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APPLICABILITY OF NO_x COMBUSTION MODIFICATIONS TO CYCLONE BOILERS (Furnaces)

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APPLICABILITY OF NO_x COMBUSTION MODIFICATIONS TO CYCLONE BOILERS (FURNACES)

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ABSTRACT

Cyclone furnaces are a significant source of stationary NO_x emissions. It was estimated that 0.76×10^6 tonnes of NO_x (over 6% of stationary source NO_x) were emitted from all cyclone-coal-fired utility boilers in 1973. This represents from 19% to 22% of the total NO_x emissions from all coal-fired utility boilers in the U.S.

Several techniques of combustion modifications were applied in the past to cyclone boilers/furnaces in an attempt to lower their NO_x emissions. These include boiler load reduction, low excess air firing, two-stage firing, and switching fuels. This report summarizes available NO_x emission data when applying these techniques to cyclone boilers/furnaces. Even though significant reductions in NO_x were achieved, none of the techniques was shown to reduce NO_x emissions to the level meeting the New Source Performance Standard.

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TABLES (continued).

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ACKNOWLEDGMENT

The authors wish to acknowledge the significant contribution of the Babcock & Wilcox Company and the data and information provided by Commonwealth Edison and KVB Engineering, Inc.

SECTION 1

INTRODUCTION

Cyclone-fired boiler units are widely used for generating steam. They are used primarily in large electric power plants and are also used to a lesser extent by industry and by large institutions to supply steam for power generation or other uses. Cyclone-fired, primary steam-generating capacity in the U.S. totals approximately 26,000 kg/s, about 9% of the total U.S. steam-generating capacity.

Cyclone boilers have traditionally been labeled as high NO_x emitters. Coal-fired cyclone boilers contribute nearly 20% of the NO_x emissions from all coal-fired utility boilers.

The first purpose of this study was to update available information on cyclone furnace/boiler characteristics, population, sales trends, and emissions. The second purpose was to develop judgmental information on the combustion modifications capable of reducing NO_x emissions from cyclone combustion.

SECTION 2

CONCLUSIONS AND RECOMMENDATIONS

1. A cyclone-fired boiler unit is a complex, integrated, combustion system that operates under a well-defined and a rather restricted range of conditions. It was developed to fire troublesome coals high in ash content and having low ash fusion temperatures. These coals are difficult to burn in both stoker and pulverized coal combustion systems. The heart of the cyclone boiler is the cyclone furnace. Successful operation of the cyclone furnace depends on maintaining a liquid or wet slag within the furnace. To meet this condition, furnace heat absorption rates as well as ash fusion temperatures of coal fired in the furnace must be low. If these conditions are not met, the advantages of cyclonic combustion are lost, and other conventional methods of combustion become a prerequisite.

2. Combustion of coal in a cyclone furnace results in heat release rates 8 to 10 times higher than in pulverized coal combustion. Cyclone furnace gas temperatures are about 1922K (3000°F). These temperatures are sufficient to melt the ash into a liquid slag, a thin layer of which adheres to the walls of the cyclone. Coal particles are thrown to the walls by centrifugal force and are caught in the running slag where they are quickly combusted. Slag is then tapped, cooled, and sent to disposal.

3. The key to successful operation of the cyclone boiler is to maintain a noncorrosive and fluid ash in the cyclone furnace throughout the whole range of loads at which the boiler operates. The abilities of coal fuels to meet these requirements can limit the use of certain coals. Lignite, oil, and gas fuels are also routinely fired in cyclone boilers even though the cyclone furnace was originally designed for bituminous coal firing.

4. Cyclone boilers under normal operating conditions do not exhibit any unusual or peculiar corrosion characteristics. Operation at reduced excess air, however, aggravates formation of corrosive iron and iron sulfide, which has had catastrophic effects in several boilers.

5. Cyclone firing has explicit operating advantages and disadvantages. Its primary advantage is the ability to burn slagging coals economically, which cannot be done by other conventional methods of combustion. Among other advantages are simplicity and reliability, low excess-air requirement (10 to 17%), low carbon loss when burning bituminous coals, higher full-load boiler efficiency, lower total particulate emissions, an ash more suitable for landfill, smaller size furnace, low coal-preparation cost, and easy conversion to the firing of other types of fuel. Some disadvantages include limited operating flexibility, high NO_x emissions, high pressure drop, high carbon loss when burning western coals of nonwetting ash characteristics, and perhaps a respirable particulate emission problem from the fineness of the ash emitted through the stack. All of these disadvantages are associated with the principal method of firing utilized in cyclonic combustion.

6. There are 149 cyclone boilers in the U.S. These boilers are fired by a total of 736 cyclone furnaces and generate 26,000 kg/s of primary steam (about 9% of the total U.S. steam generating capacity). Cyclone boilers are located in 26 states, with nearly half of the capacity and one-third of the boilers located in Illinois, Missouri, and Indiana. A significant portion of the steam raising capacity (94%) is operated by electric utilities.

7. The Babcock & Wilcox Company (B&W) is the sole supplier and manufacturer of cyclone boilers. Since 1973, B&W has not sold a single cyclone unit. The decline of sales started when New Source Performance Standards (NSPS) for SO_x emission control were put into effect. The coals with low ash fusion temperatures normally have high sulfur content. The final event restricting the sale of bituminous-coal-fired cyclone boilers was the implementation of the NSPS for NO_x emissions.

8. Due to the nature of cyclonic combustion requiring high combustion temperatures, the cyclone boilers are the highest NO_x emitters among all presently available combustion methods. At full load and when firing bituminous coals, they emit nitrogen oxides in the concentration range of 960 to 1200 vppm. This translates into 576 to 688 ng NO_x per joule of heat input (1.4 to 1.6 lb/10^6 Btu). The present new source performance standard (NSPS) applicable to cyclone boilers burning bituminous coal is 301 ng NO_x per joule (0.7 lb/10^6 Btu).

9. Bituminous coal firing produces the highest NO_x emissions among all fuel types. In general, the ranges of full-load NO_x emissions appear to decrease in the following order: bituminous coal (960 vppm to 1,197 vppm [576 ng/J to 688 ng/J]),

sub-bituminous coal (910 vppm [546 ng/J]), lignite (485 vppm to 593 vppm [291 ng/J to 355 ng/J]), natural gas (415 vppm to 650 vppm [207 ng/J to 325 ng/J]), and residual oil (441 vppm to 530 vppm [254 ng/J to 310 ng/J]).

The corresponding NSPS for these fuels are:

	ng/J
Bituminous coal	302
Sub-bituminous coal	Not available
Lignite	258
Oil	129
Gas	86

10. It was estimated that in 1973, 62 x 10^9 kg (68.4 x 10^6 tons) of coal were burned at power plants employing cyclone firing. The overwhelming majority of this coal was bituminous with an average heating value of 26 MJ/kg (11,200 Btu/lb).

11. Using the emission factor of 12.28 g NO_x per kg of bituminous coal, it was estimated that 0.76 x 10^6 tonnes (0.84 x 10^6 tons) of NO_x were emitted from all cyclone-coal-fired utility boilers in 1973. This represents from 19% to 22% of the total NO_x emissions from all coal-fired utility boilers. With respect to all (137) identified stationary sources of NO_x, the cyclone-fired utility boilers burning bituminous coal ranked third. It was estimated that over 6% of the total NO_x emitted by all 137 stationary sources came from this equipment type.

12. The principles of NO_x formation during cyclonic combustion are not well understood. It is believed that NO_x originates from two sources. First, NO_x is thermally formed by fixation of atmospheric nitrogen. This reaction is primarily influenced by oxygen concentration, combustion temperature, and reaction time at the combustion temperature. A second source is fuel-bound nitrogen which is oxidized to NO_x in the combustion process. The most critical factor in fuel NO_x formation appears to be the local conditions under which fuel volatilization takes place. Under reducing conditions, fuel nitrogen may form N_2 or other nitrogen intermediates which can revert to N_2, whereas in an oxidizing environment, NO is formed.

13. Preferably, any combustion modification made to a cyclone boiler to reduce NO_x emissions should act on both the thermal and fuel-bound NO formation mechanisms. Available information reveals that four types of combustion modifications have been applied, singly or in combination, to cyclone combustion units. These are (1) boiler load reduction, (2) low excess air (LEA) firing, (3) simulated staged

firing, and (4) switched fuel firing. Most of the data are available for the first two modifications. Despite the fact that the cyclone furnaces are significant NO_x emitters, only a relatively small number of cyclone boilers were found to have been examined and tested in some way to determine the effect of combustion modifications on NO_x emissions. One reason for the lack of adequate field data on this combustion equipment class is the relative inflexibility of the cyclone boilers toward modification.

14. Boiler load reduction produced the highest and the most consistent degree of NO_x emission reduction. Reducing the boiler load from 100% to 80% resulted in an average NO_x reduction of 29% with coal fired units and an average NO_x reduction of 19% with oil fired units. Even with this reduction in NO_x emissions, however, the cyclone boilers could not meet New Source Performance Standards.

15. Low excess air (LEA) firing reduced NO_x generally at the cost of increased CO emissions. Reducing excess air in one lignite boiler resulted in an NO_x reduction of 50% although supplemental oil was required to maintain ignition in the furnace. Applying LEA firing to oil-fired units resulted in less dramatic changes (10% to 16% reductions) at acceptable CO levels. One bituminous coal-fired unit tested showed an 11% reduction in NO_x with no change in CO. NO_x reductions achieved with LEA firing alone in cyclone boilers could not meet the NO_x NSPS.

16. Staged firing was simulated in several coal-, oil-, and gas-fired boilers. A 28% to 36% NO_x reduction was achieved by firing eastern coal, and a 48% reduction was achieved by firing natural gas using a two-stage concept. Pattern firing, the other simulated stage firing concept applicable to boilers with a multitude of cyclones and consisting of varied fuel and air flows through these cyclones, produced mixed results for a variety of fuels. B&W does not recommend the stage firing methods for application because of the combination of the following reasons: lack of significant, long-term testing experience; reluctance of boiler owners to accept the method on a permanent basis; and risk of catastrophic tube corrosion.

17. Switching from bituminous coal to fuels such as natural gas, residual oil, or lignite can cut NO_x emission in half. However, different standards apply to different fuels, and none of the fuels cyclonically fired can meet NO_x emissions standards.

18. The data in this report indicate that the NO_x New Source Performance Standard (NSPS) cannot be met at normal full-load firing for any type of fuel fired in a cyclone boiler unit,

with the possible exception of lignite. The proposed lignite standard was met during one test conducted by B&W at very low excess air levels and with supplemental oil fuel. Both load reduction and switching fuels may be considered as practical interim measures in reducing NO_x emissions from some cyclone boilers during serious episode conditions. Both of these methods, however, are least desirable to the boiler owner for operational and economic reasons.

19. Flue gas recirculation (FGR) was applied to only one boiler unit and showed no change in NO_x level of a coal-fired unit. The potential of this method cannot be properly evaluated because of limited data and application of FGR to the point in the cyclone boiler where maximum NO_x control effectiveness could not be achieved.

20. Because detailed information was not available on conditions under which the tests summarized in this report were implemented, it is not certain if the tests were thorough, comparable, and representative of all permanent cyclone operations and if all possibilities for cyclone boiler modification to achieve reduced NO_x emissions were thoroughly explored. Many tests were cost- and/or scope-limited. It is therefore recommended that a comprehensive test program be developed that would concentrate on causes and locations of NO_x formation in the cyclonic combustion process. The comprehensive test program should investigate the following:

    a. Variations in operation of individual cyclones in multicyclone fired facilities and the influence of these variations on the total boiler NO_x emissions.

    b. The effect of boiler modifications on cyclone furnace NO_x emissions with a comprehensive evaluation of variables and conditions having a strong influence on NO_x formation.

    c. Long-duration tests of the successful modifications to develop reliability and operational data.

    d. Applicability of the successful modifications to all cyclone boiler facilities.

    e. Cost of such modifications.

21. Whether any NO_x emission control methods, even if effective in meeting NO_x emission standards, will be practical and acceptable to boiler operators is not presently known. For the last 6 years, no cyclone boilers have been sold in the United States. A large majority of cyclone boilers (49% steaming capacity) are 12 to 32 years old. The normal life expectancy for boiler facilities is from 25 to 35 years.

Thus, within the next 3 to 13 years, some 49% of cyclone steaming capacity will be obsolete and will have to be replaced. This process may be dramatically encouraged by a strong enforcement of existing NO_x emission standards. A study is therefore recommended to determine the influence of the NSPS applicable to NO_x emissions from cyclone boilers on American industries.

SECTION 3

CHARACTERIZATION OF CYCLONE FURNACES/ BOILER TYPES, POPULATION, AND EMISSIONS

The following four sub-sections characterize cyclone furnaces/ boilers. All references to cyclone-furnace-fired boiler units in this report are made solely to units originally patented, developed, and designed by the Babcock and Wilcox Company for the original purpose of burning coal. At least one other manufacturer markets a "cyclonic" method of firing coal. Fluor Utah, Inc., a subsidiary of Fluor Corporation, markets the Lucas Cyclonic Furnace System developed in England, which is primarily used for tire disposal.

Section 3.1 gives a detailed account of the principles of operation, design, auxiliary equipment, and fuel requirements. Section 3.2 presents available population-related data pertaining to installations. Section 3.3 summarizes the available emissions data. Section 3.4 gives an updated estimate of the need for NO_x control in this equipment class.

3.1 CYCLONE FURNACE/BOILER TYPES AND OPERATION

3.1.1 Principles of Cyclone Combustion

A cyclone-fired boiler unit is a complex, integrated combustion system whose purpose is to generate steam. The heart of this system is the cyclone furnace. The cyclone method of firing coal was developed about 35 years ago by the Babcock and Wilcox Company. At the time it was introduced, it represented a major breakthrough in the art of firing troublesome coals high in ash content and having low ash fusion temperatures. These coals proved difficult to burn in both stoker and pulverized units. Cyclone firing still is one of the better ways to burn this low-quality coal. Although all existing cyclone furnaces were originally designed to burn coal, many other types of fuels have been and are still being successfully fired in them. These fuels include residual and distillate oils, solid waste (wood bark, coke), and natural gas.

Figure 1 shows a side view of a typical cyclone furnace in operation.[1] The diameters of existing furnaces range from 1.8 m to 3.1 m (6 ft to 10 ft) with lengths normally 3.4 m (11 ft) or longer.[2] These sizes correspond to heat input firing rates ranging from 44 MW to 123 MW (150 and 420 million Btu/hr).[3] With a typical low-rank coal of 24.4 MJ/kg (10,500 Btu/lb), this corresponds to a coal feed rate between 1.8 and 5.0 kg/s (7 and 20 tons/hr) per furnace. The full load heat release rate is independent of furnace size and is approximately 2.52 MW/m^2 (800,000 Btu/hr - ft^2) of wall surface.[4] This rate is generally 8 to 10 times higher than that for pulverized coal furnaces. Full-load heat release rates on a furnace volume basis for a 3.1 m (10 ft) diameter cyclone are 4.7 MW/m^3 (450,000 Btu/hr - ft^3) and increase to 7.8 MW/m^3 (750,000 Btu/hr - ft^3) for a 1.8 m (6 ft) diameter furnace. A typical heat release rate on a furnace volume basis for a pulverized-coal-fired unit is 0.2 MW/m^3 (20,000 Btu/hr - ft^3). Because of the small amount of wall surface area and the insulating effect of the wall refractory and the liquid slag layer, the heat absorption through the cyclone furnace walls is low. Heat absorption ranges from 0.13 to 0.25 MW/m^2 (40,000 to 80,000 Btu/hr - ft^2) with high temperature refractory (e.g., Super Hi-Bond 3000®) covering studded tubes lining the furnace walls.[2] This amounts to approximately 5% to 10% of the total heat release rate at full load. Successful operation of the cyclone furnace depends on maintaining a liquid or wet slag condition within the furnace. This is a characteristic of a properly operated cyclone. Heat absorption rates as well as ash fusion temperatures must be low to provide this condition. Consequently, the cyclone furnaces operate under a well-defined and a rather restricted range of conditions. If these conditions are not met, the advantages of cyclonic combustion are lost, and other more conventional methods of combustion (pulverized coal firing, stokers, etc.) become a prerequisite.

S. T. Potterton of Babcock & Wilcox (B&W) has described the general coal firing arrangement in cyclone furnaces.[3] His description is paraphrased as follows:

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[1]New Cyclone-Fired Boiler for E. H. Werner Station, Jersey Central Power & Light Company. Bulletin G-81 by the Babcock and Wilcox Company, New York, New York, 1953. 9 pp.

[2]The Babcock and Wilcox Company. Steam--Its Generation and Use. 38th Edition. New York, New York, 1972.

[3]Potterton, S. T. Combination Fuel Firing in Cyclone Furnaces. The Babcock and Wilcox Company. (Presented to 1970 Industrial Coal Conference. Lafayette, Indiana October 7, 1970). Barberton, Ohio. 9 pp.

[4]Shields, Carl D. Boilers - Types, Characteristics, and Functions. F. W. Dodge Corporation, New York, New York, 1961. 559 pp.

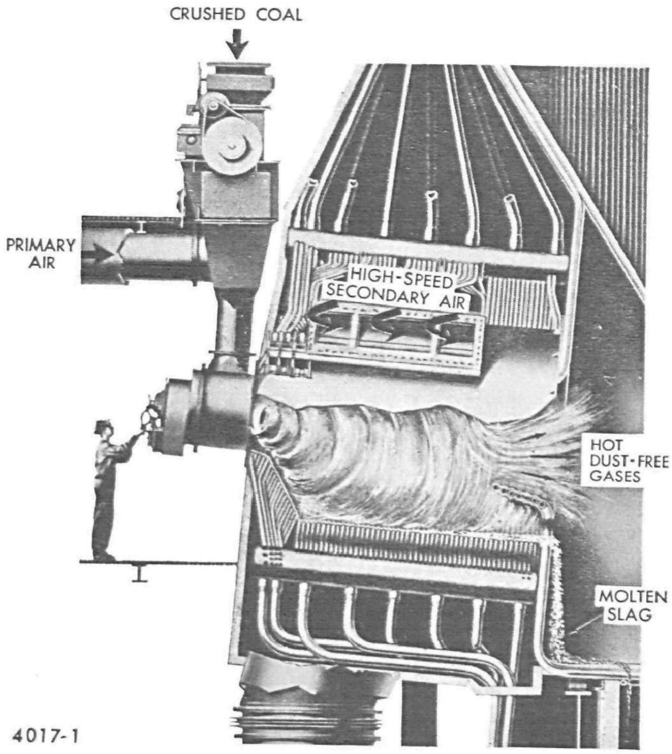

Figure 1. Cyclone furnace side view.[1]

> "The cyclone furnace is a water-cooled, horizontal cylinder in which fuel is fired, heat is released, and combustion is completed. Coal crushed so that 95% will pass through a 4 mesh screen is introduced tangentially through a primary burner at the front of the cyclone. About 20% of the required combustion air also enters the cyclone tangentially through the primary burner at about 349 K (250°F). This pre-heated air enters tangentially and serves to distribute the coal over the surface of the cyclone. The remaining combustion air is also preheated and enters the cyclone at a high velocity of about 91.4 m/s (18,000 FPM) and at about 672 K (750°F) through a secondary air port near the top of the cyclone and extending over almost its full length. All air is preheated by using a heat exchanger operating off the waste heat of the flue gas. The port is arranged for tangential air entry."

The tangential admission of secondary high velocity air increases the whirling or centrifugal action on the fuel. A small amount of air (up to about 5%) is also admitted through the inlet at the center of the burner behind the primary coal/air stream and is called tertiary air. The tertiary air port is used to cool the burner and help maintain fuel ignition. Either a gas or oil lighter with a capacity of 2.9 MW (10 million Btu/hr) is used to ignite the fuel. The lighter (igniter) is normally lit prior to the introduction of the crushed coal.

Figure 2 shows the arrangement of cyclone components.[3] Along with the basic coal furnace components are shown the oil and gas burners which can be used for multifuel firing or ignition of coal. G. W. Kessler of B&W has described the cyclone combustion process environment.[5] The following paragraphs paraphrase his description:

> "The fuel in the cyclone furnace is burned at heat release rates exceeding 5.2 MW/m^3 (500,000 Btu/hr - ft^3) and with gas temperatures of about 1922 K (3000°F). These temperatures are sufficient to melt the ash into a liquid slag, a thin layer of which adheres to the walls of the cyclone. The incoming fuel particles, except those fines burned in suspension, are thrown to the walls by centrifugal force and are caught in the running slag. The secondary air entering the cyclone tangentially sweeps past the coal particles embedded in the slag surface at high speed. Thus, the air required to burn the coal is quickly supplied, and the products of combustion are rapidly removed.
>
> "The products of combustion are discharged through a water-cooled reentrant throat at the rear of the cyclone into the boiler furnace. The part of the molten slag which adheres to the cyclone walls, or impacts on the boiler target, flows toward the rear of the cyclone and is discharged through a tap hole into the boiler furnace. Slag is tapped into a slag tank, solidified, and disintegrated for disposal. The part of the molten slag which does not adhere to the cyclone walls is discharged with the combustion gases into the boiler furnace.
>
> "The fundamental difference between cyclone furnaces and pulverized coal-fired furnaces is the manner in which combustion takes place. In pulverized coal-fired furnaces, the particles of coal move along with the gas stream, and relatively large furnaces are required to complete the combustion of the suspended fuel. With cyclonic firing, the coal is held in the cyclone, and the air is passed over the fuel. Thus, large quantities of fuel can be fired and combustion completed in a relatively small volume. The boiler furnace (boiler volume outside of cyclone furnace proper) is used to cool the

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[5]Kessler, G. W. Cyclone Furnace Boilers. The Babcock and Wilcox Company. (Proceedings of the American Power Conference, 1954). New York, New York. pp. 78-90.

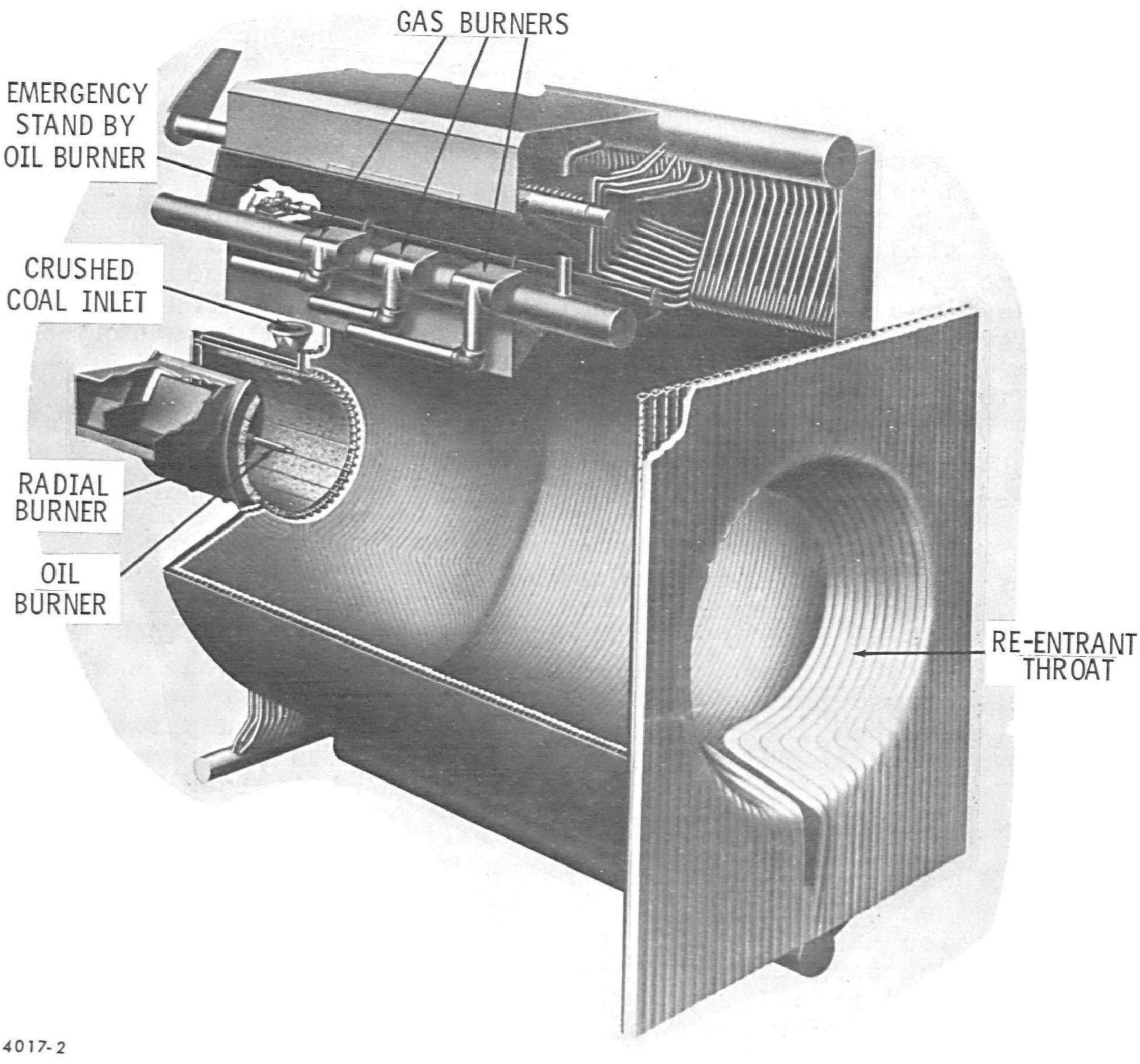

Figure 2. The cyclone furnace.[3]

products of combustion, and since the temperatures are high (3000°F), high heat release rates are observed."

Figure 3 gives a better view of the primary and secondary air inlets which cause the great degree of swirl turbulence within the cyclone.[3] The oil burner is normally retracted after startup when burning coal.

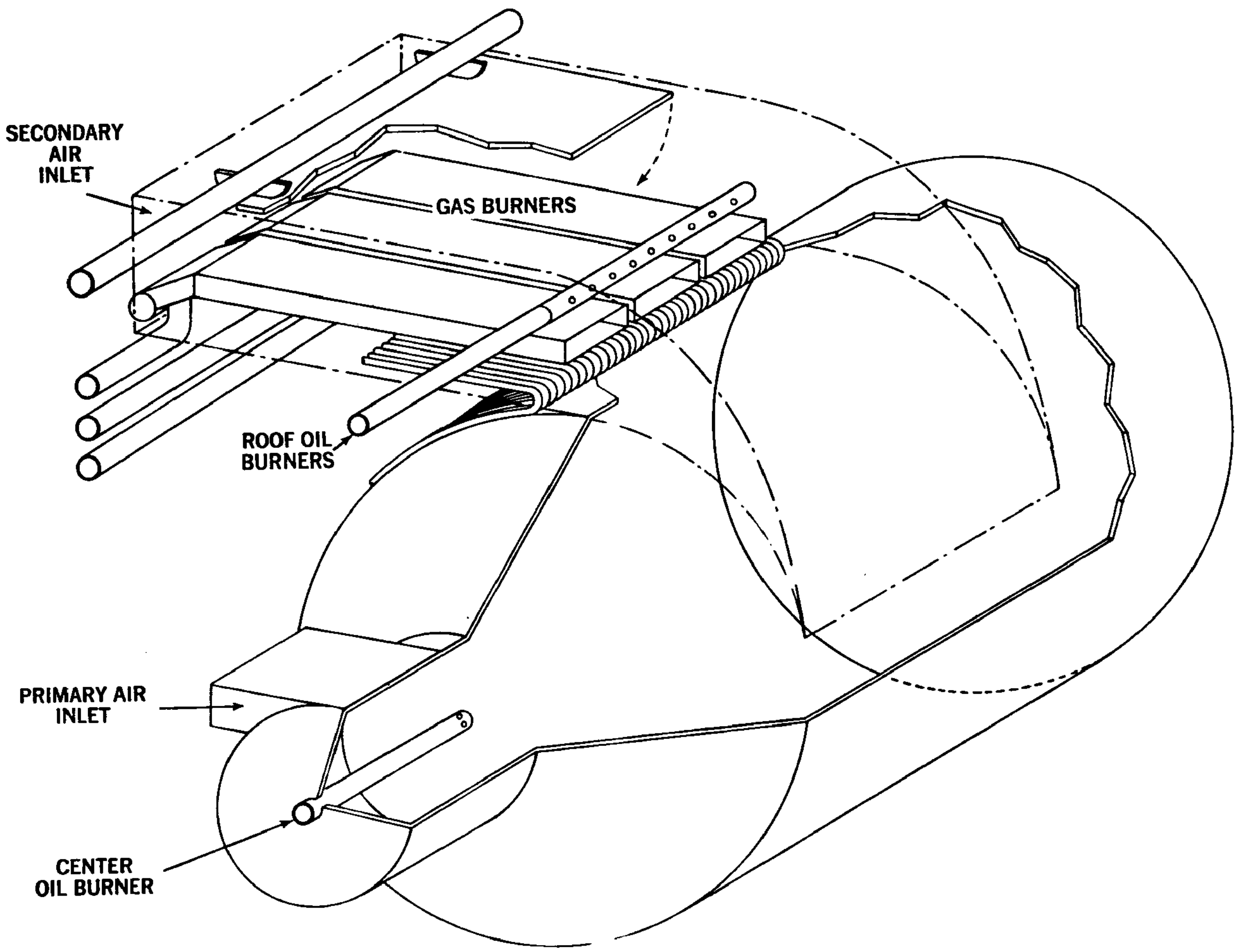

Figure 3. Furnace schematic.[3]

Two views[4,6] of existing cyclone furnaces are shown in Figures 4 and 5. Figure 4 shows an interior rear view of a cyclone furnace with a normal accumulation of slag deposits (solidified). Figure 5 shows a view of the cyclone furnace discharge throat (at right) and boiler target (at left).

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[6]Grunert, A. E., L. Skog, and L. S. Wilcoxson. The Horizontal Cyclone Burner. Transactions of the ASME, 69:613-634, August 1947.

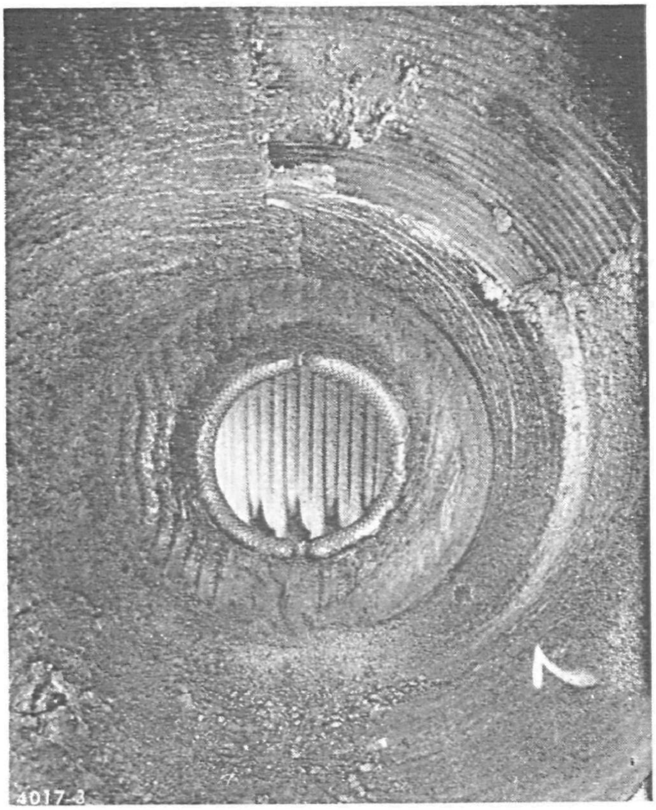

Figure 4. Interior rear view of cyclone furnace.[6]

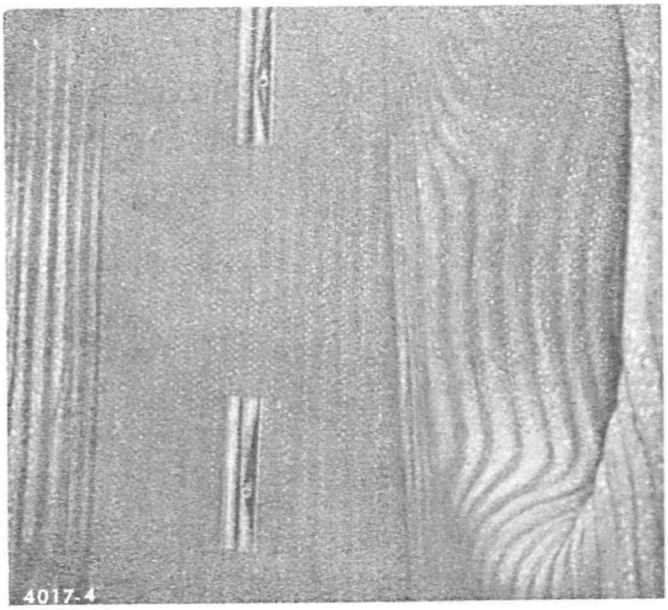

Figure 5. Cyclone furnace throat (right) and attached boiler target (left).[5]

3.1.2 Cyclone Furnace/Boiler Arrangements

The part of the steam-generating unit downstream of the primary cyclone furnace but upstream of the main heat transfer surface is called a secondary furnace or a boiler furnace. The cyclone furnace is attached to the steam generating boiler in one of two ways. Figure 6 shows the two possibilities.[5] The configuration on the left is called the screened furnace. It consists of a slag screen of tubes dividing the boiler furnace into upper and lower sections. The slag screen divides the boiler furnace into the primary and secondary components. The second arrangement is the open furnace, which has no dividing tubes. Either arrangement may be found in existing installations. Space limitations and heat transfer area required generally dictate which configuration is used. In the screened furnace, the fly ash loading of the flue gases will be about 10% of the total ash fired in contrast to 15% for the open furnace.[4]

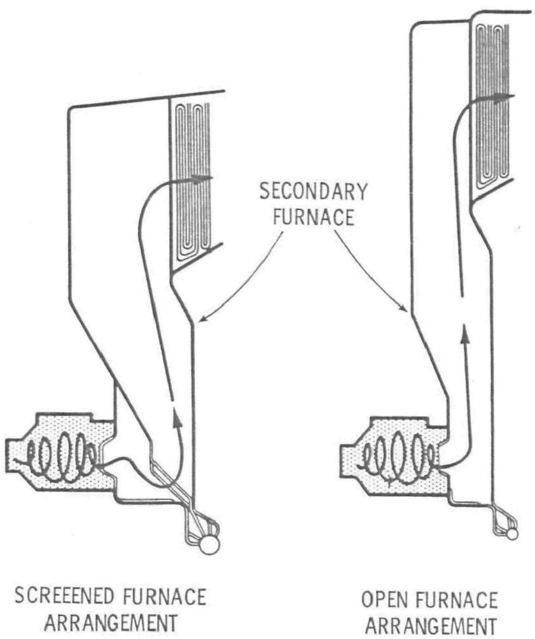

Figure 6. Furnace arrangements for cyclone-type primary furnaces.[7]

One or more cyclone furnaces may be used to fire a single boiler to achieve the heating capacity desired. Two general firing arrangements are used, namely, one-wall firing and opposed firing. A schematic of the firing arrangements is shown in Figure 7 using open furnaces.[2] The furnaces may also be stacked one on top of another to obtain sufficient firing capacity.

