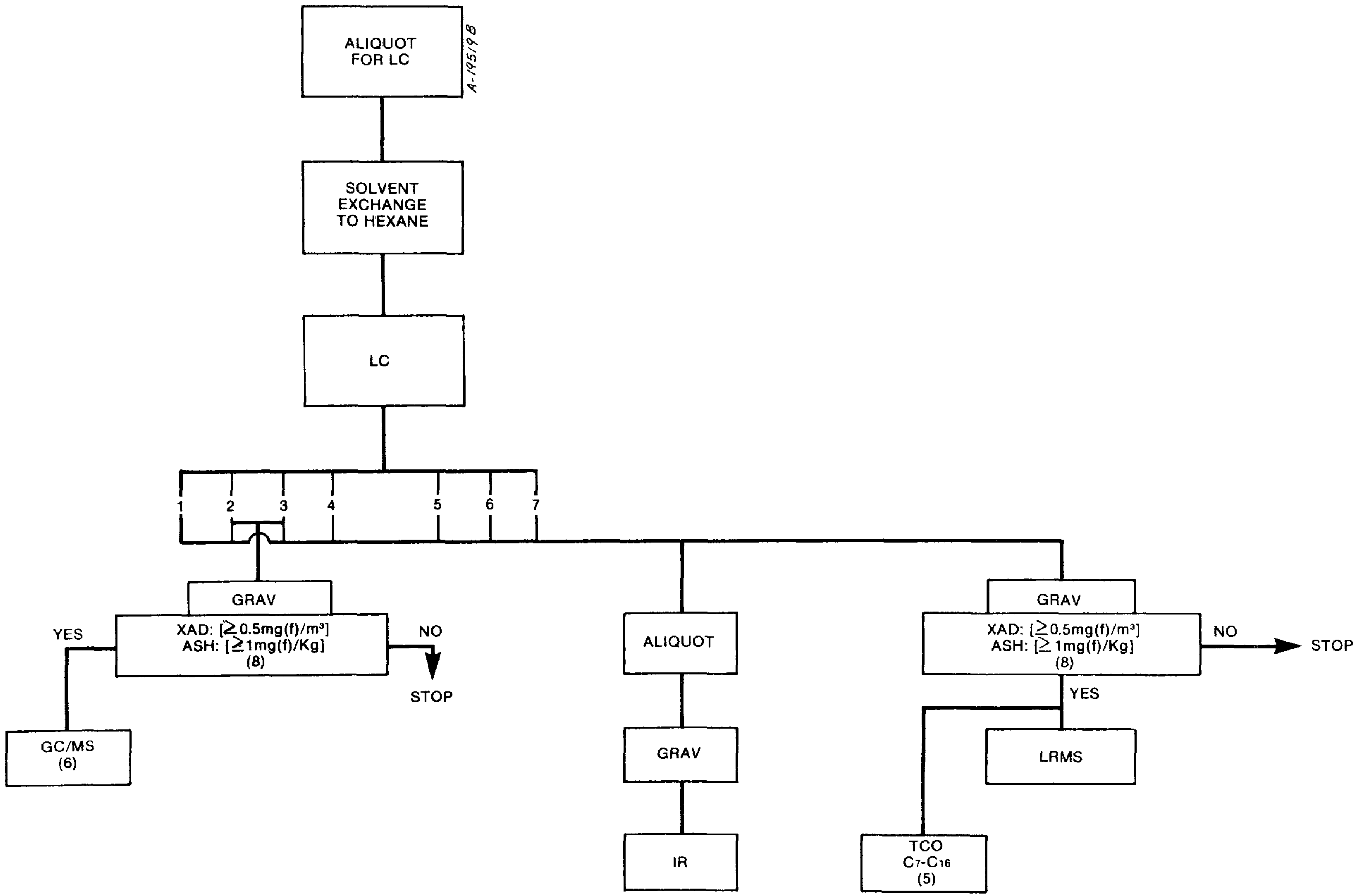



Figure 5-4. LC separation scheme.

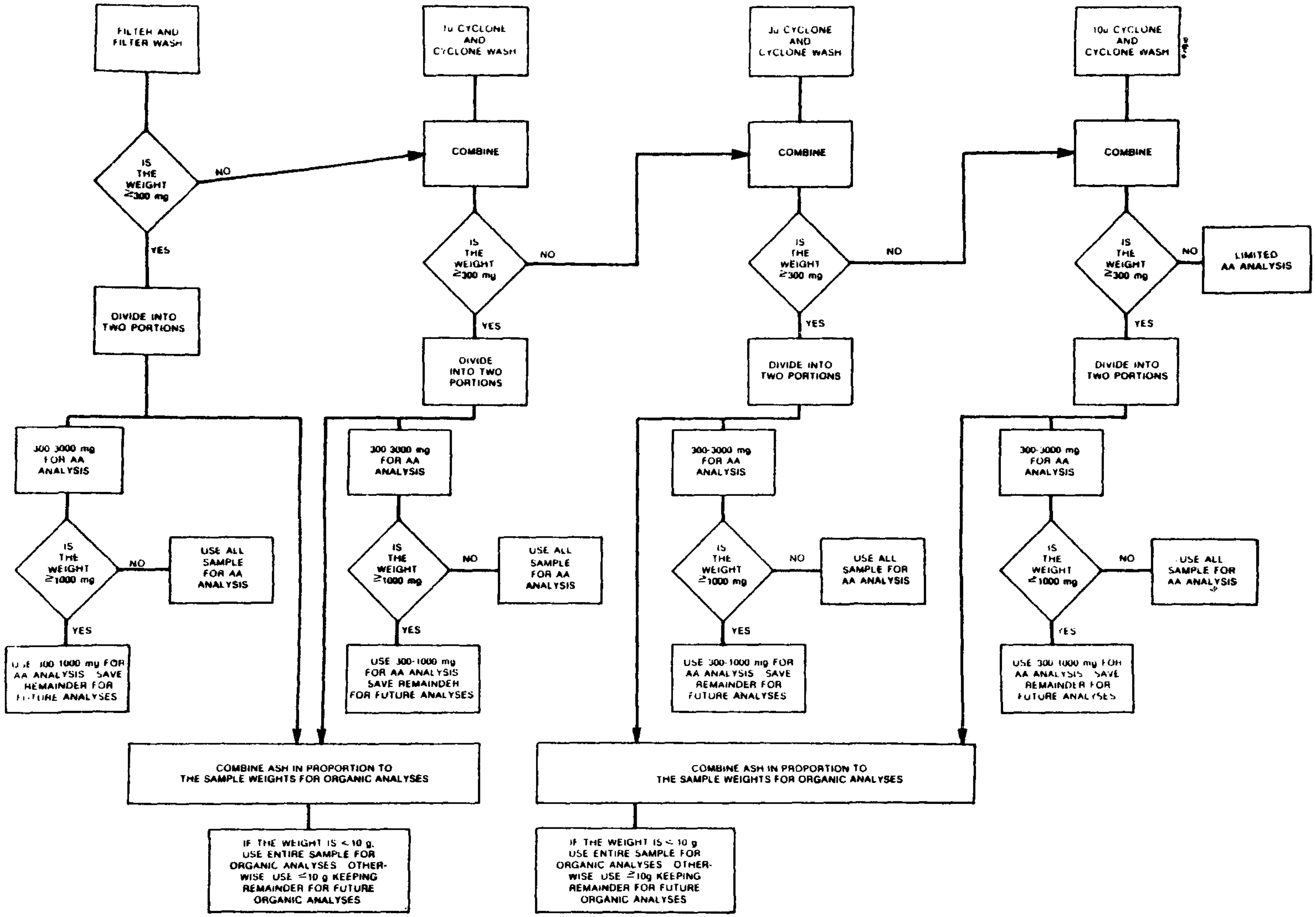



Figure 5-5. SASS particulate sample combining scheme.

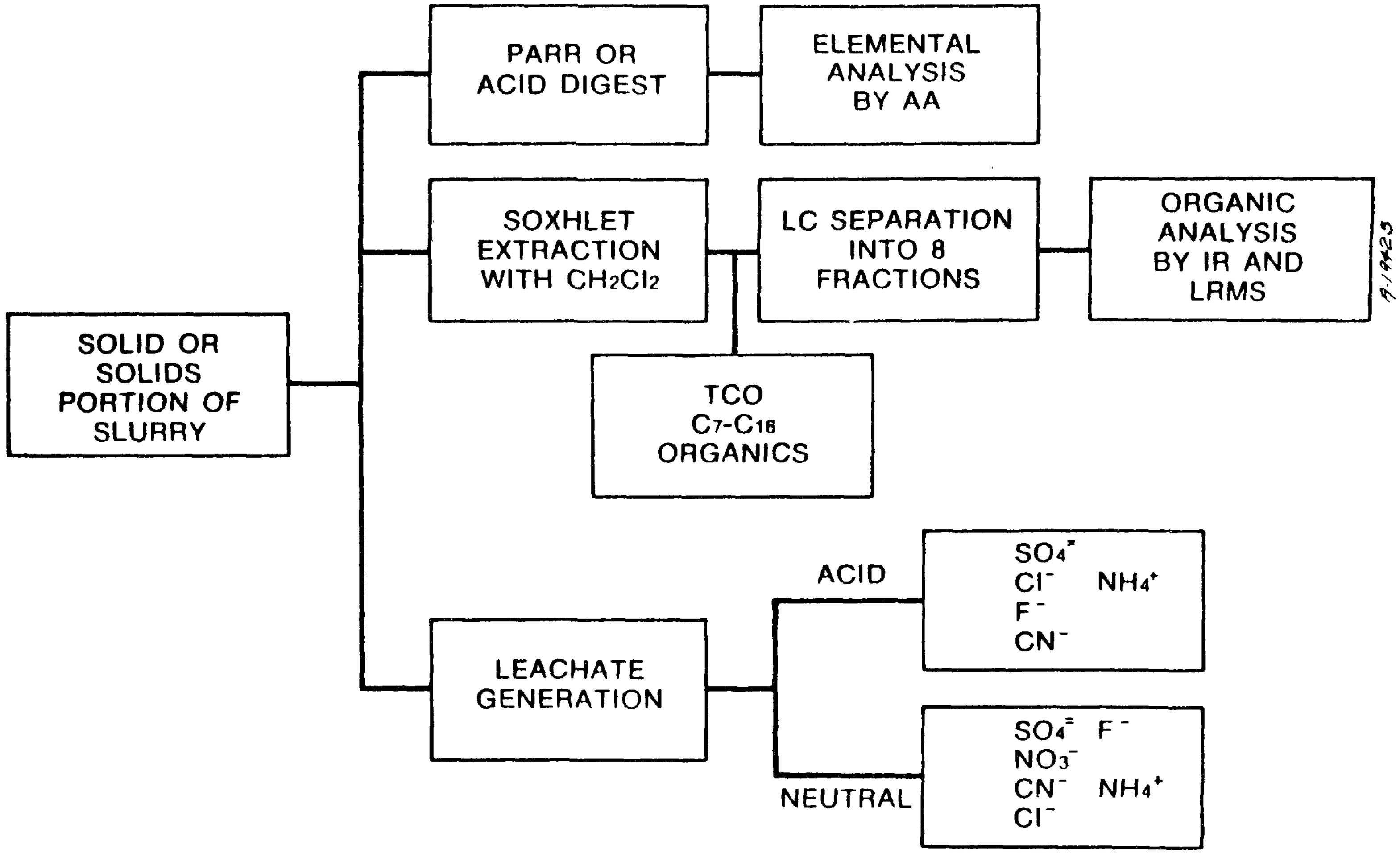



Figure 5-6. Analysis scheme for liquid/solid samples.

- Flue gas $< C_7$ organic composition in terms of seven compound polarity fractions and flue gas POM composition for the 11 POM species listed in Table 5-10

- Particulate composition for the 23 elements listed in Table 5-9 and the six ionic species listed in Table 5-11, as a function of particulate size

- Particulate organic composition for seven polarity fractions, and for the 11 POM species listed in Table 5-10, as a function of particulate size

- Liquid/solid stream (bottom, hopper ash) composition for the 23 elements listed in Table 5-9 and the six ionic species listed in Table 5-11

- Liquid/solid stream (bottom, hopper ash) organic composition for seven polarity fractions and for the 11 POM species listed in Table 5-10

- Particulate and ash C, H, O, N, and S content

- Fuel proximate and ultimate analysis (heating value, and water, C, H, O, N, and S content)

- Fuel trace element content for the 23 elements listed in Table 5-9

The above data satisfy the specific needs identified in earlier $NO_x$ EA efforts (Reference 5-2). Specific attention was focused on obtaining data on emitted POM, $SO_3$ and condensed sulfate, and trace element levels as a function of particulate size, especially as these are affected by $NO_x$ control applications.

In addition to the chemical analysis program, bioassay testing in accordance with IERL-RTP guidelines (Reference 5-6) will also be performed on samples collected during the gas turbine, oil-fired utility boiler, second coal-fired utility boiler, and second coal-fired industrial stoker tests. The general bioassay protocol to be followed is indicated in Table 5-12.

As Table 5-8 indicated, all seven planned tests have been completed. Sample chemical analyses, bioassay testing, and test data reduction are currently underway and will be available in the near future.

TABLE 5-12. BIOASSAY ANALYSIS PROTOCOL

| Sample Type | Bioassay Test Protocol | Sample Size Requirements |
|---|---|---|
| SASS cyclones, 10μ + 3μ | Microbial Mutagenesis<br>Cytotoxicity, RAM | 1.0g<br>0.5g |
| SASS cyclones, 1μ + filter | Microbial Mutagenesis<br>Cytotoxicity, RAM | 1.0g<br>0.5g |
| XAD-2 extract | Microbial Mutagenesis<br>Cytotoxicity, WI-38 | 50 mℓ<br>50 |
| Bottom ash | Microbial Mutagenesis<br>Cytotoxicity, RAM<br>Rodent Acute Toxicity<br>Freshwater Algal Bioassay<br>Freshwater Static Bioassay | 1.0g<br>0.5g<br>100g<br>50 kg<br>(200 ℓ if sluiced) |
| ESP Hopper ash | Microbial Mutagenesis<br>Cytotoxicity, RAM<br>Rodent Acute Toxicity<br>Freshwater Algal Bioassay<br>Freshwater Static Bioassay | 1.0g<br>0.5g<br>100g<br>50 kg |

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5-5 Lentzen, D. E., et al., "IERL-RTP Procedures Manual: Level 1 Environmental Assessment (Second Edition)," EPA-600/7-78-201, January 1979.

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## SECTION 6

## CONTROL TECHNOLOGY OVERVIEW

The control technology assessments in the $NO_x$ EA will compile and evaluate process data to provide environmental assessments of combustion modification control technologies. The overall objectives of the assessments are to:

- Characterize current and advanced $NO_x$ combustion process modifications and project schedules for applying them
- Assess the technical and environmental soundness of these control technologies
- Recommend R&D for filling technological gaps and producing needed data
- Provide objective evaluations of important aspects of $NO_x$ control systems

The results will be documented in a series of reports covering the seven major stationary source equipment categories.

The main efforts in the second year focused on the assessment of $NO_x$ control techniques for the utility boiler source category. Results from this study were recently documented (Reference 6-1) and are briefly summarized in this section, which presents an overview of utility boiler $NO_x$ control techniques, and in Section 7, which presents the detailed results of the environmental assessment of applying the more promising current technology controls.

Modifying the combustion process conditions is the most effective and widely used technique for achieving moderate (20 to 60 percent) reduction in combustion generated oxides of nitrogen from utility boilers. This section reviews the combustion modification techniques either demonstrated or currently under development. The review begins with a discussion of the status and prospects of control requirements.

### 6.1 CONTROL REQUIREMENTS

The incentive for developing $NO_x$ controls derives from two separate mechanisms: the Federal Standards of Performance for New

Stationary Sources (NSPS) and the State Implementation Plans (SIP's). The NSPS are intended largely to assist in maintaining air quality by offsetting increases due to source growth. By law, EPA reviews, revises, and sets NSPS as advanced control technology is developed and demonstrated. If emission standards in addition to the NSPS are required to attain and/or maintain the National Ambient Air Quality Standards in Air Quality Control Regions within the jurisdiction of the states, these standards are set through SIP's.

In the following sections, present and developing control techniques that can help meet projected standards for utility boilers are reviewed.

## 6.2 STATE-OF-THE-ART CONTROLS

There are several effective combustion modification techniques that may be used singly or in combination on utility boilers. These techniques include low excess air firing, biased burner firing, burners out of service, overfire air, flue gas recirculation, and reduced firing rate. These methods for controlling $NO_x$ may be used on existing boilers although modifications to the units may be necessary.

### 6.2.1 Low Excess Air

Reducing the excess air level in the furnace is an effective method of $NO_x$ control. In this technique, the combustion air is reduced to a minimum amount required for complete combustion, maintaining acceptable furnace cleanliness, and maintaining steam temperature. With less oxygen available in the flame zone, both thermal and fuel $NO_x$ formation are reduced. In addition, the reduced airflow lowers the quantity of flue gas released resulting in an improvement in boiler efficiency.

Low excess air firing is usually the first $NO_x$ control technique applied. Reductions in $NO_x$ emissions of 10 to 20 percent can be expected. It may be used with virtually all fuels and firing methods. However, furnace slagging and tube wastage considerations may limit the degree of application. Low excess air may also be employed in combination with the other $NO_x$ control methods.

### 6.2.2 Off Stoichiometric Combustion (OSC)

Off stoichiometric, or staged, combustion seeks to control $NO_x$ by carrying out initial combustion in a primary, fuel-rich, combustion zone, then completing combustion, at lower temperatures, in a second, fuel-lean zone. In practice, OSC is implemented through biased burner firing (BBF), burners out of service (BOOS), or overfire air injection (OFA).

#### Biased Burner Firing, Burners Out Of Service

Biased burner firing consists of firing the lower rows of burners more fuel rich than the upper rows of burners. This may be accomplished by maintaining normal air distribution to the burners while adjusting fuel flow so that a greater amount of fuel enters the furnace through the lower rows of burners than through the upper rows of burners. Additional air required for complete combustion enters through the upper rows of burners which are firing air rich.