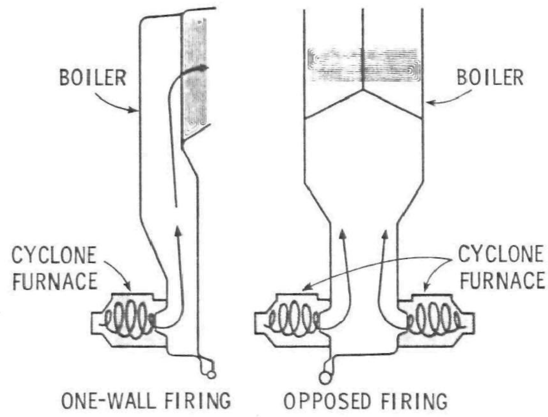

Figure 7. Schematic of boiler-firing arrangements using cyclone furnaces.[2]

3.1.3 Auxiliary Equipment

A variety of auxiliary equipment supports the operation of cyclone-fired boiler units. This support equipment includes:

- Coal preparation system and feeding arrangement
- Slag handling equipment
- Ash recovery and dust collectors
- Combustion controls

Each category is described in the following subsections.

3.1.3.1 Coal Preparation and Feeding--

B&W describes the types of coal preparation and feeding systems used:[2]

> "There are two general types of coal preparation and feeding (see Figure 8), the bin or storage system and the direct firing system. The former is preferred for most bituminous coals when the plant layout permits. The range of sizing of crushed coal required with either system is given in Figure 9.
>
> "With the bin system, coal is crushed in a central preparation plant to a size suitable for firing, and the crushed coal is delivered to the bunker. Because the crushed coal is relatively large in particle size, the hazards associated with pulverized coal systems do not exist. The only precaution necessary is to provide adequate venting of the bunkers to assure removal of the small amounts of combustible gases released from freshly mined coal of certain types. With the bin system, there is less equipment in the boiler room,

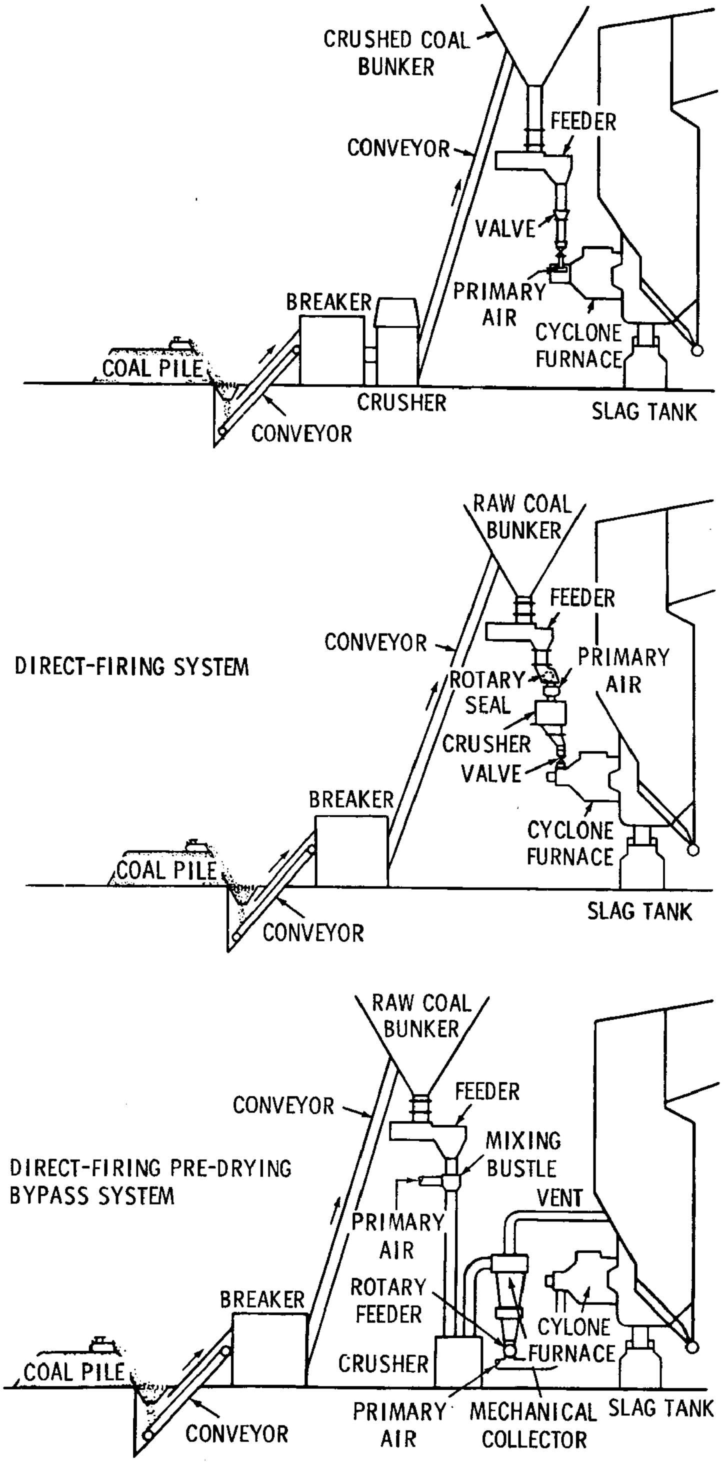

Figure 8. Bin, direct-firing, and direct-firing predrying bypass systems for coal preparation and feeding to the cyclone furnace (schematic).[2]

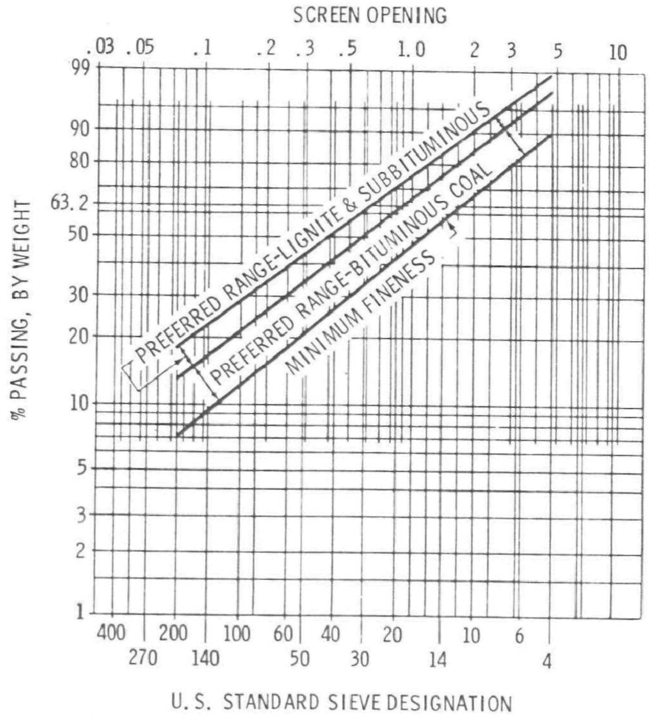

Figure 9. Sizing of crushed coal fired in the cyclone furnace.

and short crusher outages can be accommodated without interrupting boiler operation.

"The second method of coal preparation is the direct firing system, which has a separate crusher located between the feeder and the burner of each cyclone furnace. The crusher is swept by hot air, and the intimate mixing of coal and hot air in the crusher helps to dry the coal. This improves crusher performance and ignition with high moisture coals. It is often easier to accommodate the direct firing system in existing plants, where the coal handling equipment cannot readily be adapted to the bin system.

"The direct firing, predrying bypass system (Figure 8) is a variation of the second method, incorporating a mechanical dust collector between the crusher and the cyclone furnace. The collector is vented to the boiler furnace. This system is used when firing extremely high moisture coals. Its advantage is that moisture is removed from the coal during crushing and then vented to the boiler furnace instead of the cyclone furnace. This maintains maximum temperature in the cyclone with improved performance and slag tapping characteristics.

"The coal feeders normally used are of the belt type, illustrated in Figure 10.[2] A rotating distributor is provided at the coal discharge from the feeder to assure a continuous and uniform rate of feed. This is necessary because the coal is burned almost instantaneously when it reaches the cyclone furnace, and fluctuations in feed are reflected in combustion conditions. The rapidity of combustion makes the cyclone furnace very responsive to load demands, and it has been demonstrated that boiler output can be made to respond very quickly to demand by changing coal-feeder speed. Continuous weighing devices can be applied to the belt feeder so that it can serve the dual function of coal scale and feeder.

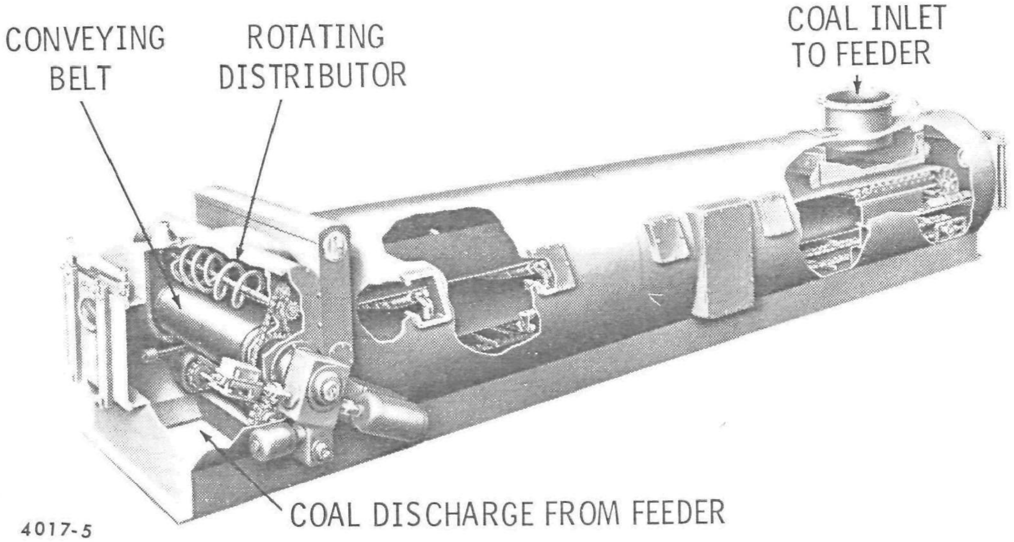

Figure 10. Belt-type coal feeder for the cyclone furnace.[2]

"Feeders of other types may also be used. Some are equipped with an angled cutoff plate at the coal discharge from the feeder to provide a uniform rate of feed."

3.1.3.2 Slag Handling--
A slag handling system for cyclone-fired boiler units is shown in Figure 11.[2] Newkirk describes the operation of the Dow Chemical Company's slag taps and ash pits which is a typical facility:[7]

"The slag is discharged from the secondary furnace to a slag chamber on each side of the furnace. Here it is

[7]Newkirk, M. Cyclone-Fired Pressurized Steam Generator. Transactions of the ASME, Journal of Engineering for Power, 73:215-223, 1951.

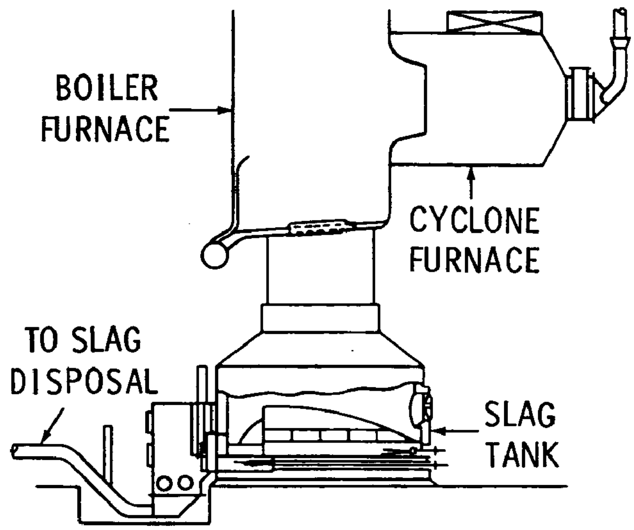

Figure 11. Batch-removal slag-handling system for cyclone-furnace boiler.

> swept by a stream of hot gases, maintaining a liquefied state, to the point where the ash is deposited in circulated cool water through a water screen which expedites the diffraction. The slag is distributed by propeller agitation to three hopper bottoms. The ejection of the ash is by oscillating hydrojets with upstream hydrojets to help. The ash is ejected through a water-operated slide gate directly to grinder--to sump--to ash pump--to fill. In the new units, it is deposited through a pressure door to a sluiceway--to an ash pit for deposition."

Besides batch systems for removing slag from the furnaces, many installations employ a continuous method of slag removal. After the slag is quenched with water, it is removed immediately by means of a conveyor belt to the disposal facility.

3.1.3.3 Fly Ash Control and Handling--
Cyclone firing produces a stack dust highly concentrated in fine material (approximately 85% is less than 10 microns in diameter). Electrostatic precipitators are most commonly used to collect this dust efficiently. Disposal of the fines collected is difficult because it is poor landfill material. As a result, it is reinjected into the cyclone furnace and converted into more easily disposable slag.

3.1.3.4 Combustion Control--
A cyclone-fired boiler unit is very adaptable to automatic combustion control. B&W describes the control criteria:[2]

"Automatic combustion controls for cyclone-furnace boilers are generally based on maintaining equal coal weights and equal total air flows in the proper proportion to each cyclone furnace. Where volumetric-type feeders are used, equal coal weights are obtained by maintaining equal feeder speeds. Where gravimetric-type feeders are used, they measure and control the coal weights to the cyclone furnaces.

"Combustion air flow is measured separately to each cyclone. Where individual ducts supply combustion air to individual cyclones, a venturi throat in each duct measures the air to each cyclone. Where cyclones are installed in a common windbox, secondary air flow is measured at the bell-mouth section of the secondary air port of each cyclone, then added to the primary and tertiary air flows of that cyclone. These flows are measured at orifices in the individual ducts.

"Using these measurements, the controls maintain equal coal rates and air flows to each cyclone furnace. The overall excess air is controlled in the usual manner with a boiler meter based on steam flow and air flow. Oxygen recorders are usually provided as operating guides to monitor the controls."

3.1.4 Examples of Cyclone-Fired Boiler Installations

Figure 12 gives a sectional view of boiler unit No. 20-A at the Calumet Station of Commonwealth Edison Company in Chicago, Illinois.[6] This unit, incidentally, was the first cyclone-fired coal-burning installation and went onstream in September 1944. The unit generates 18.9 to 22.7 kg/s of steam (150,000 to 180,000 lb/hr). Design pressure of this boiler is 4.14×10^6 Pa (600 psi) with temperatures reaching 755 K (900°F) in the superheater. It was originally designed to burn low-grade Central Illinois coal. Table 1 describes the equipment contained in unit No. 20-A.[6] This installation utilizes one cyclone furnace of the one-wall screened furnace arrangement. This boiler unit is operational but is presently fired with natural gas rather than coal.

Another example of cyclone-fired installations is the Philo-6 unit owned by the Ohio Power Company. Unlike the Calumet installation, it is a supercritical steam unit. The supercritical steam generator increases the thermal efficiency of the steam turbine through the use of higher initial boiler pressure and multiple reheat stages. The Philo-6 has throttle conditions of 31.0×10^6 Pa (4,500 psi) at 894 K (1150°F) with two reheats of 7.9×10^6 Pa (1143 psi) at 839 K (1050°F) with 1.3×10^6 Pa (192 psi) at 811 K (1000°F).[3] The boiler is fired with three cyclone furnaces in a one-wall, screened furnace arrangement.

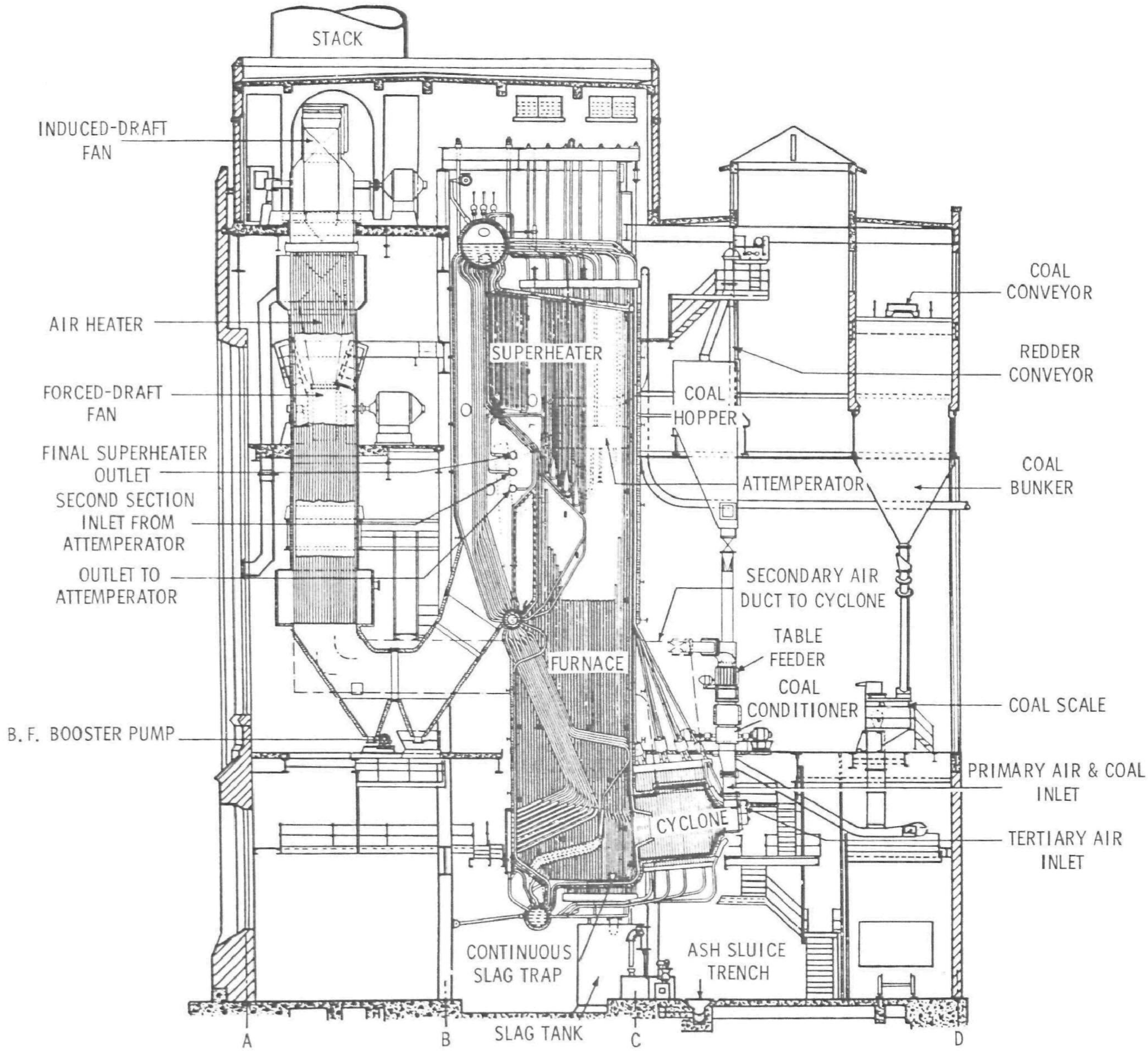

Figure 12. Sectional side view of boiler unit No. 20-A, Calumet Station, Commonwealth Edison Company, Chicago, Illinois, with horizontal-cyclone-burner firing.[6]

TABLE 1. DESCRIPTION OF EQUIPMENT; UNIT NO. 20-A, CALUMET STATION[6]

Boiler type. . . . . .B&W radiant water tube

Furnace

Dimensions: Plan. . . . 4.57 m x 2.74 m (15 ft x 9 ft) below 0.58 m (23 in) drum, 3.58 m x 2.74 m (11 ft 9 in x 9 ft) above 0.58 m (23 in) drum

Volume . . . . .178.4 m^3 (6,300 cu ft)

Secondary-furnace-wall construction. . .Rear wall tubes below intermediate 0.58 m (23 in) drum; side-wall and front-wall tubes are 8.3 cm (3 1/4 in) centers

Floor. . . . . Bailey block construction

Following sections are full-stud construction. . .Front wall below reflecting arch over cyclone discharge; side walls under reflecting arch, and also to approximately the top of the lower section of platen tubes, and the rear wall from the furnace floor to approximately the top of the lower section of platen tubes. The remaining wall sections have flat-stud construction.

Reflecting arch construction. . . .Tubes 8.3 cm (3 1/4 in) OD, slag-screen section fully studded and on 34.3 cm (13 1/2 in) centers. Baffle section fully studded and arch section studded only on side facing floor are spaced on 11.4 cm (4 1/2 in) centers. Remaining section above arch, bare tubes on 34.3 cm (13 1/2 in) centers

Platen tube construction. . .Tubes 8.3 cm (3 1/4 in) OD, spaced on 34.3 cm (13 1/2 in) centers. Lower section, fully studded. Remaining section, bare tube

Cyclone-burner construction. . . . Burner walls 3.8 cm (1 1/2 in) OD fully studded tubes on 5.7 cm (2 1/4 in) centers. Portion of tube section at secondary air inlet bare with blocks welded between tubes for smooth air entry. Each tube made in two semicircular sections of 2.44 m (8 ft) diam. Rear wall and throat formed by fully studded front-wall tubes of secondary furnace. Slag-tap opening in bottom rear wall. Inlet cone at front of cyclone, 3.8 cm (1 1/2 in) OD tubes on 4.8 cm (1 7/8 in) centers, bare tubes with blocks welded on tubes for wear surface. Burner axis slopes 8.73 x 10^{-2} rad (5 deg) toward discharge end of furnace.

Superheater type . . . . .Convection, continuous-tube, pendant

Air heater type. . . . . . . Vertical-tubular type enclosed in circular casing

Effective heating surface	m^2	ft^2
Boiler	755.2	8,129

(continued)

TABLE 1 (continued).

Effective heating surface	m^2	ft^2
Furnace side walls	182.0	1,959.5
Furnace front walls	95.6	1,029
Furnace rear walls	33.5	360.5
Furnace platens	132.7	1,428
Cyclone burner	29.4	316
Superheater, primary	349.6	3,763
Superheater, secondary	418.7	4,507
Attemperator	47.2	508
Desuperheater	47.2	508
Air heater	2,633	28,346

Induced-draft fan

Type . . . . American blower

Capacity . . . . . 61.4 m^3/s (130,000 cfm) at 450 K (350°F), 2.24 kPa (9 in) static pressure

Drive. . . . . . . Two-speed motor, 360 and 705 rpm, 261 kW (350 hp), 2300 V

Volume and pressure control. . . . . .Damper on discharge duct

Forced-draft fan

Type . . . . B. F. Sturtevant Co., No. 250, 365 compressor

Capacity . . . . . .28.3 m^3/s (60,000 cfm) at 300 k (80°F), 15.4 kPa (62 in) static pressure at 3557 rpm

Drive. . . . . .Constant speed, 746 kW (1000 hp), 2300 V

Volume and pressure control. . . . . Adjustable inlet vane

Raw-coal scales

Type . . . . .Richardson automatic

Capacity . . . . .136 kg (300 lb) per dump--2.3 kg/s (9 tons/hr)

Boiler conveyor

Capacity . . . . 3.8 kg/s (15 tons/yr)

Feeder

Type . . . . B&W table

(continued)

TABLE 1 (continued).

Capacity	3.1 kg/s (12 1/2 tons/yr)
Drive	Variable-speed, d-c motor
Coal crusher (Original design, 24 in diam)	
Type	B&W hammer
Capacity	3.1 kg/s (12 1/2 tons/hr)
Crusher speed	1140 rpm
Number of hammers	30
Classifier	Perforated plate
Coal crusher (Second design, 48 in diam)	
Type	B&W hammer
Capacity:	
Crusher speed	Variable
Number of hammers	240
Classifier	Grid

The three-cyclone boiler unit is designed to produce 85 kg/s of steam (675,000 lb/hr).

Figure 13 illustrates the general layout of the Philo-6 installation.[4] The supercritical steam unit design is not typical of the cyclone boiler population since only about seven supercritical units are in operation. The Calumet installation is more representative of the units in operation.

3.1.5 Fuel Requirements

3.1.5.1 Coal--

The cyclone furnace was developed to burn a particularly troublesome Illinois coal. Table 2 gives typical analysis data for this coal.[8] This is a high-ash content, low-ash fusion temperature coal which is rather difficult to burn in stokers or dry-bottom pulverized coal units.

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[8]Stone, V. L. and I. L. Wade. Operating Experiences with Cyclone-Fired Steam Generators. Mechanical Engineering. 74:359-368, 1972.

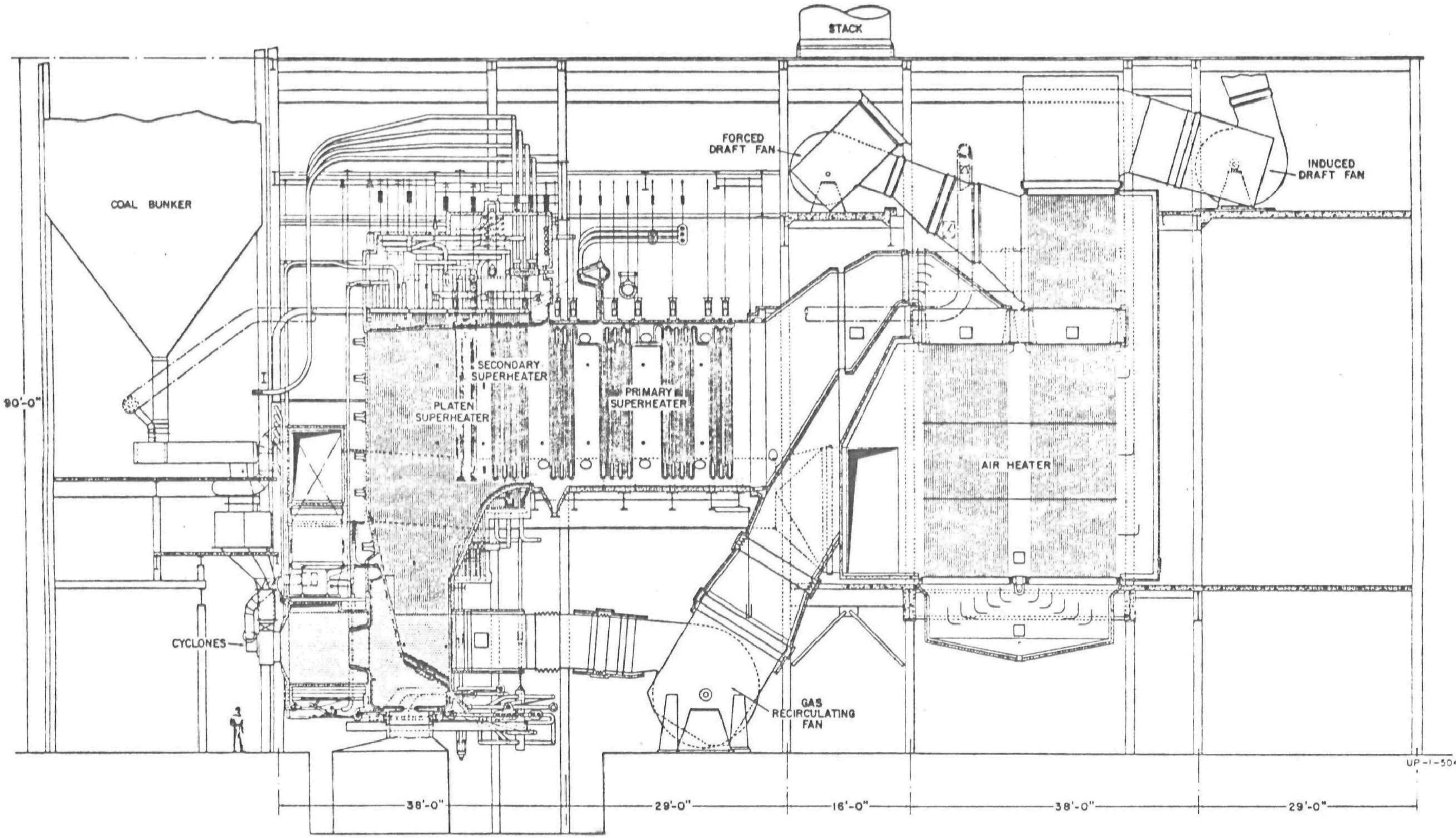

Figure 13. Philo-6 once-through supercritical Benson boiler installation (Ohio Power Co.).[4]

TABLE 2. TYPICAL ANALYSES OF CENTRAL ILLINOIS COAL AND ASH[8]

Proximate, %	
Moisture	14.0
Volatile matter	34.0
Fixed carbon	37.8
Ash	14.2
TOTAL	100.0
Ultimate, moisture and ash-free, %	
Sulfur	6.48
Hydrogen	5.43
Carbon	77.16
Nitrogen	1.39
Oxygen	9.54
Chloride as NaCl, % on dry basis	0.37
Heating value, as fired, MJ/kg (Btu/lb)	23.4 (10,050)
Ash, % by weight	
Silica, SiO_2	40.43
Alumina, Al_2O_3	19.98
Iron oxide, Fe_2O_3	25.11
Calcium oxide, CaO	5.08
Magnesium oxide, MgO	1.09
Sulfuric anhydride, SO_4	5.19
Phosphorus pentoxide, P_2O_5	0.01
Alkalies, sodium and potassium oxides, Na_2O and K_2O	3.04
Chloride, Cl	0.07
TOTAL	100.00
Water-soluble constituents in ash, % by weight	
Ferrous sulfate, $FeSO_4$	0.30
Sodium sulfate, $NaSO_4$	1.37
Calcium sulfate, $CaSO_4$	4.87
Magnesium sulfate, $MgSO_4$	1.43
Sodium chloride, NaCl	0.05
TOTAL	8.02
Coal ash-fusing temperatures (reducing atmosphere), K (°F)	
Initial deformation	1355 (1980)
Softening	1380 (2025)
Fluid	1555 (2340)

As mentioned previously, the cyclone furnace can also burn a wide variety of other coals. There are, however, some restrictions to the types of coals which can be successfully fired in the cyclone furnace. The key to successful firing is to maintain a noncorrosive and fluid ash state in the furnace throughout the boiler load range. The suitability of coals is thus dependent on the moisture, ash, and volatile contents of the coal together with the chemical composition of the ash.[2]

B&W states that the volatile matter should be higher than 15% (dry basis) to obtain the required high combustion rate. Ash content should be at least 6% to provide a proper slag coating in the furnace and can be as high as 25% (dry basis). A wide range of moisture contents is permissible depending on coal rank, secondary air temperature range for drying, and fuel preparation equipment.[2]

The two most important factors which determine the suitability of a coal for cyclone firing are slag viscosity or fluidity and tendencies of coal to form corrosive iron and iron sulfide. A fluid slag layer in the furnace is desirable for proper combustion (i.e., bulk of coal burns in slag layer), ease of tapping, and minimal ash accumulation. Formation of iron and iron sulfide in the furnace can result in catastrophic tube failure. A further discussion of these two factors is presented below.

Regarding slag viscosity, B&W indicates that it must be 25 Pa•s (250 poises) or below at a temperature of 1700 K (2600°F). In addition, the ash softening temperature must be 1600 K (2500°F) or below when tested in a reducing atmosphere. The ash softening point is that temperature at which an ash cone when heated has fused down to a spherical lump (as per American Society for Testing Materials--ASTM Standard Method D-1857).

Hot melt slag viscosity is often determined with a special viscometer. When hot melt slag viscometer data are not available, a useful correlation developed by Hay and Roberts can be used.[9] This correlation obtains a relative indication of slag viscosity at 1700 K (2600°F) based on ash composition.

The correlation states that if the Equivalent Silica Content (often called Silica Ratio) is below a value of 72, the coal will have a viscosity below 25 Pa•s (250 poises) at 1700 K (2600°F). The Equivalent Silica Content (ESC) is defined as:

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[9]Lowry, H. H. (ed). Chemistry of Coal Utilization. Supplementary volume, prepared by the committee on Chemistry of Coal, Division of Chemistry and Chemical Technology, National Academy of Sciences - National Research Council. John Wiley and Sons, Inc., New York, New York, 1963. 1,142 pp.

$$ESC = \frac{SiO_2 \times 100}{SiO_2 + Fe_2O_3 + MgO + CaO} \quad (1)$$

where SiO_2 = weight percent of SiO_2 in coal ash
Fe_2O_3 = weight percent of equivalent Fe_2O_3 in coal ash
MgO = weight percent of MgO in coal ash
CaO = weight percent of CaO in coal ash
ESC = Equivalent Silica Content, %

Slagging tests performed by B&W on coals for cyclone furnaces indicate that a wide range of coals meet the viscosity criteria. Figure 14a shows the results of these tests.[5] However, to be truly suitable, the coal must not have a marked tendency to form iron and iron sulfide. Figure 14b indicates[2] that the coal ash Fe_2O_3/(CaO + MgO) ratio (termed CAR) and the percent sulfur in coal are most important in determining this tendency. Corrosion is discussed in more detail in Section 3.1.6.

Table 3 lists analysis data[10] for five coals typically suited for firing in cyclone furnaces. These coals meet the two most important criteria (low slag viscosity and minimal corrosion tendencies) as well as the other related suitability factors (ash, volatile matter, and moisture content). Table 4 gives the range of proximate analyses of coals which have been successfully fired in cyclone furnaces.[2]

In summary, criteria were presented which indicate the general suitability of a coal for cyclone firing. A suitable analysis alone is necessary but not sufficient to determine the combustion characteristics of a specific coal. In practice, once a coal is judged suitable, it then undergoes boiler firing tests which determine operating difficulties. Examples of difficulties that might be encountered when changing to a suitable western coal include: high combustible carbon carryover as a result of poor combustion; need for increased coal feeding and drying capacity; and increased crusher wear due to higher coal rates.

3.1.5.2 Other Fuels--
Natural gas and residual or crude oils are the most commonly used alternate fuels in cyclone fired boilers. Wood bark, coal chars, petroleum coke, and fuel oil may also be satisfactorily fired if economics or other needs dictate. No actual instances of these types of firings were found in the literature. Bark, chars, coke, and certain coals may require supplemental fuel for successful firing. Firing fuels other than coal in cyclone furnaces is not normally competitive with other firing methods unless coal is the principal fuel.[2]

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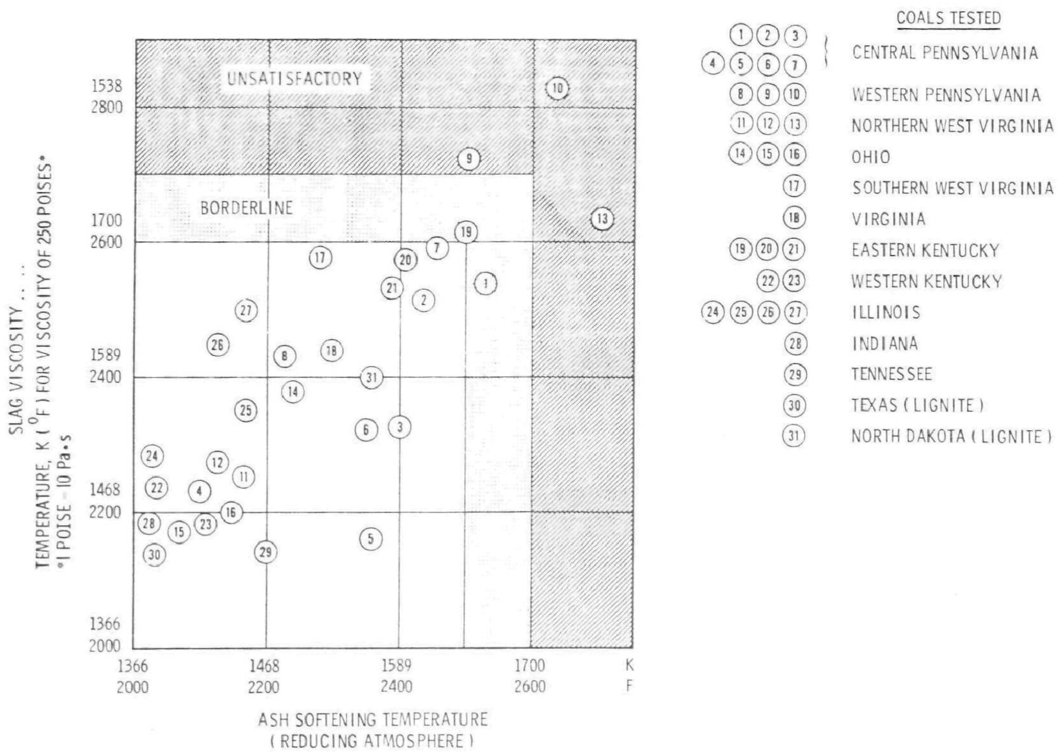
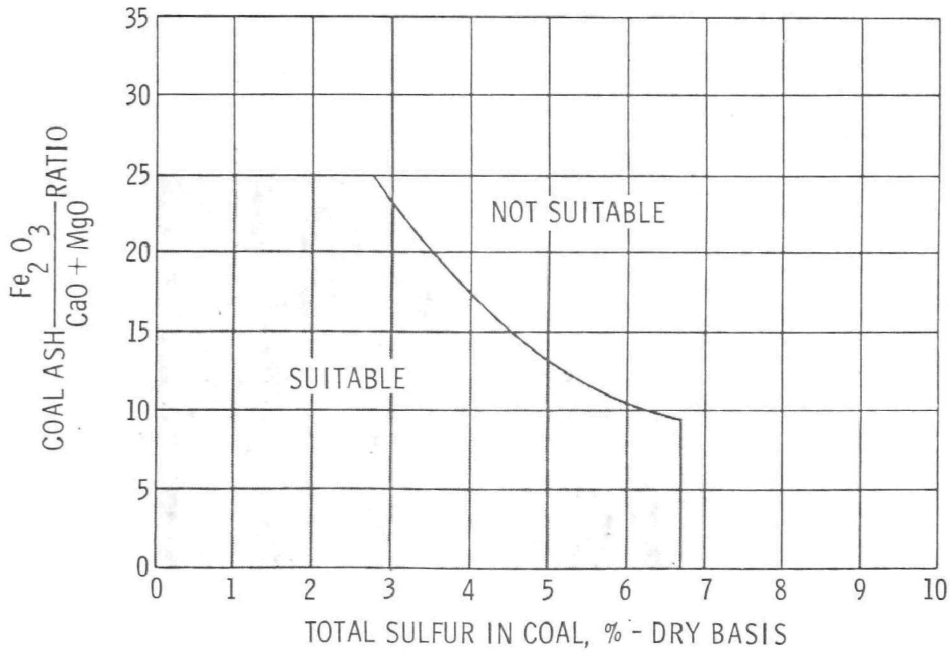
[10]Selvig, W. A. and F. H. Gibson. Analyses of Ash from United States Coals. Bull. No. 567. Bureau of Mines, U.S. Department of the Interior. 1956. 33 pp.



(a) Results of slagging tests of coals for cyclone furnaces[5] (590 K combustion air temperature).



(b) Coal suitability for cyclone furnaces based on tendency to form iron and iron sulfide.[2]

Figure 14. Coal suitability factors.[2,5]

TABLE 3. TYPICAL COALS SUITABLE FOR CYCLONE FIRING[10]

State	Illinois	Montana	North Dakota	Pennsylvania	Kentucky
County	Williamson	Carbon	Mercer	Fayette	Muhlenberg
Bed	No. 6	No. 3	Zap	Pittsburgh	Nos. 9 and 11
Mine	No. 12	North Side	Indian Head	Banning No. 2	Mixture from two mines
Rank	Bituminous	Subbituminous	Lignite	Bituminous	Bituminous
Heating value, MJ/kg (Btu/lb)	26.2 (11,260)	25.7 (11,030)	16.9 (7,250)	31.4 (13,520)	26.6 (11,440)
Ash softening temperature, K (°F)[a]	1,405 (2,070)	1,400 (2,060)	1,528 (2,290)	1,466 (2,180)	1,389 (2,040)
Equivalent silica content (ESC)[a]	63.0	47.0	31.0	62.0	60.0
Coal ash ratio (CAR)[a]	2.30	1.30	0.60	4.40	3.10
Sulfur, wt %	3.60	1.70	1.00	2.20	3.90
Proximate analysis, wt % (as received basis)					
Moisture[a]	9.60	10.1	33.6	1.90	6.10
Volatile matter[a]	33.4	34.5	28.4	33.5	36.1
Fixed carbon	44.4	46.7	31.1	54.8	43.6
Ash	12.6	8.70	6.90	9.80	14.2
Ash (moisture free)[a]	13.9	9.70	10.3	10.0	15.2
Ash analyses, wt %					
SiO_2	41.2	30.7	17.5	43.4	44.0
Al_2O_3	15.9	19.6	9.90	24.0	18.3
Fe_2O_3	23.1	18.9	15.0	21.2	21.7
TiO_2	0.80	1.10	-	1.10	0.90
P_2O_5	0.12	-	-	0.30	0.34
CaO	9.40	11.3	17.8	4.10	6.20
MgO	0.40	3.70	5.60	0.70	0.80
Na_2O	0.60	1.90	-	0.90	-
K_2O	1.90	0.50	-	0.80	-
SO_3	7.40	12.2	28.3	3.70	6.4

[a]Relates to coal suitability.

TABLE 4. RANGE OF COAL ANALYSES[2]

Component	Percent by weight
Moisture	2 to 40
Volatile matter (dry)	18 to 45
Fixed carbon (dry)	35 to 75
Ash (dry)	4 to 25

Typical compositions and heating values for natural gas and oils are shown in Tables 5 and 6, respectively.[2,11] Residual oil with low sulfur and low vanadium contents is normally desired so as to minimize boiler corrosion. Fuel oil is not commonly used due to its high cost.

Wood bark may also be burned in the cyclone furnace. The analyses and heating value of bark varies significantly. Table 7 gives some typical analyses of wood bark and ash.[2]

Char, the nonvolatile portion of coal which results from certain gasification processes, can be successfully burned in cyclone furnaces. Table 8 gives analyses of chars from coal conversion processes.[11]

Petroleum coke can also be burned in cyclone furnaces. Table 9 gives a typical range of analyses for the two most commonly occurring petroleum cokes which originate from the delayed coke process and the fluid coke process.[12]

3.1.6 Corrosion

The cyclone furnace boiler unit does not appear to exhibit any unusual or peculiar corrosion characteristics. The axially fired furnace design combined with the studded furnace wall sections are the furnace characteristics to which low tube corrosion rates are usually attributed. The integrity of the studded furnace wall sections indicate when preventive furnace maintenance is to be performed. However, furnace tube wastage as well as superheater and reheater tube corrosion has occurred in several installations. It is reasonable at this point to discuss corrosion characteristics of cyclone furnaces because of the possible connection between corrosion and combustion modifications for NO_x control.

[11] Perry, R. H. and C. H. Chilton (eds). Chemical Engineers' Handbook. 5th edition. McGraw-Hill Book Company, New York, New York, 1973. 1,650 pp.

[12] Perry, R. H., C. A. Chilton, and S. O. Kirkpatrick (eds). Chemical Engineers' Handbook, 4th edition. McGraw-Hill Book Company, New York, New York, 1963. 1,650 pp.

TABLE 5. SELECTED SAMPLES OF NATURAL GAS FROM UNITED STATES FIELDS.[2]

	Sample number Source of gas				
	1 Pennsylvania	2 Southern California	3 Ohio	4 Louisiana	5 Oklahoma
Analyses					
Constituents, vol %					
H_2 Hydrogen	-	-	1.82	-	-
CH_2 Methane	83.40	84.00	93.33	90.00	84.10
C_2H_4 Ethylene	-	-	0.25	-	-
C_2H_6 Ethane	15.80	14.80	-	5.00	6.70
CO Carbon monoxide	-	-	0.45	-	-
CO_2 Carbon dioxide	-	0.70	0.22	-	-
N_2 Nitrogen	0.80	0.50	3.40	5.00	8.40
O_2 Oxygen	-	-	0.35	-	-
H_2S Hydrogen Sulfide	-	-	0.18	-	-
Ultimate, wt %					
S Sulfur	-	-	0.34	-	-
H_2 Hydrogen	23.53	23.30	23.20	22.68	20.85
C Carbon	75.25	74.72	69.12	69.26	64.84
N_2 Nitrogen	1.22	0.76	5.76	8.06	12.90
O_2 Oxygen	-	1.22	1.58	-	1.41
Specific gravity (relative to air)	0.636	0.636	0.567	0.600	0.630
Higher heat value					
MJ/m^3 [a]	42.1	41.6	35.9	37.4	36.3
Btu/cu ft [b]	1,129	1,116	964	1,002	974
MJ/kg of fuel	53.9	53.3	51.4	50.8	46.9
Btu/lb of fuel	23,170	22,904	22,077	21,824	20,160

[a] 289 K, 101.3 kPa

[b] 60°F, 30 in. Hg

TABLE 6. TYPICAL ULTIMATE ANALYSES OF PETROLEUM FUELS[11]

Composition, %	No. 1 fuel oil (41.5° A.P.I.)	No. 2 fuel oil (33° A.P.I.)	No. 4 fuel oil (23.2° A.P.I.)	Low sulfur, No. 6 fuel oil (12.6° A.P.I.)	High sulfur, No. 6 fuel oil (15.5° A.P.I.)
Carbon	86.4	87.3	86.47	87.26	84.67
Hydrogen	13.6	12.6	11.65	10.49	11.02
Oxygen	0.01	0.04	0.27	0.64	0.38
Nitrogen	0.003	0.006	0.24	0.28	0.18
Sulfur	0.09	0.22	1.35	0.84	3.97
Ash	<0.01	<0.01	0.02	0.04	0.02
C/H ratio	6.35	6.93	7.42	8.31	7.62

TABLE 7. ANALYSES OF WOOD AND WOOD ASH[2]

	Pine bark	Oak bark	Spruce bark[a]	Redwood bark[a]
Wood analyses (dry basis), wt %				
Proximate				
Volatile matter	72.9	76.0	69.6	72.6
Fixed carbon	24.2	18.7	26.6	27.0
Ash	2.9	5.3	3.8	0.4
Ultimate				
Hydrogen	5.6	5.4	5.7	5.1
Carbon	53.4	49.7	51.8	51.9
Sulfur	0.1	0.1	0.1	0.1
Nitrogen	0.1	0.2	0.2	0.1
Oxygen	37.9	39.3	38.4	42.4
Ash	2.9	5.3	3.8	0.4
Heating value, MJ/kg (Btu/lb)	21.0 (9,030)	19.5 (8,370)	20.3 (8,740)	19.4 (8,350)
Ash analyses, wt %				
SiO_2	39.0	11.1	32.0	14.3
Fe_2O_3	3.0	3.3	6.4	3.5
TiO_2	0.2	0.1	0.8	0.3
Al_2O_3	14.0	0.1	11.0	4.0
Mn_3O_4	Trace	Trace	1.5	0.1
CaO	25.5	61.5	25.3	6.0
MgO	6.5	1.2	4.1	6.6
Na_2O	1.3	8.9	8.0	18.0
K_2O	6.0	0.2	2.4	10.6
SO_3	0.3	2.0	2.1	7.4
Cl	Trace	Trace	Trace	18.4
Ash fusibility, K (°F)				
Reducing				
Initial deformation	1466 (2180)	1750 (2690)		
Softening	1500 (2240)	1766 (2720)		
Fluid	1539 (2310)	1778 (2740)		
Oxidizing				
Initial deformation	1483 (2210)	1744 (2680)		
Softening	1522 (2280)	1772 (2730)		
Fluid	1561 (2350)	1783 (2750)		

[a]Salt-water stored.

TABLE 8. EXAMPLES OF ANALYSES OF COAL FEEDS AND RESULTING CHARS FROM VARIOUS COAL-CONVERSION PROCESSES.[11]

Process	FMC[a]				IGT[b]	
Coal bed	Pittsburgh-Federal		Illinois No. 6		Pittsburgh	
Composition and properties	Coal, dry basis	Char, dry basis	Coal, dry basis	Char, dry basis	Coal, dry basis	Char, dry basis
Analysis, wt %						
Volatile matter	36.8	3.7	38.6	3.5	32.7	1.2
Fixed carbon	57.0	86.8	50.0	76.4	52.3	77.5
Ash	6.2	9.5	11.4	20.1	14.1	21.3
Sulfur	2.9	1.9	3.8	3.1	4.3	1.7
Heating value, MJ/kg	33.6	31.1	29.3	27.6	30.7	28.4
(Btu/lb)	(14,470)	(13,400)	(12,600)	(11,870)	(13,200)	(12,200)

[a]FMC process involves multistage fluidized-bed pyrolysis of coal to produce a liquid, residual char, and some gas.

[b]IGT process involves hydrogasification of coal to produce a gas of pipe-line quality (about 1,000 Btu/cu ft) and char.

TABLE 9. TYPICAL ANALYSES OF PETROLEUM COKES[12]

	Delayed-process coke, range	Fluid-process coke, range
Volatile, wt %	8 to 13	3.7 to 7.0
Ash, wt %	0.05 to 1.6	0.1 to 2.8
Bulk density, kg/m^3	-	881 to 1,041
True density, kg/m^3	1.28 to 1.42	1,500 to 1,600
Heating value as received,	-	32.3 to 33.5
MJ/kg (Btu/lb)	-	(13,900 to 14,400)
Hydrogen, wt %	-	1.6 to 2.1
Carbon, wt %	-	88 to 95
Sulfur, wt %	-	1.5 to 10.0
Ash-softening temp, K	-	1478 to 1811
Ash-softening temp, °F	-	2200 to 2800

The only available corrosion information was for coal fuel. Corrosion susceptibility of coal-fired units appears to stem not from design or construction flaws but rather from improper fuel selection or boiler operation (sometimes both).

During the course of this study, personnel at both B&W and Commonwealth Edison Company (Chicago), an electric utility operating 20 cyclone boilers, were asked to describe any common corrosion problems. The consensus of opinion was that significant tube corrosion can occur when the furnaces are running at low excess air levels. The localized reducing atmospheres within the furnace aggravate the tendencies of a coal to form iron and iron sulfide. These species then attack the tubes and, if not corrected in time, can cause catastrophic failure. Normally, careful control of combustion conditions alleviates this problem. A bad batch of coal that has inherent tendencies to form iron and iron sulfide can also cause tube corrosion even more rapidly at a low excess air level. Primarily for these reasons, B&W does not support or recommend any NO_x combustion modification that would result in reducing conditions within the furnace.

Dow Chemical Company (Midland, Michigan) has experienced tube failures in its cyclone furnaces, but from a different cause. M. Newkirk of Dow summarizes his findings:[7]

> "The major cause of tube failure in the cyclone has been due to the up and down firing brought about by numerous interruptions of coal feed. This intermittent operation causes a wide variation in temperature which results in expansion and contraction of the cyclone. Consequently, the slag cracks and peels off leaving parts of the throat and the cyclone tubes bare. Since the heat

release in the cyclone burner itself is very great (5.6 MW/m^3 [545,000 $Btu/hr - ft^3$]), extreme heat-transfer is effected in this localized area. The high temperature damages the protective film of iron oxide which, under favorable conditions, covers the inside of the tubes. Any condition which damages the protective film permits corrosion to continue. It is this repetitive process of forming an iron oxide coating that robs the iron from the tubes. When this happens to a limited area, the attack will be localized and eventually will result in tube failure."

Thus, a smooth, continuous firing operation with a minimal number of shutdowns is desirable to avoid catastrophes.

Catastrophic failure of superheater and reheater tubes occurred in both the Ridgeland and Will County Stations of Commonwealth Edison (Chicago, Illinois).[9,13] The high metal temperatures of the superheaters (approximately 1478 K, [2200°F]) combined with the high sulfur content (4.6%) and high alkali content of the coal (0.63% as Na_2O) was determined to be the cause of the severe corrosion. Reduction of gas temperatures and subsequent tube metal temperature along with some minor mechanical modifications reduced the corrosion significantly. Coals having both high ash alkalinity and high sulfur should be avoided when operating at high steam temperatures.

3.1.7 Advantages/Disadvantages of Cyclone Furnaces/Boilers

The cyclone firing method reduces the amount of ash passing through the boiler and results in uniform and complete combustion of the crushed coal. These and other operating advantages of cyclone furnace firing with coal are summarized below:[2,3,5,6]

- Excess air requirement is low (10% to 17%), and carbon loss is low. As a result, full-load boiler efficiency is higher (88% to 90%) than that for stoker (66% to 80%) or pulverized coal-fired units (85% to 88%). Some cyclone units, however, operate with excess air levels as high as 42%. This is so mainly with older boiler units to prevent local reducing conditions and consequent boiler damange.
- The amount of ash going through the flue is about 10% to 15% of that fired compared to 50% to 85% for pulverized coal firing. This ultimately results in

[13]Sedor, P., E. K. Diehl, and O. H. Barnhart. External Corrosion of Superheaters in Boilers Firing High-Alkali Coals. Transactions of the ASME, Journal of Engineering for Power, 82:181-190, 1960.

reduced slag formation on heat absorption surfaces and reduced particulate air pollution.

- Fly ash collected in dust collecting equipment can be reinjected so that all ash removed from the boiler will be a granular, chemically inert slag (as a result of molten slag quenching). This ash consistency is easier to use for landfill.

- Furnace size is reduced because of reduced combustion gas residence time requirements.

- There are savings in the cost of fuel preparation since only crushing is required instead of pulverization.

- The cyclone furnace can handle a wide variety of coals and is easily adapted to firing gas and coal.

- Operation of the cyclone furnace is simple and reliable.

- Stack dust from cyclone furnace boilers is much finer than that from pulverized-coal-fired units. About 85% of the dust from cyclone-fired boilers is less than 10 μm in size compared with about 30% for pulverized units at the same stack loading. Thus, erosion of boiler internals is greatly reduced using cyclone firing.

Along with the decided advantages of cyclone-fired boiler units, there are disadvantages to burning coal in cyclone furnaces besides the high level of NO_x emissions (see Section 3.3). The pressure drop across the cyclone furnace is rather high, ranging from 5.0 to 10.0 kPa (20 to 40 in. of water) depending on load. This requires a rather powerful forced draft fan to maintain the high volume and velocity of secondary air necessary for cyclone combustion. The fan power accounts for over 90% of the total auxiliary power requirement. The auxiliary power requirements for cyclonic firing are less than those of pulverized coal units firing low-grindability (difficult to pulverize), low-heating-value coals, and greater than pulverized units firing high-grindability (less difficult to pulverize), high-heating-value coals.[5] Figure 15 compares auxiliary power requirements of typical cyclone furnace boilers and pulverized dry bottom boiler units as a function of grindability and heating value of coals fed to pulverized units.[2] The decided advantage of cyclone furnace boilers over pulverized dry bottom boilers burning coals with heating values below 22.3 MJ/kg (9,600 Btu/lb) and grindabilities below 50 (Hardgrove Grindability Index) is apparent from Figure 15.

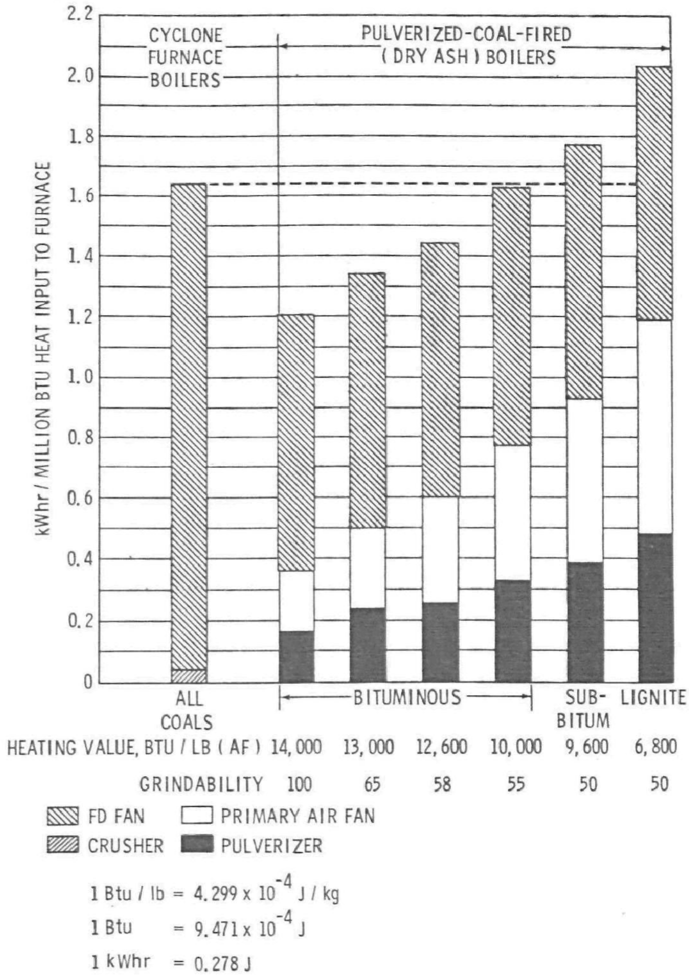


Figure 15. Auxiliary power requirements of typical high-capacity pressure-fired cyclone-furnace and pulverized-coal units.[2]

Holyoak of Commonwealth Edison has described problems encountered when burning western coals in cyclone-fired utility boilers not specifically designed for them.[14] One of the more serious problems encountered has been achieving proper combustion in cyclone-fired boilers. In Holyoak's study, several low-sulfur Montana coals were tested. Very high carbon carryover was experienced when burning straight western coal. Adding 15% to 25% Illinois coal to the western coals somewhat reduced carbon loss.

During initial tests at the Will County Station on Unit 2, Holyoak indicated that only 80% to 90% of full load could be achieved without excessive carbon carryover.[14] Exceeding maximum load in

[14]Holyoak, R. H. Burning Western Coals in Northern Illinois. Commonwealth Edison Company, Chicago, Illinois, ASME Paper 73-WA/FU-4, August 17, 1973. 8 pp.

this unit resulted in carbon carryover so heavy that ash conveying systems could not handle the quantity produced. Ash samples at maximum loads had a heat content of 27.9 MJ/kg (12,000 Btu/lb). Two serious air heater fires and extensive precipitator damage resulted from the high carbon losses.

Holyoak also indicates that load cannot be regulated while burning western coals without bursts of carbon carryover. During load swings, the coal was not burning in the cyclone; it was carried through the cyclone and boiler without burning.

The carbon carryover problems were postulated by Holyoak to be caused by the "nonwetting" characteristics of western coal slag in the furnaces. The cyclone combustion depends greatly on burning the bulk of coal on the sticky slag layer. It is difficult and impractical to increase wettability of western coal slag (Holyoak's conclusion). Equipment changes were made in the boilers to provide more retention time in the cyclone along with better coal fineness and higher temperature to shorten the combustion process.[14]

The 1973 Holyoak study summarized that there were many operating problems and loss of capacity as well as the possibility of major equipment damage from fire or from reducing atmospheres in combustion spaces. Since then, many of the problems evidently have been solved or at least temporarily abated because western coal is the primary fuel in at least four Commonwealth Edison stations (Waukegan, Fisk, State Line, and Joliet).

The fineness of fly ash resulting from cyclone combustion may constitute a serious health hazard. A large fraction of stack dust may be in the respirable size range below 3 μm in diameter. Information or quantitative data on this aspect of cyclone combustion were not available. This subject requires further investigation.

3.2 POPULATION

The first full-scale cyclone-furnace-fired boiler unit was placed on-stream in 1944 at the Calumet Station (Calumet, Illinois) of the Commonwealth Edison Company based in Chicago, Illinois. Since then, a total of 84 cyclone-fired installations have been built in the United States. These installations are located in 26 states and contain a total of 149 boiler units fired by a total of 736 cyclone furnaces generating approximately 26,000 kg/s of primary steam (2 x 10^8 lb/hr). Figure 16 shows the geographical distribution of boiler units and indicates that the bulk of boilers and primary steaming capacity are in the states of Illinois, Missouri, and Indiana. These three states account for nearly half of the total cyclone steaming capacity and one-third of the boilers.

Table 10 gives a further breakdown of cyclone-fired boiler population. It shows that over 94% of the total primary steaming

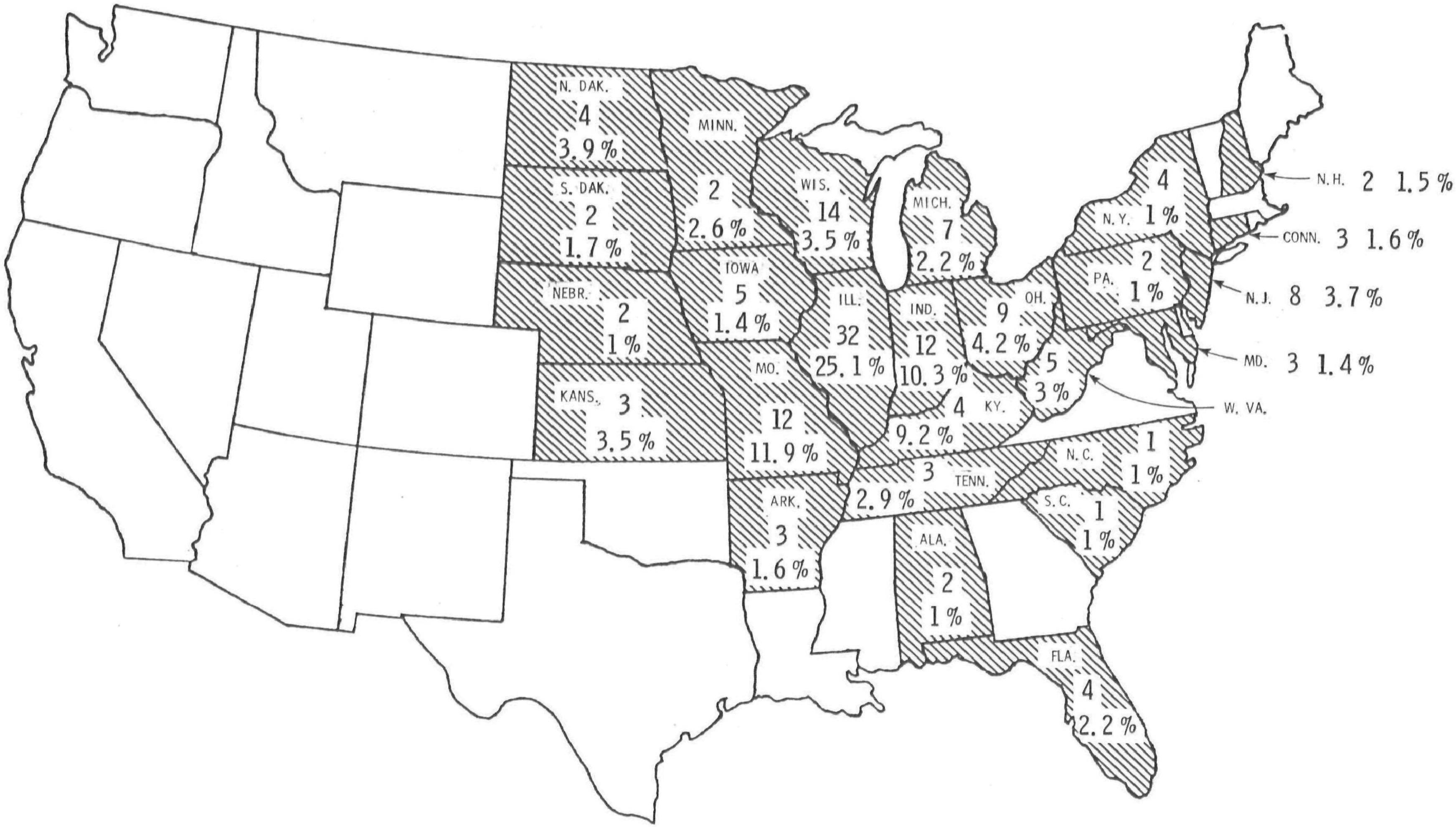


Figure 16. States with cyclone-fired boiler units showing number of boilers and percent of total U.S. primary cyclone steaming capacity (149 boilers generating 2.6×10^4 kg/s steam (data courtesy of the Babcock & Wilcox Co.).

TABLE 10. STATE-BY-STATE POPULATION DISTRIBUTION OF CYCLONE-FIRED BOILERS[a]

State	Electric utility units: Number of boilers	Number of cyclones	Primary steam flow, kg/s	Percent of total	Industrial and commercial units: Number of boilers	Number of cyclones	Primary steam flow, kg/s	Percent of total	Total number of boilers	Total number of cyclones	Total primary steam flow, kg/s	Percent of U.S. total
Alabama	0	0	0.0	0.0	2	4	113.4	7.8	2	4	113.4	0.4
Arkansas	1	8	289.8	1.2	2	4	113.4	7.8	3	12	403.2	1.6
Connecticut	3	13	425.3	1.7	0	0	0.0	0.0	3	13	425.3	1.6
Florida	4	14	539.4	2.2	0	0	0.0	0.0	4	14	539.4	2.2
Illinois	33	196	6,454.2	26.6	0	0	0.0	0.0	33	196	6,454.2	25.1
Indiana	10	56	2,551.4	10.5	2	2	46.6	3.2	12	58	2,598.0	10.3
Iowa	3	9	290.5	1.2	2	3	76.3	5.2	5	12	366.8	1.4
Kansas	3	22	906.4	3.7	0	0	0.0	0.0	3	22	906.4	3.5
Kentucky	4	54	2,375.1	9.8	0	0	0.0	0.0	4	54	2,375.1	9.2
Maryland	2	8	342.6	1.4	1	1	15.8	1.1	3	9	358.4	1.4
Michigan	1	7	264.6	1.2	6	12	307.4	21.1	7	19	572.0	2.2
Minnesota	2	17	673.5	2.8	0	0	0.0	0.0	2	17	673.5	2.6
Missouri	12	79	3,058.7	12.6	0	0	0.0	0.0	12	79	3,058.7	11.9
Nebraska	2	6	195.2	0.8	0	0	0.0	0.0	2	6	195.2	0.8
New Hampshire	2	10	392.5	1.6	0	0	0.0	0.0	2	10	392.5	1.5
New Jersey	7	28	931.6	3.8	1	1	27.1	1.8	8	29	958.7	3.7
New York	0	0	0.0	0.0	4	8	220.5	15.1	4	8	220.5	0.8
North Carolina	0	0	0.0	0.0	1	1	18.9	1.3	1	1	18.9	0.1
North Dakota	4	43	1,003.5	4.1	0	0	0.0	0.0	4	43	1,003.5	3.9
Ohio	7	29	943.9	3.9	2	4	124.1	8.5	9	33	1,068.0	4.2
Pennsylvania	0	0	0.0	0.0	2	5	100.8	6.9	2	5	100.8	0.4
South Carolina	0	0	0.0	0.0	1	2	37.8	2.6	1	2	37.8	0.2
South Dakota	2	13	436.0	1.8	0	0	0.0	0.0	2	13	436.0	1.7
Tennessee	3	21	756.0	3.2	0	0	0.0	0.0	3	21	756.0	2.9
West Virginia	4	20	726.9	3.0	1	2	50.4	3.4	5	22	777.3	3.0
Wisconsin	7	24	696.2	2.9	6	10	204.7	14.2	13	34	900.9	3.5
TOTALS	116	677	24,253.3 (94.3% of total)	100.0	33	59	1,457.2 (5.7% of total)	100.0	149	736	25,710.5	100.0

[a]Data courtesy of the Babcock and Wilcox Company.

capacity is held by the electric utility sector (24,253 kg/s) which operates 116 of the 149 boilers. These boilers are fired by 677 furnaces. The 33 remaining boiler units are owned by private industry and institutions. Industries employing cyclone-fired units include pulp and paper manufacturers, chemical and steel producers, and one glass manufacturer. Several large midwestern universities employ cyclone firing to meet their utility demands. Primary steam generating capacities of individual boiler units built range from 16 to 70 kg/s (127,000 to 555,000 lb/hr) for industrial and commercial units and from 23 to 1,160 kg/s (182,000 to 9,200,000 lb/hr) for electric utility units. Tables A-1 and A-2, Appendix A, give a detailed listing of all 84 cyclone-fired installations organized by type, state, customer, and size of installation.

Although the statistical population information indicates that 149 boiler units were erected since the inception of cyclone firing, it is difficult to determine exactly the number of units that are currently in operation. Some units may be at the end of their useful life span and might well be in the process of being replaced. This information problem was discussed with B&W, the sole manufacturer of cyclone units in the United States. They estimate that the majority of boilers are still in use, but some may have been derated because of their age.

Since their inception in 1944, cyclone-fired boilers have sold well. The technology was able to meet the demands of boiler owners who wished to burn low-quality coals with low ash fusion temperatures. In the 1950's, 1960's, and early 1970's, cyclone boilers accounted for a major portion of B&W's total sales. However, since about 1973, B&W has not sold a single cyclone unit. The decline of sales started with the strict federal SO_x regulations imposed on new stationary sources [New Source Performance Standards(NSPS)]. The low ash fusion coals burned in the cyclone boiler normally have high sulfur content. Switching to low-sulfur coals normally results in ash with a high fusion temperature. The higher ash fusion temperature coals cause slag tapping and corrosion difficulties with cyclone boilers. Thus, a balance could not, in general, be obtained between low SO_x emissions and adequate boiler operating characteristics. The final event which restricted the sale of bituminous coal-fired cyclones was the limitation of NO_x emissions as per the NSPS.[15] These New Source Performance Standards for NO_x are given below:[16]

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[15] Federal Register. 36(247):24879, December 23, 1971.

[16] Shimizu, A. B., R. J. Schreiber, H. B. Mason, et al. NO_x Combustion Control Methods and Costs for Stationary Sources. Summary Study. Aerotherm Division, Acurex Corporation, U.S. Environmental Protection Agency, EPA 600/2-75-046, September 1975. 104 pp.

Gas	Oil	Bituminous coal
86.1 ng/J	129.1 ng/J	301.2 ng/J
0.2 lb/10^6 Btu	0.3 lb/10^6 Btu	0.7 lb/10^6 Btu
∿160 vppm	∿225 vppm	∿500 vppm
(3% O_2 basis)	(3% O_2 basis)	(3% O_2 basis)

Cyclone firing results in the highest NO_x production of any coal-firing method and is the most difficult to control in this regard. Presently, boilers burning lignite are exempt from the NO_x standard. EPA is expected to propose a standard of 257.9 ng NO_x/J (0.6 lb $NO_x/10^6$ Btu) for lignite-fired utility boilers during the latter part of 1976.

3.3 BASELINE EMISSIONS FROM UNMODIFIED CYCLONE FURNACE INSTALLATIONS

Baseline emissions are defined to be those NO_x, SO_x, CO, and particulate emissions reflecting normal or near-normal boiler operation at various loads. The available data on baseline emissions from cyclone furnaces are included in this section. Some data were simply "spot checks" of boiler operation and may or may not be representative of the true emission levels.

Altogether, 29 cyclone-furnace-fired boiler units were found to have been field sampled for NO_x, SO_x, CO, and particulates. The types of data compiled include results of spot checks as well as comprehensive boiler test programs. The data were gathered from the open literature, from B&W (the boiler manufacturer), and from Commonwealth Edison (an electric utility company). The testing agencies whose data were found in the open literature were government contractors (Exxon and KVB), Federal EPA, and the TVA. The Natural Emission Data System (NEDS) was also thoroughly searched for cyclone-furnace-fired boiler data.[17] The potentially valuable data source dated March 1, 1976 showed that only one of the 134 cyclone boilers listed had been field tested. Data for this boiler unit are included here. The NEDS file indicated that the remaining 133 boilers had been estimated via emission factors. Because the emissions determined by means of an emission factor do not lend themselves to observation of variations in emissions from individual emission sources, the NEDS emission data for the other 133 boilers are not included in this report.