In the burners out of service mode, individual burners, or rows of burners, admit air only. This reduces the airflow through the fuel admitting, or active, burners. Thus, the burners are firing more fuel rich than normal, with the remaining air required for combustion being admitted through the inactive burners.

These methods reduce $NO_x$ emissions by reducing the excess air available in the active burner zone. This reduces fuel and thermal $NO_x$ formation. These techniques are applicable to all fuels and are particularly attractive as control methods for existing units since few, if any, equipment modifications are required. Average $NO_x$ reductions of 30 to 50 percent can be expected. In some cases, however, derating of the unit may be required if there is too limited extra firing capability with the active burners. This is most likely to be a problem with pulverized coal units without spare pulverizer capacity.

Overfire Air

The overfire air technique for $NO_x$ control involves firing the burners more fuel rich than normal while admitting the remaining combustion air through overfire air ports.

Overfire air is very effective for $NO_x$ reduction and may be used with all fuels. Reductions in $NO_x$ of 30 to 50 percent can be expected. However, there is an increased potential for furnace tube wastage due to local reducing conditions when firing coal or high sulfur oil. There is also a greater tendency for slag accumulation in the furnace when firing coal. In addition, with reduced airflow to the burners, there may be reduced mixing of the fuel and air. Thus, additional excess air may be required to ensure complete combustion. This may result in a decrease in efficiency.

Overfire air is more attractive in original designs than in retrofit applications for cost considerations. Additional duct work, furnace penetrations, and extra fan capacity may be required. There may be physical obstructions outside of the boiler setting making installation more costly. Or, there may also be insufficient height between the top row of burners and the furnace exit to permit the installation of overfire air ports and the enlarged combustion zone created by the off stoichiometric combustion technique.

### 6.2.3 Flue Gas Recirculation

Flue gas recirculation for $NO_x$ control consists of extracting a portion of the flue gas from the economizer outlet and returning it to the furnace, admitting the flue gas through the furnace hopper or through the burner windbox or both. Flue gas recirculation lowers the bulk furnace gas temperature and reduces oxygen concentration in the combustion zone.

Flue gas recirculation through the furnace hopper and near the furnace exit has long been used for steam temperature control. Flue gas recirculation through the windbox and, to a lesser degree, through the furnace hopper is very effective for $NO_x$ control on gas- and oil-fired units. However, it has been shown to be relatively ineffective on coal-fired units.

Flue gas recirculation for $NO_x$ control is more attractive for new designs than as a retrofit application. Retrofit installation of flue gas recirculation can be quite costly. The fan, flues, dampers, and controls as well as possibly having to increase existing fan capacity due to increased draft loss, can represent a large investment. In addition, the flue gas recirculation system itself may require a substantial maintenance program due to the high temperature environment experienced and potential erosion from entrained ash. Thus, the cost effectiveness of this method of $NO_x$ control has to be examined carefully when comparing it to other control techniques.

As a new design feature, the furnace and convective surfaces can be sized for the increase in mass flow and change the furnace temperatures. In contrast, in retrofit applications the increased mass flow increases turbulence and mixing in the burner zone, and alters the convective section heat absorption. Erosion and vibration problems may result. Flame detection can also be difficult with flue gas recirculation through the windbox. In addition, controls must be employed to regulate the proportion of flue gas to air so that sufficient concentration of oxygen is available for combustion.

Limited data indicate that FGR alone reduces $NO_x$ by about 15 percent for coal, 20 to 30 percent for oil, and 30 to 60 percent for gas. For oil and gas firing, FGR is more effective when combined with off stoichiometric firing.

### 6.2.4 Reduced Firing Rate

Thermal $NO_x$ formation generally increases as the volumetric heat release rate or combustion intensity increases. Thus, $NO_x$ can be controlled by reducing combustion intensity through load reduction, or derating, in existing units and by enlarging the firebox in new units. The reduced heat release rate lowers the bulk gas temperature which in turn reduces thermal $NO_x$ formation.

The overall heat release rate per unit volume is generally independent of unit rated power output. However, the ratio of primary flame zone heat release to heat removal often increases as the unit capacity is increased. This causes $NO_x$ emissions for large units to be generally greater than for small units of similar design, firing characteristics, and fuel.

The increase in $NO_x$ emissions with increased capacity is especially evident for gas-fired boilers, since total $NO_x$ emissions are due to thermal $NO_x$. However, for coal-fired and oil-fired units the effects of increased capacity are less noticeable, since the conversion of fuel nitrogen to $NO_x$ for these fuels represents a major component of total $NO_x$ formation. Still, a reduction in firing rate will affect firebox aerodynamics which may, consequently, affect fuel $NO_x$ emissions. But such effects on fuel $NO_x$ production are less significant.

Analyses of test data show that for coal firing, an average of 15 percent reduction in $NO_x$ resulted from a 28 percent reduction in firing rate. For oil firing, an average of 30 percent reduction in $NO_x$ resulted from a 42 percent reduction in firing rate. For gas firing, an average of 44 percent reduction in $NO_x$ resulted from a 44 percent reduction in firing rate. Thus, reduction of $NO_x$ with lowered firing rate is most evident with gas-fired boilers.

Reduced firing rate often leads to several operating problems. Aside from the limiting of capacity, low load operation usually requires higher levels of excess air to maintain steam temperature and to control smoke and CO emissions. The steam temperature control range is also reduced substantially. This will reduce the operating flexibility of the unit and its response to changes in load. The combined results are reduced operating efficiency due to higher excess air and reduced load following capability due to a reduction in control range.

When the unit is designed for a reduced heat release rate, the problems associated with derating are largely avoided. The use of an enlarged firebox produces $NO_x$ reductions similar to load reduction on existing units.

## 6.3 ADVANCED CONTROLS

Two advanced control techniques hold special promise for the future: low $NO_x$ burners with near term applications, and ammonia injection with possible widespread application in 1985 and beyond.

### 6.3.1 Low $NO_x$ Burners

Several utility boiler manufacturers have recently been active in the development of new burners designed to reduce $NO_x$ emissions from coal-fired units. Although other techniques such as low excess air, off stoichiometric combustion, and flue gas recirculation have been shown to be effective in reducing $NO_x$ levels, there has been some concern as to the efficacy of those techniques and the adverse side effects resulting from their application. Consequently, low $NO_x$ burners are being installed in many new wall fired units either as the primary $NO_x$ control device or for use in conjunction with other $NO_x$ reduction methods.

Most low $NO_x$ burners designed for utility boilers control $NO_x$ by reducing flame turbulence, delaying fuel air mixing, and establishing fuel-rich zones where combustion initially takes place. This represents a departure from the usual burner design procedures which promote high turbulence, high intensity, rapid combustion flames. The longer, less intense flames produced with low $NO_x$ burners result in lower flame temperatures which reduce thermal $NO_x$ generation. Moreover, the reduced availability of oxygen in the initial combustion zone inhibits fuel $NO_x$

conversion. Thus, both thermal and fuel $NO_x$ are controlled by the low $NO_x$ burners.

These new, optimized design burners are capable of reducing $NO_x$ emissions 40 to 60 percent with coal firing (References 6-2 and 6-3). New wall fired boilers designed to meet current NSPS now come equipped with low $NO_x$ burners. Retrofit application, however, is still in the demonstration stage.

In addition to the new burner designs being developed by utility boiler manufacturers, EPA-IERL/CRB is also conducting a development program which seeks to demonstrate an advanced low emission pulverized coal burner design on both utility and industrial boilers. Pilot scale prototype burners have been shown capable of reducing $NO_x$ emissions below 100 ppm (Reference 6-4). Demonstration programs are currently being initiated.

Based on all this work, low $NO_x$ burners appear to be a very promising control technology, with fewer potential problems than most traditional combustion modification techniques.

### 6.3.2 Ammonia Injection

The selective, noncatalytic reduction of $NO_x$ via ammonia injection has received increasing attention as a possible means to reach quite stringent levels of control in utility boilers. In this technique ammonia is used to reduce nitric oxide, in the presence of oxygen, to nitrogen in a series of gas phase reactions occurring in the temperature range of 980 to 1310K (1500 to 1900°F) (Reference 6-5). Demonstration tests in Japan on oil- and gas-fired sources have shown the technique capable of achieving 40 to 60 percent $NO_x$ reductions at optimum temperatures in the 1200 to 1250K (1700 to 1800°F) range (Reference 6-5). Further demonstrations in the U.S., including tests on coal-fired sources, are planned.

Based on results to date, ammonia injection can be considered as available control technology for gas- and oil-fired sources, but must be treated as still in the development stage for coal-fired boilers. In all applications, though, many practical problems remain to be solved. One problem is the precise residence time/temperature conditions required for the process. Other concerns include the effect of high dust loadings and sulfur oxide concentrations on the effectiveness of ammonia injection in coal-fired applications. A related problem concerns the fate, and potential effects of any ammonium bisulfate formed from excess ammonia present in $SO_2$/$SO_3$ containing flue gases. In any event, projected applications of the technique have focused on reducing the $NO_x$ remaining after other combustion modifications have been applied.

## 6.4 OTHER CONTROL METHODS

There are several other possible control techniques for reducing utility boiler $NO_x$ emissions. However, they have less promise for widespread application than those described earlier, for such reasons as energy penalties, high cost, or technical difficulties. These are briefly discussed below.

### 6.4.1 Reduced Air Preheat

Reduced combustion air preheat (RAP) lowers the peak temperatures in the combustion zone, thus lowering thermal $NO_x$ emissions. However, with the associated severe loss in boiler efficiency, RAP is not considered a practical control technique.

### 6.4.2 Water Injection

Water injection reduces flame temperature, and hence lowers thermal $NO_x$. However, boiler efficiency losses of the order of 10 percent have been reported. Thus, water injection is not seen as a feasible $NO_x$ reduction technique for utility boilers based on the large energy penalty incurred.

### 6.4.3 Flue Gas Treatment

While combustion modification techniques seek to lower $NO_x$ emissions by minimizing NO formation, flue gas treatment (FGT) processes involve post-combustion $NO_x$ removal from the flue gas. Flue gas treatment has potential for use combined with combustion modifications when very high removal efficiencies are required.

FGT has been applied to only a few commercial oil- and gas-fired boilers in Japan. No FGT installation for $NO_x$ control on utility boilers exists in the United States as combustion modifications represent the most cost effective approach to achieving moderate $NO_x$ reductions. However, combustion modifications alone may not be able to provide the degree of control necessary to meet future $NO_2$ ambient air quality standards. Thus EPA has initiated several demonstration projects to investigate the use of FGT in the U.S. (Reference 6-6).

FGT processes can be divided into two main categories: dry processes and wet processes. Dry processes reduce $NO_x$ by catalytic reduction and generally operate at temperatures between 570 to 700K (570 to 800°F). Wet systems are generally either oxidation/absorption or absorption/reduction processes, both operating in the 310 to 320K (100 to 120°F) range.

Among the many dry process variations, selective catalytic reduction (SCR) using ammonia has been perhaps the most successful. Over 50 percent $NO_x$, and often up to 90 percent reductions have been claimed using such processes. However, plugging of the catalyst bed and fouling of the catalyst itself are major operational concerns, especially with coal firing. Moreover, use of SCR has raised concerns in that any ammonia left in the flue gas may combine with existing $SO_3/SO_2$ to produce a visible plume, and byproducts, such as ammonium bisulfate, which are corrosive to boiler equipment.

Wet FGT processes utilize more complex chemistry than dry processes. In the oxidation/absorption processes, strong oxidants such as ozone or chlorine dioxide are used to convert the relatively inactive NO in the flue gas to $NO_2$ or $N_2O_5$ for subsequent absorption. In the absorption/oxidation processes, chelating compounds, such as ferrous ethylenediaminetetracetic acid are required in the scrubbing solution to trap the NO. However, because wet processes rely on absorption, most of them create troublesome byproducts such as nitric acid, potassium nitrate, ammonium sulfate, calcium nitrate, and gypsum which may have little commercial value. In addition, the high cost of an absorber and an oxidant or chelating agent is likely to be prohibitive for flue gases with high $NO_x$ concentrations.

In general, the dry FGT techniques used in Japan can probably be applied to gas- and oil-fired sources in the U.S. However, the applicability of dry processes to coal-fired boilers remains to be determined. Wet processes are less well developed and costlier than dry FGT processes; however, wet processes have the potential to remove $NO_x$ and $SO_x$ simultaneously. In any case, more field tests are needed to determine the costs, secondary effects, reliability, and waste disposal problems. Flue gas treatment holds some promise as a control technique for use when high $NO_x$ removal efficiencies are necessitated by stringent emission standards. However, compared to combustion modifications FGT is considerably more expensive.

## REFERENCES FOR SECTION 6


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6-3. Vatsky, J., "Attaining Low $NO_x$ Emissions by Combining Low Emission Burners and Off-Stoichiometric Firing," presented at the 70th Annual AIChE Meeting, New York, November 1977.

6-4. Gershman, R., *et al.*, "Design and Scale-up of Low Emission Burners for Industrial and Utility Boilers," in *Proceedings of the Second Stationary Source Combustion Symposium: Volume V*, EPA-600/7-77-073e, NTIS PB-274 897, July 1977.

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6-6. Mobley, J.D., and R.D. Stern, "Status of Flue Gas Treatment Technology for Control of $NO_x$ and Simultaneous Control of $NO_x$ and $SO_x$ ," in *Proceedings of the Second Stationary Source Combustion Symposium: Volume III*, EPA 600/7-77-073c, NTIS PB-271 757/7BE, July 1977.

## SECTION 7

## CONTROL TECHNOLOGY ASSESSMENT

As noted in Section 1, the key objectives of the $NO_x$ EA are to identify the environmental impact of combustion modification $NO_x$ controls applied to stationary combustion sources and to specify the most cost-effective and environmentally sound $NO_x$ controls to attain and maintain $NO_2$ air quality goals. To satisfy these goals, a major aim of the program is to extend the control technology process background presented in Section 6 to include detailed evaluations of the emissions, source performance, and cost impacts of applying these controls.

Second year results from the assessment of $NO_x$ combustion modification controls applied to utility boilers are presented in this section. The basis and effectiveness of these controls and their process operational, cost, and environmental impacts are discussed.

### 7.1 EFFECTIVENESS OF $NO_x$ CONTROLS

Combustion modification techniques control $NO_x$ formation by decreasing primary flame zone $O_2$, lowering peak flame temperature, and shortening the flame zone residence time. The percentage reductions in $NO_x$ that can be expected with application of the various techniques were briefly discussed in Section 6. To reiterate, fine tuning and application of low excess air (LEA) can reduce $NO_x$ emissions 10 to 20 percent. Off stoichiometric combustion (OSC), biased burner firing (BBF), burners out of service (BOOS), and overfire air (OFA) can lower $NO_x$ emissions 30 to 50 percent. Low $NO_x$ burners show great promise, reducing $NO_x$ 40 to 60 percent for new coal-fired boilers, with retrofit application feasible. Flue gas recirculation (FGR) is an effective technique for oil and gas firing, especially when combined with OSC, lowering $NO_x$ by 30 to 75 percent.

The above control performance expectations were quantitatively derived by applying the $NO_x$ emissions correlation model outlined in Section 4.3.1. to an emission data base assembled from the results of 61 $NO_x$ control application field test programs and including 563 individual test points. The data base included test programs on coal-, oil-, and gas-fueled tangential, opposed wall, and single wall fired boilers as shown in Table 7-1. Controls tested included LEA, OSC, FGR, load reduction, and combinations of these, as shown in Table 7-2. Both published, and previously unreported data were included.

TABLE 7-1. FIELD TEST PROGRAM DATA COMPILED

| Fuel | Firing Type | | | Total |
|---|---|---|---|---|
| | Tangential | Opposed Wall | Single Wall | |
| Coal | 13 | 6 | 10[a] | 29 |
| Oil | 2 | 7 | 7 | 16 |
| Natural Gas | 1 | 8 | 7[b] | 16 |
| Total | 16 | 21 | 24 | 61 |

[a]Includes two wet bottom furnaces
[b]Includes one unit originally designed for coal firing with a wet bottom furnace

## TABLE 7-2. INDIVIDUAL TEST POINTS CORRELATED

| Firing Type | Fuel | Baseline[b] | Single Controls: LEA[c] | OSC[d] | FGR[e] | Low Load[f] | Combined Controls[a]: Low load + OSC | Low Load + FGR | OSC + FGR | Low Load + OSC + FGR | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Tangential | Coal | 21 | 29 | 46 | -- | 24 | 27 | -- | -- | -- | 147 |
| Opposed Wall | Coal | 8 | 11 | 11 | 7 | 7 | 5 | 1 | 2 | -- | 52 |
| Single Wall | Coal | 18 | 23 | 29 | -- | 19 | 19 | -- | -- | -- | 108 |
| Tangential | Oil | 1 | -- | 1 | -- | 1 | 1 | 1 | -- | 1 | 6 |
| Opposed Wall | Oil | 6 | 5 | 11 | 2 | 7 | 7 | 5 | 2 | 11 | 56 |
| Single Wall | Oil | 4 | 6 | 5 | 4 | 8 | 6 | 10 | 10 | 8 | 61 |
| Tangential | Nat gas | 1 | 1 | -- | 2 | 2 | 1 | 5 | 1 | -- | 13 |
| Opposed Wall | Nat gas | 7 | 9 | 18 | -- | 13 | 13 | 3 | 3 | 8 | 74 |
| Single Wall | Nat gas | 5 | 4 | 9 | 2 | 7 | 7 | 3 | 4 | 5 | 46 |
| All Boilers | All fuels | 71 | 88 | 130 | 17 | 88 | 86 | 28 | 22 | 33 | 563 |

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[a]Low excess air also generally employed

[b]Baseline = no controls applied; boiler load near or at maximum rating; excess air at normal or above normal settings

[c]LEA = low excess air setting

[d]OSC = off stoichiometric combustion (includes: biased burner firing, burners out of service, overfire air)

[e]FGR = flue gas recirculation; generally includes low excess air setting

[f]Load less than 80 percent of maximum continuous rating (MCR)

The $NO_x$ correlation model showed that the key boiler/burner design and operating variables affecting $NO_x$ emissions were:

- Heat input per active burner
- Stoichiometry to active burners
- Firing rate
- Number of burners firing (degree of BOOS)
- Surface heat release rate
- Furnace stoichiometry
- Percent flue gas recirculation
- Number of furnace division walls

The only fuel property statistically required for use was the fuel type: coal, oil, or natural gas. Thus the effective $NO_x$ controls were the ones that controlled an "optimal combination" of selected variables.