The data gathered reflect emissions arising from the cyclone combustion of bituminous coal, sub-bituminous coal, lignite, residual oil, and natural gas. The smallest unit tested at maximum continuous full load produced 65 kg/s of steam. The largest unit produced 350 kg/s of steam.

[17]National Emissions Data System (NEDS). Computer File Listing of Detailed Point Sources of Utility and Industrial Cyclone-Fired Boilers, March 1, 1976. 134 pp.

The bulk of the data was reported in units of volume or mass concentration (e.g., vppm, g/m^3), with some organizations also reporting emission levels on a mass-per-heat basis (e.g., ng/J). One set of emissions data was reported on an annualized mass basis (NEDS data).

The data reported by the various testing organizations were obtained using a variety of sampling test methods. Table 11 gives a brief summary of the instruments and methods used in obtaining the field data. Detailed descriptions of the boiler sampling techniques are beyond the scope of this report but can be obtained by referring to the references cited in Sections 3.3.2 to 3.3.7.

The accuracy of the emissions data from field sampling is unknown since no error estimates were available from the pertinent data sources. It is recommended that the baseline emission levels as well as any other field-sampled emissions data in this report be interpreted with proper caution because of the variance in test methods and techniques used by different testing organizations and because of the unknown data accuracy.

3.3.1 Emissions Data Summary

A summary of the comparable baseline NO_x data compiled during the course of this study is presented in Table 12. The data are organized by a boiler identification code number (boiler number), type of fuel burned during the test, and organization performing the testing. The rated boiler capacities are reported if they could be determined from the open literature or the manufacturer's data. With the exception of boiler number 7, which is an industrial unit, all of the boilers are classified as utility units. NO_x ($NO + NO_2$) data in Table 12 are reported as a volume concentration on a dry 3% O_2 corrected basis at the percent load at which the test was made. Data on mass of emissions per heat input basis (ng/J) are shown in parentheses.

Only 16 of the 29 boilers field sampled were included in Table 12. The emissions data for the remaining 13 boilers could not be expressed on a 3% O_2 dry basis, and the test loads could be estimated only qualitatively. Hence, the data on the last 13 boilers would not be comparable with the data from the first 16 boiler units.

As shown in Table 12, full-load NO_x levels for 8 bituminous-coal-fired units with the rated capacities between 167 and 618 kg/s of steam ranged between 960 and 1,197 vppm (arithmetic average was 1,074 vppm). It appears that NO_x volume concentrations for all these units drop with decreasing load. This drop may be as high as 30% for decreased loads of up to 30% (boiler numbers 1, 4, and 6). As suggested from the data for boiler number 7, a further decrease of the load does not seem to have too much effect on NO_x

TABLE 11. SUMMARY OF BASELINE EMISSIONS TEST METHODS

Organization	NO_x	SO_x	Particulate	CO
NAPCA (EPA)	Method 7 (phenoldisulfonic acid colorimetric)	Methods 6 and 8 (barium-thorin titrations)	Method 5 (impingers)	Method 10 (IR Spectrometer)
B&W	Dynascience Monitor NX330 (electrochemical cell, 0 to 5,000 ppm range)	Unknown	NFS[a]	Unknown
Exxon	Beckman nondispersive IR and UV spectrometers	NFS[a]	NFS[a]	Beckman nondispersive IR spectrometer
KVB	Thermo Electron Chemiluminescent analyzer	Titration with lead perchlorate (Shell-Emeryville)	Method 5	Beckman nondispersive IR spectrometer
TVA	UV photometric analyzer	NFS[a]	NFS[a]	NFS[a]
NEDS (EPA)	Method 7	Methods 6 and 8	Method 5	NFS[a] (emission factor estimate)
Commonwealth Edison	Wet methods and Beckman spectrometers	NFS[a]	NFS[a]	Unknown

[a]NFS = not field sampled.

TABLE 12. SUMMARY OF BASELINE NO_x EMISSIONS DATA FOR CYCLONE BOILERS

Boiler I. D. No.	Fuel type	Testing organization	Maximum unit rated capacity: Electric, MW	Maximum unit rated capacity: Steam, kg/s	NO_x, vppm, dry 3% O_2 basis (ng/J) at % maximum boiler load: 40 to 50	51 to 60	61 to 70	71 to 80	81 to 90	91 to 100
1	Bituminous coal	NAPCA	206[a]	171	NA	NA	NA	784 (774)	NA	1,160 (946)
2	Bituminous coal	B&W	NA	NA	NA	NA	NA	1,020 (612)[b]	NA	NA
3	Bituminous coal	B&W	200	167[a]	NA	NA	NA	NA	NA	1,020 (612)[b]
4	Bituminous coal	B&W	NA	NA	NA	NA	NA	NA	730 (438)[b]	975 (585)[b]
5	Bituminous coal	B&W	240	200[a]	NA	NA	NA	NA	NA	960 (576)[b]
6	Bituminous coal	Exxon	704	618	NA	NA	NA	886 (532)[b]	NA	1,197 (688)[b]
7	Bituminous coal	KVB	NA	64.7	742 (447)	NA	800 (482)	790 (473)	NA	NA
8	Bituminous coal	TVA	300	250[a]	NA	NA	NA	NA	NA	1,130 (678)[b]
Ranges			200 to 704	65 to 618	742 (447)	NA	800 (482)	784 to 1,020 (774 to 612)	730 (438)	960 to 1,197 (576 to 688)
Arithmetic averages					742 (447)	NA	800 (482)	870 (600)	730 (438)	1,074 (680)
5	Sub-bituminous coal	B&W	240	200[a]	NA	NA	NA	NA	NA	910 (546)[b]
Ranges			240	200	NA	NA	NA	NA	NA	910 (546)
9	Lignite	B&W	NA	NA	NA	NA	NA	NA	NA	593 (355)[b]
10	Lignite	B&W	NA	NA	NA	NA	NA	NA	NA	485 (291)[b]
Ranges			NA	NA	NA	NA	NA	NA	NA	485 to 593 (291 to 355)
Arithmetic averages					NA	NA	NA	NA	NA	539 (323)
11	Residual oil	B&W	NA	NA	NA	NA	NA	NA	NA	460 (276)[b]
12	Residual oil	Exxon	450	309	NA	206 (124)[b]	NA	NA	NA	530 (310)
13	Residual oil	Exxon	136	117	261 (150)	NA	NA	404 (232)	NA	441 (254)
14	Residual oil	Exxon	168	158	NA	NA	NA	NA	NA	361 (206)
Ranges			136 to 450	117 to 309	261 (150)	206 (124)	NA	404 (232)	NA	441 to 530 (254 to 310)
Arithmetic averages					261 (150)	206 (124)	NA	404 (232)	NA	448 (261)
15	Natural gas	B&W	NA	NA	NA	NA	NA	NA	NA	415 (207)[c]
16	Natural gas	TVA	300	250	NA	NA	NA	NA	NA	650 (325)[c]
Ranges			300	250	NA	NA	NA	NA	NA	415 to 650 (207 to 325)
Arithmetic averages					NA	NA	NA	NA	NA	532 (266)

[a]Estimated value.

[b]1 vppm ≈ 0.6 ng/J was assumed.

[c]1 vppm ≈ 0.5 ng/J was assumed.

NA = Not available.

volume concentration. It is probably the initial decrease of the boiler load that has the most significant influence on NO_x emissions. All of the emission data appear relatively independent of boiler size at common loads (1,074 vppm + 11.5%, -10.6% at loads between 91 and 100%, and 870 vppm + 17.2%, -9.9% at loads between 71 and 80%).

One boiler unit, number 5, was fired with two types of coal, bituminous and sub-bituminous. Its NO_x level at full load when fired with sub-bituminous coal (910 vppm) was slightly lower than when fired with bituminous coal (960 vppm). The rated size of boiler number 5 is 200 kg/s of steam (primary flow).

Two lignite-fired boilers were field sampled. NO_x levels at full load ranged from 485 to 593 vppm and averaged 539 vppm. The sizes of these boilers were not available.

Data from four residual-oil-fired units indicated full-load NO_x emission levels ranging between 441 and 530 vppm with an average of 448 vppm. Rated sizes of these boilers ranged between 117 to 309 kg/s of steam, with one boiler size unknown. The partial load data indicate that NO_x emission concentration appears more significant at higher boiler load reduction than the decrease observed when firing bituminous coal.

The two natural-gas-fired units shown in Table 12 (units 15 and 16) emitted between 415 and 650 vppm (average 532 vppm) NO_x at full load. The size of boiler number 16 was known and is 250 kg/s of steam. Partial load data for gas-fired units were not available.

At full load, none of the bituminous coal-, oil-, or gas-fired cyclone units were able to meet the New Source Performance Standards for NO_x with respect to each fuel (refer to Section 3.2 for standards). In general, the full-load NO_x emission data indicate that the NO_x concentrations decrease with a fuel type in the following order: bituminous coal firing $\approx$sub-bituminous coal firing $>>$lignite firing $\approx$ residual oil firing $\approx$ natural gas firing.

The summary of full-load baseline emission levels for CO, SO_2, SO_3, SO_x, and particulates is shown in Table 13. The summary is broken down by fuel types fired at full boiler load (e.g., >90% of rated capacity) and shows the identification numbers of units tested for these emissions. No data were found for boilers firing natural gas.

CO emissions were highest for units firing residual or heavy oils (3 to 85 vppm dry) and were generally zero for bituminous coal and lignite units. No information was found on CO emissions for sub-bituminous-coal-fired cyclone boilers. Emissions of sulfur oxide fluctuated greatly, and the highest levels occurred in bituminous coal-fired units. The single unit tested for particulate

TABLE 13. BASELINE CO, SO_2, SO_3, AND PARTICULATE EMISSION DATA RANGES FOR CYCLONE BOILERS AT FULL LOAD (>90% OF RATED CAPACITY)

Fuel type	CO, vppm dry	SO_2 vppm dry	SO_3 vppm dry	SO_x (SO_2 + SO_3), vppm dry	Particulates, g/m^3 (12% CO_2, dry basis)
Bituminous coal (boiler I. D. Nos.)[b]	0 (1, 3)	1,360 to 2,140 (1, 5)	14 to 31 (1, 5)	1,374 to 2,171 (1, 5)	0.89[a] (1)
Subbituminous coal (boiler I. D. Nos.)[b]	NA (NA)	535 (5)	14 (5)	549 (5)	NA (NA)
Lignite (boiler I. D. Nos.)[b]	0 (9)	580 to 800 (9)	NA (NA)	NA (NA)	NA (NA)
Residual oil (boiler I. D. Nos.)[b]	3 to 85 (11, 12, 13, 14)	NA (NA)	NA (NA)	NA (NA)	NA (NA)

[a]Downstream of electrostatic precipitator operating at 74.5% mass efficiency.

[b]Refers to units field sampled for these emissions.

NA = not available.

emissions showed a level of 0.89 g/m^3 at 74.5% collection efficiency firing bituminous coal.

The following sections present the available baseline emission data in greater detail. The sections are organized by the organizations which performed the boiler tests.

3.3.2 NAPCA Data (Boiler I. D. No. 1)

In 1967 the National Air Pollution Control Administration (now EPA) published a report on emissions from coal-fired power plants.[18] This report included results of testing performed on a cyclone-fired boiler unit. The boiler is rated at 171.5 kg/s of steam (1,360,000 lb/hr) at 16.65 MPa (2,400 psig) and 839 K (1050°F). It is assumed that four cyclone furnaces fired this unit although this was not specified in the report. Two forced-draft fans with a capacity of 174.6 m^3/s (370,000 scfm) supply combustion air to the furnace and maintain positive pressure throughout the boiler system. Flue gas leaving the boiler passes through secondary and primary superheater sections, an economizer, an air preheater, and finally a fly ash collector. The fly ash collectors include two parallel electrostatic precipitators. Collected fly ash is normally reinjected into the furnace. Figure 17 shows the general equipment and sampling arrangements at this installation.[18]

The location of this boiler was not specifically identified. During emissions testing of the boiler, a single type of high-volatile bituminous coal from Pennsylvania was burned. Three tests were run at about full load, two of which included fly ash reinjection. Two additional tests were run at 75% load, both with fly ash reinjection. Here, full load is defined on the basis of maximum continuous steaming capacity (171.5 kg/s). All tests were conducted with normal amounts of excess air (42% to 46.2%). The results of the emissions testing are presented in summary form in Table 14. The data indicate the expected high levels of NO_x (1,200 vppm) emitted at full load from the cyclone-furnace-fired boiler when burning high-volatile A or B bituminous coals. This high value is in contrast to a full load NO_x level of 221 vppm emitted by a vertically fired dry-bottom unit burning pulverized coal that was also tested in this study.[18] Coal of the same rank and nitrogen content (1.4% by weight) was burned in the pulverized coal unit. Excess air level in the pulverized coal unit was slightly higher, 44% versus 42% for a cyclone-fired unit.

With the exception of the particulate data, which are corrected to 12% CO_2, all other data are listed at stack conditions. The data represent averages from the five tests performed. No CO data were available for this unit at full load. Sampling probes were placed

[18]Cuffe, S. T. and R. W. Gerstle, Emissions from Coal-Fired Power Plants: A Comprehensive Summary. U.S. Department of Health, Education, and Welfare, NAPCA, Durham, North Carolina, 1967. 26 pp.

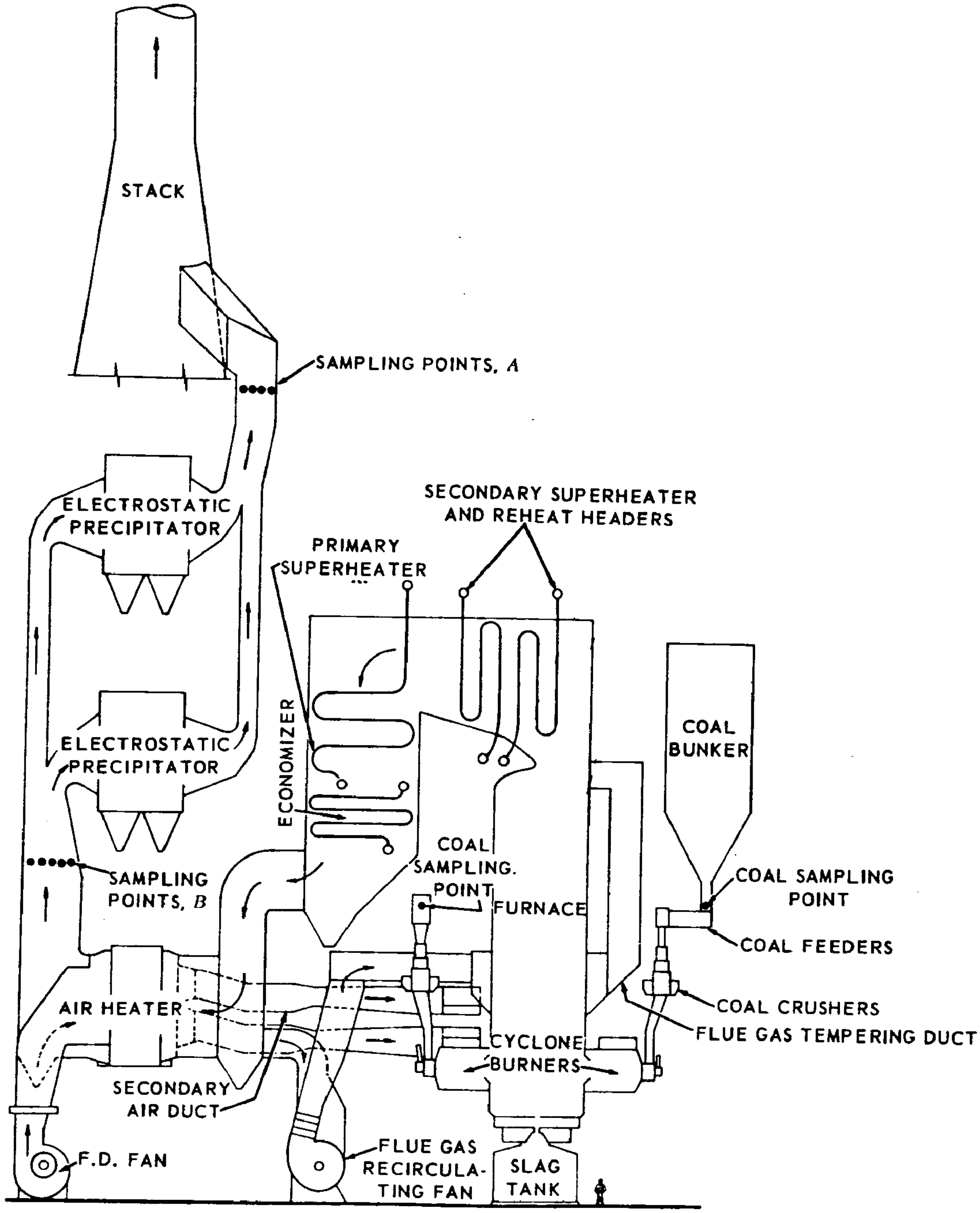

Figure 17. Boiler outline for cyclone-type unit showing sampling positions.[18]

in two locations--before the dust collection device and after it. A side project of this study was to determine if gaseous emission levels were affected by passage through the particulate collection device. No significant change in any of the levels is evident from the data in Table 14. Table 15 lists fuel, boiler, and flue gas data averages which represent the conditions under which the testing occurred. The data are presented as they appear in the literature (with the exception of their conversion to metric equivalents).

TABLE 14. EMISSIONS SUMMARY FOR UNIDENTIFIED COAL-FIRED CYCLONE BOILER UNIT[18]

Boiler I. D. No. 1	Full load	75% Load
Particulates,[a] g/m^3		
Before[b]	3.4	4.1
After[c]	0.89	0.50
ESP collector efficiency, %	74.5	86.3
Nitrogen oxides,[d] vppm (dry 3% O_2), ng/J ($lb/10^6$ Btu)		
Before[b]	1,204; 1,075 (2.5)	742; 817 (1.9)
After[c]	1,160; 946 (2.2)	784; 774 (1.8)
Carbon monoxide, vppm (dry 3% O_2)		
Before[b]	No data	15
After[c]	No data	10
Sulfur dioxide, vppm (dry 3% O_2)		
Before[b]	1,350	1,380
After[c]	1,360	1,370
Sulfur trioxide, vppm (dry 3% O_2)		
Before[b]	21	13
After[c]	31	22

[a]Corrected to 12% CO_2 dry basis standard conditions.

[b]Before fly ash collector.

[c]After fly ash collector.

[d]Reported as NO_2.

3.3.3 Boiler Manufacturer Data (Boiler I. D. Nos. 2 to 5, 9 to 11, 15)

B&W, the manufacturer of cyclone-furnace-fired boiler units, has tested several cyclone boilers for NO_x and other emissions. The emission data made available for this study by B&W are presented in Table 16. The data presented reflect uncontrolled emissions from boiler units and are given at stack conditions which are unknown. There are some data gaps in defining the load the boiler was under during testing. For example, it is not known whether the full load is defined as the maximum continuous rating of the

TABLE 15. AVERAGE COAL, BOILER, AND FLUE GAS DATA FOR UNIDENTIFIED BOILER UNIT[18]

Boiler I. D. No. 1	Full load	75% Load
Proximate analysis of coal (as fired), %		
Moisture	1.1	1.1
Volatile matter	37.0	37.0
Fixed carbon	54.5	54.5
Ash	7.4	7.4
Ultimate analysis of coal (as fired), %		
Hydrogen	5.2	5.2
Carbon	77.4	77.4
Nitrogen	1.4	1.4
Oxygen	6.1	6.1
Sulfur	2.4	2.4
Ash	7.7	7.4
Heating value, MJ/kg	32.4	32.4
Boiler conditions		
Steam rate, kg/s	168.0 (98% load)	128.9
Coal feed rate, kg/s	16.2	10.4
Flue-gas volume, m^3/s		
Before[b]	263	208
After[c]	237	190
Average flue-gas temperature, K (°F)		
Before[b]	410 (279)	402 (264)
After[c]	397 (255)	388 (239)
Flue moisture, %		
Before[b]	6.3	6.6
After[c]	5.9	6.4
CO_2, %		
Before[b]	12.8	12.0
After[c]	12.7	12.2
O_2, %		
Before[b]	6.4	6.8
After[c]	6.3	
Excess air, %		
Before[b]	42.6	46.0
After[c]	42.0	46.2

[a]Expressed at standard conditions of 288 K (59°F) and 1.013 x 10^5 (1 atm).

[b]Before fly ash collector.

[c]After fly ash collector.

[d]Measured at fly ash collector.

TABLE 16. EMISSIONS FROM CYCLONE-FIRED BOILERS[a]

Boiler I. D. No.	Fuel burned	Gross boiler load, MW	Percent of full load	O_2 in flue gas, %	NO_x, vppm dry (3% O_2 basis)	CO, vppm dry	SO_2, vppm dry	SO_3, vppm dry
2	Bituminous coal	NA	76	4.5	1,020	15	NA	NA
3	Bituminous coal	200	100	3.6	1,020	0	NA	NA
4	Bituminous coal	NA	100	5.4	975	NA	NA	NA
4	Bituminous coal	NA	85	5.2	730	NA	NA	NA
5	Bituminous coal (Illinois)	240	100	2.6	960	NA	2,140	14
5	Subbituminous coal (Montana)	240	100	3.5	910	NA	535	14
9	Lignite	NA	100	7.0	NA	NA	765	NA
9	Lignite	NA	100	6.4	685	NA	NA	NA
9	Lignite	NA	100	4.9	562	NA	NA	NA
9	Lignite	NA	100	4.6	503	NA	NA	NA
9	Lignite	NA	100	5.6	640	NA	590	NA
9	Lignite	NA	100	5.1	575	NA	580	NA
				5.6[b]	593[b]		645[b]	
10	Lignite	NA	100	4.8	480		NA	NA
10	Lignite	NA	100	5.0	490	NA	NA	NA
				4.9[b]	485[b]			
11	Residual oil	NA	100	3.2	460	50	NA	NA
15	Natural gas	NA	100	2.9	415	NA	NA	NA

[a]Data courtesy of the Babcock & Wilcox Company, Engineering Services Group, Barberton, Ohio.

[b]Average of results obtained from a specific boiler.

NA = not available.

boiler or some other basis such as normal full load (a percentage of maximum load). Although the information contained in Table 16 is less complete than the previous data of Cuffe and Gerstle,[18] it gives some idea of the variation of NO_x emissions with fuel type. In general, at full load, these data indicate that NO_x emission levels decrease in the following order: bituminous coal, subbituminous coal, lignite, residual oil, and natural gas.

3.3.4 Exxon Data (Boiler I. D. Nos. 6, 12 to 14)

Exxon Research and Engineering Company (Linden, New Jersey) has performed an extensive series of emissions testing on utility boilers.[19,20] The primary objective of this work was to develop NO_x and other pollutant control technology through combustion modification (see Section 4.1). In the course of Exxon's work, a total of four cyclone-fired steam generators were tested, and their uncontrolled NO_x and CO emissions were determined. Three of these units were oil fired, and one was coal fired. The emission data are presented in Table 17.

The unidentified boiler is an oil-fired unit with a maximum continuous rating of 309 kg/s primary steam flow and a full-load gross electrical rating of 450 MW. It is fired by eight cyclone furnaces. The next four sets of data were also obtained for oil-fired units located at the B. L. England Station of Atlantic City Electric (New Jersey).

Boiler unit No. 1 has a maximum continuous rating of 117 kg/s primary steam flow with a full-load gross electrical rating of 136 MW. Three cyclones fire this unit. Boiler unit No. 2 has a maximum continuous rating of 158 kg/s primary steam flow with a full-load gross electrical rating of 168 MW. Four cyclones fire unit No. 2. No fuels analyses were given for these two boiler units.

The last two sets of data were obtained from a large coal-fired unit owned by the Tennessee Valley Authority located at the Paradise, Kentucky station, where the boiler is designated as Unit 1. The maximum continuous rating of the boiler is 618 kg/s primary steam flow with a full-load gross electrical rating of 704 MW.

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[19] Bartok, A. R., Crawford, and G. J. Piegari. Systematic Field Study of NO_x Emission Control Methods for Utility Boilers. Esso Research and Engineering Company (for: U.S. Environmental Protection Agency. Research Triangle Park, North Carolina, Contract No. CPA 70-90). December 31, 1971. 215 pp.

[20] Crawford, A. R., E. H. Manny, and W. Bartok. Field Testing: Application of Combustion Modifications to Control NO_x Emissions from Utility Boilers. Exxon Research and Engineering Company, Government Research Laboratory. (for: U.S. Environmental Protection Agency, Washington, D. C. EPA-650/2-74-066). June 1974. 151 pp.

TABLE 17. SUMMARY OF EXXON EMISSIONS DATA FOR CYCLONE-FIRED BOILERS[19,20]

Boiler I. D. No.	Boiler unit identification	Fuel burned	Gross boiler load, MW	Percent of fuel load	Stack temperature, K (°F)	NO_x			
						O_2 % dry	vppm dry 3% O_2	ng/J (lb/10^6 Btu)	CO, vppm dry 3% O_2
12	Unidentified boiler	Residual oil	415	91	611 (640)	4.0	530[a]	310 (0.72)	6.5
12	Unidentified boiler	Residual oil	258	57	589 (601)	4.6	206[a]	NA (NA)	3
13	B. L. England boiler unit 1	Residual oil	133	98	679 (763)	1.5	441	254 (0.59)	57
13	B. L. England boiler unit 1	Residual oil	62	45	603 (626)	4.2	261	150 (0.35)	54
13	B. L. England boiler unit 1	Residual oil	105	77	659 (727)	2.7	404	232 (0.54)	59
14	B. L. England boiler unit 2	Residual oil	167	100	645 (702)	2.2	361	206 (0.48)	85
6	TVA Paradise unit 1	Bituminous coal	665	95	601 (622)	5.3	1,197	688 (1.60)	NA
6	TVA Paradise unit 1	Bituminous coal	545	77	585 (594)	5.3	886	NA (NA)	NA

[a]Average of two runs.

NA = not available.

The only actual excess air measurement found in the Exxon literature was for TVA Paradise Unit No. 1 boiler, which was operated at 20% excess air level. The other boilers were operated at excess air levels reflecting their normal operation (15% to 30%). Details concerning the test conditions and boiler characteristics are given in Table 18.

TABLE 18. SUMMARY OF BOILER OPERATING DATA CORRESPONDING TO EXXON EMISSION TESTS[19,20]

	Boiler designation			
		B. L. England		
	Unidentified boiler	Boiler unit 1	Boiler unit 2	TVA Paradise unit 1
Boiler I. D. No.	12	13	14	6
Maximum continuous steam rating, kg/s	309	117	158	618
Full-load rating, MW	450	136	168	704
Initial year of operation	1964	1957	1964	1963
Nominal heat rate, Btu/kW hr	NA	NA	NA	8,777
Fuel burned	Oil	Oil	Oil	Coal
Furnace volume, m^3	4,313	NA	NA	9,646
Furnace heating surface, m^2	1,932	NA	NA	3,818
Number of cyclones	8	3	4	14
Main steam pressure, kPa	NA	1,251	1,251	1,654
Main steam temperature, K (°F)	NA	811 (1000)	811 (1000)	840 (1053)

NA = not available.

Table 19 lists the available oil and coal analyses representative of test conditions.

3.3.5 KVB Data (Boiler I. D. No. 7)

The first phase of an ongoing study to determine the effectiveness of combustion modification techniques to control emissions of NO_x from industrial boilers has been completed by KVB Engineering, Incorporated of Tustin, California (see Section 4.1 for details).[21] As part of this study, one cyclone-fired boiler was tested for its baseline emissions at various loads firing bituminous coal.

[21]Cato, G. A., H. J. Buening, C. C. DeVivo, B. G. Morton, and J. M. Robinson. Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers-Phase I. KVB Engineering, Inc. Tustin, California. (for EPA, Office of Research and Development. EPA-650/2-74-078-a). PB 238 920. October 1974. 196 pp.

TABLE 19. AVAILABLE FUEL ANALYSIS DATA FOR BOILERS TESTED BY EXXON[19]

	Oil analyses		
		B. L. England	
	Unidentified (Boiler I. D. 12)	Boiler unit 1 (Boiler I. D. 13)	Boiler unit 2 (Boiler I. D. 14)
Ash, wt %	0.02	NA	NA
C, wt %	85.2	NA	NA
H, wt %	11.8	NA	NA
N, wt %	0.5	NA	NA
S, wt %	0.46	NA	NA
Fe, ppm	2.0	NA	NA
Ni, ppm	7.5	NA	NA
V, ppm	29	NA	NA
High heating value, MJ/kg (Btu/lb)	44.6 (19,185)	NA	NA
Kin. Vis. at 372 K (210°F), m^2/s	35.86×10^{-6}	NA	NA

Coal analyses for the TVA Paradise boiler unit 1, boiler I. D. 6 (as received basis)

Proximate analysis, wt %	
Moisture	6.8
Ash	15.6
Volatile matter	31.0
Ultimate analysis, wt %	
Carbon	61.6
Hydrogen	5.1
Nitrogen	1.3
Sulfur	3.6
Oxygen	15.0
High heating value, MJ/kg (Btu/lb)	25.8 (11,090)

NA = not available.

The cyclone-fired industrial boiler tested during the KVB program is located in New York and was built in 1967. It has a rated maximum continuous primary steam capacity of 64.7 kg/s (513,000 lb/hr). Two cyclone furnaces each 3.66 m long and 3 m in diameter fire a water tube secondary furnace which has a tube furnace area of 35 m^2 and a volume of 32 m^3. The burners are spaced 1 m apart and are located horizontally on a single wall. The full-load furnace heat release is 3.9 MW (gross)/m^2 (1,250,000 Btu/hr - ft^2) on an area basis and 4.7 MW (gross)/m^3 (454,500 Btu/hr cu ft) on a volume basis. The primary air temperature when burning 100% coal during the emissions testing was 559 K (546°F).

Table 20 summarizes the available emissions data for this boiler extracted from the KVB study. Full load is defined in terms of maximum steam capacity (64.7 kg/s). Table 21 gives a representative analysis of the coal burned during the emissions testing.

TABLE 20. EMISSIONS DATA FOR NEW YORK BOILER (BOILER I. D. NO. 7)[21]

					NO_x		CO		SO_2		SO_3		Particulates,
Fuel burned	Test load, kg/s steam	Percent of full load	Flue gas O_2 % dry	Stack temperature, K (°F)	vppm dry 3% O_2 basis	ng/J ($lb/10^6$ Btu)	vppm	ng/J ($lb/10^6$ Btu)	vppm	ng/J ($lb/10^6$ Btu)	vppm	ng/J ($lb/10^6$ Btu)	ng/J ($lb/10^6$ Btu)
Bituminous coal	50.7	78.4	3.2	418 (293)	790	473 (1.10)	0	0	NA	NA	NA	NA	NA
Bituminous coal	40.3	62.4	3.4	418 (293)	800	482 (1.12)	0	0	1,122	937 (2.18)	13	10.7 (0.025)	513 (1.19)
Bituminous coal	30.3	46.8	3.2	418 (293)	742	447 (1.04)	0	0	NA	NA	NA	NA	NA

NA = not available.

TABLE 21. COAL ANALYSIS, A NEW YORK BOILER (BOILER I. D. NO. 7)[21]

Moisture, wt %	1.43
Heat of combustion gross, MJ/kg	30.7
Carbon, wt %	76.6
Hydrogen, wt %	5.5
Sulfur, wt %	2.9
Nitrogen, wt %	1.6
Ash, wt %	7.8
Carbon residue, wt %	52.7

3.3.6 TVA Data (Boiler I. D. Nos. 8, 16)

The Tennessee Valley Authority (TVA) owns and operates several cyclone-fired utility boilers. NO_x emission data were found for three of these boiler units. One set of data for a TVA station (Boiler I. D. No. 6, Paradise Station Unit No. 1) has already been presented as part of Exxon's data (Section 3.3.4). Presented here are data for two other units tested by TVA.[22]

[22]Hollinden, G. A., S. S. Ray, N. D. Moore, J. T. Reese, and C. Gottschalk. NO_x Control at TVA Coal-Fired Steam Plants. Tennessee Valley Authority, Chattanooga, Tennessee. Paper Presented at National Symposium ASME Air Pollution Control Division. 30 pp.

The two boilers tested are located in Memphis, Tennessee at the T. H. Allen station. Unit No. 1 (boiler I. D. No. 16) has a full-load rating of 300 MW, is fired by seven cyclones, and was fueled with gas during its test. Unit No. 2 (boiler I. D. No. 8) has similar characteristics, but was fueled with bituminous coal during its test. The maximum continuous primary steaming rate of each unit is 380 kg/s. Both tests occurred under full-load conditions of 290 MW for each boiler (97% of maximum continuous rating). The NO_x concentration for gas-fired unit No. 1 was 650 vppm (3% O_2 dry) or about 430 ng/J (1.0 lb/10^6 Btu). The NO_x concentration for coal-fired boiler unit No. 2 was 1,130 vppm (3% O_2 dry) or about 663 ng/J (1.54 lb/10^6 Btu). Boiler unit No. 2 emitted about the same amount of NO_x at 290 MW as did the Paradise unit No. 1 firing at 665 MW.

3.3.7 Commonwealth Edison Data (Boiler I. D. Nos. 17 through 28)

The largest number of cyclone boiler units is owned by the Commonwealth Edison Company, a large electric utility company in Chicago, Illinois. It is estimated that about 25% of the total U.S. cyclone-fired steaming capacity is owned by this company. This section includes baseline data for 12 boiler units spot-checked by Commonwealth Edison's Operational Analysis Department over a period of about 3 years. The remainder of the NO_x emission data on Commonwealth Edison facilities were generated by the equipment supplier, B&W, and were not made available for this study.

The available emission data are presented in Table 22. The data give NO_x, NO_2, and CO emissions and are organized by type of fuel burned during testing. At the time when these tests were performed, in most cases the mass emission rates (ng/J) were not calculated. According to Commonwealth Edison, it would be difficult if not impossible to reconstruct these tests. Consequently, the Commonwealth Edison data should be evaluated with caution and should be viewed as spot-check results rather than the results representative and typical of cyclone furnace operation.

The exact boiler loads for the data in Table 22 could not be determined; however, a qualitative indication of the loads during these tests is provided as given from the data supplier. In addition, none of the emissions data were corrected to a comparable "dry 3% O_2 basis." For these reasons, it would be difficult to properly compare the Commonwealth Edison data with emission data presented elsewhere in this report. The Commonwealth Edison data were also excluded from the Emissions Data Summary, Section 3.3.1, and Load Reduction Field Test Data, Section 4.2.4.