Correlation results were obtained for seven of the nine possible firing type/fuel combinations. Data for controls applied to gas- and oil-fired tangential boilers were too scattered to give good results.

As an example, for coal-fired tangential boilers, $NO_x$ emissions were predicted (with a correlation coefficient of 0.87) as:

$$y = 389.4 + 1.962 \times 10^{-7}(x_1)(x_2) - 3.017 \times 10^{-5}(x_1) + 3.249 \times 10^{-6}(x_3)(x_4) + 1.57 \times 10^{-3}(x_1)^2$$

where

$y$ = $NO_x$ emissions (ppm dry at 3 percent $O_2$)
$x_1$ = Heat input per active burner (W)
$x_2$ = Stoichiometry to active burners (percent)
$x_3$ = Surface heat release rate ($W/m^2$)
$x_4$ = Furnace stoichiometry (percent)

Figures 7-1 and 7-2 are graphical presentations of these results. The correlation fit is good considering that the data were from 147 tests carried out on a total of 13 boilers, in several different test programs. Results for other boiler/fuel classifications were comparable, and are reported elsewhere (Reference 7-1).

## 7.2 PROCESS ANALYSIS OF $NO_x$ CONTROLS

This section summarizes the major impacts of combustion modification controls on boiler operation and incremental emissions. The discussion is organized by fuel type and control technique, the dominant factors.

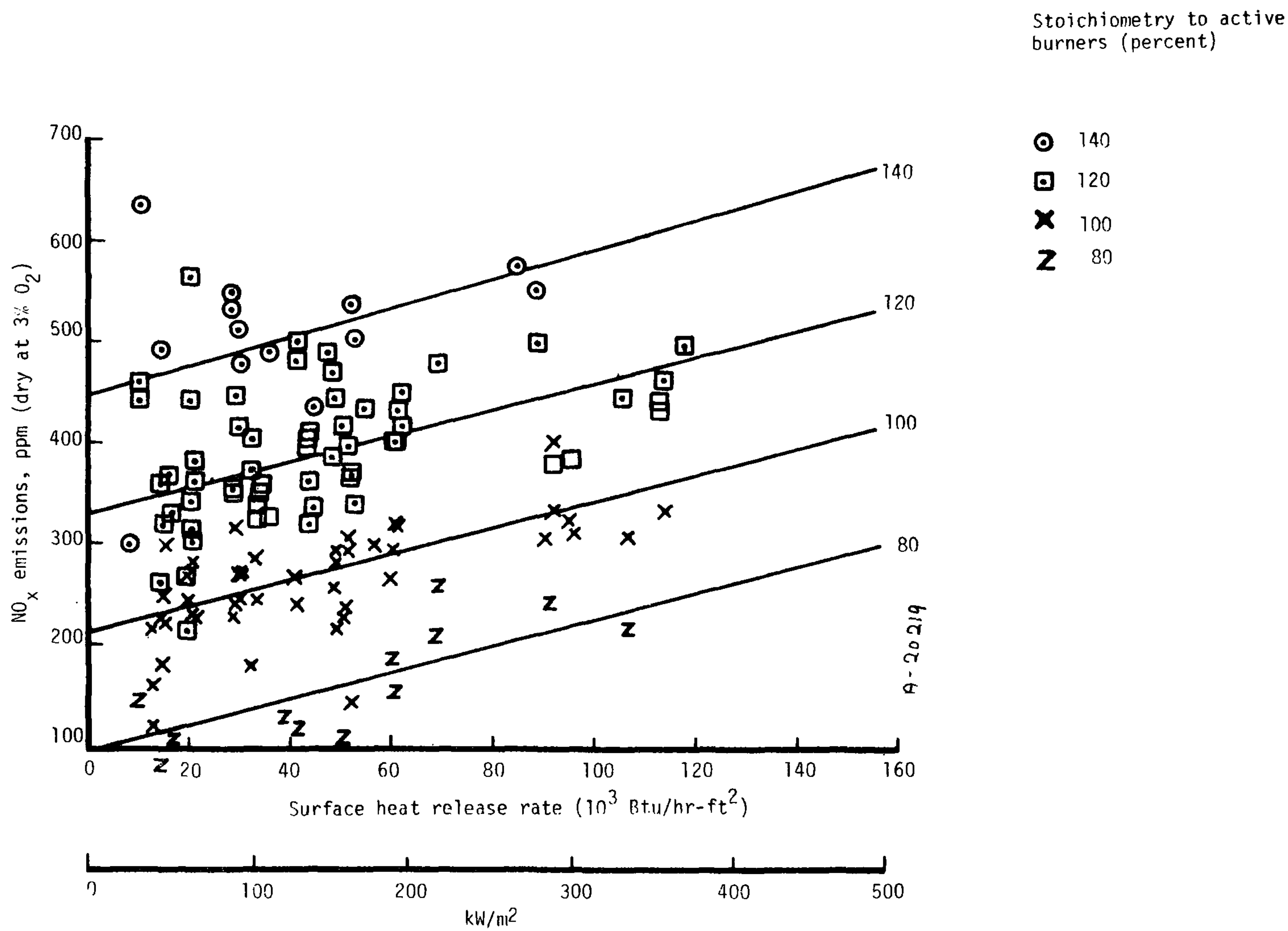


Figure 7-1. Effect of surface heat release rate and burner stoichiometry on $NO_x$ from tangential coal-fired boilers.

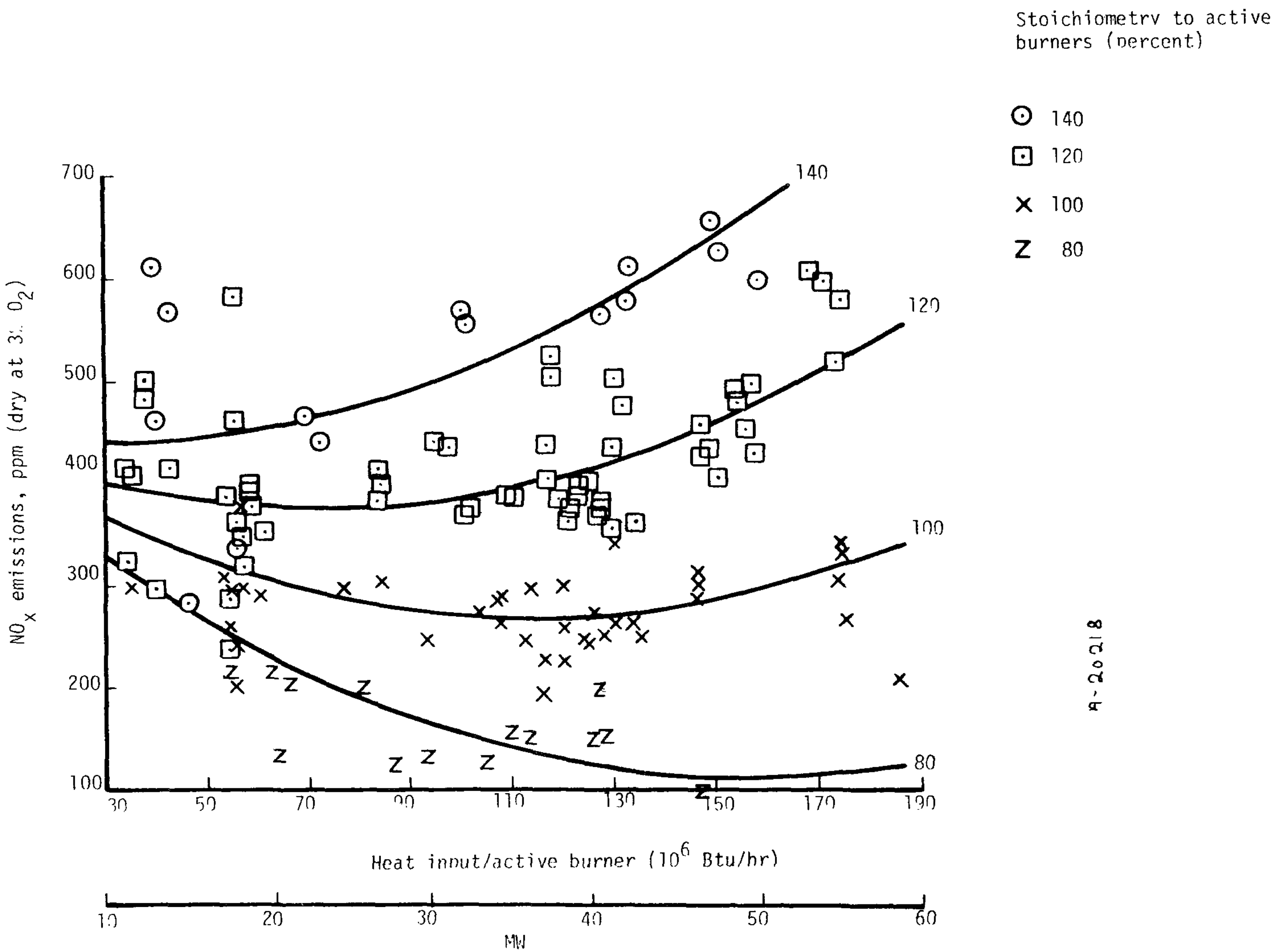


Figure 7-2. **Effect of heat input and burner stoichiometry on $NO_x$ from tangential coal-fired boilers.**

### 7.2.1 Coal-Fired Boilers

The effects of low $NO_x$ operation on coal-fired boilers are summarized in Table 7-3. The most commonly applied low $NO_x$ techniques for coal-fired boilers are low excess air and off stoichiometric combustion. Low $NO_x$ burners are also being installed on some new units and have been found to be effective. Other techniques which have been tested but are less commonly employed are flue gas recirculation, which has been found to be relatively ineffective, and water injection (WI), which is not preferred because of efficiency losses.

The major concerns regarding low $NO_x$ operation on coal-fired boilers have been the effects on boiler efficiency, load capacity, water wall tube corrosion and slagging, carbon loss, particulate loading and size distribution, heat absorption profile, and convective section tube and steam temperatures.

In most past experience with OSC, optimal excess air levels have been comparable to those used under baseline conditions. In these cases the efficiency of the boiler would remain unaffected if unburned carbon losses do not increase appreciably. However, in some cases when, due to nonuniform fuel/air distribution or other causes, the excess air requirement increases substantially with OSC, a significant decrease in efficiency may occur. From Table 7-3, it is seen that efficiency decreases up to 1 percent may occur under OSC. It is also seen that the same boiler (Widows Creek No. 5) tested at a different time under LEA and BOOS showed an average increase in efficiency by 1 percent.

Many new boilers now come factory equipped with OFA ports. Older boilers can be retrofitted with OFA ports or operate with minimal hardware changes under BOOS or biased firing. BOOS firing is normally accomplished by shutting off one or more pulverizers supplying the upper burner levels. If the other pulverizers cannot handle the extra fuel to maintain the total fuel flow constant, boiler derating will be required. From Table 7-3, it is seen that boiler derating of 10 to 25 percent is not uncommon with BOOS firing. Biased firing (reducing but not shutting off completely, fuel flow to upper burner levels) may reduce or eliminate the amount of derating a boiler has to suffer. However, this type of firing has not been tested sufficiently to establish its effectiveness as a $NO_x$ control technique.

The possibility of increased corrosion has been a major cause for concern with OSC operation. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be especially susceptible to corrosion attack under reducing atmospheres. Local reducing atmosphere pockets may exist under OSC operation even when burner stoichiometry is slightly over 100 percent. The problem may be further aggravated by slagging as slag generally fuses at lower temperatures under reducing conditions. The sulfur in the molten slag may then readily attack tube walls. Still, it has been found in general that no significant acceleration in corrosion rates occurs under OSC conditions. More recent experience has substantiated this conclusion (Reference 7-2). Nevertheless, the issue cannot be considered resolved until definitive

## TABLE 7-3. EFFECT OF LOW $NO_x$ OPERATION ON COAL-FIRED BOILERS

| Boiler | Low $NO_x$ Technique | Efficiency | Corrosion[a] | Load Capacity | Carbon Loss in Flyash | Dust Loading[a] | Part. Size Distribution[a] | Other Effects, Comments |
|---|---|---|---|---|---|---|---|---|
| Tangential | | | | | | | | |
| Barry No. 2 | BOOS | Unaffected | Measured 75% increase, but within normal range | 20% derate | Slight increase | ~100% increase | -- | Minor changes in heat absorption profile SH attemperation increased by 70% |
| | OFA | Unaffected | Measured 70% increase, but within normal range | Unaffected | Slight increase | ~100% increase | -- | Minor changes in heat absorption profile SH attemperation increased over 200% |
| Columbia No. 1 | OFA | Unaffected | No change | Unaffected | Slight increase | -- | -- | Minor changes in heat absorption profile SH attemperation increased by 70% |
| Huntington Canyon No. 2 | OFA | Unaffected | Measured 25% decrease, but within normal range | Unaffected | Slight increase | -- | -- | Minor changes in heat absorption profile No SH attemperation required |
| Barry No. 4 | LEA, BOOS | Unaffected | No significant change | 20% or more derate with BOOS | ~50% average decrease | ~50% average increase | -- | |
| Navajo No. 2 | LEA, BOOS, OFA | Unaffected | No significant change | Unaffected | No change | ~40% average increase | No change | |
| Comanche No. 1 | OFA | Unaffected | No significant change | Unaffected | ~30% average decrease | ~20% average decrease | No significant change | |
| Opposed Wall | | | | | | | | |
| Harllee Branch No. 3 | LEA, BOOS | 0.6% average decrease | Slight increase | Up to 17% derate with BOOS | ~130% average increase | ~10% average increase | -- | |
| Four Corners No. 4 | LEA, BOOS | 0.6% increase | No significant change | Up to 25% derate with BOOS | ~50% average decrease | ~15% average decrease | -- | |
| Hatfield No. 3 | BOOS | 0.3% decrease | -- | 10% derate | ~30% average increase | Unaffected | -- | No slagging or fouling. No significant increase in tube temperatures. |

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TABLE 7-3. Concluded

| Boiler | Low $NO_x$ Technique | Efficiency | Corrosion[a] | Load Capacity | Carbon Loss in Flyash | Dust Loading[a] | Part Size Distribution[a] | Other Effects, Comments |
|---|---|---|---|---|---|---|---|---|
| | FGR | 0.4% decrease in boiler efficiency. Some decrease in cycle efficiency due to RH attemperation | -- | Unaffected | ~120% average increase | Unaffected | -- | Stable flames and uniform combustion. Increase in RH attemperation. No significant increase in tube temperatures. |
| E.C. Gaston No. 1 | LNB, LEA, BOOS | 0.3% decrease on average (LNB baseline) | No significant increase | Up to 30% derate (LNB with BOOS) | ~130% average increase (LNB baseline) | ~15% average increase (LNB baseline) | Shift towards smaller particles (LNB, with or without BOOS) | Unit retrofitted with low $NO_x$ burners. Baseline, LEA and BOOS tests with LNB compared to baseline tests on sister boiler with no LNB. |
| <u>Single Wall</u> | | | | | | | | |
| Widows Creek No. 5 (TVA test) | BOOS | 1% decrease | Results of tests inconclusive | Unaffected | 30% increase | No significant increase | -- | |
| Widows Creek No. 5 (Exxon test) | LEA, BOOS | 1% average increase | No significant increase | Unaffected | 30% average decrease | 15% average decrease | -- | |
| Widows Creek No. 6 | LEA, BOOS | Unaffected | -- | Unaffected | 70% average increase | 20% average decrease | -- | |
| Mercer Station No. 1 (wet bottom) | LEA, Biased firing | Unaffected | No significant increase | Unaffected | 80% average increase | 10% average increase | No significant change | |
| Crist Station No. 6 | LEA, BOOS | 0.4% decrease | -- | Up to 15% derate | 60% increase | 50% increase | -- | |

[a]Denotes not investigated

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results from long term tests with measurements on actual water wall tubes are available. Insofar as slagging is concerned, short term tests performed to date indicate no increase in slagging or fouling of tubes under OSC operation.

Increased carbon loss in flyash may occur with OSC if complete burnout of the carbon particles does not occur in the furnace. High carbon loss will result in decreased boiler efficiency and may also cause electrostatic precipitator (ESP) operating problems. From Table 7-3, it is seen that increases in carbon loss vary over a wide range and can be as high as 70 to 130 percent in some cases. However, increased carbon loss is not perceived as one of the major problems associated with OSC operation. If the carbon content in flyash increases to levels where it threatens to impair the operation of dust collection systems, the unburned carbon can usually be easily controlled by increasing the overall excess air level in the furnace. Although this will tend to increase stack heat losses, the decrease in boiler efficiency will be partially compensated for by reduced unburned carbon losses.

Increased particulate loading with OSC may be a source of problems if baseline loadings are close to acceptable limits. Installing larger or more efficient dust removal devices may be necessary. The problem can be particularly severe if the particle size distribution shifts toward smaller sizes because the efficiency of many dust collectors, such as ESP's, decreases in the 0.1 to 1.0 $\mu$m range. From Table 7-3 it is seen that dust loading changes can vary widely. In some cases, dust loading may double with OSC operation, although from the few size distribution data available no shift in distribution is evident. It should be noted, however, that most of the particulate loading measurements were carried out at the economizer outlet and do not necessarily reflect stack outlet conditions.

Extension of the combustion region to higher elevations in the furnace may result in potential problems with excessive steam and tube temperatures. However, among the numerous short term OSC tests conducted no such problems have been reported. In some tests where furnace and convective section tube temperatures were measured directly, no significant increase was found. Changes in heat absorption profiles were also found to be minor, thus indicating no need for addition or removal of heat transfer surfaces. Superheater attemperator spray flowrates tripled in one case under OFA operation, but in all cases were well within spray flow capacities of the unit. Reheater attemperator spray flowrates did not show any increase due to OSC operation, thus cycle efficiencies were not affected.