Four fuel types were tested by Commonwealth Edison; i.e., bituminous coal, blend of bituminous and subbituminous coals, subbituminous coal, and residual oil. The full-load data (NFL in Column 6 of Table 22) were arranged by fuel type. In general, these data indicate that at full load, NO_x emission levels decrease in the

TABLE 22. BASELINE FLUE GAS CONCENTRATIONS AND EMISSION RATES OF NITROGEN OXIDES AND CARBON MONOXIDE FOR 12 COMMONWEALTH EDISON-OWNED CYCLONE FURNACE FIRED-BOILER UNITS[a,b]

Boiler I. D. No.	Station	Unit No.	Fuel burned during spot test	Net MW rating	Boiler load[c]	NO_x (as NO_2) vppm	NO_x (as NO_2) ng/J ($lb/10^6$ Btu)	NO_2 vppm	NO_2 ng/J ($lb/10^6$ Btu)	CO vppm	CO ng/J ($lb/10^6$ Btu)
17	Kincaid	2	Illinois bituminous coal 4.2% S	616	NFL	467	NA	NA	NA	200	NA
18	Powerton	51	Illinois bituminous coal 3.6% S	425	NFL	913	671 (1.56)	11	0.86 (0.002)	22	9.9 (0.023)
18	Powerton	51	Illinois bituminous coal 3.6% S	425	RL	437	409 (0.952)	1	0.86 (0.002)	4	2.1 (0.005)
19	Will County	2	Illinois bituminous coal 3.6% S	157	NFL	525	856 (1.99)	NA	NA	1	NA
19	Will County	2	Illinois bituminous coal 3.6% S	157	SRL	518	899 (2.09)	NA	NA	1	NA
20	Stateline	4	50/50 Blend western subbituminous and Illinois bituminous coals	358	NFL	674	NA	2	NA	NA	NA
20	Stateline	4	50/50 Blend western subbituminous and Illinois bituminous coals	358	RL	645	NA	0.9	NA	NA	NA
20	Stateline	4	50/50 Blend western subbituminous and Illinois bituminous coals	358	NFL	582	NA	0.9	NA	NA	NA
21	Fisk	18	Western subbituminous coal 0.7% S	78	NFL	292	NA	0.05	NA	132	NA
22	Waukegan	17	Western subbituminous coal 0.6% S	119	NFL	442	NA	1.0	NA	227	NA
23	Will County	1	Western subbituminous coal 0.4% S	144	NFL	484	NA	0.05	NA	560	NA
23	Will County	1	Western subbituminous coal 0.4% S	144	ML	241	NA	0.05	NA	260	NA
23	Will County	1	Western subbituminous coal 0.4% S	144	LL	360	NA	0.05	NA	475	NA
24	Ridgeland	1	No. 6 residual oil with additive A	74	NFL	286	241 (0.561)	NA	NA	10	4.3
25	Ridgeland	2	No. 6 residual oil 1% S	84	NFL	268	NA	NA	NA	NA	NA
26	Ridgeland	4	No. 6 residual oil with additive B	74	NFL	419	379 (0.882)	NA	NA	NA	NA
27	Ridgeland	5	No. 6 residual oil 1% S	156	NFL	185	NA	NA	NA	NA	NA
27	Ridgeland	5	No. 6 residual oil 1% S	156	NFL	215	NA	NA	NA	NA	NA
28	Ridgeland	6	No. 6 residual oil with additive C	138	NFL	187	125 (0.291)	NA	NA	NA	NA

[a]Data courtesy of the Commonwealth Edison Company.

[b]All data have been corrected to 29.92 in Hg and 70°F but not to a dry 3% O_2 basis. Test methods may vary. Instrumental methods were used in some instances. All concentrations and rates are approximate averages; in some cases, individual tests showed substantial variation. MW shown are net ratings, not loads experienced.

[c]NFL = near full load, RL = reduced load, ML = medium load, LL = low load, SRL = slightly reduced load. No quantitative load data were available.

NA = not available.

following order: bituminous coal = 50/50 blend bituminous/subbituminous coals > subbituminous coal >> residual oil. This trend is identical to the one indicated by the data developed by B&W (see Section 3.3.3). In addition to this trend, it appears that CO emissions from cyclone boilers burning western subbituminous coals are excessively high and may constitute an emissions problem. The same is true for one of the bituminous coals from Illinois containing 4.2% sulfur.

3.3.8 NEDS Data (Boiler I. D. No. 29)

As stated previously, only one boiler listed in the NEDS file[17] as of March 1976 was designated as being "source tested." Source testing refers to actual stack sampling measurements made on that boiler unit. The information on this utility boiler is presented in Table 23. The unit is owned by Minnkota Power Cooperative, Inc., and constitutes the Milton R. Young generating station (235 MW) located 5 miles southeast of Center, North Dakota. The boiler burns lignite and is fired by a total of seven cyclone furnaces generating 216 kg/s of primary steam at full load. The boiler is relatively new (made operational in 1972), and the data indicate that the boiler was operating at its maximum design capacity (load factor = 1.04). A centrifugal collector operating at 70% mass efficiency was used for removing particulates during this testing. No other details are known concerning the assumptions made in arriving at these annualized emissions.

TABLE 23. ANNUALIZED 1972 EMISSIONS DATA FOR A 235 MW CYCLONE-FIRED UTILITY BOILER UNIT (Boiler I. D. No. 29)[17]

	NEDS data	Estimated data
Fuel burned	Lignite[a]	
Particulates	0.281 kg/s[b]	0.65 g/m^3
NO_x	0.375 kg/s[b]	683 vppm (410 ng/J)
CO	0.025 kg/s[c]	75 vppm (45 ng/J)
SO_x	0.500 kg/s[b]	645 vppm (392 ng/J)
Normal operation	24 hours/day	
	336 days/year	
Annual load factor	1.04[d]	
Stack temperature	439 K (331°F)	
Flue gas rate (actual)	78.8 m^3/s	430 m^3/s
Fuel consumption	45.87 kg/s	
Maximum fuel design rate	47.69 kg/s	
Fuel heat value	15.1 MJ/kg	
Boiler design heat release rate	732.6 MJ/s	

[a] Sulfur content = 0.7%, ash content = 8.0%
[b] Source test.
[c] NADB approved non-EPA emission factor.
[d] Based on maximum fuel design rate.

One possible discrepancy was noted in these data from the NEDS file. The flue gas rate of 78.8 m^3/s appears low for a unit of this size (235 MW). A report by W. S. Smith and C. W. Gruber[23] indicates that for a 235 MW coal-fired plant, the stack effluent rate should be approximately 283.2 m^3/s at 289 K and 100 kPA. Assuming an ideal gas law, the flue gas rate can be corrected to 439 K. This results in a flue gas rate of 430 m^3/s, a rate more than five times higher than that approximated by NEDS. This corrected rate, rather than the NEDS figure, was used in arriving at the estimates shown in Table 23. It was also assumed that the NO_x was reported as NO_2, and the SO_x was reported as SO_2. Emission rates (ng/J) were estimated by assuming that 1 vppm $\sim$0.6 ng/J (bituminous coal ratio). None of the estimates made could be corrected to a consistent basis such as 3% O_2 dry and 12% CO_2 because of insufficient information.

3.4 NEED FOR NO_x CONTROL

An estimate of the total annual amount of NO_x emitted from the population of cyclone-fired boiler units can be made using the emission factor method. Total NO_x emitted is obtained by multiplying the total quantity of fuel burned by the appropriate emission factor (weight of NO_x emitted/unit of fuel consumed). The only currently accepted emission factor for cyclone firing is for large boiler units (>29 x 10^6 J/s) burning bituminous coal. The value of this emission factor is 12.28 g NO_x emitted per kg of coal burned.[24]

The electric utility industry was found to have the most complete information on annual coal consumption. This industry is most important in terms of NO_x emissions because over 94% of the primary steam produced by cyclone furnaces is generated in the electric utility sector (see Section 3.2).

By examining a compilation of boiler records published by the National Coal Association, an estimate of the total amount of coal burned at power plants employing cyclone furnace firing was made.[25] No actual data on fuel consumption in cyclone furnaces per se could be found in the literature. Appendix B includes information which was used to arrive at the estimates of major fuel types

[23] Smith, W. S., and C. W. Gruber. Atmospheric Emissions from Coal Combustion - An Inventory Guide. U.S. HEW, Public Health Service, Division of Air Pollution. Cincinnati, Ohio. April 1966. 112 pp.

[24] Anon. Compilation of Air Pollutant Emission Factors. 2nd edition, U.S. Environmental Protection Agency, April 1973. pp. 1.1-1 to 1.4-3.

[25] Anon. Steam-Electric Plant Factors, 1974 Edition. National Coal Association, 24th edition, 1974. 110 pp.

(coal, oil, and gas) used for utility cyclone firing. There are some limitations connected with these estimates. Also contained in Appendix B are fuel consumption, electric load factor, and net power generation data for all power plant installations in the United States employing cyclone fuel firing (coal, oil, and gas).

It was estimated that in 1973, 62 x 10^9 kg (68.4 x 10^6 tons) of coal were burned at power plants employing cyclone firing. The overwhelming majority of this coal was bituminous with an average heating value of 26 MJ/kg (11,200 Btu/lb). If the 62 x 10^9 kg of coal burned is multiplied by the emission factor of 12.28 g NO_x emitted per kg coal burned, the result is 0.76 x 10^6 tonnes (0.84 x 10^6 tons) of NO_x emitted from all cyclone coal-fired utility boilers in 1973.

A recent EPA-sponsored study by the Aerotherm Division of the Acurex Corporation estimated that in 1972, 3.44 x 10^6 tonnes/yr (3.79 x 10^6 tons/yr) of NO_x were emitted from all coal-fired utility boilers.[16] Using this 1972 estimate as the emission base and a cyclone NO_x estimate of 0.76 x 10^6 tonnes (0.84 x 10^6 tons/yr), bituminous coal-fired cyclone furnace utility boilers contributed 22% of the total NO_x emissions from all coal-fired utility boilers in 1973. (The emissions base was assumed to be unchanged for 1973.) These statistics clearly indicate a need for NO_x control in this equipment class.

The same Aerotherm study ranked cyclone-fired utility boilers burning bituminous coal third out of a possible 137 ranked stationary sources of NO_x in 1972. It was estimated that over 6% of the total NO_x emitted by all 137 sources (10.58 x 10^6 tonnes, 11.66 x 10^6 tons total NO_x in 1972) came from bituminous-coal-fired cyclone furnace utility boilers. The first-ranked source was gas-fired, spark ignition internal combustion engines, which contributed 16% of total 1972 NO_x. The second was tangentially fired bituminous-coal-burning utility boilers, which contributed 12% of total 1972 NO_x.[15] Aerotherm estimated that 19% of the total NO_x from all coal-fired utility boilers in 1972 was contributed by bituminous-coal-fired cyclone furnace utility boilers. A summary of pertinent statistics from the Aerotherm study is given in Table 24. From this table, it is seen that within the cyclone-fired boiler category, over 91% of the NO_x emissions result from utility boilers burning bituminous coal.

TABLE 24. SUMMARY OF AEROTHERM NO_x EMISSION ESTIMATES FOR ALL CYCLONE-FIRED BOILERS IN 1972[16]

Rank out of 137 NO_x sources	Boiler type	Fuel[a]	NO_x tonnes/yr x 10^6	Distribution of NO_x within cyclone boiler category, %
3	Utility	Bituminous coal	0.65[b]	91.2
55	Industrial	Bituminous coal	0.025	3.5
64	Utility	Residual oil	0.017	2.4
79	Industrial	Residual oil	0.012	1.7
89	Utility	Lignite	0.008[b]	1.1
130	Utility	Distillate oil	0.001	0.1
TOTAL			0.713	100.0

[a]No data available for natural gas firing.

[b]MRC estimate was 0.76 x 10^6 tonnes/yr in 1973 for these two categories based on information in Appendix B.

SECTION 4

APPLICABILITY OF COMBUSTION MODIFICATIONS TO CYCLONE FURNACES/BOILERS

The term combustion modification as used in the context of this report refers primarily to any modification or change in the major combustion operating conditions or fuels of a boiler unit to suppress formation of NO_x. Some equipment modifications related to the basic combustion equipment design could also be considered as combustion modifications. In the combustion process, oxides of nitrogen are formed both from the nitrogen in the combustion air (thermal NO_x) and by conversion of chemically bound nitrogen in the fuel (fuel NO_x). Section 4.1 presents a review of combustion modification strategy with reference to controlling NO_x formed both thermally and from the fuel. Section 4.2 cites instances of field experience with cyclone-fired boiler units. Section 4.3 reviews the significance of the NO_x combustion modification experience. Section 4.4 includes recommendations for further work.

4.1 COMBUSTION MODIFICATION STRATEGY IN GENERAL

Combustion modifications seek to suppress the formation of NO_x which results from two sources; namely, chemically bound nitrogen in the fuel and atmospheric nitrogen. Atmospheric nitrogen reacts with oxygen at high temperatures during the combustion process to form NO_x. Oxygen also reacts with nitrogen chemically bound in the fuel during the combustion process. For natural gas and light distillate oil firing, the bulk of NO_x is formed via atmospheric (nitrogen) fixation.[26] With residual (crude) oil and coal, the contribution from fuel-bound nitrogen can be significant, and under certain operating conditions, it can be predominant.[26] Pohl states that U.S. coals contain 0.5% to 2.0% nitrogen by weight, of which about 10% to 50% may be converted to nitric oxide in combustion.[27] The fate of the remaining 50% to 90% of the nitrogen in coal is not well known. Fine, Slater, and Sarofin, et al.

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[26]Brown, R. A., H. B. Mason, and R. J. Schreiber. Systems Analysis Requirements for Nitrogen Oxide Control of Stationary Sources. Aerotherm/Acurex Corporation (California). U.S. Environmental Protection Agency, EPA-650/2-74-091, 1974.

[27]Pohl, J. H. and A. F. Sarofim. Fate of Coal Nitrogen During Pyrolysis and Oxidation. Fuels Research Laboratory, Massachusetts Institute of Technology, Paper presented at "Symposium on

postulate that the remainder of the bound nitrogen in U.S. coals is converted into molecular nitrogen (N_2).[28]

The major oxide of nitrogen formed during the combustion process is nitric oxide, NO. Other oxides of nitrogen formed, such as nitrogen dioxide, NO_2, and its dimer, N_2O_4, require prior formation of NO. The formation of thermal and fuel NO is discussed below in relation to combustion modifications.

The kinetics of thermal NO formation are complex and coupled to the kinetics of fuel oxidation. Both fuel and atmospheric nitrogen oxidation kinetics are influenced by effects of turbulent mixing in the flame zone.[26] It is generally accepted that the most significant reactions which form thermal NO are those of the Zeldovich chain mechanism involving formation of oxygen radicals:

$$O_2 + M \rightleftharpoons O + O + M \qquad (1)$$

$$N_2 + O \rightleftharpoons NO + N \qquad (2)$$

$$O_2 + N \rightleftharpoons NO + O \qquad (3)$$

Reaction 2 is rate controlling. M is any third-body molecule, which can result in formation of oxygen radical.

Brown, et al. further describe thermal NO formation[26] in combustion equipment:

> "Due principally to the high energy required to break the N_2 bond in Reaction 2, the activation energy for NO formation via the Zeldovich mechanism is considerably larger than for typical rate-controlling reactions in hydrocarbon oxidation. This entails that thermal NO formation is initiated well after initiation of fuel combustion and is extremely temperature sensitive with virtually all NO being formed in the high temperature regions of the flame. For the time scales involved in the flow through commercial combustors, the high temperature dependence of the NO system means that total NO emissions are far below equilibrium levels. NO formation is thus kinetically controlled with the emission level dependent on time of exposure to the high temperature."

The amount of combustion air supplied for fuel oxidation also influences the level of thermal NO. Increasing the level of air

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Stationary Source Combustion" sponsored by Combustion Research Section, U.S. Environmental Protection Agency, September 24-26, 1975 (Atlanta, Georgia), 22 pp.

[28]Fine, D. H., S. M. Slater, A. F. Sarofim, and G. C. Williams. Nitrogen in Coal as a Source of Nitrogen Oxide Emission from Furnaces. Fuel, 53(4):120-125, 1974.

(O_2 level) above the amount required for complete theoretical combustion generally increases the concentration of NO formed. Thus, there are three factors that influence the extent to which thermal NO is formed:

(1) Peak temperature
(2) Time of exposure to peak temperature
(3) Oxygen level at peak temperature

The current strategy behind combustion modifications is to act on the three factors mentioned above. Figures 18 and 19 illustrate the importance of each factor.[29] The data presented in Figures 18 and 19 are for natural gas fuel where NO is formed largely due to thermal effects with no or negligible fuel NO contribution. Data presented are not actual field data but were theoretically derived from fundamental kinetic and thermodynamic relationships.[29] Figure 18 shows the equilibrium concentration of NO in the combustion products of natural gas versus percent theoretical air with temperature as a parameter. Equilibrium NO levels are the highest achievable at a given temperature and percent theoretical air. A cyclone furnace operating at 1920 K (3000°F) and 20% excess air, for example, should have an equilibrium NO concentration of approximately 2,000 ppm.

Figure 19 gives theoretical kinetic information (assuming the Zeldovich mechanism) for the reaction between nitrogen and oxygen versus percent theoretical air with time and temperature as parameters. James of B&W concludes the following from Figures 18 and 19.[28]

- "As the oxygen concentration in the combustion products is increased, the amount and the rate of NO formation increases.
- "As the temperature of the combustion products is raised, the amount and the rate at which thermal NO is formed increases.
- "As the time available for reaction at high temperature increases, the amount and the NO concentration also increase."

James also states that the converse of these conclusions may be observed under specific boiler combustion conditions. Since the majority of cyclone furnaces operate at temperatures above 1920 K (3000°F), it is evident that the NO formation in these furnaces never reaches equilibrium (e.g., about 2,000 ppm NO at 20% excess

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[29]James, D. E. A Boiler Manufacturer's View on Nitric Oxide Formation. The Babcock & Wilcox Company, Presented to the Fifth Technical Meeting, West Coast Section of the Air Pollution Control Association, San Francisco, California, October 8-9, 1970. 26 pp.

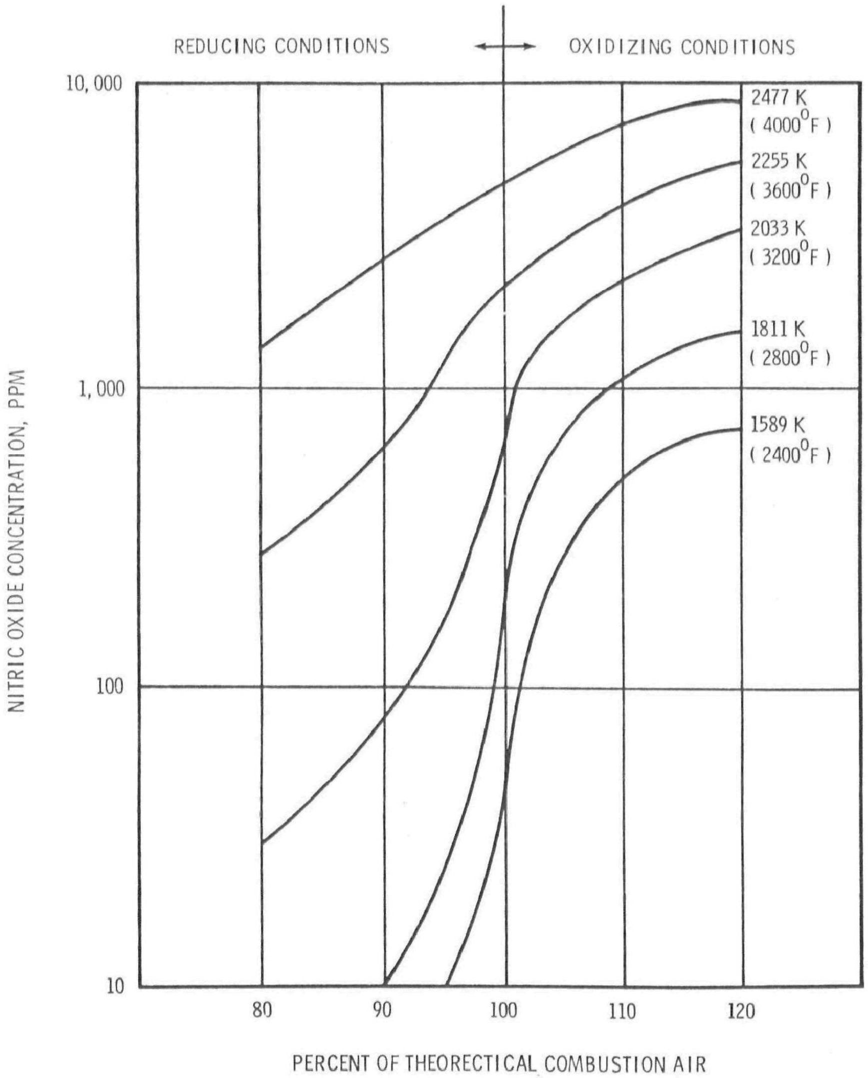


Figure 18. Thermodynamic equilibrium data for natural gas fuel.[29]

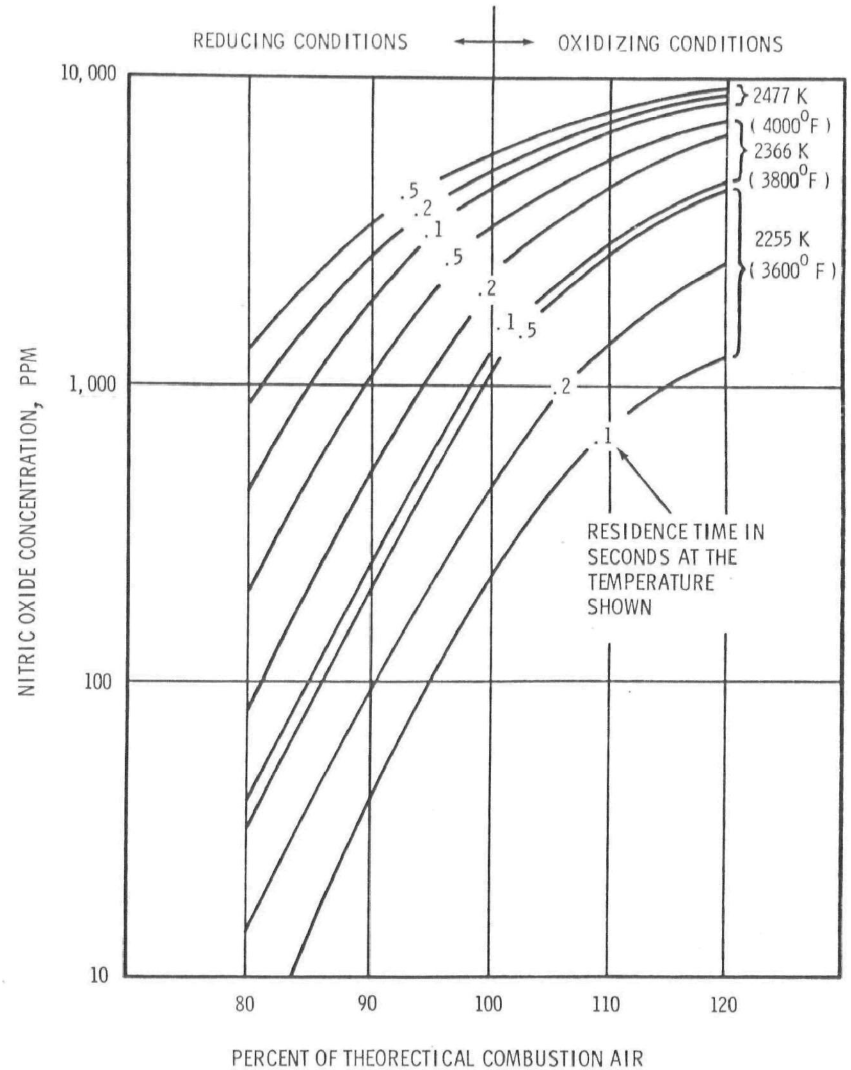


Figure 19. Kinetic data for natural gas fuel.[29]

air, Figure 18), based on this theory. The highest NO_x emissions measured on a cyclone furnace were just over 1,100 ppm.

A heirarchy of effects leading to thermal NO_x formation in cyclone boilers is shown in Table 25. The boiler's primary equipment and fuel parameters must be dealt with if thermal NO_x is to be reduced through a combustion modification approach. The causal relationships between the primary, secondary, and fundamental parameters are not known for cyclone boilers.

TABLE 25. POTENTIAL FACTORS CONTROLLING THE FORMATION OF THERMAL NO_x IN CYCLONE BOILERS

Primary equipment and fuel parameters	Secondary combustion parameters	Fundamental thermal NO_x parameters		Degree to which primary parameters have been explored in existing cyclone boilers for NO_x control
1. Combustion air temperatures (primary, secondary, tertiary)				1. Not explored
2. Combustion air velocity (primary, secondary, tertiary)				2. Not explored
3. Cyclone furnace aerodynamics				3. Not explored
4. Fuel type (switching)				4. Fairly well explored
5. Fuel composition within same fuel type or rank	Turbulence within the furnace			5. Not explored
	Heat removal rate in the furnace	Oxygen level		
6. Injection pattern of fuel and air (staging)	Mixing of combustion products into flame	Peak temperature	Thermal NO_x	6. Some staging patterns have been applied to boiler furnaces but not to individual cyclones where bulk of NO is formed
	Local fuel air ratio	Exposure time at peak temperature		
7. Size of fuel particles or droplets	Turbulent distortion of flame zone			7. Not explored
8. Excess air				8. Fairly well explored for oil-fired units only
9. Monitoring individual cyclone NO_x behavior				9. Not explored
10. Flue gas recirculation				10. Not explored
11. Load reduction				11. Well explored

Also shown in Table 25 is the degree to which primary parameters have been explored in existing cyclone boilers to effect NO_x reduction. This information summarizes qualitatively the state of the art of combustion modifications for cyclone boilers as determined from the literature and the boiler manufacturer (B&W). Of the 11 primary parameters shown, only 4 have been explored in some way for NO_x reduction potential (4, 6, 8, 11). A description of field testing performed to determine the significance of primary parameters 4, 6, 8, and 11 is given in Section 4.2.

Research on the role of fuel-bound nitrogen in forming NO_x is in its preliminary stage. As mentioned previously, conversion of nitrogen in the fuel could account for 10% to 50% of the NO present in the flue gas. Fuel nitrogen conversion is generally regarded to be relatively insensitive to temperature. Brown states that[26]

> "The most critical factor in fuel NO_x conversion appears to be the local conditions in which volatilization and formation of nitrogen intermediate compounds occur. In a reducing atmosphere, it is suspected that the intermediate compounds go to form N_2, or other more complex unknown nitrogen compounds with little

subsequent conversion to NO. In an oxidizing atmosphere, conversion of the intermediates to NO is thermodynamically favored over conversion to N_2. Although basic understanding of these phenomena is only in the preliminary stage, a promising strategy for fuel NO_x reduction appears to be modification of the burner or combustion conditions to allow volatilization to occur prior to massive entrainment of oxygen in the flame zone.

"The fate of fuel-bound nitrogen which does not go to NO under oxidation conditions is uncertain. There are indications that other pollutants, such as HCN, may result when NO formation is suppressed. This possibility may, indeed, constitute a limitation to fuel NO_x reduction strategies and requires further investigation."

Brown's observation should be explored further in light of potential application to cyclone boilers.

4.2 COMBUSTION MODIFICATION EXPERIENCES WITH CYCLONE-FIRED BOILER UNITS

Section 3.4 of this report states that out of 137 stationary sources of NO_x in 1972, the cyclone-fired, bituminous-coal-burning utility boilers ranked third. They were the source of 6% of stationary source NO_x emissions in the U.S. despite the fact that the cyclone furnaces are significant NO_x emitters. Only a relatively small number of cyclone boilers were found to have been examined and tested in some way to determine the effect of combustion modifications on NO_x emissions. One reason for lack of field data on this combustion equipment class is the relative inflexibility of the cyclone boilers toward modification. Robert Lundberg, an expert on cyclone furnaces for over 30 years at Commonwealth Edison of Chicago, describes the cyclone as being ". . .more like a digital device that really functions in about one mode." The rigid operating specifications of the cyclone furnace are dictated by proper furnace temperature and high heat release rates to maintain furnace slagging. Operating experiences suggest that these parameters cannot be altered to the degree required for adequate NO_x control without ending with a furnace which is no longer a "cyclone."

The literature as well as the boiler manufacturer (B&W) reveal that four types of combustion modifications have been applied either singly or in combination to reduce NO_x emissions from cyclone furnaces. These modifications are: load reduction, low excess air firing, simulated staged firing, and switched fuel firing. No boiler unit has ever been tested under sustained conditions with any of these four modifications. The modification techniques applied most often have been load reduction and low excess air firing because they require no modification or changes of existing cyclone units. To date, NO_x reduction for all boilers tested was achieved by load reduction.

The prognosis for long-term application of any of the modifications previously mentioned to existing boiler units is dim. The reasons for this prognosis are further discussed in Section 4.3. Table 26 lists the boiler units tested and shows the type of combustion modification applied in each test. The boilers are identified by numbers corresponding to those used in Section 3.3. This enables the reader to identify the boiler with its design and operation characteristics and available emission data.

All forms of modifications utilize one or more of the three factors that influence thermal NO formation; i.e., peak flame temperature, residence time of gas at peak temperature, and oxygen level. One of the methods, staged firing also acts on the variables that control fuel NO formation. The concept of staged firing provides a localized reducing atmosphere which favors chemical conversion of nitrogen containing intermediates in the fuel (coal and heavy oils) to N_2 or unknown nitrogen compounds with little subsequent conversion to NO.[26] Basically, the method works on the principle of lowering the oxygen supply to the burner zone where fuel nitrogen is volatilized.

The following subsections present the combustion modification field data extracted from the open literature and the cyclone boiler manufacturer (B&W). Except for the tests performed with load reduction, all other data are presented in alphabetical order by the organization performing the tests. All available data on load reduction are combined and presented last in Section 4.2 since load reduction is perhaps the least desirable NO_x control alternative from an operational standpoint. Section 4.3 summarizes and discusses all the field data in light of the suitability of combustion modifications as NO_x control alternatives and presents recommendations for further work.

4.2.1 Boiler Manufacturer Field Experience (B&W)

B&W tested at least six cyclone boilers to determine the effects of nonload-reduction combustion modifications on NO_x emissions. No written reports concerning these tests were available in the open literature. In general, the data that were obtained from B&W during the course of this work were sketchy and incomplete because of the age of the data and because of confidentiality agreements between B&W and the boiler owners. None of the boiler units could be specifically identified. However, all the boilers were of the utility type. Modifications of cyclone furnaces investigated by B&W include low-excess-air firing (LEA), fuel switching, and simulated staged firing.

TABLE 26. CYCLONE BOILER UNITS FIELD-TESTED FOR COMBUSTION MODIFICATION APPLICABILITY[18-21]

Testing agency	Boiler I. D. number	Boiler identification	Size (maximum continuous steam), kg/s	Fuels used during tests	Combustion modifications applied: Load reduction	Low excess air	Staged firing	Switched-fuel firing
B&W	3	Unidentified utility boiler	167[b] (200 MW)	Bituminous coal, coal and gas		X		X
B&W	4	Unidentified utility boiler	NA	Bituminous coal	X			
B&W	5	Unidentified utility boiler	200[b] (240 MW)	Bituminous, sub-bituminous, and 50/50 coal blend				X
B&W	9	Unidentified	NA[a]	Lignite		X		
B&W	11	Unidentified	NA	Residual oil		X	X	
B&W	15	Unidentified	NA	Natural gas			X	
Exxon	6	TVA Paradise Station, Unit No. 1 utility boiler	618	Bituminous coal	X		X	
Exxon	12	Unidentified utility boiler	309	Residual oil	X		X	
Exxon	13	Atlantic City Electric--England Station, Unit No. 1 utility boiler	117	Residual oil	X	X	X	
Exxon	14	Atlantic City Electric--England Station, Unit No. 2 utility boiler	158	Residual oil		X		
KVB	7	Unidentified industrial boiler located in New York	64.7	Bituminous coal, blends of coal and oil	X	X		X
NAPCA (EPA)	1	Unidentified utility boiler	171.5	Bituminous coal	X			

[a]NA = not available.

[b]Estimated.

4.2.1.1 Low Excess Air Firing (LEA)--
One boiler (I. D. No. 9) firing lignite and one boiler (I. D. No. 11) firing residual oil were tested under LEA conditions to determine NO_x emission reductions. Boiler No. 9 was tested at its full (unknown) load. The results of this test are shown in Table 27. Reducing excess air by 75% (6.4% O_2 reduced to 1.6% O_2 in the flue gas) reduced the NO_x level by 47%. However, CO emissions increased as the excess air was being reduced.

TABLE 27. LIGNITE-FIRED BOILER (Boiler I. D. No. 9)[a]

O_2 in flue gas, %	NO_x, vppm dry 3% O_2 basis	CO, vppm	SO_2 vppm
7.0	-	-	765
6.4	685	-	-
5.6	640	-	590
5.1	575	-	580
4.9	562	-	-
4.6	503	-	-
4.3	600	10	735
4.0	640	12	660
2.9	540	12	845
1.6[b]	360	17	800

[a]Data courtesy of the Babcock & Wilcox Co.

[b]Low excess air required supplemental oil to maintain ignition.

In addition, the lowest excess air setting (1.6% in flue gas) required supplemental oil to maintain ignition. At present there is no lignite NO_x NSPS which could be used to compare the NO_x reduction achieved during this test. The proposed standard is 258 ng/J (0.6 lb/10^6 Btu) or approximately 430 vppm. Table 27 indicates that this proposed standard can be met for boiler No. 9 but only at the 1.6% O_2 level with supplemental oil fuel.

Boiler No. 11 was fired with residual fuel oil. Normal firing of this cyclone with oil at 2.6% O_2 in the flue gas yielded about 360 vppm NO_x and 1,000+ vppm CO. When the O_2 was increased to 3.2% in the flue gas, the NO_x increased by 28% to 460 vppm, and CO decreased to about 50 vppm. The reduction in NO_x could not be justified by the high levels of CO which occurred during this test.

4.2.1.2 Combined LEA and Switched Fuel Test--
Boiler No. 3 was a 200-MW (about 167 kg/s primary steam) coal-fired unit equipped with flue gas recirculation for steam

temperature control. At normal full load, it operated at 3.6% O_2 in the flue gas, yielding 1,020 ppm NO_x with negligible CO. This unit was operated at 1.6% O_2 in the flue gas, firing one cyclone with coal and the remainder with natural gas. It is not known how many cyclones the boiler had. At full load, the test yielded an NOx level of 700 ppm. At the same time, the CO level increased to 2,100 ppm. Flue gas recirculation was used during this test but not for NO_x control. From the available data, it was not possible to distinguish the individual effects of the switched fuel and LEA on NO_x emissions. As with boiler No. 11, the NO_x reduction achieved could not be justified by the high CO levels.

4.2.1.3 Switched Fuel Test--
Boiler No. 5 was a 240-MW (about 200 kg/s primary steam) coal-fired unit equipped with flue gas recirculation and gas tempering for steam temperature control. This unit was tested to determine the effect of coal type on boiler emissions. Table 28 summarizes the data. Sulfur oxide emissions were significantly reduced by switching to the western coal, which apparently had low sulfur content. At the same time, NO_x emissions were reduced only slightly. Blending the eastern and western coals resulted in NO_x emissions slightly higher than when these coals were individually fired. No other test details were available. For the purposes of NO_x control, at least, switching to low-sulfur western coal did not appear to significantly affect the high NO_x level which is characteristic of coal firing. Sulfur oxide emissions were reduced, however, by 75%.

TABLE 28. EFFECT OF FUEL SWITCHING ON NO_x EMISSIONS FROM COAL-FIRED BOILER I. D. NO. 5[a]

Coal type	O_2 in flue gas, %	Concentration, ppm		
		NO_x	SO_2	SO_3
Illinois (bituminous)	2.6	960	2,140	33
Montana (subbituminous)	3.5	910	535	14
50/50 Blend of Illinois and Montana	3.4	1,020	1,365	NA

[a]Data courtesy of the Babcock & Wilcox Co.

4.2.1.4 Simulated Staged Firing--
Babcock & Wilcox, the originators of the staged-firing concept, have applied simulated staged firing to several cyclone boilers with limited success. Staged firing consists of sustaining part of the combustion in a reducing atmosphere zone. Combustion is then completed in an oxidizing atmosphere. The concept of staged firing is particularly attractive in that it can simultaneously lower both fuel and thermal NO contributions. Several forms of

staged firing have been applied to specific boiler units. The forms specifically applied by B&W to cyclone boilers include two-staging and pattern firing.