Many new wall fired coal boilers are being fitted with low $NO_x$ burners (LNB). These burners are designed to reduce $NO_x$ levels to meet statutory requirements either alone or in some cases in combination with OFA ports. Using LNB has the advantage of eliminating or decreasing the need for reducing or near reducing conditions near furnace walls. Corrosion problems associated with reducing atmospheres should thus not arise with these systems. Although the LNB flames can be expected to be less turbulent and hence longer than flames from normal burners, the combustion zone will probably not extend any farther up the furnace than with OSC. Potential changes in heat absorption profile and excessive steam and tube temperatures are, therefore, less likely to occur.

As fuel and airflows are controlled more closely in LNB equipped systems, nonuniform distribution of fuel/air ratios leading to excessive CO generation or high excess air requirements should be eliminated. Boiler efficiencies should, therefore, not be affected by installation of LNB. However, Table 7-3 shows that the efficiency of one boiler decreased slightly when retrofitted with LNB. The decrease in efficiency was mainly due to the large increase in unburned carbon loss. Particulate loading also increased slightly with LNB, and there was a distinct shift towards smaller size particles. Still, more testing is required to check whether these changes were isolated instances or whether they form a pattern with LNB operation. It should be noted that the decrease in efficiency and increases in carbon loss and particulate loading were not greater than those encountered with OSC operation. Corrosion rates inferred from tests with corrosion coupons showed no significant increase with LNB. Some BOOS tests were also carried out on the LNB equipped boiler. A substantial decrease in $NO_x$ emissions resulted, below those already achieved with LNB alone. However, the boiler was derated by up to 30 percent. Other potential problems associated with OSC could also arise with this type of firing.

FGR to the windbox has been tested as a $NO_x$ control technique for coal-fired boilers. FGR inhibits thermal $NO_x$ formation but is not very effective in controlling fuel $NO_x$. Thus, the technique has not been used widely on coal-fired units as it is not very effective in these applications. The tests on Hatfield No. 3 showed that OSC was indeed much more effective in controlling $NO_x$ than FGR. Table 7-3 summarizes some of the effects of FGR operation on that unit. The increase in carbon loss averaged 120 percent, although there were wide variations in the measured values. Load capacity and dust loading remained unaffected. There was a slight decrease in boiler efficiency attributable to the power consumption by the FGR fans. There were no significant increases in tube temperature and stable flames and uniform combustion were observed throughout the tests, even at high recirculation rates (up to 15 percent at full load and 34 percent at reduced loads). Reheat steam spray attemperation increased at high recirculation rates which could result in a loss in cycle efficiency. No corrosion measurements were made so that the effects of FGR on corrosion are not known. Corrosion due to chemical attack is not expected to be a major problem with FGR. However, tube erosion may increase as the higher gas velocities may result in greater particle impact on exposed surfaces.

Some data were available on the effect of water injection on $NO_x$ emissions. Water injection, however, results in a significant deterioration of boiler performance. It has therefore not been recommended as a $NO_x$ control measure for coal-fired boilers.

It should be emphasized that the effects of $NO_x$ control, in many cases, will be critically dependent on boiler operating conditions. Still, with proper design of retrofit systems and adequate maintenance programs, low $NO_x$ operation should not result in a substantial increase in operational problems over normal boiler operation. Moreover, when $NO_x$ controls are designed into new units, potential problems can be anticipated and largely corrected.

### 7.2.2 Oil-Fired Boilers

The effects of low $NO_x$ operation on oil-fired boilers are summarized in Table 7-4. The most common low $NO_x$ techniques tested for oil-fired boilers are low excess air (LEA), off stoichiometric combustion (OSC), and flue gas recirculation (FGR). Other techniques which have been tested are water injection (WI) and reduced air preheat (RAP). However, these have found little application due to attendant efficiency losses.

The major concerns regarding low $NO_x$ operation on oil-fired boilers are effects on boiler efficiency, load capacity, vibration and flame instability, and steam and tube temperatures.

OSC operation generally increases the minimum excess air requirements of the boiler, which may result in a loss in boiler efficiency. In extreme cases when the boiler is operating close to the limits of its fan capacity, boiler derating may be required. Derates of as much as 15 percent have been reported due to the lack of capability to meet the increased airflow requirements at full load.

In many cases, BOOS operation in oil-fired boilers has been found to be more effective in controlling $NO_x$ than OFA firing. Under BOOS firing the fuel flow to the active burners must be increased if load is to remain constant. In some cases, it has been necessary to enlarge the burner tips in order to accommodate these increased flows.

Other potential problems attendant with applying OSC in oil-fired boilers have concerned flame instabilities, boiler vibrations, and excessive convective section tube temperatures. However, in past experience, none of these problems has been significant. Staged operation does usually result in hazy flames and obscure flame zones. Thus new flame scanners and detectors are often required in retrofit applications. In addition, because OSC produces an extended flame zone, flame carryover to the convective section may occasionally occur. However, in one case where intermittent flame carryover occurred, no excessive tube temperatures were recorded.

Similarly there are a number of potential problems which can occur in retrofit FGR applications. The most common problems, such as FGR fan and duct vibrations, can usually be avoided by good design. Other problems such as flame instability, which can lead to furnace vibrations, are caused by the increased gas velocity at the burner throats. Modifications to the burner geometry and design such as enlarging the throat, altering the burner tips, or adding diffuser plates or flame retainers, may then be required. These modifications are usually made by trial and error for each boiler and are often very time consuming. If the problems of excessive boiler vibration and flame instabilities persist at high loads, the boiler may have to be derated.

TABLE 7-4. EFFECT OF LOW $NO_x$ OPERATION ON OIL-FIRED BOILERS

| Boiler | Low $NO_x$ Technique | Efficiency[a] | Load Capacity[a] | Vibration and Flame Instability[a] | Steam and Tube Temperatures[a] | Other Effects, Comments |
|---|---|---|---|---|---|---|
| **Tangential** | | | | | | |
| South Bay No. 4 | LEA | 5% increase | -- | -- | -- | No adverse effects reported. Fan power consumption reduced. |
| | BOOS | Decrease in efficiency compared to LEA due to increased excess air requirements | | | | No other adverse effects reported |
| | RAP | Unaffected due to special preheater design | -- | -- | -- | Limited tests. NOx control effectiveness not demonstrated. |
| Pittsburg No. 7 | OFA and FGR | -- | Slower startups and load changes | FGR fan vibration problems | High water wall tube temperatures | |
| SCE tangential boilers | BOOS and FGR | -- | -- | -- | -- | No adverse effects reported |
| **Opposed Wall** | | | | | | |
| Moss Landing Nos. 6 and 7 | OFA and FGR | Increased excess air requirements resulting in decreased efficiency | -- | FGR fan and duct vibration, furnace vibration problems. Associated flame instability | -- | High furnace pressures. Increased FGR and forced draft fan power consumption. |
| Ormond Beach Nos. 1 and 2 | BOOS and FGR | Increased excess air requirements resulting in decreased efficiency | 10 to 15% derate due to maxed FD fan capacity | Flame instability and associated furnace vibration | -- | Flame detection problems due to change in flame characteristics |
| | Water injection | Increased sensible and latent stack losses | -- | -- | -- | Limited tests carried out with WI at partial loads. Excess air requirements increased |
| SCE B&W Units | BOOS and FGR | FGR reduced minimum excess air requirements increasing unit efficiency | -- | Boiler vibration problems | -- | Flame detection problems due to change in flame characteristics |
| Sewaren Station No. 5 | LEA, BOOS | -- | -- | -- | -- | Tests carried out at partial loads. No adverse effects reported. Particulate loading and size distribution unaffected. |

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## TABLE 7-4. Concluded

| Boiler | Low $NO_x$ Technique | Efficiency[a] | Load Capacity[a] | Vibration and Flame Instability[a] | Steam and Tube Temperatures[a] | Other Effects, Comments |
|---|---|---|---|---|---|---|
| <u>Single Wall</u> | | | | | | |
| Encina Nos. 1, 2 and 3 | LEA and BOOS (2 burners on air only) | Increased unit efficiency. Some adverse effect on cycle efficiency due to lower steam temperatures | -- | -- | Decrease in SH & RH steam temperature | No other adverse effects reported |
| | BOOS (3 burners on air only) | Increased excess air requirements resulting in reduced efficiency | 5% derate due to maxed ID fan capacity | In most tests no flame instability or blowoff noted | Intermittent flame carryover to SH inlet but tube temperature limits not exceeded | No abnormal tube fouling, corrosion or erosion noted. Increased tendency to smoke and obscure flame zone. |
| <u>Turbo</u> | | | | | | |
| South Bay No. 3 | Airflow adjustments | Slight reduction in EA resulting in slight increase in efficiency | -- | -- | -- | No adverse effects reported |
| | Water injection | 6% decrease at full load | -- | No flame instability noted even at high rates of WI | -- | No other adverse effects reported |
| | Reduced air preheat | Reduction in efficiency greater than that with water injection | -- | -- | -- | Limited tests |
| Potrero No. 3-1 | OFA and FGR | Higher excess air requirements, but addition of economizer surface expected to improve efficiency | 5% derate due to excessive tube temperatures | Side to side windbox oxygen cycling | Tube and steam temperature limits approached. Increased SH tube failures. | Increased tendency to smoke required higher minimum excess $O_2$ levels. RH surface removed to avoid excessive RH steam attemperation. Larger economizer installed to compensate for RH surface removal. |

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[a]Denotes not investigated

Another potential problem associated with FGR is high tube and steam temperatures in the convective section. The increased mass velocities which occur with FGR cause the convective heat transfer coefficient to rise. This, coupled with reduced furnace heat absorption, can give rise to high convective section temperatures leading to tube failures, exceeding attemperator spray flow limits, or loss in cycle efficiency due to excessive reheat steam attemperation. Increased mass flowrates in the furnace may also cause furnace pressures to increase beyond safe limits. FGR usually, however, has an advantage of not increasing minimum excess air levels. Boiler efficiency is therefore relatively unaffected except for the power consumed by the FGR or booster fans.

The combination of OSC and FGR is very effective in reducing $NO_x$ emissions. However, the problems associated with each technique are also combined. Tube and steam temperature problems in the upper furnace are particularly exacerbated, as both OSC and FGR tend to increase upper furnace temperatures and convective section heat transfer rates. In addition, boiler efficiencies usually decline slightly with combined OSC and FGR firing due to higher excess air requirements and greater fan power consumption.

As with coal-fired boilers, before low $NO_x$ techniques are applied to an oil-fired boiler, it is important to assure that it is in good operating condition. Uniform burner air and fuel flows are essential for optimal $NO_x$ control. Retrofit $NO_x$ control systems must be designed and installed properly to minimize potential adverse effects. Despite these precautions, in some cases inevitable problems will occur, such as flame instability or high tube temperatures. In some of these cases, certain hardware modifications will be required to resolve the problems. In other cases, increased vigilance will be needed on the part of the boiler operator, and an accelerated schedule of maintenance and overhaul may be required. Many of the problems experienced in the past can now be avoided because of hindsight and experience. Thus, retrofit systems can now be designed and installed with care to avoid any potential adverse effects. New units with built-in OFA and FGR systems or LNB should function without problems.

### 7.2.3 Gas-Fired Boilers

The effects of low $NO_x$ operation on gas-fired boilers are summarized in Table 7-5. The low $NO_x$ techniques used and their effects are very similar to those for oil-fired boilers. Usually, there is no distinction between oil- and gas-fired boilers as they are designed to switch from one fuel to the other according to availability. Since boiler design details, $NO_x$ control methods, and the effects of low $NO_x$ operation are similar for gas- and oil-fired units, most of the above discussion of applicable $NO_x$ control measures to oil-fired boilers and potential problems resulting applies. Some effects specific to gas-fired boilers alone are treated briefly below.

$NO_x$ emissions oftentimes are difficult to control after switching from oil to gas firing. Residual oil firing tends to foul the furnace due

# TABLE 7-5. EFFECT OF LOW $NO_x$ OPERATION ON GAS-FIRED BOILERS

| Boiler | Low $NO_x$ Technique | Efficiency[a] | Load[a] Capacity | Vibration and[a] Flame Instability | Steam and Tube[a] Temperatures | Other Effects, Comments |
|---|---|---|---|---|---|---|
| <u>Tangential</u> | | | | | | |
| South Bay No. 4 | LEA | 2 to 3% increase | -- | -- | -- | No adverse effects reported |
| | BOOS | Decrease in efficiency compared to LEA due to increased excess air requirements | | | | No other adverse effects reported |
| Pittsburg No. 7 | OFA and FGR | -- | 25% derate due to excessive steam temperatures, slower load change response | Fan and duct vibration problems | High tube and RH steam temperatures | |
| <u>Horizontally Opposed</u> | | | | | | |
| Moss Landing Nos. 6 and 7 | OFA and FGR | 0.8% decrease in cycle efficiency due to RH steam attemperation | Load curtailment to 50% after oil burns due to SH tube temperature limits being exceeded | Furnace and duct vibration problems. Flame instability. | RH spray and SH tube temperature limits approached after oil burns upper wall tube failures | Furnace pressure limit approached. FGR fan power requirements increased by as much as 66%. Problems associated with switching to gas after oil burning could be eliminated only with complete water washing of furnace. |
| Pittsburg Nos. 5 and 6 | OFA and FGR | -- | -- | FGR fan and duct vibrations. Flame instability problems. | Upper water wall tube failures | Boiler initially restricted to manual operation due to problems with flame instability on automatic control |
| Contra Costa Nos. 9 and 10 | OFA and FGR | -- | -- | FGR duct vibrations | High SH and RH steam temperatures. SH tube temperature limits being approached. | Furnace pressure limits approached after oil firing. FGR fan preheating required to reduce vibrations on cold boiler startups. |
| <u>Single Wall</u> | | | | | | |
| Encina Nos. 1, 2 and 3 | BOOS (2 and 3 burners out of service) | Low EA levels were possible even with BOOS, resulting in increased efficiency | No derate. Load pickup response not affected | Some pressure pulsing at corners of firebox | Some flame carryover to SH but no problems with high tube temperature or tube wastage | No other adverse effects reported |

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[a]Denotes not investigated

TABLE 7-5. Concluded

| Boiler | Low $NO_x$ Technique | Efficiency[a] | Load[a] Capacity | Vibration and[a] Flame Instability | Steam and Tube[a] Temperatures | Other Effects, Comments |
|---|---|---|---|---|---|---|
| <u>Turbo</u> | | | | | | |
| South Bay No. 3 | Airflow adjustments | Slight reduction in EA resulting in slight improvement in efficiency | -- | -- | -- | No adverse effects reported |
| | Water injection | 10% decrease at full load | -- | No flame instability noted even at high rates of WI | -- | No other adverse effects reported |
| Potrero No. 3-1 | OFA and FGR | Installation of larger economizer expected to improve efficiency | 5% derate due to problems with high temperatures | Side to side windbox oxygen cycling | Tube metal and steam temperature limits reached at high loads | Hardware modifications included partial RH surface removal to avoid excessive RH steam attemperation. Larger economizer then installed to compensate for smaller RH surface. |

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[a]Denotes not investigated

to the oil ash content. Thus, $NO_x$ control measures which have been tested on a clean furnace with gas may be found inadequate after oil firing due to the changed furnace conditions. These problems can be resolved by complete water washing of the furnace after any oil burns. This is not very practical, however, especially if oil to gas fuel switching occurs frequently.

Boilers fired with gas usually have higher gas temperatures at the furnace outlet than when fired with oil. Gas flames are less luminous and therefore radiate less energy to the furnace walls than oil flames. The upper furnace and convective section inlet surfaces are thus subject to higher temperatures with gas firing. These temperatures may increase further when the combustion zone is extended due to OSC. Furthermore, heat transfer rates in the convective section will rise with increased mass velocities due to FGR. Upper furnace and convective section tube failures and excessive steam temperatures are therefore more likely to occur with OSC and FGR applied to gas-fired boilers. The situation may be aggravated further if switching from gas fuel occurs after an oil burn, as fouling will further reduce furnace absorption and, hence, increase gas temperatures. Excessive tube temperatures will usually result in a derating of the system. However, problems with gas firing are not commonly encountered at present due to the scarcity of natural gas fuels, and that trend is likely to continue in the future.

## 7.3 COSTS OF $NO_x$ CONTROLS

In the detailed environmental assessment of $NO_x$ controls applied to utility boilers, representative control costs were prepared for the following typical boiler/control combinations:

| Boiler/Fuel Type | $NO_x$ Control |
|---|---|
| Tangential/Coal | OFA |
| Opposed Wall/Coal | OFA |
| Opposed Wall/Coal | Low $NO_x$ Burners |
| Opposed Wall/Coal | BOOS |
| Single Wall/Oil and Gas | BOOS |
| Single Wall/Oil and Gas | OFA and FGR |

Overfire air and low $NO_x$ burners were selected as the retrofit control methods for coal firing. Burners out of service was not necessarily recommended for coal-fired units, but was included to demonstrate the prohibitively high cost of derating a unit, as is often the case for pulverized coal units. Burners out of service, and flue gas recirculation through the burners combined with overfire air were selected as the retrofit control methods for the single wall oil- and gas-fired unit. These methods have been shown to be effective in retrofit applications, as discussed earlier in this report.

### 7.3.1 Retrofit Control Costs

Based on the cost analysis methodology presented in Section 4.3.3, typical retrofit control costs (1977 dollars) are summarized in

Table 7-6. It is assumed here that low excess air represents standard operating procedure. Any investment costs for this control are usually offset by savings in operating efficiency. All other assumptions and detailed cost input data are summarized elsewhere (Reference 7-1). It should be emphasized here that the control costs shown in Table 7-6 are only representative typical retrofit control costs. They represent retrofitting relatively new boilers, say 5 to 10 years old with at least 25 years of service remaining. With the exception of BOOS for coal-fired units, and FGR/OFA for oil- and gas-fired units, annualized control costs generally fall in the $0.50 to 0.70/kW-yr, based on a 7000-hour operating year. For comparison, the cost of operating a power plant is approximately $175/kW-yr.

Burners out of service was treated in the cost analysis not as a recommended control technique for coal firing but to show the prohibitively high cost of derating. This high cost was due principally to the need to purchase make up power from elsewhere and to account for the lost capacity of the system through a capital charge.

Table 7-7 presents projected retrofit control requirements for alternative $NO_x$ emissions levels. Control techniques are also recommended to achieve each given $NO_x$ emission level. These requirements and techniques, combined with the cost to control column, complete the cost effectiveness picture.