Two-staging consists of operating the cyclone(s) slightly fuel-rich. The amount of combustion air fed into the cyclone is reduced. Consequently, the bulk of combustion with the cyclone occurs at slightly fuel-rich or reducing atmosphere conditions. This reduces fuel NO formation. The remainder of the required combustion air is fed into the boiler at a point near the exit of the cyclone furnace proper, usually through the flue gas recirculation (FGR) ductwork. This means that the overall combustion is extended over a longer time and furnace space resulting in lower cyclone furnace heat release rates and temperatures. Lower furnace temperatures then result in lower thermal NO formation. Figure 20 shows the schematic of the two-staging concept. Two-staging requires some additional ductwork and controls and therefore slight boiler modification.

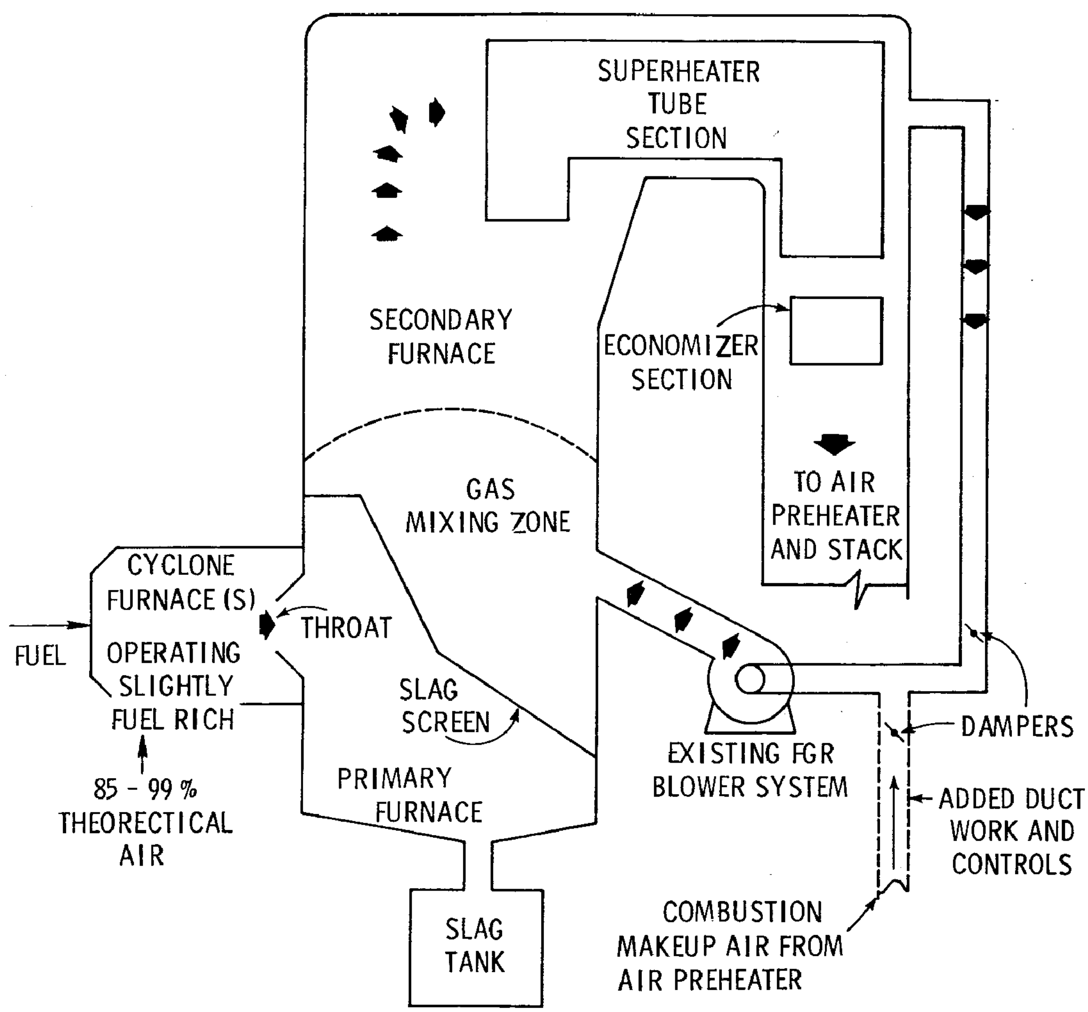


Figure 20. Two-staging concept.

B&W evaluated an eastern-coal-fired boiler and a gas-fired boiler, both modified for two-staging tests. The first unit (unidentified) firing eastern coal showed a 28% to 36% reduction in NO_x emissions. NO_x emissions at full load are normally about 1,110 ppm. With two-staging, NO_x levels were between 700 ppm and 800 ppm. This does not appear sufficient to meet the 500 ppm stated in the NSPS. B&W also found that oil supplement may be required to maintain ignition and flame stability in the cyclone furnace depending on the primary fuel burned. According to B&W, more oil may be required for lignitic coals than for bituminous coals.

The gas-fired cyclone boiler unit (boiler No. 15) showed a 48% reduction in NO_x emissions using the two-staging concept. Specifically, the NO_x emissions were reduced from 500 vppm to 260 vppm. This is 100 vppm above the NSPS of 160 vppm. B&W indicated a strong reluctance to recommend two-staging as a viable NO_x control alternative. The reasons given include a combination of the following factors: (1) lack of significant long-term testing experience, (2) reluctance of boiler owners to accept two-staging on a permanent basis, and (3) risk of catastrophic tube corrosion in the primary furnace (refer to Section 3.1.6).

Another form of staged firing applied to cyclone boilers is called pattern firing. Pattern firing is possible only in multiple cyclone units in stacked configuration. The idea behind pattern firing is to operate the upper row of cyclones and the bottom row of cyclones in such a way as to produce a staged effect. Normally, in stacked multiple cyclone firing at full load, each cyclone (in both the upper and lower rows) is fed equal amounts of fuel at identical air/fuel ratios. With pattern firing, the amount of fuel fed in each cyclone as well as the air-to-fuel ratios are adjusted in one of the combination modes shown in Table 29. The effect of all of the pattern combinations shown is to produce a fuel-lean condition in the upper row(s) of cyclones. Using the experience from two-staging, the most effective pattern-firing combination for reducing NO_x is to run the lower cyclones under reducing conditions and the upper row of cyclones under oxidizing conditions. This practice, however, is prohibited by B&W for safety reasons. Sustained operation of cyclones in reducing atmospheres can cause catastrophic tube failure due to iron sulfide and iron formation (see Section 3.1.6).

A residual oil unit was tested by B&W to determine the degree of NO_x control achievable with pattern firing. This unit (No. 11) was tested at full load, both in normal operation and in the pattern-firing mode. Under normal full-load conditions with 1.3% O_2 in the stack (about 6.3% excess air) the baseline NO_x level was about 380 vppm on a 3% O_2 dry basis. Patterned firing capable of full load showed NO_x levels between 290 vppm and 300 vppm (3% O_2, dry) at 1.6% O_2 in stack (about 7.8% excess air). Thus, NO_x reductions achieved ranged between 21% and 24%. At the

TABLE 29. SEVEN FUEL AND AIR FLOW COMBINATIONS FOR STACKED-CYCLONE FIRING (PATTERN FIRING)

Firing mode	Change in fuel feed	Change in excess air feed
1. Normal full load	Zero	Zero
2. Normal partial load	Zero	Zero
3. Normal partial load	One or more burners out of service	Zero (cut air flow to inoperative burners)
4. Pattern full load[a]	Zero	+ Upper row - Lower row
5. Pattern partial load[a]	- Upper row + Lower row	+ Upper row - Lower row
6. Pattern partial load[a]	Upper row air only + Lower row	- Upper row - Or normal lower row
7. Pattern partial load[a]	- Upper row + Lower row	Zero

[a]Lower cyclone row should not be run in highly reducing atmosphere because of corrosion risks.

same time, the level of excess air increased by 22%. No other details or implications were made available concerning this test. Also, the degree of boiler operating difficulties, efficiency penalties, pattern firing combination, and corrosion potential were not defined.

4.2.2 Exxon Field Experience

The Government Research Laboratory of Exxon Research and Engineering Company, Linden, New Jersey, has tested four cyclone boilers (Nos. 6, 12, 13, 14). These boilers were field tested during the course of EPA-sponsored programs to determine application of combustion modification to control NO_x from utility boilers.[20,21] Altogether, three residual-oil-fired units and one bituminous-coal-fired unit were tested. The combustion modifications applied were LEA, FGR, pattern firing, load reduction, and combinations thereof.

4.2.2.1 Boiler No. 6--

Boiler No. 6 constitutes Unit 1 of the TVA Paradise Station located in Drakesboro, Kentucky. The maximum rated capacity of the unit is 704 MW at 618 kg/s (4.9×10^6 lb/hr) of primary steam flow. High-sulfur bituminous coal is used as fuel. The main steam pressure is 16,546 kPa (2,400 psi) at 840 K (1053°F). The unit is equipped with a steam reheat capacity of 435 kg/s (3.45×10^6 lb/hr) at 2,103 kPa (305 psi) and 813 K (1003°F).

Fourteen B&W cyclones fire the unit and are arranged in two facing, front and rear, walls containing seven cyclones each. The cyclones are arranged in the stacked cyclone configuration shown in Figure 21. Each cyclone is 3 m in diameter and 3.6 m long. The cyclones are located on approximately 5 m centers.

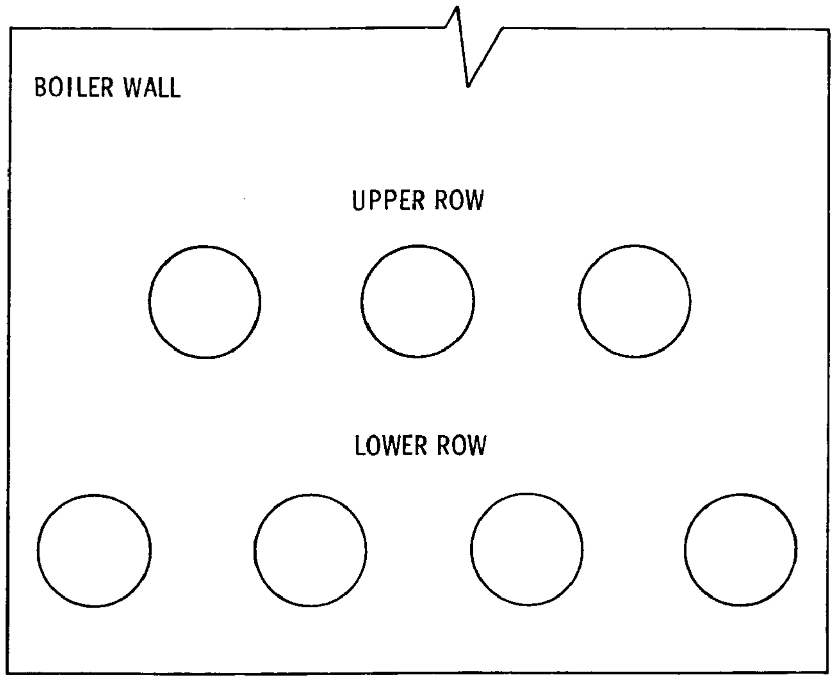


Figure 21. Cyclone firing arrangement, TVA Unit No. 1, Drakesboro, Kentucky (view facing front or rear wall).

Exxon formulated the boiler test program based upon recommendations provided by B&W, a subcontractor for the program. B&W stipulated that during Exxon's testing, the total air feed to the cyclones would not be reduced below 122% to prevent fireside corrosion. In addition, B&W required that cyclone temperatures not be reduced below a point where slag chilling could result in slag tapping problems.

The entire test program was of short duration (2 days) and did not involve any major hardware changes. The baseline full and partial load NO_x data generated during this program were presented in Section 3.3.4 of this report and are also part of the load reduction data presented in Section 4.2.4 (Runs 1 and 4).

Exxon's boiler test program is presented in Table 30. All burners were in service during the six test runs. Runs 1 through 3 were performed at near full boiler load (94%). Run 1 established boiler baseline NO_x emissions. In run 2 the ratio of gas

TABLE 30. BOILER TEST PROGRAM IMPLEMENTED BY EXXON (BOILER I. D. NO. 6, TVA PARADISE UNIT NO. 1)

Run No.	Load, % (MW)	Excess air level, %	FGR variations		Cyclone	
			Gas recirculation	Tempering	Change in fuel feed	Change in air feed
1	100 (704)	120	Minimum	Maximum	Zero	Zero
2	100 (704)	120	Increase	Decrease	Zero	Zero
3	100 (704)	120	Minimum	Maximum	+ Bottom	Zero
4	78 (550)	120+	Minimum	Maximum	Zero	Zero
5	78 (550)	120+	Minimum	Maximum	Bottom normal - top (50%)	Zero
6	78 (550)	120+	Minimum	Maximum	Bottom normal - top (50%)	Zero - bottom + - top

recirculation and gas tempering was varied to determine the effects of FGR. If applied properly, FGR can lower the peak flame zone temperature and also reduce the amount of O_2 available for NO formation. Section 4.3.3 defines and illustrates FGR, which is normally used for steam temperature control in boiler units so equipped. For Run 3, more coal was fed to the bottom cyclone rows than to the top rows at no air flow change and full load. Runs 4 through 6 were performed at about 3/4 load. Run 4 is a baseline NO_x run at this partial load. During Run 5, the normal full load amounts of coal were fed to the bottom cyclones, and about 50% less than normal, full-load amounts were fed to the top row of cyclones at zero air flow change. The same coal flows were used during Run 6, but the secondary air was increased to the upper row of cyclones until boiler excess O_2 increased from 3.9% to 4.9%. The overall attempt in Runs 3, 5, and 6 was to produce a staging effect of the top and bottom cyclone combination. The upper burners in Runs 3, 5, and 6 were operated under highly lean conditions. B&W prohibited the lower cyclones to be run under reducing conditions for any of these tests.

Table 31 presents the results of the test program. Exxon and B&W concluded that no significant change in boiler efficiency was experienced during the tests, and nitric oxide production was significantly decreased by reducing the boiler load. Flue gas recirculation (FGR) applied to the maximum extent reduced NO_x by 7% (1,197 vppm to 1,112 vppm, Runs 1 and 2). Feeding more coal to the bottom cyclones at full load at zero air flow change in Run 3

TABLE 31. SUMMARY OF EMISSION DATA, BOILER I. D. NO. 6, 704 MW COAL-FIRED, TVA PARADISE UNIT NO. 1[18]

Run No.	Type of test	Operating data: Gross boiler load, MW	Boiler efficiency, %	Boiler excess air level	FGR	Total coal flow, kg/s	Distribution of coal between upper and lower rows, % upper/lower	Change in air flow feed	Flue gas components[a]: O_2 dry basis, %	CO_2 dry basis, %	NO_x 3% O_2 dry basis, vppm	Flue gas temperature, K (°F)
1	Full load baseline	665	91.1	Normal	Minimum	70.5	51/49	Zero	5.3	13.1	1,197	604 (627)
2	FGR effects at full load	668	91.5	Normal	Maximum	70.1	51/49	Zero	5.3	13.2	1,112	597 (615)
3	Changed coal feed[b] between upper and lower cyclones at full load	660	90.8	Normal	Minimum	75.0	44/56	Zero	5.4	13.0	1,203	602 (624)
4	Partial load baseline	545	91.6	Normal	Minimum	56.2	51/49	Zero	5.3	13.3	886	585 (593)
5	Changed coal feed between upper and lower cyclones at 3/4 load	545	92.0	Normal	Minimum	59.8	38/62	Zero	5.1	13.6	915	594 (609)
6	Changed coal feed and excess air flow between upper and lower cyclones at 3/4 load	548	91.7	Normal	Minimum	60.6	38/62	Increased[c]	5.6	13.0	846	595 (611)

[a]Average of 16 data points per run. Each data point from a composite of three gas sample streams. CO emissions were not measured. Hydrocarbons emissions measured <1 ppm.

[b]"Staged firing" simulated by operating top cyclone burners under highly fuel-lean conditions.

[c]Boiler excess O_2 increased 25% by increasing secondary air to upper rows.

had no effect on NO_x but reduced boiler efficiency slightly. At partial load, NO_x increased by 3% when coal feed was changed and at no air flow change (Runs 4 and 5). Operating the boiler with both fuel and air changed lowered the NO_x level by 4% (886 vppm to 846 vppm, Runs 4 and 6).

The relatively insignificant changes in NO_x level witnessed during these runs perhaps exemplify the improper application of FGR and staging to cyclone boilers. As regards FGR, Figure 22 shows the entry points of recirculated flue gas in boiler No. 6. It should be noted that the recirculated flue gas enters the secondary boiler furnace rather than the cyclone furnace. FGR was originally built into boiler units for purposes of steam temperature control (refer to Section 4.3.2). The entry points of recirculated flue gas in boiler No. 6 provide for optional steam temperature control but are not effective for NO_x control. To be truly effective, FGR must be applied directly to or very near the combustion flame zone within each cylone. In an existing unit such as boiler No. 6, this is difficult to do without extensive equipment modifications. Modifying boiler No. 6 in such a fashion was beyond the scope of Exxon's program.

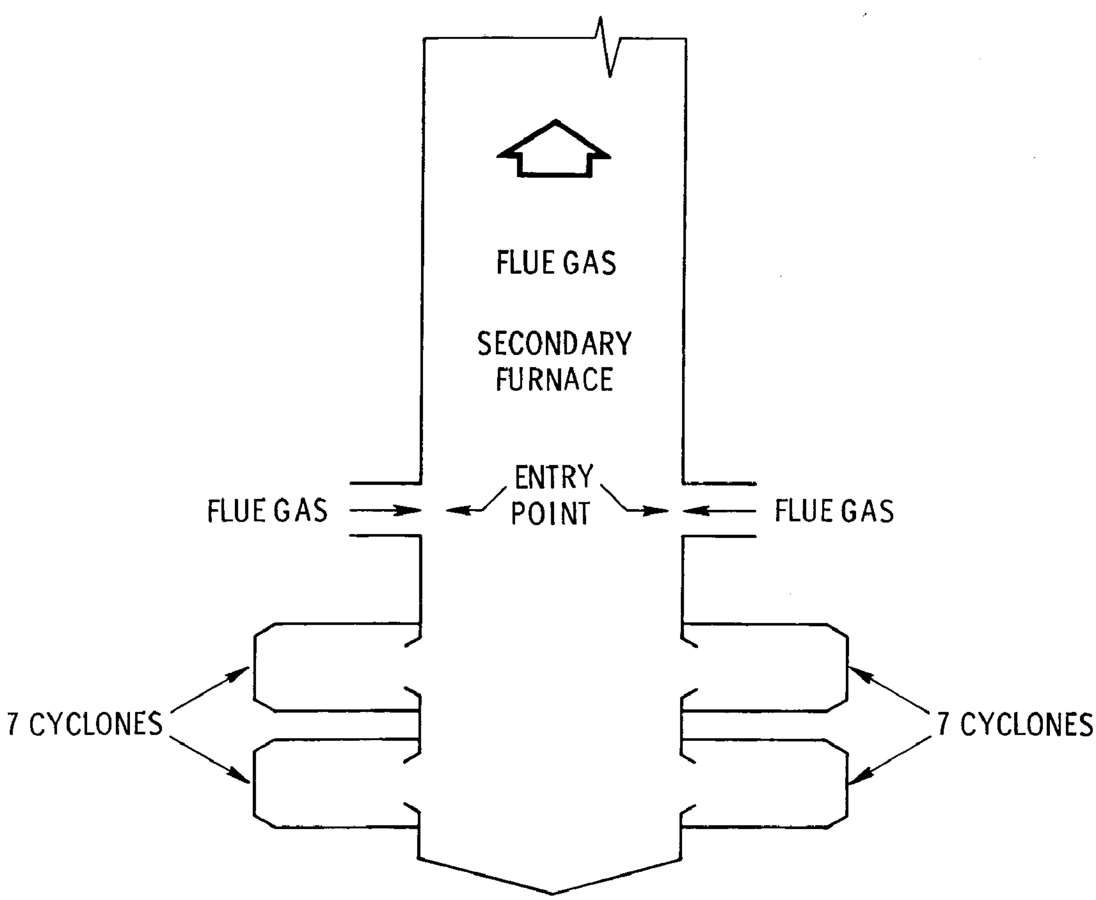


Figure 22. Recirculated flue gas entry points for boiler No. 6.

The staging tests performed by Exxon were very limited in that none of the boiler combustion occurred under reducing atmosphere conditions (B&W's lower limit of 122% total air), which are necessary for NO_x reduction.

4.2.2.2 Boiler No. 12--
Residual-oil-fired boiler No. 12 was tested for NO_x emissions at LEA conditions, simulated staged combustion (pattern firing), and at reduced load. Baseline emissions and load reduction data for this unit are contained in Sections 3.3.4 and 4.2.4 of this report and are also included here for comparison.

A summary of emissions data for boiler No. 12 is given is Table 32. The emissions from the two ducts sampled are given separately in Table 32 due to wide differences in the gas composition in these sampling locations. The significance of the data variability was not explained in the literature. Evidently some difficulties in determining excess O_2 in the boiler were experienced during this test, as indicated by the flue gas O_2 measurements made by Exxon and the boiler recording instrument. The point of minimum excess air was not defined. In any case, it can be assumed that Runs 1 and 3 were baseline runs at full and partial load, respectively, and that Runs 2 and 4 were LEA runs as suggested by the NO_x emission data. The suggested classification of the runs is also presented in Table 32 (second column).

TABLE 32. SUMMARY OF EMISSION DATA FROM BOILER NO. 12, 450 MW[21]

				Flue gas compositions[a] and temperatures											
				Duct No. 1					Duct No. 2						
		Gross boiler	No. of	Dry basis, %		ppm, 3% O_2 dry basis		Temp,	Dry basis, %		ppm, 3% O_2 dry basis		Temp,	
Run No.	Type of test	load, MW	cyclones firing	O_2	CO_2	NO_x	CO	K (°F)	O_2	CO_2	NO_x	CO	K (°F)	O_2, %[b]
1	Full load baseline	421	8	4.1	12.2	548	8	594 (610)	2.7	12.8	572	6	625 (666)	2.1
2	LEA	410	8	4.9	11.4	505	6	597 (615)	4.3	11.8	497	6	628 (671)	2.7
3	Partial load baseline	255	8	4.6	12.0	214	NA	584 (592)	6.5	7.4	200	NA	618 (653)	2.2
4	LEA	262	8	2.5	13.3	211	3	578 (581)	4.9	11.3	200	3	578 (581)	4.2
5	Pattern firing	275	6[c]	5.1	11.2	315	1	600 (621)	6.9	9.5	306	2	591 (604)	4.5

[a]Average of four data points. Each data point from compositie of three gas sample streams.

[b]Boiler O_2 recorder data.

[c]6 cyclones firing oil and 2 cyclones on air only to simulate staged combustion.

NA = not available.

At full load (about 93%), the NO_x level for this cyclone unit was reduced with LEA firing by only 11% (based on average values from ducts No. 1 and 2; 560 reduced to 501 vppm). The 3% reduction in boiler load between test Runs 1 and 2 may account for some of the NO_x lowering. At partial load (57%), LEA did not reduce baseline NO_x although the boiler O_2 data indicate that excess air was reduced by one-third (Exxon O_2 data averages). As has been the usual case with cyclone boilers, these data also show that load reduction results in the most dramatic NO_x level decrease (over 60% NO_x reduction for 38% load reduction).

Run 5 was made to simulate staged combustion (within the flexibility of this boiler). Two upper-level cyclones were fired on air only, while the other six cyclones were fired at increased rates to maintain load. This change resulted in an increase of NO_x emissions by about 50% (206 ppm to 310 ppm), presumably because of the higher intensity firing of the operating six cyclones.

4.2.2.3 Boiler Nos. 13 and 14--
Boiler No. 13 and boiler No. 14 constitute steam generating Units 1 and 2 of the B. L. England Station owned by Atlantic City Electric (New Jersey). Boiler No. 13 (117 kg/s steam, 136 MW) is fired by single mechanical atomizing oil burners in each of the three cyclones. The cyclones are arranged in a triangular fashion with two cyclones on one level and the third cyclone elevated. All three cyclones are in the front wall of the furnace.

Boiler No. 14 (157 kg/s steam, 168 MW) is also fired by single mechanical atomizing oil burners. This boiler has four cyclones arranged in a square pattern, two cyclones at each elevation. All four cyclones are installed in the front wall of the boiler. Both boilers burn crude oil.

During the testing performed on boiler No. 13, the influence of excess air, load reductions, and combinations thereof were studied. Boiler No. 14 was tested at normal and LEA conditions at full load only. Baseline emissions and load reduction data for these two boilers are contained in Sections 3.3.4 and 4.2.4 of this report and also in this section for comparison.

For boiler No. 13, LEA at full load was defined as 1.1% on the boiler O_2 meter (0.5% avg O_2 measured by Exxon). At these oxygen concentrations, the smoke density on ACE's smoke meter was normal, and no visible emissions were apparent from the stack. However, carbon monoxide emissions increased (>1,500 ppm) and continued operation at this low level of excess air could not be recommended. At partial load (103 MW), the minimum excess air was defined as that which produced only a slightly visible stack plume, no appreciable increase in smoke density, and reasonable CO emissions (about 200 ppm max.).

For boiler No. 14, LEA was defined similarly to that for boiler No. 13 at partial load.

The operating and emissions data for these two boilers are presented in Table 33. With the exception of Run 3 for boiler No. 13, normal cyclone firing patterns were used. Data for boiler No. 13, Run 3 were taken at low load with the middle (upper) cyclone taken out of service.

The comments of A. R. Crawford, E. H. Manny, and W. Bartok best summarize the conclusions made during this boiler testing program.[20]

> Boiler No. 13
>
> "Baseline operations (test run No. 1) conducted with all three cyclones operated normally, produced average flue gas concentrations of 441 ppm NO_x (3% O_2, dry basis) at 1.5% oxygen. Reducing the excess air level to 1.1% and 0.5% oxygen in the flue gas resulted in a reduction in average emission levels at this load to 396 ppm and 313 ppm NO_x (3% O_2, dry basis), respectively. Baseline operation at 105 MW output produced 404 ppm NO_x (3% O_2, dry basis) at the level of 2.7% O_2 in the flue gas. Reducing excess air to 2.4% and 1.0% O_2 in the flue gas reduced NO_x emissions to 364 ppm and 241 ppm, respectively, at the intermediate load. At the minimum load of 62 MW, a baseline emission level of 261 ppm NO_x (3% O_2, dry basis) was measured at 4.2% oxygen. This level is about the same as the emissions at the intermediate load level of 105 MW at low excess air conditions, indicating the particularly significant contribution of fuel nitrogen oxidation to NO_x emission at intermediate to low load levels; i.e., at lowered combustion intensity conditions.
>
> "Decreasing excess air levels at both full and intermediate loads had a substantial effect on reducing NO_x emission levels. With cyclone operation, at least at present, staged firing patterns which might effect further reductions are not possible.
>
> "To sum up, this boiler has baseline NO_x emissions of 441 ppm which are higher than the original recommended new source emission standards of about 225 ppm for oil-fired boilers. (The maximum NO_x reduction achievable at full load with an acceptable level of CO was 10%.) Low excess air operation at full and intermediate loads resulted in significant lowering of NO_x emissions as shown in Table 33. However, decreases in load and reductions in excess air levels could not reduce emissions below the recommended standards for new boilers which are subject to reassessment at present by EPA."

TABLE 33. SUMMARY OF OPERATING CONDITIONS AND EMISSIONS DATA FOR OIL-FIRED BOILER NOS. 13 AND 14 (ACE, B. L. ENGLAND UNITS 1 AND 2)[20]

Boiler operating conditions				Average flue gas measurements[a]						
Test run No.	Gross load, MW	Excess air level	Firing pattern	Smoke density	O_2, %	NO_x 3% O_2 dry basis, vppm	NO_x, ng/J ($lb/10^6$ Btu)	CO 3% O_2 basis, vppm	CO_2, %	Temperature, K (°F)
				Boiler No. 13						
1	133	Normal	All cyclones on	30	1.5	441	254 (0.59)	57	13.1	679 (762)
2	133	Intermediate	All cyclones on	30	1.1	396	228 (0.53)	74	13.1	678 (760)
3	132	Low[b]	All cyclones on	30	0.5	313	181 (0.42)	1,523	13.2	671 (748)
4	62	Normal	Middle cyclone off	24	4.2	261	151 (0.35)	54	11.9	603 (625)
5	105	Normal	All cyclones on	26	2.7	404	232 (0.54)	59	12.7	695 (726)
6	105	Intermediate	All cyclones on	26	2.4	364	206 (0.48)	53	12.9	653 (715)
7	103	Low	All cyclones on	25	1.0	241	138 (0.32)	68	13.8	643 (697)
				Boiler No. 14						
1	167	Normal	All cyclones on	24	2.2	361	206 (0.48)	85	13.5	645 (701)
2	167	Low	All cyclones on	24	1.6	303	181 (0.42)	231	13.5	643 (697)

[a]Flue gas measurements made on composite gas samples from three individual sampling tubes. Measurements shown are averages of three analyses from three sampling tubes (short, medium, and long) for each of four probes.

[b]Excessively high CO emissions at this condition.

Boiler No. 14

"Baseline operations (test run No. 1) conducted at full load with all four cyclones firing crude oil, produced average flue gas NO_x concentrations of 361 ppm (3% O_2, dry basis) at 2.2% oxygen. Reducing the excess air level to that corresponding to 1.6% oxygen in the flue gas resulted in an average level of 303 ppm NO_x (3% O_2, dry basis), or a decrease of 16% from baseline conditions.

"To sum up, this boiler has baseline NO_x emissions of 361 ppm NO_x which are higher than the original EPA recommended standards of about 225 ppm for new oil-fired boilers. Low excess air operation resulted in a 16% reduction in NO_x emissions, but could not reduce them below recommended standard levels. This reduction in NO_x emissions was achieved without any adverse effects, such as significantly increased smoke, unburned combustible emissions, or reduced operability."

4.2.3 KVB Field Experience (Industrial Boiler)

During the first phase of an EPA-sponsored study to determine application of combustion modifications to control NO_x from industrial boilers, KVB Engineering, Inc., Tustin, California, field sampled 47 representative boilers of various firing types ranging from 1.3 to 65 kg/s of steam capacity.[22] One of these units was a large industrial boiler of 64.7 kg/s steam capacity fired by two cyclone furnaces; it is identified in this report as boiler No. 7. Details on this boiler unit, which is located in New York state, are given in Section 3.3.5. Boiler No. 7 normally fires coal at a baseline load of 40 kg/s (62% of max. load).

The combustion modifications testing performed on boiler No. 7 were limited in scope. Altogether eight test runs were made. One LEA run and four switched fuel runs were performed in addition to three baseline runs. Table 34 presents all of the cyclone boiler data compiled in KVB's Phase I final report.[22]

Run 4 was conducted at about 9% lower excess air than that used for normal firing at the same load (62% of full load). Comparing Run 2 (baseline) with Run 4 shows that NO_x emissions were reduced by 11%, from 800 vppm to 755 vppm. At the same time, carbon monoxide concentration did not increase.

Mixtures of coal and No. 5 fuel oil were used to determine their effect on boiler NO_x emissions. KVB's conclusions for the switched fuel tests follow:

"A 9% increase of NO_x was shown when 30% of No. 5 fuel oil was fired along with the coal at normal excess air levels (run No. 6). But when the excess oxygen was

TABLE 34. BASELINE AND COMBUSTION MODIFICATION EMISSIONS DATA (BOILER LOCATED IN NEW YORK, BOILER NO. 7)[20]

Run No.	Type of test	Fuel burned	Test load, kg/s steam	Full load, %	Flue gas O_2, % dry	Stack temp, K (°F)	NO_x Dry 3% O_2 basis, vppm	NO_x ng/J ($lb/10^6$ Btu)	CO vppm	CO ng/J ($lb/10^6$ Btu)	SO_2 vppm	SO_2 ng/J ($lb/10^6$ Btu)	SO_3 vppm	SO_3 ng/J ($lb/10^6$ Btu)	Particulates, ng/J ($lb/10^6$ Btu)
1	Baseline	Bituminous coal	40.3	78.4	3.2	418 (293)	790	473 (1.10)	0	0	NA	NA	NA	NA	NA
2	Baseline	Bituminous coal	40.3	62.4	3.4	418 (293)	800	482 (1.12)	0	0	1,122	937 (2.18)	13	10.7 (0.025)	513 (1.19)
3	Baseline	Bituminous coal	30.3	46.8	3.2	418 (293)	742	447 (1.04)	0	0	NA	NA	NA	NA	NA
4	LEA	Bituminous coal	40.5	62.6	3.1	418 (293)	755	455 (1.06)	0	0	NA	NA	NA	NA	NA
5	Switched fuel	70/30[a]	40.3	62.4	3.4	423 (302)	710	408 (0.95)	0	0	NA	NA	NA	NA	184 (0.43)
6	Switched fuel	70/30[a]	51.4	79.5	3.6	423 (302)	860	494 (1.15)	0	0	NA	NA	NA	NA	NA
7	Switched fuel	50/50[a]	40.3	62.4	3.5	421 (298)	716	408 (0.95)	0	0	NA	NA	NA	NA	NA
8	Switched fuel	50/50[a]	50.4	77.9	3.7	421 (298)	797	456 (1.06)	0	0	NA	NA	NA	NA	NA

[a]The ratio of bituminous coal and No. 5 fuel oil fired during testings.

NA = not available.

returned to the baseline level of 3.4% (as measured in the flue gas) and the load was reduced to baseline level in run No. 5, the NO_x decreased by 11% (compare run Nos. 2 and 5). Apparently, at this mixture the nitrogen oxides formation was very sensitive to the amount of excess air being fired. A 50-50 mixture of coal and oil showed no change in NO_x; however, there was insufficient time available to investigate completely whether or not it was possible in this latter case to lower the excess oxygen and thereby lower the NO_x, as had been done in run No. 5."

As was true with Exxon's tests, KVB observed that the cyclone-fired boiler had the highest NO_x emission levels of any other boiler firing method that they field sampled. It was noted during KVB's tests that the molten slag acts as thermal insulation, helping to produce more of an adiabatic combustion zone. In addition, of all boilers tested during KVB's study, boiler No. 7, the only cyclone boiler, had the smallest furnace volume per unit heat release rate [0.19 m^3/MW (gross)] and the highest burner heat release rate [75 MW (gross)/burner]. These two factors account for high combustion temperatures (>1920 K) and associated high NO_x emissions.

4.2.4 Load Reduction Field Test Data

Under reduced load conditions, a boiler operates at a fraction of its maximum steaming rate because of lowered fuel and air settings. Load reduction is commonly applied to boilers at off-peak loads to save fuel. For cyclone-fired boilers, the maximum load reduction is about 40% of the maximum continuous steam rating. Reduction below this point can result in flame instability with possible loss of ignition, lack of adequate steam temperature control, and excessive slagging on cyclone walls when firing coal due to decreased cyclone furnace temperature.

Load reduction of a boiler unit results in decreased combustion turbulence and volumetric heat release rate. The net effect of load reduction is to produce lower effective peak temperatures for NO formation in the primary and secondary furnace sections of the boiler unit. This ultimately results in lower stack NO_x emissions.

Load reduction in cyclone-fired boilers results in consistently lower NO_x emissions when compared to the same boilers at full or normal loads. Load reduction primarily affects thermal NO formation and cannot effectively reduce the conversion of fuel-bound nitrogen to NO. In addition, it is usually considered an economically unattractive method for reducing NO_x emissions because of the penalties incurred and because of reduced thermal efficiency and reduced boiler flexibility.

Figure 23 summarizes the available data on load reduction for six cyclone-fired boilers. (These data also appear in Section 3.3 of this report.) NO_x emissions levels were determined for these boilers at both full and partial loads, making reduction comparisons possible. The only data available were for bituminous-coal-fired and oil-fired units. None of the Commonwealth Edison data presented previously in Section 3.3.7 are presented or discussed here because of insufficient data on the exact boiler loads and uncertainties as to whether the data were corrected to a comparable dry 3% O_2 basis.

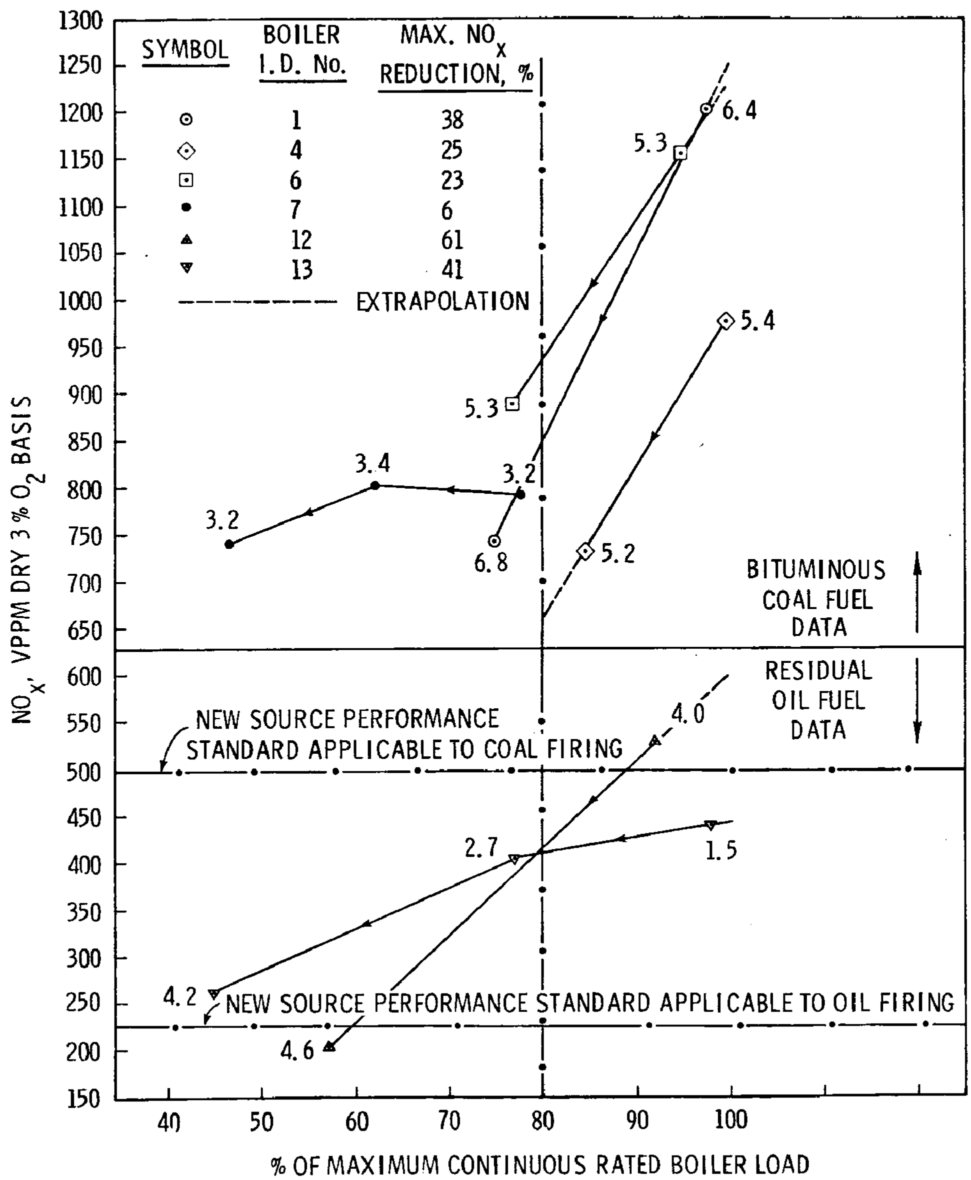


Figure 23. Overall reduction of NO_x emissions for six coal- and oil-fired cyclone furnace boilers using load reduction (stack % O_2 levels indicated adjacent to data points).

The purpose of Figure 23 is to show the degree of NO_x reduction achievable when load reduction was the only combustion modification applied to six specific boiler units. Five of the six units tested showed an overall reduction in NO_x emissions as load was reduced. One bituminous-coal-fired unit showed a 10 vppm gain in NO_x as the load was reduced by 16%. The highest overall reduction in NO_x--61%--was achieved in the two residual-oil-fired units.

Bituminous-coal-fired units showed overall NO_x reductions ranging from 7% to 38% compared to full or normal load NO_x levels. Available data for the six boiler units shown in Figure 23 are presented in summary form in Table 35. Figure 23 indicates that the amount of excess air fed to the furnaces at reduced loads generally increases or remains constant in comparison to full-load conditions. Increasing excess air at low loads serves to negate any dramatic gains in NO_x reduction by furnishing more N_2 and O_2 for thermal and fuel NO formation. In oil-fired boiler No. 13, for example, the percent O_2 in the stack rose from 1.5% at full load to 4.2% at reduced load (see Figure 23 and Table 35). This corresponds to an excess air level of 7.3% at full load and 24% at reduced load. It is partially for this reason that the NO_x reduction in boiler unit No. 10 (41%) is not as dramatic as that of boiler No. 12 (61%), which operated at near constant excess air as load was reduced. Why operators increase the excess air at low loads is discussed further in Section 4.3.3.

Several other trends in NO_x control by load reduction become apparent by further data analysis. In this analysis, the boiler load span between 80% and 100% is investigated because this is the span where the bulk of available data exists (boiler Nos. 1, 4, 6, 12, and 13, Figure 23).

None of the data covered the entire span. Hence, they were extrapolated over the load range between 80% and 100%. For a 20% reduction in load, an average NO_x reduction of 29% was calculated for the three coal-fired boilers (boiler Nos. 1, 4, 6), and a 19% reduction was estimated for the two oil-fired boilers (boiler Nos. 12 and 13). Thus, it appears that slightly better NO_x reductions with reduced boiler loads could be obtained with coal-fired units in the load range between 80% and 100%. A summary of the calculations is given in Table 36.

Even with the significant decreases in NO_x emissions achieved by load reduction, Figure 23 shows that only boiler No. 12 was able to meet the NSPS for NO_x, and this occurred at a load reduction of over 40%. The approximate NSPS limits in units of vppm NO_x for both coal and oil are also shown in Figure 23 (dotted horizontal lines).

The data for all six boiler units, whether fired with oil or coal, indicate that NO_x emissions levels remain fairly constant with widely varying boiler unit size. For example, at full load the

TABLE 35. LOAD REDUCTION TEST DATA

Boiler No.	Boiler identification	Testing agency	Fuel burned	Heating value, MJ/kg	Nitrogen in fuel, wt %	Maximum continuous steaming rate, kg/s	Boiler load, %	NO_x, dry 3% O_2 basis, vppm	NO_x reduction, (gain), %	O_2 in flue gas, %	Symbol on Figure 23
1	Unidentified utility boiler	NAPCA	Bituminous coal	32.4	1.4	171.5	98	1,204	-[b]	6.4	⊙
1	Unidentified utility boiler	NAPCA	Bituminous coal	32.4	1.4	171.5	75	742	38	6.8	⊙
4	Unidentified utility boiler	B&W	Bituminous coal	NA[a]	NA[a]	NA[a]	100	975	-[b]	5.4	◈
4	Unidentified utility boiler	B&W	Bituminous coal	NA[a]	NA[a]	NA[a]	85	730	25	5.2	◈
6	TVA Paradise Station, unit No. 1, utility boiler	Exxon	Bituminous coal	25.8	1.3	618	95	1,155	-[b]	5.3	⊡
6	TVA Paradise Station, unit No. 1, utility boiler	Exxon	Bituminous coal	25.8	1.3	618	77	886	23	5.3	⊡
7	Unidentified industrial boiler located in New York	KVB	Bituminous coal	30.7	1.6	64.7	78	790	-[b]	3.2	●
7	Unidentified industrial boiler located in New York	KVB	Bituminous coal	30.7	1.6	64.7	62	800	(1)	3.4	●
7	Unidentified industrial boiler located in New York	KVB	Bituminous coal	30.7	1.6	64.7	47	742	6	3.2	●
12	Unidentified utility boiler	Exxon	Residual oil	44.6	0.5	309	92	530	-[b]	4.0	△
12	Unidentified utility boiler	Exxon	Residual oil	44.6	0.5	309	57	206	61	4.6	△
13	Atlantic City Electric England Station, unit No. 1 utility boiler	Exxon	Residual oil	NA[a]	NA[a]	117	98	441	-[b]	1.5	▽
13	Atlantic City Electric England Station, unit No. 1 utility boiler	Exxon Exxon	Residual oil	NA[a]	NA[a]	117	77	404	8	2.7	▽
13	Atlantic City Electric England Station, unit No. 1 utility boiler	Exxon	Residual oil	NA[a]	NA[a]	117	45	261	41	4.2	▽

[a]NA = not available.

[b]Not applicable.

TABLE 36. NO_x REDUCTIONS FOR A 20% REDUCTION IN BOILER LOAD

Boiler No.	Fuel	NO_x at 100% load, vppm[a]	NO_x at 80% load, vppm[a]	NO_x reduction, vppm	%
1	Coal	1,240	840	400	32
4	Coal	975	660	315	32
6	Coal	1,220	930	290	24
Average		1,145	810	335	29
12	Oil	600	420	180	30
13	Oil	445	410	35	8
Average		522	415	107	19

[a]Extrapolations from Figure 23, vppm dry 3% O_2 basis.

coal-fired units with boiler steaming rates between 100 kg/s and 600 kg/s showed emission levels ranging between 1,000 vppm and 1,200 vppm. At three-quarter loads, the boilers with steaming rates between 100 kg/s and 500 kg/s emitted between 750 vppm and 850 vppm. The trend is similar for oil-fired boilers, but NO_x emission levels are substantially lower, normally one-half or less of coal emissions for similar loads and sizes. These trends are illustrated in Figure 24.

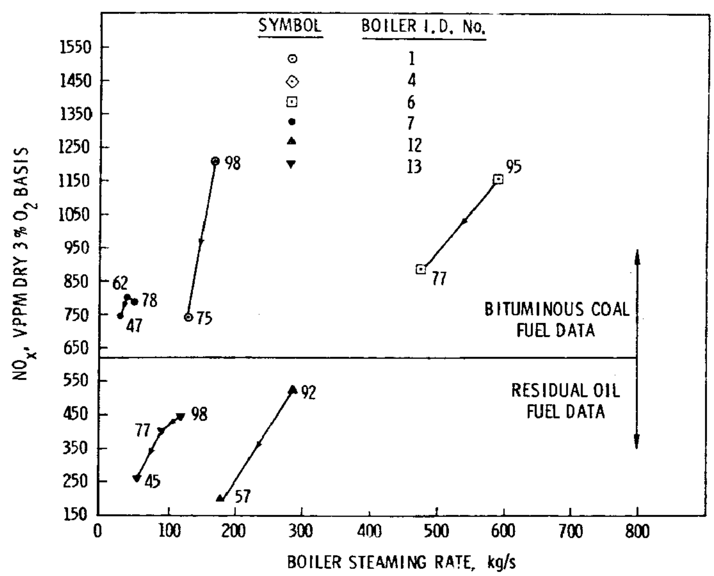


Figure 24. NO_x emissions as a function of boiler size and % load (boiler loads indicated adjacent to data points).

4.3 IMPLICATIONS OF APPLYING STATE OF THE ART NO_x COMBUSTION MODIFICATIONS TO EXISTING CYCLONE COMBUSTION UNITS

This section examines the information presented in Section 4.2, including operating experience with cyclone boiler and furnace modifications for potential application of these modifications to existing cyclone boilers.

In summary, the most consistent NO_x emission reduction in any of the boilers tested was achieved with load reduction. Reducing boiler load from 100% to 80% resulted in average NO_x reductions of 19% with oil-fired units and 29% with coal-fired units. However, even with this reduction in NO_x emissions, the cyclone boilers could not meet the New Source Performance Standard.

The fuel type and characteristics generally have some influence on the NO_x level emitted by cyclone boilers. From rather limited information, it was observed that natural gas-, residual oil-, or lignite-fired boilers had NO_x emissions significantly lower (up to 50%) than units burning the following fuels:

- bituminous coal
- subbituminous coal
- blends of bituminous/subbituminous coals
- blends of fuel oil and bituminous coals

The data in this report indicate that the NO_x NSPS cannot be met at normal full-load firing for any type of fuel in a cyclone boiler unit, with the possible exception of lignite. The proposed lignite standard was met during one test conducted by B&W at very low excess air levels and with supplemental oil fuel (refer to Section 4.2.1.1, boiler No. 9). Thus fuel switching does not appear to be a viable method of NO_x control for purposes of meeting the appropriate fuel NO_x NSPS.

Both load reduction and fuel switching may, however, be practical interim measures in reducing NO_x emissions from some units during serious episode conditions. But both of these methods are the least desirable to the boiler owner for operational and economic reasons. Implications of applying these combustion modifications to cyclone furnaces/boilers are further discussed in Sections 4.3.1 and 4.3.2.

A form of flue gas recirculation (FGR) was applied to only one unit as witnessed by Exxon's data for boiler No. 6. This short duration test, with no hardware modifications, produced no NO_x reduction. FGR for this particular boiler NO_x emission test implied that the recirculated gas was reinjected downstream of the cyclone furnace combustion zone rather than directly into the cyclone where it could possibly be more effective.

Low excess air (LEA) firing gave mixed results for different boilers and fuel types. Of the boilers tested under LEA firing conditions, a lignite boiler showed the highest NO_x reduction; residual oil units showed lesser reductions; and a coal-fired unit showed the least reduction. The general trend observed indicates that NO_x can be reduced by this method at the cost of higher CO emissions. Reducing excess air in one lignite boiler (boiler No. 9, Section 4.2.1.1) resulted in NO_x reductions of 50% with a negligible CO emission increase. Supplemental oil fuel was required at the lower air levels to maintain ignition. Applying LEA firing to residual-oil-fired units (Section 4.2.2) reduced NO_x by 10% to 16% at full load and yielded acceptable CO concentrations (<200 vppm). Reducing excess air further to achieve higher NO_x reductions resulted in excessive CO, with resultant boiler carbon loss and loss of boiler efficiency. A bituminous-coal-fired boiler unit running under LEA conditions showed an NO_x reduction of 11% with no change in CO emissions (0 vppm). Thus NO_x reductions achieved with LEA firing alone in cyclone boilers have not been spectacular, and the resultant NO_x emission levels are well above NSPS.

Staged firing was simulated in several coal-, oil-, and gas-fired boilers. The first method, two-staging, showed a 28% to 36% reduction in NO_x emissions when eastern coal was used. Two-staging with gas firing showed a 48% reduction in NO_x. No test data or details were available to support these figures given by B&W, the originators of the concept.

Pattern firing, the other simulated staged firing concept applied to cyclone boilers, gave mixed results with different boiler units. While B&W claims that 21% to 24% NO_x emission reductions are achievable using this method when burning residual oil, Exxon noticed an increase in NO_x (about 34%) with pattern firing due to increased combustion turbulence in the operating cyclones. Exxon also noticed no change in NO_x level when a bituminous-coal-fired unit was subjected to pattern firing. In either case, B&W does not recommend these staged firing methods for application to existing units for reasons stated in Section 4.2.1.4.

According to B&W, the cyclone boiler manufacturer, all practical possibilities of NO_x reduction have been exhausted for existing cyclone boilers. Even though data on NO_x emissions from a variety of cyclone combustion units are available, it does not appear that the data are sufficient to fully evaluate the effectiveness of different combustion modifications to reduce NO_x emissions. It is true that most combustion modifications have a strong influence on NO_x formation within a cyclone boiler. Despite this influence, NO_x emission reduction to the level that would satisfy existing environmental regulations was rarely achieved. Cyclone furnaces are rather unique and complex systems that were developed primarily to burn low quality fuels. The combustion process in these furnaces is very efficient due to the highly turbulent conditions. Moreover, cyclonic furnaces must operate within a specific range of operating conditions which, if not met, defeat the purpose for which the cyclonic furnace was originally developed, and the cyclonic method of combustion loses its advantages compared to other conventional combustion methods.

The variables that influence cyclonic combustion are not fully understood. This is especially true for variables that can influence formation of NO_x in cyclones. Conversations with boiler owners and the manufacturer (B&W) alike stressed that cyclonic furnaces do not all operate alike. Even in cases of the same boiler fired by multiple but identical cyclones burning identical fuels, it is believed that not all cyclones operate in the same way. This variability requires further definition. When firing at LEA conditions, for example, although the total boiler flue gas O_2 levels could be readily determined, the O_2 levels of the exhaust gases from individual cyclones are not known. As a consequence, NO_x contributions from different cyclones might vary significantly. Therefore, if the combustion characteristics of each cyclone are individually monitored, it is believed that better NO_x reductions might be achievable. It is not possible to state in advance, however, that this reduction would be adequate to meet existing NO_x emission regulations. Additional restrictions and controls applied to the cyclone boilers would further reduce their flexibility, increase their costs, and worsen their acceptance by the users.

4.3.1 Switched Fuel Firing

Bituminous-coal-fired units produce the most NO_x. Switching from coal to another fuel such as natural gas can reduce NO_x by as much as 50%. The data contained in this report also indicate that (1) there is no NO_x reduction advantage when bituminous coal is blended with subbituminous coal or No. 5 fuel oil, (2) there is only a slight NO_x reduction advantage when subbituminous coal is fired in place of bituminous coal, (3) switching from bituminous coal to lignite can reduce NO_x as much as using natural gas, (4) switching from bituminous coal to residual oil fuel also can reduce NO_x by as much as 58%.

The implications of fuel switching to achieve NO_x control may be complex. Fuel availability, economics, operating difficulties, and possible derating of boilers must be considered on an individual boiler basis. Even if fuel switching were implemented for NO_x control of cyclone boilers, it is unlikely that the NSPS for the substitute fuel will be met, but the absolute contribution of NO_x from the cyclone-fired units could be significantly reduced.

4.3.2 Load Reduction

Load reduction effectively reduces the quantity of NO_x emitted from the stack. The strategy of load reduction as an NO_x control alternative implies that boilers be operated at sustained reduced loads. The concept of operating utility or industrial boiler units at sustained reduced loads is not attractive to the boiler operator. The major factors to consider under low-load conditions are steam temperature control to maintain thermal efficiency, ability to meet load fluctuations, and fouling. Full-load steam temperatures (i.e., temperatures as high as at full load), are desirable at lower loads to maintain prime mover (steam turbine) efficiency. There are two widely used methods for steam temperature control at partial load. These will be discussed in terms of sustained boiler operation such as would be required to implement NO_x control via load reduction.

The bulk of the heat absorbed in the superheater, reheater (if so equipped), and economizer is transferred by convection.[2] In a boiler unit, the heat transfer to these surfaces is controlled by two variables which both control convective heat transfer; namely, gas temperature and gas mass velocity. The extent to which these variables are controlled largely determines the degree of superheat recoverable at low or partial loads.

The first widely used steam temperature control method is excess air control. This method primarily affects the gas mass velocity rather than the gas temperature. When excess air steam temperature control is used in a boiler unit, the boiler operators will slightly increase the excess air level at partial load. This increased gas flow produces an increase in recoverable superheat.[5] At the same time, the gas temperature within the boiler unit and the furnace heat absorption decrease, affecting boiler efficiency. The resulting greater gas weight increases the heat loss through the stack, which also lowers the overall boiler efficiency. The boiler operators, however, under low boiler load conditions, are willing to sacrifice boiler efficiency to some extent for the amount of recoverable superheat, which is important to maintaining high steam temperatures at the steam turbine inlet. The concept of steam temperature control by excess air control is illustrated in Figure 25.

Steam temperature control by the excess air method was probably used in oil-fired boiler Nos. 12 and 13 and coal-fired boiler No. 2 whose NO_x data are shown in Figure 23 and Table 35. The excess air levels were increased by 6% in boiler No. 1, 15% in boiler No. 12, and 35% in boiler No. 13 during the load reduction tests. It is not known, however, if the excess air was increased in these units solely for steam temperature control. There is also the problem of reduced cyclone furnace combustion turbulence at lower loads, which may require correction with more excess air to achieve adequate fuel combustion.

Another common method of steam temperature control in cyclone-fired boilers is flue gas recirculation (FGR). This method works on similar principles as excess air control but results in higher boiler efficiencies than excess air control. FGR influences both

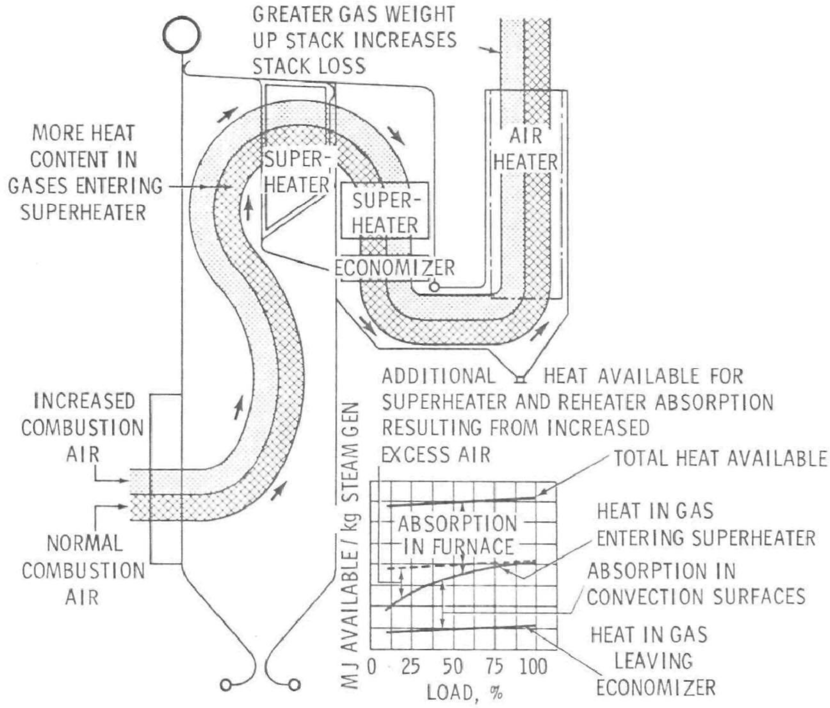


Figure 25. Steam-temperature control by use of increased excess air.[2]

gas mass velocity and gas temperature, the major convective heat transfer variables.

The flue gas used for recirculation is normally withdrawn from the economizer outlet. The hot gas is then distributed by the FGR system to a point above the combustion zone (termed gas recirculation) and/or to a point near the furnace exit (termed gas tempering). The points of reintroduction are dictated by the control desired.[2] Gas recirculation flow controls furnace absorption and superheat and reheat temperatures, while gas tempering conditions and controls the temperatures of the flue gas entering the superheater sections only. Proportioning the amounts of flue gas recirculated to each point in the boiler results in control of steam temperature.

Figure 26 depicts a cyclone-fired boiler unit equipped with gas tempering and gas recirculation control. Boiler No. 6 is equipped with an FGR system of this sort. The effects of FGR on boiler heat absorption patterns are shown in Figure 27. Both FGR and excess air control may be used simultaneously in a specific boiler unit for steam temperature control.

FGR control of steam temperature at low loads has several advantages. Sensible heat loss up the stack is negligible compared to excess air control and is comparable to the loss for full-load firing. In addition, boiler slagging and fouling are minimized because the gas recirculation temperature can help to keep the

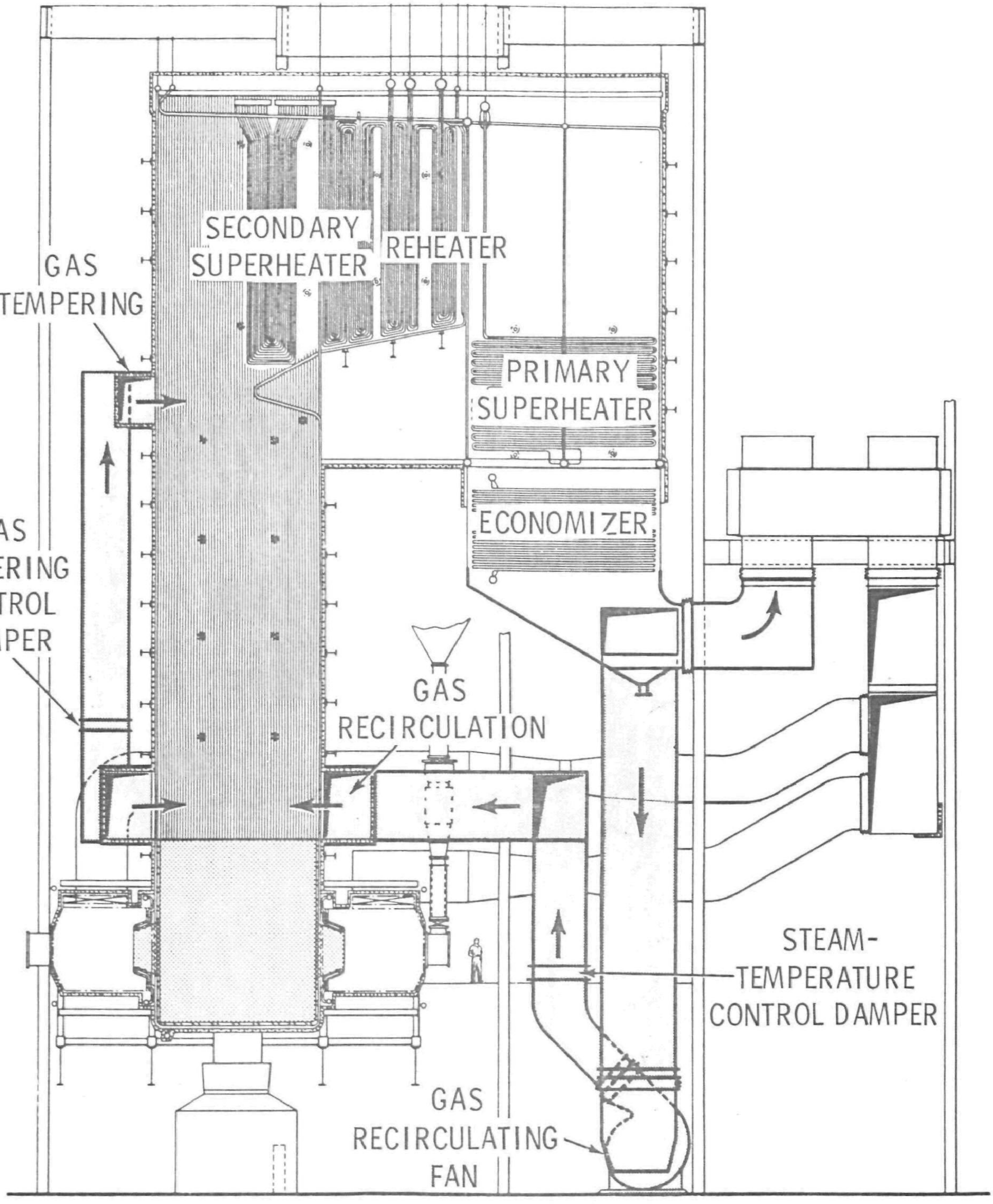
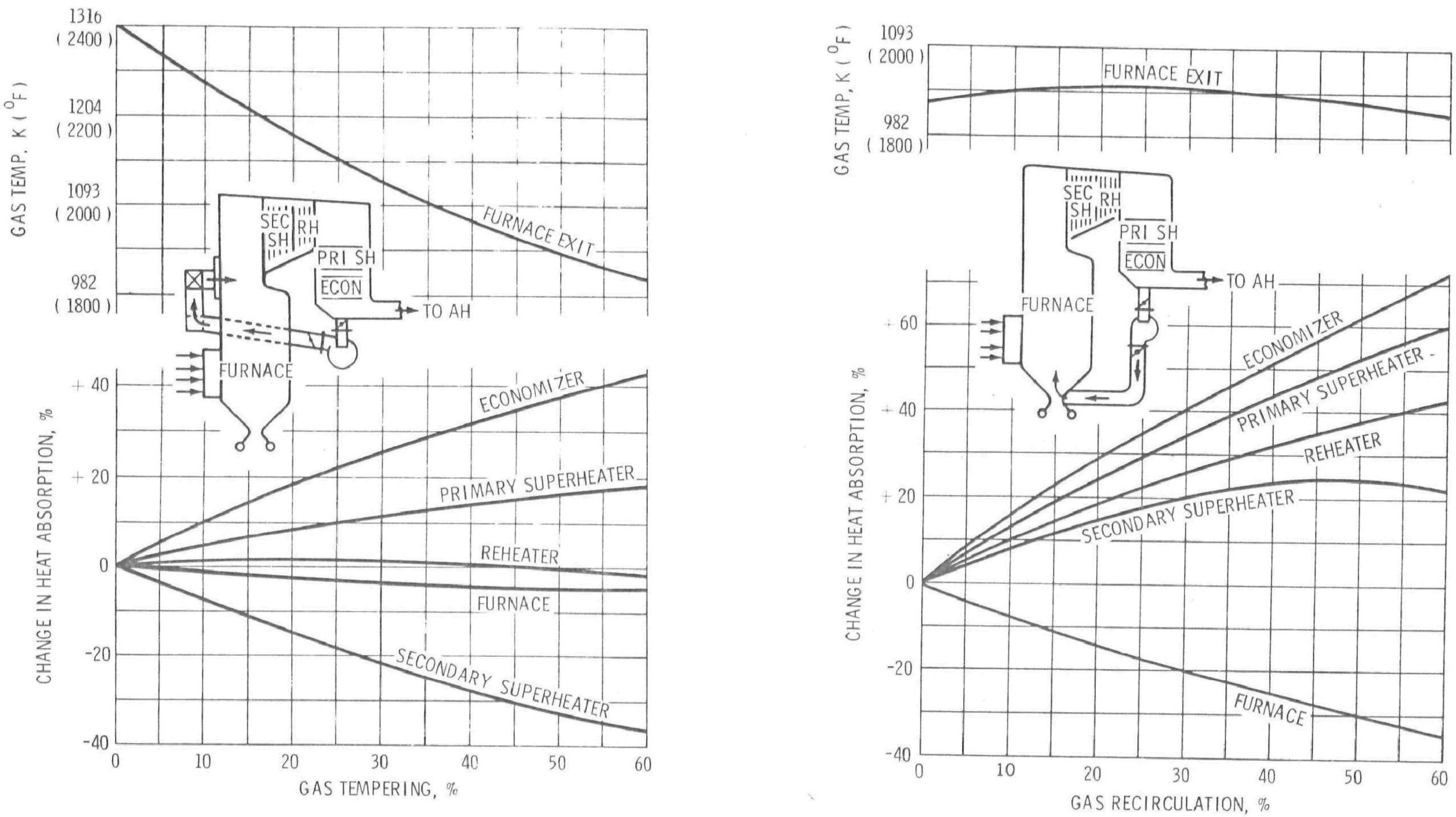


Figure 26. Cyclone-fired boiler with gas tempering for gas-temperature control and gas recirculation for control of furnace absorption and reheat temperature.[2]



(a) Effect of gas tempering on heat-absorption pattern at a constant firing rate.

(b) Effect of gas recirculation on heat-absorption pattern at a constant firing rate.

Figure 27. Flue gas recirculation.[2]

boiler temperatures below the ash fusion point.[4] However, sustained operation of the FGR system at low loads can become expensive. This is primarily due to the higher operating cost of its operation (increased FGR fan horsepower) when compared to excess air control. Exact horsepower cost figures were not available.

Besides being a steam temperature control method at low boiler loads, FGR is considered as a combustion modification for NO_x control in large utility and industrial boilers of various firing types (if FGR equipped) at full loads. In pulverized-coal-fired units, for example, FGR serves to lower the peak flame zone temperature and reduces the amount of O_2 available for NO formation. Only one instance of its application to cyclone firing was in the literature. A limited test of FGR on NO_x emissions was performed during Exxon's study, as discussed in Section 4.2.2. NO_x emissions for this one bituminous-coal-fired boiler were not affected by varying flue gas recirculation or gas tempering flows This is probably due to the fact that most of the combustion occurs within the cyclone and FGR has very little if any effect on NO_x formation after the combustion gases leave the cyclone.

Either of the two steam temperature control methods discussed above (i.e., excess air and FGR) were originally developed to keep the boiler unit efficiency fairly constant throughout load fluctuation. Neither control method was intended, nor was it suitable, for sustained operation such as might be required for NO_x control implementation. Loss of boiler efficiency and higher boiler operating costs are the associated penalties.

In addition to these drawbacks, a derated boiler will not be able to meet the load demands for which it was originally designed. Implementation of load reduction might in some cases require peaking power supplied by prime movers such as reciprocating engines and gas turbines whose NO_x emissions are also quite high. Such strategy could defeat the purpose of cyclone boiler load reduction for NO_x control. Further study is recommended in this area.

When coal-fired cyclone boilers are operated at reduced loads, a serious problem with fouling can occur. The lower combustion turbulence, heat release rate, and temperatures in the furnace at partial loads can cause slag buildup with certain high-ash-fusion-temperature coals which are marginally suitable for cyclone firing. Sustained burner operation at low loads can result in plugging and resultant shutdown. Areas that require further investigation in this regard before implementing load reduction for NO_x control include (1) changing to coals having desired slagging characteristics at partial loads and (2) use of fluxing agents to lower slagging viscosity of marginal coals.

The load reduction NO_x data analysis performed in Section 4.2.4 suggests that the NO_x NSPS cannot be met at practical reduced loads. Implementing load reduction to reduce NO_x emissions from cyclone boilers during severe urban pollution episodes may be a practical control alternative; but, clearly, sustained operation of cyclone-fired boiler units at partial loads is not likely to be readily accepted until all implications are resolved.

4.4 RECOMMENDATIONS FOR FURTHER WORK

Previous sections of this report have summarized available data on NO_x emissions from cyclone furnaces/boilers. Even though large amounts of data were available in most cases, it was not possible to obtain information on all the details and conditions under which the data were generated. Thus, it is not possible to be certain that all the tests were thorough, comparable, and representative of all permanent cyclone operations and that all possibilities for cyclone boiler modification for achieving reduced NO_x emissions were thoroughly explored.

Because the boilers tested were fully operational, there was too much at stake for the boiler owner as well as for the boiler manufacturer to expose the boiler to conditions that would significantly deviate from the conditions at which the boiler was originally designed to operate. Examples of factors that significantly influenced many of the tests include the cost of the test program and the necessary boiler modifications, safety, serious damage to an existing facility, and maintaining boiler efficiency during the test program. Because of these reasons, some furnace/boiler modifications could not be properly tested for their effect on NO_x formation.

Also, the penalties associated with these modifications could not be properly assessed. This is especially true for the modifications involving flue gas recirculation (FGR) and forms of staged firing. To be effective, these modifications should be applied as near the flame front as possible. The bulk of combustion and associated NO formation in cyclone boilers occurs within the cyclone furnace. Any FGR or staged-firing concept applied to places where the combustion is nearly complete could not be too effective in influencing NO_x formation.

The cyclone furnace has special operational characteristics. It operates at high temperatures (3000°F). Coal particles are caught and burned in the molten slag. This is a well balanced system that has demonstrated low corrosion rates. A change of the conditions under which the cyclone furnace operates can upset this delicate balance and cause serious corrosion, equipment damage, and accidents (refer to Section 3.1.6). Operation under changed conditions permanently would require re-evaluation of the balance and development of materials (e.g., for the boiler tubes and/or for the protection of the tubes) with adequate corrosion resistance in the new environment. The cyclone furnace would have to be redesigned and rebuilt using these materials. Then the rebuilt furnace would be able to operate under fuel-rich conditions (low excess air).