Based on the favorable process analysis results presented in Section 7.2, it is evident from an examination of Tables 7-6 and 7-7 that OFA and low $NO_x$ burners (LNB) are the preferred, cost-effective $NO_x$ controls for coal firing. For very high levels of $NO_x$ control for coal-fired units (170 ng/J), both OFA and LNB would be required. For more moderate levels of control, LNB are less expensive and more cost-effective than OFA in reducing $NO_x$ in wall fired units. However, the use of LNB technology in retrofit application is still a few years away. Thus, LNB is not recommended now for moderate levels of control in retrofit applications in spite of the fact that the technology is potentially less expensive than OFA.

As far as moderate control for oil- and gas-fired units, off stoichiometric combustion via BOOS appears to be the preferred route, as indicated in Tables 7-6 and 7-7. Initial investment is minimized since there are no associated major hardware requirements, only engineering and startup costs. To reach the next level of $NO_x$ control (86 ng/J for oil, 43 ng/J for gas), FGR with OFA would seem to be in order. However, the increase in cost from $0.49/kW-yr for BOOS to $3/kW-yr for FGR and OFA does not make the option attractive. Besides, from a regulatory point of view, requirement of the emission level achievable with FGR and OFA would not be particularly attractive since oil- and gas-fired units with BOOS would already have very low $NO_x$ emissions (129 ng/J for oil, 86 ng/J for gas) compared to coal-fired units.

TABLE 7-6. SUMMARY OF RETROFIT CONTROL COSTS

| Boiler/Fuel Type | Initial Investment ($/kW) | Annualized Indirect Operating Cost ($/kW-yr) | Annualized Direct Operating Cost ($/kW-yr)[a] | Total to Cost Control ($/kW-yr)[a] |
|---|---|---|---|---|
| **Tangential/Coal-Fired** | | | | |
| OFA | 0.90 | 0.21 | 0.32 | 0.53 |
| **Opposed Wall/Coal-Fired** | | | | |
| OFA | 0.62 | 0.16 | 0.52 | 0.69 |
| LNB | 2.03 | 0.34 | 0.06 | 0.40 |
| BOOS | 0.08 | 5.34 | 24.78 | 30.12 |
| **Single Wall/Oil- and Gas-Fired** | | | | |
| BOOS | 0.30 | 0.05 | 0.44 | 0.49 |
| FGR/OFA | 5.71 | 1.14 | 1.91 | 3.05 |

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[a]Based on 7000-hour operating year. Typical costs only.

TABLE 7-7. PROJECTED RETROFIT CONTROL REQUIREMENTS FOR ALTERNATE $NO_x$ EMISSIONS LEVELS

| Fuel/$NO_x$ Emission Level ng/J (lb/$10^6$ Btu) | Recommended Control[a] | Cost to Control \$/kW-yr[b] | Cost Effectiveness \$/kg $NO_x$ Removed |
|---|---|---|---|
| Coal | | | |
| 301 (0.7) | OFA | 0.50 to 0.70 | 0.03 to 0.04 |
| 258 (0.6) | OFA | 0.50 to 0.70 | 0.02 to 0.03 |
| 215 (0.5) | LNB[c] | 0.40 to 0.50 | 0.01 to 0.02 |
| 172 (0.4) | OFA + LNB[c] | 0.95 to 1.20 | 0.02 to 0.03 |
| Oil | | | |
| 129 (0.3) | BOOS | 0.50 to 0.60 | 0.04 to 0.05 |
| 86 (0.2) | FGR + OFA | ~3.00 | ~0.16 |
| Gas | | | |
| 86 (0.2) | BOOS | 0.20 to 0.30 | 0.03 to 0.04 |
| 43 (0.1) | FGR + OFA | ~3.00 | ~0.12 |

[a]LEA considered standard operating practice.
[b]Typical installation only; could be significantly higher.
[c]Technology not thoroughly demonstrated for retrofit yet.

### 7.3.2 Control Costs for New Boilers

Estimating the incremental costs of $NO_x$ controls for NSPS boilers is in some respects an even more difficult task than costing retrofits. Certain modifications on new units, though effective in reducing $NO_x$ emissions, were originally incorporated due to operational considerations rather than from a control viewpoint. For example, the furnace of a typical NSPS unit has been enlarged to reduce slagging potential and allow the burning of process quality fuels. But this also reduces $NO_x$ due to the lowered heat release rate. Thus, since the design change would have been implemented even without the anticipated $NO_x$ reduction, the cost of that design modification should not be attributed to $NO_x$ control.

Babcock & Wilcox has estimated the incremental costs of $NO_x$ controls on an NSPS coal-fired boiler (Reference 7-3). The two units used in the comparison were identical except for $NO_x$ controls on the NSPS unit which included:

- Replacing the high turbulence, rapid-mixing cell burner with the limited turbulence dual register (low $NO_x$) burner
- Increasing the burner zone by spreading the burners vertically to include 22 percent more furnace surface
- Metering and controlling the airflow to each row of burners using a compartmented windbox

To provide these changes for $NO_x$ control, the price increase was about \$1.75 to \$2.50/kW (1977 dollars). If these costs are annualized according to the format of Section 4.3.3, they translate to 0.28 to 0.40 \$/kW-yr.

In addition, Foster Wheeler has performed a detailed design study aimed at identifying the incremental costs of $NO_x$ control to meet 1971 NSPS (Reference 7-4). Foster Wheeler looked at three unit designs with the following results:

| Boiler Design | | Relative Cost |
|---|---|---|
| Unit 1: | Pre-NSPS base design | 100 |
| Unit 2: | Enlarged furnace, no active $NO_x$ control | 114 |
| Unit 3: | NSPS design; enlarged furnace, new burner design, perforated hood, overfire air, boundary air | 115.5 |

Assuming the cost of a pre-NSPS coal-fired boiler to be about \$100/kW in 1969, or \$180/kW in 1977 construction costs, the incremental cost of active $NO_x$ controls (NBD plus OFA) is \$2.78/kW, or about \$0.44/kW-yr annualized. The Foster Wheeler estimate which includes both

NBD and OFA, thus agrees quite well with the Babcock & Wilcox estimate, which includes only NBD and associated equipment.

Comparing these costs with the retrofit costs (0.40 to 0.70 $/kW-yr for LNB or OFA) presented in Table 7-7 and considering the better $NO_x$ control anticipated with NSPS units, it is certainly more cost effective to implement controls on new units. Furthermore, fewer operational problems are expected with factory installed controls.

## 7.4 ENVIRONMENTAL ASSESSMENT OF $NO_x$ CONTROLS

Modification of the combustion process in utility boilers for $NO_x$ control reduces the ambient levels of $NO_2$, which is both a toxic substance and a precursor for nitrate aerosols, nitrosamines, and photochemical smog. These modifications can also cause changes in emissions of other combustion generated pollutants. If unchecked, these changes, referred to as incremental emissions, may have an adverse effect on the environment, in addition to effects on overall system performance. However, since the incremental emissions are sensitive to the same combustion conditions as $NO_x$, they may, with proper engineering, also be held to acceptable levels during control development so that the net environmental benefit is maximized. In fact, control of incremental emissions of carbon monoxide, hydrocarbons, and particulate has been a key part of all past $NO_x$ control development programs. In addition, recent control development has been giving increased attention to other potential pollutants such as sulfates, organics, and trace metals.

Unfortunately, previously developed incremental emissions data for other than the criteria pollutants are quite scarce. Thus, $NO_x$ EA evaluations to date have relied heavily on combustion fundamentals and pollutant formation theory to postulate expected changes in emission levels of noncriteria pollutants with $NO_x$ control application. Of course, $NO_x$ EA field testing efforts are underway to resolve these data insufficiencies. However, results from the utility boiler tests performed are still not complete.

Table 7-8 shows the cumulative evaluation of the potential effects of $NO_x$ control application on incremental emissions from utility boilers of CO, vapor phase hydrocarbon (HC), sulfate, particulate, organics (POM), and trace metals. Entries in the table are based on actual data, where available, or fundamental hypothesis, where data were insufficient.

As Table 7-8 illustrates, using preferred $NO_x$ combustion controls on boilers should have few adverse effects on incremental emissions of CO, vapor phase hydrocarbons, or particulates. Indiscriminately lowering excess air can drastically affect boiler CO emissions, and particulate emissions can increase with off stoichiometric combustion and flue gas recirculation. However, with suitable engineering during development and careful implementation, these incremental emissions problems can be minimized.

In contrast, applying almost every combustion control has intermediate to high potential impact on incremental emissions of sulfate,

TABLE 7-8. EVALUATION OF INCREMENTAL EMISSIONS DUE TO $NO_x$ CONTROLS APPLIED TO BOILERS

| $NO_x$ Control | Incremental Emission | | | | | | |
|---|---|---|---|---|---|---|---|
| | CO | Vapor Phase HC | Sulfate | Particulate | Organics | Segregating Trace Metals | Nonsegregating Trace Metals |
| Low Excess Air | ++ | 0 | + | 0 | ++ | + | 0 |
| Staged Combustion | 0 | 0 | + | + | ++ | + | 0 |
| Flue Gas Recirculation | 0 | 0 | + | + | + | + | + |
| Reduced Air Preheat | 0 | 0 | + | 0 | + | 0 | + |
| Reduced Load | 0 | 0 | + | 0 | + | 0 | 0 |
| Water Injection | 0 | 0 | + | + | + | 0 | 0 |
| Ammonia Injection | 0 | 0 | ++ | + | 0 | + | 0 |

Key: ++ denotes having high potential emissions impact
+ denotes having intermediate potential emissions impact, data needed
0 denotes having low potential emissions impact

organics, and trace metals. For trace metal and organic emissions, substantiating data are largely lacking, but fundamental formation mechanisms cause justifiable concern. In the sulfate case, fundamental formation mechanisms suggest that these emissions remain unchanged or decreased with all controls except ammonia injection. However, complex interactive effects are difficult to clarify, and this pollutant class is considered sufficiently hazardous to justify some concern in the absence of conclusive data.

As quantitative data on incremental emissions become available from the $NO_x$ EA field testing program, the impacts of $NO_x$ controls on the environment will be better characterized through application of source analysis models (References 7-5, 7-6, and 7-7).

## 7.5 BEST CONTROL OPTIONS

Pending final data resolution of incremental emissions, combustion modification $NO_x$ controls are deemed to be environmentally sound, cost-effective means of reducing $NO_x$ emissions. As discussed in Section 7.3 and summarized in Table 7-7, off stoichiometric combustion and low $NO_x$ burners are the preferred techniques for both retrofit and new application. For coal firing, OFA or LNB are both cost effective, with LNB the preferred route for new wall fired boilers. Low $NO_x$ burners still require further full scale demonstration and development before retrofit application can be considered routine. For more stringent control, both OFA and LNB may be required. For oil and gas firing, BOOS is the recommended technique. It is not cost effective to install FGR and OFA for stringent control for oil and gas.

With proper design and implementation of the recommended controls, there should be minimal impact, in general, on boiler operation. Long term operation testing should be continued to confirm this assessment.

REFERENCES FOR SECTION 7

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## SECTION 8

## ENVIRONMENTAL ALTERNATIVES ANALYSIS

As noted in Section 4, impact assessments of three general types are being performed in the $NO_x$ EA:

- Baseline and controlled multimedia environmental assessments of stationary combustion sources
- Operational and cost impact evaluations of $NO_x$ combustion modification control applications
- Systems analysis assessments of applying $NO_x$ control strategies on a regional basis

Second year results of the process evaluations of applying $NO_x$ controls to utility boilers were discussed in Section 7. This section discusses results to date from applying the methodologies outlined in Section 4 to:

- Evaluating baseline combustion source pollutant impact potential and source ranking based on this evaluation (Section 8.1)
- Projecting the air quality implications of enforcing various control strategies on a regional basis and identifying $NO_x$/hydrocarbon/oxidant control strategy interactions (Section 8.2)

### 8.1 BASELINE IMPACT RANKINGS

During the second year, the Source Analysis Model discussed in Section 4.1.3 (extended SAM I) was used to identify and rank potential environmental problems from stationary combustion sources due either to specific pollutants from a single effluent stream or from the entire source. The model was used to calculate impact potential either for a single source or the nationwide aggregate of sources considering population proximity to the source.

Data for use in the model were compiled for source emissions, human health impact threshold criteria, population densities near source concentrations, and emission growth rates. Emissions data and growth projections were discussed in Section 2. Population densities and urban/rural region designations were defined from EPA and Bureau of Census data. Urban/rural equipment populations and regional fuel consumption data were obtained from the National Emissions Data System (NEDS). Multimedia Environmental Goals (Reference 8-1) were used for health impact threshold criteria. Although these data are not as complete as desired, they were used with the SAM model to obtain a tentative indication of potential problem areas. The following list summarizes capabilities of the SAM model and notes specific cases which were evaluated. Detailed discussion of data sources and cases evaluated appears in Reference 8-2.

| Source Analysis Model Capabilities | Calculations Performed |
|---|---|
| • Total nationwide potential impact factors for specific source types, considering population exposure and all pollutants inventoried for gaseous effluent streams | -- Total gaseous effluent stream pollution potential ranking for 1974 |
| | -- Average gaseous effluent stream pollution potential ranking for 1974 |
| • Total nationwide potential impact factors for all pollutants inventoried for liquid and solid effluent streams | -- Total liquid and solid effluent stream pollution potential ranking for 1974 |
| • Projections of total nationwide impact factors | -- Total gaseous effluent stream pollution potential ranking for 1985 and 2000 |
| | -- Total gaseous effluent stream pollution potential cross ranking for 1974, 1985 and 2000 |
| • Single source, single pollutant potential impact not considering population exposure | -- $NO_x$ single source pollution potential ranking for stationary sources |
| | -- Pollution potential of single pollutants from utility boilers, packaged boilers, gas turbines, IC engines and industrial process heating |

Additional results are tabulated in the Appendices of Volume II of Reference 8-2.

Although the potential impact factor results generated in this study were useful for detecting gross qualitative trends, firm quantitative conclusions were precluded by inadequacies in the data and the uncertainties in projected energy usage. Key data needs identified are as follows:

- Multimedia source emissions data

  -- Most of the noncriteria pollutant emissions data are for compound classes or sample fractions; species concentrations are needed for compound classes showing pollution potential

  -- POM and trace element data are sparse and exhibit large scatter from different sampling programs. Emissions of these pollutants are highly dependent on the origin of the fuel and the specific stationary source and effluent stream from which the data were obtained.

  -- Data on emissions during transient or nonstandard operation are virtually nonexistent. New tests are needed if these effects are to be considered.

  -- Liquid and solid emissions data are only quantified for the utility and large industrial boiler equipment sector. Although this sector represents the major portion of liquid and solid pollution potential, further study of packaged boilers and industrial process heating effluent streams should be pursued. In addition, the fractions of total ash which are emitted as bottom ash and flyash vary with boiler type. However, sufficient data were not available to estimate this effect.

- Health impact threshold criteria

  -- The Multimedia Environmental Goals (MEG's) employed (Reference 8-1) are preliminary, and designed for screening purposes only. They are not ambient standards, but rather indications of ambient concentrations at which health effects from continuous exposure should be investigated. In addition, compounds were not speciated. Since one health effects value was used to represent an entire pollutant class, various individual species were not considered.

- Population exposure to source emissions

  -- Specific values for average source size and urban/rural splits were in many cases based on poor quality data. For utility and large industrial boilers, and most packaged units, the data were adequate. However, for internal combustion engines and industrial process heating, data exhibited a wide range of values making specification difficult.

Given the above qualifications, selected results from the potential impact factor calculations and projections are discussed briefly below.

The 1974 total pollution potential rankings are shown in Table 8-1. The table indicates that coal-fired utility and industrial sources have the largest total potential impact factors. Small stoker fired boilers rank highest, primarily because:

- They have high particulate (trace element) emission factors (low degree of particulate control application)
- They have low stacks
- They are located in urban (high population density) regions

Utility boilers rank next highest in the total pollution potential ranking because of the shear quantity of emissions from these sources.

This point is illustrated in Table 8-2 which shows average source gaseous pollution potential impact ranking. As indicated, opposed wall coal-fired boilers have the highest average source pollution potential. This potential impact value was obtained by dividing the total impact factor by the total number of sources of a specific equipment type and thus represents a measure of the impact of a single typical source. Opposed wall fired units are used in the larger capacity ranges (>400 MW electric output). Thus because of their large size and resulting high fuel consumption, opposed wall boilers have a high average source pollution potential. However, this result must be used with care since the ranking is not normalized for energy consumption. For example, a 600 MW (electrical output) opposed wall fired boiler may have less pollution potential than three 200 MW (electrical output) single wall fired boilers required to supply the same power. This ranking is primarily intended to assess characteristic average source impacts. Stokers are lower in the ranking because their impact is a result of many smaller sources rather than a few large single sources.

Table 8-3 shows the results of potential impact calculations considering $NO_x$ emissions only. The table illustrates that cyclone boilers have the highest single source $NO_x$ impact. This is primarily because uncontrolled $NO_x$ emissions from cyclone (coal-fired) boilers are more than double the emissions from tangential units and about 75 percent higher than from wall fired units. However, the total nationwide pollution potential of cyclone boilers should decline in the future since the use of this unit type is projected to decrease.

## 8.2 AIR QUALITY PROJECTIONS

The goals of the systems analysis task of the $NO_x$ EA, and the methodologies assembled were described in Section 4.3. In this section, results from applying the preliminary model and the two advanced models are presented. Results in three main areas are discussed. The preliminary model with source weighted rollback was used to examine $NO_x$

TABLE 8-1. TOTAL POLLUTION POTENTIAL RANKING (GASEOUS) STATIONARY SOURCES IN YEAR 1974

| Rank | Sector | Equipment Type | Fuel | Total Impact Factor |
|---|---|---|---|---|
| 1 | Packaged Boilers | Stoker Firing WT[c] <29 MW[a] | Coal | $6.73 \times 10^{11}$ |
| 2 | Packaged Boilers | Stoker Firing FT[d] <29 MW[a] | Coal | $5.59 \times 10^{11}$ |
| 3 | Utility Boilers | Tangential | Coal | $1.42 \times 10^{11}$ |
| 4 | Utility Boilers | Wall Firing | Coal | $1.09 \times 10^{11}$ |
| 5 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Coal | $7.78 \times 10^{10}$ |
| 6 | Packaged Boilers | Stoker Firing WT[c] >29 MW[a] | Coal | $7.64 \times 10^{10}$ |
| 7 | Utility Boilers | Vertical & Stoker | Coal | $5.69 \times 10^{10}$ |
| 8 | Utility Boilers | Cyclone | Coal | $4.12 \times 10^{10}$ |
| 9 | Utility Boilers | Horizontally Opposed | Coal | $2.10 \times 10^{10}$ |
| 10 | Utility Boilers | Tangential | Oil | $2.65 \times 10^{9}$ |
| 11 | Utility Boilers | Wall Firing | Oil | $2.22 \times 10^{9}$ |
| 12 | Utility Boilers | Horizontally Opposed | Oil | $1.13 \times 10^{9}$ |
| 13 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Oil | $7.02 \times 10^{8}$ |
| 14 | Packaged Boilers | Scotch FT[d] <29 MW[a] | Oil | $5.50 \times 10^{8}$ |
| 15 | Packaged Boilers | Firebox FT[d] <29 MW[a] | Oil | $3.64 \times 10^{8}$ |
| 16 | Utility Boilers | Tangential | Gas | $3.20 \times 10^{8}$ |
| 17 | Packaged Boilers | Scotch FT[d] | Gas | $2.88 \times 10^{8}$ |

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TABLE 8-1. Concluded

| Rank | Sector | Equipment Type | Fuel | Total Impact Factor |
|---|---|---|---|---|
| 18 | Ind. Process Comb. | Coke Oven Underfire | Process Material | $2.84 \times 10^8$ |
| 19 | Reciprocating IC Engines | SI[e] >75 kW/cyl[b] | Gas | $2.30 \times 10^8$ |
| 20 | Packaged Boilers | Single Burner WT[c] <29 MW[a] | Oil | $2.28 \times 10^8$ |
| 21 | Packaged Boilers | HTR Boiler <29 MW[a] | Oil | $2.25 \times 10^8$ |
| 22 | Packaged Boilers | Brick & Ceramic Kilns | Process Material | $2.01 \times 10^8$ |
| 23 | Utility Boilers | Horizontally Opposed | Gas | $1.61 \times 10^8$ |
| 24 | Utility Boilers | Wall Firing | Gas | $1.28 \times 10^8$ |
| 25 | Utility Boilers | Cyclone | Oil | $1.27 \times 10^8$ |
| 26 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Gas | $2.72 \times 10^7$ |
| 27 | Ind. Process Comb. | Cement Kilns | Process Material | $2.71 \times 10^7$ |
| 28 | Packaged Boilers | Cast Iron | Oil | $2.47 \times 10^7$ |
| 29 | Gas Turbines | Simple Cycle >15 MW[b] | Oil | $2.39 \times 10^7$ |
| 30 | Ind. Process Comb. | Refinery Htr. Nat. Draft | Gas | $2.22 \times 10^7$ |

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[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Spark ignition

TABLE 8-2. AVERAGE SOURCE POLLUTION POTENTIAL RANKING (GASEOUS) STATIONARY SOURCES IN YEAR 1974

| Rank | Sector | Equipment Type | Fuel | Average Impact Factor |
|---|---|---|---|---|
| 1 | Utility Boilers | Horizontally Opposed | Coal | $4.26 \times 10^{8}$ |
| 2 | Utility Boilers | Cyclone | Coal | $3.52 \times 10^{8}$ |
| 3 | Utility Boilers | Tangential | Coal | $3.11 \times 10^{8}$ |
| 4 | Utility Boilers | Wall Firing | Coal | $1.76 \times 10^{8}$ |
| 5 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Coal | $1.21 \times 10^{8}$ |
| 6 | Packaged Boilers | Stoker Firing WT[c] <29 MW[a] | Coal | $8.45 \times 10^{7}$ |
| 7 | Packaged Boilers | Stoker Firing WT[c] >29 MW[a] | Coal | $8.35 \times 10^{7}$ |
| 8 | Utility Boilers | Vertical and Stoker | Coal | $7.34 \times 10^{7}$ |
| 9 | Packaged Boilers | Stoker Firing FT[d] <29 MW[a] | Coal | $2.29 \times 10^{7}$ |
| 10 | Utility Boilers | Horizontially Opposed | Oil | $1.52 \times 10^{7}$ |
| 11 | Utility Boilers | Tangential | Oil | $1.39 \times 10^{7}$ |
| 12 | Utility Boilers | Cyclone | Oil | $3.27 \times 10^{6}$ |
| 13 | Utility Boilers | Wall Firing | Oil | $2.21 \times 10^{6}$ |
| 14 | Utility Boilers | Horizontally Opposed | Oil | $1.76 \times 10^{6}$ |
| 15 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Oil | $7.71 \times 10^{5}$ |
| 16 | Utility Boilers | Wall Firing | Gas | $2.49 \times 10^{5}$ |
| 17 | Utility Boilers | Tangential | Gas | $1.54 \times 10^{5}$ |
| 18 | Utility Boilers | Cyclone | Gas | $9.55 \times 10^{4}$ |

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TABLE 8-2. Concluded

| Rank | Sector | Equipment Type | Fuel | Total Impact Factor |
|---|---|---|---|---|
| 19 | Gas Turbines | Simple Cycle >15 MW[b] | Oil | $8.70 \times 10^4$ |
| 20 | Ind. Process Comb. | Refinery Htr. Nat. Draft | Oil | $6.60 \times 10^4$ |
| 21 | Ind. Process Comb. | Refinery Htr. Forced Draft | Oil | $5.81 \times 10^4$ |
| 22 | Gas Turbines | Simple Cycle >15 MW[b] | Gas | $5.80 \times 10^4$ |
| 23 | Packaged Boiler | Wall Firing WT[c] >29 MW[a] | Gas | $5.26 \times 10^4$ |
| 24 | Packaged Boiler | Single Burner WT[c] <29 MW[a] | Oil | $3.21 \times 10^4$ |
| 25 | Ind. Process Comb. | Refinery Htr. Forced Draft | Gas | $2.73 \times 10^4$ |
| 26 | Ind. Process Comb. | Refinery Htr. Nat. Draft | Gas | $2.09 \times 10^4$ |
| 27 | Ind. Process Comb. | Coke Oven Underfire | Process Material | $1.92 \times 10^4$ |
| 28 | Packaged Boilers | Scotch FT[d] <29 MW[a] | Gas | $1.26 \times 10^4$ |
| 29 | Ind. Process Comb. | Cement Kilns | Process Material | $1.24 \times 10^4$ |
| 30 | Packaged Boilers | Scotch FT[d] <29 MW[a] | Oil | $1.20 \times 10^4$ |

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[a] Heat input

[b] Heat output

[c] Watertube

[d] Firetube

TABLE 8-3. $NO_x$ POLLUTION POTENTIAL RANKING STATIONARY SOURCES IN 1974 ($NO_2$ BASIS)

| Rank | Sector | Equipment Type | Fuel | $NO_x$ Impact Factor |
|---|---|---|---|---|
| 1 | Utility Boilers | Cyclone | Bituminous | $4.97 \times 10^9$ |
| 2 | Utility Boilers | Horizontally Opposed | Lignite | $3.40 \times 10^9$ |
| 3 | Utility Boilers | Horizontally Opposed | Gas | $2.80 \times 10^9$ |
| 4 | Utility Boilers | Horizontally Opposed | Bituminous | $2.78 \times 10^9$ |
| 5 | Utility Boilers | Cyclone | Lignite | $2.44 \times 10^9$ |
| 6 | Utility Boilers | Tangential | Bituminous | $9.82 \times 10^8$ |
| 7 | Utility Boilers | Horizontally Opposed | Oil | $9.21 \times 10^8$ |
| 8 | Utility Boilers | Tangential | Lignite | $8.22 \times 10^8$ |
| 9 | Utility Boilers | Tangential | Gas | $3.79 \times 10^8$ |
| 10 | Utility Boilers | Wall Firing | Lignite | $2.88 \times 10^8$ |
| 11 | Utility Boilers | Tangential | Oil | $2.55 \times 10^8$ |
| 12 | Utility Boilers | Wall Firing | Bituminous | $2.43 \times 10^8$ |
| 13 | Utility Boilers | Wall Firing | Gas | $2.30 \times 10^8$ |
| 14 | Utility Boilers | Cyclone | Gas | $1.37 \times 10^8$ |
| 15 | Gas Turbines | Simple Cycle >15 MW[b] | Oil | $1.24 \times 10^8$ |
| 16 | Gas Turbines | Simple Cycle >15 MW[b] | Gas | $5.30 \times 10^7$ |
| 17 | Ind. Process Comb. | Refinery Htr. Forced Draft | Oil | $5.14 \times 10^7$ |

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TABLE 8-3. Concluded

| Rank | Sector | Equipment Type | Fuel | $NO_x$ Impact Factor |
|---|---|---|---|---|
| 18 | Utility Boilers | Wall Firing | Oil | $4.81 \times 10^{7}$ |
| 19 | Utility Boilers | Cyclone | Oil | $4.07 \times 10^{7}$ |
| 20 | Ind. Process Comb. | Refinery Htr. Nat. Draft | Oil | $3.89 \times 10^{7}$ |
| 21 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Oil | $2.59 \times 10^{7}$ |
| 22 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Bit./Lig. Coal | $2.59 \times 10^{7}$ |
| 23 | Ind. Process Comb. | Refinery Htr. Forced Draft | Gas | $2.45 \times 10^{7}$ |
| 24 | Packaged Boilers | Wall Firing WT[c] >29 MW[a] | Gas | $2.25 \times 10^{7}$ |
| 25 | Ind. Process Comb. | Refinery Htr. Nat. Draft | Gas | $1.26 \times 10^{7}$ |
| 26 | Packaged Boilers | Stoker Firing WT[c] >29 MW[a] | Bit./Lig. Coal | $6.00 \times 10^{6}$ |
| 27 | Reciprocating IC Engines | CI[e] >75 kW/cyl[b] | Oil | $4.09 \times 10^{6}$ |
| 28 | Reciprocating IC Engines | SI[f] >75 kW/cyl[b] | Gas | $3.51 \times 10^{6}$ |
| 29 | Packaged Boilers | Stoker Firing WT[c] <29 MW[a] | Bit./Lig. Coal | $2.47 \times 10^{6}$ |
| 30 | Reciprocating IC Engines | CI[e] >75 kW/cyl[b] | Dual (Oil + Gas) | $1.97 \times 10^{4}$ |

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[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Compression ignition

[f]Spark ignition

control needs for eight AQCR's for a variety of growth and source weighting cases. The Eulerian photochemical model, LIRAQ, was used to investigate one hour $NO_2$ levels for the San Francisco AQCR. And, specific questions related to stack height effects and urban sprawl were examined with a photochemical trajectory model.

These results are not intended to indicate what specific sources should be controlled but, rather, are used to examine the impact of various levels of control. Control needs must be specifically investigated on an individual AQCR basis.

### 8.2.1 Preliminary Model Results

Over 20 different emissions growth/source weighting combinations for eight AQCR's, listed in Table 8-4, were considered. The eight AQCR's were selected to represent a variety of source category, fuel use, and mobile/stationary source mixes. Results for Chicago and Los Angeles were discussed in Reference 8-3. Results for two additional AQCR's, St. Louis and San Francisco, and composite results are presented below.

TABLE 8-4. AQCR's INVESTIGATED WITH PRELIMINARY MODEL

| | | Low -- Recorded Annual Average $NO_2$, 1972-1975 ($\mu g/m^3$) | High -- Rolling Quarter Average $NO_2$, 1972-1975 ($\mu g/m^3$) |
|---|---|---|---|
| Los Angeles | (024) | 132 | 182 |
| Chicago | (067) | 96 | 121 |
| Philadelphia | (045) | 83 | 121 |
| New York City | (043) | 99 | 113 |
| Denver | (036) | 88 | 110 |
| San Francisco | (030) | 76 | 101 |
| Pittsburgh | (197) | 62 | 98 |
| St. Louis | (070) | 76 | 85 |

#### Composite Results

The variety of emissions source growth scenarios, described in Section 4.3, resulted in predicted uncontrolled* $NO_x$ emissions changes

*No stationary source controls beyond 1971 NSPS. Each scenario does assume a specified level of mobile source control.

relative to 1973 emissions of -6 percent to +3 percent in 1985 and of +5 percent to +50 percent in 2000. The relatively small spread in 1985 emissions reflects the impact of currently planned mobile source controls. The very large spread in 2000 reflects the different projected impacts from low stationary source growth with very strict mobile control and high stationary source growth (~3 percent per year) compounded over 28 years.

Changes in ambient concentration corresponding to the above emissions changes, ranged between -12 and +3 percent for 1985 and zero to +43 percent in the year 2000. Since these results are from a variety of AQCR's, they are representative of the range of expected change in ambient concentrations for all AQCR's. These calculated changes in ambient concentration do not exactly follow the percent changes in emissions since the use of the source weighting factors in the preliminary model can reduce or increase the impact of emissions growth of selected sources.

In the present analysis, the most significant use of source weighting factors was to reduce the relative impact of powerplants to 20 percent of their emissions. This was to account for the dispersion of powerplant emissions prior to impact on urban receptors, and represents a reasonable lower limit for powerplant impact. Furthermore, as discussed in Section 3, area sources are thought to have a more significant impact on annual average $NO_2$ levels than do powerplants, thus use of a weighting factor less than unity for powerplants would seem appropriate.

The level of $NO_x$ control required to offset the increase in ambient concentration depends on the initial value (1973) of the annual average $NO_2$ concentration. As discussed in Section 3, the current number of nonattainment (for $NO_2$) AQCR's may be between 4 and 30. A conservative estimate is that at least four AQCR's will need significant application of combustion modification $NO_x$ controls to attain the annual average $NO_2$ standard by 1985. By the year 2000 this number will conservatively increase to 15. (Assuming an average 25 percent increase in ambient concentration*, any AQCR with a 1973 annual average greater than 80 $\mu g/m^3$ would exceed 100 $\mu g/m^3$ by 2000.) In addition, one-half of these would also need implementation of advanced controls such as ammonia injection and possibly flue gas treatment.

It should be emphasized that these conservative estimates are used to compensate for the extreme uncertainty in the monitoring data and the inherent errors in the assumptions of the model. It should also be noted that conservative growth rates and a successful mobile control program are "built-in" to the estimates. All of this is to say that the above should

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*A 25 percent increase in annual average $NO_2$ level by the year 2000 is most representative of expected changes. The zero percent lower limit referred to above applies only to heavily mobile dominated AQCR's with an extremely effective mobile control program.

be considered an optimistic view of future $NO_x$ control needs for the compliance with the current annual average standard.

San Francisco, AQCR 030

The San Francisco AQCR is representative of those AQCR's which are not currently nonattainment areas for $NO_2$ but which could become so in the future based on the current annual average air quality standard. Emissions of $NO_x$ in the region are heavily dominated by mobile sources (~70 percent), and the region is a nonattainment area for oxidant. Furthermore, if a one hour $NO_2$ standard of 500 $\mu g/m^3$ were promulgated, San Francisco would be in violation. An additional reason for presenting results for San Francisco is for comparison with the photochemical model results discussed in Section 8.2.2.

Table 8-5 shows the results of the matrix of calculations performed for San Francisco. The growth scenarios are described in Section 4.3 and Reference 8-3 and are briefly defined at the bottom of the table. Both the high and low base year concentrations (Table 8-4) are used for the calculations, and results for 1985 and 2000 are shown for each case. The required $NO_x$ control levels, indicated by 0, 1, 2, 3 and V, are described in Table 8-6. Controls are applied in the most cost-effective manner*, and new controls are introduced, if required, at the time (year) they are assumed to be developed.

The results shown in Table 8-5 are representative of mobile source dominated AQCR's with 1973 concentrations in the range of 75 to 100 $\mu g/m^3$. The dominance of mobile sources is clearly indicated by the significant reduction in predicted 1985 concentrations in all cases and by the results for the low mobile cases in both 1985 and 2000. The results for the high base year concentrations (BYR = 101 $\mu g/m^3$) show that a mobile dominated AQCR that is near nonattainment now will need the maximum amount of combustion modification $NO_x$ control by the year 2000. Furthermore, if powerplants are not a significant contributor to the annual average (PP = 0.2), then even more stationary source $NO_x$ control will be required.

St. Louis, AQCR 070

St. Louis is representative of an industrialized region dominated by stationary sources (75 percent) with coal firing as a significant source of $NO_x$ (72 percent of stationary source $NO_x$ is from coal-fired sources). Results for St. Louis are shown in Table 8-7. The relatively minor impact of different mobile source growth and control scenarios is illustrated by comparing the nominal growth and low mobile cases. Similarily, high stationary growth begins to have significant impact by

*When required, a control type is applied to all sources in a given source category.