The low-excess-air (LEA) combustion modification as applied to cyclone furnaces could not be fully evaluated during test programs mentioned in this report due to the apparent danger of corrosion and equipment damage. Therefore, the potential success of the LEA combustion modification for reducing NO_x emissions from cyclone-fired boilers will depend on the ability to operate the cyclone furnace safely under fuel-rich combustion conditions. In the opinion of B&W, there are presently no materials that could be used in this application. Nevertheless, a study is recommended to EPA for their consideration which would evaluate the potential for redesigning cyclone furnaces for permanent operation in a reducing atmosphere. The study should also determine the costs of furnace redesigning if applied to the existing cyclone-fired units.

It is not certain whether any of the possible cyclone boiler modifications could reduce NO_x emissions to the level adequate for meeting existing NO_x emission regulations and at the same time maintaining cyclone boilers as a competitive combustion technique. In order to determine this, a comprehensive boiler test program should be developed. This program should concentrate on determining the causes for NO_x formation and their location in the cyclonic combustion process. Better understanding of cyclonic combustion would surely identify new opportunities as well as proper conditions for application of available combustion modifications to cyclone boilers to attain NO_x emission control. Sampling a large number of cyclone combustion facilities for NO_x emissions would not be considered an adequate substitute for such a test program, which should evaluate:

- Variations in operation of individual cyclones in multicyclone-fired facilities and the influence of these variations on the total boiler NO_x emissions;
- The effect of boiler modifications on cyclone furnace NO_x emissions, with a comprehensive evaluation of variables and conditions having a strong influence on NO_x formation;
- Long duration operation of the successful modifications to develop reliability and operational data;
- The applicability of the successful modifications to all cyclone boiler facilities; and
- The cost of such modifications.

An example of a test program for further evaluation of cyclone furnace combustion conditions and their influence on NO_x formation has been prepared by KVB Engineering, Inc., Tustin, California. This test program is offered to EPA for consideration as an initial step in the assessment of cyclone boilers and is presented in Appendix C.

Whether any NO_x emission control methods, even if effective in meeting NO_x emission standards, will be practical and acceptable to boiler operators is not presently known. For the last 6 years, no cyclone boilers have been sold in the United States. The large majority of cyclone boilers (49% steaming capacity) are 12 to 32 years old. The normal life expectancy for boiler facilities is from 25 years to 35 years. Thus within the next 3 years to 13 years, some 49% of the present cyclone steaming capacity will be obsolete and will have to be replaced.

This process may be dramatically encouraged by a strong enforcement of existing NO_x emission standards. A study is therefore recommended to determine the influence of the NSPS applicable to NO_x emissions from cyclone boilers on American industries.

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APPENDIX A

CYCLONE-FIRED BOILER INSTALLATIONS

Tables A-1 and A-2 list specific information related to each of the 84 known cyclone-fired boiler installations. Information supplied in these tables includes all known plant expansions to date and was derived from a list of contract agreements made and furnished to us by Babcock & Wilcox. Boiler steam flows listed are capacities at maximum continuous rating. Table A-1 pertains to electric utility installations while Table A-2 presents information on industrial and commercial boiler units.

TABLE A-1. INSTALLATIONS OF CYCLONE-FIRED BOILER UNITS - UTILITIES

State	Plant or city	Customer	Number of units			Boiler steam flow, kg/s		Total primary steam flow, kg/s
			Boilers	Cyclones	Cyclones per boiler	Primary	Reheat	
Arkansas	Helana	Arkansas Power & Light Company	1	8	8	289.8	246.6	289.8
Connecticut	Middletown	Hartford Electric	1	5	5	207.9	161.9	207.9
Connecticut	Bridgeport	United Illuminating Company	1	5	5	144.9	122.1	144.9
Connecticut	Bridgeport	United Illuminating Company	1	3	3	72.5	63.0	72.5
Florida	Gannon	Tampa Electric Company	1	4	4	158.8	143.6	158.8
Florida	Gannon	Tampa Electric Company	1	4	4	146.2	128.5	146.2
Florida	Gannon	Tampa Electric Company	1	3	3	119.7	103.3	119.7
Florida	Gannon	Tampa Electric Company	1	3	3	114.7	99.2	114.7
Illinois	Coffeen	Central Illinois Power Company	1	14	14	529.2	469.1	529.2
Illinois	Coffeen	Central Illinois Power Company	1	8	8	315.0	233.1	315.0
Illinois	Calumet	Commonwealth Edison	1	1	1	22.7	0.0	22.7
Illinois	Fisk	Commonwealth Edison	2	8	4	94.5	0.0	189.0
Illinois	Joliet	Commonwealth Edison	2	6	3	75.6	0.0	151.2
Illinois	Joliet	Commonwealth Edison	1	9	9	277.2	250.1	277.2
Illinois	Kincaid	Commonwealth Edison	2	28	14	529.2	474.3	1,058.4
Illinois	Pekin	Commonwealth Edison	2	20	10	382.7	438.0	765.4
Illinois	Pekin	Commonwealth Edison	1	10	10	NA[a]	NA	NA
Illinois	Ridgeland	Commonwealth Edison	2	8	4	88.2	0.0	176.4
Illinois	Ridgeland	Commonwealth Edison	2	8	4	88.2	0.0	176.4
Illinois	Ridgeland	Commonwealth Edison	1	6	6	138.6	126.9	138.6
Illinois	Ridgeland	Commonwealth Edison	1	6	6	138.6	126.9	138.6
Illinois	Waukegan	Commonwealth Edison	1	4	4	104.6	92.4	104.6
Illinois	Waukegan	Commonwealth Edison	1	2	2	39.8	0.0	39.8
Illinois	Will County	Commonwealth Edison	2	10	5	151.2	136.1	302.4
Illinois	Baldwin	Illinois Power Company	1	14	14	1,159.2	477.2	1,159.2
Illinois	Baldwin (Randolph County)	Illinois Power Company	1	14	14	529.1	477.2	529.1
Illinois	Marion	Southern Illinois Power Company	3	6	2	42.2	0.0	126.6
Illinois	Marion	Southern Illinois Power Company	1	4	4	NA	NA	NA
Illinois	Dallman Plant	Springfield Water, Light, and Power Department	1	3	3	86.9	0.0	86.9
Illinois	Dallman Plant	Springfield Water, Light, and Power Department	1	3	3	86.9	0.0	86.9
Illinois	Lakeside	Springfield Water, Light, and Power Department	1	2	2	40.3	0.0	40.3
Illinois	Lakeside	Springfield Water, Light, and Power Department	1	2	2	40.3	0.0	40.3

(continued)

TABLE A-1 (continued).

State	Plant or city	Customer	Number of units: Boilers	Number of units: Cyclones	Number of units: Cyclones per boiler	Boiler steam flow, kg/s: Primary	Boiler steam flow, kg/s: Reheat	Total primary steam flow, kg/s
Indiana	State Line	Commonwealth Edison	1	9	9	277.2	250.1	277.2
Indiana	Tanners Creek	Indiana & Michigan Electric Company	1	11	11	483.8	401.4 335.7	483.8
Indiana	Breed	Indiana & Michigan Electric Company	1	8	8	368.3	285.8	368.3
Indiana	Michigan City	Northern Indiana Public Service Company	3	6	2	47.3	0.0	141.9
Indiana	Michigan City	Northern Indiana Public Service Company	1	10	10	407.0	0.0	407.0
Indiana	Baileytown	Northern Indiana Public Service Company	1	8	8	315.0	233.1	315.0
Indiana	Baileytown	Northern Indiana Public Service Company	1	4	4	151.2	130.5	151.2
Indiana	Michigan City	Northern Indiana Public Service Company	1	NA	NA	407.0	NA	407.0
Iowa	Southerland	Iowa Electric Light & Power Company	1	3	3	72.5	64.6	72.5
Iowa	Missouri River Sioux City	Iowa Public Service Company	1	3	3	132.3	115.5	132.3
Iowa	Muscatine	Muscatine Municipal Electric	1	3	3	85.7	0.0	85.7
Kansas	Quindaro Station (No. 2)	Kansas City Board of Public Utilities	1	2	2	72.5	64.9	72.5
Kansas	Kaw	Kansas City Board of Public Utilities	1	2	2	53.6	46.0	53.6
Kansas	La Cygne	Kansas City Power & Light	1	18	18	780.3	632.5	780.3
Kentucky	E. Smith	City of Owensboro	1	3	3	132.3	114.7	132.3
Kentucky	Paradise	Tennessee Valley Authority	1	23	23	1,008.0	700.6	1,008.0
Kentucky	Paradise	Tennessee Valley Authority	1	14	14	617.4	444.2	617.4
Kentucky	Paradise	Tennessee Valley Authority	1	14	14	617.4	444.2	617.4
Maryland	Crane	Baltimore Gas & Electric	1	4	4	171.0	131.4	171.0
Maryland	Crane	Baltimore Gas & Electric	1	4	4	171.6	130.3	171.6
Michigan	St. Clair	Detroit Edison Company	1	7	7	264.6	239.5	264.6
Minnesota	Riverside	Northern States Power	1	5	5	189.0	166.3	189.0
Minnesota	Stillwater (A. S. King)	Northern States Power	1	12	12	484.5	417.4	484.5
Missouri	New Madrid	Associated Electric Co-op	1	14	14	548.7	503.4	548.7
Missouri	New Madrid	Associated Electric Co-op	1	14	14	548.1	510.3	548.1
Missouri	Thomas Hill	Associated Electric Co-op	1	6	6	241.4	210.9	241.4
Missouri	Thomas Hill Allen S. King	Associated Electric Co-op	1	4	4	157.5	138.6	157.5
Missouri	Chamois	Central Electric Power Co-op	1	2	2	52.4	0.0	52.4
Missouri	Asbury	Empire District Electric Company	1	5	5	163.8	143.0	163.8
Missouri	Sibley	Missouri Public Service Company	1	8	8	325.6	279.6	325.6

(continued)

TABLE A-1 (continued).

State	Plant or city	Customer	Number of units: Boilers	Number of units: Cyclones	Number of units: Cyclones per boiler	Boiler steam flow, kg/s: Primary	Boiler steam flow, kg/s: Reheat	Total primary steam flow, kg/s
Missouri	Sibley	Missouri Public Service Company	1	2	2	56.7	0.0	56.7
Missouri	Sibley	Missouri Public Service Company	1	2	2	56.7	0.0	56.7
Missouri	Lake Road Pt.	St. Joseph Power & Light	1	2	2	78.8	69.9	78.8
Missouri	Sioux Plant	Union Electric	1	10	10	414.5	373.0	414.5
Missouri	St. Charles Co.	Union Electric	1	10	10	414.5	373.0	414.5
Nebraska	Sheldon (Hallam)	Consumers Public Power Company	1	3	3	99.4	0.0	99.4
Nebraska	Sheldon (Hallam)	Consumers Public Power Company	1	3	3	95.8	86.9	95.8
New Hampshire	Merrimack Pt.	Public Service of New Hampshire	1	7	7	289.8	252.0	289.8
New Hampshire	Merrimack Pt.	Public Service of New Hampshire	1	3	3	102.7	90.5	102.7
New Jersey	Beesley's Pt.	Atlantic City Electric Company	1	4	4	141.8	124.1	141.8
New Jersey	Beesley's Pt.	Atlantic City Electric Company	1	3	3	116.8	102.3	116.8
New Jersey	Deepwater	Atlantic City Electric Company	1	3	3	77.6	68.0	77.6
New Jersey	Sayreville	Jersey Central Power & Light	1	4	4	113.4	89.5	113.4
New Jersey	Sayreville	Jersey Central Power & Light	1	4	4	113.4	89.5	113.4
New Jersey	South Amboy	Jersey Central Power & Light	1	2	2	59.9	47.3	59.9
New Jersey	Marion	Public Service Company of New Jersey	1	8	8	308.7	248.2	308.7
North Dakota	Leland Olds	Basin Electric	1	12	12	378.0	344.0	378.0
North Dakota	Center	Minnkota Power Co-op, Inc.	1	12	12	NA	NA	NA
North Dakota	Center	Minnkota Power Co-op, Inc.	1	7	7	216.0	193.3	216.0
North Dakota	Beulah	Ottertail Power	1	12	12	409.5	364.1	409.5
Ohio	Conesville	Columbus & Southern Ohio Electric	1	4	4	126.0	106.5	126.0
Ohio	Conesville	Columbus & Southern Ohio Electric	1	4	4	126.0	106.5	126.0
Ohio	Niles	Ohio Edison Company	2	8	4	111.5	98.9	223.0
Ohio	Muskingum	Ohio Power Company	1	5	5	191.9	148.4	191.9
Ohio	Muskingum	Ohio Power Company	1	5	5	191.9	148.4	191.9
Ohio	Philo	Ohio Power Company	1	3	3	85.1	65.5	85.1
South Dakota	Ben French	Black Hills Power & Light Company	1	1	1	26.5	0.0	26.5
South Dakota	Big Stone	Ottertail Power	1	12	12	409.5	364.1	409.5
Tennessee	Thomas H. Allen	Tennessee Valley Authority	3	21	7	252.0	204.1	756.0
West Virginia	Willow Island	Monongahela Power Company	1	5	5	151.2	135.5	151.2
West Virginia	Kammer	Ohio Power Company	2	10	5	191.9	148.4	383.8
West Virginia	Kammer	Ohio Power Company	1	5	5	191.9	148.4 325.3	191.9

(continued)

TABLE A-1 (continued).

State	Plant or city	Customer	Number of units			Boiler steam flow, kg/s		Total primary steam flow, kg/s
			Boilers	Cyclones	Cyclones per boiler	Primary	Reheat	
Wisconsin	Bay Front	Lake Superior District Power Company	1	2	2	40.3	0.0	40.3
Wisconsin	Nelson Dewey	Wisconsin Power & Light Company	1	3	3	88.2	78.6	88.2
Wisconsin	Nelson Dewey	Wisconsin Power & Light Company	1	3	3	88.2	78.0	88.2
Wisconsin	Rock River	Wisconsin Power & Light Company	1	3	3	66.2	57.3	66.2
Wisconsin	Rock River	Wisconsin Power & Light Company	1	3	3	66.2	57.3	66.2
Wisconsin	Sheboygan	Wisconsin Power & Light Company	1	7	7	271.5	238.1	271.5
Wisconsin	Sheboygan	Wisconsin Power & Light Company	1	3	3	76.6	0.0	75.6
U.S. TOTAL			116[a]	677[a]	-	-	-	24,253.3[a]

[a]Total of available data excluding information not available.

NA = not available.

TABLE A-2. INSTALLATION OF CYCLONE-FIRED BOILER UNITS - INDUSTRIAL AND COMMERCIAL

State	Plant or city	Customer	Number of units: Boilers	Number of units: Cyclones	Number of units: Cyclones per boiler	Boiler steam flow, kg/s: Primary	Boiler steam flow, kg/s: Reheat	Total primary steam flow, kg/s
Alabama	Mobile	Southern Kraft Company	2	4	2	56.7	0.0	113.4
Arkansas	Pine Bluff	Southern Kraft Company	2	4	2	56.7	0.0	113.4
Indiana	Terre Haute	Indiana State University	1	1	1	25.2	0.0	25.2
Indiana	Notre Dame	University of Notre Dame	1	1	1	21.4	0.0	21.4
Iowa	Clinton	Clinton Corn Products	1	2	2	41.6	0.0	41.6
Iowa	Clinton	Clinton Corn Products	1	1	1	34.7	0.0	34.7
Maryland	Woodland	St. Croix Paper Company	1	1	1	15.8	0.0	15.8
Michigan	Midland	Dow Chemical Company	2	4	2	50.4	0.0	100.8
Michigan	Midland	Dow Chemical Company	2	4	2	50.4	0.0	100.8
Michigan	Midland	Dow Chemical Company	1	2	2	55.4	0.0	55.4
Michigan	Midland	Dow Chemical Company	1	2	2	50.4	0.0	50.4
New Jersey	Bound Brook	American Cyanamid Company	1	1	1	27.1	0.0	27.1
New York	Kodak Park	Eastman Kodak Company	1	2	2	69.3	0.0	69.3
New York	Kodak Park	Eastman Kodak Company	1	2	2	50.4	0.0	50.4
New York	Kodak Park	Eastman Kodak Company	1	2	2	50.4	0.0	50.4
New York	Kodak Park	Eastman Kodak Company	1	2	2	50.4	0.0	50.4
North Carolina	Enka	American Enka Corporation	1	1	1	18.9	0.0	18.9
Ohio	Barberton	Columbia Southern Chemical	1	2	2	75.6	0.0	75.6
Ohio	Barberton	Columbia Southern Chemical	1	2	2	48.5	0.0	48.5
Pennsylvania	Erie	General Electric Company	1	2	2	37.8	0.0	37.8
Pennsylvania	Clarton	U.S. Steel Corporation	1	3	3	63.0	0.0	63.0
South Carolina	Greenwood	Greenwood Mills	1	2	2	37.8	0.0	37.8
West Virginia	Luke Md.	West Virginia Pulp & Paper Company	1	2	2	50.4	0.0	50.4
Wisconsin	Biron	Consolidated Water Power & Paper	1	2	2	31.5	0.0	31.5
Wisconsin	Green Bay	Fort Howard Paper Company	1	2	2	63.0	0.0	63.0
Wisconsin	Tomahawk	Owens-Illinois	1	1	1	18.9	0.0	18.9
Wisconsin	Rhinelander	Rhinelander Paper Company	1	2	2	31.5	0.0	31.5
Wisconsin	Kaukauna	Thilmany Pulp & Paper	1	2	2	40.3	0.0	40.3
Wisconsin	Kaukana	Thilmany Pulp & Paper	1	1	1	19.5	0.0	19.5
U.S. TOTAL			33	59	-	-	-	1,457.2

APPENDIX B

LOAD FACTORS AND FUEL CONSUMPTION AT CYCLONE-FIRED ELECTRIC POWER STATIONS IN 1973

Table B-1 lists the net power generated, electric load factor, and fuel consumption for individual cyclone-fired electric power stations in 1973. Information contained in this table was obtained by matching the list of boiler contracts furnished by Babcock & Wilcox (B&W) against the station operating records published by the National Coal Association.[25] The list of cyclone-fired boiler contracts furnished by B&W was presented in Tables A-1 and A-2 of Appendix A.

Table B-1 should be interpreted with caution. The data contained therein do not represent the exact amounts of gas, oil, and coal burned solely in cyclone-fired boiler units in 1973. Rather, Table B-1 reflects the total amounts of gas, oil, and coal burned at power plants whose facilities contain cyclone firing as a mode of power generation.

For the NO_x emission estimate presented in Section 3.4, the only annual fuel consumption which could be estimated with reasonable accuracy was for coal fuel. The total coal consumption at stations known to have cyclone-fired boiler units was 62×10^9 kg (68,386,000 tons) in 1973. This figure includes all ranks of coal since no breakdown by coal rank was available. For the emission estimate in Section 3.4, it was assumed that all of this coal was bimuminous in order to use the NO_x emission factor for bituminous coal (12.28 g NO_x per kg coal). The error of this assumption is expected to be less than 5% since only small amounts of lignite and no anthracite coals are burned in cyclone-fired units.

Another possible source of error in the coal- fuel consumption estimate concerns multiple-mode firing. At a particular power station, coal may be burned in cyclone furnaces as well as some other mode such as pulverized coal firing. It was difficult to determine the extent of this error from the available data. Mr. Robert Lundberg of Commonwealth Edison (Chicago) was contacted concerning this. He estimated that nearly all of Commonwealth Edison's cyclone-fired stations were 100% cyclone fired and did not have multiple modes. Commonwealth Edison owns nearly 25% of the cyclone-fired boiler capacity in the United States. There are exceptions to single-mode cyclone firing, of course, such as the Leland Olds Station owned by Basin Electric in North Dakota. This station operates a horizontally opposed pulverized coal unit and will soon be operating a cyclone-fired boiler unit. Our estimate of coal fuel consumption may include some coal which is not necessarily cyclone-fired. However, this amount of coal should not, in our estimation, exceed 5% of the total coal fired in cyclone boilers.

The influence of the two sources of error just mentioned on our coal fuel consumption estimate cannot be accurately determined. However, both error sources suggest that our coal fuel consumption estimate may be slightly inflated. As a result of these possible error sources, we estimate that the total coal consumption of 62×10^9 kg in 1973 is perhaps 5% to 10% high. Multiplying the bituminous coal NO_x emission factor of 12.28 g NO_x/kg coal burned by 62×10^9 kg coal burned in 1973 results in an annual emission rate of 0.76×10^6 tonnes of NO_x per year for 1973. Because of the above-mentioned reasons, this NO_x estimate may also be 5% to 10% high.

The total amounts of gas and oil burned in cyclone-furnace-fired boiler units could not be estimated from the available data. Hence, NO_x emissions from these fuel types burned in cyclone-furnace-fired boiler units could not be accurately estimated. The gas and oil fuel consumption data presented in Table B-1 include the amounts of oil and gas burned in cyclone furnaces as well as the amounts burned in other gas- and oil-fired units which may be present at a particular power staation. The types of units present could include gas turbines, reciprocating engines, and oil and gas boilers fired by other methods (spud, ring burners, etc.).

A summary of the fuel data presented in Table B-1 is given below. Heat released as a result of burning gas, oil, and coal fuels at cyclone-furnace-fired installations was 1.95×10^9 GJ in 1973. As indicated from Table B-1, on a heat basis 82.4% of all fuel burned at these plants in 1973 was bituminous coal and lignite. The remaining 17.6% of heat was provided by oil and natural gas. Residual and distillate oils provided 12.5% of the total heat released, while gas provided 5.1%.

Using the data in B-1, the fuel average heating values were also determined. Average heating value of coal was 26 MJ/kg (11,200 Btu/lb). Oil had an average heating value of 40 GJ/m^3 (144,000 Btu/gal), and natural gas had a heat value of 37 MJ/m^3 (1,000 Btu/ft^3).

In 1973, a total of 62×10^9 kg (68,386,000 tons) of coal, 6.1×10^6 m^3 (38,258,700 barrels @ 42 gallons each) of oil, and 2.7×10^9 m^3 (94,348 million cubic feel) of natural gas were burned at all utility installations possessing cyclone furnaces.

TABLE B-1. LOAD FACTORS AND FUEL CONSUMPTION FOR CYCLONE-FIRED ELECTRIC POWER PLANTS IN 1973[a]

State	Plant or city	Customers	Net power generation, 10^6 KW/hr	Load factor	Fuel consumed: Coal 10^6 kg	Coal (MJ/kg)	Oil 10^3 m^3	Oil (MJ/m^3)	Gas 10^6 m^3	Gas (MJ/m^3)
Arkansas	Helena	Arkansas Power & Light Company	3,500	0.44	–[b]	–[b]	532	42,700	404	37.7
Connecticut	Middletown	Hartford Electric	3,590	0.49	18.1	27.3	963	40,200	–[b]	–[b]
Connecticut	Bridgeport	United Illuminating	3,720	0.65	–[b]	–[b]	987	40,400	–[b]	–[b]
Florida	Gannon	Tampa Electric Company	4,880	0.44	2,040	21.1	–[b]	–[b]	–[b]	–[b]
Illinois	Coffeen	Central Illinois Power Company	2,980	0.34	1,570	21.8	3.97	38,600	–[b]	–[b]
Illinois	Calumet	Commonwealth Edison	295	0.31	–[b]	–[b]	–[b]	–[b]	107	37.2
Illinois	Fisk	Commonwealth Edison	1,940	0.41	1,030	21.7	–[b]	–[b]	21.4	38.8
Illinois	Joliet	Commonwealth Edison	8,150	0.52	3,550	23.5	–[b]	–[b]	121	38.4
Illinois	Kincaid	Commonwealth Edison	4,900	0.42	2,400	22.6	–[b]	–[b]	–[b]	–[b]
Illinois	Pekin	Commonwealth Edison	4,020	0.38	1,860	24.6	–[b]	–[b]	–[b]	–[b]
Illinois	Ridgeland	Commonwealth Edison	2,830	0.76	–[b]	–[b]	802	41,600	–[b]	–[b]
Illinois	Waukegan	Commonwealth Edison	4,190	0.51	1,920	23.5	–[b]	–[b]	–[b]	–[b]
Illinois	Will County	Commonwealth Edison	4,940	0.44	2,470	22.1	–[b]	–[b]	–[b]	–[b]
Illinois	Baldwin	Illinois Power Company	6,270	0.57	2,760	23.9	.795	39,000	–[b]	–[b]
Illinois	Marion	Southern Illinois Power Company	607	0.65	312	24.8	.159	38,700	–[b]	–[b]
Illinois	Dallman Plant	Springfield Water, Light, & Power Department	815	0.58	403	25.1	–[b]	–[b]	–[b]	–[b]
Illinois	Lakeside	Springfield Water, Light, & Power Department	343	0.27	201	24.6	.635	37,900	–[b]	–[b]
Indiana	State Line	Commonwealth Edison	5,030	0.59	2,460	22.8	–[b]	–[b]	–[b]	–[b]
Indiana	Breed	Indiana & Michigan Electric	2,720	0.63	1,080	25.2	.636	38,400	–[b]	–[b]
Indiana	Tanners Creek	Indiana & Michigan Electric	6,390	0.66	2,410	25.9	3.97	37,800	–[b]	–[b]
Indiana	Baileytown	Northern Indiana Public Service Company	3,000	0.56	1,220	25.9	–[b]	–[b]	5.38	37.2
Indiana	Michigan City	Northern Indiana Public Service Company	803	0.43	282	24.6	–[b]	–[b]	94.9	37.2
Iowa	Southerland	Iowa Electric Light	1,070	0.78	178	24.2			288	37.1
Iowa	Sioux City	Iowa Public Service Company	65.1	0.18	1.91		–[b]	–[b]	36.9	36.7
Iowa	Muscatine	Muscatine Municipal Electric	604	0.59	197	25.0	–[b]	–[b]	56.3	37.2
Kansas	Kaw.	Kansas City Board of Public Utilities	668	0.46	29.0	27.6	–[b]	–[b]	201	37.0
Kansas	Quindaro Station (No. 3)	Kansas City Board of Public Utilities	938	0.45	93.4	26.5	–[b]	–[b]	216	35.0
Kansas	La Cygne	Kansas City Power and Light	938	0.09	474	21.5	16.8	38,300	–[b]	–[b]
Kentucky	E. Smith	City of Owensboro	993	0.76	420	25.7	.063	37,900	–[b]	–[b]
Kentucky	Paradise	Tennessee Valley Authority	14,500	0.65	6,050	27.1	–[b]	–[b]	–[b]	–[b]
Maryland	Crane	Baltimore Gas & Electric	2,480	0.71	-	–[b]	665	40,500	–[b]	–[b]
Michigan	St. Clair	Detroit Edison Company	10,500	0.63	3,230	27.4	321	41,700	5.66	37.7

(continued)

TABLE B-1 (continued).

State	Plant or city	Customers	Net power generation, 10^6 KW/hr	Load factor	Fuel consumed: Coal 10^6 kg	Coal (MJ/kg)	Oil 10^3 m^3	Oil (MJ/m^3)	Gas 10^6 m^3	Gas (MJ/m^3)
Missouri	New Madrid	Associated Electric Co-op	2,790	0.49	1,240	25.4	-[b]	-[b]	-[b]	-[b]
Missouri	Thomas Hill Allen S. King	Associated Electric Co-op	2,680	0.67	1,210	25.4	-[b]	-[b]	-[b]	-[b]
Missouri	Chamois	Central Electric	245	0.47	116	26.1	-[b]	-[b]	-[b]	-[b]
Missouri	Asbury	Empire District Electric Company	1,260	0.68	600	23.8	.635	40,600	-[b]	-[b]
Missouri	Sibley	Missouri Public Service Company	1,800	0.40	746	27.7	-[b]	-[b]	-[b]	-[b]
Missouri	Riverside	Northern States Power	2,140	0.54	875	21.6	4.45	38,900	177	37.7
Missouri	Stillwater	Northern States Power	3,000	0.57	1,230	24.6	-[b]	-[b]	-[b]	-[b]
Missouri	Lake Road Pt.	St. Joseph Power & Light	936.3	0.71	58.1	24.0	4.93	41,800	323	35.8
Missouri	St. Charles Co.	Union Electric	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]
Missouri	Sioux Plant	Union Electric	3,360	0.39	1,420	25.4	1.58	38,200		
Nebraska	Sheldon	Consumers Public Power Company	1,340	0.67	236	27.5			222	37.1
New Hampshire	Merrimack Pt.	Public Service of New Hampshire	2,750	0.68	945	31.4	.318	40,400	-[b]	-[b]
New Jersey	Beesley's Point	Atlantic City Electric Company	1,950	0.75	33.6	26.9	508	38,700	-[b]	-[b]
New Jersey	Deepwater	Atlantic City Electric Company	1,390	0.51	12.7	26.7	325	40,100	80.8	38.3
New Jersey	Sayreville	Jersey Central Power and Light	2,000	0.66	-[b]	-[b]	563	40,200	27.4	37.7
New Jersey	South Amboy	Jersey Central Power and Light	454	0.45	-[b]	-[b]	152	40,100	-[b]	-[b]
New Jersey	Marion	Public Service Company of New Jersey	443	0.40	-[b]	-[b]	172	40,000	-[b]	-[b]
North Dakota	Leland Olds	Basin Electric	1,440	0.76	1,080	15.5	.479	39,000	-[b]	-[b]
North Dakota	Center	Minnkota Power Co-op	1,720	0.84	1,358	15.2	.477	39,000		
North Dakota	Beulah	Ottertail Power	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]
North Dakota	Center	Square Butte	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]
Ohio	Conesville	Columbus & Southern Ohio Electric	3,780	0.34	1,560	24.4	6.04	38,200	-[b]	-[b]
Ohio	Muskingham	Ohio Power Company	858	0.64	3,530	24.3	5.88	39,000	-[b]	-[b]
Ohio	Niles	Ohio Power Company	1,460	0.67	631	26.1	.159	37,600	-[b]	-[b]
Ohio	Philo	Ohio Power Company	1,360	0.31	729	24.4	1.27	38,100	-[b]	-[b]
South Dakota	Ben French	Black Hills Power & Light Company	146	0.76	103.4	18.6	.159	38,700	-[b]	-[b]
South Dakota	Big Stone	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]	-[c]
Tennessee	*Thomas H. Allen*	Tennessee Valley Authority	4,790	0.55	1,410	25.9	-[b]	-[b]	311	40.0
West Virginia	Willow Island	Monongahela Power Company	1,440	0.76	621	26.1	-[b]	-[b]	-[b]	-[b]
West Virginia	Krammer	Ohio Power Company	3,780	0.61	1,430	27.6	.635	38,700	-[b]	-[b]
Wisconsin	Bay Front	Lake Superior District Power	338	0.48	72.6	30.5	35.6	36,800	32.0	37.2
Wisconsin	Nelson Dewey	Wisconsin Power & Light Company	1,370	0.69	548	25.2	.159	39,300	-[b]	-[b]
Wisconsin	Rock River	Wisconsin Power & Light Company	862	0.66	376	25.8	.317	39,300	-[b]	-[b]
Wisconsin	Sheboygan	Wisconsin Power & Light Company	2,800	0.67	1,200	25.3	.529	40,299	-[b]	-[b]
U.S. TOTALS AND AVERAGES			-[b]	-[b]	62,000	26.0	6,100	40,000	2,700	37

[a] Data obtained by matching B & W contract list to data in Reference 25.

[b] Not applicable.

[c] Not available.

APPENDIX C

PROPOSED CYCLONE BOILER TEST PROGRAM
(KVB)

INTRODUCTION

Cyclone furnaces constitute the major class of coal-fired utility boilers for which means to reduce NO_x emissions have not been developed. They also have the highest NO_x emissions of any utility boiler coal firing system (in excess of 1,000 ppm at 3% O_2, dry basis). When the NO_x generation has been as high on other type boilers, and the mechanism controlling the rate of NO_x formation have been understood, then relatively simple operating adjustments have led to 40% to 80% nitric oxide emission reductions.

Published literature on NO_x emissions from coal-fired cyclone units do not indicate that any substantial program has been undertaken to explore the operating variables which could influence NO_x formation, these include:

1. Primary air flow
2. Tertiary air flow
3. Coal fineness
4. Excess air
5. Combustion air temperature
6. Staged combustion air

Load reduction of 20% has been shown to reduce NO_x emissions by 25%, which suggests that NO_x emissions might be reduced by reducing the peak temperature achieved in the cyclone. The temperature must be sufficiently high to maintain the ash in the cyclone furnace in a molten state, but excessive flue gas temperature would only serve to generate additional NO_x. The addition of fluxing agents to the coal to reduce ash fusion temperature might permit further lowering of flue gas temperature by such means as water injection, gas recirculation, or lower air preheat.

Staged firing has been attempted by varying fuel supply to individual cyclone furnaces but has not been effective. It is suspected that the increased heat release in the majority of the cyclones offset any reduction in NO_x generation produced by excess air variation in individual cyclones.

PROPOSED PROGRAM

It is proposed that a boiler with four cyclone furnaces in one wall be selected for testing to develop an understanding of the influence of operating variables on NO_x emissions. The program would be conducted in two phases.

In the first phase, the unit would be tested as normally operated to ascertain variations in NO_x emissions from individual cyclones by furnace probing at the outlet of each cyclone. Measurements at the economizer outlet would establish the NO_x generated in the overall bulk gas. It is expected that variations in NO_x from individual cyclones of several hundred ppm may occur. Significant differences would be examined in terms of air distribution, fuel distribution, excess air, slagging, or damper settings. Fuel and air metering to individual cyclones would be used to verify excess air measurements and heat release. This phase of the work will first establish if the NO_x varies with cyclone operation and the reasons why it varies; and then secondly it would establish the gains, if any, which could be made through individual cyclone excess oxygen monitoring and adjustment.

In the second phase, the following variables would be investigated with uniform air and fuel to each cyclone furnace.

1. Excess air
2. Primary air
3. Tertiary air
4. Combustion air temperature
5. Coal fineness
6. Boiler load

It has been observed that oil-fired cyclones exhibit the characteristic of premixed flames in that high O_2 results in a decrease in NO_x. If coal-fired cyclones exhibit similar behavior or if a substantial amount of NO_x is generated in the bulk gas, staged combustion air with uniform fuel flow to each cyclone furnace would also be investigated.

Fuel and ash properties will have a considerable bearing on the ability to modify operation without interfering with normal slagging conditions in the cyclone. The range of fuels available would be a consideration in selecting a test site. The base fuel should be one permitting maximum flexibility in cyclone operation. Thus the possible reductions and the controlling mechanisms will be established through this probing and adjustment program. A second, additional fuel type will be tested to explore and demonstrate fuel difference problem areas.

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16. ABSTRACT

Cyclone furnaces are a significant source of stationary NO_x emissions. It was estimated that 0.76 x 10^6 tonnes of NO_x (over 6% of stationary source NO_x) were emitted from all cyclone-coal-fired utility boilers in 1973. This represents from 19% to 22% of the total NO_x emissions from all coal-fired utility boilers in the U.S.

Several techniques of combustion modifications were applied in the past to cyclone boilers/furnaces in an attempt to lower their NO_x emissions. These include boiler load reduction, low excess air firing, two-stage firing, and switching fuels. This report summarizes available NO_x emission data when applying these techniques to cyclone boilers/furnaces. Even though significant reductions in NO_x were achieved, none of the techniques was shown to reduce NO_x emissions to the level meeting the New Source Performance Standard.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Nitrogen Oxides	Stationary Sources	07B
Boilers	Cyclone Boilers	13A
Furnaces	Combustion Modification	
Combustion	Emission Factors	21B
	NOx Reduction	

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