TABLE 8-5. SUMMARY OF CONTROL LEVELS REQUIRED TO MEET THE ANNUAL AVERAGE $NO_2$ STANDARD IN SAN FRANCISCO, AQCR 030

| Case | BYR[a] = 76 $\mu g/m^3$ | | | BYR = 101 $\mu g/m^3$ | | |
|---|---|---|---|---|---|---|
| | PP[b] = 1.0 MS[c] = 1.0 | PP = 0.5 MS = 1.2 | PP = 0.2 MS = 1.0 | PP = 1.0 MS = 1.0 | PP = 0.5 MS = 1.2 | PP = 0.2 MS = 1.0 |
| Nominal Growth[e] | 0(67)[d] / 0(83) | 0(64) / 0(80) | 0(65) / 0(81) | 0(88) / 3 | 0(85) / 3 | 0(86) / V |
| Low Mobile[f] | 0(60) / 0(66) | 0(56) / 0(62) | 0(57) / 0(64) | 0(79) / 0(88) | 0(74) / 0(81) | 0(75) / 0(84) |
| High Stationary[g] | 0(75) / 0(85) | 0(69) / 0(81) | 0(68) / 0(82) | 0(100) / 3 | 0(91) / 3 | 0(90) / V |

1985 / 2000

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[a]BYR -- Base year ambient concentration for calibration
[b]PP -- Powerplant weighting factor
[c]MS -- Mobile source weighting factor
[d]Numbers in parentheses indicate annual average concentration in $\mu g/m^3$. If no number given, annual average equals or exceeds 100 $\mu g/m^3$.
[e]Stationary source growth less than historical, mobile sources grow at 3.5%/yr, 0.62 g/km in 1981
[f]Stationary source growth less than historical, mobile sources grow at 1.0%/yr, 0.25 g/km in 1985
[g]Stationary source growth at approximately historical rates, mobile sources grow at 3.5%/yr, 0.62 g/km in 1981

TABLE 8-6. DEFINITION OF STATIONARY SOURCE $NO_x$ CONTROL LEVELS

| Level[a] | |
|---|---|
| 0 | • No controls (assumes 1971 NSPS for large boilers is met) |
| 1 | • 40 - 80 percent control of new residential and commercial furnaces<br>• 6 - 16 percent control by low excess air for industrial and utility boilers |
| 2 | • Off stoichiometric combustion, flue gas recirculation, low-$NO_x$ burners and other advanced designs for boilers<br>• Operating adjustments and new design for IC engines<br>• Water injection and new designs for gas turbines |
| 3 | • Ammonia injection for boilers (50 percent reduction in $NO_x$ beyond Level 2 controls) |
| V | • Combustion control limits exceeded, flue gas treatment required |

[a]Control levels are ordered by increasing cost of the controls. Within each level controls are applied in order of increasing cost.

TABLE 8-7. SUMMARY OF CONTROL LEVELS REQUIRED TO MEET THE ANNUAL AVERAGE $NO_2$ STANDARD IN ST. LOUIS, AQCR 070

| Case | BYR[a] = 76 μg/m³ | | | BYR = 85 μg/m³ | | |
|---|---|---|---|---|---|---|
| | PP[b] = 1.0 MS[c] = 1.0 | PP = 0.5 MS = 1.2 | PP - 0.2 MS = 1.0 | PP = 1.0 MS = 1.0 | PP = 0.5 MS = 1.2 | PP = 0.2 MS = 1.0 |
| Nominal Growth[e] | 0(77)[d] / 0(96) | 0(75) / 0(98) | 0(76) / 1 | 0(86) / 2 | 0(84) / 2 | 0(85) / 3 |
| Low Mobile[f] | 0(73) / 0(85) | 0(70) / 0(81) | 0(70) / 0(84) | 0(82) / 0(95) | 0(79) / 0(91) | 0(78) / 0(94) |
| High Stationary[g] | 0(80) / 2 | 0(79) / 2 | 0(80) / 2 | 0(90) / 3 | 0(88) / 3 | 0(92) / V |

1985 / 2000

T-1292

[a]BYR -- Base year ambient concentration for calibration
[b]PP -- Powerplant weighting factor
[c]MS -- Mobile source weighting factor
[d]Numbers in parentheses indicate annual average concentration in μg/m³. If no number given, annual average equals or exceeds 100 μg/m³.
[e]Stationary source growth less than historical, mobile sources grow at 3.5%/yr, 0.62 g/km in 1981
[f]Stationary source growth less than historical, mobile sources grow at 1.0%/yr, 0.25 g/km in 1985
[g]Stationary source growth at approximately historical rates, mobile sources grow at 3.5%/yr, 0.62 g/km in 1981

the year 2000, even for the low base year concentration (76 $\mu g/m^3$). The difference in control requirements between mobile and stationary source dominated AQCR's is further illustrated by comparison of the low base year cases for St. Louis and San Francisco. This base year concentration is the same, but the ambient levels or control requirements in the year 2000 are much different.

A significant feature of these results, which are typical of stationary source dominated AQCR's, is that although no $NO_x$ controls are needed in 1985, considerable $NO_x$ control is required by the year 2000, even though the present ambient level is well below the annual average standard. It is expected that a one hour $NO_2$ standard less than 500$\mu g/m^3$ would necessitate even further $NO_x$ controls.

### 8.2.2 LIRAQ Results*

The Association of Bay Area Governments has sponsored an extensive study of predicted future air quality in the San Francisco AQCR to provide the air quality maintenance portion of an environmental management plan for the San Francisco Bay Region. A variety of source growth and control scenarios has been examined using the LIRAQ photochemical model, described in Section 4.3.2. Some of the details and results of the study are presented in Reference 8-4. Of primary interest to the $NO_x$ EA are the various $NO_x$/HC control strategies and their impact on both $NO_2$ and $O_3$ ambient levels.

All the model calculations obtained were made for the meterology of a high oxidant day, since oxidant is presently the most pressing air quality issue in the San Francisco AQCR. For the purposes of the $NO_x$ EA a high $NO_2$ day would be preferred; the meteorology of a high $NO_2$ day is significantly different from a high oxidant day. However, the primary use of the results was to make relative comparision of the effects of control strategies rather than specific predictions of one hour $NO_2$ maximum. That is, the percent change in the predicted area wide one hour maximum value with respect to percent reductions in HC and $NO_x$ emissions was examined. This is perhaps the best way to use the high oxidant day results to infer the impact on $NO_2$ one hour peaks, 24 hour averages, and annual averages.

The cases considered were the following combinations of percent HC reduction and percent $NO_x$ reduction: 80/0, 40/0, 40/20, 80/40, and 0/40. In all cases the emissions reductions were applied uniformly throughout the region. Results from these cases were used to examine the effect of $NO_x$ and HC controls, separately and in combination, on the region wide one hour maximum of $NO_2$ and ozone. The impact of these

*LIRAQ output was provided by Mr. Lewis Robinson, of the Bay Area Air Pollution Control District, from work performed for the Association of Bay Area Governments.

control strategies on the annual average $NO_2$ concentration was also inferred from the results. Of particular interest were the interactive effects of the control strategies.

Tables 8-8 and 8-9 show the percent reduction in one hour peak values of $NO_2$ and $O_3$ respectively for these cases. For a 40 percent reduction in $NO_x$ the peak $NO_2$ value was reduced only 14 percent. This is a very different result from what would be expected from a rollback model (40 percent). However, several additional factors need to be considered.

The location of the predicted maximum one hour $NO_2$ level in the region shifted in both time and location. At the location of the original peak value a 20 percent reduction in peak $NO_2$ occurred. For the controlled case the peak value occurred earlier in the day (by about an hour) and decayed faster. The $NO_2$ concentration behavior at the location of the original $NO_2$ peak is illustrated in Figure 8-1. At this location concentrations throughout most of day are 30 to 50 percent less than the uncontrolled case. The 24 hour average $NO_2$ concentration is reduced by 35 percent, which indicates that the reduction in annual average would probably be much closer to 40 percent than that suggested by the peak reduction.

Figure 8-1 also shows the time history of $NO_2$ concentration for the case of 20 percent $NO_x$ reduction and 40 percent HC reduction. The $NO_2$ peak is reduced by 35 percent; whereas, reductions for other times are much closer to the 20 percent $NO_x$ emissions reduction. The 24 hour average $NO_2$ concentration is reduced by 25 percent, which is more representative of the impact of the annual average than is the reduction in peak value. This clearly illustrates the influence of HC controls on the $NO_2$ peak, and the difference in control strategies that may be required to meet annual average one hour standards.

The interactive effects of $NO_x$ and HC controls on maximum one hour ozone concentrations are illustrated by the results shown in Table 8-9. In all cases, control of $NO_x$ increases the peak ozone levels and partially offsets the gains from HC control. However, such a combination control strategy will be necessary to meet both $NO_2$ and ozone ambient goals.

In conclusion, these results support the use of a rollback type model to examine the effect of controls on the annual average $NO_2$ if the controls are applied uniformly throughout the region of interest. It is also apparent from the difference in the response to controls of the one hour peak and the annual average (as implied by the 24 hour average) that the ratio of one hour peak to annual average may significantly change as a result of large scale control implementation programs. Therefore, care should be taken in using values of this ratio calculated from existing monitoring data to represent future conditions. This difference in response also indicates that $NO_x$ control requirements may be different for meeting annual average or one hour standards. Furthermore, the combination of $NO_x$ and HC control strategies is very significant to

TABLE 8-8. EFFECTS OF $NO_x$ AND HC REDUCTION ON ONE HOUR PEAK VALUE OF $NO_2$

| % $NO_x$ Reduction | | 0 | 20 | 40 |
|---|---|---|---|---|
| % HC Reduction | 0 | | --[a] | 14 |
| | 40 | 30[b] | 35 | -- |
| | 80 | 55 | -- | 60 |

[a]Data not available
[b]Percent reduction in one hour $NO_2$ peak

TABLE 8-9. EFFECT OF $NO_x$ AND HC REDUCTION ON ONE HOUR PEAK VALUE OF $O_3$

| % $NO_x$ Reduction | | 0 | 20 | 40 |
|---|---|---|---|---|
| % HC Reduction | 0 | | --[a] | (33)[c] |
| | 40 | 55[b] | 36 | -- |
| | 80 | 80 | -- | 70 |

[a]Data not available
[b]Percent reduction in one hour $O_3$ peak
[c]Ozone peak increased by 33 percent

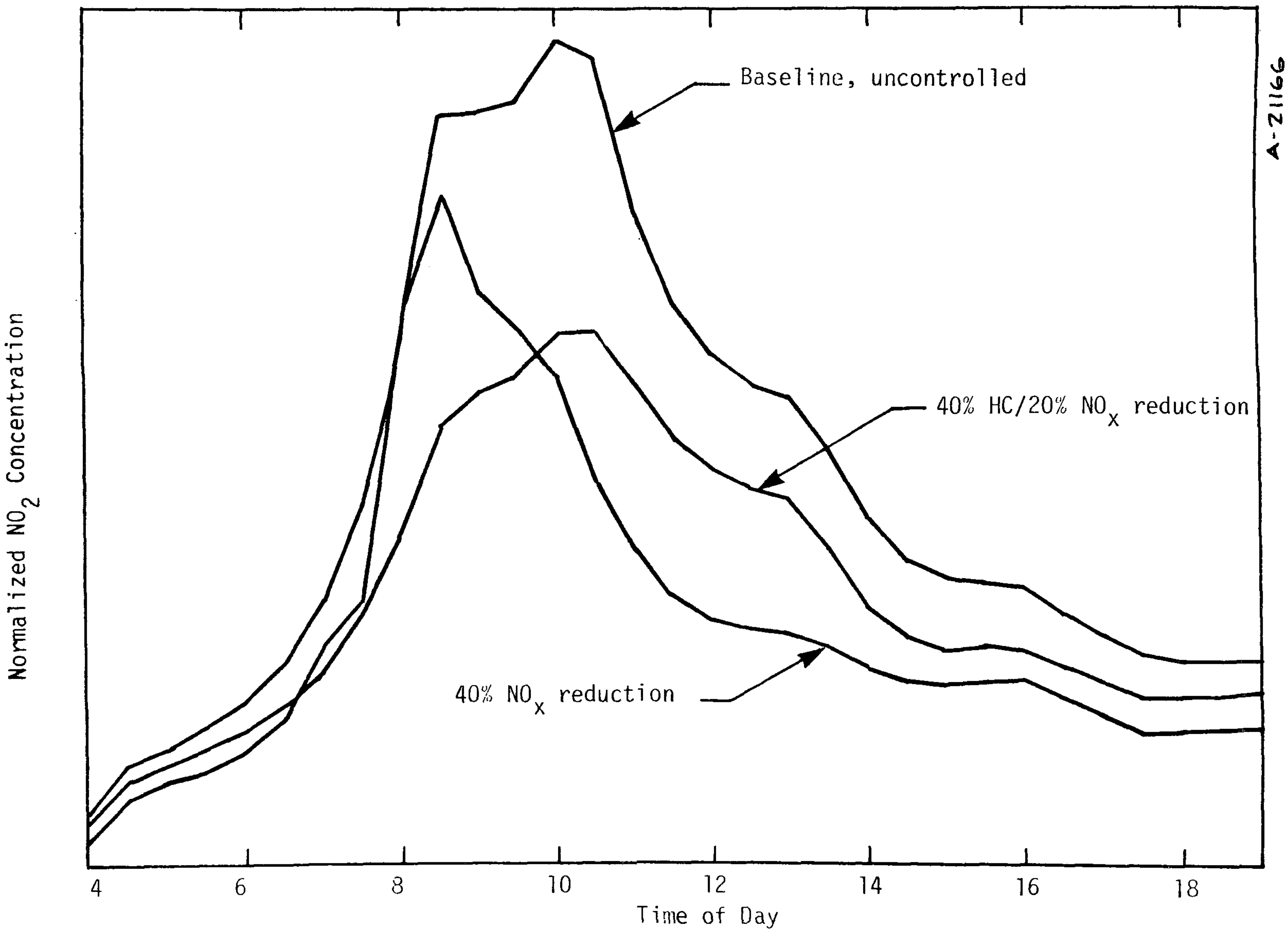


Figure 8-1. Comparison of time history of $NO_2$ concentration at the San Jose station for various $HC/NO_x$ reductions.

meeting both a short term and annual average $NO_2$ standard and an oxidant standard.

### 8.2.3 Photochemical Trajectory Model Results

A photochemical trajectory model, described in Section 4.3.2, was selected to investigate four specific issues regarding $NO_x$ controls:

- The influence on peak $NO_2$ levels of a large powerplant upwind of a metropolitan area
- The influence of the stack height of the powerplant for the above case
- The effectiveness of $NO_x$ control applied to the powerplant compared to the effectiveness of area source control on the peak $NO_2$ level
- The impact of simultaneous urban sprawl and area source control on peak $NO_2$ concentrations

For the purposes of the present investigations, a trajectory through downtown Los Angeles on the third day of an $NO_2$ episode was selected as representative of severe $NO_2$ meteorological conditions. This trajectory is shown in Figure 8-2. The location of the air mass of interest at each hour of the day from 1 am to 2 pm is shown on the trajectory map. In those cases with a powerplant on the trajectory, it was located at 2 am on the trajectory. It should be emphasized that this trajectory was selected to provide a representative case. No further relationship to specific sources on the Los Angeles area should be inferred.

Meteorological conditions (wind speeds, mixing heights, etc.) and emission fluxes were prepared by Environmental Research and Technology Inc. (ERT) from data available for Los Angeles. Meteorological conditions were characterized by:

- High, 50 kPa pressure surface heights
- Low wind speeds both at the surface and aloft
- Weak offshore surface pressure gradient
- Fog, low clouds, or haze along the coast during night and morning hours
- Early morning inversion height of 213 m, lifting to 700 m by mid-morning

A series of computer simulations using these meteorological conditions and several combinations of source emission strengths (corresponding to growth and/or control) were made. It should be emphasized that the purpose of these runs was not to verify the model for this day, but to provide a relative comparison of the air quality for

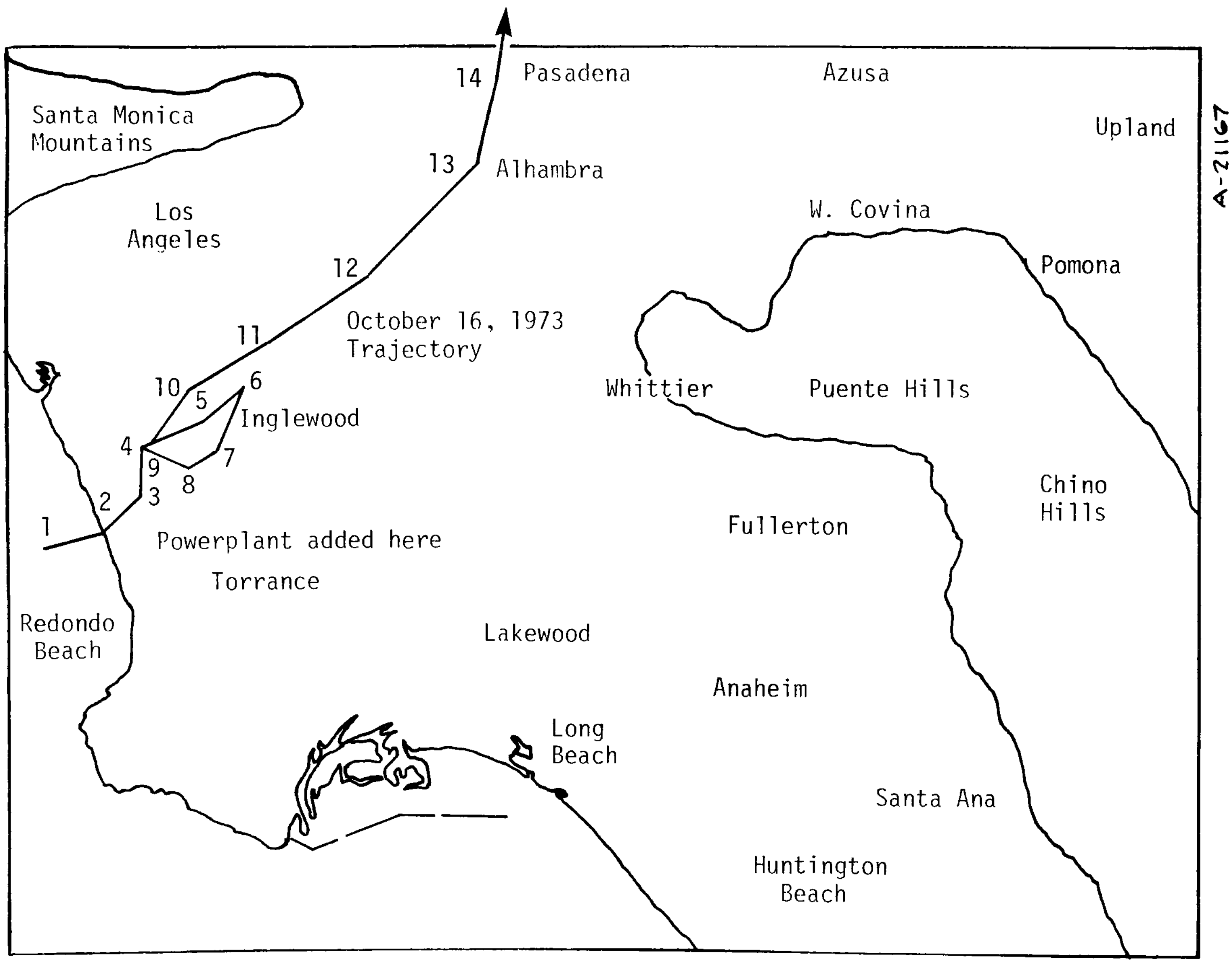


Figure 8-2. Map of an air parcel trajectory for high $NO_2$ day.

different emissions patterns. No powerplant was on the trajectory; therefore, for the purpose of simulation, one was added as described above. The following cases were examined:

- Baseline emissions, no large point sources
- Baseline emissions with a large powerplant situated on the early part of the trajectory, emissions from a 200 m stack
- Baseline emissions, with a large powerplant at ground level
- Reduction of 40 percent in $NO_x$, 50 percent in HC from baseline case (no powerplant emissions)
- Baseline emissions with increased area sources in early portion of trajectory (no powerplant emissions)

The results presented here are somewhat restricted in that only limited meteorological conditions and initial conditions were examined. (Initial conditions were rolled back for those calculations where emissions levels were reduced). The results from all the calculations are summarized in Table 8-10. They are presented in terms of the change in the 9 am to 12 noon maximum $NO_2$ concentration relative to the baseline case. The 9 am to 12 noon maximum was used since the $NO_2$ one hour maximum usually occurred within this time period and the air parcel was in the downtown Los Angeles area (the location of the measured $NO_2$ maximum for the day) during this time period.

The effects of of a large upwind point source are shown by comparing the first two cases in Table 8-10. As shown in Figure 8-2, a large powerplant is located near the coast, approximately 10 hours upwind of the downtown Los Angeles monitoring station (DOLA). The total emissions introduced into the air mass from the powerplant are 267 kg* (assumed to be 90 percent NO) compared to total area source $NO_x$ emissions prior to 10 am of 55 kg and prior to noon of 88 kg. The presence of the powerplant increases the morning maximum by 30 percent, regardless of whether the emissions are introduced at the surface or at 200 m. Examination of the time history of the surface concentrations of the air mass reveals that about 4 hours downwind of the powerplant there is almost no difference between the two cases. This, at first surprising, result is a consequence of the low early morning inversion height (213 m) which does not begin to break up until 9 am. The powerplant emissions are trapped below the inversion layer and diffuse vertically to fill the entire layer. Therefore, the height of the emissions source has almost no impact on the morning maximum value. This situation (a trapped plume) represents a "worst case" for the impact of elevated emissions.

The influence of $NO_x$ control on the powerplant can be approximated by comparing the baseline and the two powerplant cases

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*All emissions are expressed as $NO_2$.

TABLE 8-10. RESULTS OF THE PHOTOCHEMICAL TRAJECTORY MODEL CALCULATIONS

| | Percent Change in 9 am to 12 noon Max $NO_2$ Concentration from Baseline Case with no Powerplant |
|---|---|
| Powerplant at 200 m | + 30 |
| Powerplant at surface | + 30 |
| 40% $NO_x$, 50% HC reduction | - 45 |
| 40% $NO_x$ reduction | - 30 |
| Increased upwind emissions | + 17 |
| Increased upwind emissions with 40% $NO_x$, 50% HC reduction | - 35 |

described above except that the baseline case is now treated as the complete $NO_x$ control case. Complete $NO_x$ control of the powerplant, i.e., 83 percent reduction in upwind emissions (267/322), would result in a 23 percent reduction (30/130) in peak $NO_2$. This is not really surprising since emissions from this major $NO_x$ source have ample time to disperse prior to the point of maximum ground level impact and since a significant portion of the $NO_2$ concentration comes from initial $NO_2$ levels in the air mass*. However, this is not the only consequence of controlling the powerplant. The concentrations of $NO_2$ aloft are also reduced by approximately 23 percent. This serves to reduce afternoon $NO_2$ by as much as 50 percent. Furthermore, in cases where emissions are carried to sea by late night winds and returned to land in the morning, the presence of the powerplant could greatly change the early morning initial concentrations in the returning air mass, which is known to have a significant impact on $NO_2$ concentrations later in the day.

The impacts of both $NO_x$ and HC controls on the $NO_2$ peak concentration are illustrated by the two emissions reduction cases, 40 percent $NO_x$ and 50 percent HC, and 40 percent $NO_x$ only, shown in Table 8-10. Combined $NO_x$ and HC controls are more effective in reducing the $NO_2$ peak than control of $NO_x$ only (Table 8-10, 45 percent reduction compared to 30 percent reduction**). It should also be noted that the late afternoon ozone peak was reduced by 40 percent for the combined $NO_x$/HC reductions but was increased by almost 40 percent with only $NO_x$ reduction. This further emphasizes the necessity of combined $NO_x$/HC control strategies.

The impact of urban sprawl with and without controls is shown by comparing the baseline case and the last two cases in Table 8-10. In the first of these cases, $NO_x$ and HC emissions in the pre-1 am portion of the trajectory*** were assumed to increase by 20 percent of the prenoon emissions in the baseline case. This was used to simulate extensive urban growth into rural areas or increased industrialization of previously underdeveloped areas. The second case has 40 percent reduction in $NO_x$ and 50 percent reduction in HC applied to this first case. This represents outward growth combined with controls.

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* Another factor which must also be considered is the percent conversion to $NO_2$ of the NO from the powerplant and the area sources.

** Control of $NO_x$ only was more effective in this simulation than in the LIRAQ one because here the initial concentration of $NO_2$ which numerically represents 30 percent of the morning is also reduced by 40 percent maximum value. Therefore 12 percent of the reduction in the morning peak results from the change in initial conditions and the remaining 18 percent from reduction in emissions. This compares well with the LIRAQ results shown in Table 8-8.

***The fact that the trajectory is over the ocean prior to 1 am is of no consequence at this point since we are not interested in the specifics of the trajectory.

Figure 8-3 shows the percent change in the 9 am to 12 noon $NO_2$ maximum as a function of the percent change in the prenoon $NO_x$ emissions for cases where the HC emissions are also changed. These cases represent sprawl, sprawl and control, and control only. The approximate linearity shown in Figure 8-3 suggests that the morning maximum $NO_2$ is primarily a function of the total prenoon emissions (and the initial conditions) and is not significantly influenced by the exact upwind distribution of those emissions. Thus growth in emissions either by sprawl or increased density can be offset by an equivalent emissions reduction by control. This linearity also lends support to the use of rollback to approximate changes in ambient concentration.

Before concluding, two very important facts should be noted relative to the above discussion of the results shown in Figure 8-3. First, there was no horizontal dispersion of the upwind emissions since it was assumed that growth occurred uniformly. This is much different than if a single point source were located on the trajectory. Second, HC emissions were adjusted in nearly the same ratio as $NO_x$ emissions in all cases. The significance of such simultaneous $NO_x$/HC reduction to the results has been previously discussed.

Based on these limited calculations, the following conclusions can be made:

- Stack height is not a significant factor on far downwind concentrations for low inversion heights
- The mid-morning $NO_2$ peak is a linear function of upwind $NO_x$ emissions provided the ratio of $NO_x$ to HC emissions is constant; therefore, use of a rollback model is justified in these cases
- Stringent control of $NO_x$ emissions from a large point source located several hours upwind does not have a proportional effect on maximum $NO_2$ concentration
- Combined $NO_x$/HC reduction has much more impact on the $NO_2$ peak than $NO_x$ control only

Additional calculations are planned to investigate the impact of changing the initial conditions and meteorology. Calculations representative of St. Louis may also be made since the model has been applied to St. Louis and meteorological and emissions data have been prepared.

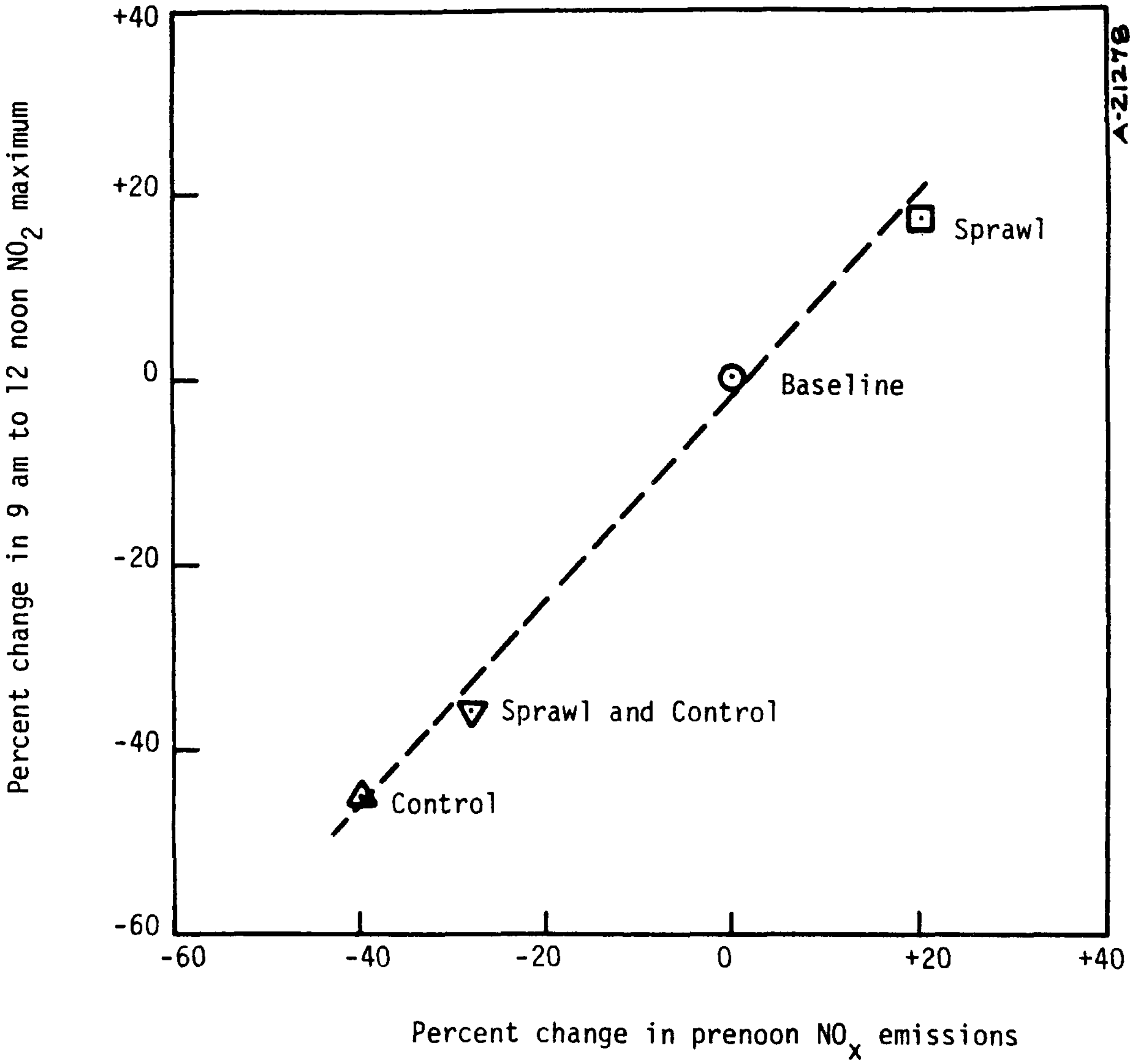


Figure 8-3. Comparison of the effects of sprawl and control on 9 am to 12 noon $NO_2$ maximum (simultaneous $NO_x$ and HC emission changes).

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## SECTION 9

## TECHNOLOGY TRANSFER

Results of the first year of the $NO_x$ EA were previously documented in the first annual report on the program (Reference 9-1). Results and findings from various second year task efforts were discussed in detail in the preceeding sections of this report. Of course, a key aim of this program is to ensure that these conclusions are widely disseminated to the pollution control development, industrial user, and regulatory communities at large. Therefore, in addition to this report, program outputs were documented in several other reports issued in the past year. These include:

- Results of the Emissions Characterization Task to determine the baseline multimedia emissions from stationary combustion sources, to rank sources by pollution potential, and to establish priorities for developing and implementing $NO_x$ controls (Reference 9-2)

- Results from the Alternate Clean Fuels task to evaluate the differential environmental impact and costs of potential alternate clean fuels use in area sources (Reference 9-3)

- Results from the Process Engineering and Environmental Assessment task to evaluate the operational, cost, and environmental impacts of applying combustion modification $NO_x$ controls to utility boilers (Reference 9-4)

- Results of the Source Analysis Modeling task to develop rapid and intermediate screening models (References 9-5 and 9-6)

Further technology transfer activities were performed as part of the General Program Support task of the $NO_x$ EA. Perhaps the most significant among these was the preparation of a Standards Support Plan for Stationary Conventional Combustion Sources (Reference 9-7). This report documents the activities of each EPA office responsible for providing regulatory support information (Office of Research and Development), and for setting standards (Office of Air Quality Planning and Standards, Office of Water Planning and Standards, Office of Toxic Substances, and Office of Enforcement). The focus of the report is on documenting the schedules which show the interrelationships among regulatory mandates, EPA Program Office plans, and the IERL R&D plans.

Other general program support technology transfer activities included:

- Continuing publication of "$NO_x$ Control Review," a quarterly technology status report on $NO_x$ control development and implementation, and regulatory strategy
- Coordination of the Second Stationary Source Combustion Symposium, held in New Orleans in August 1977, and publication of the symposium proceedings (Reference 9-8)
- Presentation of the keynote paper at the above symposium
- Updated documentation of the status of IERL developmental programs in combustion modification controls, for use in the IERL annual report (Reference 9-9)
- Participation in various IERL-EACD environmental assessment coordination meetings
- Support of the Conventional Combustion Environmental Assessment efforts

REFERENCES FOR SECTION 9


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## SECTION 10

## FUTURE EFFORTS

The focus of the technical effort performed in the first two years of the $NO_x$ EA program was described in the introductory discussion of this report in Section 1. Future efforts in the third and final year of the program will bring together and extend the methodology development, data compilation, process evaluation, and systems analysis results of these past activities to address the stated objectives of the program. Specifically, third year emphasis will be placed on:

- Updating the baseline source evaluation and emissions inventories to 1977
- Completing the process analysis and environmental assessment studies of $NO_x$ controls applied to industrial boilers, gas turbines, residential and commercial heating systems, and internal combustion engines
- Evaluating the effectiveness, cost, operational and environmental impacts of advanced $NO_x$ control concepts
- Identifying preferred $NO_x$ control strategies and future control R&D priorities

In updating the baseline emissions characterization to 1977, more recent equipment population, fuel consumption, and emission factor information will be incorporated. In completing the process engineering studies, the same methods used for the utility boiler effort, described in Section 4.2, will be extended to the remaining source categories to be treated. In addition, results for the gas turbine, IC engine, and residential/commercial heating systems studies will be reported in IERL-EACD Environmental Assessment Report format. In both the above efforts, newly available results from the field test programs discussed in Section 5.2 will be factored in.

All of the above efforts will be integrated in the systems analysis task to specifically give stated program outputs. Specific attention will be afforded to the factors discussed in Section 3 in deriving recommendations for regional $NO_x$ control strategies and scoping control R&D needs.

# TECHNICAL REPORT DATA
*(Please read Instructions on the reverse before completing)*

| | | |
|---|---|---|
| 1. REPORT NO. EPA-600/7-79-147 | 2. | 3. RECIPIENT'S ACCESSION NO. |
| 4. TITLE AND SUBTITLE Environmental Assessment of Stationary Source NOx Control Technologies: Second Annual Report | | 5. REPORT DATE June 1979 |
| | | 6. PERFORMING ORGANIZATION CODE |
| 7. AUTHOR(S) L. R. Waterland, K. J. Lim, K. G. Salvesen, R. M. Evans, E. G. Higginbotham, and H. B. Mason | | 8. PERFORMING ORGANIZATION REPORT NO. |
| 9. PERFORMING ORGANIZATION NAME AND ADDRESS Acurex/Aerotherm Division 485 Clyde Avenue Mountain View, California 94042 | | 10. PROGRAM ELEMENT NO. EHE624A |
| | | 11. CONTRACT/GRANT NO. 68-02-2160 |
| 12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711 | | 13. TYPE OF REPORT AND PERIOD COVERED Annual; 6/77 - 6/78 |
| | | 14. SPONSORING AGENCY CODE EPA/600/13 |

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Joshua S. Bowen, Mail Drop 65, 919/541-2470. EPA-600/7-78-046 was the first annual report.

16. ABSTRACT The report summarizes results of the 2nd year of an environmental assessment of stationary source NOx control technologies. The 2nd year effort focused on: (a) characterizing the baseline (uncontrolled) environmental impact of stationary combustion sources; (b) developing fuel consumption and NOx emission inventories and projecting these to the year 2000; (c) field testing selected stationary combustion sources to determine multimedia pollutant emissions under both baseline and controlled (for NOx) operation; (d) performing process engineering and environmental assessment studies of NOx controls applied to utility and industrial boilers and to gas turbines; (e) assembling and exercising reactive air quality models in systems analysis applications; and (f) developing source analysis models for environmental impact evaluation. The report summarizes program results in each of these areas. Preliminary NOx control technology analysis for utility boilers indicates that off-stoichiometric combustion and low NOx burners (LNB) are the preferred techniques for both retrofit and new applications. For coal firing, overfire air operation and LNB are both cost effective; LNB is preferred for new wall-fired boilers. For oil and gas firing, staged combustion with burners out of service is recommended.

17. KEY WORDS AND DOCUMENT ANALYSIS

| a. DESCRIPTORS | | b. IDENTIFIERS/OPEN ENDED TERMS | c. COSATI Field/Group | |
|---|---|---|---|---|
| Pollution | Emission | Pollution Control | 13B | |
| Nitrogen Oxides | Testing | Stationary Sources | 07B | |
| Assessments | Boilers | Environmental Assessment | 14B | 13A |
| Fossil Fuels | Gas Turbines | Emission Inventories | 21D | 13G |
| Fuel Consumption | Mathematical Models | | 21K | |
| Combustion | | | 21B | 12A |

| | | |
|---|---|---|
| 18. DISTRIBUTION STATEMENT Release to Public | 19. SECURITY CLASS *(This Report)* Unclassified | 21. NO. OF PAGES 199 |
| | 20. SECURITY CLASS *(This page)* Unclassified | 22. PRICE |

EPA Form 2220-1 (9-73)